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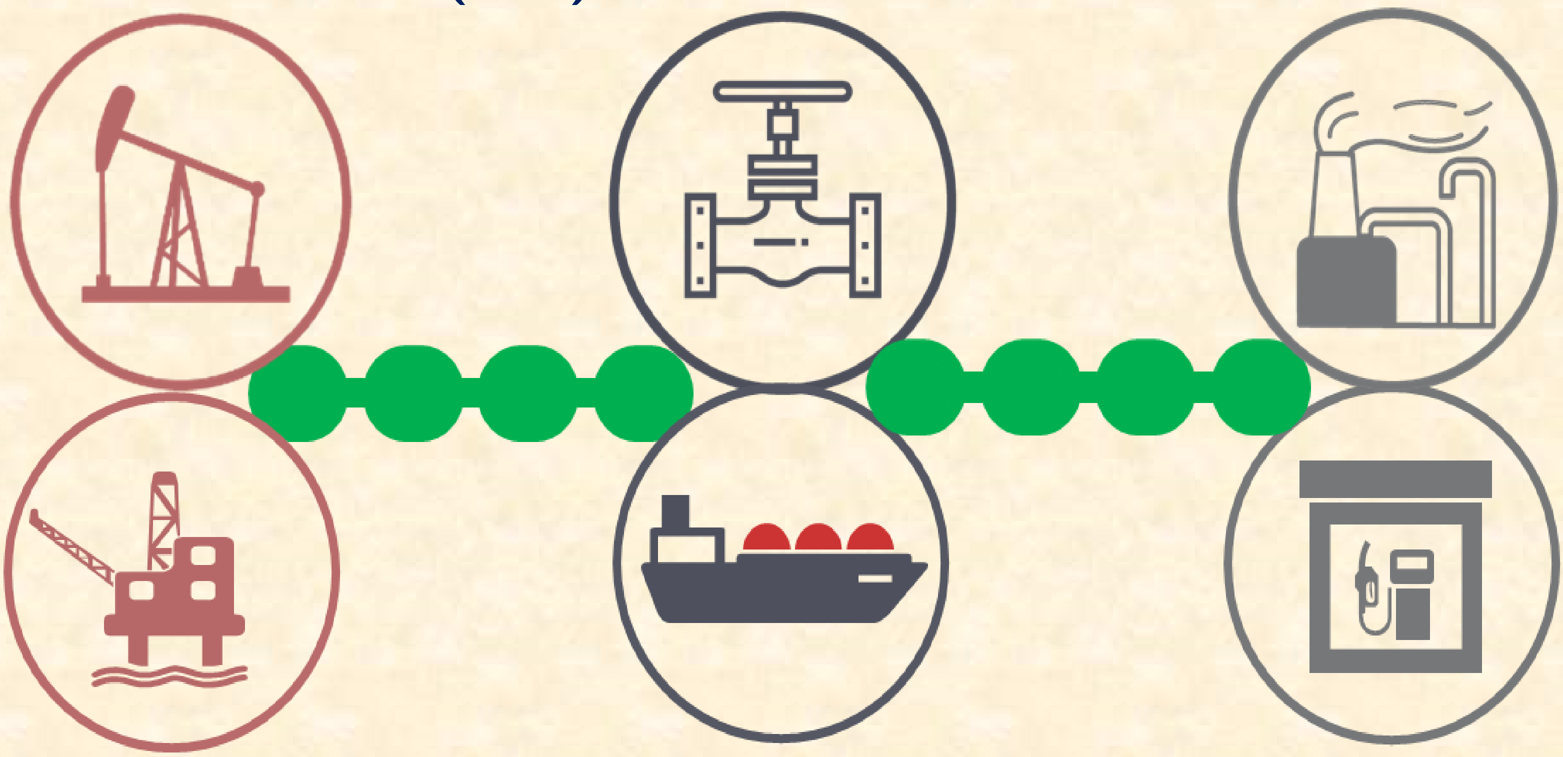
SARI/EI

IRADe Integrated Research and Action for Development

SOUTH ASIA REGIONAL INITIATIVE FOR ENERGY INTEGRATION (SARI/EI)

Study on assessment of the Cross Border Natural Gas Trading (CBNGT) potential in South Asian countries

IRADe-SARI-39 (2021)



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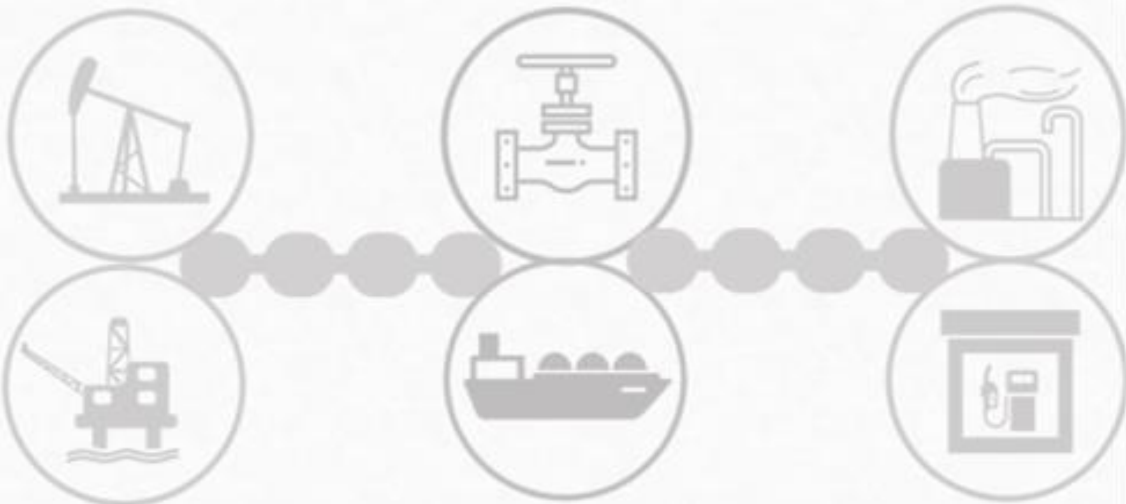

South Asia Regional Initiative for Energy Integration (SARI/EI)

ASSESSMENT OF THE CROSS BORDER NATURAL GAS TRADING (CBNGT) POTENTIAL IN SOUTH ASIAN COUNTRIES

IRADe-SARI-39 (2021)

Prepared by:

SARI/EI Secretariat

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IRADe-SARI-39 (2021)

Preface

We are delighted to present the study on "Assessment of the cross border natural gas trading (CBNGT) potential in South Asian countries", developed under the South Asia Regional Initiative for Energy Integration (SARI/EI) program, supported by the USAID and with Integrated Research and Action for Development (IRADe) as its implementing partner.

The SARI/EI program, in its fourth phase, focuses on the facilitation and creation of a regional energy market. The present study on assessing the potential of cross border natural gas trade is an important step in this direction, particularly when each of the eight countries of the region have distinctive economic profiles, energy consumption patterns and energy basket. Cross border energy trade, by using these complementarities, will certainly be beneficial for all the countries in the region.

In the past few years, the region has witnessed decline in indigenous gas production. India, Pakistan and Bangladesh have commenced import of gas as LNG for its economic benefits and these imports accounted for 60 percent, 26 percent, and 18 percent of the natural gas consumption respectively. The emergence of economical technology for transportation and distribution of LNG by road also popularly known as small-scale LNG (ssLNG) provides access to natural gas even without trunk pipelines. Considering that the South Asian countries are densely populated, it is expected to be a key enabler for penetration of gas in regions not connected by pipelines, and is promising for the growth of natural gas.

The study focuses on creation of a benchmark gas hub in the SAR that would lead towards development of institutional framework to promote fair, transparent and liquid gas market in the SAR. It provides country-wise snapshot where an as-is assessment for the gas sector has been done and long-term projections for demand and supply have been worked out. The study also captures aspects like gas ecosystem for each country including assessment of current gas demand and supply, gas value chain, infrastructure, regulations and policies, and pricing have been prepared.

I am very thankful to USAID for their continued and extensive support in the preparation of this paper. I also thank and appreciate the team at SARI/EI Secretariat at IRADe, for their sincere and sustained work and valuable contributions to complete the report, as well as to Mr. Swami Dayal Prasad, Advisor IRADe and M/s Deloitte Touche Tohmatsu India LLP for rendering all the technical support to the study.

Jyoti Parikh

Dr. Jyoti Parikh

Foreword

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) program. 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 the South Asia Regional Initiative for Energy Integration (SARI/EI), which was launched in 2012, focuses on advancing 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.

South Asia has immense potential for growth and hence demand for energy. As the world recovers from the COVID-19 pandemic, regional energy cooperation could play an instrumental role in building a cleaner, greener, and sustainable future with universal access to affordable, reliable, and clean energy for all. Regional energy cooperation would also propel South Asia's transition to a thriving and sustainable economy.

I am delighted to note that SARI/EI has finalized a strategy paper on the concept of a regional gas energy hub to help the countries in the South Asia region towards transition to cleaner fuels. The strategy paper identifies the need for optimal utilization of the gas infrastructure within the region, assesses the opportunities for Cross-Border Natural Gas Trade (CBNGT) and presents how this trade would help address the volatility in demand within the region with minimal investment in infrastructure. As cross-border trade and an institutional framework matures, South Asia may establish its own pricing benchmarks or index, which would further foster trade and promote liquid gas markets.

I would like to commend the excellent work done by the SARI/EI team at IRADe and Deloitte Touche Tohmatsu India LLP (Deloitte) in developing this paper. I hope the paper serves as a useful resource for all stakeholders in the region in the transition to clean energy.

Sincerely,

John Smith-Sreen

John Smith-Sreen
Director, Indo Pacific Office,
USAID/India

Report Outline

Under the SARI / EI initiative, another report on this subject ***'Analytical Study to Assess the Potential of Gas / LNG for Regional Energy Cooperation in BBINS Region'***, was released on 27th July 2021. The earlier report indicated that while there would be growth in demand for gas due to enablers viz policies, investments and economic benefits, the domestic production is declining in India, Bangladesh and Pakistan, and the dependence on LNG imports is likely to increase. The report also concluded that dependability on long-term availability of LNG at fair prices and terms appears fairly reliable. On the basis of the demand-supply scenario of respective countries, it emerged that India, with its upcoming infrastructure (i.e. LNG import terminals and the pipelines), could be surplus in gas, and in a good position to supply gas to neighbouring countries. The report also identified the possible options of cross border natural gas trade.

During the course of our interactions with stakeholders, it had emerged that the findings need to be supported by more definitive research to include the entire South Asia region comprising of Afghanistan, Bangladesh, Bhutan, India, Maldives, Nepal, Pakistan and Sri Lanka. Based on this request a detailed modelling study on the subject has been carried out and the current report has been finalised, in order to include the following main points:

- A thorough sector-wise analysis of demand- supply for the respective countries, so that the surpluses and shortfalls within the region can be identified;
- Identification of emerging opportunities for CBNGT, the different modes of trade and the potential economic benefits for the region;
- Analysis of the factors for the development of gas hubs in the SAR to support fair and transparent trade and in establishing a credible 'Benchmarking' gas hub in SAR;

The report has considered the gas ecosystem for the respective countries for arriving at the gas demand and supply analysis. Scenario mapping has also been carried out to incorporate the unforeseen and the uncertain. The report has also reviewed the implementation of a few cross-border projects and gas-hubs across the globe, and elicits the benefits of the learning curve which can be specifically applied in the South Asia region. It recommends CBNGT for optimal utilization of the available gas infrastructure with the aim to bridge the gap in energy inequality faced by the South Asia Region. The draft report was shared with stakeholders and their views have been suitably considered and included.

I acknowledge the committed and meticulous inputs of Deloitte in developing the demand-supply model, the research and analysis for fostering CBNGT in the SAR and in compilation of the report. I also thank SARI/EI, IRADe and the USAID for their support and associating me in this study.

(Swami Dayal Prasad)
Advior – IRADe and Former ED (Fuel Management), NTPC

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Abbreviations

Abbreviations	Full Form
ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
AEPC	Alternative Energy Promotion Centre
AFC	Annual Fixed Cost
AFCL	Ashuganj Fertiliser Company Limited
AGCL	Assam Gas Company Limited
AGE	Afghanistan Gas Enterprise
AOGRA	Afghanistan Oil and Gas Regulatory Authority
APGDC	Andhra Pradesh Gas Distribution Corporation Limited
APM	Administered Pricing Mechanism
APPI	Asia Pacific Petroleum Price Index
AREP	Alternative Renewable Energy Policy
ARISE	Accelerating Renewable Energy Integration and Sustainable Energy
ASPIRE	Accelerating Sustainable Private Investment in Renewable Energy
BAPEX	Bangladesh Petroleum Exploration and Production Company Limited
BCPL	Brahmaputra Cracker and Polymer Limited
BESS	Battery Energy Storage System
BGDCL	Bakhrabad Gas Distribution Company Limited
BGFCL	Bangladesh Gas Fields Company Limited
BNEF	Bloomberg NEF
BOOT	Build Own Operate Transfer
BP	British Petroleum
BPC	Bangladesh Petroleum Corporation
BPCL	Bharat Petroleum Corporation Ltd.
BPDB	Bangladesh Power Development Board
BTC	Baku-Tbilisi-Ceyhan
BTU	British Thermal Units
BVFCL	Brahmaputra Valley Fertiliser Corporation Limited
C and F	Cost and Freight
CAGR	Compounded Annual Growth Rate
CBG	Compressed Biogas
CBM	Coal Bed Methane
CBNGT	Cross Border Natural Gas Trade
CEA	Central Electricity Authority of India
CEB	Ceylon Electricity Board
CEEW	Council on Energy, Environment and Water
CGD	City Gas Distribution
CNG	Compressed Natural Gas
COP21	Conference of Parties

CPC	Ceylon Petroleum Corporation
CPEC	China Pakistan Economic Corridor
CPSTL	Ceylon Petroleum Storage Terminals Ltd.
CUFL	Chittagong Urea Fertilisers Limited
DABS	Da Afghanistan Breshna Sherkat
DCU	Delayed Coker Unit
DES	Delivered Ex Ship
DGH	Directorate General of Hydrocarbons
DME	Dimethyl Ether
DoT	Department of Trade
DSF	Discovered Small Fields
E & P	Exploration and Production
EETL	Engro Elengy Terminal Limited
EIA	Energy Information Administration
EMRD	Energy and Mineral Resources Division
EV	Electric Vehicle
EWPL	East-West Pipeline
FCCU	Fluid Catalytic Cracking Unit
FERC	Federal Energy Regulatory Commission
FO	Furnace Oil
FSM	Fuel Supplies Maldives Ltd.
FSRU	Floating Storage and Regasification Unit
GAIL	Gas Authority of India Limited
GAs	Geographical Areas
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GDS	Gas Development Surcharge
GEECL	Great Eastern Energy Corporation Ltd.
GEF	Global Environment Facility
GGL	Green Gas Ltd.
GIGL	GSPL India Gasnet Ltd.
GITL	GSPL India Transco Ltd.
GPUFP	Ghorashal Polash Urea Fertiliser Project
GSMP	Gas Sector Master Plan
GSPC	Gujarat State Petroleum Corporation
GSPL	Gujarat State Petronet Ltd.
GST	Goods and Services Tax
GTCL	Gas Transmission Company Limited
GUMP	Gas Utilisation Master Plan
HCU	Hydrocracker Unit
HCV	Heavy Carrier Vehicles
HDC	Heavy Duty Vehicles

HELP	Hydrocarbon Exploration Licensing Policy
HEPL	H-Energy Private Limited
HMEL	HPCL Mittal Energy Limited
HPCL	Hindustan Petroleum Corporation Ltd.
HPHT	High Pressure High Temperature
HPL	Haldia Petrochemicals Limited
HPPL	Hooghly Pipelines Private Limited
HRRL	HPCL Rajasthan Refinery Limited
HSD	High Speed Diesel
HSFO	High Sulphur Fuel Oil
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IEX	Indian Energy Exchange
IGGL	Indradhanush Gas Grid Limited
IGL	Indraprastha Gas Ltd.
IGX	Indian Gas Exchange
IMC	IMC Limited
IMF	International Monetary Fund
IMO	International Maritime Organisation
INDC	Intended Nationally Determined Contribution
INR	Indian National Rupee
IOCL	Indian Oil Corporation Limited
IPP	Iran Pakistan Pipeline
IRENA	International Renewable Energy Agency
ISGS	Interstate Gas Systems
ITLOS	International Tribunal for Laws of Seas
JFCL	Jamuna Fertiliser Company Limited
JGTDSL	Jalalabad Gas Transmission and Distribution Systems Limited
JHBDPL	Jagdishpur Haldia and Bokaro Dhamra Pipeline
JKM	Japan Korea Marker
JV	Joint Venture
JWG	Joint Working Group
KAFCO	Karnaphuli Fertiliser Company Limited
KGDCL	Karnaphuli Gas Distribution Company Limited
KPK	Khyber Pakhtunkhwa
LCNG	Liquified Compressed Natural Gas
LCV	Light Carrier Vehicles
LDO	Light Diesel Oil
LIOC	Lanka Indian Oil Corporation
LKR	Lankan Rupee
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas

LTGEP	Long-Term Generation Expansion Plan
LTL	Lakdhanavi Limited
MCFL	Mangalore Chemical and Fertilisers Limited
MEPD	Ministry of Energy – Petroleum Division
MEW	Ministry of Energy and Water
MFL	Madras Fertilisers Limited
MGL	Mahanagar Gas Ltd.
MMBTU	Million Metric British Thermal Units
MMTPA	Million Metric Ton Per Annum
MNOC	Maldives National Oil Company
MoE	Ministry of Energy, Water Resource, and Irrigation
MoI	Ministry of Industries
MoEA	Ministry of Economic Affairs
MOMP	Ministry of Mines and Petroleum
MOPEMR	Ministry of Power, Energy, and Mineral Resources
MoPNR	Ministry of Petroleum and Natural Resources
MoU	Memorandum of Understanding
MPRD	Ministry of Petroleum Resources Development
MPCL	Mari Petroleum Company Limited
MWP	Minimum Work Programme
NAESB	North American Energy Standards Board
NBP	National Balancing Point
NBT	Nation Building Tax
NCR	National Capital Region
NDC	Nationally Determined Contribution
NDR	National Data Repository
NELP	New Exploration Licensing Policy
NEP	National Electricity Policy
NEPRA	National Electric Power Regulatory Authority
NGPL	Natural Gas Plant Liquids
NIGC	National Iranian Gas Company
NOC	Nepal Oil Corporation
NOCs	National Oil Companies
NPNG	National Policy on Natural Gas
NR	Nepalese Rupee
NTPC	National Thermal Power Corporation
NUP	National Urea Policy
NZE	Net Zero Emissions
OALP	Open Acreage Licensing Policy
OEM	Original Equipment Manufacturer
OGDCL	Oil and Gas Development Corporation
OGRA	Oil and Gas Regulatory Authority

OGV	Ocean Going Vessels
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation Limited
ORE	Other Renewable Energy
OVL	ONGC Videsh Ltd.
PAL	Port and Airports development Levy
PDASL	Petroleum Development Authority of Sri Lanka
PEPP	Petroleum Exploration Promotion Project
PGCL	Pashchimanchal Gas Company Limited
PGPCL	Pakistan GasPort Consortium Limited
PKR	Pakistani Rupee
PLF	Plant Load Factor
PLL (in Pakistan section)	Pakistan LNG Limited
PLL (in India section)	Petronet LNG Limited
PNG	Piped Natural Gas
PNGRB	Petroleum and Natural Gas Regulatory Board
POL	Petroleum, Oil and Lubricants
PPAC	Petroleum Planning and Analysis Cell
PPL	Pakistan Petroleum Limited
PPP	Public Private Partnership
PRE	Price Reporting Entities
PSC	Production Sharing Contract
PSMP	Power Sector Master Plan
PSO	Pakistan State Oil
RE	Renewable Energy
REDF	Renewable Energy Development Fund
RFCL	Ramagundam Fertilisers and Chemicals Limited
RGoB	Royal Government of Bhutan
RGPL	Reliance Gas Pipeline Limited
RHCU	Residue Hydrocracker Unit
RIL	Reliance Industries Limited
RLNG	Regasified Liquefied Natural Gas
RoW	Right-of-Way
RPO	Renewable Purchase Obligation
RSP	Retail Selling Price
SAR	South Asian Region
SAARC	South Asian Association of Regional Cooperation
SAFTA	South Asian Free Trade Area
SAGE	South Asian Group for Energy
SAP	Strategic Action Plan
SEA	Sustainable Energy Authority
SFCL	Shahjalal Fertiliser Company Limited

SGCL	Sundarban Gas Company Limited
SGFL	Sylhet Gas Fields Limited
SHR	Station Heat Rate
SNGPL	Sui Northern Gas Pipelines Limited
SOCAR	State Oil Company of Azerbaijan Republic
SPIC	Southern Petrochemical Industries Corporation
SSGCL	Sui Southern Gas Company Limited
ssLNG	Small Scale Liquefied Natural Gas
STBCL	State Trading Corporation of Bhutan
STO	State Trading Organization PLC
TANAP	Trans Anatolian Pipeline
TAP	Trans Adriatic Pipeline
TAPI	Turkmenistan-Afghanistan-Pakistan-India
TCO	Total Cost of Ownership
TGDCL	Titas Gas Distribution Company Limited
TPA	Third Party Access
TPCL	TAPI Pipeline Company Limited
TSO	Transmission System Operator
TTF	Title Transfer Facility
UCG	Underground Coal Gasification
UEPL	United Energy Pakistan Limited
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
USGS	US Geological Survey Program
VAT	Value Added Tax
VTP	Virtual Trading Point

Executive summary

1. Background

The South Asian Region (SAR) is represented by the following eight countries: India, Bangladesh, Pakistan, Bhutan, Sri Lanka, Nepal, Maldives, and Afghanistan. The SAR accounts for 7.7 percent of the primary energy consumption[1] and 3.6 percent of the natural gas consumption of the world[2] while the contribution of the region to global population is 24 percent.[3]

SAR hugely depends on petroleum, oil, and lubricant fuels for meeting its energy demand and for gas consuming nations (India, Pakistan, Bangladesh and Afghanistan), share of natural gas is ~12.5 percent of energy consumption (imported gas constitutes ~40 percent of total gas consumption).

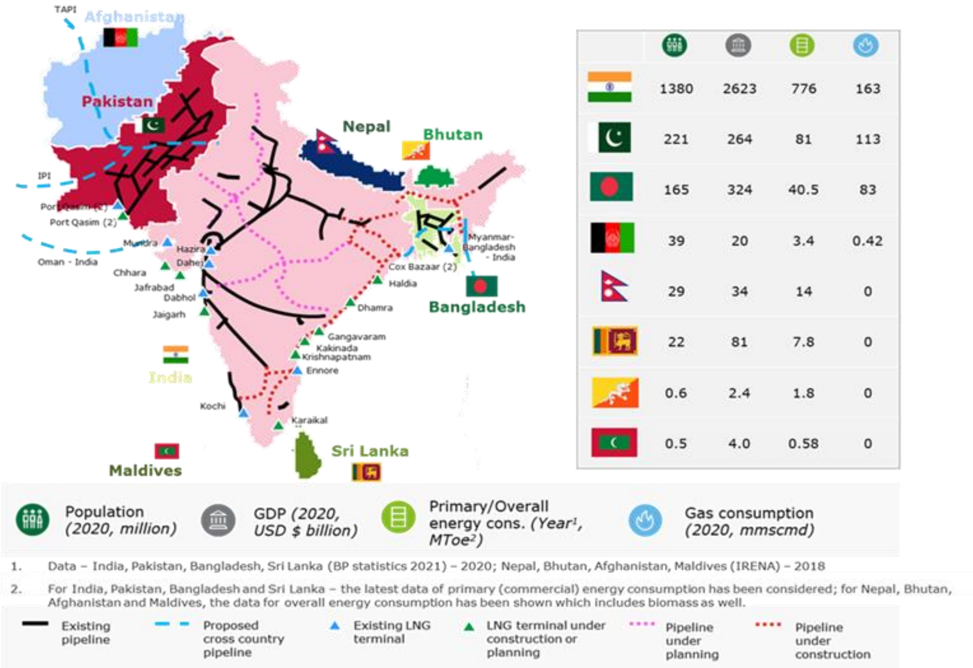
Oil accounts for ~28 percent of the energy consumption in India;[4] 20-25 percent in Pakistan and Bangladesh;[5] and more than 40 percent in Sri Lanka and Afghanistan.[6]Maldives, as of now, depends on POL fuels for its energy need.[7]Net import bills in the region for POL fuels were ~US$ 93 billion for 2020, accounting for ~14-20 percent of the overall import bill of the region.

Natural gas is a cleaner option as compared to liquid fuels, such as petrol , High-Speed Diesel (HSD), Furnace Oil (FO), etc. Post the recent COP26 summit at Glasgow, majority of the world's economies (US, UK, France) have set a target to achieve Net Zero Emissions (NZE) by 2050 while India and China have committed to achieve NZE by 2070 and 2060 respectively.[8] With these targets being set at national levels, gas[9] can help the countries in their energy transition to cleaner fuels and help decarbonise the world economy. According to the BP Statistical Review, natural gas trade increased at a CAGR of ~4 percent from 670 bcm in 2009 to more than 985 bcm in 2019 .[10]This indicates a major uptake in the global natural gas market during the past decade. In addition, growth in global LNG liquefaction capacities and shipping quantities, along with attractive trends in pricing and conditions of LNG contracts, makes LNG a dependable imported fuel option.

Discovery of oil and gas has a long history in the SAR with the major fields being discovered from 1950s to 1980s in India, Pakistan, and Bangladesh. These discoveries led to the subsequent development of pipeline infrastructure and development of gas-based economy, particularly in Pakistan and Bangladesh. Currently, the share of natural gas is ~12.5 percent of the energy consumption in the region with the imported gas constituting ~40 percent of total gas consumption. The figure below represents the summary of key statistics (population, GDP, primary energy consumption, and gas consumption) along with gas infrastructure in the region:

[1] *BP Statistical Review of World Energy*
[2] *BP Statistical Review of World Energy*
[3] *IMF, World Bank*
[4] *Energy Statistics of India, 2021*
[5] *EMRD, HDIP*
[6] *BP Statistical Review, IRENA*
[7] *IRENA*
[8] *https://www.wri.org/insights/how-countries-net-zero-targets-stack-up-cop26*
[9] *The terms "natural gas" and "gas" have been used interchangeably in the report.*
[10] *BP Statistical Review of World Energy*

Figure I Summary of key statistics and gas infrastructure in the SAR



As provided in the figure above, four South Asian countries, namely, India, Pakistan, Bangladesh, and Afghanistan have contribution of gas in their overall energy mix while other countries have remained untouched from the benefits of gas use. Afghanistan has discovered some gas reserves and production has commenced on a low scale as compared to the other three gas consuming countries. Sri Lanka is pursuing exploration of its basins in a pro-active manner as its discoveries have not yielded producible oil and gas. Nepal has a pilot gas project on a small scale but is yet to strike commercially viable gas reserves. Bhutan and Maldives do not have oil and gas basins.

In the past few years, the region has witnessed decline in indigenous gas production, and to address this, backed by economic benefits of imported LNG over imported petroleum products, India, Pakistan and Bangladesh have commenced import of gas as LNG. Imports accounted for 60 percent, 26 percent, and 18 percent of the natural gas consumption in case of India, Pakistan, and Bangladesh, respectively, for FY 2020.[11] India in particular has several LNG receiving terminals under implementation and has also invested in implementing related pipeline infrastructure. Sri Lanka too has announced plans to implement an LNG importing terminal. The emergence of economical technology for transportation and distribution of LNG by road also popularly known as small-scale LNG (ssLNG) also provides the consumers access to natural gas even without trunk pipelines. Considering that the South Asian countries are densely populated, it is expected to be a key enabler for penetration of gas in regions not connected by pipelines, and augers well for the growth of natural gas.

2. Objective

Natural gas can help the countries of the SAR in their energy transition to cleaner fuels and help decarbonise the world economy. The assessment of the demand in respective countries of the region would provide a perspective for consumers as well as policy makers to evaluate the fuel choices. The need for optimal utilisation of the gas infrastructure within the region can provide opportunities for Cross-Border Natural Gas Trade (CBNGT). CBNGT would also help to fulfil the volatility in demand within the region with minimal investment in infrastructure. With maturity in cross-border trade and institutional framework, over a period of time, the region can aim to establish its own pricing benchmarks or index, which would further foster trade and establish liquid gas markets.

[11] *PPAC, BP Energy Statistics*

In view of the importance of CBNGT in the South Asian region and achieving optimal utilisation of the gas infrastructure as well as economies of scale, the study has been conducted under USAID's South Asia Regional Initiative for Energy Integration (SARI/EI) programme by Integrated Research and Action for Development (IRADe). Following are the major objectives of the study: (i) evaluating long-term natural gas demand and supply potential; (ii) assessing cross-border natural gas trade potential and its benefits; and (iii) promoting the gas market's growth in the South Asian Region (SAR).

3. Key findings

The findings and results of the study have been based on country-wise analysis of the gas ecosystem to make projections of expected gas demand and supply upto FY 2040.

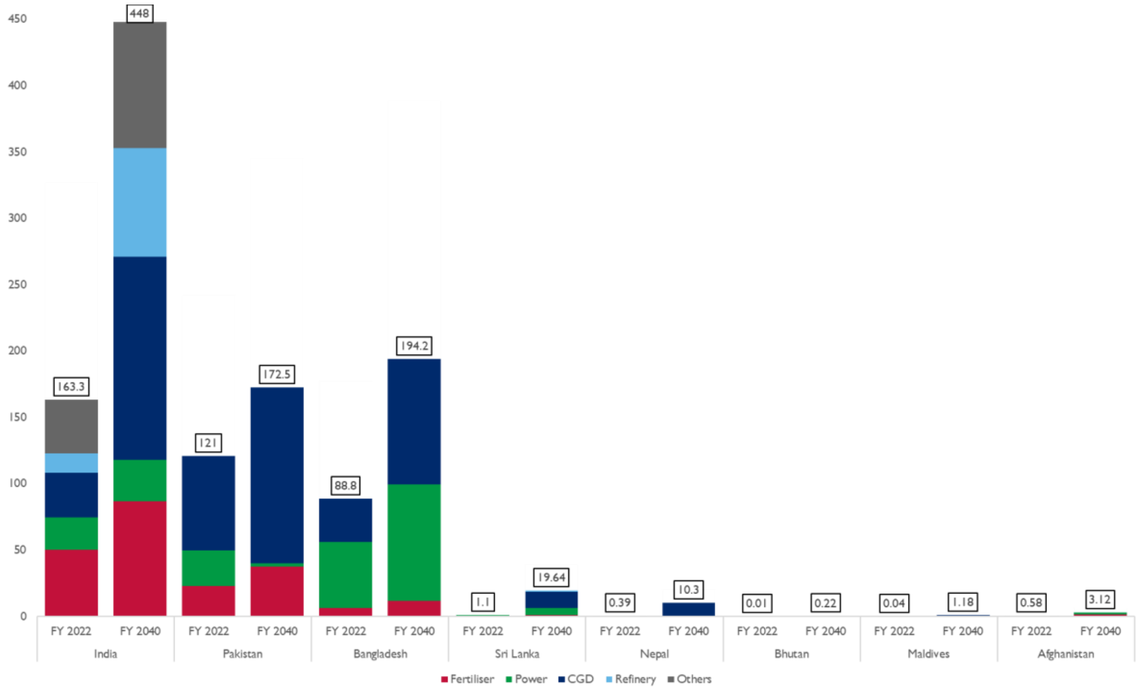
In the SAR, the gas demand is expected to increase at a CAGR of ~4.4 percent from FY 2022 to FY 2040 and net supply is expected to increase from FY 2022 to FY 2040 at a CAGR of ~3 percent (imported gas constituting ~81 percent of as supply by FY 2040).

Following table shows the summary of country-wise demands-supply analysis in the SAR:

Table 1 Summary of projected demand and supply in the SAR (in the most plausible scenario)

Country	FY 2022				FY 2040			
	Demand	Domestic Supply	Imports	Supply Deficit	Demand	Domestic Supply	Imports	Supply Deficit
India	163	89	92	17	448	42	310	-96
Pakistan	121	76	20	-25	172	34	130	-8
Bangladesh	89	64	23	-2	194	42	53	-99
Sri Lanka	1.1	0	0	-1.1	19.6	0	3.6	-16
Nepal	0.4	0	0	-0.4	10.3	0	0	-10.3
Bhutan	0.01	0	0	-0.01	0.22	0	0	-0.22
Maldives	0.04	0	0	-0.04	1.18	0	0	-1.18
Afghanistan	0.58	0.5	0	-0.1	3.13	1.8	0	-1.3
Total	**375**	**230**	**135**	**-12**	**848**	**120**	**497**	**-203**

Figure 2 Summary of increase in sector-wise natural gas demand in the SAR from FY 2022 to FY 2040 (in mmscmd)



***Note:** Refer to "Country-wise snapshots" for country specific details of demand and supply estimation.*

Infrastructure constraints have been a key deterrent of using natural gas in the SAR amongst other aspects like demand-supply challenges and policy regulations.

As of now, the SAR faces challenges in terms of demand-supply, infrastructural development and policy regulations that need to be addressed for the development of a regional gas ecosystem. Few challenges with respect to infrastructure in the region are delays in completion of gas infrastructure (pipelines and LNG terminals), cancelled LNG projects, inadequate connectivity in the region, security concerns for the completion of cross-country pipelines, and geographical constraints with respect to the location of countries.

Other challenges in the region pertaining to demand-supply and policy regulations have been declining domestic gas production leading to increased dependence on imports, no major incentives in the region for switching to gas from other polluting fuels, lack of regional trade financing, complex policies for investments in the sector, and non-existence of gas in certain countries.

Changing dynamics in the region along with construction of cross-border infrastructure to transport gas can mitigate some of the issues that have been a deterrent in the past.

Despite the challenges being faced in the SAR, the gas industry has seen changes in several dynamics, such as the policy push towards cleaner fuels, emergence of unconventional gas supply options, and newer technologies for existing/new uses in segments such as transportation, city gas distribution, and power production. These factors together present a huge opportunity for the SAR to spur both gas demand and supply. For the commencement of cross-border trade, several infrastructure options are available for the SAR:

- **Regional gas pipeline network:** Pipelines could be a suitable means of transport from India to other high-demand countries, such as Nepal and Bangladesh, which are near to the eastern coastline of India. In addition, the economics of laying undersea pipelines to connect Sri Lanka and Maldives could be explored to enable trade with island nations.
- **ssLNG through the LNG hub and spoke model:** ssLNG can transport natural gas through unconventional transportation mediums, such as cryogenic containers and vessels, in a liquid state. The typical supply chain of the ssLNG system will consist of LNG receiving terminal, transport system, and satellite regasification station. LNG growth has led to technological developments in end-user markets, especially in the US and China, for growth of ssLNG. Both the US and China have revamped policies and regulations in the form of rebates, tax exemptions, loans, and purchase criteria in tenders to promote LNG as a transport fuel. India also presents significant opportunities for LNG demand in the transport sector. This can play a major role in boosting the overall ssLNG ecosystem. For a ssLNG hub and spoke model, a centralised LNG hub/facility will be developed to distribute LNG to demand destinations. This can be used to serve demand centres with lower demand that cannot be connected to a pipeline network. Moreover, capex requirements for commencing a ssLNG-based model are significantly lower compared with pipeline-based transportation. The ssLNG hub and spoke model can be used to primarily serve Bhutan (where demand will be low) and certain remote locations in Nepal and Bangladesh where pipeline construction is not feasible. The Hambantota LNG terminal can be a potential hub for an LNG hub and spoke model amongst India, Sri Lanka, and Maldives.

Given the diverse geography and geopolitical considerations embedded in energy discussions in SAR, a regional pipeline network can be combined with an LNG hub and spoke model. The following is the summary of cross-border infrastructure options by country:

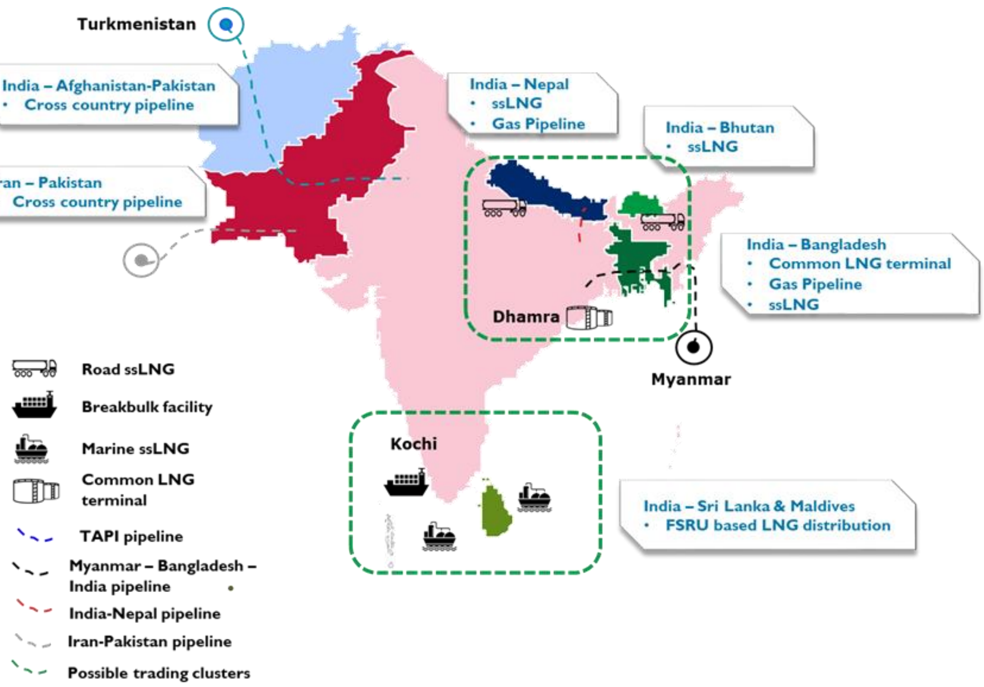


Figure 3 Cross-border infrastructure options in the SAR

Several trading infrastructure options can be created between countries:

- **India-Bangladesh:** The potential opportunity for facilitating natural gas trade between India and Bangladesh can be carried out through pipeline infrastructure, and a joint RLNG facility in the Bay of Bengal. For creation of the pipeline infrastructure, the North-Eastern (NE) gas grid needs to be completed on time to create an inter-connected gas grid and facilitate trade across nearby regions of Bangladesh with India. The feasibility assessment of creating a joint RLNG terminal will involve assessing the flexibility of port location to hold breakbulk facilities and ensure lower shipping costs. In addition, the ownership structure and financing options of the joint LNG terminal will also need to be decided.
- **India-Bhutan:** India and Bhutan have initiated regional trade relations through the purchase of power from hydro-electric projects in Bhutan. The primary sources of carrying out trade with Bhutan will be through road transportation from ssLNG and pipeline infrastructure. However, as demand in Bhutan is not expected to go beyond 0.5 mmscmd, building a pipeline from India to Bhutan might not be economically feasible. Thimphu, Chukha, and Samtse are the districts with the highest population density in Bhutan that can be supplied ssLNG from India from the Dhamra, Kukrahati, or Haldia terminals.[12] These terminals would need to be connected with a well-established road network for supplying to Bhutan.
- **India-Nepal:** The primary sources of carrying out trade with Nepal will be through road transportation and pipeline infrastructure as Nepal is a land-locked country. Dedicated pipeline infrastructure can be built between India and Nepal (to high demand areas such as Amlekhgunj, Kathmandu, and Biratnagar) and connected to the existing CGD network through sub-transmission pipelines. LNG supplies can be made in the form of ssLNG from the Kukrahati, Haldia, and Dhamra terminals from India.
- **India-Sri Lanka-Maldives:** Natural gas trade between India, Sri Lanka, and Maldives can be facilitated through ssLNG. India, Sri Lanka, and Maldives can carry out joint natural gas demand assessment studies to identify anchor customers for gas. Thereby, an FSRU-based LNG hub and spoke distribution model in Sri Lanka, Maldives, and India could be considered for carrying out natural gas trade amongst the nations. Kochi and Ennore terminals need to augment a breakbulk facility and have a well-established sea transportation route with Sri Lanka and Maldives.
- **Pakistan-Afghanistan:** The trade between both the countries can happen through ssLNG.
- **Myanmar-South Asian Region:** Myanmar has significant potential for gas. However, the country is unable to meet its domestic demand on account of its export commitments to Thailand and China. In view of the country's increasing gas demand and no significant upcoming gas production, Myanmar is expected to import gas/LNG in future. Pipeline connectivity of Myanmar to Bangladesh and further to

[12] *Population and Housing Census of 2017, Bhutan*

India can be explored for meeting the country's gas deficit. Alternatively, if there are new discoveries with potential for exports, gas can be supplied from Myanmar to Bangladesh and further to India.

Global examples of using break-bulk LNG and developing markets in vicinity exist including pipeline trade amongst countries that are not politically aligned.

Several key learnings can be adopted for SAR from the global examples as provided below.

- **Setting up regional/sub-regional LNG terminals:** The terminal built by Sempra Energy Mexico provides the learning for having a regional gas hub to supply the excessive gas to neighbouring countries after meeting the needs of local industries. The under-construction Dhamra terminal has the potential to become a hub for supply to nations such as Bangladesh, Nepal and Bhutan.[13]
- **Breakbulk LNG terminals:** The breakbulk LNG terminals built by Golar LNG can provide learning in terms of distributing LNG to island nations. SAR countries, such as Maldives and Sri Lanka, with low gas requirements could benefit from a larger consumer (such as India) developing a breakbulk facility at Kochi or Ennore LNG terminals. Alternatively, the terminal could also be built in Sri Lanka on a hub-and-spoke model at Hambantota port.[14]
- **Pipeline development:** There are different learnings for the TAPI and IPP pipelines that can be taken from global case studies of the Siberia, BTC, TAP and TANAP pipelines. The policies created during the construction of the BTC pipeline can also be contextually applied to the TAPI project for upholding the rights of local communities. Similar to the TAP and TANAP pipelines, the TAPI and IPP pipeline projects will need to undergo tough negotiations between the concerned governments.
- **Innovative infrastructure models:** Innovative infrastructure models, such as floating power plants, can help island economies, including Sri Lanka and Maldives, to transition towards cleaner fuels, such as LNG.

There is potential to import ~20-25 mmscmd natural gas by FY 2040 in the SAR (within most plausible scenario) by facilitating cross-border trade, resulting in potential savings of ~$US 338 million to the region along with environmental and social benefits.

Increasing gas demand in SAR, surplus and deficit amongst nations, benefits of gas over other fuels, and the widening demand-supply difference will be major contributors towards facilitation of cross-border trade. Basecase demand and supply of natural gas have been considered to assess the overall cross-border trading potential between the SAR countries. India is expected to be the main facilitator of cross-border natural gas trade within the region and supply gas/LNG to other member countries. Apart from India, Bangladesh can also act as a facilitator of cross-border trade provided it is able to build sufficient infrastructure. The combined trading potential of India with Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives in the most plausible scenario is expected to reach up to ~10-15 mmscmd by FY 2030 and ~20-25 mmscmd by FY 2040. However, there can be another scenario for cross-border trade if Bangladesh comes up with additional sources of supply through commencement of offshore domestic production (from FY 2028) and additional LNG import terminals within the country (from FY 2025). In this scenario, the combined trading potential of India with Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives would be ~5-10 mmscmd by FY 2030 and ~15-20 mmscmd by FY 2040.

Benefits from cross-border trade: The potential cross-border trading in the SAR is expected to bring several economic, environmental, and social benefits to member states.

- **Economic benefits:** The commencement of cross-border gas trade amongst countries will help in switching over to affordable gas compared with alternative fuels, thus resulting in economic benefits for nations. In addition to that, gas supply through intra-regional trade rather than importing it from outside the region can also provide savings in the region. Considering a potential benefit of US$1/mmbtu after commencement of intra-regional trade and the calorific value of gas as 10,000 kcal/scm, ~US$14.5 million of savings can be achieved each year on doing 1 mmscmd of gas trade. The following can be the country-wise potential annual savings considering the trade potential in both scenarios of cross-border trade:

[13] *Adani's Dhamra LNG terminal to help supply gas to Bangladesh, Myanmar", The Hindu, Apr-2018*
[14] *"ADB Funds Feasibility Study on Setting Up an LNG Hub in Sri Lanka", Sasec, Jun-2019*

Table 2 Potential economic benefits of cross-border trade in the SAR for basecase demand and supply in Bangladesh (most plausible scenario)

Country	Potential annual economic benefit in Mn US$ (by FY 2025)	Potential annual economic benefit in Mn US$ (by FY 2030)	Potential annual economic benefit in Mn US$ (by FY 2035)	Potential yearly economic benefit in Mn US$ (by FY 2040)
Bangladesh	64.9	119.5	136.4	144.6
Sri Lanka	2.8	9.7	17	23.2
Bhutan	0.5	1.3	2.4	3.2
Nepal	25.3	59.5	101.6	149.4
Maldives	2.2	7.0	13.4	17.1
Total savings in the region	**~96**	**~197**	**~271**	**~338**

Table 3 Potential economic benefits of cross-border trade in the SAR on increased supplies in Bangladesh from offshore production and additional imports

Country	Potential annual economic benefit in Mn US$ (by FY 2025)	Potential annual economic benefit in Mn US$ (by FY 2030)	Potential annual economic benefit in Mn US$ (by FY 2035)	Potential yearly economic benefit in Mn US$ (by FY 2040)
Bangladesh	44.6	23.8	79.8	93.6
Sri Lanka	2.8	9.7	17	23.2
Bhutan	0.5	1.3	2.4	3.2
Nepal	25.3	59.5	101.6	149.4
Maldives	2.2	7.0	13.4	17.1
Total savings in the region	**~75**	**~101**	**~214**	**~287**

For India, cross-border trade is expected to improve the capacity utilisation of gas infrastructure and enable formation of gas hub in the country.

- **Environmental benefits:** Natural gas has one of the lowest emissions of CO_2, NO_2, and methane compared with conventional fuels, such as coal, diesel, and FO. According to IEA, CO_2 emissions (per unit of energy produced) from gas are about 40 percent lower than coal and nearly 20 percent lower than oil. Moreover, emissions are ~95 percent less for NO_2 and ~90 percent less for methane compared with coal.[15] Natural gas can also serve as one of the potential transitioning fuels from conventional fossil fuels for the SAR nations to move towards achievement of their INDC targets of lower GHG emissions.
- **Social benefits:** Primary social benefits of intra-regional trade are expected in terms of the direct and indirect employment expected to be generated due to gas demand and creation of gas infrastructure.

Given the challenges, infrastructural options, trade potential, and benefits mentioned above, several enablers can exist in terms of demand-supply, policies and regulations, and varied geographies of individual member states for the commencement of cross-border trade. The key enablers for accomplishing cross-border gas trade in the SAR would be gas supplies from upcoming RLNG terminals, increase in domestic production by investment in newer technologies, timely completion of ongoing infrastructural pipeline projects (TAPI, IPP, Indradhanush Gas Grid, etc.), new policies for incentivising gas usage compared to alternate polluting fuels, feasibility assessment and development of trade routes (roadways or waterways) for gas trade, evolution of gas supply chain solutions (such as ssLNG), liberalisation of domestic gas pricing, and development of a regional energy database.

India is expected to be the main facilitator of cross-border natural gas trade initiatives in the SAR that would imply better infrastructure utilisation, negotiation of intra-regional contracts, creation of additional supply options, collaboration opportunities, and development of gas hub in the region.

There can be several benefits for the Indian players on the commencement of cross-border trade:

- **Better infrastructure utilisation:** Commencement of cross-border gas trading would result in creation of additional markets for companies operating LNG terminals and pipelines. This would eventually lead to improvement in their capacity utilisation and opportunities for the government to get attractive long-term contracts for LNG procurement from global markets.

[15] *IEA*

- **Negotiation of intra-regional contracts:** There are different types of trade arrangements that can be negotiated in the region with India for the commencement of trade:
  - **LNG sales purchase agreements:** Within SAR, India, Pakistan, and Bangladesh have their own long-term contracts for LNG import. Many new contracts being signed by India do not have any destination provisions. Hence, they can be used flexibly to promote regional LNG trade.
  - **Third-party access for LNG tolling:** In India, LNG terminals, such as Dhamra, can provide third-party access to buyers from neighbouring countries (such as Bangladesh) on a tolling arrangement.
  - **LNG swaps and regional LNG aggregator:** An arrangement through physical swaps is feasible with countries such as Nepal and Bhutan where LNG is received for them by India and then an equivalent amount of gas can be supplied to these countries from nearby regions.
- **Creation of supply options:** The commencement of cross-border trade can help in creation of additional modes of gas supply and gas value chain in the region:
  - **Joint gas exploration programmes:** These programmes can be carried out in SAR. India and Bangladesh can potentially sign up additional joint gas exploration and technology sharing agreements to explore more gas hydrates in the Bay of Bengal. India and Sri Lanka can also jointly explore natural gas in the Mannar basin
  - **Development of gas supply chain:** Commencement of cross-border trade would provide impetus to the development of gas supply chain in India. LNG fuelling stations across key national highways would be created for usage of LNG as a transportation fuel. New investments will be needed from both the government and private players in India to establish an ecosystem of LNG automotive vehicles in the future. In addition, India would receive benefits by the development of LNG trade routes through roadways (for LNG trade with the eastern countries) and waterways (for LNG trade of India with Sri Lanka and Maldives).
- **Collaboration opportunities:** Countries such as Nepal, Bhutan, Sri Lanka, and Maldives are still at a nascent stage in the use of gas as a fuel and development of the gas ecosystem in their respective boundaries. There is a requirement for collaboration between the member countries for the development of the gas value chain across the region. Both public and private sector companies could collaborate to develop infrastructure and enabling trade. Within India, companies such as GAIL, GSPCL, and Reliance can be used. IOCL, ONGC, HPCL, and BPCL have their presence in other countries of the SAR. This could present significant collaboration opportunities for the development of gas ecosystem.
- **Development of gas hub in the region:** After establishing gas infrastructure connectivity with neighbouring countries (such as Bangladesh, Bhutan, and Nepal), India can provide third-party access of the exchange (IGX) to buyers and sellers from these countries. The gas exchange would act as a medium to facilitate the cross-border trade with other SAR nations at price determined by the exact demand and supply. The availability of natural gas in large quantities at a fair market price through the hub will facilitate expansion of fertilisers, gas-based power plants, pipeline infrastructure, and the industrial, petrochemical, and City Gas Distribution sectors.

Creation of a benchmark gas hub in the SAR would need steps in the right direction towards development of institutional framework to promote fair, transparent and liquid gas market in the SAR.

The initial steps towards forming a regional gas hub in South Asia have already been taken through the launch of IGX. However, several steps need to be taken for the eventual development of the platform to be able to create a regional gas hub in the South Asian region:[16]

1) **Identification of the optimum physical location of trading hub:** For the SAR, a physical hub with advanced infrastructure will be a better choice as multiple companies are operating pipelines and countries are currently not interconnected. Dhamra can be one potential location for a trading hub to determine prices as it is on the eastern coast closer to Bangladesh, Nepal, and Bhutan. It is also connected to the JHBDPL gas pipeline.
2) **Creating the required institutional structure:** The initial phase of bilateral gas trade between countries needs to commence with minimal regulations. However, with due course of time based on the experience

[16] https://www.icf.com/insights/public-policy/well-functioning-gas-trading-hub-in-india

and complexities of trade and a greater number of buyers and sellers joining IGX from other SAR countries, a platform regulator will be required. The regulator will have to be empowered with clear policy guidelines, stringent market rules, and power to enforce punitive damages for market abuse.

3) **Synchronous operation of gas pipelines:** As the gas exchange will have to operate on a real-time basis, it will require real-time access to information from across the pipeline network that requires every element to work together as one single operation.
4) **Movement of domestic gas to the hub:** Developing a mature trading hub will require changes in the policies pertaining to domestic gas allocation for priority sectors. Feasibility analysis will need to be carried out for different options to allocate domestic gas towards the trading hub.
5) **Trading through ssLNG:** At present, the IGX platform facilitates the trade of natural gas that is to be transported though pipelines. The platform will also need to account for the trade of smaller quantities of gas through ssLNG containers.
6) **Ensuring TPA (Third Party Access) to gas infrastructure (pipelines and LNG terminals) and making data of the pipeline capacity publicly available:** This is required to bring more transparency and competitiveness in the regional gas hub for operators from other countries to participate as well.
7) **Changing the existing type of contracts:** Market reform and formation of a successful hub will require contracts to be unbundled to enable competition and allow anyone to book pipeline capacity.
8) **TSO (Transmission System Operator) and gas access bulletin board:** The TSO would be responsible for integration of various pipelines along with tasks like network planning, nomination, and scheduling for different types of pipelines.
9) **Stakeholder awareness and collaboration:** A robust stakeholder communication program will be required to create awareness about the benefits of cross-border trade and gas hub formation for the SAR, policies and regulations, pricing of gas as compared to alternate fuels, infrastructural requirements, and roles and responsibilities of stakeholders in the creation of a regional gas ecosystem. Along with strong communication, stakeholders will also need to be provided regular training and skill development for their specific roles in the gas-hub ecosystem.

Country-wise snapshots

Within the SAR, natural gas has traditionally been used as a source of fuel in India, Pakistan, Bangladesh, and Afghanistan. The natural gas industry in India began in 1960s with the discovery of gas fields in Assam and Maharashtra (Bombay high). In 1976, ONGC discovered one of India's biggest gas fields in the Bassein field off Mumbai's coast. Another major gas discovery in India was in Gandhar, Cambay basin. For Pakistan, in 1952, Pakistan Petroleum Limited (PPL) made the most significant gas discovery at Sui, Balochistan post which other discoveries of natural gas were made in Uch (in 1955), Mari (in 1957), and Kandhkot (in 1959). For Bangladesh, the first gas discoveries were made in Sylhet (1951-55) and in Chattack (1959). Production from the Titas and Habiganj gas fields started in 1968. These discoveries led to the subsequent development of pipeline infrastructure and development of gas-based economy, particularly in Pakistan and Bangladesh.

However, the subsequent gas discoveries could not keep pace with the increase in demand and inhibited the development of gas transmission and supply network for the three countries. India, Pakistan, and Bangladesh have been facing difficulties in meeting their respective gas demand through domestic production, thus becoming dependent on LNG import. India began importing LNG in 2004, followed by Pakistan (2015) and Bangladesh (2018). LNG imports in these countries have increased over the past few years as they are witnessing rising gas demand. However, domestic production could not keep pace with demand.

The country-wise snapshots provide an as-is assessment for the gas sector, along with long-term projections for demand and supply, in the SAR. The as-is-assessment covers different aspects of the gas ecosystem for each country. These aspects include assessment of current gas demand and supply, gas value chain, infrastructure, regulations and policies, and pricing followed by projections of long-term demand and supply. Demand projections have been carried out using two approaches – the top-down approach and the bottom-up approach. The top-down approach has been used for India, Pakistan, Bangladesh, and Sri Lanka. It is because India, Pakistan, and Bangladesh are already consuming gas as a part of their primary energy mix while Sri Lanka has announced plans to increase the share of gas upto one-third of its fossil fuels consumption.[17] The bottom-up approach has been used to estimate the demand for all the countries. The bottom-up approach has been used for the overall demand projections since it considers all the sector-wise drivers, challenges and scenarios. For the supply analysis for different countries, domestic production from existing and upcoming fields, along with LNG supplies through imports, is considered.

I. India

In 2020, primary energy consumption of India was ~776 Mtoe consisting of ~86 percent fossil fuels (33 percent oil, 8 percent natural gas, and 45 percent coal) and 14 percent electricity.[18]

Current gas demand and supply: Natural gas accounts for ~7 percent of the total energy mix in India at present.[19] Gas demand was 154 mmscmd in FY 2020-21 and 163 mmscmd in FY 2021-22.[20] The fertiliser sector accounted for the largest demand segment at 30 percent, followed by Others, CGD, and power at 21 percent, 20 percent, and 15 percent, respectively.[21]Domestic production of gas was 76.1 mmscmd in FY 2021 and ~90.8 mmscmd in FY 2022.[22] Offshore production contributed a major share (~68 percent) to the total production, while the onshore and CBM segments accounted for the remaining share. LNG imports in India accounted for 90 mmscmd in FY 2021 and 84 mmscmd in FY 2022. Of the total net imports globally, India accounted for 7 percent.[23]

Gas value chain: This comprises of upstream, midstream and downstream segments. The Ministry of Petroleum and Natural Gas is the government ministry managing the gas sector in India. The Directorate General of Hydrocarbons is the regulatory body for the upstream sector, whereas the Petroleum and Natural Gas Regulatory Board for the midstream and downstream sectors. Within the upstream sector, ONGC and OIL hold ~85 percent share in the gas production; and the private sector and joint ventures contributed ~13 percent.[24] The major challenge for India in the upstream sector has been declining domestic gas production that has

[17] *NPNG, Sri Lanka*
[18] *Data provided on Page 61 of Energy Statistics India 2021 Report and converted from petajoules to mtoe*
[19] *Data provided on Page 61 of Energy Statistics India 2021 Report*
[20] *PPAC*
[21] *PPAC*
[22] *PPAC*
[23] *International Gas Union – World LNG Report 2021*
[24] *PNGRB annual report*

affected gas availability at competitive prices for the downstream sector, especially the power sector and industries, and increased dependency on LNG imports.

Infrastructure: India currently has six existing RLNG terminals with five along the West Coast and one along the East Coast totalling a capacity of 40 MMTPA.[25] Nine new terminals are either under construction or have been announced and two existing terminals − Dahej and Dabhol − will undergo capacity expansion. The total capacity of announced upcoming terminals is expected to be ~43 MMTPA. Within pipeline infrastructure, India has 20 fully operational common carrier natural gas pipelines, with an authorised length of 13,319 km along with ~13,186 km of under-construction common carrier pipelines (as of March 2022).[26] Government is focusing on completion of the national gas grid extending pipelines across the country and connecting the North-Eastern region.

Regulations and policies: The government of India has set a target to increase the share of natural gas to 15 percent of the energy mix by 2030. Moreover, in November 2021, India pledged to achieve net zero carbon emissions by 2070 in COP26 Summit at Glasgow.[27] Gas can act as a cleaner alternative to fossil fuels and contribute to achieving these targets. The regulations and policies for the gas sector in India have seen several advancements across years. The New Exploration Licensing Policy (NELP) and CBM policies were implemented in 1997-99 through which opportunities provided to both public and private investors. However, until 2012-13, nearly 48 percent of India's sedimentary basins remained unappraised.[28] Within 2016-17, several initiatives were launched for the upstream oil and gas sector with the major one amongst them being HELP (Hydrocarbon Exploration and Licensing Policy). The erstwhile profit-sharing model in the NELP was replaced by the revenue sharing model under the HELP along with a single licence for all forms of hydrocarbons (both conventional and unconventional ones). In addition, other policy initiatives were introduced to provide pricing and marketing freedom for gas and improve the ease of doing business for gas exploration companies. The midstream and downstream sectors in India have also seen several policy initiatives, such as plans to create a national gas grid and improve pipeline connectivity, launch of gas exchange for imported LNG, 11 bidding rounds to expand the CGD network across the country, enhanced period for achieving MWP (Minimum Work Program) targets, and a ban on the use of polluting fuels in certain specific areas. PNGRB has played a major role in authorisation of gas pipelines and accomplishing the 11th CGD bidding round recently post which ~88 percent of India's geographical area and ~98 percent of India's population will have access to CGD networks.[29]

Pricing: The pricing of domestic gas in India is linked to weighted average value of four different gas indexes (NBP, Alberta Gas, Russian Gas, and Henry Hub Gas) for gas produced from nominated fields. According to PPAC, price of domestic natural gas for 1 October 2021 to 30 March 2022 was US$2.9/mmbtu. From 1 April 2022 to 31 October 2022, the gas price has been hiked to US$6.1/mmbtu. For the gas produced from deep-water, high pressure-high temperature and discovered small fields (Pricing and Marketing freedom gas), firms allowed to devise a pricing formula. However, the government has set a price ceiling based on the prices of alternative fuels. According to PPAC, from 1 April 2022 to 30 September 2022, the price ceiling is US$9.92/mmbtu. In case of imported LNG, the price build-up for natural gas consists of DES price (which is linked largely to crude oil), custom duty, terminal charges, pipeline tariffs, GST on transportation, and terminal charges, and VAT.

Demand projections: The overall natural gas demand in India has been driven by factors such as policy push with focus on improving air quality, rising demand centres with expansion of the CGD network, increase in the pipeline infrastructure, and regasification terminal capacity. The top-down approach considered three scenarios for the share of natural gas in the energy mix – 8 percent, 12 percent, and 15 percent by 2030. The first scenario has been considered as the most plausible with gas demand projections as 327 mmscmd by 2030 and 545 mmscmd by 2040. The bottom-up approach considered the following sectors for the analysis:

- **Fertiliser sector:** Gas demand from the fertilisers sector is driven by factors such as increase in the fertiliser consumption, the government's focus on reducing import dependency in the urea sector, connectivity to pipeline infrastructure, and affordability compared with alternative fuel. Demand projection has been carried out considering various factors, such as target energy consumption per New Urea Policy for various plants using natural gas and demand expected from new revived plants

[25] PPAC Ready Recknoer
[26] PNGRB
[27] https://www.thehindubusinessline.com/news/india-committed-to-achieving-net-zero-carbon-emission-by-2070-says-modi/article37293537.ece
[28] https://economictimes.indiatimes.com/industry/energy/oil-gas/dharmendra-pradhan-launches-rs-5000cr-national-seismic-programme-in-mahanadi-basin/articleshow/54816840.cms
[29] PNGRB Annual Report

- **Refinery sector:** Gas demand from the sector will be driven by greenfield/brownfield expansions and fuel quality improvement initiatives. These lead to displacement of existing fuel with natural gas, pipeline connectivity to refineries and emission regulations, and affordability compared with alternative fuels. Demand projection has been carried out after identifying gas use in various refineries followed by estimation of gas demand based on share of gas, refinery capacity, and fuel and loss percentage.
- **Petrochemical sector:** In India, the sector has significant growth potential created by a large untapped demand and trade deficit. Natural gas and naphtha are used as feedstock to manufacture a wide variety of petrochemicals. Demand assessment for petrochemicals has been carried out by identifying existing plants producing petrochemicals, along with their historic feedstock consumption and utilisation.
- **Power sector:** Natural gas is being used as fuel in power plants with a total installed capacity of 23,485 MW accounting for 6 percent of the total installed capacity. About 20 plants of cumulative capacity of 7,435 MW were stranded in FY 2022 due to shortage in domestic gas supply, high cost of imported gas, and a competitive tariff scenario. To estimate demand from the power sector in India, multiple scenarios were considered to calculate share of natural gas in electricity generation. Within the most plausible scenario, consumption from gas-based power plants has been considered same in the future projections considering the challenges around affordability of gas. Gas-based power can be a feasible option to meet the peaking power and grid-balancing requirements with the increase in penetration of renewable power in the transmission network. Also, considering the cost economic of gas-based and battery-based power generation, gas-based power generation is expected to be more economical than battery-based generation at least until 2029.
- **CGD sector:** In India, the CGD sector is divided into four segments − domestic, transportation, commercial, and industrial. The sector has significant potential of growth as per the past trends and future projections. It is expected to experience a double-digit growth with the completion of 11th round GAs.[30] Demand from the CGD sector will be driven by priority sector allocation of domestic gas for the domestic and transportation sectors, increase in the number of GAs (Geographical Areas) from the CGD rounds and improvement in gas supply and transportation infrastructure. The following is a summary of demand from different CGD sub-sectors:
    - **CGD domestic sector:** Domestic gas demand in the CGD sector is driven by factors such as domestic gas allocation, marketing exclusivity for CGD entities, promotion of cleaner fuels for domestic use, and increase in the number of authorised GAs. To estimate demand in the domestic sector from GAs until the 11th round, existing domestic connections and the Minimum Work Programme under bidding rounds for major players have been considered. Based on those, the number of urban and rural connections, along with gas demand, has been projected.
    - **CGD transportation sector:** Demand from the transportation sector is expected to be driven an increase in prices of petrol and diesel, along with concerns of increasing environmental pollution from these fuels. For demand estimation, the number CNG stations in each state has been identified and estimated to increase per the Minimum Work Programme under bidding rounds. The throughput per station has been suitably projected to calculate demand.
    - **CGD commercial sector:** Demand from the commercial sector has been calculated by estimating packaged LPG sales in each GA and considering a percentage for potential replacement by natural gas.
    - **CGD industrial sector:** For the industrial sector, a ban on polluting fuels and promotional incentives for using cleaner fuels is expected to be major demand drivers. Demand from the industrial sector has been calculated estimating sales of industrial fuels (HSD bulk, FO bulk, LPG bulk, LDO, and naphtha) in each GA and considering a certain percentage for potential replacement for each of them by natural gas.
- **LNG in the automotive sector:** Use of LNG in the automotive sector is expected to be driven by different technological, economic, environmental, and policy drivers. Demand from the automotive sector has been calculated by estimating diesel consumption in the future from heavy-duty vehicles and buses and then LNG demand that shall arise by retrofitting existing diesel vehicles and new upcoming vehicles.

[30] https://energy.economictimes.indiatimes.com/news/oil-and-gas/cgd-sector-to-record-volume-growth-of-10-per-cent-cagr-through-2030/78269149

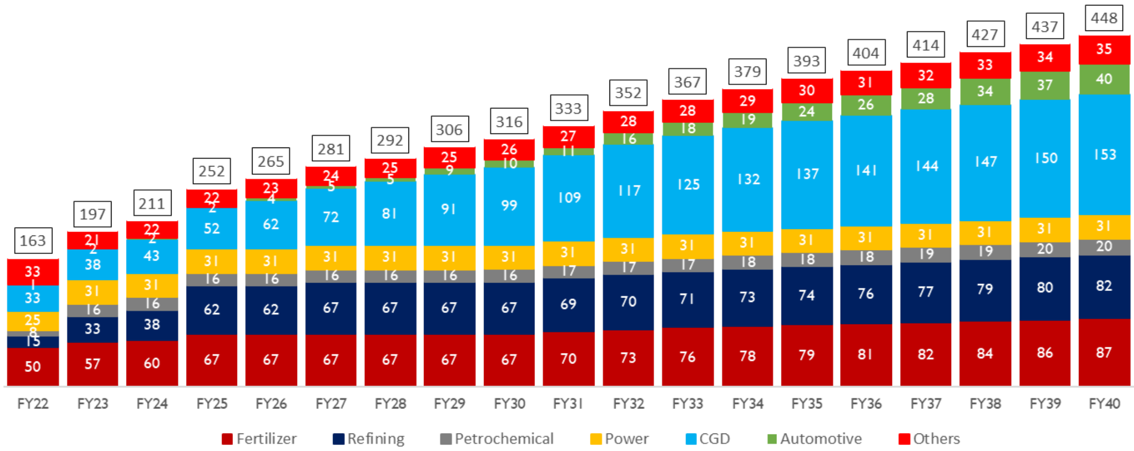
The following table shares the summary of demand projections from different sectors in India:

Table 4 Table C: Sector-wise gas demand projections for India for most plausible scenarios (in mmscmd)

Sector	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Fertiliser	50.3	57.4	59.7	67.2	67.2	67.2	67.2	67.2	67
Refining	14.6	32.6	38.3	61.7	61.7	66.5	66.5	66.5	67
Petrochemical	7.6	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16
Power	24.5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	31
CGD	33.4	37.7	42.9	51.8	61.5	71.8	80.9	90.6	99
Automotive	0.7	1.5	1.7	2.0	4.4	4.9	5.4	9.0	10
Others	33	21.1	21.8	22.4	23.1	23.8	24.5	25.2	26
Total	**163**	**197**	**211**	**252**	**265**	**281**	**292**	**306**	**316**

Sector	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Fertiliser	70.2	73.3	75.8	77.7	79.2	80.8	82.4	84.1	85.7	87
Refining	68.6	70.0	71.4	72.8	74.3	75.7	77.3	78.8	80.4	82
Petrochemical	16.6	17.0	17.3	17.6	18.0	18.4	18.7	19.1	19.5	20
Power	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	31
CGD	108.7	117.4	125.3	131.9	137.1	140.9	144.2	147.1	150.0	153
Automotive	11.0	16.1	17.6	19.3	23.7	25.9	28.2	34.1	37.0	40
Others	26.7	27.5	28.3	29.2	30.1	31.0	31.9	32.8	33.8	35
Total	**333**	**352**	**367**	**379**	**393**	**403**	**414**	**427**	**437**	**448**

Figure 4 Trend of sector-wise demand projections in India for most plausible scenarios (in mmscmd)



Supply projections: In India, supply projections has considered production from existing domestic fields and through import from LNG terminals. For existing domestic fields, gas supply has been projected based on the historical production trend and an expected future decline in gas production. Actual natural gas supply available for sale was reduced by 20 percent to account for losses and internal consumption. Gas supply from the upcoming fields has been projected based on the production data available in the public domain. Supply from existing and new terminals has been calculated by multiplying their capacities with the expected utilisation. The terminals have been assumed to reach high utilisation in the future. This would be supported by the increasing transmission and distribution infrastructure that is being built across the country. The following is a summary of overall supply projection in India:

Table 5 Gas supply projections for India (in mmscmd)

Segment	Gas supply (mmscmd)	
	FY 2029-30	FY 2039-40
Net production from existing fields	44	31
Production from upcoming fields (announced)	33	11
Imports from existing terminals	134	134
Imports from upcoming terminals	150	176
Total	**361**	**352**

The integrated demand-supply projections for India are provided in the table below:

Table 6 Integrated gas demand-supply projections for India for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Demand	163	197	211	252	265	281	291	306	316
Supply	180	210	243	293	304	325	341	354	361
Deficit (-)/surplus (+)	17	12	32	41	39	44	49	49	45

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Demand	333	352	367	379	393	403	414	426	437	448
Supply	367	367	364	360	359	358	356	355	353	352
Deficit (-)/surplus (+)	34	15	-3	-20	-34	-46	-57	-72	-84	-96

2. Pakistan

In 2020, primary energy consumption for Pakistan was ~81 Mtoe, consisting of 86 percent fossil fuels (44 percent natural gas, 24 percent oil, and 18 percent coal), and 14.5 percent supplies from electricity.[31]

Current gas demand and supply: Pakistan's dependence on natural gas in the overall energy mix was about 43 percent in FY 2020. Pakistan used ~102 mmscmd in FY 2020 and ~104 mmscmd in FY 2021.[32] The major users of gas are the power (32 percent), domestic (25 percent), and fertilisers (19 percent) sectors.[33] Consumption from most sectors has remained almost constant across the years and the power sector has been the major gas consumer. The commercial and CNG sectors have contributed the least across the years in the overall gas consumption in Pakistan. According to BP Statistical Review, the domestic production and LNG imports were 84 mmscmd and 29 mmscmd, respectively, for FY 2020.[34] About 26 percent of the natural gas demand in Pakistan was being met from LNG imports in FY 2020.[35]

Gas value chain: The Ministry of Petroleum and Natural Resources (MoPNR) controls upstream activities in Pakistan's gas value chain. The Oil and Gas Regulatory Authority (OGRA) governs midstream and downstream activities. Pakistan's domestic gas production comes from 42 onshore fields, mainly located in southeast and central Pakistan. The major challenge for the upstream sector and gas exploration in Pakistan is the security conditions of the remaining basins, along with offshore drilling campaigns not yielding any results.

Infrastructure: Pakistan has a gas network of ~12,971 km transmission pipelines, 139,827 km distribution pipelines, and 37,058 services gas pipelines. Two cross-country pipelines are planned in Pakistan: the Iran-

[31] *Pakistan Energy Yearbook, HDIP*
[32] *Pakistan Energy Yearbook, HDIP, Pakistan Economic Survey*
[33] *Pakistan Economic Survey*
[34] *BP Statistical Review*
[35] *BP Statistical Review*

Pakistan pipeline (expected to be completed by 2024) and the TAPI pipeline. The existing LNG import infrastructure in Pakistan consists of two FSRUs – the Engra Elengy and Gasport LNG terminals that are located at Port Qasim. Both of these have a combined capacity of 1440 mmscfd. For both these existing terminals, expansion projects were announced and those will be completed by 2022. In addition, three new terminals have been announced in Pakistan for 2024. The total capacity of upcoming LNG projects in Pakistan is ~20 MMTPA.

Regulations and policies: The Ministry of Energy − Petroleum Division (MEPD) is the primary regulator for oil and gas related policies in Pakistan. It allocates import of natural gas and domestic production of gas from gas fields. The government of Pakistan has the first right to purchase gas produced in the country (directly or indirectly) through SNGPL and SSGCL (the gas transmission and distribution companies). OGRA performs the functions regarding granting of different licenses (like sales, transmission, and distribution of gas), determination of revenue requirements for gas-utility companies, enforcement of rules, and handling of cases related to gas infrastructure projects. Exploration and production concessions are granted primarily through a competitive bidding process. The gas allocation policy assigns the following priority to different sectors for domestic gas allocation – the domestic and commercial sectors, the power and zero-rated industry, the general industry, fertilisers, captive power, and CNG. For the power sector, the government released Indicative Generative Capacity Expansion Plan 2021-30 in which the country aims to reduce reliance on imported RLNG and reach ~90 percent of power generation from indigenous resources, including local coal, hydro, wind, and solar power.[36] This policy shift is expected to ease the gas shortages for other sectors.

Pricing: Gas prices for producers in Pakistan are determined by their revenue requirement that is indexed to international prices of crude oil specifying floor and ceiling according to the pricing agreements between the government and producers. Prices received by companies are different for each gas field they have. The current weighted average wellhead prices are ~US$3.5/mmbtu.[37] For consumers, the prescribed price by OGRA has the following elements: producer gas prices linked with international prices of crude oil and HSFO, transmission and distribution costs, depreciation, and returns to SNGPL and SSGCL. For imports, Pakistan gets more than half of its LNG under long-term contracts with Qatar Gas. The pricing of LNG consists of components such as DES price, margins, terminal charges, retainage volume adjustment, and cost of supply for transmission and distribution companies. The weighted average price of imported RLNG in Pakistan was in the range of US$ 14.7-15.7/mmbtu in November 2021.[38] Cost economics of natural gas are more favourable in Pakistan compared with other POL fuels, such as gasoline and diesel.

Demand assessment: The overall demand for gas in Pakistan is driven by factors such as Pakistan's priority sector allocation and setting up of the China-Pakistan Economic Corridor (CPEC). For the top-down demand assessment, a correlation was drawn between GDP and energy consumption data for Pakistan. The approach considered two scenarios for GDP growth rate until 2040 – the first scenario took a five-year CAGR between 2021 and 2026 and the second scenario took a seven-year CAGR between 2019 and 2026. The second scenario was considered the most plausible with demand projected at 196.4 mmscmd by FY 2030 and 273.1 mmscmd by FY 2040.

For the bottom-top demand assessment, the following sectors were considered:

- **Fertilisers:** Gas demand from the fertilisers sector in Pakistan is expected to be driven by fertiliser-responsive crop varieties, supplementary irrigation water, and a favourable policy environment. Demand for the fertiliser sector has been calculated using the historical proportion of the sector's demand from the overall industrial sector.
- **Power:** The power sector is challenged by a high cost of electricity generation, along with various inefficiencies in the transmission and distribution system. Gas demand for the power sector has been calculated using two scenarios – the first scenario considered Indicative Generation Capacity Expansion Plan 2021-30 (IGCEP) which intended to reduce the reliance on RLNG. The second scenario is based on the CAGR growth of gas-based power plants. The first scenario has been assumed as the most plausible one for the power sector.
- **CGD:** Demand from the CGD sector has been calculated for the industrial, commercial, domestic, and CNG segments. The demand calculation for each segment has been calculated from the number of connections for each of these segments and average gas demand.

[36] *IGCEP, Pakistan*
[37] *Gas and Petroleum Market Structure and Pricing by Pakistan Institute of Development Economics*
[38] *https://www.sngpl.com.pk/web/download/rlng_price_august06_2021.pdf*

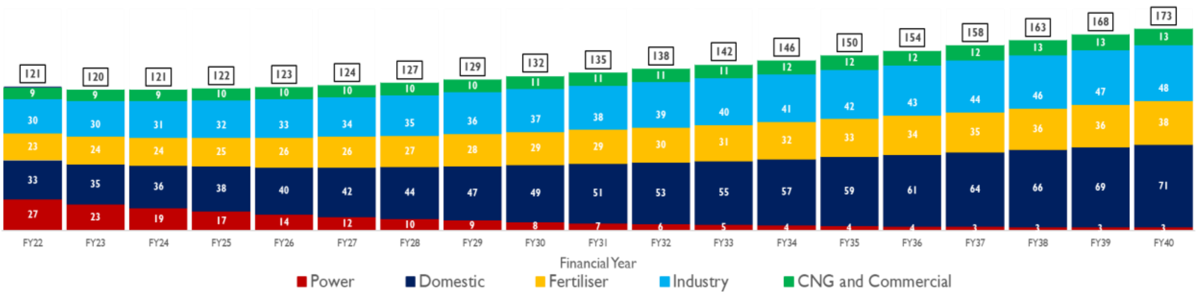
The following is the summary of demand projections from different sectors in Pakistan:

Table 7 Sector-wise gas demand projections for Pakistan for most plausible scenarios (in mmscmd)

Sector	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	26.8	22.5	19.2	16.5	14.0	11.9	10.1	8.7	7.6
Domestic	32.7	34.5	36.4	38.4	40.4	42.3	44.4	46.5	48.7
Commercial	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Fertiliser	23.0	23.6	24.3	25.0	25.6	26.3	27.1	27.8	28.6
Industry	29.5	30.3	31.2	32.0	32.9	33.8	34.7	35.7	36.7
CNG	6.4	6.6	6.8	6.9	7.1	7.3	7.5	7.7	8.0
Total	**121.0**	**120.3**	**120.5**	**121.6**	**122.7**	**124.4**	**126.5**	**129.2**	**132.2**

Sector	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	6.5	5.7	5.0	4.4	4.0	3.6	3.4	3.1	2.9	2.8
Domestic	50.7	52.7	54.8	57.0	59.2	61.4	63.7	66.1	68.5	71.0
Commercial	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Fertiliser	29.4	30.2	31.0	31.9	32.7	33.6	34.6	35.5	36.5	37.5
Industry	37.7	38.7	39.8	40.9	42.0	43.2	44.3	45.6	46.8	48.1
CNG	8.2	8.4	8.6	8.9	9.1	9.4	9.6	9.9	10.2	10.4
Total	**135.1**	**138.4**	**141.9**	**145.7**	**149.7**	**153.9**	**158.3**	**162.8**	**167.6**	**172.5**

Figure 5 Trend of sector-wise demand projections in Pakistan for most plausible scenarios (in mmscmd)



Supply assessment: The major gas fields for domestic production are - Sui (PPL), Uch (OGDCL), Qadirpur (OGDCL), Sawan (ENI, PPL), Kandhkot (PPL), and Mari (MPCL) that represent more than 50 percent of the country's proven gas reserves.[39] There has not been any significant change in supply from domestic fields over the past decade. The gas supply from domestic fields has been projected based on the historical and expected decline in gas production based on an annual report of OGRA. For imports, there are currently three upcoming LNG terminals in Pakistan, along with the capacity expansion of the two existing ones – Engro and Gasport. Supply from LNG terminals has been calculated based on their capacity, expected utilisation, and year of pipeline connectivity. For both the current and upcoming LNG infrastructure, unconstrained supplies have been assumed with utilisation reaching upto 90 percent in few years. In addition, Pakistan has two upcoming cross-country pipelines – Iran Pakistan Gas Pipeline (IPP) and Turkmenistan-Afghanistan-Pakistan-India Pipeline (TAPI). For supply calculation from both these pipelines, scenarios have been considered for whether they would be completed or not and the most plausible scenario has been considered for the completion of only IPP pipeline.

The following is the summary of supply from different sources and the integrated demand-supply model for Pakistan:

Table 8 Integrated gas demand-supply projections for Pakistan for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Demand	121.0	120.3	120.5	121.6	122.7	124.4	126.5	129.2	132.2
Domestic supply	75.7	70.7	66.0	61.7	57.6	53.8	50.2	46.9	43.8
Imports	20.2	24.2	79.5	89.2	95.0	101.1	104.3	110.5	115.9

[39] https://www.globalvillagespace.com/pakistan-energy-mix-overview-of-gas-sector-upstream/

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Deficit (-)/surplus (+)	-25	-25	25	29	30	31	28	28	28

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Demand	135.1	138.4	141.9	145.7	149.7	153.9	158.3	162.8	167.6	172.5
Domestic supply	41.6	40.0	38.8	38.0	37.2	36.5	35.8	35.1	34.4	33.7
Imports	121.6	123.9	127.1	128.2	129.3	130.3	130.3	130.3	130.3	130.3
Deficit (-)/surplus (+)	28	26	24	21	17	13	8	3	-3	-8

3. Bangladesh

In 2020, primary energy consumption of Bangladesh was ~40.5 Mtoe consisting of natural gas (63 percent), oil (20 percent), coal (12 percent), LPG (2 percent), and electricity (3 percent).[40] Natural gas has been the most economical fuel in the country.

Current gas demand and supply: Natural gas fulfilled a significant portion (~63 percent) of energy demand in FY 2020.[41] According to the Bangladesh Hydrocarbon Unit's report for FY 2021, gas consumption in Bangladesh was ~79 mmscmd. The power (59 percent) and industrial (18 percent) sectors have been the major contributors of gas demand in Bangladesh. To tide over the shortage and meet demand for a large gas-based power sector, Bangladesh began importing LNG in 2018. In FY 2021, Bangladesh imported ~20 percent of its natural gas to meet domestic demand.[42] Domestic production for FY 2021 was 68 mmscmd and LNG imports were 17 mmscmd.[43]

Gas value chain: The Ministry of Power, Energy, and Mineral Resources (MOPEMR) overlooks at the whole energy scenario within the country. Petrobangla is the government-owned national state oil and gas company that reports to MOPEMR and acts as an upstream regulator of gas supply. Bangladesh Energy Regulatory Commission is the oil and gas regulator that decides natural gas tariffs for the midstream and downstream segments. Natural gas demand in the country has been consistently increasing over the years, whereas supply from domestic fields has been declining. Hence, Bangladesh's dependence on natural gas import to meet demand has increased and the country installed two FSRUs in 2018 and 2019 to import LNG.

Infrastructure: In December 2019, the pipeline network infrastructure in the country was about ~24,336 km. This included ~2,872 km of the transmission pipelines, ~2,381 km of the distribution pipelines, ~236 km of the lateral lines, and ~16,738 km feeder main and service lines.[44] As mentioned above, Bangladesh has two existing FSRU terminals at Moheshkhali. One is operated by Excelerate Energy and another is by Summit LNG Terminal Co. Pvt. Ltd. (both terminals have capacity of ~4.28 MMTPA). The government of Bangladesh has been laying a strong focus on the completion of national gas grid and connecting the North-Eastern region. The Matarbari LNG terminal is expected to come up in 2023 to augment LNG imports which has capacity of ~7.8 MMTPA.[45]

Regulations and policies: The government of Bangladesh has been working on short-, mid-, and long-term plans for gas extraction, development, and production. The government has planned for several initiatives to promote the gas sector - increasing financial capacity of BAPEX by forming a separate gas development fund, improving gas sector's financial operations, adopting a time-based action plan for discovering new gas fields (particularly offshore fields), etc. Different forms of unconventional energy, such as CBM, shale gas, and unconventional gas, are also being explored. Preliminary studies have been carried out in the country for the potential of shale gas and an action plan for CBM and hard rock development in Bangladesh.

Pricing: Gas distribution companies in the country compute their gas tariffs for different consumer categories on the basis of two factors - future sales forecast and average revenue requirements. MOPEMR has set a weighted average of the price of gas produced by Petrobangla and that purchased by Petrobangla from

[40] *EMRD, Bangladesh*
[41] *EMRD, Bangladesh*
[42] *EMRD, Bangladesh*
[43] *EMRD, Bangladesh*
[44] *Petrobangla Annual Report 2019-20*
[45] *https://www.gem.wiki/Bangladesh_and_fossil_gas*

international oil companies. Bangladesh's wellhead gas prices have varied between US$1.3-2.6/mmbtu.[46] The price for end-consumers is set considering gas cost (for Petrobangla) and additional margins (a return and costs associated with transmission and distribution of natural gas). Petrobangla subsidises the gas prices offered to end consumers. For the import LNG, a 15 percent VAT is applicable for import price and value addition (being done through regasification).[47] Despite Petrobangla bearing costs of ~US$18/mmbtu, LNG is sold to customers at BERC subsidised rates. For each category of end consumers, cost economics is favourable for natural gas compared with other POL fuels, such as gasoline and diesel. Bangladesh follows the following priority order for the allocation of gas to different sectors – fertilisers, power, industry/tea gardens, captive power, residential/commercial, and CNG.

Demand assessment: Gas demand in Bangladesh is expected to be driven by several factors – the government's "electricity for all" mission that aims to electrify 100 percent of the country, to achieve the status of high-income country by 2041, rapid urbanisation, potential for improvement in the fertilisers sector and increasing concerns for environmental sustainability in the country. Through the top-down approach (using a regression analysis between GDP and primary energy consumption), gas demand is projected to increase up to 122.6 mmscmd in FY 2030 and 171.4 mmscmd in FY 2040 (after considering the scenario of seven-year growth rate of GDP).

Within the bottom-up approach, along with major demand drivers, data from several different reports, the GSMP (Gas Sector Master Plan), the Power Sector Master Plan (PSMP), the revised PSMP, and the annual publications from Hydrocarbons Unit, Bangladesh (HCU) was looked upon as well. The following sectors were considered for demand assessment:

- **Fertilisers:** At present, Bangladesh has five existing fertiliser plants that manufacture urea along with Ghorashal Polash starting its operations in 2023. Utilisation of fertiliser plants is expected to increase in the future considering that the government of Bangladesh plans to undertake the necessary steps to enable these plants to function on full capacity on account of increasing urea demand in the country. Demand estimation for the fertiliser sector has been made based on the consumption data published in Petrobangla's daily gas report and completion of gas pipelines for fertiliser plants.
- **CGD:** Demand from the CGD sector has been calculated for the transportation, domestic, commercial, and industrial segments:
    - **CGD transportation:** CNG is one of the least priority sectors for natural gas allocation in Bangladesh. Many times, supply to the sector is burdened to service demand from other sectors in the country. Therefore, a slowdown in gas demand is highly likely in this sector. However, according to an analysis by ExxonMobil, the sector is expected to witness a positive growth rate in demand. This demand could be fuelled by the increasing LNG supply through imports and switching of the gas-intensive sectors to alternative fuels that can spare more gas for CNG. Demand from the CNG sector has been calculated both for the growth scenario and the constrained demand scenario considering the increase in the number of CNG stations and average throughput.
    - **CGD domestic:** A majority of domestic gas in Bangladesh is being supplied by six distribution subsidiaries of Petrobangla on a fixed monthly fee. For demand estimation from the domestic sector, the increase in the number of households in the next few years, along with consumption per household, have been considered.
    - **CGD industrial:** Demand from the sector has been calculated by building a regression model with GDP considering that with an increase in GDP, economic activity for the industrial sector will have a significant increase. Due to this, natural gas demand will rise. Different scenarios have been created for the regression model – with constant slope, increasing slope, and increasing slope up to a certain time frame.
    - **CGD commercial:** Demand from the commercial sector has been considered per the energy scenario of the Bangladesh report from hydrocarbons unit in Bangladesh.
- **Power:** The government of Bangladesh has been taking various steps to make electricity accessible for a larger population of Bangladesh. More than 72 percent of the rural areas in Bangladesh have already been added to the electricity grid through government initiatives.[48] The government intends to electrify 100 percent of the country under the "electricity for all" vision. Demand from the power sector has been calculated after considering three cases for overall electricity generation and within those, three

[46] https://tribune.com.pk/story/2176787/review-gas-sector-prices
[47] National Board of Revenue, Bangladesh
[48] BPDB Annual Report

different scenarios were considered for the total electricity that would be generated by natural gas. Demand for captive power plants has been considered from the “Energy Scenario of Bangladesh (2019-20)” report.

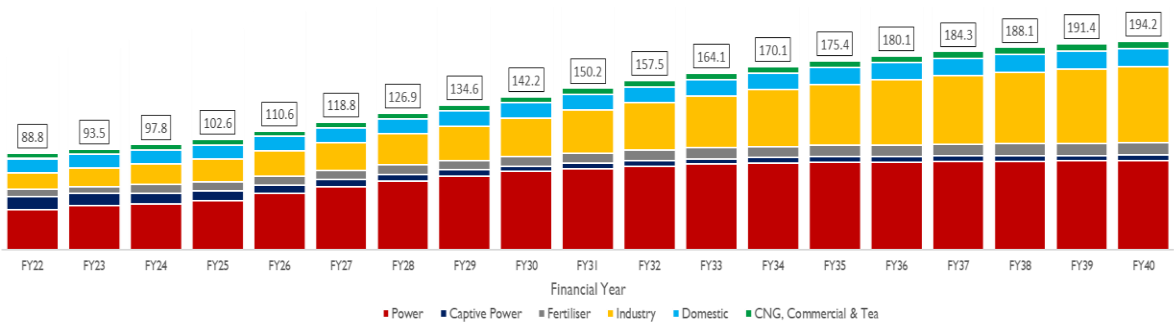
The following is the summary of demand projections from different sectors in Bangladesh:

Table 9 Sector-wise gas demand projections for Bangladesh for most plausible scenarios (in mmscmd)

Sector	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	37.5	41.2	42.6	46	52.2	58.2	63.8	68.5	72.6
Captive power	12.1	10.9	9.8	8.8	7.9	7.1	6.4	5.8	5.2
Fertiliser	6.4	6.7	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Industry	15.3	17.0	18.8	20.9	23.3	25.9	28.9	32.2	36.0
Domestic	12.7	12.8	13.0	13.1	13.3	13.6	13.8	13.9	14.0
Commercial and tea	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
CNG	3.7	3.8	3.9	4.0	4.1	4.3	4.4	4.5	4.7
Total	**88.8**	**93.5**	**97.8**	**102.6**	**110.6**	**118.8**	**126.9**	**134.6**	**142.2**

Sector	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	75.6	77.9	79.5	80.6	81.3	81.7	82.0	82.3	82.6	82.9
Captive power	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Fertiliser	9.1	9.6	10.0	10.3	10.5	10.7	10.9	11.2	11.4	11.6
Industry	40.2	44.4	48.6	52.8	56.7	60.4	63.7	66.6	69.0	70.7
Domestic	14.2	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.6	17.0
Commercial and tea	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
CNG	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7
Total	**150.2**	**157.5**	**164.1**	**170.1**	**175.4**	**180.1**	**184.3**	**188.1**	**191.4**	**194.2**

Figure 6 Trend of sector-wise demand projections in Bangladesh for most plausible scenarios (in mmscmd)



Supply assessment: Gas fields in the country are primarily located in the north-eastern Sylhet, Chittagong, and Dhaka divisions. Production in Bangladesh has steadily increased over the years; however, it is faced with rapidly dwindling reserves. Imports might be needed to meet the requirements of new gas-powered and fertiliser plants that are coming up in the future. For existing domestic fields, gas supply has been projected on the basis of three scenarios. The first scenario considered the historical production trend and an expected future decline in gas production. The other two scenarios have been considered from Gas sector Master Plan (GSMP) – a realistic scenario and high production scenario. Gas supply from the upcoming fields has been projected based on the production data available in the public domain.

The overall supply from imports might depend on a mix of the government's spot and long-term contracts to import LNG. However, as supply deficit will rise in the next few years with domestic production not being able to catch up, the utilisation of LNG terminals would increase. Bangladesh currently has two existing terminals and the Matarbari terminal is expected to come up in the future. Supply from the existing and new terminals has been calculated by multiplying their capacities with the expected utilisation. 2 scenarios have been considered for supply from imports: (i) Within the first scenario, the supply has been considered from 2 existing terminals and the upcoming Matarbari terminal per the public data; (ii) Within the second scenario, apart from the public data, additional import infrastructure of ~7.8 MMTPA has been assumed to be built in Bangladesh by FY 2025. In addition, some amount of production has been assumed to come from domestic offshore fields by considering certain volumes for offshore production from FY 2028.

The first scenario has been considered as the most plausible scenario because there hasn't been any offshore production in the country post closure of Sangu offshore field in 2013 and the utilisation of additional import infrastructure would depend on the volumes of long-term LNG contracts to be secured by the country.

The following is the summary of supply from different sources and the integrated demand-supply model for Bangladesh for the most plausible scenario:

Table 10 Integrated gas demand-supply projections for Bangladesh for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	88.8	93.5	97.8	102.6	110.6	118.8	126.9	134.6	142.2
Domestic supply	63.9	62.1	60.3	58.7	57.1	55.6	54.1	52.7	51.4
Production from upcoming fields	0.0	0.2	0.3	0.4	2.1	2.9	3.7	4.4	4.9
Imports	22.6	23.1	28.8	34.6	40.3	47.3	50.1	52.9	52.9
Total supply	86.5	85.3	89.4	93.6	99.5	105.8	107.9	110.0	109.2
Deficit (-)/surplus (+)	-2.2	-8.1	-8.4	-9.0	-11.0	-13.0	-19.0	-24.6	-33.0

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	150.2	157.5	164.1	170.1	175.4	180.1	184.3	188.1	191.4	194.2
Domestic supply	50.1	48.9	47.8	46.6	45.6	44.5	43.6	42.6	41.7	40.8
Production from upcoming fields	4.1	3.4	2.7	1.9	1.7	1.7	1.7	1.0	1.0	0.7
Imports	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Total supply	107.2	105.2	103.4	101.5	100.2	99.1	98.1	96.5	95.6	94.4
Deficit (-)/surplus (+)	-43.0	-52.3	-60.7	-68.7	-75.2	-80.9	-86.2	-91.6	-95.8	-99.8

In case Scenario – 2 plays out for the supply from imports and offshore production, following would be the projections and summary for overall demand and supply for natural gas in Bangladesh:

Table 11 Integrated gas demand-supply projections for Bangladesh for Scenario-2 in supply from imports (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	88.8	93.5	97.8	102.6	110.6	118.8	126.9	134.6	142.2
Domestic supply	63.9	62.1	60.3	58.7	57.1	55.6	54.1	52.7	51.4
Production from upcoming fields	0.0	0.2	0.3	0.4	2.1	2.9	3.7	4.4	4.9
Production from offshore fields	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	4.0
Imports	22.6	23.1	28.8	37.4	44.5	55.7	62.7	72.5	75.3
Total supply	86.5	85.3	89.4	96.4	103.7	114.2	122.5	131.6	135.6
Deficit (-)/surplus (+)	-2.2	-8.1	-8.4	-6.2	-6.8	-4.6	-4.4	-3.0	-6.6

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	150.2	157.5	164.1	170.1	175.4	180.1	184.3	188.1	191.4	194.2
Domestic supply	50.1	48.9	47.8	46.6	45.6	44.5	43.6	42.6	41.7	40.8

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Production from upcoming fields	4.1	3.4	2.7	1.9	1.7	1.7	1.7	1.0	1.0	0.7
Production from offshore fields	4.0	6.0	6.0	6.0	6.0	8.0	8.0	10.0	10.0	10.0
Imports	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
Total supply	136.4	136.4	134.6	132.7	131.4	132.3	131.3	131.7	130.8	129.6
Deficit (-)/surplus (+)	-13.8	-21.1	-29.5	-37.5	-44.0	-47.7	-53.0	-56.4	-60.6	-64.6

Within both the scenarios, Bangladesh is expected to face gas shortage in meeting the projected demand within the country.

4. Nepal

In 2018, overall energy consumption of Nepal was ~14 Mtoe consisting of 72 percent biomass, 19 percent POL products, 6 percent coal, and 3 percent from hydroelectricity, and other renewable energy resources.[49] Nepal is rich in fuels such as biomass (from firewood) and hydro reserves. However, it has small quantities of coal reserves and no proven petroleum reserves.

Current gas demand and supply: As of now, there is no gas demand or supply in Nepal. Role of gas-based power in Nepal is non-existent as it has huge hydropower potential. However, the recent floods and blackouts due to forced shutdown of several hydropower stations exposed the need for a back-up generation source in which natural gas can prove to be an important fuel. Nepal is also exploring the feasibility of introducing natural gas through a pipeline from India for supply to industries.

Gas value chain: Natural gas consumption is negligible compared with other fuels in the primary energy mix. The country's energy sector is managed by the Ministry of Energy, Water Resource, and Irrigation (or MoE). It is responsible for formulating policies for the power and energy sector alongside the Ministry of Industries (MoI) (takes care of policies and regulations for coal and POL products). Nepal Oil Corporation (NOC), a public enterprise under the Ministry of Industry, is responsible for managing imports, storage, and distribution of petroleum products throughout the country. The country faces the following challenges with respect to gas – no large-scale fossil fuel reserves, earthquake prone areas, and impact on supply and imports after COVID-19.

Infrastructure: The government is still in the process of exploring opportunities associated with natural gas. Recently, a seismic survey was conducted in the Dailekh district of Nepal to explore petroleum and natural gas per an agreement between Nepal and China. The country has also recently discovered 300 MCM of a proven gas reserve in the Kathmandu Valley, which the country plans to exploit for use as a cooking fuel in a pilot project. Nepal and India have agreed to study the feasibility of the liquefied natural gas pipeline stretching from Gorakhpur in India to Rupandehi in Nepal.

Regulations and policies: The government is encouraging the use of natural gas in the country through various measures, such as collaborating with the Indian government and setting up a Joint Working Group (JWG). The JWG has deliberated on several projects related to setting up LPG bottling plants, as well as laying cross-border LPG pipelines, LNG pipelines, petroleum products pipelines, etc. In alternative fuels, use of bio Compressed Natural Gas (bio CNG) is increasing to reduce dependence on fossil fuels.

Pricing: As natural gas is not being consumed, the authorities have made no provision that demonstrates the gas pricing strategy. However, considering the potential demand in the future, the country can be supplied natural gas from India from the nearby areas on the eastern side. The primary sources of carrying out trade with Nepal will be through road transportation and pipeline infrastructure as Nepal is a land-locked country. The analysis has been made for landed cost of LNG from India to Nepal through a pipeline and ssLNG road transportation. The overall estimated cost of natural gas comes in the range of US$19.5-31.2/mmbtu in case of pipeline transportation and US$20-32 in case of ssLNG (including retail distribution costs).

Demand assessment: Gas demand in Nepal is expected to be driven by several factors – setting up of urea factories and industries at a large scale, shifting towards cleaner fuels in the domestic sector, and more economical pricing of natural gas compared with other alternative fuels. Demand calculation has been done for

[49] *IRENA*

the CGD sector based on the data provided by Nepal Oil Corporation for the historical consumption of LPG, petrol, and diesel in Nepal. Two scenarios have been created for projecting the future consumption of petrol, diesel, and LPG – first is based on a historical CAGR and second is based on regression with GDP. Based on the projections in both the scenarios, switch over percentage to natural gas is assumed to calculate the overall demand. Further analysis has been carried out for Nepal to calculate overall demand by region in which Biratnagar, Amlekhgunj, and Kathmandu are expected to constitute over 50 percent of the natural gas demand in Nepal.

Supply assessment: A limited amount of natural gas reserves has been found in some pockets of the Kathmandu Valley. Probable reserves identified so far need further confirmation to be of any use for commercial exploitation. Further, the Nepalese Ministry of Supplies has decided to build a urea factory in Bardaghat and Nawalparasi. These upcoming projects can boost natural gas consumption that can be provided through imports.

The following is the summary of integrated demand-supply model for Nepal:

Table 12 Integrated gas demand-supply projections for Nepal for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.39	0.83	1.29	1.74	2.07	2.45	2.81	3.26	4.11
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.39	-0.83	-1.29	-1.74	-2.07	-2.45	-2.81	-3.26	-4.11

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	5.15	5.56	6.01	6.49	7.01	7.57	8.17	8.83	9.53	10.30
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-5.15	-5.56	-6.01	-6.49	-7.01	-7.57	-8.17	-8.83	-9.53	-10.30

5. Sri Lanka

In 2020, primary energy consumption of Sri Lanka was ~7.88 Mtoe consisting of 64 percent oil, 21 percent coal, and 15 percent renewables.[50] Non-renewable energy sources, such as oil and coal, form the major backbone of the energy supplies in the country.

Current gas demand and supply: As of now, there is no gas demand or supply in Sri Lanka. To comply with LTGEP plans, Sri Lanka is looking to build up LNG-based power plants in the future. In addition, an LNG trading hub is planned for bunkering, using its proximity to a busy shipping lane and supply to neighbouring regions. Demand exists for at least ~10 mmscmd to meet gas requirements from planned power plants, the transport (CNG) sector, and industries.[51]

Gas value chain: As of now, there is no use of natural gas within the country. Hence, the exact value chain of natural gas cannot be defined for Sri Lanka. The government has published a "National Policy on Natural Gas," which aims to facilitate the transition towards natural gas from conventional energy sources. The country faces several challenges in gas exploration – difficulties in attracting investors, de-risking of exploration activities, technological challenges for getting necessary data, etc.

Infrastructure: As of now, no natural gas has been produced or imported within Sri Lanka over the past few years. However, the country has undertaken various exploration and production activities of oil and natural gas over the past few years. Pearl Energy Ltd. has signed an agreement to launch the Hambantota LNG hub. A US-based company called New Fortress Energy has signed a framework agreement with Sri Lanka's government to construct a new offshore LNG terminal.

Regulations and policies: Several policy initiatives have already been undertaken to introduce natural gas in the country – creation of the Long-Term Generation Expansion Plan (LTGEP) in which LNG will be one of the major power-generating sources and the National Policy on Natural Gas (NPNG) by the Petroleum Development

[50] *BP statistical review*
[51] *Economic Times, January 2018 - https://rb.gy/f6drwt, Deloitte analysis*

Authority of Sri Lanka in 2019 to define natural gas vision and consideration by the government to negotiate deals for LNG procurement. However, in case of alternative fuels, several trends have emerged – discarding of construction plans for coal-based power plants in the country, increasing demand for POL fuels in the future due to economic growth, and encouraging the private sector to set up Other Renewable Energy (ORE) plants.

Pricing: At present, there is no public data for gas pricing mechanism in the country. This is because natural gas has not been produced or imported within the country. Gas can be supplied to Sri Lanka from India through ssLNG cargoes (through breakbulk facilities). The transport of fuels through ssLNG considers various cost components – DES price for India, custom duty, port handling charges, loading charges (along with GST), transportation costs, port charges for Sri Lanka, and retail distribution costs. The estimated price of natural gas would come in the range of US$19.5-30.6/mmbtu, making it more economical compared with petrol and diesel for Sri Lanka.

Demand assessment: Gas demand in Sri Lanka is expected to be driven by several key drivers – production of urea fertilisers within the country, increase in power consumption, commitments for conversion of fuel-oil based power plants to LNG, and shift from dendro as a fuel source. Through the top-down approach (using a regression analysis between GDP and primary energy consumption), gas demand is projected to increase up to 10 mmscmd in FY 2030 and 18 mmscmd in FY 2040 (after considering the scenario of seven-year growth rate of GDP).

For the bottom-top demand assessment, the following sectors were considered:

- **Fertilisers:** In the current scenario, there is no indigenous fertilisers production in Sri Lanka and demand is met through imports. The government of Sri Lanka now prepares to produce the urea fertiliser locally and a study is being conducted to assess its feasibility. The estimation of gas demand from the fertiliser plant has been done on the basis of expected urea requirement in the future, expected energy consumption of the fertiliser plant, and the announced capacity.
- **Refining:** For the refining sector, currently two refineries in Sri Lanka have been considered to estimate natural gas demand – the Sapugaskanda refinery operated by the Ceylon Petroleum Corporation and the Hambantota refinery. For estimating demand from both the refineries, the following factors have been considered – refining capacity, percentage of natural gas in fuel mix, fuel and loss percentage, and the expected year of pipeline connectivity.
- **Power:** Demand from the power sector in Sri Lanka is expected to be driven by the following drivers - West Coast and Kelanithissa Combined cycle plants are likely to be converted into natural gas and about 10 gas-based fire power plants are expected to come up in Sri Lanka in the future (according to LTGEP). Demand from the power sector has been assessed after taking the following factors into consideration – upcoming and retiring power plants per LTGEP, capacity of power plants, and expected utilisation.
- **CGD:** Demand from the CGD sector in Sri Lanka can be driven by the government's initiatives – using dimethyl ether as a substitute for diesel, development of necessary infrastructure, concessions on purchase of CNG fitted vehicles, encouraging use of LNG in public transport, public-private partnerships, and building new infrastructure. Demand from the CGD sector has been estimated by projecting demand for POL fuels in future and, assuming two scenarios of switch over rates, from POL fuels.

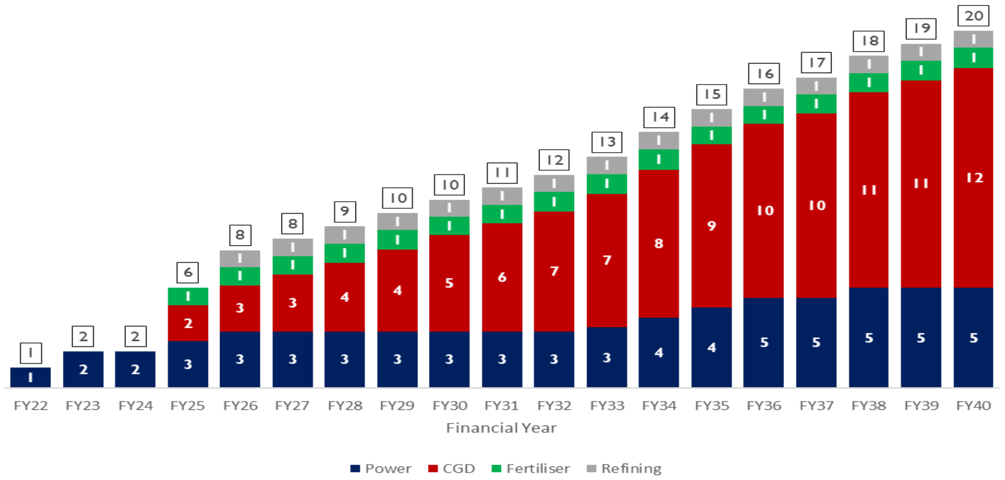
The following is the summary of demand projections from different sectors in Sri Lanka:

Table 13 Sector-wise gas demand projections for Sri Lanka for most plausible scenarios (in mmscmd)

Sector	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	1.1	2.0	2.0	2.6	3.1	3.1	3.1	3.1	3.1
CGD	0	0	0	2.0	2.5	3.1	3.8	4.5	5.3
Fertiliser	0	0.0	0.0	1.0	1.0	1.0	1.0	1.1	1.0
Refining	0	0	0	0	0.9	0.9	0.9	0.9	0.9
Total	**1.1**	**2.0**	**2.0**	**5.5**	**7.6**	**8.2**	**8.9**	**9.6**	**10.3**

Sector	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	3.1	3.1	3.3	3.9	4.4	5.0	5.0	5.5	5.5	5.5
CGD	5.9	6.6	7.3	8.1	9.0	9.5	10.1	10.7	11.4	12.1
Fertiliser	1.0	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.1	1.1
Refinery	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**11.0**	**11.7**	**12.7**	**14.0**	**15.3**	**16.4**	**17.0**	**18.2**	**18.9**	**19.6**

Figure 7 Trend of sector-wise demand projections in Sri Lanka for most plausible scenarios (in mmscmd)



Supply assessment: Sri Lanka has undertaken various exploration and production activities of oil and natural gas. The first bidding round for the Mannar and Cauvery basins was held in 2007. Several bids have been awarded to different companies for undertaking seismic data collection and exploration activities in different blocks of Mannar and Cauvery basins. To address demand in the next few years, Sri Lanka is increasingly looking towards FSRU-based LNG distribution. Pearl Energy (Pvt) Ltd. signed an agreement with the Board of Investment of Sri Lanka to launch 'Hambantota LNG Hub' - a floating storage LNG trading facility at the Port of Hambantota. The initial capacity of the LNG trading facility is expected to be 1 MMTPA and the facility has been assumed to commence from FY 2025. New York-based New Fortress Energy has signed a framework agreement with Sri Lanka's government to construct a new offshore LNG terminal and supply LNG to the existing 300 MW Yugadanavi power plant.[52]

The following is the summary of the integrated demand-supply model for Sri Lanka:

Table 14 Integrated gas demand-supply projections for Sri Lanka for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	1.1	2.0	2.0	5.5	7.6	8.2	8.9	9.6	10.3
Total supply	0	0	0	3.6	3.6	3.6	3.6	3.6	3.6
Deficit (-)/surplus (+)	-1.1	-2.0	-2.0	-1.9	-4.0	-4.6	-5.3	-6.0	-6.7

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	11.0	11.7	12.7	14.0	15.3	16.4	17.0	18.2	18.9	19.6
Total supply	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Deficit (-)/surplus (+)	-7.4	-8.1	-9.1	-10.4	-11.7	-12.8	-13.4	-14.6	-15.3	-16.0

6. Afghanistan

In 2018, the overall energy consumption of Afghanistan was ~3.4 Mtoe consisting of 42 percent oil, 4 percent natural gas, 29 percent coal and others, 20 percent biomass, and 5 percent solar and hydro.[53]

Current gas demand and supply: In 2018, according to IRENA, natural gas accounted for ~4 percent of the overall energy consumption in Afghanistan. About 200 MW of a gas-based power plant is planned in Sheberghan that would require 0.8-1 mmscmd of natural gas.[54] In addition, demand for natural gas is generated from the Mazar-e-Sharif (Kod-e-Barq) fertiliser plant in Afghanistan. However, no public data for natural gas demand and supply numbers in Afghanistan is available.

[52] *https://www.businesswire.com/news/home/20210713005674/en/New-Fortress-Energy-to-Develop-New-350-MW-Power-Plant-in-Sri-Lanka*
[53] *IRENA*
[54] *SARI/EI, IFC, Diesel and gas turbine worldwide - https://rb.gy/kb4td4*

Gas value chain: The Ministry of Energy and Water (MEW) mainly manages Afghanistan's energy sector. MEW is responsible for formulating policies for power, coal and gas, and other primary fuels. MEW collaborates with the Ministry of Mines and Petroleum (MOMP) to formulate policies and attract investments for the energy sector. Afghanistan Oil and Gas Regulatory Authority (AOGRA) is the oil and gas regulator. Afghanistan Gas Enterprise (AGE) is the state-owned enterprise primarily responsible for upstream gas exploration and production in the country.

Infrastructure: The country currently has an 89-km gas pipeline (built in 1974) that connects Sherberghan gas fields to the Mazar-e-Sharif fertiliser plant. Afghanistan recently started extracting gas from a newly discovered field in the Sherberghan gas fields only.[55]Construction of a new 94.5 km pipeline from Sherberghan to Mazar-e-Sharif is in process; of which, 45 km has already been completed. Major upcoming infrastructure for gas imports in Afghanistan is the TAPI pipeline. The pipeline was expected to be operational from late 2022. However, the expected completion might get delayed due to recent political matters in the country.

Regulations and policies: Afghanistan did not have any laws and regulations for the oil and gas sector until 2005. Afghanistan's first hydrocarbon law was adopted in 2009, under which two exploration and production-sharing contracts were awarded. No public data revealing any latest policies for promoting natural gas, is available. For the alternative fuels, Afghanistan's government had formed in a policy to promote the use of renewable energy sources – "Afghanistan National Renewable Energy Policy". This policy aimed to introduce renewable energy in the national energy sector plans through commencement of different RE projects in the country.

Pricing: No legal framework is available in the country to regulate gas pricing. A few methodologies had developed but were not adopted because of lack of consensus. Pricing for current customers is being decided by the AGE Board of Directors.[56]

Demand assessment: Given the lack of electricity access to a large section of the population in the country, there is a significant potential to expand gas-based power generation once the gas fields are developed in the country or the TAPI pipeline is operational. In addition, as new fertiliser plants are announced in the country, gas demand would subsequently increase in the future.

For the bottom-up approach of demand assessment, the following sectors were considered in Afghanistan:

- **Fertilisers:** For analysing natural gas demand from the fertiliser sector, data from only one plant (the Kod-e-Barq fertiliser plant) has been considered from the public domain. Most of the fertiliser demand in the country is met through imports through the China Pakistan Economic Corridor (from Gwadar Port in Pakistan). Demand calculation has been done on the basis of projections of expected capacity utilisation and average consumption per KT urea production.
- **Power:** The penetration of electricity within the households of Afghanistan has been close to ~35 percent[57] and most of the un-electrified households in the country live in rural areas. For non-renewable power generation, the country had 14 diesel-based and two oil-based power plants, as of FY 2018. Two power plants have been considered for the analysis of power sector demand in Afghanistan – Mazar[58] and Sherberghan gas power plants.[59] The PLF of these plants has been considered to improve gradually considering the increasing power demand in Afghanistan. Demand calculation has been done on the basis of the capacity of these power plants, expected PLF, and gas required for 1 MW power generation.

The total demand projection using the bottom-up approach for Afghanistan is expected to increase from 0.58 mmscmd in FY 2022 to 1.95 mmscmd in FY 2030 and 3.13 mmscmd in FY 2040.

Supply assessment: Major gas reservoirs of Afghanistan are located in the north and northwest regions near the Uzbekistan and Turkmenistan borders. The country currently produces only 5 percent of its domestic fuel demand and the rest of the fuel demand is fulfilled by imports from other countries.[60] Domestic production has been calculated at an expected CAGR considering discovery of new domestic resources in the next few years. Supply through imports for Afghanistan was assessed through the TAPI pipeline and scenarios were considered

[55] https://www.aa.com.tr/en/asia-pacific/afghanistan-starts-gas-extraction-after-4-decades/1789496
[56] ADB Assessment of Gas and Power Subsector in Afghanistan
[57] SAARC Energy Outlook
[58] https://www.nsenergybusiness.com/projects/mazar-e-sharif-gas-to-power-project/
[59] https://momp.gov.af/work-progress-%C2%A0bayat%C2%A0power-plant-production-electrical-energy-natural-gas
[60] SAARC Energy Outlook

for both its completion and non-completion. Within the basecase scenario, the pipeline was assumed not to get completed.

The following is the summary of integrated demand-supply projection for natural gas in Afghanistan:

Table 15 Integrated gas demand-supply projections for Afghanistan for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total Demand	0.58	0.75	0.81	0.86	1.38	1.53	1.69	1.82	1.95
Total Supply	0.5	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1
Deficit (-)/Surplus (+)	-0.1	-0.2	-0.2	-0.2	-0.6	-0.7	-0.8	-0.8	-0.8

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	2.13	2.30	2.46	2.61	2.74	2.86	2.94	3.00	3.06	3.13
Total supply	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8
Deficit (-)/surplus (+)	-1.0	-1.1	-1.2	-1.3	-1.3	-1.4	-1.4	-1.4	-1.3	-1.3

7. Bhutan

In 2018, the overall energy consumption of Bhutan was ~1.8 Mtoe consisting of 12 percent oil, 6 percent coal and others, 33 percent solar and hydro, and 49 percent biomass.[61] Bhutan is rich in fuels such as biomass (from firewood, biogas, and briquettes) and hydro reserves. However, it has small quantities of coal reserves and no proven petroleum reserves.

Current gas demand and supply: As of now, there is no gas demand or supply in Bhutan. However, gas demand in the country in the future is expected to come primarily from the transport and domestic sectors.

Gas value chain: The Department of Trade under the Ministry of Economic Affairs (MoEA) oversees the refinery's operations. The Department of Trade (DoT) oversees the import of oil and petroleum products and their distribution. The Royal Government of Bhutan (RGoB) has a long-term agreement with the government of India to supply petroleum products. Bhutan does not consume natural gas due to unavailability of proven domestic sources and lack of pipelines from India or China. Natural gas may have a role to play in the transport sector and industry depending on the development of the gas ecosystem in the country.

Infrastructure: Bhutan does not have any planned infrastructure for transportation and distribution of natural gas. The following can be infrastructure options for supply to Bhutan – extension of the Barauni-Guwahati pipeline from Jalpaiguri to Thimphu, gas import from Darjeeling and Kalimpong, and supplies through ssLNG.

Regulations and policies: Bhutan aims to remain carbon neutral, building upon a commitment made by the country in 2009. The Alternative Renewable Energy Policy (AREP) 2013 provided a comprehensive set of guidelines on suitable policy instruments, deployment pathways, and capacity developments for renewable energy. The government is encouraging people to use EVs to reduce dependency on fuel imports. Popularity of biogas is also increasingly in rural Bhutan.

Pricing: As Bhutan completely depends on imports with no domestic reserves, no policy pertaining to gas pricing could be ascertained. Natural gas can be supplied to Bhutan from either through ssLNG road transportation or from pipeline infrastructure. The levelised tariff from pipeline transportation are expected to be quite high because of low demand of the country. Approximate end-consumer prices of LNG supplies through ssLNG are expected to fall in the range of US$20-32/mmbtu in Bhutan, making it more economical than petrol and diesel.

Demand assessment: Some drivers that can lead to an increase in gas demand are – the country's aim to remain carbon neutral, expected demand from the transport sector, and potential of replacing LPG as fuel after the introduction of piped natural gas through CGD networks. Demand calculation has been done for the CGD sector based on the data provided by National Statistics Bureau (Bhutan) for the historical consumption of LPG, petrol, and diesel. Two scenarios have been created for projecting the future consumption of petrol, diesel, and LPG – first is based on historical CAGR and second is based on regression with GDP. Based on the projections in both the scenarios, switch over percentage to natural gas has been assumed to calculate the overall demand.

[61] *IRENA*

Supply assessment: Several options can be considered for the gas supply to Bhutan considering cost economics are favourable – sourcing from Jalpaiguri through the Barauni-Guwahati pipeline, small diameter take-off pipelines from Darjeeling or Kalimpong, and ssLNG supply through cryogenic tankers from the Dhamra terminal. The ssLNG option seems to be the most feasible one considering low initial investments and overall low demand from Bhutan.

The following is the summary of integrated demand-supply model for Bhutan:

Table 16 Integrated gas demand-supply projections for Bhutan for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.08	0.09
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.01	-0.02	-0.03	-0.04	-0.04	-0.05	-0.06	-0.08	-0.09

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	0.10	0.12	0.13	0.15	0.17	0.18	0.19	0.20	0.21	0.22
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.10	-0.12	-0.13	-0.15	-0.17	-0.18	-0.19	-0.20	-0.21	-0.22

8. Maldives

In 2018, the overall energy consumption of Maldives was 0.58 Mtoe consisting of 86 percent diesel, 11 percent petrol, and 3 percent cooking gas .[62]

Current gas demand and supply: As of now, there is no gas demand or supply in Maldives. The government is focusing on usage of clean energy such as natural gas that can eventually lead to demand generation from different sectors.

Gas value chain: Due to lack of indigenous fossil fuels reserves, Maldives fully depends on imported POL to meet its energy needs. The Ministry of Environment and Energy is the primary body responsible for the government's environmental, energy, and climate policy.[63]The State Trading Organisation PLC (STO) is responsible for undertaking trading and commercial activity on behalf of the Maldivian government.[64]Maldives faces several challenges for the gas sector in the country ‑ no proven large-scale gas reserves, threat from climate change, and challenge of laying pipeline infrastructure for connecting islands with natural gas.

Infrastructure: As on date, no gas grid/existing pipeline infrastructure is dedicated towards transportation and distribution of natural gas in Maldives. LNG can be sourced for Maldives from several locations through ssLNG (from a breakbulk facility) – the Dahej LNG terminal, the Kochi LNG terminal, the Colombo port, and the Hambantota port. Internally within Maldives, LNG would be distributed in smaller-sized parcels directly to end-users using a combination of sea and land transport. Within the Greater Male region, gas can be distributed through a pipeline. For islands outside Male, ssLNG can be distributed through small-scale LNG carriers.

Regulations and policies: Maldives' Intended Nationally Determined Contribution (INDC) has established the country's intention to reduce its greenhouse gas emissions by 10 percent compared with business-as-usual by 2030 unconditionally.[65] The policy instruments supporting Maldives' vision for its energy sector are the Energy Policy and Strategy 2016 and the Strategic Action Plan (SAP) 2019‑2023. The government considers that investing in renewable energy is crucial to improve energy security and reverse the country's dependence on imported fossil fuels.

Pricing: As natural gas is not being consumed, the authorities have made no provision for the gas pricing.

Demand assessment: Several demand drivers could boost demand for LNG ‑ the government's push towards power generation through alternative energy sources, substitution possibilities for natural gas in heating processes, and usage of LNG in sea transport. Demand projections have been done for the CGD sector based on the data provided by Maldives Custom Services for the historical consumption of LPG, petrol, and diesel. Based

[62] *https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Maldives_Asia_RE_SP.pdf*
[63] *https://www.environment.gov.mv/biodiversity/about-us*
[64] *https://sto.mv/AboutUs*
[65] *https://www4.unfccc.int/sites/NDCStaging/Pages/All.aspx*

on the historical consumption, the future demand of these fuels has been projected at a reducing CAGR. Gas demand has been considered to increase from FY 2022 onwards based on penetration rates for conventional fuels. The expectation of the gas demand has been considered from the following sectors – power, industry, sea transport, and road transport.

Supply assessment: There are several opportunities to supply natural gas in Maldives. Petronet LNG Ltd. is exploring an opportunity to set up an LNG terminal in Maldives.[66] Pearl Energy plans to deploy small LNG carriers to redistribute LNG from Sri Lanka to Maldives. ssLNG can be built as modular structures with options to build upon existing infrastructures (e.g., harbours, jetty, and access roads).

The following is the summary of integrated demand-supply model for Maldives:

Table 17 Integrated gas demand-supply projections for Maldives (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.04	0.07	0.11	0.15	0.20	0.25	0.32	0.40	0.48
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.04	-0.07	-0.11	-0.15	-0.20	-0.25	-0.32	-0.40	-0.48

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	0.56	0.64	0.72	0.82	0.92	0.97	1.02	1.07	1.12	1.18
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.56	-0.64	-0.72	-0.82	-0.92	-0.97	-1.02	-1.07	-1.12	-1.18

[66] https://www.livemint.com/Industry/GzBJlonvBR5UYE2vNT9H5I/LNG-diplomacy-India-plans-to-build-terminals-in-4-nations.html

1. Overview

Natural gas is an odourless, gaseous mixture of hydrocarbons predominantly made up of methane. The fuel has several qualities that make it an efficient, relatively clean burning, and economical energy source. Burning of natural gas results in fewer emissions of nearly all types of pollutants compared with other Petroleum, Oil and Lubricant (POL) fuels. The clean burning properties of natural gas have contributed towards its increased use for electricity generation and as a transportation fuel in many countries. Moreover, fuel is less expensive compared with gasoline and diesel.

According to the International Energy Agency (IEA), global gas[67] demand forecast is expected to be up by 7 percent from the pre-COVID levels by 2024.[68]The demand would be driven by increased economic activity and gas, replacing other more polluting fuels in sectors such as electricity generation, industry, and transport. Almost half of the increase in gas demand is expected to come from the Asia Pacific region.

1.1 Background, objective, and scope of study

Background

South Asian Region (SAR) accounts for 24 percent of the world's population but only 4 percent of the global GDP.[69] The region accounts for 7.7 percent of the world's primary energy consumption and 3.6 percent of the world's natural gas consumption.

At present, Bangladesh, Pakistan, and India are the gas producing and consuming countries in the region. The share of natural gas in the total primary energy consumption for Bangladesh and Pakistan is quite significant at 63 percent and 43 percent, respectively, while for India, it is about 8 percent. Besides, these countries face challenges in their domestic gas production − which is on a decline and needs significant investments in exploration and production activities. These countries have installed LNG receiving terminals to fulfil gas demand − India in 2004, Pakistan in 2015, and Bangladesh in 2018. Imports accounted for 60 percent, 26 percent, and 18 percent of the natural gas consumption in case of India, Pakistan, and Bangladesh, respectively, for FY 2020.[70]

As LNG imports are more expensive, these countries have been facing challenges with respect to gas demand (affordability, switching costs, and awareness) and supply (due to declining or no domestic gas production, and lack of infrastructure for gas import). Shortage of domestic gas production has inhibited investments in pipeline infrastructure and consequently limited the penetration of natural gas.

In the past 5-7 years, new LNG receiving terminals have come up in India while Pakistan and Bangladesh have plans to add LNG receiving infrastructure. While Sri Lanka has initiated plans to import LNG and include natural gas in its energy basket, the remaining South Asian countries (Nepal, Bhutan, and Maldives) do not have any natural gas infrastructure. However, studies have indicated at potential benefits of imported gas in their energy basket. Implementation of regional gas trading in South Asia (supported by market reforms and regulations) can make a substantial difference towards addressing the shortage of domestic gas in the region and introducing gas in countries such as Nepal, Bhutan, and Maldives.

The figure below provides an overview of the current status of the gas market in the SAR.

[67] *The terms "gas" and "natural gas" have been used interchangeably in the report.*
[68] https://www.iea.org/reports/gas-2020/2021-2025-rebound-and-beyond
[69] https://data.worldbank.org/country/8S
[70] *PPAC, BP Energy Statistics*

Figure 8 Overview of the gas market in the SAR

Context

Role of natural gas in SAARC countries

- The three major countries in South Asia, India, Bangladesh, and Pakistan, have either a significant role of natural gas or plans to increase natural gas's contribution to the energy mix. However, other countries have not yet realised the benefits of the fuel.
- There are no significant incentives in terms of policy measures to use natural gas compared with other more polluting fuels. In addition, there is a huge possibility of reduced E&P activity of global oil and gas majors in the region unless fiscal policies become attractive.
- The growth in LNG supply capacities and the attractive terms and conditions of LNG supply contracts offer enhanced degree of dependability on a long-term basis on imports.

Demand-supply dynamics and impact on end-use sectors

- South Asian countries are facing increasing challenges with respect to gas self-reliance due to declining domestic gas production and reserves, along with increasing imports of LNG.
- The supply-demand imbalance has led to curtailing of gas supply to certain sectors and increased reliance on alternative costly liquid fuels or reduced production in the industrial sector and stranded gas power plants.
- Gas demand in many sectors is price sensitive. While for other sectors, it is curtailed due to lack of infrastructure for gas supply and distribution.
- New technologies for 'small-scale LNG transportation' or the 'virtual pipeline' mode are being adopted and have emerged as a key enabler for timely availability of gas for consumers in far-flung areas not connected with pipelines. In addition, with increased investments in infrastructure of LNG terminals and pipelines, the 'latent' demand is likely to be fulfilled.

Regional trading and co-operation

- Energy trading across the South Asian region has been limited except for bilateral trades between India-Nepal, India-Bhutan, India-Bangladesh, and India-Pakistan.
- Cross-boundary trading in the oil and gas sector started recently with the commissioning of an oil product pipeline between India and Nepal in 2019.
- Despite the presence of substantial gas infrastructure in India, Pakistan, and Bangladesh and increased need for natural gas, cross-boundary gas trading is non-existent. Moreover, initiatives for cross-country pipelines (TAPI, IPI) have not really taken off and each country has relied on costly LNG infrastructure and volumes.

Demonstrated benefits of regional gas trading and hubs

- Markets in North American and Europe have benefited from establishing regional gas hubs. Cross-boundary trade through pricing freedom, increased competition, and flexibility of securing gas supplies, has spurred natural gas demand.

Potential benefits of regional gas trading in South Asia

- Implementing gas trading in South Asia, supported by market reforms, can make a substantive difference to players in this region and along the value chain.
- Gas trading hubs will augur well for better price discovery that will spur both supply and demand of gas. Further, trading may lead to reduced costs through sharing import infrastructure, favourable LNG contracts, and better utilisation.

As discussed above, several dynamics are changing in domestic production, supply,[71] demand, and infrastructure in the SAR. Emergence of new technologies for economical distribution of LNG such as ssLNG (small scale or 'virtual' LNG) has established that potential consumers in far flung areas not connected by pipelines can be supplied gas/LNG (at competitive prices) in less time compared with laying pipelines. These dynamics are impacting the policy push towards cleaner fuel, emergence of unconventional gas supply options, and newer technologies for existing/new uses, such as transportation, City Gas Distribution (CGD), and power production.

[71] *IEA 2018, BP Energy Statistical Review 2020, IRENA, World Bank, WITS – World Integrated Trade Solution, Oxford Energy, Deloitte Analysis*

The figure below provides a snapshot of key challenges[72] and changing dynamics in the industry.

Figure 9 Key challenges and changing dynamics in the industry

	Key challenges	Changing dynamics
Supply	• Declining domestic gas production and/or reserves • Increasing reliance on LNG import to meet supply shortfall	• Incremental domestic gas production expected from recently awarded fields, along with increased regasification terminals capacity • Innovations in small-scale LNG to provide economical solutions to areas that are not connected by pipelines
Demand	• Supply-demand imbalance has led to curtailing of gas supply to certain sectors; this increased reliance on alternative costly liquid fuels or reduced production in the industrial sector and stranded gas power plants	• Increased investments in the pipeline infrastructure and regasification terminal capacity by India, Pakistan, and Bangladesh for accommodating additional LNG volumes • Increasing awareness for gas as a more economical and environmentally friendly fuel than liquid petrol • Easing of the gas supply constraints and the ease in switching is likely to spur demand
Consumption of natural gas	• India, Bangladesh, and Pakistan have lower per capita energy and gas consumption vs. global peers • Remaining countries, such as Bhutan, Nepal, Sri Lanka, and Maldives have not yet realised the benefits of natural gas	• Increased policy support to increase adoption of natural gas. For example, NPNG in Sri Lanka • LNG being promoted for use in the power sector and commercial transportation
Regional gas infrastructure	• Regional initiatives on cross-country pipelines have not materialised. • Concerns exist around tariff, security, and required investments.	• Regional gas trading would help address supply-demand imbalances, efficient utilisation of infrastructure, and promote free market pricing. • Increased need to address supply shortage would put pipelines back in focus. • Several gas pipelines are being laid closer to the geographical boundaries and have the potential to be used for cross-border trade
Policies and regulations	• No specific incentives for preferring natural gas over other relatively polluting fuels • Limited market pricing of natural gas	• Climate commitments to reduce emissions • Possibility of reduced E&P activity of global oil and gas majors unless fiscal policy is attractive

Several LNG liquefaction projects face issues around financial closure on account of lack of long-term contracts serving as a guarantee for the project's capacity usage. According to multiple analysts,[73] the LNG market is expected to remain oversupplied because of these new liquefaction capacities, resulting in lower prices. The oversupply may also lead companies to offer attractive prices for renegotiation of long-term contracts. These contracts are expected to provide certainty in the availability of LNG at transparent prices for consumer countries. Therefore, opportunities are emerging in the LNG market for negotiating profitable deals for long-term and mid-term contracts to bring financial closures to these LNG liquefaction projects.

Several new capacities of LNG receiving terminals have been planned in India, Pakistan, and Bangladesh that could provide opportunities for securing profitable long-term and mid-term LNG contracts. With a spurt in the LNG receiving capacities coming up in the region, there is an opportunity to explore the potential of intra-regional trade amongst India, Pakistan, and Bangladesh as well as Nepal, Bhutan, Sri Lanka, and Maldives (which as of now, do not consume natural gas). Trade amongst the SAR countries can help overcome seasonal variations in demand and optimise the utilisation of the LNG receiving terminals and pipeline infrastructure in the region.

That said, cross border natural gas trade needs to be enhanced to spur both gas supply and demand in the region.

[72] *BP Statistical Review 2020; Ministry of Mines – Afghanistan, Tribune - shorturl.at/kmDFL, Down to Earth - shorturl.at/kEW34, Time of India - shorturl.at/blqEN*

[73] *BNEF, International Gas Union, SP Global*

The figure below provides a snapshot of key statistics of eight countries in the South Asian region – Bangladesh, India, Maldives, Pakistan, Sri Lanka, Afghanistan, Bhutan, and Nepal:[74]

Figure 10 A snapshot of key statistics of South Asian countries (2020)

	1380	2623	776	163
	221	264	81	113
	165	324	40.5	83
	39	20	3.4	0.42
	29	34	14	0
	22	81	7.8	0
	0.6	2.4	1.8	0
	0.5	4.0	0.58	0

Population *(2020, million)* | GDP *(2020, USD $ billion)* | Primary/Overall energy cons. *(Year¹, MToe²)* | Gas consumption *(2020, mmscmd)*

1. Data – India, Pakistan, Bangladesh, Sri Lanka (BP Statistics 2021) – 2020; Nepal, Bhutan, Afghanistan, Maldives (IRENA) – 2018
2. For India, Pakistan, Bangladesh, and Sri Lanka – the latest data of primary (commercial) energy consumption has been considered; for Nepal, Bhutan, Afghanistan and Maldives, the data for overall energy consumption, including biomass, has been shown.

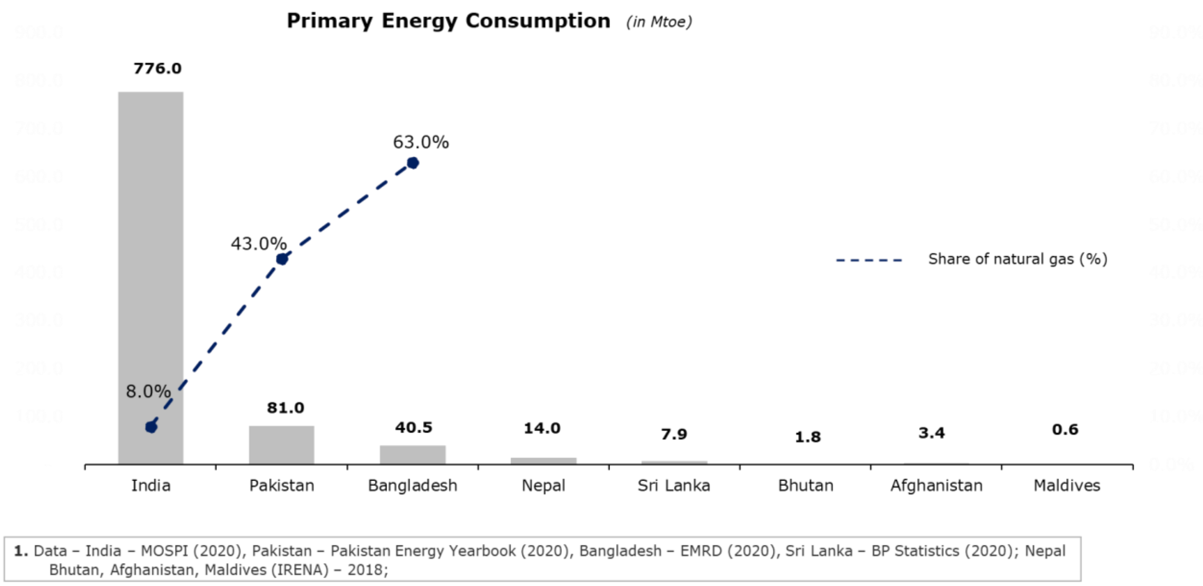
Existing pipeline | Proposed cross country pipeline | Existing LNG terminal | LNG terminal under construction or planning | Pipeline under planning | Pipeline under construction

- The region accounts for 24 percent of the world's population but only 4 percent, 6.9 percent, and 3.4 percent of the GDP, primary energy, and natural gas consumption, respectively. However, in terms of growth, it has grown faster than the world in terms of GDP (5 percent vs. 2.5 percent) and primary energy (3.6 percent vs. 1.0 percent).
- Per capita energy consumption in the region is one-third of the world average (0.5 vs. 1.7 in terms of toe per capita).
- Both the growth rate and lower per capital consumption signify the region's growth potential.
- In the region, only Bangladesh, India, and Pakistan consume natural gas.
- Trade within the region is limited except for the three landlocked countries of Afghanistan, Bhutan, and Nepal.
- India is the largest constituent in terms of area, population, economy size, energy consumption, and natural gas consumption.

[74] *Sources – IEA 2018, BP Energy Statistical Review 2021, IRENA 2018, Deloitte Analysis*

A wide disparity is seen in the total energy consumption as well as the share of natural gas for SAR countries, as shown in the figure below.

Figure 11 Primary energy consumption and share of natural gas, by country



Objective and scope of work

The objective of the study is to: (i) Make an assessment of long-term gas demand and supply potential; (ii) Assess cross-border natural gas trade potential and its potential benefits; (iii) Promote development of the gas market in the South Asian Region. A modelling exercise has been undertaken in the study to identify the cross-border natural gas trade potential in the SAR over the next 20 years. The study has been broadly divided into three sections. The first section majorly focuses on the assessment of the present gas ecosystem and long-term demand-supply projections in the SAR. The second section takes it forward to explore the potential of Cross Border Natural Gas Trade (CBNGT) in the region through demand-supply deficit and its potential benefits for member countries. The third and final section provides roadmap and recommendations for accelerating CBNGT in the region and development of the gas hub.

The first section of the study involves as-is assessment for the gas sector, along with long-term projections for demand and supply in the SAR. Within this section, an analysis has been made for countries with respect to different aspects of the gas ecosystem. These aspects include gas value chain, infrastructure, regulations and policies, and pricing followed by assessment of long-term demand and supply for the next 20 years. The study also assesses, reviews, and recommends the construction of appropriate Regasified Liquefied Natural Gas (RLNG) infrastructure to optimise gas trade in the SAR, after taking into account the existing and planned gas infrastructure. Moreover, for countries in the SAR that do not currently have gas, the study tries to assess the potential modes of gas supply and estimate the landed cost of LNG from India.

Based on this analysis, the second section of the study has been created. This involves assessing the overall regional CBNGT (Cross Border Natural Gas Trade) potential and trading potential for each South Asian country for the next 20 years. The likely economic, social, and environmental benefits of gas, along with the potential benefits of trading and switching to gas, have also been identified across the region. An analysis of different trade and infrastructure options to carry out gas trade in the region has also been done in the study. The exercise explores, analyses, and deliberates on the concept of modelling and sharing Regional Gas Hub in South Asia; this includes LNG infrastructure for regional optimisation both in terms of economy as well as energy sustainability. In addition, the section includes analysis of the regional gas hub models in global markets and identifies the key pre-requisites and enablers for development of a successful gas trading hub in South Asia.

Based on the above-mentioned information, the third section of the study involves creating a regional roadmap and recommending an action plan for initiating/accelerating the CBNGT in the region.

1.2 Import dependency for petroleum, oil, and lubricant fuels in the SAR

The SAR has been experiencing a rapid pace of industrialisation that has spiked fuel demand and energy consumption in the past few years for countries. Most countries rely on POL fuels to provide a significant portion of the energy consumption – India has ~28 percent of energy consumption from oil;[75] Pakistan and Bangladesh have ~20-25 percent;[76] Sri Lanka and Afghanistan have more than 40 percent;[77] and Maldives, as of now, has whole of its energy consumption from POL fuels.

The region has high levels of import dependence particularly for crude oil. Therefore, it is vulnerable to volatility in global crude prices and currency exchange rates. Import bills for countries in the region for POL fuels have been consistently on the rise. This would also lead to increasing strains on government budgets as POL fuels are more expensive, especially if subsidy policies remain in place that shield consumers from paying market-based energy prices. In addition, the large increase in POL fuel import raises energy security concerns. SAR nations spending on oil imports is mentioned below.

India: It imports close to 85 percent of its domestic oil needs. According to PPAC data, India imported ~US$ 62.2 billion of crude oil and ~US$ 14.8 billion of POL products for FY 2021. The POL fuels formed ~19.5 percent of India's overall import bill in FY 2021.[78] Due to a surge in oil demand and increasing crude oil prices, import bills for oil stood at US$ 51 billion and POL at ~US$ 10.1 billion for April−September in FY 2022.

Pakistan: It meets ~80 percent of its domestic oil needs through imports. According to the Pakistan Energy Yearbook, the country imported 6.7 million tons of crude oil in FY 2020, whereas the import of the finished petroleum products was 7.5 million tons. Overall oil import bill for petroleum and petroleum products was ~US$ 6.7 billion for FY 2020. The imports of POL fuels accounted for ~14 percent of the country's overall import bill.[79]

Bangladesh: According to the Energy Scenario report from Bangladesh Hydrocarbon Unit, Bangladesh meets ~94 percent of its crude oil demand though imports. The country imported about 1.26 million metric tons of crude oil, along with 4.04 million metric tons of refined petroleum products for FY 2020. The government spent ~US$ 5 billion for POL imports in FY 2020.[80] The imports of POL fuels formed ~10 percent of the country's overall import bill in FY 2020.[81]

Nepal: For FY 2019, crude oil import bill of Nepal was ~US$ 1.9 billion. The bill surged ~25 percent from the previous fiscal year due to increasing industrialisation and electrification in the country. Imports of petroleum products accounted for 15.2 percent of the country's total import bill.[82]

Sri Lanka: For FY 2020, the import bill for crude oil and refined petroleum products for Sri Lanka was ~US$ 2.3 billion which was ~14.5 percent of the country's overall import bill.[83]

Bhutan: According to the data from National Statistics Bureau, imports of POL products for Bhutan were ~US$ 98 million for 2020. The import of POL imports formed around 11 percent of the overall import bill in Bhutan.[84]

Afghanistan: It imports 100 percent of its total POL products requirement, mainly from Iran, Turkmenistan, and Uzbekistan. According to the SAARC Energy Outlook report, the country's import demand remained almost constant between FY 2013 and FY 2018 at ~2 million tonnes. In 2019, the country imported ~US$ 49.2 of the crude petroleum and ~US$ 325 million of the refined petroleum products.[85]

Maldives: It meets its energy needs through the imports of fossil fuels. According to the customs data of Maldives, the country had an import bill of ~US$ 242 million 2020 for POL fuels which was ~14 percent of the country's overall imports bill.

The following is a summary of the import data for crude oil and POL products for different SAR nations:

[75] *Energy Statistics of India, 2021*
[76] *EMRD (Bangladesh), Pakistan Energy Yearbook (Pakistan)*
[77] *IRENA (Afghanistan), BP Statistical Review (Sri Lanka)*
[78] https://www.india-briefing.com/news/indias-import-export-trends-in-2020-21-trade-diversification-fta-ftp-plans-23305.html/
[79] *Pakistan Bureau of Statistics*
[80] http://www.bpc.gov.bd/site/page/ce5d1818-8964-4446-96a9-c36f609e2647/-
[81] https://thefinancialexpress.com.bd/economy/bangladesh/bangladeshs-trade-deficit-snowballing-as-imports-far-outstrip-exports-1628045750
[82] https://kathmandupost.com/money/2019/08/06/oil-import-bill-soared-25-percent-to-rs214-48-billion-in-last-fiscal
[83] *Sri Lanka Socio Economic Data 2021*
[84] *National Statistics Bureau, Bhutan*
[85] https://oec.world/en/profile/bilateral-product/refined-petroleum/reporter/afg

Table 18 Import of crude oil and POL products in the SAR for 2020

Country	Crude oil (in Mn MT)	Refined petroleum products (in Mn MT)	Overall import bill (in Mn $)
India	227.0	43.8	77000.0
Pakistan	6.7	7.5	6700.0
Bangladesh	1.5	4.2	5000.0
Nepal	0.0	2.6	1900.0
Sri Lanka	0.6	1.7	2300.0
Bhutan	0.0	0.2	98.0
Afghanistan	0.2	1.8	374.0
Maldives	0.0	0.6	242.0

Net import bills in the region for POL fuels were ~US$ 93 billion accounting for ~14-20 percent of the overall import bill of the region. With the growing industrialisation and urbanisation in the region, demand is expected to increase sharply in the future. This will increase dependency on imports and burden on the government's coffers. This indicates the need for switching to affordable and less polluting sources of energy, along with promoting intra-regional trade amongst countries in the region.

Impact of Russia-Ukraine war on gas markets: The Russia-Ukraine war in 2022 led to huge increases in the crude oil prices in response to the uncertainty regarding the Russian supply to Europe, which ended up affecting the global spot market for LNG. The prices at different benchmark hubs like TTF (Title Transfer Facility), Henry Hub, JKM (Japan Korea Marker), etc. have moved in correlation with the crude oil prices. In response to the war, the European Union has developed plans to reduce its demand of Russian energy by at least two-thirds by 2022.[86] This is expected to create additional competition for spot LNG cargoes in the Atlantic basin.[87]The European Union intends to reduce the Russian dependence through increasing imports of piped and liquefied natural gas from other exporters, switching to alternate energy sources, and increasing energy efficiency. The European Union and US have recently signed a memorandum of understanding to develop energy relations and security between the two entities.[88] If the European Union depends solely on US for its additional LNG imports, there could still be adequate LNG capacity in the US already approved by the FERC (Federal Energy Regulatory Commission) that could provide supplies to other regions of the world. US currently has ~95 MMTPA of existing LNG export infrastructure along with ~49 MMTPA of FERC approved, under-construction and ~160 MMTPA of FERC approved, not under-construction LNG export terminals. Apart from that, even Mexico has ~14 MMTPA and Canada has ~216 MMTPA of government approved, not-under construction LNG export terminals.[89]

India purchases around 3 percent of its crude oil imports from Russia.[90] Moreover, in 2022, India intends to import ~2.5 MMTPA gas from Russia which would form ~2.7 percent of its imports.[91] Despite of the Russia-Ukraine conflict, India continues to purchase oil and gas from Russia as it is difficult for the country to replace the oil and gas requirements from other suppliers – who are already under strain. The increase in LNG imports from Europe has driven up the overall prices for gas and other fuels for the SAR because of the global fluctuations in crude oil prices. The spot market LNG prices in Asia have increased nearly three-fold from the levels of May 2021.[92] This might create short-term impact on the gas demand in the SAR because of the price-sensitivity of buyers in the region. In addition, the newly developed import infrastructure might remain underutilised within the short-term. However, the natural gas buyers in the SAR are now seeking to secure additional supplies through long-term contracts as a buffer against the volatile spot market prices. The prices of long-term imported LNG are expected to be more economical as compared to alternate POL fuels. Moreover, the volatility in spot LNG prices would provide additional incentives to domestic upstream companies in the region to produce more gas because it would be available at cheaper rates for the buyers as compared to spot LNG.

[86] https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511
[87] *IGX Gas Connect, March 2022*
[88] https://ec.europa.eu/commission/presscorner/detail/en/statement_22_2041
[89] https://cms.ferc.gov/media/north-american-lng-export-terminals-existing-approved-not-yet-built-and-proposed-8
[90] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/oil/050322-lured-by-cheap-oil-india-becomes-largest-customer-of-russian-urals-crude
[91] https://www.energyvoice.com/oilandgas/416676/indias-gail-seeks-long-term-lng-deal-eyes-expanding-ties-with-russias-gazprom/
[92] https://www.reuters.com/markets/commodities/europe-asia-gas-buyers-switching-long-term-supplies-beat-volatile-prices-2022-05-25/

SECTION A: DEMAND-SUPPLY ASSESSMENT IN THE SOUTH ASIAN REGION

2 India

2.1 Country overview

India is the largest country in the region in every aspect – area, population, primary energy, and natural gas consumption.[93]

2.1.1 Economy (GDP), population, primary energy consumption, and fuel mix

India is the sixth-largest economy in the world with a GDP of US$ 2623 billion[94] in 2020. Due to the impact of the pandemic, GDP contracted by 7.3 percent in FY 2020-21. The economy is expected to rebound the subsequent year, putting the country back on the economic growth path. The population was estimated to be ~1.38 billion in 2020.[95] India has the second-largest population in the world after China.

According to the Energy Statistics Data of India, primary energy consumption in 2020 was ~776 Mtoe and increased at an annual average growth rate of 3.6 percent in the past decade.[96] Here, the primary energy consumption consists only of the commercially traded energy sources and does not include non-commercial sources, such as biomass. Biomass power is also being used in different states and sectors of India. As of 2021, ~10 GW of biomass power generation projects have been installed in the country.[97] India's primary energy mix consists of ~86 percent fossil fuels (33 percent oil, 8 percent natural gas, and 45 percent coal) and 14 percent from electricity.

Figure 12 India: Primary energy consumption by source (2020)

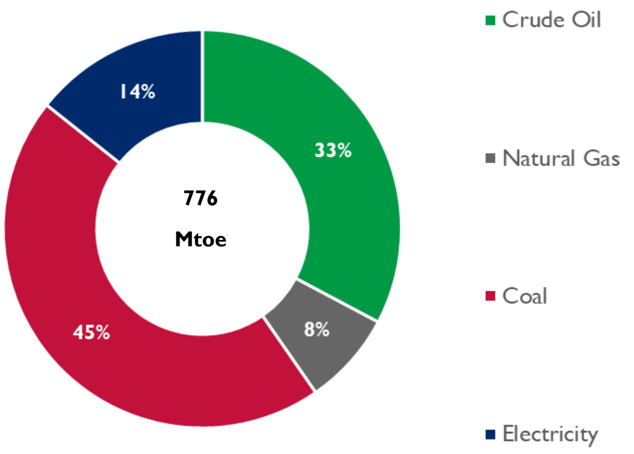


Table 19 India: Primary energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Crude oil (33%)	256
Natural gas (8%)	62
Coal (45%)	349
Electricity (14%)	109

[93] *World Bank, IMF, BP Energy Statistics*
[94] *World Bank, GDP at current $*
[95] *World Bank*
[96] *Data provided on Page 61 of Energy Statistics India 2021 Report and converted from petajoules to mtoe*
[97] *https://mnre.gov.in/bio-energy/current-status*

2.1.2 Gas value chain

Gas value chain in India consists of various players in the upstream, midstream, and downstream segments, along with various regulators and ministry bodies.

Upstream

Natural gas is produced from onshore, offshore, and Coal Bed Methane (CBM) fields in India by public-sector companies, such as Oil and Natural Gas Company (ONGC) and Oil India Ltd. (OIL), and private players, such as Reliance Industries Ltd. (RIL), Cairn, Great Eastern Energy Corporation Ltd. (GEECL), and Essar.

Midstream

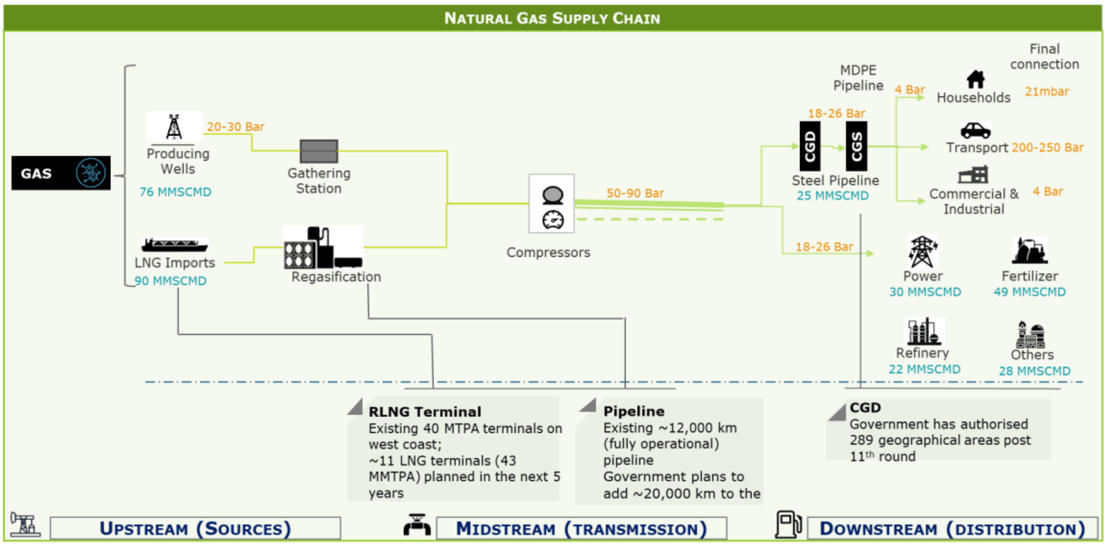
The midstream sector is dominated by Gas Authority of India Ltd. (GAIL) that operates ~65 percent of the total operational natural gas pipelines in India. Other players are Gujarat State Petronet Ltd. (GSPL), Indian Oil Corporation Ltd. (IOCL), Assam Gas Company Ltd. (AGCL), and Reliance Gas Pipelines Ltd. (RGPL).

In the LNG import segment, players consist of Petronet LNG, Shell, GAIL, IOCL, Gujarat State Petroleum Corporation (GSPC), and Adani that operate RLNG terminals. The number of players will increase after commissioning of under construction or announced RLNG terminals.

Downstream

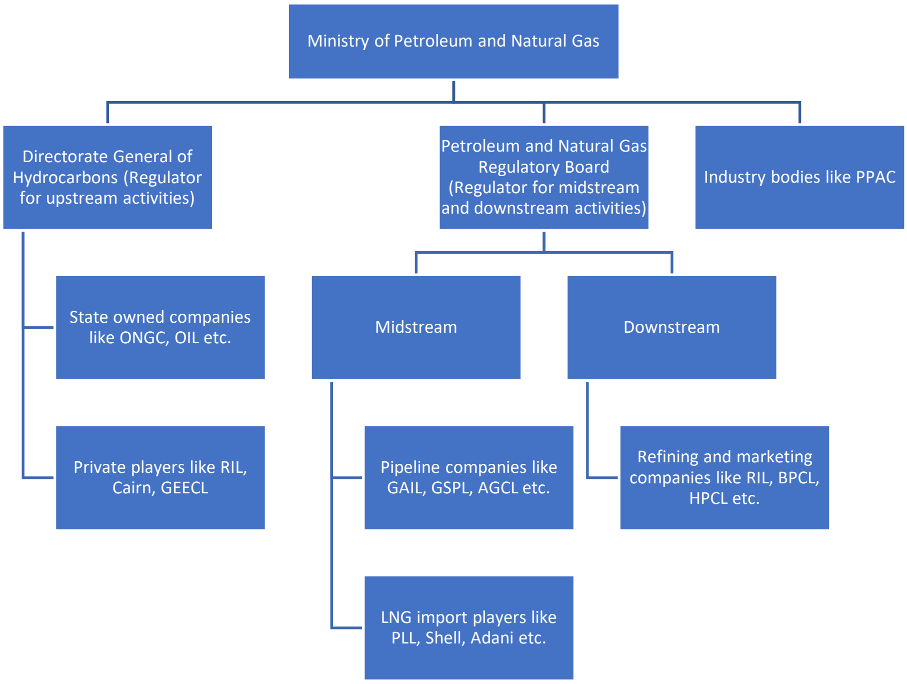
The downstream sector consists of players from major demand segments – City Gas Distribution (CGD), power, fertilisers, refining, petrochemicals, and others.

Figure 13 Natural gas supply chain (for FY 2021)



In addition to the players mentioned above, the Ministry of Petroleum and Natural Gas is the government ministry managing natural gas sector in India. The Directorate General of Hydrocarbon is the Indian governmental regulatory body under the Ministry of Petroleum and Natural Gas. It looks after the development and regulation of the upstream oil and gas sector. The Petroleum and Natural Gas Regulatory Board regulates the refining, processing, storage, transportation, distribution, marketing, and sale of petroleum, petroleum products, and natural gas, excluding production of crude oil and natural gas. Following is the organogram of the hydrocarbon sector in India:

Figure 14 Organogram of hydrocarbon sector in India



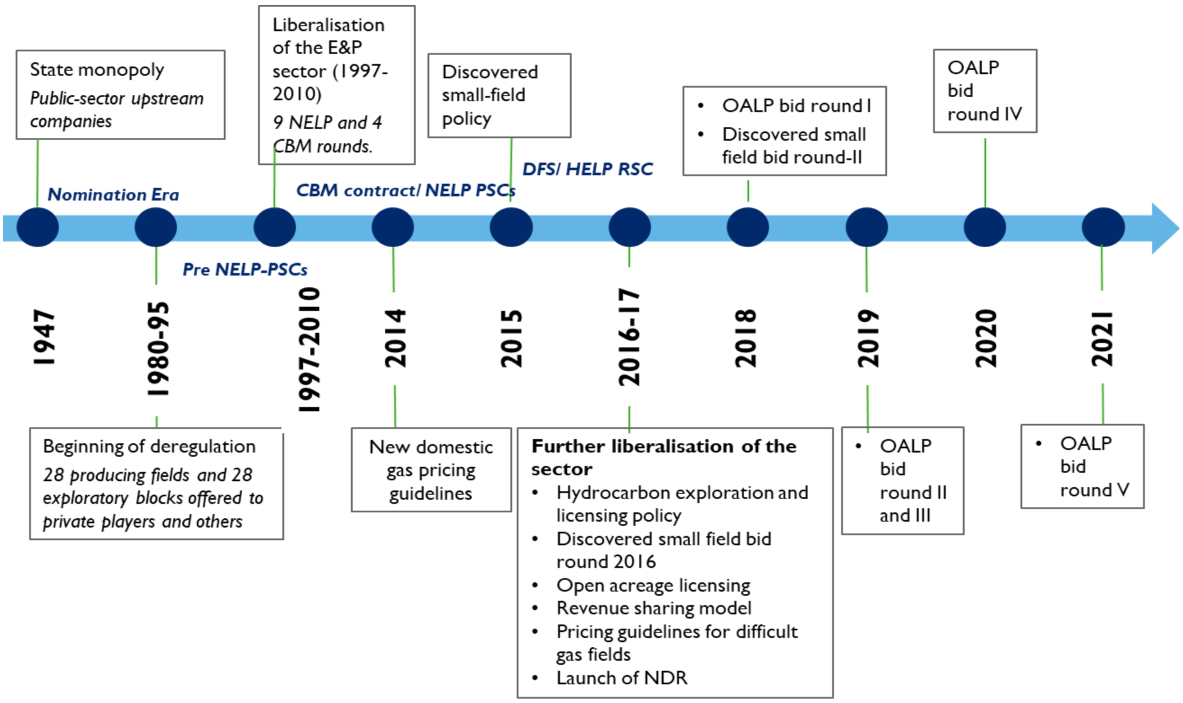
2.1.3 As-is assessment and challenges in the gas sector

Natural gas accounts for ~8 percent of the total energy mix in India at present. The government has set an ambitious target to increase the share of natural gas to 15 percent of the energy mix by 2030.

Upstream exploration and production scenario in India

When India gained independence in 1947, there was a state monopoly in the oil and gas sector. After the independence, Indian leaders realised utility of oil and natural gas in rapid industrialisation and security of the country. While formulating industrial policy in 1948, the development of the petroleum industry in the country was given a top priority.

Figure 15 Timeline of upstream exploration and production development in India



The natural gas industry in India began in the 1960s with the discovery of gas fields in Assam and Maharashtra (Bombay high). In 1976, ONGC discovered one of India's biggest gas finds in the Bassein field off Mumbai's coast. Another major discovery in India in terms of gas was in Gandhar, Cambay basin. The period of 1980-95 marked the beginning of deregulation. The government took initiatives to attract foreign investment, technology, and capital to deal with future commitment and challenges in the oil and gas sector. The government started offering blocks systematically through bidding. These bidding rounds were also known as pre-NELP exploration rounds. The exploration and production for oil and natural gas underwent major reforms during 1991-93 through the participation of private and oil companies for the auctioning of 28 discovered fields.

The New Exploration Licensing Policy (NELP) and CBM policies were implemented in 1997-99 through which a level playing field was provided to private investors by giving the same fiscal and contract terms as applicable to National Oil Companies (NOCs) for the offered exploration acreage. However, there were challenges faced for some reformative changes in the policy framework and issues around the production sharing contracts between the government and oil companies. Other challenges, such as poor quality of geological data and delayed clearances (because of which it could not attract significant investments from big players) associated with the policy also existed. Within 2014, resource potential in India was reassessed and new guidelines were launched for natural gas pricing.

The discovered small fields policy was launched in 2015 that offered improved incentives to upstream oil and gas companies in terms of no oil cess applicable on crude oil production, moderate royalty rates, no upfront signature bonus, pricing and marketing freedom for oil and gas, and no carried interest by national oil companies. Within this policy, fields were awarded under the revenue-sharing contract regime.

Within 2016-17, other initiatives were launched for upstream oil and gas production. The major one amongst them was HELP (Hydrocarbon Exploration and Licensing Policy) to further enable transparency and enhance the ease of doing business in the sector. The policy had the below-mentioned key features:

- Single licence for all forms of hydrocarbons, including conventional and unconventional ones
- The profit-sharing model of NELP was replaced with revenue-sharing contract model between the government and oil companies
- Open Acreage Licensing Policy (OALP) where the continuous bidding rounds are conducted on investor selected blocks
- Marketing and pricing freedom for sale of crude oil and natural gas, depending on the type of the extraction field
- Low and graded royalty rates

According to the current status of the upstream sector in India, ONGC and OIL had about 85 percent of the share in the gas production (excluding the share of JVs) in 2019-20. ONGC had nearly 76 percent of the country's gas production whereas OIL had 9 percent share.[98]The share of private/JV companies for 2019-20 was 13 percent and 2 percent share was for Coal Bed Methane (CBM). Sedimentary basins in India have been divided into three categories based on the prospectivity: category 1 basins have established hydrocarbon production; category 2 basins have known accumulation of hydrocarbons but no commercial production yet; and category 3 basins have prospective resources to be explored and discovered. India produced ~76.1 mmscmd of natural gas in FY 2021 (net of flare and loss) against the production of ~82.9 mmscmd in FY 2020. The production was less than that of 2019-20 because of COVID-19. However, the production increased upto ~90.8 mmscmd in FY 2022. About 68 percent of natural gas production was from offshore domestic fields in FY 2022.[99] The list of both major onshore and offshore natural gas fields in India has been mentioned in Annexure 17.1.1.

Despite the overall progress in policies of the upstream sector, challenges exist around supply, demand, and infrastructure, limiting consumption of natural gas. The major one amongst them has been the challenge of declining domestic gas production that has affected gas availability at competitive prices for the downstream sector, especially power and industries, and increased the dependency on imports. However, dynamics are changing with the policy push towards cleaner fuels and emergence of gas supply options.

[98] *MoPNG Annual Report*
[99] *PPAC*

2.2 Gas infrastructure analysis

Natural infrastructure primarily consists of pipelines used for transportation of natural gas from producing fields or RLNG terminals and RLNG terminals for unloading and storing LNG from ships.

2.2.1 Existing RLNG terminal and pipeline infrastructure

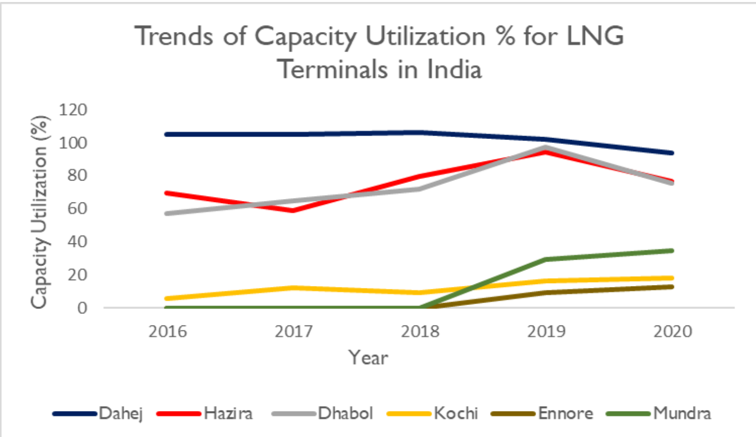
There are six existing RLNG terminals in India with five along the West Coast and one along the East Coast totalling a capacity of 40 MMTPA. The details of the terminals are given in the table below,

Table 20 List of existing RLNG terminals in India

Location	Developer	Capacity (MMTPA)	Utilisation factor (%) (April-Nov 2021)
Dahej	Petronet LNG Ltd. (PLL)	17.5	91.4
Hazira	Shell Energy India Ltd.	5.2	70.1
Dabhol	Konkan LNG Ltd.	2.5[100]	52.3
Kochi	Petronet LNG Ltd. (PLL)	5	22.1
Ennore	Indian Oil LNG Pvt. Ltd.	5	14.0
Mundra	GSPC LNG Ltd.	5	20.5
Total		**40**	

The weighted average capacity of the existing RLNG terminals in India is close to ~23.8 MMTPA and the overall capacity utilisation is ~45 percent. Use of the Dahej, Hazira, and Dabhol terminals is higher compared with others as they are connected to natural gas pipeline networks. The Mundra terminal is underutilised as volumes are limited by existing pipeline capacity that is being augmented. The Kochi terminal historically had a low utilisation factor. As the Kochi Mangalore pipeline has been commissioned, the factor is expected to increase. The pipeline connecting the Ennore terminal is still under construction, limiting its utilisation factor.[101] Use of the Dahej terminal has traditionally been high compared with others. It has even operated at more than 100 percent utilisation to cater to the increased demand. The overall utilisation for the terminals saw a drop in 2020 from the 2019 levels because of COVID-19. For new terminals, utilisation is expected to increase in the future with the completion of the pipeline projects.

Figure 16 Capacity utilisation trends for LNG Terminals in India (from IPNG 2019-20)



[100] *The capacity of Dabhol terminal is expected to increase upto 5 MMTPA with breakwater expansion.*
[101] *Ready Reckoner July 2021, PPAC*

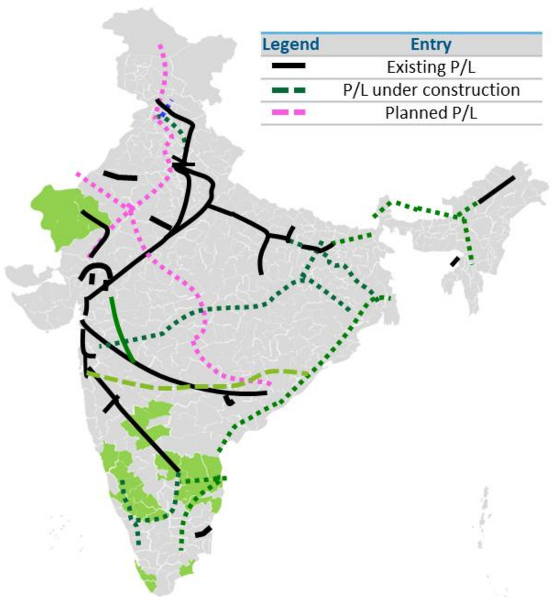
According to the latest PNGRB data, India has ~20,629 km of operational common-carrier pipelines (as of March 2022). In addition, India has 20 fully operational common carrier natural gas pipelines, with an authorised length of 13,319 km and capacity of ~333 mmscmd (as of March 2022). GAIL is the largest operator of natural gas pipelines in India. The average utilisation of these pipelines per 2019 data from PPAC was ~48 percent. Additionally, the country has tie-in connectivity, dedicated, and sub-transmission pipelines.

Table 21 Details of fully operational existing natural gas pipeline developers in India

Developer	Length	Capacity (mmscmd)	Capacity utilisation % (per PPAC, 2019)
GAIL	8,908	167.2	46%
GSPL	2,265	43	80%
PIL	1,459	85	Data not available
IOCL	132	20	53%
AGCL	105	2.4	69%
RGPL	312	3.5	26%
Others	139	11.7	29%
Total	**13,319**	**333**	**48%**

Other operators include GGL, DFPCL and ONGC.

Figure 17 Existing pipeline infrastructure in India



2.2.2 Planned infrastructure

Nine new terminals are under construction or have been announced. Two existing terminals – Dahej and Dabhol – will undergo expansion, adding an additional capacity of 43 MMTPA. New terminals have been announced largely along the East Coast that has been traditionally underserved. Moreover, the Ministry of Petroleum and Natural Gas released a draft LNG policy that aims to increase the country's LNG re-gasification capacity to ~70

MMTPA by 2030 and 100 MMTPA by 2040.[102] The government of India also launched Indian Gas Exchange in June 2020 for trading imported LNG in the spot and forward markets. The government aims to spend about INR 7.5 lakh crore over the next five years to develop the oil and gas infrastructure in the country.[103]

Figure 18 List of existing and upcoming RLNG terminals in India

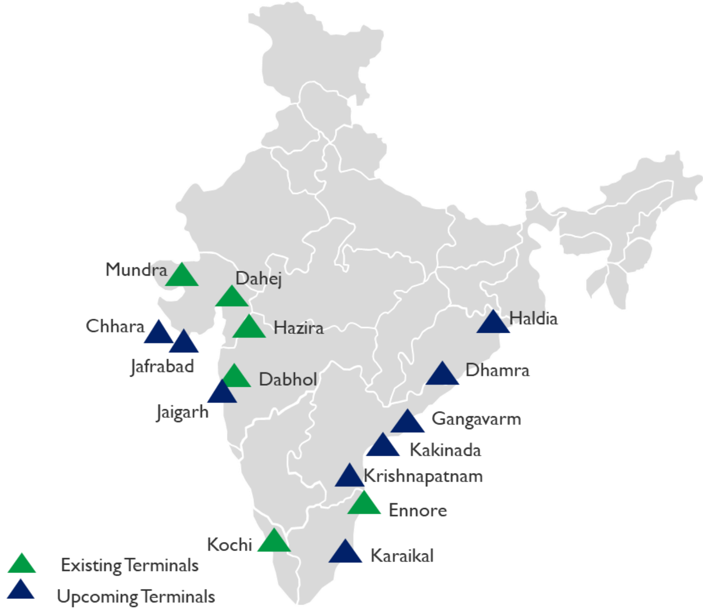


Table 22 List of upcoming RLNG terminals

Terminal	Capacity (MMTPA)	Expected year of operation	Expected year of pipeline connectivity
Dhamra (under construction)	5	2022	2022
Jafrabad (under construction)	5	2021	2021
Dhabol (expansion)	2.5	2023	2023
Haldia	2.5	2024	2024
Krishnapatnam	1	2024	2024
Chhara (under construction)	5	2023	2023
Jaigarh (under construction)	4	2021	2021
Hazira	6	2022	2022
Kakinada – FSRU	4	2023	2023
Kukrahati, WB	3	2023	2023

[102] *IBEF Oil and Natural Gas Industry Analysis*

[103] *https://www.business-standard.com/article/economy-policy/india-to-spend-rs-7-5-trillion-on-oil-and-gas-infra-in-next-5-yrs-pm-modi-121021700989_1.html*

Terminal	Capacity (MMTPA)	Expected year of operation	Expected year of pipeline connectivity
Dahej Expansion Phase 1	2.5	2025	2025
Dahej Expansion Phase 2	2.5	2028	2028
Total	**43**		

According to PNGRB, the country has a total of 9 partially commissioned pipelines. The overall length of the common carrier partially commissioned pipelines in India is ~12979 km; in which, ~6180 km has been operationalised and ~6871 km is still under construction. The carrying capacity of these pipelines is ~406 mmscmd (as of March 2022).

Table 23 Details of partially commissioned pipelines in India

S. no.	Name of natural gas pipelines	Entity	Date of authorisation	Authorised length (KM)	Authorised capacity (MMSCMD)	Operating length (KM)	Under const. length (KM)	Target date of completion (issued to completion entity)	States from which the pipeline passes	Capacity utilisation % of the pipeline (per data from PPAC and PNGRB)
1	Chainsa-Jhajjar-Hissar	GAIL	13-Dec-10	455	35	300.73	154.28	May 2021	Haryana, Rajasthan	2%
2	Dadri-Bawana-Nangal	GAIL	15-Feb-11	886	31	908.46	50	April 2021	Punjab, Haryana, Uttar Pradesh, Uttarakhand, Delhi	16%
3	Mehsana - Bhatinda	GIGL	7-Jul-11	1940	80.11	1030	910	June 2021	Gujarat, Rajasthan, Haryana, Punjab	Data unavailable
4	Bhatinda - Gurdaspur	GIGL	7-Jul-11	392	42.42	101	291	Feb 2022	Punjab and UT of Jammu & Kashmir	Data unavailable
5	Mallavaram - Bhopal - Bhilwara - Vijaipur	GITL	7-Jul-11	1811	78.25	365	1446	March 2020	Andhra Pradesh, Telangana, Madhya Pradesh, Rajasthan	Data unavailable
6	Dabhol-Bangalore	GAIL	14-Nov-11	1414	16	1147.59	266.66	Feb 2013	Maharashtra, Karnataka, Goa	10%
7	Kochi-Koottanad-Bangalore-Mangalore	GAIL	31-May-11	1104	16	639.21	464.79	Feb 2022	Kerala, Tamil Nadu, Karnataka, UT of Puducherry	18%
8	Ennore-Tuticorin	IOCL	10-Dec-15	1431	84.67	165.82	1265.18	Feb 2022	Tamil Nadu, Karnataka, Andhra Pradesh, UT of Puducherry	15%
9	Jagdishpur-Haldia-Bokaro Dhamra-Paradip-Barauni-Guwahati	GAIL	29-Jan-18	3546	23	1522.55	2023	Dec 2021	Uttar Pradesh, Bihar, Jharkhand, West Bengal, Odisha, Assam	0.17%

The government focuses on completing the national gas grid extending pipelines across the country and connecting the North-Eastern region. According to PNGRB, India has ~13,186 km of under-construction common carrier pipelines (as of March 2022). The major under-construction pipelines are expected to be operational by 2023.

Table 24 Details of under-construction pipelines in India

S. no.	Name of natural gas pipeline	Authorised entity	Date of authorisation	Authorised length (KM)	Authorised capacity (MMSCMD)	Target date of completion (issued to completion entity)	States from which pipeline passes
1	Kakinada – Visag – Srikakulam	APGDC	16-Jul-14	275	90	KVPL: June,2021 VSPL: June, 2022	Andhra Pradesh
2	Jaigarh - Mangalore	HEPL	28-Jun-16	635	17	March, 2021	Maharashtra, Goa, Karnataka
3	Kakinada - Vijayawada- Nellore	IMC	19-Feb-18	667	18	Feb, 2021	Andhra Pradesh
4	North-East Natural Gas Pipeline Grid	IGGL	17-Nov-20	1656	4.75	Nov, 2023	Assam, Mizoram, Manipur, Arunachal Pradesh, Tripura, Nagaland, Meghalaya, Sikkim
5	Kanai Chhata - Shrirampur	HPPL	8-Jul-19	317	19.2	July, 2022	West Bengal
6	Srikakulam-Angul	GAIL	23-Jul-19	690	6.65	July, 2022	Andhra Pradesh, Odisha
7	Mumbai-Nagpur- Jharsuguda	GAIL	15-May-20	1755	16.5	May, 2023	Maharashtra, Madhya Pradesh, Chhattisgarh, Odisha
8	Ennore-Nellore	GTIL	2-Dec-14	220	36	April, 2020	Andhra Pradesh, Tamil Nadu
9	Jamnagar to Dwarka (Gujarat)	GSPL	19-Aug-21	100	3	August, 2024	Gujarat

2.3 Policy, regulatory enablers, and emerging trends

2.3.1 Policy and regulatory support and incentives for promoting the sector

The government has set a target to achieve a 10 percent reduction in energy import by 2022 and increase natural gas contribution to 15 percent by 2030. It has already taken several policy measures to encourage gas demand in the country. It has made several efforts to open the gas sector to international and private entities.

The pricing policy in India has evolved over the years and multiple pricing regimes exist for existing and new fields. Pricing of domestic gas from existing fields is fixed based on formula that considers natural gas prices in the US, the UK, Canada, and Russia. Although this formula has helped keep prices low and benefited priority end-use sectors, it is less attractive to upstream producers. To counter this, the government has launched various programmes − recently discovered small fields, Open Acreage Licensing Policy (OALP), the hydrocarbon exploration policy − to augment domestic gas production in the country. With these and other policies, the government has introduced pricing and marketing freedom, a unified licensing system for hydrocarbons, including Coalbed Methane (CBM), and a favourable contractual and taxation regime. Further, the government is considering a proposal to link domestic gas price to the Asia LNG benchmark price to incentivise producers. Being the fourth-largest LNG importer and having bilateral relations, India can reduce pricing of various long-term LNG contracts in its favour.

The government has taken various initiatives in the mid-stream and downstream sectors to promote natural gas use. Some of these are mentioned below:

- Making plans to create a national gas grid by improving pipeline connectivity through projects such as the Urja Ganga pipeline and the North-East gas grid
- Taking steps to unbundle marketing and transportation operations of gas in the country and improve access to pipelines
- Launching gas exchange for trading imported LNG
- Allowing the regulator Petroleum and Natural Gas Regulatory Board (PNGRB) to conduct 11 bidding rounds to date to increase the coverage of City Gas Distribution (CGD) across India. Post the 11th round, 289 GAs have been added to the CGD network, increasing the reach of gas to ~98 percent of the population and 88 percent of India's area.[104]

[104] https://pib.gov.in/PressReleasePage.aspx?PRID=1811907

- Establishing priority sectors to allocate domestic natural gas. The priority sector allocation for gas is there in the given order - PNG (domestic) and CNG (transport), fertiliser, power, and others.
- Increasing number of cities are adopting CNG for public transport vehicles
- Easing rules for setting up LNG fuel stations, benefitting small-scale, LNG end-use applications and commercial transportation
- Banning use of petcoke and furnace oil in certain areas that will lead to increased industrial volumes for natural gas
- Announcing brownfield expansions, plant revivals of refineries, petrochemical and fertiliser plants (by public sector units); the power ministry's[105] recent proposal to procure power from 4000 MW gas-based power plants that will increase demand for natural gas.

2.3.2 Emerging trends with respect to alternative fuels

- India had earlier set a target of 450 GW capacity of renewables by 2030. It recently achieved a milestone of 150 GW of installed renewable capacity in January 2022.[106] Moreover, in November 2021, India pledged to achieve net zero carbon emissions by 2070 in COP26 Summit at Glasgow.[107] Net zero emissions refers to the balance between the amount of greenhouse gas produced and the amount removed from the atmosphere. For achieving this, the following targets have been announced by the government to be achieved by 2030:[108]
    - Expansion of renewable energy capacity to 500 GW by 2030.
    - 50 percent of the country's energy needs being met from renewable sources.
    - Reduction of total projected carbon emissions by one billion tonnes till 2030.
    - Reduction of carbon intensity of the country's economy by less than 45%.

  In addition, India's oil and gas ministry is proactively asking oil and gas companies to look into induction of renewable energy and green hydrogen to offset emissions from operations. Moreover, India's major state-owned oil and gas companies – IOCL, BPCL, HPCL and GAIL are in the process of preparing a detailed roadmap for the same.
- As India imports more than 85 percent of its crude requirements, promoting alternative fuels, such as bioethanol, biodiesel, and Compressed Biogas (CBG), in addition to CNG and PNG are some key focus areas for the government. Earlier this year, the cabinet approved a policy related to ethanol production from sugarcane juice and syrup to accelerate the ethanol-blended petrol programme. For the second time this year, the central government advanced its target of achieving 20 percent ethanol blending to 2023 from 2025 compared with 2030 originally. The government approved the supply of used cooking oil-based blended biodiesel.
- Green hydrogen produced from using electricity from renewable sources is also emerging and the country has announced a national hydrogen mission. The power ministry has floated draft rules, allowing purchase of green hydrogen to meet the Renewable Purchase Obligation (RPO).
- The adoption Electric Vehicles (EVs) is emerging, and the government aims to push EV penetration to 30 percent by 2030 through high growth in three wheelers and the commercial cars segment. Policies to promote the EV ecosystem in India are mentioned below:
    - NITI Aayog has proposed incentives worth INR 338 bn by 2033 to electric-vehicle battery manufacturers to help the country reduce its dependence on oil.
    - The government has notified that the basic import duty on battery packs used in manufacturing electric vehicles will be tripled to 15 percent from the current 5 percent with effect from April 2021.
- Various Indian states have launched policies to offer incentives to promote adoption of electric vehicles. The central government has launched phase II of the faster adoption and manufacturing of (hybrid and) electric vehicles in 2019. Under this scheme, the government supports roll out of charging stations, electric buses for state/city transport undertakings, and incentives for other vehicles. While current charging infrastructure is underdeveloped, regulatory clarity and a phased approach to develop infrastructure would provide necessary impetus in the future. To achieve the government targets, the total number of EV charging stations (including complex and individual) required in India is ~8,00,000, whereas the number of stations is ~2,000 currently. Though battery prices have gone down by as much

[105] Economic Times, January 2020 - https://rb.gy/3ujyhh
[106] https://www.livemint.com/industry/energy/indias-renewable-energy-generation-capacity-addition-in-fy23-estimated-at-16-gw-11641807620654.html
[107] https://www.thehindubusinessline.com/news/india-committed-to-achieving-net-zero-carbon-emission-by-2070-says-modi/article37293537.ece
[108] https://www.cnbc.com/2021/11/05/can-india-achieve-net-zero-carbon-emissions-by-2070-the-road-is-long-but-not-impossible.html

as 80 percent in the past decade, they need to be reduced significantly to make EVs feasible for personal mobility applications. At present, Total Cost of Ownership (TCO) is favourable for three wheelers and comparable for commercial taxis compared with their CNG counterparts due to extensive subsidy by the government on commercial EVs. With continued subsidy support from the government, development of infrastructure, and a steep fall in battery prices, EV adoption in the taxi segment is expected to see a fillip in 2025. However, if subsidy is reduced further, EV adoption in the taxi segment can be delayed to ~2027. If subsidy is removed, the TCO may not be comparable even up to 2030.

- EVs could capture 5-7 percent of the target CNG demand by 2030. These estimates have been factored in while estimating CNG demand up to 2040 by considering a lower throughput than that would be normally expected. To mitigate the impact of EV on CNG demand, CGD companies need to take the following steps:
  - Tracking the status for EV adoption in India
  - Making strategies for faster conversions to CNG to gain a first mover advantage over EVs
  - Exploring regulating margins in the CNG segment to improve cost competitiveness to EVs
  - Cross subsidising CNG sales with non-fuel retail sales to increase customer engagement

2.4 Pricing assessment

2.4.1 Gas pricing mechanisms

The pricing of natural gas in India has undergone multiple changes in the past. The current applicable pricing regime for suppliers of domestic and imported LNG are given below:

1. Pricing for domestic gas
   a. Pricing for nominated fields
      i. Prices are indexed to weighted average value of four different gas indexes (NBP, Alberta Gas, Russian gas, and Henry Hub gas)
      ii. Price of domestic natural gas for 1 October 2021 to 30 March 2022 was US$2.9/mmbtu. According to PPAC data, from 1 April 2022 to 31 October 2022, gas price has been hiked to US$6.1/mmbtu. The domestic gas price increase was driven by the significant run-up in the prices of gas at global gas hubs due to the Russia-Ukraine war.
   b. Pricing for deep-water, high pressure-high temperature and discovered small fields
      i. Firms allowed to devise a price formula; however, the government sets a price ceiling based on the price of alternative fuel basket
      ii. The ceiling for 1 October 2021 to 30 March 2022 was US$6.13/mmbtu on a GCV (Gross Calorific Value) basis. According to PPAC data, from 1 April 2022 to 31 October 2022, the price ceiling of natural gas from deep-water and other difficult fields has been increased to US$9.92/mmbtu.
   c. Earlier the term "Administered Pricing Mechanism" (APM) gas was used to refer to gas produced from fields that were awarded before production-sharing contract regimes. However, the government now uses a constant pricing methodology for domestic gas, in addition to pricing and marketing freedom gas.
2. Pricing for RLNG
   a. RLNG is the imported natural gas acquired in the LNG form and re-gasified at LNG terminals. Long-term LNG contracts from RasGas and Gorgon are crude linked with slopes upwards of ~12.5 percent. At crude of US$70/barrel, LNG would be US$9.6/mmbtu.
   b. Additionally, GAIL has signed gas-linked LNG contracts (Henry Hub linked) with the US (Sabine and Cheniere Pass).
   c. Besides one-third supplies are on spot, indicating a huge volatility. Prices have ranged from US$3-12/mmbtu in the past few months.

In case of imported LNG, terminal charges are applicable for regasification of LNG. These charges vary amongst terminals with key LNG terminals, such as Hazira, Dahej, Kochi, and Mundra charging ~US$1.05, US$0.73, US$ 1.1, and US$0.88 per mmbtu, respectively, for regasification. New LNG terminals are expected to charge ~US$ 1/mmbtu.[109]

[109] *PPAC*

Price build-up for natural gas from imports will consist of the following:

1. DES (price) at the RLNG terminal
2. Custom duty
3. Terminal charges
4. Pipeline tariff
5. GST on transportation
6. GST on terminal
7. VAT

Assumptions

1. RLNG prices are assumed considering a contract slope of 12.50 percent and an intercept of 0.5. Terminal charges vary from terminal to terminal (US$0.7–1.05/mmbtu). To ensure consistency, these charges have been assumed as US$1/mmbtu.
2. Custom duty, including a cess of 2.75 percent, is applicable on RLNG price. Transportation tariff for different states has been considered according to the PNGRB order for EWPL (East-West Gas Pipeline).
3. VAT applicable on natural gas will vary from state to state.
4. GST/service charge of 12 percent will be applicable on transportation charges.
5. GST/service of 18 percent will be applicable on terminal charges.

Table 25 Typical price build-up for a natural gas customer in different states for US$65/mmbtu crude price (in US$/mmbtu)

Price components	Unit		GUJ	MAH	TN	ODS	KER	RAJ	KAR	AP	MP	UP	HAR
Crude price	$/Barrel		65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
DES	$/MMBTU	A	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
Custom duty	$/MMBTU	B=A*custom duty	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Terminal charges	$/MMBTU	C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
EWPL tariff	$/MMBTU	E	0.44	0.50	0.22	0.96	0.57	0.96	0.57	0.96	0.55	0.55	0.65
GST on EWPL (@12%)	$/MMBTU	H=E*GST rate	0.05	0.06	0.03	0.11	0.07	0.11	0.07	0.11	0.07	0.07	0.08
GST on terminal charge (@18%)	$/MMBTU	D = C*GST rate	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
VAT	$/MMBTU	I=(A+B+C+D+E+H)*VAT Rate	1.55	1.41	0.51	1.64	1.52	1.09	1.52	2.68	1.47	1.52	1.32
Total	**$/MMBTU**	**sum(A:I)**	**12.09**	**12.01**	**10.80**	**12.75**	**12.20**	**12.21**	**12.20**	**13.79**	**12.12**	**12.18**	**12.10**

The price of imported RLNG lies in the range of US$10.8-13.8/mmbtu on crude oil price of US$65/barrel. Similarly, in the future, if crude prices change up to US$75/barrel or US$55/barrel, RLNG prices for customers will be in the range of US$12.1-15.4/mmbtu and `US$9.5-12/mmbtu respectively. In addition, because of certain special circumstances like the Russia-Ukraine war, if the crude oil prices reach upto US$100/barrel and US$120/barrel, the prices for long-term imported RLNG would also subsequently increase in the range of US$15.5-19.4/mmbtu and US$18.2-22.6/mmbtu respectively.

Table 26 Typical price build-up for a natural gas customer in different states for US$75/mmbtu crude price (in US$/mmbtu)

Price components	Unit		GUJ	MAH	TN	ODS	KER	RAJ	KAR	AP	MP	UP	HAR
Crude price	$/Barrel		75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
DES	$/MMBTU	A	9.88	9.88	9.88	9.88	9.88	9.88	9.88	9.88	9.88	9.88	9.88
Custom duty	$/MMBTU	B=A*custom duty	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Terminal charges	$/MMBTU	C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
EWPL tariff	$/MMBTU	E	0.44	0.50	0.22	0.96	0.57	0.96	0.57	0.96	0.55	0.55	0.65
GST on EWPL (@12%)	$/MMBTU	H=E*GST rate	0.05	0.06	0.03	0.11	0.07	0.11	0.07	0.11	0.07	0.07	0.08
GST on terminal charge (@18%)	$/MMBTU	D = C*GST rate	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
VAT	$/MMBTU	I=(A+B+C+D+E+H)*VAT Rate	1.75	1.58	0.57	1.83	1.71	1.22	1.71	2.99	1.65	1.71	1.48
Total	**$/MMBTU**	**sum(A:I)**	**13.57**	**13.47**	**12.14**	**14.23**	**13.67**	**13.62**	**13.67**	**15.39**	**13.59**	**13.65**	**13.54**

Table 27 Typical price build-up for a natural gas customer in different states for US$55/mmbtu crude price (in US$/mmbtu)

Price components	Unit		GUJ	MAH	TN	ODS	KER	RAJ	KAR	AP	MP	UP	HAR
Crude price	$/Barrel		55.00	55.00	55.00	55.00	55.00	55.00	55.00	55.00	55.00	55.00	55.00
DES	$/MMBTU	A	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38
Custom duty	$/MMBTU	B=A*custom duty	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Terminal charges	$/MMBTU	C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
EWPL tariff	$/MMBTU	E	0.44	0.50	0.22	0.96	0.57	0.96	0.57	0.96	0.55	0.55	0.65
GST on EWPL (@12%)	$/MMBTU	H=E*GST rate	0.05	0.06	0.03	0.11	0.07	0.11	0.07	0.11	0.07	0.07	0.08
GST on terminal charge (@18%)	$/MMBTU	D = C*GST rate	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
VAT	$/MMBTU	I=(A+B+C+D+E+H)*VAT Rate	1.36	1.23	0.44	1.45	1.34	0.96	1.34	2.36	1.29	1.33	1.16
Total	**$/MMBTU**	**sum(A:I)**	**10.61**	**10.56**	**9.45**	**11.28**	**10.73**	**10.79**	**10.73**	**12.19**	**10.66**	**10.70**	**10.65**

Table 28 Typical price build-up for a natural gas customer in different states for US$100/mmbtu crude price (in US$/mmbtu)

Price components	Unit		GUJ	MAH	TN	ODS	KER	RAJ	KAR	AP	MP	UP	HAR
Crude price	$/Barrel		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
DES	$/MMBTU	A	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
Custom duty	$/MMBTU	B=A*custom duty	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Terminal charges	$/MMBTU	C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
EWPL tariff	$/MMBTU	E	0.44	0.50	0.22	0.96	0.57	0.96	0.57	0.96	0.55	0.55	0.65
GST on EWPL (@12%)	$/MMBTU	H=E*GST rate	0.05	0.06	0.03	0.11	0.07	0.11	0.07	0.11	0.07	0.07	0.08
GST on terminal charge (@18%)	$/MMBTU	D = C*GST rate	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
VAT	$/MMBTU	I=(A+B+C+D+E+H)*VAT Rate	2.23	2.01	0.73	2.31	2.17	1.54	2.17	3.78	2.10	2.17	1.89
Total	**$/MMBTU**	**sum(A:I)**	**17.26**	**17.12**	**15.52**	**17.92**	**17.35**	**17.15**	**17.35**	**19.39**	**17.25**	**17.32**	**17.15**

Table 29 Typical price build-up for a natural gas customer in different states for US$120/mmbtu crude price (in US$/mmbtu)

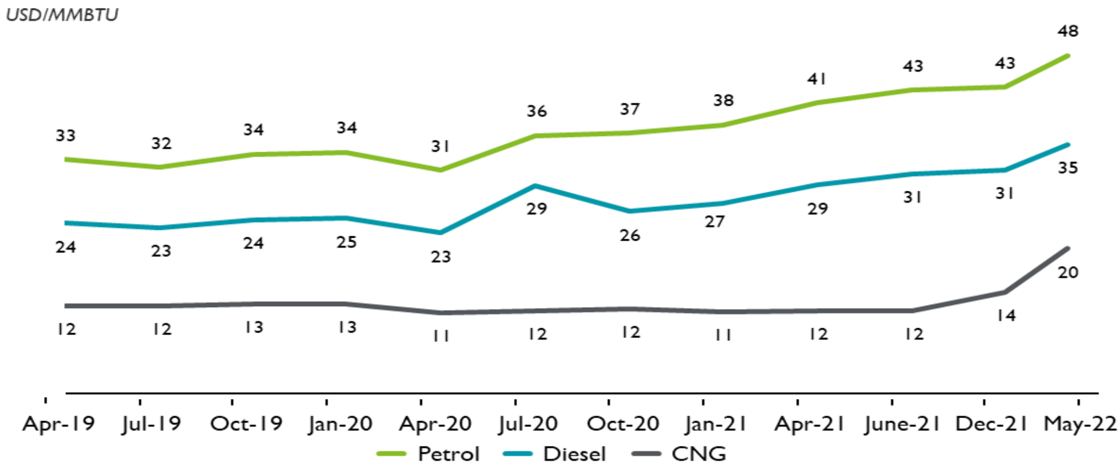
Price components	Unit		GUJ	MAH	TN	ODS	KER	RAJ	KAR	AP	MP	UP	HAR
Crude price	$/Barrel		120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00
DES	$/MMBTU	A	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50
Custom duty	$/MMBTU	B=A*custom duty	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
Terminal charges	$/MMBTU	C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
EWPL tariff	$/MMBTU	E	0.44	0.50	0.22	0.96	0.57	0.96	0.57	0.96	0.55	0.55	0.65
GST on EWPL (@12%)	$/MMBTU	H=E*GST rate	0.05	0.06	0.03	0.11	0.07	0.11	0.07	0.11	0.07	0.07	0.08
GST on terminal charge (@18%)	$/MMBTU	D = C*GST rate	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
VAT	$/MMBTU	I=(A+B+C+D+E+H)*VAT Rate	2.61	2.36	0.86	2.70	2.55	1.80	2.55	4.41	2.46	2.54	2.21
Total	**$/MMBTU**	**sum(A:I)**	**20.21**	**20.03**	**18.21**	**20.88**	**20.29**	**19.98**	**20.29**	**22.59**	**20.18**	**20.26**	**20.04**

2.4.2 Pricing of alternative fuels and comparison with natural gas

India has levied high taxes on petrol and diesel that account for more than 60 percent of the Retail Selling Price (RSP) of fuels. If prices of CNG, petrol, and diesel are compared over a period, natural gas is cost competitive compared with diesel and petrol.

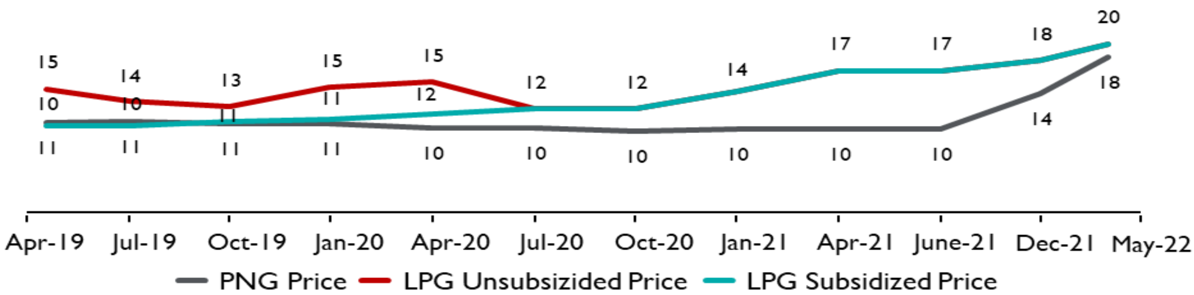
Below figures provide a short-term historic RSP comparison for alternative fuels compared with natural gas.

Figure 19 Comparison of prices of transport fuels (Illustration for Delhi)



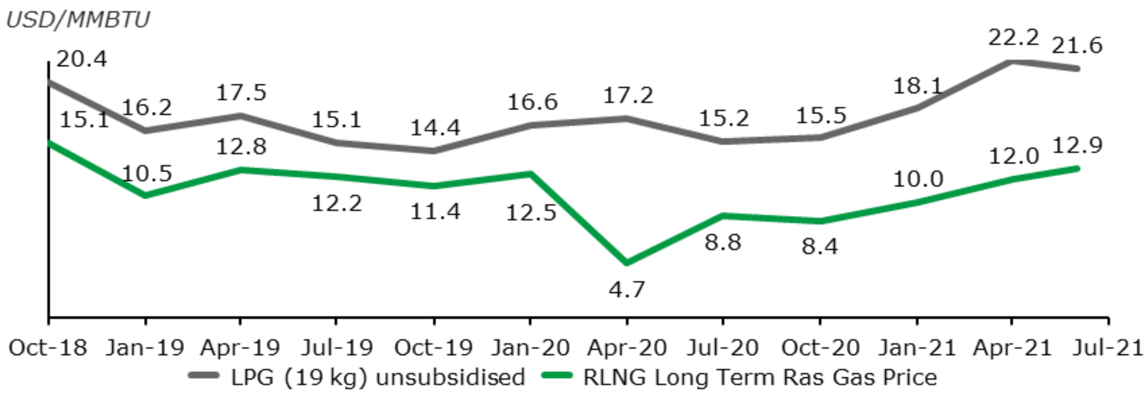
For domestic usage, on comparing natural gas with other alternative fuels like LPG, domestic gas price is lower than that of LPG (14.2 kg domestic) prices. Hence, conversion to natural gas will make economic sense.

Figure 20 Comparison of domestic fuels in US$/mmbtu (illustration for Delhi)



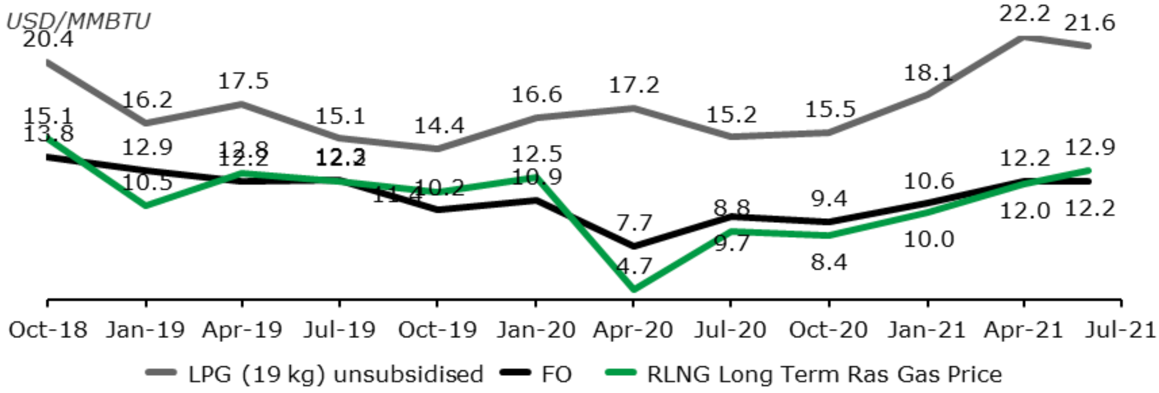
Based on cost comparisons, NG is cheaper in the commercial segment and comparable in the industrial segment.

Figure 21 Comparison of commercial fuels (illustration for Mumbai)



Commercial LPG prices are still higher than long-term LNG RasGas prices and **conversions would not depend on price variations.**

Figure 22 Comparison of industrial fuels (illustration for Mumbai)



Price of furnace oil (assuming a 20 percent discount on quoted prices) is comparable to long-term LNG RasGas prices (without considering taxes). However, conversion from FO can be pushed due to regulations.

Each segment − households, CNG, industries, and commercial – has positive margins to alternative fuels. The CNG and commercial segments have a high profitability. The CNG and industries segments drive volumes.

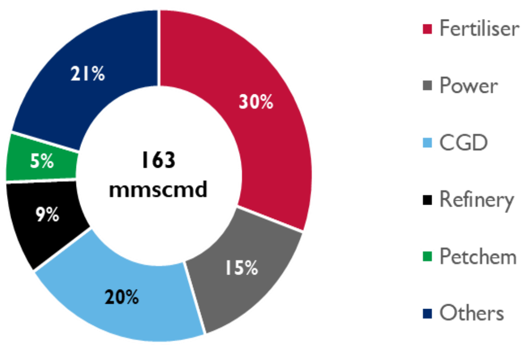
2.5 Demand analysis

2.5.1 Existing demand

Gas demand was 154 mmscmd in FY 2020-21 and 163 mmscmd in FY 2021-22[110]. The fertiliser sector accounted for the largest demand segment at 30 percent, followed by Others, CGD, and power at 21 percent, 20 percent, and 15 percent, respectively.[111] In India, gas demand in various sectors is driven largely by the government's allocation policies for domestic natural gas, which has been cheaper than imported LNG.

Within India, overall natural gas consumption increased from 2009-11 and then decreased up to 2014. After 2014, consumption increased at a low growth rate. Current gas demand is lower than peak gas demand achieved in 2011. This has been a consequence of the decrease in domestic production due to which the domestic gas supply has been constrained. As a result, the industrial and power sectors have found it difficult to access gas at competitive prices and therefore, the gas demand from these sectors has not grown across the years.

Figure 23 Natural gas demand in India by sector for 2021-22 (in mmscmd)



Sector	Gas consumption (in mmscmd)
Fertiliser (30%)	50
Power (15%)	24
CGD (20%)	33
Refinery (9%)	15
Petrochemicals (5%)	8
Others (21%)	34

110 PPAC
111 PPAC

Figure 24 Natural gas consumption trend in India per PPAC (in mmscmd)

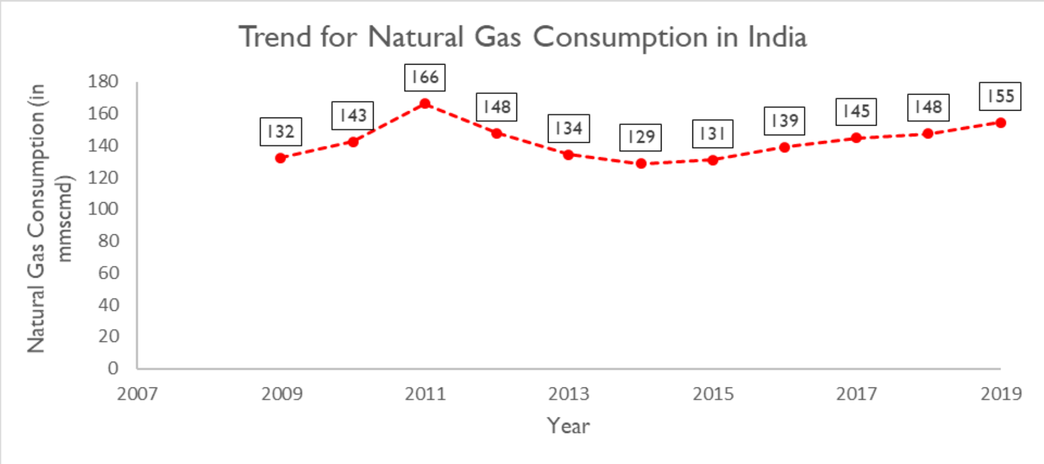
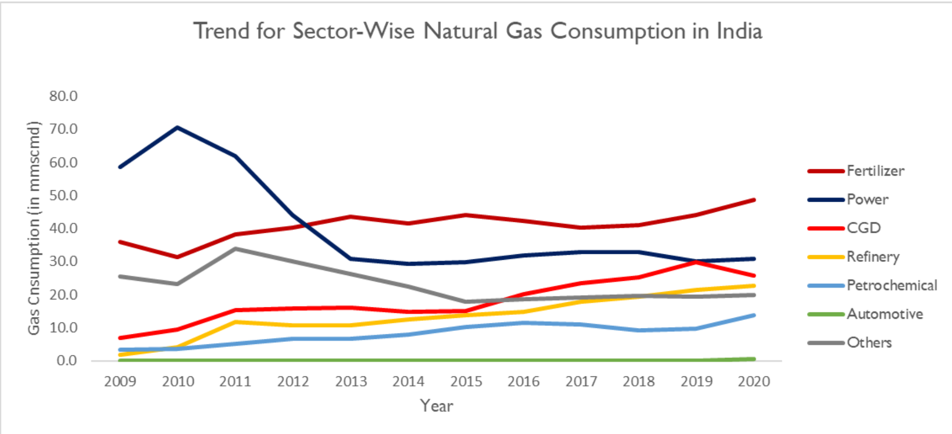


Figure 25 Gas consumption trend by sector (in mmscmd)



2.5.2 Key drivers for demand

Demand for natural gas in India will be primarily driven by the following factors:

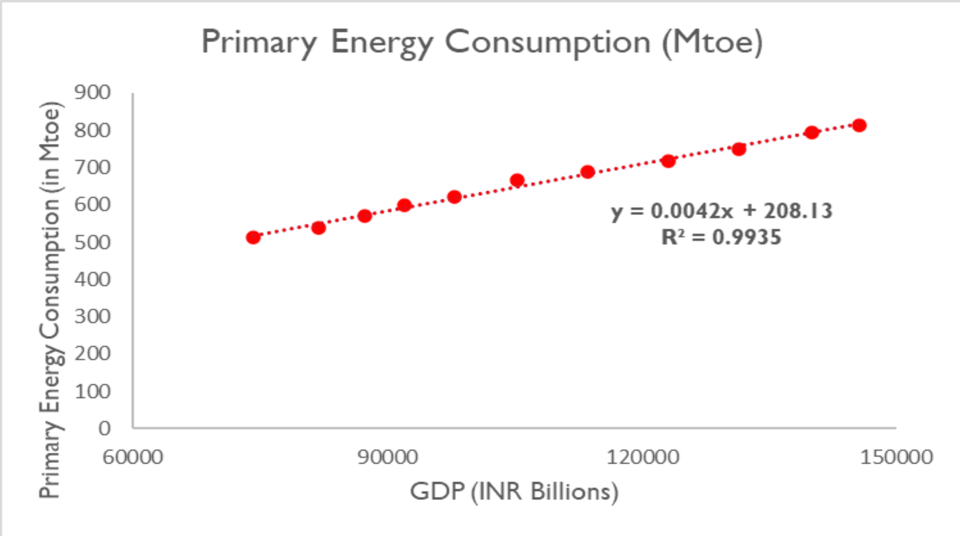
- The government's objective to increase a share of natural gas to 15 percent in the overall energy mix by 2030
- Expansion of the City Gas Distribution network - Geographical Areas (GAs) of CGDs have grown from ~35 in 2007 to ~289 in 2022 post the 11th round bidding.
- Need to improve air quality by enforcing natural gas as fuel for certain segments of vehicles and industries
- Proactive concerns by the Supreme Court and high courts for reducing emissions from the industrial and power sectors. The Supreme Court in 2017 banned the use of petcoke and furnace oil in the National Capital Region (NCR) and suggested similar steps in other states. Following the Supreme Court's order, Rajasthan, Uttar Pradesh, and Haryana also imposed the ban. Similar steps are being considered by other states, such as Gujarat in 2019 also imposed a blanket ban on FO and polluting fuels. These interventions are likely to continue in the future.
- Increase in capacity of infrastructure for importing LNG, and transportation and distribution infrastructure across the country
- Reforms in gas pricing to help unlock additional domestic supply

2.5.3 Top-down approach

It is one the two approaches used to determine demand projection for natural gas until 2040. This approach uses the corelation between the Indian economy's size and energy consumption, and a share of natural gas in the energy mix. A regression model using the macroeconomic indicator of GDP has been created to draw the corelation. The primary energy consumption of India from 2009-19 was collated from the data published by the BP Statistical Review.

The GDP data that has been considered for doing analysis is real GDP (i.e., GDP that is calculated at constant price levels). GDP numbers for regression analysis have been considered in the local currency value of India. The real GDP is being considered for regression analysis as it provides GDP without the impact of inflation or currency appreciation and depreciation.

Figure 26 Regression equation for primary energy consumption and GDP of India



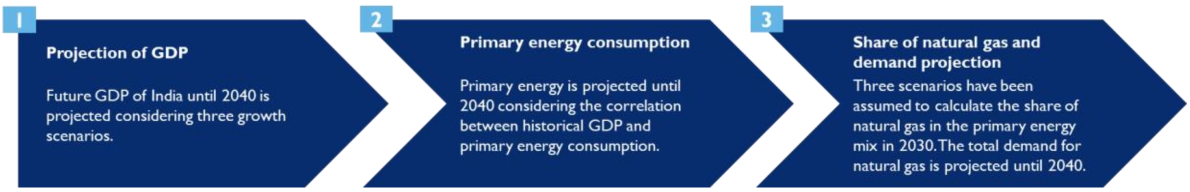
Primary energy consumption (Mtoe) = 0.0042(GDP in INR billion) + 208.13*

Historical data shows a strong correlation between GDP and primary energy consumption (R^2- 99.4 percent). Primary energy consumption is linked to GDP as the relationship between primary energy consumption and GDP accounts for 99.4 percent of the variation. GDP can be said to be a good predictor of primary energy consumption. Energy demand increases with economic growth due to factors such as industrial growth, urbanisation, and increased disposable income, coupled with technological advancement.

Some decoupling of GDP and energy demand will happen in advanced economies due to lowering of energy intensity of GDP on account of a shift from industrial to the service dominated economy, and an increase in energy efficiency and renewable energy consumption.

However, the effect will be lower in India as its energy use and emissions are less than half of the world average. Moreover, with rising income, Indian households are expected to buy new appliances, air conditioning units, and vehicles, thus increasing energy demand.

Figure 27 Overview of methodology for the top-down approach for projecting natural gas demand in India



<u>Detailed methodology</u>

1. Step 1 – GDP projection for India
    a. The historical GDP of India from 2009 to 2019 was collated.
    b. The GDP from 2020 to 2026 was sourced from IMF.
    c. Beyond 2026, three scenarios have been used to project the GDP until 2040
        i. The first scenario took the five-year CAGR between 2021 and 2026 and projected GDP beyond 2026 at a calculated growth rate.

   ii. The second scenario took the seven-year CAGR between 2019 and 2026 and projected GDP beyond 2026 at a calculated growth rate.
   iii. The third scenario took a uniformly reducing growth rate from 5 percent in 2026 to 3 percent in 2040. This scenario of lower GDP growth has been considered as a pessimistic case to account for various uncertainties. Global agencies, such as IMF, World Bank, and Moody's, have cut economic growth forecast for India in FY 2023 on account of delayed and subdued recovery from COVID-19 in the near term. As the analysis is for a long term of 20 years, accounting for the case of lower economic growth due to such uncertainties, is necessary.
2. Step 2 – Projection of primary energy consumption
   a. Historical primary energy consumption of India from 2009 to 2019 was collated from the BP Statistical Review.
   b. Historical GDP and primary energy consumption from 2009 to 2019 was regressed; the resulting linear equation was used to project primary energy consumption until 2040. The R-square for the model was 99.7 percent that can be considered a good statistical fit.
3. Step 3 – Projection of natural gas demand
   a. The government of India has set a goal to increase natural gas share in the overall energy mix to 15 percent by 2030.
   b. However, historical data shows that the peak share natural has never exceeded 11 percent. Therefore, two additional scenarios of 8 percent and 12 percent by 2030 have been considered for analysis.
   c. For projecting gas demand beyond 2030, the CAGR of the increase in the share of gas between 2020 and 2030 was calculated. This CAGR was reduced to one-fourth of its value and used to project demand for gas beyond 2030. A reduced value of CAGR was used after 2030 because of limited visibility beyond that year.

Analysis

Gas demand under various scenarios was projected to increase from 183-237 mmscmd 2022 to 326–612 mmscmd by 2030, and 545-1174 mmscmd by 2040. The scenario – 1 with the following considerations is expected to be the most plausible one - 8 percent share of natural gas in the energy mix and 5.3 percent annual increase in GDP year 2026 onwards considering seven-year CAGR of GDP. The reason for considering this as the most plausible scenario is the fact that the share of natural gas in total energy consumption in India has been limited and reached a peak of 10.6 percent in 2010. The average share of natural gas in the total energy mix has also been ~8 percent in the past decade.

From 2009-19, CAGR growth in natural gas demand has been ~1.6 percent. From 2020 onwards, if natural gas needs to have an 8 percent share in the primary energy mix by 2030, overall CAGR of demand for fuel from 2019-30 needs to be 7 percent. For a 12 percent share by 2030, overall CAGR from 2019-30 needs to be 11 percent; for a 15 percent share, overall CAGR has to be 13.3 percent.

Table 30 Summary of gas demand in India under the top-down approach

Scenario	Gas demand (mmscmd)		Remarks
	2030	2040	
Scenario – 1 (most plausible scenario)	326.3	545	8 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR
Scenario – 2	489.5	895	12 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR
Scenario - 3	611.9	1173.7	15 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR

The data used for analysis and the detailed projections has been included in the annexure.

2.5.4 Bottom-up approach

This approach has been considered to estimate natural gas demand from each sector that uses gas as a source of energy or feedstock. Key sectors where natural gas is being used are mentioned below.

2.5.4.1 Fertiliser sector

It is one of the leading consumers of natural gas in India. At present, 31 urea units in the country use natural gas. The three units − Madras Fertilisers (MFL), Mangalore Chemical and Fertilisers (MCFL), and Southern Petrochemical Industries Corporation (SPIC, Tuticorin) − that used naphtha as feedstock have started using natural gas. Used as a feedstock for manufacturing urea, natural gas accounts for 50-80 percent of the raw material cost.[112]

The market for fertiliser is expected to significantly expand in India due to the following reasons:

1. Scarcity of nutrients[113] - More than 50 percent districts in India are deficient in essential plant nutrients, including nitrogen, providing a significant headroom for growth.
2. Improving fertiliser consumption – In India, fertiliser consumption per unit area is amongst the lowest[114] in the world. With the government's focus on improving crop yields, use of fertilisers is likely to see an increase. This will provide a significant headroom for growth in the industry.
3. Government focus on reducing import dependency in the urea sector – The government's focus is on facilitating fresh investment, making India self-reliant, and reducing import dependency in the urea sector. This is because dependence on imports for fertilisers and raw materials is risky for local players and the government. India is the largest importer of urea, ammonia, and phosphate-based fertilisers. Its import dependence on urea remains pretty high as ~27 percent of its urea demand was met through imports in 2020.[115] Besides the global market size is about 200 Mn MT of nutrients. Even a slight increase in demand can lead to volatility in prices. Moreover, international prices in a balanced 'demand-supply scenario' follow gas prices. Not only that, with a limited number of global suppliers, the bargaining power of government with these suppliers is limited to a certain extent. Thus, the industry faces both availability and pricing issues on a regular basis because of import dependence. However, India still has the capability to produce more of urea-ammonia if it revives closed units.

In addition to existing 31 urea units, 9 additional units (Matix Fertilisers Phase 1, RFCL – Ramagundam, HURL – Gorakhpur, Sindri and Barauni, Matix Fertilisers Phase 2, BVFCL – Namrup IV, IFFCO – Kalol, HFCL – Durgapur) are expected to be completed by 2024. Apart from urea, India has 12 units of DAP (Di-Ammonium Phosphate) fertilisers that use rock phosphate as primary raw material and 20 units for producing fertilisers with complex nutrients.

With demand drivers shaping up, demand for natural gas from the fertiliser sector is expected to increase.

112 *CARE Ratings*
113 *IISS Bhopal*
114 *FAO, IFA, The Global Economy, Coromandel Investor Presentation*
115 *https://www.worldfertiliser.com/special-reports/24092020/indias-fertiliser-under-pressure/*

Figure 28 Fertiliser plants in India

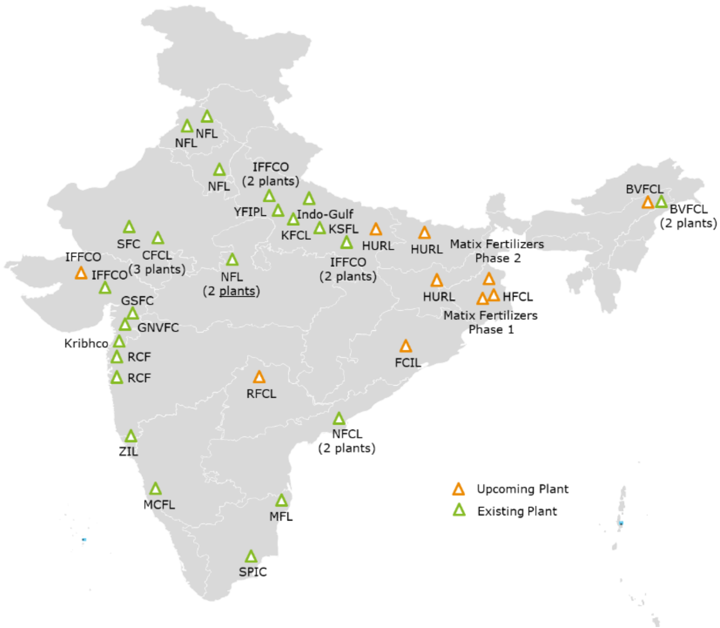
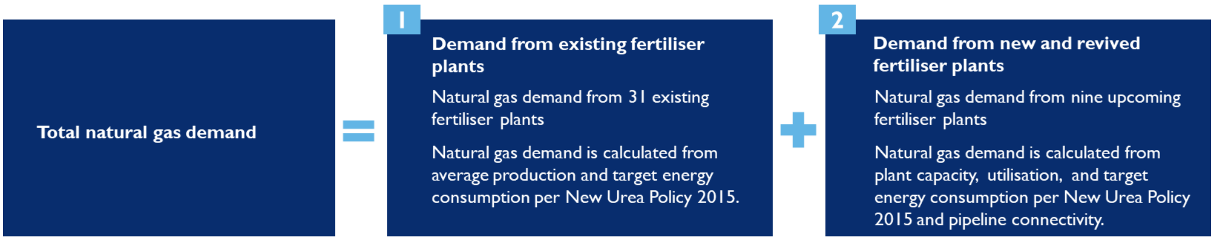


Figure 29 Overview of methodology for projecting natural gas demand for the fertiliser sector in India



Detailed methodology for assessment of natural gas demand

1. Step 1 – Projection of natural gas demand from existing urea plants
    a. The list of three types of fertiliser plants across India was collated through secondary research. Plants which manufacture urea were only considered for the analysis.
    b. Average urea production from FY 2013-14 to FY 2017-18 was calculated for each plant.
    c. Based on National Urea Policy 2015, energy consumption targets (Gcal/MT) for urea production plants were identified for various categories. According to NUP 2015, the target consumption is as follows:
        i. Group I – 5.5 Gcal/MT
        ii. Group II – 6.2 Gcal/MT
        iii. Group III – 6.5 Gcal/MT
    d. The average natural gas consumption for the past five years was calculated for each plant. The minimum of the actual and target consumption has been considered for calculating natural gas demand.
    e. For gas demand from FY 2030-31 to FY 2039-40, CAGR for natural demand from FY 2021-2030 was calculated. For projection of demand from FY 2031 to FY 2040, CAGR was reduced by 1 percent year-on-year with a minimum growth rate cap of 2 percent.
2. Step 2 – Projection of natural gas demand from new and revived fertiliser plants
    a. The total urea production capacity of new plants and revival fertiliser plants was identified.
    b. Considering an increase in urea demand , utilisation of these plants was assumed to be 100 percent from the year of start of operations.
    c. The target energy consumption of new and revival plants was assumed to be in the lowest slab of targets, provided by NUP 2015 (i.e., 5.5 Gcal/MT)

   d. For gas demand from FY 2030 to FY 2040, CAGR for natural demand from FY 2021 to FY 2030 was calculated. For projection of demand from FY 2031 to FY 2040, CAGR was reduced by 1 percent year-on-year with a minimum growth rate cap of 2 percent.
3. Step 3 – Total natural gas demand
   a. Total natural gas demand was arrived from demand of individual existing and upcoming plants calculated in steps in 1 and 2.

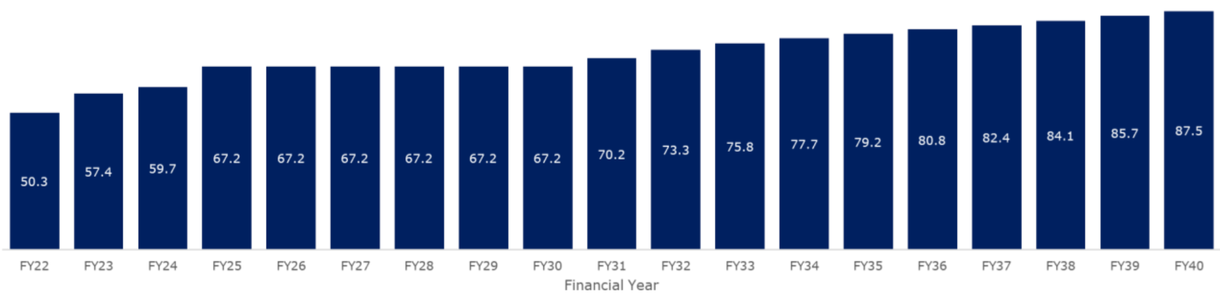
Assumptions:

1. Only plants using natural gas as feedstock have been considered for gas demand assessment. Plants that use alternative fuels such as coal have not been considered for natural gas demand estimation due to lack of affordability. Moreover, the plants that do not manufacture urea have not been considered.
2. Connectivity to a gas pipeline of fertiliser plants has been assessed. For the plants that are not yet connected to any gas pipeline, the year of completion of natural gas pipeline has been considered based on announcements in the public domain. Natural gas consumption for these plants was consequently commenced from the respective year.
3. Plants that were not brought under National Urea Policy 2015 have been identified. The plants that were not included in the policy due to lack of connectivity to a pipeline have been considered in the policy targets for NG consumption based on status pipeline connectivity. The plants that were not included in the policy targets due to the use of old technology are undergoing a revamp in technology. They have been considered under the Group I target from FY 2024.

Analysis

Gas demand for the fertiliser sector is expected to increase from current 50.3 mmscmd in FY 2022 to 67.2 mmscmd in FY 2030 and to 87.5 mmscmd in FY 2040. By 2040, ~ 10.2 mmscmd and ~28.7 mmscmd incremental demand is expected from existing and upcoming plants, respectively.

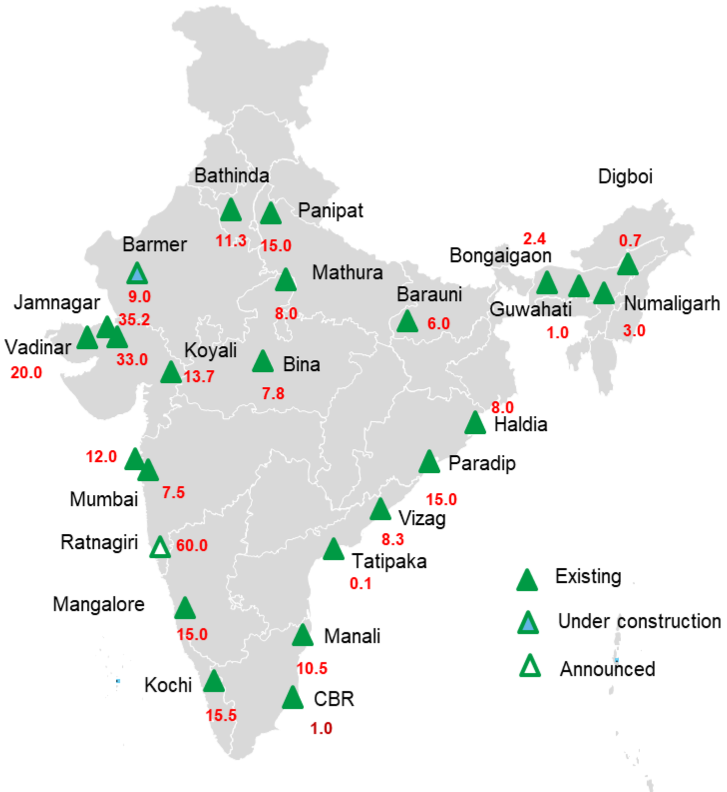
Figure 30 Projected natural gas demand in India from the fertiliser sector (in mmscmd)



2.5.4.2 Refining sector

In a refinery, fuel is primarily used in process heaters, hydrogen generation, and utilities. The entire 100 percent of the fuel requirement in a refinery can be met by in-house production.

Figure 31 Refineries in India

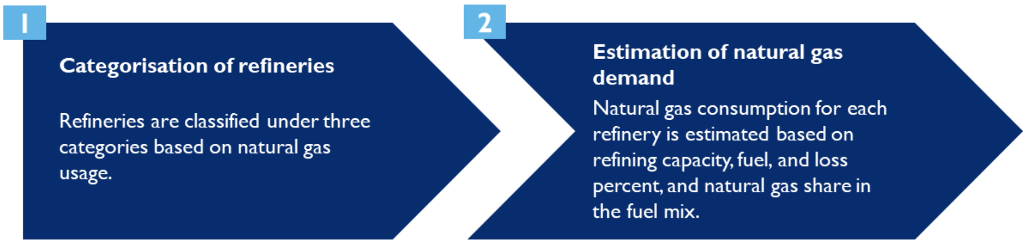


Drivers for natural gas use in the refining sector

1. Greenfield/brownfield expansions, leading to an increase in refining capacity – Refinery capacity is expected to increase from the current capacity of 249.4 MMTPA to 414.4 MMTPA by FY 2025 and to 438.7 MMTPA by FY 2030. The increase will be driven by a rise in demand for petroleum products.
2. Fuel quality improvement initiatives
    a. India has adopted BS VI fuel norms since 1 April 2021, limiting sulphur content to 10 ppm.
    b. A new rule[116] on sulphur content in fuel oil used on board ships came into force on 1 January 2020. The rule limits sulphur in fuel oil used on board ships operating outside designated emission control areas to 0.50 percent, a significant reduction from the previous limit of 3.5 percent.
    c. Both these initiatives will increase the requirement of hydrogen needed to remove sulphur and thereby, increase the requirement of natural gas.
3. Integration of petrochemical and refineries – There is an increasing trend of integrated refining-cum-petrochemical complexes that will produce even more value-added products. This will require fuel oil, naphtha, and components of fuel gas to be freed for conversion, thereby increasing requirement of natural gas.
4. Displacement of existing fuel with natural gas – Fuel gas, fuel oil, and naphtha are part of the product mix. Natural gas can potentially replace these fuels if the sourcing cost of natural gas is less than the selling price of fuels.
5. Pipeline connectivity to refineries – Of the 25 existing and upcoming refineries, 15 are connected to natural gas pipelines and others are expected to be connected in the next 4-5 years. With the availability of pipeline connectivity, use is expected to go up.
6. Emission regulations – Stricter regulations for emissions will increase use of natural gas.

[116] *https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx*

Figure 32 Overview of methodology for projecting natural gas demand for the refining sector in India



Detailed methodology

1. Step 1 – Categorisation of refineries based on natural gas consumption,
    a. A refinery consumes fuel gas, fuel oil, naphtha, and natural gas either as feed and/or fuel for hydrogen generation and gas turbines. The primary consumers of fuel in a refinery are process heaters, hydrogen generators and utilities.
    b. Fuel and loss for a refinery is expressed as a share of crude throughput consumed as fuel. Typically, this is in the range of 5-7 percent for a refinery with minimum conversion units, 7-9 percent for a refinery with conversion facilities with maximum bottom upgrading, and more than 10 percent for refinery-cum-petrochemical complexes that are highly energy intensive.
    c. Based on configuration, refineries are categorised into three buckets:
        i. Category 1 - Refineries classified under category 1 are the ones with secondary units; for example, Hydrocracker Unit (HCU) and Fluid Catalytic Cracker Unit (FCCU) that have a low share of natural gas in the fuel mix
        ii. Category 2 - Refineries categorised under category 2 are the ones with tertiary and petrochemical units; for example, Delayed Coker Unit (DCU) and Residue Hydrocracker Unit (RHCU) that have a medium share of natural gas in the fuel mix
        iii. Category 3 - Refineries categorised under category 3 are the ones with tertiary units; they have a high share of natural gas in the fuel mix
2. Step – 2 Estimation of natural gas demand
    a. Current refining capacity and expansion of existing and upcoming refineries was collated.
    b. Fuel and loss percentage for each refinery was collated from PPAC data.
    c. Based on the category of refinery, the share of natural gas in the fuel mix for that refinery was identified. The year-wise gas demand for refineries was calculated as a product of the overall refinery capacity, the percentage share of natural gas in the fuel mix, and the fuel and loss percentage up to FY 2030.

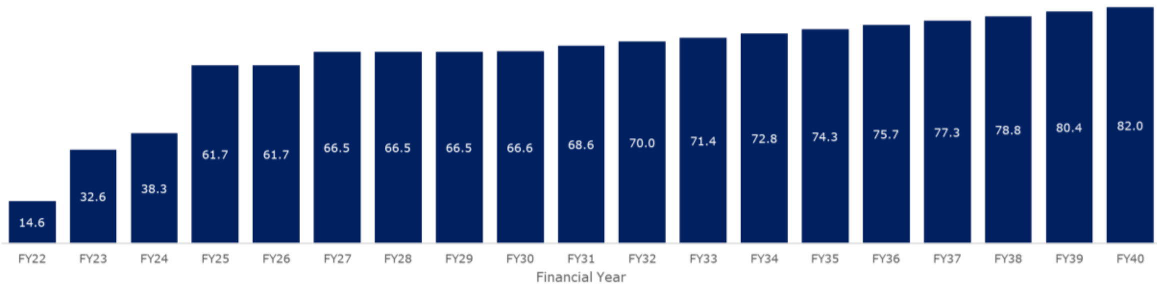
Assumptions

1. Connectivity to a gas pipeline for upcoming refineries has been assessed. For the refineries that are not yet connected to the gas grid, the year of connection to a natural gas pipeline was checked; natural gas consumption for these refineries was consequently commenced from the respective year.
2. For gas demand from FY 2031 to FY 2040, CAGR for production of petroleum products was calculated. For the projection of demand from FY 2031 to FY 2040, CAGR was reduced by 1 percent year-on-year, with a minimum growth rate cap of 2 percent.

Analysis

The gas demand for the refining sector is expected to increase from current 14.6 mmscmd in FY 2022 to 66.6 mmscmd in FY 2030 and to 82 mmscmd in FY 2040.

Figure 33 Projected natural gas demand in India from the refineries sector (in mmscmd)



2.5.4.3 Petrochemical sector

In India, the petrochemical sector accounted for 8.4 mmscmd of natural gas demand in FY 2020-21. The chemical sector has significant growth potential created by a large untapped demand, trade deficit, and ambition to increase share of manufacturing in overall GDP. Natural gas and naphtha are used as feedstock to manufacture a wide variety of petrochemicals.

India has 13 petrochemical plants; of which, seven are dependent on natural gas for feedstock and others require naphtha as feedstock.

Table 31 List of existing petrochemical plants

Petrochemical plants	Dual feed	Feedstock
RIL (Baroda)	No	Naphtha
HPL, Haldia	No	Naphtha
IOC Cracker, Panipat	No	Naphtha
RIL (Hazira) (Naphtha)	Yes	Naphtha
ONGC Petro additions Ltd. (OPaL) (Naphtha)	Yes	Naphtha
BCPL (Naphtha)	Yes	Naphtha
RIL (Nagothane)	No	Natural gas
RIL (Gandhar)	No	Natural gas
GAIL, Auraiya	No	Natural gas
RIL, Jamnagar	No	Natural gas
RIL (Hazira) (Natural Gas)	Yes	Natural gas
ONGC Petro additions Ltd. (OPaL) (Natural Gas)	Yes	Natural gas
BCPL (Natural Gas)	Yes	Natural gas

Table 32 Upcoming petrochemical plants

Petrochemical plants	Dual Feed	Feedstock	Expected year of operation
ONGC Mangalore	No	Naphtha and refinery off gases	
BPCL Kochi	No	Naphtha and refinery off gases	2022
HMEL Bhatinda	No	Naphtha and refinery off gases	2021

Petrochemical plants	Dual Feed	Feedstock	Expected year of operation
IOCL Barauni	No	Naphtha and refinery off gases	2023
IOCL Paradeep	No	Naphtha and refinery off gases	2023
HRRL Barmer	No	Naphtha and refinery off gases	2024
IOCL Dumad	No	Naphtha and refinery off gases	2023
JBF Petrochemicals	No	PX supplied by ONGC MRPL	2022
GAIL Usar, Maharashtra	No	Liquid propane imports	2024
Chemplast Cuddalore	No	Alcohol and chlorine	2022

Drivers for natural gas use in the petrochemical sector

1. Headroom for growth - India's per capita consumption of polymers[117] was only ~10 kg/capita in FY 2019 compared with a global average of ~30kg/capita. This will require major additional petrochemical capacity in India that will increase demand for natural gas in the sector.
2. Shift to refining-cum-petrochemical complexes – Major players in the Indian oil and gas industry are implementing petrochemical projects that will increase demand for natural gas.[118]

Detailed methodology

1. Step 1 – Identification of plants producing petrochemicals
    a. The petrochemical plants in India and feedstock used by them for petrochemicals production were identified.
    b. The units that are integrated with refinery would largely use naphtha as feedstock and refinery off-gases. Hence, standalone units have been considered.
2. Step 2 - Tabulate historical feedstock consumption
    a. Historical consumption of feedstock used by petrochemical plants was identified.
    b. For dual feed plants, the share of natural gas and naphtha in the total feedstock was identified and natural gas demand has been considered.
3. Step 3 – Identification of new petrochemicals plants
    a. New petrochemicals plants were listed and feedstock for those was identified. For the plants that are part of a refinery integrated complex, feedstock would be either naphtha or off-gases from refineries.
    b. Feedstock used for new standalone units was identified.
4. Step 4 - Utilisation of petrochemical plants
    a. Historical utilisation of these petrochemical plants was identified and projected until FY 2030.
    b. Utilisation has been gradually increased to 100 percent for the plants not operating at full capacity.
5. Step 5 – Consumption of natural gas
    a. The consumption of natural gas feedstock identified in step 2 has been multiplied with utilisation in step 4 to project natural gas demand from the petrochemical sector until FY 2030.
6. Step 6 – Projection of demand for natural gas
    a. Natural gas demand from the petrochemical sector from FY 2031–2040 was calculated through an appropriate growth rate.

Assumptions

1. Growth rate for natural gas consumption from FY 2031–2040 was considered according to the table given below.

117 *Chemical and Petrochemical Statistics 2019*
118 https://www.investindia.gov.in/sector/oil-gas

Table 33 Growth rate for natural gas consumption in the petrochemical sector

Year	FY31	FY32	FY33	FY34	FY35	FY36
Growth rate	2.96%	2.0%	2.0%	2.0%	2.0%	2.0%
Year	FY37	FY38	FY39	FY40		
Growth rate	2.0%	2.0%	2.0%	2.0%		

Analysis

The gas demand for the petrochemical sector is expected to increase from current 7.6 mmscmd in FY 2022 to 16.1 mmscmd in FY 2030, and to 19.9 mmscmd in FY 2040.

Figure 34 Projected natural gas demand in India from the petrochemicals sector (in mmscmd)

2.5.4.4 Power sector

In India, 62 power plants use natural gas as fuel with a total installed capacity of 23,485 MW which accounts for 6 percent of the total installed capacity in the country. Power generation from natural gas is more advantageous over other conventional energy sources (such as coal and diesel) mainly on the account of its lesser impact on the environment and lower fixed costs. A gas-based power plant would require significantly less land and water in comparison with a coal-based power plant of the same capacity.

The Government of India has set a target of 450 GW of installed capacity of renewable energy (RE) by 2030. Thus, large scale renewable energy capacity addition is being implemented in the country. Such large-scale renewable integration is likely to pose challenges to system operations. One of the challenges would be to provide support to the grid, particularly during the peak hours when solar energy is going down and the load is ramping up. Within those scenario, gas-based power plants can play a vital role in grid stability especially during intermittency and provide the much-needed balancing power for integrating renewable sources-based power generation into the grid, particularly in view of their fast ramp down and ramp up capability.

In future, if there is a fall in Asian LNG pricing benchmarks, such as JKM (Japan Korea Marker) and West India DES, affordability of gas-based power is likely to improve. However, the gas-based power plants in India are not able to run efficiently. About 20 plants of a cumulative capacity of 7435 MW were stranded in FY 2022 due to a shortage in domestic gas supply, high cost of imported gas in international markets resulting in higher cost of generation using RLNG, and a competitive tariff scenario. Traditionally, the gas-based power plants in India have been able to operate at an average PLF of only 25 percent. Therefore, the gas-based power plants are not expected to generate high gas demand in the future.

Detailed methodology

1. Step 1 – Estimation of electricity generation by natural gas across India
    a. Multiple scenarios have been considered to calculate the share of natural gas in the electricity generation mix:
        i. Base case (most plausible scenario) – Gas consumption of power plants (from FY 2021 to FY 2040) that are currently based on gas has been considered similar to current consumption of FY 2018 to FY 2021. The gas consumption of FY 2022 has not been considered for making future projections because the consumption from power sector decreased due to the increased price of imported gas (due to several factors).

ii. Scenario 1 – Central Electricity Authority of India (CEA) has provided total generation projections of ~ 2518 BU until FY 2030. According to this scenario, the expected CAGR of total generation from FY 2020-30 is ~7 percent. The total generation has been considered constant thereafter. CEA has also provided the share of natural gas (~1.5 percent) in the electricity generation mix for FY 2030. Correspondingly, the share of natural gas has been projected at a reducing CAGR from ~3.5 percent in FY 2020 to ~1.5 percent in FY 2030.
iii. Scenario 2 – In its World Energy Outlook report, IEA (International Energy Agency) has projected natural gas-based power generation in India to be ~223 TWh by FY 2030 and ~336 TWh by FY 2040. This accounts for a CAGR of ~7.2 percent and ~7.4 percent, respectively. The same percentage share has been used to project demand on CEA's power generation projections.
iv. Scenario 3 – This scenario was considered on the basis of electrical energy requirement by CEA. According to CEA projections and forecasts, electrical energy requirement is expected to increase at a CAGR of ~6.18 percent over FY 2016−22, ~5.51 percent over FY 2022−27 and ~4.33 percent thereafter. The same numbers have been used to forecast the total energy generation. The share of natural gas percent has been assumed to be the same as in Scenario 1.

2. Step 2 – Plant load factor of natural gas plants
   a. For existing plants
      i. CEA provides historical power generation for each gas-based power plant in India.
      ii. From the historical power generation, the corresponding share in PAN India gas-based electricity generation was calculated for each plant. The same percentage share was used to project the PLF until 2040.
      iii. The PLF of each power plant was projected up to 2040 in each of the above-mentioned scenarios after multiplying their percentage share in electricity generation with the total gas-based electricity generation and dividing the result with their maximum generation capacity. For plants reaching 100 percent PLF, the latter has been stagnated (PLF by plant has been broadly predicted to estimate demand considering certain assumptions, while actual PLF of each plant may vary).
   b. For stranded plants
      i. From secondary research, those gas-based power plants were identified in which there had been no electricity generation in the past 2-3 years.
      ii. These power plants were considered stranded due to non-availability of gas. These were not considered for revival on account of challenges around affordability of gas.
3. Step 3 – Estimation of demand from natural gas demand (mmscmd)
   a. Plant load factor projected until FY 2040 in step 2 provides electricity generation estimate for each plant until 2040.
   b. CEA provides the natural gas consumed by each power plant.
   c. For existing plants, future NG consumption is projected in the same ratio as historical NG consumed to generate one unit of electricity.

<u>Assumptions</u>

1. A base case has been considered as the most plausible scenario considering the challenges around affordability of gas-based power plants.
2. Gas required by 1 MW power = 0.004541 mmscmd

<u>Analysis</u>

Under the basecase (most plausible scenario), gas demand in the power sector is expected to remain same at 30.9 mmscmd from FY 2023 until FY 2039-40. The gas demand in FY 2022 from the power sector was ~25 mmscmd and it has not considered for making the future projections under the most plausible scenario. It is because the decrease in gas demand was due to high prices of imported LNG. Following is the summary of gas demand from power sector under different scenarios:

Table 34 Summary of gas demand from power sector in India under different scenarios

Scenario	Gas demand (in mmscmd)	
	FY 2030	FY 2040
Basecase (most plausible scenario)	31	31
Scenario - 1	22	22
Scenario - 2	76	77
Scenario -3	22	33

Comparison of power from battery storage and power from natural gas

A Battery Energy Storage System (BESS) is a storage system that can capture energy from different resources (like solar power), accumulate it and store it in rechargeable batteries. This energy can then be released through discharge of batteries when necessary – peak demands, power outages and several other applications.

In case of India, the total cost of generation from gas lies in the range of INR 7.3–8.4/kWh (excluding Andhra Pradesh) when the price of crude oil is assumed to be US$65/barrel. If the share of domestic gas or PLF is increased, the total cost of generation will decrease. This cost of power generation from gas was computed through the following steps:

1. The landed cost of gas was calculated for each state where RLNG is being imported. This cost is directly proportional to crude price considered US$65/barrel. The following additional cost components were added to this cost:
    a. Delivered ex-ship (DES) cost (US$8.63/mmbtu)
    b. Custom duty (2.75 percent)
    c. Terminal charges (US$1/mmbtu)
    d. Pipeline tariff (depends on the state)
    e. 12 percent GST on EWPL (the East-West pipeline)
    f. 18 percent GST on terminal charges
    g. VAT percent (depends on the state)
2. Gas-based power generation was assumed to be 100 percent through RLNG at 40 percent PLF.
3. Based on that, amount of gas required for power generation was computed for different states using the station heat rate of 1900 kcal/kWh and gross calorific value of gas as 10,000 kcal/scm.
4. The variable cost of generation was calculated by state after dividing the total price of gas with the number of units produced.
5. The total cost of generation was calculated after adding the levelised fixed cost of generation assumed at PLF of 25 percent and 40 percent. At PLF of 25 percent, the levelised fixed cost of generation was calculated at INR 1.6/unit, whereas at 40 percent, it was calculated at INR 1/unit.

Table 35 Price calculation of gas-based power generation on crude oil price of US$65/barrel, by state

Gas		Gujarat	Maharashtra	Tamil Nadu	Odisha	Kerala	Rajasthan	Karnataka	AP
Gas price	$/mmbtu	12.1	12.0	10.8	12.8	12.2	12.2	12.2	13.8
	INR/1000SCM	35984.6	35755.7	32131.1	37952.8	36321.0	36326.0	36321.0	41043.8
Units generated	MU	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Units sold	MU	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Gas required	Mn SCM	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Gas price	INR (cr)	2.4	2.4	2.1	2.5	2.4	2.4	2.4	2.7

Variable cost of generation	INR/unit	7.0	7.0	6.3	7.4	7.1	7.1	7.1	8.0
Fixed cost of generation	INR/unit	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6
Total cost of generation	INR/unit	8-8.6	8-8.6	7.3-7.9	8.4-9	8.1-8.7	8.1-8.7	8.1-8.7	9-9.6

The following tables show an analysis of the change in the total cost of generation from gas with different prices of crude oil:

Table 36 Price calculation of gas-based power generation on crude oil price of US$55/barrel, by state

Gas		Gujarat	Maharashtra	Tamil Nadu	Odisha	Kerala	Rajasthan	Karnataka	AP
Gas price	$/mmbtu	10.6	10.6	9.4	11.3	10.7	10.8	10.7	12.2
	INR/1000SCM	31588.6	31417.2	28117.4	33556.9	31944.2	32121.2	31944.2	36284.8
Units generated	MU	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Units sold	MU	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Gas required	Mn SCM	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Gas price	INR (cr)	2.1	2.1	1.9	2.2	2.1	2.1	2.1	2.4
Variable cost of generation	INR/unit	6.2	6.1	5.5	6.5	6.2	6.3	6.2	7.1
Fixed cost of generation	INR/unit	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6
Total cost of generation	INR/unit	7.2-7.8	7.1-7.7	6.5-7.1	7.5-8.1	7.2-7.8	7.3-7.9	7.2-7.8	8.1-8.7

Table 37 Price calculation of gas-based power generation on crude oil price of US$75/barrel, by state

Gas		Gujarat	Maharashtra	Tamil Nadu	Odisha	Kerala	Rajasthan	Karnataka	AP
Gas price	$/mmbtu	13.6	13.5	12.1	14.2	13.7	13.6	13.7	15.4
	INR/1000SCM	40380.5	40094.3	36144.8	42348.8	40697.8	40530.8	40697.8	45802.9
Units generated	MU	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Units sold	MU	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Gas required	Mn SCM	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Gas price	INR (cr)	2.7	2.7	2.4	2.8	2.7	2.7	2.7	3.0
Variable cost of generation	INR/unit	7.9	7.8	7.0	8.3	7.9	7.9	7.9	8.9
Fixed cost of generation	INR/unit	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6	1-1.6
Total cost of generation	INR/unit	8.9-9.5	8.8-9.4	8-8.6	9.3-9.9	8.9-9.5	8.9-9.5	8.9-9.5	9.9-10.5

In case of additional scenarios for crude oil prices at US$55/barrel and US$75/barrel, the price of gas-based power generation will vary in the range of INR 6.5-8.1 and INR 8-9.9, respectively, per kWh (excluding AP because of 24 percent VAT that is significantly higher than other states).

Advancements in battery technology and a decline in costs are shaping up battery storage as a potential option for large grid scale storage applications to provide on-demand and balancing power. According to BNEF (Bloomberg NEF), cell cost and pack price of battery for four-hour discharge time will decline in the next few years. Based on their projections, the total cost of power generation from battery was calculated as follows:

1. According to BNEF projections, the cell and pack price for the Battery Energy Storage System (BESS) will be US$58/kWh by 2030[119] in an optimistic scenario. CEA too has given its projections for BESS cell and pack price of US$100/kWh by 2030[120] in a pessimistic scenario. Based on that and the current battery price, CAGR was computed (~8.2 percent and ~3.09 percent for optimistic and pessimistic scenarios, respectively) and the expected BESS cell and pack price was calculated for different years. The battery prices will be decided on the global demand and hence, a range has been considered by taking projections from both CEA and BNEF.
2. The cell and pack price was assumed to be ~60 percent of the capex for the overall BESS system. Based on this assumption, the BESS capex requirement was calculated for 1 MW power generation from battery.
3. From the BESS capex requirement, the average fixed cost in INR/kWh was calculated for different years based on standard industry assumptions for different variables associated with setting up of the BESS infrastructure. The battery's charging and discharging efficiency was assumed 92 percent with 94 percent depth of discharge; the number of cycles was assumed 5,500. For capital costs, the debt-to-equity ratio was considered 70:30 with a 9 percent interest rate of debt. The battery's lifespan was considered 15 years and terminal value was assumed at 5 percent after depreciation. Further, two scenarios were considered for the return on equity and opex costs:
    a. Scenario – 1: This scenario considered 1 percent operations and maintenance costs (increasing by 3 percent every year), along with 14 percent pre-tax return on equity. Using a 10 percent discount rate, a levelised annual fixed cost was calculated per kWh of power generation. In addition, this scenario considered the fixed charging cost of INR 2.5/kWh through solar power based on latest discussions around solar tariffs.
    b. Scenario – 2: This scenario considered 2 percent operations and maintenance costs (increasing by 3 percent every year), along with 16.2 percent pre-tax return on equity. Using a 10 percent discount rate, the levelised annual fixed cost was calculated per kWh of power generation. In this scenario, instead of a fixed charging cost through solar power, a levelised charging cost of INR 2.94/kWh was considered for battery charging. This levelised charging cost was calculated by assuming INR 2.5/kWh of renewable energy charging cost, which is increasing by 3 percent per annum using a 10 percent discount rate for 15 years.
4. The same procedure was followed to compute cost of generating power from battery considering a pessimistic scenario of the BESS cell and pack price.

Table 38 Scenario – 1: Cost of generating power using the BESS system per BNEF projections

BNEF projections		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cell and pack price	$/kWh	126	115	106	97	89	82	75	69	63	58
BESS capex	$/kWh	210	192	176	162	149	136	125	115	105	97
BESS capex	INR Cr/MW	6.3	5.8	5.3	4.9	4.5	4.1	3.8	3.4	3.2	2.9
BESS AFC	INR/kWh	8.6	7.8	7.2	6.6	6.1	5.6	5.1	4.7	4.3	3.9
Total cost of generation	INR/kWh	11.1	10.3	9.7	9.1	8.6	8.1	7.6	7.2	6.8	6.4

[119] https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/
[120] CEA Optimal Generation Capacity Mix Report

Table 39 Scenario – 1: Cost of generating power using the BESS system per CEA pessimistic projections

CEA pessimistic		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cell and pack price	$/kWh	133	129	125	121	117	113	110	106	103	100
BESS capex	$/kWh	221	214	208	201	195	189	183	177	172	167
BESS capex	INR Cr/MW	6.6	6.4	6.2	6.0	5.9	5.7	5.5	5.3	5.2	5.0
BESS AFC	INR/kWh	9.0	8.7	8.5	8.2	7.9	7.7	7.5	7.2	7.0	6.8
Total cost of generation	INR/kWh	11.5	11.2	11.0	10.7	10.4	10.2	10.0	9.7	9.5	9.3

Table 40 Scenario – 2: Cost of generating power using the BESS system per BNEF projections

BNEF projections		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cell & pack price	$/kWh	126	115	106	97	89	82	75	69	63	58
BESS capex	$/kWh	210	192	176	162	149	136	125	115	105	97
BESS capex	INR Cr/MW	6.3	5.8	5.3	4.9	4.5	4.1	3.8	3.4	3.2	2.9
BESS AFC	INR/kWh	9.5	8.7	8.0	7.4	6.8	6.2	5.7	5.2	4.8	4.4
Total cost of generation	INR/kWh	12.5	11.7	11.0	10.3	9.7	9.1	8.6	8.2	7.7	7.3

Table 41 Scenario – 2: Cost of generating power using the BESS system per CEA pessimistic projections

CEA pessimistic		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cell and pack price	$/kWh	133	129	125	121	117	113	110	106	103	100
BESS capex	$/kWh	221	214	208	201	195	189	183	177	172	167
BESS capex	INR Cr/MW	6.6	6.4	6.2	6.0	5.9	5.7	5.5	5.3	5.2	5.0
BESS AFC	INR/kWh	10.1	9.7	9.4	9.2	8.9	8.6	8.3	8.1	7.8	7.6
Total cost of generation	INR/kWh	13.0	12.7	12.4	12.1	11.8	11.5	11.3	11.0	10.8	10.5

The expected cost of gas-based power generation would fall between INR 6.5-9.9/kWh considering the variations in crude oil prices. Within battery-based power generation, as the cell and pack price is expected to decrease during 2021-2030, the total cost of generation from battery would also decrease in almost the same proportion. Within scenario 1, the total cost of generation from battery storage is expected to fall from INR 11.1-11.5/kWh currently to INR 6.4-9.3/kWh by 2030. Within scenario 2, the total cost of generation from battery storage is expected to fall from INR 12.5-13/kWh currently to INR 7.3-10.5/kWh by 2030. Therefore, gas-based power generation is expected to be more economical than battery-based generation at least until 2029. This augers well for the gas-based power sector in India, which has nearly 16 GW of stranded gas-based capacity due to non-availability of gas at competitive prices. From 2030 onwards, when prices of battery decrease significantly, power generation from battery becomes more economical in the future, considering assumptions in scenario 1.

2.5.4.5 CGD sector

In India, the CGD sector is the third-largest consumer of natural gas. It is expected to grow rapidly due to expansion of existing, recently announced, and upcoming GAs. At present, 289 GAs have been authorised by

PNGRB in 27 states and union territories covering about 88 percent of the country's area and 98 percent of its population post the completion of the 11th bidding round.

Demand from the CGD sector is further divided into the following four segments:

1. CGD (domestic) – Piped natural gas supplied to households for primarily cooking
2. CGD (transportation) – Compressed natural gas supplied to vehicles
3. CGD (commercial) - Piped natural gas supplied to commercial establishments, such as hotels
4. CGD (Industrial) - Industrial consumers with a requirement of lower than 100,000 scmd are typically supplied through a CGD network

Drivers for natural gas use in the CGD sector

1. Availability of domestic natural gas on priority for the CGD (domestic) and CGD (transportation) sectors that has significantly improved economics as prices of alternative fuel (LPG, petrol, and diesel) have been on an increasing trend.
2. Increase in the number of GAs – The coverage of the CGD sector has been increasing as a large number of GAs have been bid out by PNGRB.
3. Improvement in gas supply and transportation infrastructure - The recently commissioned, under-construction, and recently announced pipelines and LNG import terminals will improve the availability of natural gas in areas that were earlier not connected to the gas grid.

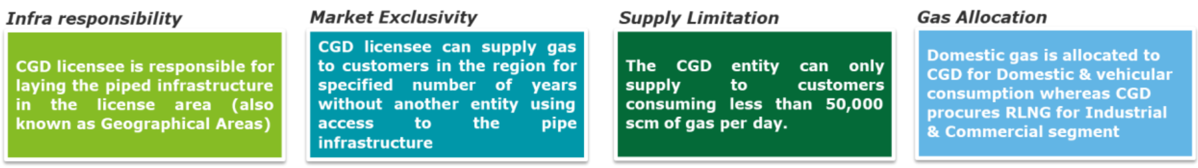
2.5.4.5.1 CGD domestic sector

The CGD system is one of the key gas consuming sectors in India. CGDs provide gas as either CNG used as a fuel for transportation or PNG supplied to domestic, industrial, and commercial establishments through pipelines.

The sector is a regulated business by the Petroleum and Natural Gas Regulatory Board (PNGRB).

In 2006, the PNGRB was constituted under the Petroleum and Natural Gas Regulatory Board Act, 2006. The board is mandated to regulate the refining, processing, storage, transportation, distribution, marketing, and sale of petroleum, petroleum products, and natural gas excluding production of crude oil and natural gas. This will help ensure uninterrupted and adequate supply of petroleum, petroleum products, and natural gas in each part of the country.

A CGD licensee secures two types of exclusivity viz. marketing and infrastructure. As part of marketing exclusivity, it can supply gas to customers in the region for a specified number of years without another entity using access to the pipe infrastructure. As part of infrastructure exclusivity, the CGD licensee is responsible for laying the piped infrastructure in the licence area (also known as GA). Apart from exclusivity, the licensee gets gas allocation specifications from the government for the domestic and transportation segment.



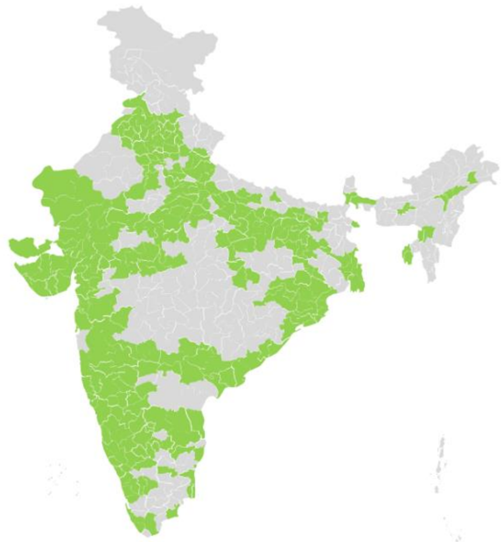
Key market metrics of the CGD industry

- The share of CGD in natural gas consumption increased from 11 percent in FY 2016-17 to 16 percent in FY 2020-21. Of the 30 mmscmd gas used in the CGD sector in FY 2020, 14 mmscmd (47 percent) was imported. Customers from the commercial and industrial segments are serviced using RLNG, whereas the domestic and CNG segments are provided domestic natural gas.
- The impact of COVID-19 has stagnated growth of natural gas for the past year. However, the demand recovered in the second half of FY 2021 compared with the initial drop of sales in Q1 and Q2 of FY 2021.
- Based on cost comparisons, natural gas is cheaper than substitutes available in the domestic, CNG, and commercial segments. It is comparable to base fuels used in the industrial segment.

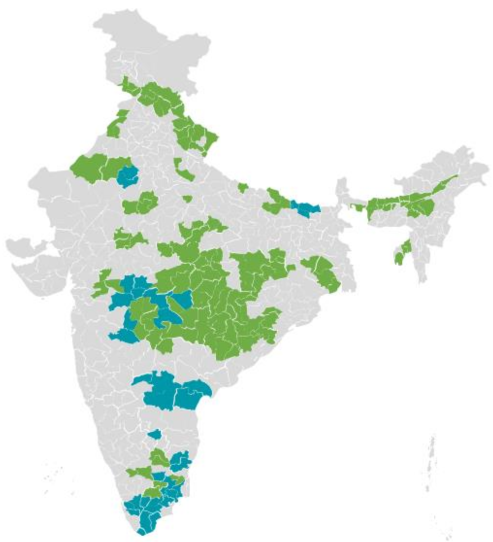
- The number of GAs of CGD increased from ~35 since 2007 to ~228 until 2019 and around 61 new GAs got added in the 11th round bidding. The coverage up to the last 10th and 11th rounds is shown below.

Figure 35 CGD coverage in India for 10 and 11 rounds

CGD coverage (up to the Xth round)



CGD coverage (XIth round)



Key drivers for the CGD Industry

1. Regulatory push
   - **Domestic gas allocation:** Low-cost domestic gas allocated on a priority basis for the CNG (transport) and PNG (domestic) segments, led to an increase in penetration. Also, a CGD entity has an option to source gas sold by upstream entities under the marketing freedom mechanism for the industrial and consumer segments. Most likely this could be cheaper than LNG, and an upside for the industrial and consumer segments.
   - **Marketing exclusivity:** CGD entities in rounds 9 and 10 get marketing exclusivity for eight years, up from five years offered until round 8. It could help them establish their business without facing competition.
   - **Increase in the number of GA authorisation:** In bidding rounds 9 and 10, the government authorised more GAs than rounds 1 to 8 combined. The 11th round has also been conducted with a total of 289 GAs being awarded.
   - **Clarity in regulations:** PNGRB and MoPNG have introduced various regulations and amendments to improve clarity of operations in this sector. For instance, the CGD access code regulation and the regulation for capacity determination of CGD network.
   - **Gas exchange:** In June 2020, the Indian Energy Exchange (IEX) launched the country's first gas exchange with an aim to gradually move towards the deregulation of gas prices and encourage investment in gas infrastructure.
2. Demand for cleaner fuel
   - **Ban on polluting fuels:** In 2017, the Supreme Court banned the use of petcoke and furnace oil in the National Capital Region (NCR) and suggested similar steps in other states. Following this order, Rajasthan, Uttar Pradesh, and Haryana imposed a ban on these items. In 2019, Gujarat also imposed a blanket ban on Furnace Oil (FO) and polluting fuels. Other states are also considering similar steps.
   - **Increase in share of natural gas:** The government of India has envisioned to increase the share of natural gas in India's energy mix to 15 percent by 2030, from ~6.5 percent at present.
   - **Cleaner fuel for domestic use:** The government pushes availability of LPG in rural India through the Ujjwala scheme. The scheme aims to improve access to cleaner fuel for the domestic purpose. To meet LPG demand from rural areas, the government has set aggressive targets for PNG roll-out in urban areas.

- **India's emission reduction targets:** Current primary energy requirement is largely met by coal (56 percent) and oil (29 percent). The government has committed to reduce the emission intensity of GDP by 33-35 percent by 2030 from the 2005 level (INDC Commitment).

3. Economic advantage
    - **Discount to alternative fuels:** CNG is cheaper compared with petrol and diesel; this results in lower running costs of vehicles. Further, domestic PNG is more affordable than LPG, thus driving household adoption.
    - **Lower taxes on CNG vehicles:** In September 2019, the oil ministry proposed reducing GST on CNG vehicles from current 28 percent to 5 percent. If the proposal is passed, it could provide a boost to CNG demand.
    - **Adoption of OEM-fitted CNG vehicles:** The recent shift in the automotive sector from BS-IV to BS-VI has increased prices for petrol and diesel automobiles, thus making CNG vehicles more cost competitive. To address this concern, OEMs plan to introduce factory-fitted CNG vehicles that will make the shift to BS-VI for the CNG sector easier and hassle-free.

4. Announcements from the government

    Within Budget 2021, the government announced the following key initiatives for the next few years to boost the demand in the gas sector:
    - About 100 more districts to be added to the City Gas Distribution network in the next three years
    - Gas pipeline to be constructed in Jammu and Kashmir
    - An independent gas transport system operator to be set up to facilitate and coordinate booking of common carrier capacity in all-natural gas pipelines on a non-discriminatory open access
    - Approval of 60 percent capital grant (~INR 5,555 crore) to Indradhanush Gas Grid Ltd to develop the North East Region Gas Grid

Detailed methodology

1. Step 1 – Estimation of demand from GAs until 10th round
    a. The total number of domestic connections have been estimated.
        i. For existing GAs, existing domestic connections have been considered for demand estimation segregated at the state level.
        ii. The Minimum Work Programme (MWP) under the 9th and 10th rounds provides the number of domestic connections, by state, to be implemented until 2030. Based on historical performance of CGD companies, such as IGL, MGL, and Adani, the connections expected under MWP have been calculated.
        iii. The schedule, by year, for connections has been projected based on the ramp up rate provided by PNGRB from year 1 to 8.
        iv. Further, total connections in each year have been segregated on the basis of urban and rural population in each state provided by Census 2011; most companies target urban connections before branching out into rural areas. This is due to the higher density of population in urban areas, leading to a lower capex per connection.
    b. Natural gas demand
        i. The total number of urban and rural connections projected for each year has been multiplied by 0.45 scmd for an urban household and 0.35 scmd for rural household to arrive at the total demand.
2. Step 2 – Estimation of demand from GAs announced in 11th round
    a. Total number of domestic connections
        i. The total number of urban and rural households for each GA from Census 2011 was collated.
        ii. To arrive at the total households for each year (starting from FY 2020-21 to FY 2039-40), a modified growth rate has been considered based on the growth rate of households between FY 2000-01 and FY 2010-11.
        iii. Based on historical penetration rates and considering initial demand from FY 2023, the number of households that would adopt PNG was estimated for each year.

b. Natural gas demand
    i. The total number of urban and rural connections projected for each year has been multiplied by 0.45 scmd for an urban household and 0.35 scmd for rural household to arrive at the total demand.
c. Total demand from the domestic sector
    i. The demand, by year, from both the groups is added to arrive at the total demand from the CGD domestic sector.

Assumptions

1. Consumption for a rural household: 0.35 scmd
2. Consumption for urban household: 0.45 scmd
3. Maximum realisable connections under MWP: 30 percent (based on an average of progress achieved by CGD companies, such as Indraprastha Gas Ltd., Mahanagar Gas Ltd., and Adani Gas.
4. Annual MWP targets considered as stated by PNGRB and modified for availability of pipeline connectivity from 2022

Analysis

Gas demand for the CGD domestic sector is expected to increase from current 2.86 mmscmd in FY 2022 to 9.87 mmscmd in FY 2030 and to 14.53 mmscmd in FY 2040.

2.5.4.5.2 CGD transportation sector

The transportation sector will be one of the major demand drivers for consumption of natural gas for CGD. With an increase in price of POL fuels such as petrol and diesel across the years, along with concerns of increasing environmental pollution from these fuels, the transportation sector saw a shift towards CNG. CNG also offers a significant value in the TCO for vehicles compared with petrol and diesel. The TCO refers to the purchase price of a vehicle, along with additional costs borne during the lifecycle of the vehicle. On considering the commercial four-wheelers segment, the expected TCO that the owner has to incur during the lifespan of a vehicle considering an average life of five years, is shown below:

Table 42 Comparison of TCO for petrol, CNG, and diesel vehicles

Type of cost	CNG	Petrol	Diesel	Unit
Capex	4.1	3.2	4.4	INR/km
Running cost	7.7	10.0	8.8	INR/km
Total permit cost	0.04	0.04	0.04	INR/km
Total maintenance cost	1.1	1.1	1.2	INR/km
Final TCO cost	13.0	14.4	14.5	INR/km

Compared with petrol and diesel vehicles, the TCO for CNG vehicles is lower by ~9.7 percent across a vehicle's lifetime. The detailed assumptions and calculations for TCO have been mentioned in annexure 17.1.2. Hence, a significant penetration and demand for CNG in the road transportation segment is expected.

Detailed methodology

1. Step 1 – Estimation of demand from CNG stations until 10th round up to FY 2029-2030
    a. Calculate the total CNG stations
        i. The number of the existing CNG stations in each state has been determined based on the available data.
        ii. The total CNG stations expected in the 9th and 10th rounds have been calculated as defined by the Minimum Work Programme (MWP). The MWP provides implementation schedule, by year (from 1 to 8 years), for each GA. The growth of these CNG stations is expected to evolve from 5 percent in 2022 to 30 percent in 2025 and finally 100 percent in 2030, assuming a delay of two years on MWP targets for round 10 GAs. However, there may be further delays in meeting MWP for CNG stations; this may defer demand.

iii. Although a delay has been considered in meeting MWP targets, considering that CNG is the most profitable business, we have assumed that MWP targets will be met in full.

b. Estimation of CNG demand

i. The initial and final throughput for CNG stations was calculated on the basis of the following assumptions. These assumptions were taken based on the utilisation percentage of the respective GAs.

Table 43 CNG throughput from CNG stations

Scenario	Consumption (scmh)	Utilisation (%)	Operation hours per day	Throughput (thousand scm/month)
Initial	650	20%	9	35.1
Final	650	30%	12	70.2

ii. The CNG throughput from a CNG station in a particular state was ramped up to final throughput of 70 tscm/month if the current average throughput was less than it. For example, if the throughput for the state in which a CNG station is located is less than 50 tscm/month, it was ramped up to reach 70 tscm/month in seven years. If the throughput was greater than the final throughput of 70 tscm/month, the as-is throughput is maintained.

Table 44 Ramp-up of throughput for CNG stations

Current throughput (thousand scm/month)	Years to finalisation
< 50	7
> 50 and < 70	5
> 70	0

iii. The total demand for each GA was calculated using the expected throughput for CNG stations and the total number of CNG stations expected to come up each year

2. Step 2 – Estimation of demand from CNG stations from the 11th round

a. Estimation of petrol and diesel sales for each GA

i. Sale of alternative fuels, such as petrol and diesel, was determined for each GA based on consumption in each district.

ii. The growth rate of fuel demand was determined based on historical sales data of FY 2018 and FY 2019. The growth rate was reduced by 5 percent each year for all the subsequent years post FY 2021.

iii. From FY 2021 onwards, the total demand for petrol and diesel was projected on the basis of current fuel demand and the growth rate calculated for each year.

b. Availability of natural gas

i. CNG sales were assumed to start in respective GAs based on the status of the nearest natural gas pipeline. If the pipeline is yet to commissioned, the expected year of operation is considered for the first year of CNG sales.

c. Pool of alternative fuel available for substitution

i. In case of petrol, only three wheelers and motor vehicles will be converted to run on CNG as two wheelers cannot be converted.

ii. In case of diesel, buses, commercial and private cars, and three wheelers will be converted to run on CNG.

iii. Based on vehicle sales data for each vehicle segment, the pool of alternative fuel was proportionately calculated.

iv. Further, based on historical CNG conversion data, the penetration of CNG for each vehicle was determined to calculate possible CNG sales.

   d. Considering these factors, the total CNG sales were estimated for each GA and subsequently for round 11.
3. Step 3 - Consideration of scenarios for CNG penetration
   a. According to the industry analysis of the CNG sector, demand for CNG in road transportation will decrease by ~7-10 percent by FY 2030 because of the gradual shift towards electric vehicles. The shift is expected to be fuelled by regulatory policies and subsidies in the future. Therefore, two scenarios were considered for the overall analysis.
   b. Scenario – 1 (Most plausible scenario): The base case scenario considered EV-constrained demand. The penetration assumptions for CNG vehicles, along with the throughput values of CNG stations, were taken conservatively based on that.
   c. Scenario – 2 (EV unconstrained demand): The second scenario was based on the assumption that EV would not affect CNG demand. Hence, a higher utilisation percentage for CNG stations and penetration rates were assumed within this scenario to calculate demand.

<u>Assumptions</u>

1. CNG penetration for vehicle segments is assumed on the basis of historical data given below:
   a. Three wheelers – 75 percent
   b. Four wheelers (petrol) – 10 percent
   c. Diesel commercial cars – 60 percent
   d. Diesel private cars – 5 percent
   e. Diesel buses – 10 percent
2. Breakdown of petrol consumption by vehicle type
   a. Bikes – 60 percent
   b. Three wheelers – 8 percent
   c. Motor vehicles – 32 percent
3. Breakdown of diesel consumption by vehicle type
   a. Buses – 7 percent
   b. Commercial cars – 11 percent
   c. Private cars – 11 percent
   d. Three wheelers – 8 percent
   e. Motor vehicles – 63 percent

<u>Analysis</u>

Gas demand for the CGD transport sector is expected to increase up to 50.3 mmscmd in FY 2030 and 77.24 mmscmd in FY 2040 in the base case scenario. In a scenario for EV unconstrained demand, demand is expected to be 54.7 mmscmd in FY 2030 and 85.61 in FY 2040.

2.5.4.5.3 CGD commercial sector

<u>Detailed methodology</u>

1. Step 1 – Projection of demand from GAs existing before round nine in FY 2019-20
   a. The existing commercial connections, by state, were calculated.
   b. Based on industry experience, an average consumption of 50 scmd of natural gas was considered per commercial unit.
   c. Based on the two above-mentioned factors, existing sales of the commercial sector were calculated.
   d. To estimate sales in the commercial sector until FY 2029-30, a 5 percent growth rate has been considered for existing GAs based on the data from various CGD companies. This is supported by the fact that existing GAs typically have a slow growth rate after the initial growth phase.
2. Step 2 – Projection of demand from GAs from rounds 9 and 10 after FY 21
   a. Estimation of packaged LPG sales and replacement by natural gas
      i. Sales of package LPG, by state, was determined considering the GAs that were announced for the year before the bidding round 9.
      ii. The pipeline connectivity and year availability was calculated for each GA.
      iii. The replacement of packaged LPG by natural gas was assumed to ramp up from 2.5 percent in year 1 to 20 percent in year 11. Here, year 1 is considered from the time nearest pipeline connectivity is established.

iv. Based on consumption reports published by the Ministry of Petroleum and Natural Gas, in FY 2019, ~12 percent of packaged LPG was consumed in the commercial and industrial segments.
v. As consumption of LPG in industries in typically through bulk supply, ~8 percent of overall packaged LPG has been assumed to be used in the commercial segment.
vi. The increase in LPG consumption was calculated assuming the five-year CAGR of GSDP from tertiary sectors, including hotels, restaurants, and public administration services.
vii. The equivalent consumption of natural gas was calculated assuming 1 MT of LPG equals 3.26 scmd of natural gas.

3. Step 3 – Projection of demand from existing GAs up to FY 2040
    a. The total demand for GAs up to round 10 until FY 2030 was calculated through steps 1 and 2.
    b. The CAGR for commercial consumption was calculated for FY 26 to FY 30.
    c. It was progressively reduced from FY 31 onwards and capped at 2 percent to calculate the total natural gas consumption until FY 40.
    d. Demand for FY 2031 to FY 2040 was decided considering a growth rate calculated in the previous step.
4. Step 4 – Estimation of demand from the round 11
    a. Repeat steps 2 and 3 to project demand from GAs announced in round 11.
5. Step – 5 – Calculation of total demand from GAs
    a. The demand calculated in steps 3 and 4 was added to arrive at the final demand.

Assumptions

1. 1 MT of LPG = 3.26 scmd of natural gas
2. Penetration rate of natural gas in the commercial segment

Table 45 Penetration rate for natural gas in CGD – the commercial sector using packaged LPG as fuel

Year	0	1	2	3	4	5
Penetration rate	0%	2.5%	5%	7.5%	10%	12.5%
Year	6	7	8	9	10	11
Penetration rate	15%	17.5%	20%	20%	20%	20%

Analysis

Gas demand for the CGD commercial sector is expected to increase from current 1.9 mmscmd in FY 2022 to 4.1 mmscmd in FY 2030 and to 5.8 mmscmd in FY 2040.

2.5.4.5.4 CGD industrial sector

Detailed methodology

1. Step 1 – Estimation of demand from the industrial segment from GAs authorised before round nine
    a. The total number of industrial connections using natural gas as a fuel was mapped based on published secondary data.
    b. Based on industry experience, an average consumption of 400 scmd of natural gas was considered per industrial unit.
    c. Based on the two above-mentioned factors, existing sales of the industrial sector were calculated.
    d. Natural gas consumption is assumed to increase at an average annual rate of 3 percent until FY 2029-30. The lower growth rate is assumed as the growth declines for older GAs after an increase in penetration of gas.
    e. To estimate sales in the commercial sector until FY 2029-30, a 3 percent growth rate has been considered for existing GAs based on data from various CGD companies. The lower growth rate is assumed as the growth declines for older GAs when penetration of gas increases.
2. Step 2 - Projection of demand from GAs from rounds 9 and 10 from FY 21 onwards

a. Estimation of sales of fuels in the industrial sector and replacement by natural gas
   i. Sales of HSD (High Speed Diesel) bulk, FO (Furnace Oil) bulk, LPG bulk, LDO (Light Diesel Oil), and naphtha, in each state was determined for GAs in these two rounds.[121]
   ii. The total sales of packaged LPG for the commercial and industrial sectors were calculated considering ~12 percent of the packaged LPG was consumed in these segments based on consumption reports published by the Ministry of Petroleum and Natural Gas. Sales of packaged LPG for the industrial sector were calculated considering ~4 percent of the overall packaged LPG has been assumed to be consumed in this sector.
   iii. The pipeline connectivity and the year of pipeline availability of was calculated for each GA.
   iv. The replacement of these fuels by natural gas was assumed to increase gradually from year 1 to year 11 according to the table below. Here, year 1 is considered from the time nearest pipeline connectivity is established.

Table 46 Penetration rate for natural gas in CGD – the industrial sector using bulk HSD as fuel

Year	0	1	2	3	4	5
Penetration rate	0%	0.6%	1.3%	1.9%	2.5%	3.1%
Year	6	7	8	9	10	11
Penetration rate	3.8%	4.4%	5.0%	5.0%	5.0%	5.0%

Table 47 Penetration rate for natural gas in CGD – the industrial sector using bulk FO as fuel

Year	0	1	2	3	4	5
Penetration rate	0%	3.8%	7.5%	11.3%	15.0%	18.8%
Year	6	7	8	9	10	11
Penetration rate	22.5%	26.3%	30.0%	30.0%	30.0%	30.0%

Table 48 Penetration rate for natural gas in CGD – the industrial sector using bulk LPG and packaged LPG as fuel

Year	0	1	2	3	4	5
Penetration rate	0%	6%	13%	19%	25%	31%
Year	6	7	8	9	10	11
Penetration rate	38%	44%	50%	50%	50%	50%

Table 49 Penetration rate for natural gas in CGD – the industrial sector using LDO and naphtha as fuel

Year	0	1	2	3	4	5
Penetration rate	0%	5%	10%	15%	20%	25%
Year	6	7	8	9	10	11
Penetration rate	30%	35%	40%	40%	40%	40%

[121] *Government data*

v. Based on consumption reports published by the Ministry of Petroleum and Natural Gas, in FY 2019, ~12 percent of the packaged LPG was consumed in the commercial and industrial segments. As the consumption of LPG in industries in typically through bulk supply, ~4 percent of the overall packaged LPG has been assumed to be used in the industrial segment.
vi. The year-wise growth of respective fuel consumption was calculated assuming the 5-year CAGR of GSDP from manufacturing sectors.
vii. Using the penetration rate stated in the tables above, year-wise equivalent natural gas consumption was calculated.
viii. The total natural gas consumption from replacing all the above fuels is calculated for each year.

3. Step 3 – Projection of natural gas demand from FY 2031 to FY 2040 up to round 10
   a. The total demand for all GAs upto round 10 till FY 2030 was calculated from steps 1 and 2
   b. The CAGR for commercial consumption was calculated for FY 2026 to FY 2030.
   c. This CAGR was progressively reduced from FY 2031 onwards and capped at 2 percent to calculate the total natural gas consumption till FY 2040.
   d. The demand for FY 2031 to FY 2040 was calculated by considering a growth rate calculated in the previous step.
4. Step 4 – Estimation of demand from 11th round
   a. Repeat steps 2 and 3 to project demand from GAs announced in round 11.
5. Step – 5 – Calculation of total demand from all GAs
   a. The demand calculated in steps 3 and 4 is added to arrive at the final demand.

Assumptions

1. 1 MT of HSD = 3.41 scmd of natural gas
2. 1 MT of LPG = 3.26 scmd of natural gas
3. 1 MT of LDO = 2.93 scmd of natural gas
4. 1 MT of FO = 2.88 scmd of natural gas
5. 1 MT of naphtha = 2.95 scmd of natural gas
6. Growth rate assumption by year, for natural gas demand from industrial sector for the period FY 2031 to FY 2040,

Table 50 Growth rate, by year, for natural gas demand from the industrial sector

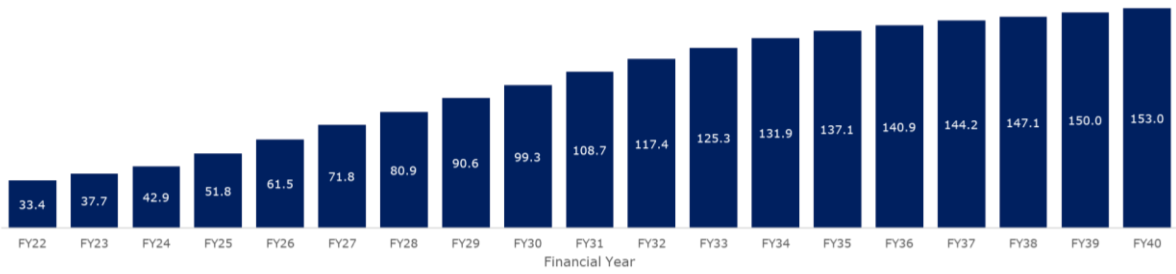
Year	FY31	FY32	FY33	FY34	FY35	FY36
Growth rate	9%	8%	7%	6%	5%	4%
Year	FY37	FY38	FY39	FY40		
Growth rate	3%	2%	2%	2%		

Analysis

Gas demand for the CGD industrial sector is expected to increase from current 13.2 mmscmd in FY 2022 to 35.0 mmscmd in FY 2030 and 55.4 mmscmd in FY 2040.

The overall demand from the CGD sector would rise from current 33 mmscmd in FY 2022 to 99.3 mmscmd in FY 2030 and 153 mmscmd in FY 2040.

Figure 36 Projected natural gas demand in India from the CGD sector for most plausible scenario (in mmscmd)



2.5.4.6 LNG in road transportation

The transport sector consumes a significant amount of energy and can be targeted using new solutions, such as LNG vehicles.

<u>Drivers for LNG in road transportation</u>

1. Technological driver
    a. LNG fuel is technologically proven and widely used in China, the US, and Europe
    b. LNG vehicles can run longer distances, thus reducing refuelling frequency with no chances of pilferage
2. Economical driver
    a. Diesel is about three times costlier compared with LNG at the terminal. If LNG delivery cost is optimised, it can potentially lead to savings for end-consumers.
    b. LNG's logistical flexibility also implies that it can reach distant locations without incurring capital expenditure on gas pipeline infrastructure.
3. Environmental driver
    a. For an equal energy content, LNG would have a 25 percent lower Carbon-di-oxide (CO_2) content than diesel with negligible Sulphur-di-oxide (SO_2)
    b. LNG is one of the faster ways to improve air quality standards in the transportation sector and avoids investment in pipeline infrastructure.
4. Policy drivers
    a. India inaugurated its first LNG plant in Nagpur in July 2021.
    b. In June 2020, PNGRB issued a notice that LNG stations would be excluded from the purview of CGD exclusivity licences in specific GAs. This would allow any entity to set up LNG infrastructure in any GAs irrespective of the fact that whether it is an authorised entity for that specific GA.

<u>Detailed methodology</u>

1. Step 1 – LNG demand from HDVs and buses
    a. HSD consumption by HDVs (Heavy Duty Vehicles) and buses has been estimated. Historical HSD consumption growth rate was calculated.
    b. HSD demand from this segment (HDVs and buses) was projected from FY 2022 to FY 2040 using calculated growth rates.
    c. LNG demand was calculated by converting the above-mentioned HSD demand into LNG using fuel conversion factor based on density and calorific value.
2. Step 2 - LNG demand from suited vehicles
    a. HDVs and buses are not expected to get converted into LNG because of its varied suitability to the industry. As a result, vehicles suited for LNG conversion were identified.
    b. The population of suited vehicles as a percentage of the total vehicles was identified.
    c. LNG demand from suited vehicles was calculated by multiplying LNG demand from step 1 with the above-mentioned percentage.
3. Step 3 - LNG demand from retrofitted vehicles
    a. Of the total vehicles suited for LNG conversion, not all would be converted into LNG considering the associated costs of retrofitting LNG equipment.

   b. Hence, it was assumed that only 40 percent of the existing suited vehicles are expected to be retrofitted with LNG equipment.
   c. LNG demand from retrofitted vehicles was calculated as 40 percent of the demand from suited vehicles.
4. Step 4 - LNG demand from new vehicles
   a. In addition to retrofitted vehicles, new LNG vehicles would be added each year.
   b. It was assumed that, of the total vehicles suited for LNG conversion, 12.5 percent new vehicles are expected to be added each year.
   c. Of these 12.5 percent new vehicles, only 40 percent are expected to be LNG operated. This gives LNG demand from new vehicles.
   d. LNG demand from both new and retrofitted vehicles was added.
5. Step 5 - LNG demand from top 15 routes
   a. Conversion into LNG would be witnessed on routes closer to industrial clusters.
   b. Hence, top 15 routes by traffic would witness a major shift towards LNG for HDVs and buses.
   c. Of the total vehicles (new + retrofitted) calculated in step 4, 55 percent run on the top 15 routes in India.
   d. LNG demand was estimated on the top 15 routes.
6. Step 6 - Ramp up
   a. Conversion to LNG shall take place in a phased manner.
   b. Hence, a ramp-up percentage was assumed to calculate the gradual uptake of LNG in the road transportation segment by FY 2040.

Assumptions

1. 1 MMTPA LNG = 1.16 MMTPA of diesel
2. Growth rate for demand of LNG = 7.31 percent
3. M and HCV vehicles suited for LNG = 45 percent
4. New vehicles added each year = 12.5 percent
5. New vehicles that can be converted into LNG = 40 percent
6. Vehicles running on the top 15 routes in India = 55 percent

Analysis

Gas demand for the LNG transportation sector is expected to increase from 0.7 mmscmd in FY 2022 to 10 mmscmd in FY 2030 and 40.2 mmscmd in FY 2040.

2.5.5 Total demand projection until 2040

The total demand through bottom-up approach is projected to increase to 316 mmscmd in 2030 and 448 mmscmd in 2040. The bottom-up approach is expected to give a more accurate representation of demand than the top-down approach because the overall demand calculation in bottom-up approach considers sector-wise drivers and challenges. In addition, it also takes into account the different scenarios that can play out in the future. Therefore, the bottom-up approach has been considered for projecting the overall demand numbers for every country. The following table shows each sector's contribution to demand for the basecase scenarios for India:

Table 51 Natural gas demand projection for each sector in India from FY 2022 to FY 2030 for most plausible scenarios (in mmscmd)

	FY22[122]	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Fertiliser	50.3	57.4	59.7	67.2	67.2	67.2	67.2	67.2	67
Refining	14.6	32.6	38.3	61.7	61.7	66.5	66.5	66.5	67
Petrochemical	7.6	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16
Power[123]	24.5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	31
CGD	33.4	37.7	42.9	51.8	61.5	71.8	80.9	90.6	99

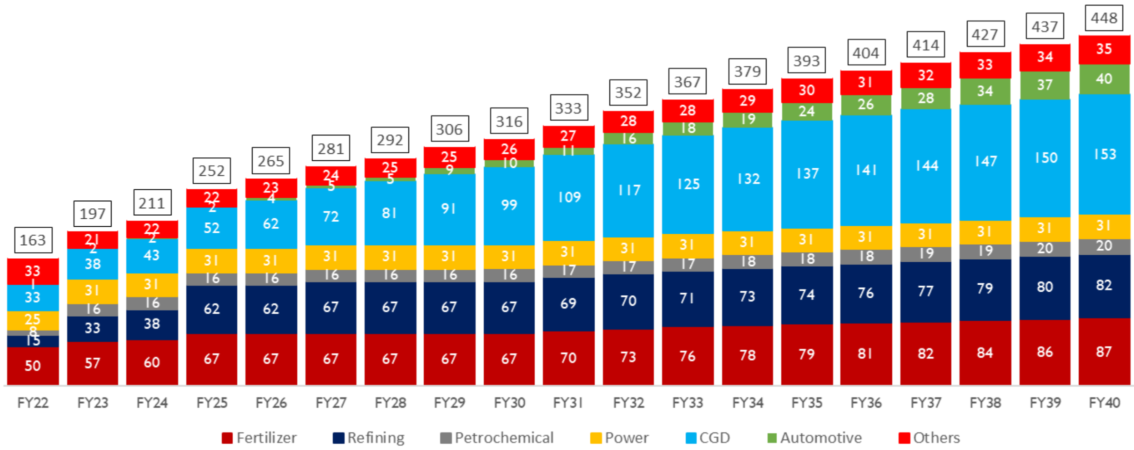
[122] The demand from different sectors for FY 2022 have been considered according to the latest numbers published by PPAC.
[123] The power sector experienced lesser gas demand in FY 2022 compared to the last few years. For the projection of demand numbers in the most plausible scenario from FY 2023 onwards, the average of last few years has been considered.

	FY22[122]	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Automotive	0.7	1.5	1.7	2.0	4.4	4.9	5.4	9.0	10
Others[124]	33	21.1	21.8	22.4	23.1	23.8	24.5	25.2	26
Total	**163**	**197**	**211**	**252**	**265**	**281**	**292**	**306**	**316**

Table 52 Natural gas demand projection for each sector in India from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Fertiliser	70.2	73.3	75.8	77.7	79.2	80.8	82.4	84.1	85.7	87
Refining	68.6	70.0	71.4	72.8	74.3	75.7	77.3	78.8	80.4	82
Petrochemical	16.6	17.0	17.3	17.6	18.0	18.4	18.7	19.1	19.5	20
Power	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	31
CGD	108.7	117.4	125.3	131.9	137.1	140.9	144.2	147.1	150.0	153
Automotive	11.0	16.1	17.6	19.3	23.7	25.9	28.2	34.1	37.0	40
Others	26.7	27.5	28.3	29.2	30.1	31.0	31.9	32.8	33.8	35
Total	**333**	**352**	**367**	**379**	**393**	**403**	**414**	**427**	**437**	**448**

Figure 37 Projections of sector-wise demand in India for most plausible scenarios (in mmscmd)



The CGD sector will achieve the largest share in the natural gas demand pie in FY 2040, followed by the fertiliser and refinery sectors.

2.6 Supply analysis

The supply projection methodology considers the existing and upcoming fields, along with LNG regasification terminals.

<u>Detailed methodology to assess natural gas supply in India</u>

1. Step 1 – Projection of natural gas supply from domestic fields
    a. Existing domestic fields
        i. Gas production from both the onshore and offshore existing domestic gas fields of ONGC, OIL, and other private companies/JVs was identified.

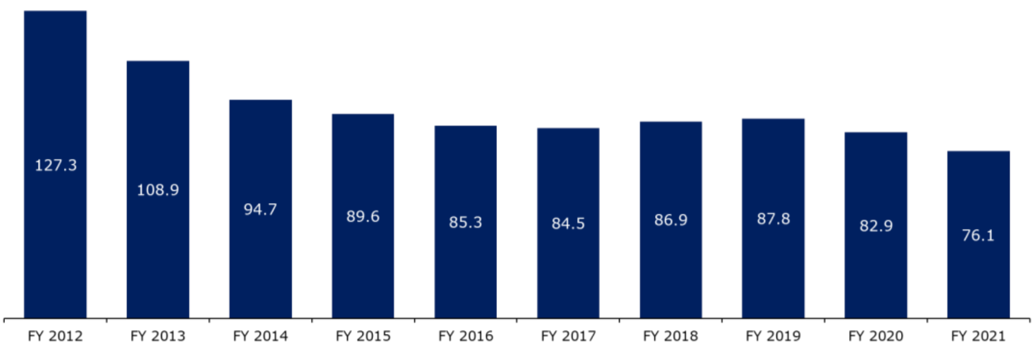
[124] FY 2022 experienced a significant increase in actual gas demand from the "Other" sectors. The demand from "Other" sectors has been projected based on the CAGR of demand growth between FY 2016 to FY 2021. For projecting the demand in future, he CAGR growth percentage has been applied on the average gas demand of "Other" sectors from FY 2016 to FY 2022.

   ii. Gas supply was projected through FY 2021–2040 based on the historical and expected future decline in gas production based on the information available in the public domain and annual reports of gas producers.
   iii. Certain percent of domestic supply available for sale has been reduced due to losses and internal consumptions.
   b. Upcoming domestic fields
      i. Gas production from the upcoming domestic gas fields (for example, the KG basin) has been projected based on the information available in the public domain
2. Step 2 – Projection of natural gas supply from LNG terminals
   a. Existing LNG terminals
      i. Existing LNG terminals and their capacities were identified.
      ii. Historical utilisation of these terminals was also identified.
      iii. Terminals' utilisation gradually increased year-on-year to reach 90 percent.
   b. Upcoming LNG terminals
      i. Natural gas supply not served by any of the three means (existing fields, upcoming fields, and existing LNG terminals) mentioned earlier was calculated.
      ii. Upcoming LNG terminals and their capacities were identified.
      iii. These terminals' utilisation has been determined by considering:
         1. start year of terminal operations
         2. gap in natural gas supply
         3. calculation of terminal utilisation based on the supply gap
         4. terminal utilisation was capped at 90 percent

2.6.1 Existing domestic production

Gas-producing regions are primarily located at the western offshore and eastern offshore regions and Assam. India has conducted successive exploration programmes and focused on making available geological data; domestic gas reserves have increased over the years. However, domestic production has not kept up and plateaued. It dropped significantly after achieving the peak production in 2010 from the KG-D6 basin because of lowering production from ageing fields and muted response from the industry for new project development (mainly due to lack of adequate incentives). Domestic production was 76.1 mmscmd in FY 2021.[125]

Figure 38 Trend of domestic natural gas production in India (in mmscmd)



According to latest data, the production increased upto ~90.8 mmscmd in FY 2022. Offshore production contributed a major share (~68 percent) in the total production, while the onshore and CBM segments accounted for the remaining share. Public sector units accounted for ~85 percent of the production, whereas the balance production came from private or joint ventures. The government has launched several policy initiatives to promote investments to explore natural gas in the country. The Discovered Small Fields Policy (DSF) was recently launched that aimed at monetising hydrocarbon resources locked-in for years in a timebound manner to boost domestic production of oil and gas. The government has a Hydrocarbon Exploration Licensing Policy (HELP) for the award of hydrocarbon acreages in the upstream sector. Within this policy, until December

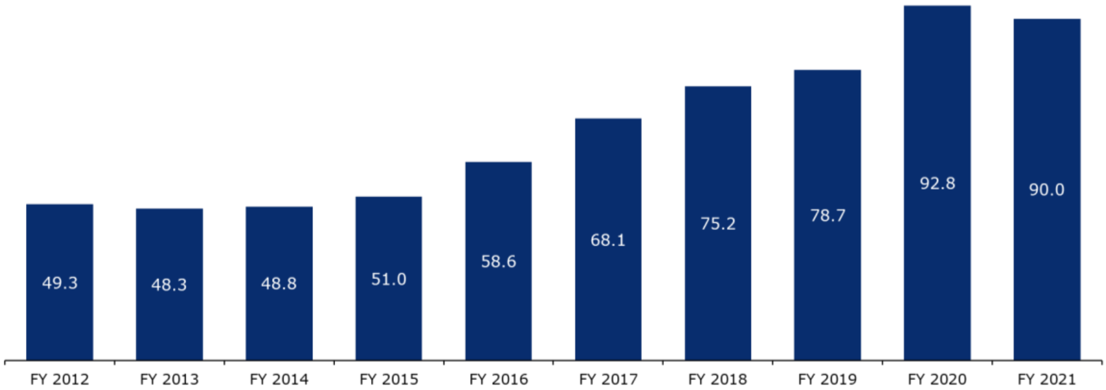
[125] *BP Statistical Review*

2020, five bidding rounds have been concluded. In these rounds, 105 exploration blocks covering an area of ~156,580 sq. km had been awarded. National Data Repository (NDR) has been set up to make the entire Exploration and Production (E&P) data available for commercial exploration, research, and academic purposes.

2.6.2 Existing supply through imports

Started in FY 2004, the LNG imports in India steadily increased to 90 mmscmd in FY 2021. Of the total net imports globally, India accounted for 7 percent in 2020.[126]The country imported LNG from 14 countries with Qatar alone accounting for ~40.2 percent.

Figure 39 Trend of natural gas imports in India (in mmscmd)



According to latest data, the LNG imports decreased upto ~84 mmscmd in FY 2022 because of ~20 percent increase in the domestic production.[127] LNG was imported through six existing LNG terminals accounting for 42.5 MMTPA capacity[128] – Dahej, Hazira, Dabhol, Kochi, Ennore, and Mundra. Dependence on LNG imports increased to ~54 percent of the total natural gas consumption in FY 2021. However, in FY 2022, due to increase in the domestic production, dependence on imports decreased upto ~48 percent of total natural gas consumption.

2.6.3 Supply projection until 2040

The future supply is projected from the existing and upcoming fields, along with LNG regasification terminals.

2.6.3.1 Supply projection for domestic production

Decline in production was calculated for existing fields. The same rate was used to project natural gas supply until FY 2040. The actual natural gas supply available for sale is reduced by 20 percent to account for losses and internal consumption based on historical data on gross and net production.

Table 53 Supply projection from existing fields (in mmscmd)

Segment	Decline (avg. yearly – FY16 to FY20)	Gas supply (mmscmd)	
		FY 2029-30	FY 2039-40
OIL – Onshore	**-2.0%**	5.7	4.6
ONGC – Offshore	**-4.0%**	32.4	21.6
ONGC – Onshore	**-4.0%**	9.1	6.0
Private/JVs – CBM	**-5.0%**	1.1	0.7

[126] *International Gas Union – World LNG Report 2021*
[127] *PPAC*
[128] *Only 2.5 MMTPA capacity is available at Dabhol terminal in absence of breakwater.*

Segment	Decline (avg. yearly – FY16 to FY20)	Gas supply (mmscmd)	
		FY 2029-30	FY 2039-40
Private/JVs – Offshore	-5.0%	3.2	1.9
Private/JVs - Onshore	-5.0%	3.1	1.9
Grand production		54.6	36.7
Net production		43.7	31.2

For upcoming fields, including K6 D6, KG D5, and Deen Dayal, the total reserves of ~200 bcm have been established based on information from annual reports. The annual production profile was assumed according to the table given below.

Table 54 Production trend from upcoming fields

Year	FY21	FY22	FY23	FY24	FY25
Yearly production	3%	5%	7%	9%	11%
Year	FY26	FY27	FY28	FY29	FY30
Yearly production	9%	9%	8%	7%	6%
Year	FY31	FY32	FY33	FY34	FY35
Yearly production	5%	4%	3%	2%	2%
Year	FY36	FY37	FY38	FY39	FY40
Yearly production	2%	2%	2%	2%	2%

The upcoming fields are projected to produce ~29 mmscmd in FY 2022, eventually rising to 33 mmscmd in FY 2030 and then gradually declining to 11 mmscmd in FY 2040. Production can be augmented if any new field is discovered and brought into the production phase.

Supply from CBM

CBM is also another source of gas used in India. It is basically methane produced during the coal formation process in coal mines; if effectively recovered, CBM can be used as a clean hydrocarbon energy source. Three bidding rounds happened in 2003, 2005, and 2008. In these rounds, about 33 CBM blocks had been awarded to different companies. The commercial production of CBM in India started in 2007 in Raniganj (the South block) in West Bengal. The total recoverable reserves for CBM blocks that have been established as of 2020 are ~75.3 bcm. However, as of December 2020, the total CBM production in the country was 1.82 mmscmd from six blocks. During the extraction of CBM, several challenges were faced that have kept overall production low for several years:

- CBM extraction is typically easier from reserves that have a high grade of coal. Higher the grade of coal, more is the potential of extraction. As high-grade coal reserves are limited in India, the overall CBM potential is low. According to inputs provided from Coal India, the overall CBM potential in the country is limited to 5-6 mmscmd even if production can increase in the future.

- CBM extraction from coal beds is sequential. CBM extraction and coal mining cannot take place simultaneously within any region. CBM extraction needs to be done before coal mining can start in a particular region. Hence, a huge opportunity cost is involved while extracting CBM.
- The exploration and production of CBM is a capital-intensive process. The typical capex for a CBM block is ~2,000 crore. In addition, production cost for CBM is high compared with natural gas. The typical costs charged from end consumers are in the range of US$6-7/mmbtu. There is no upper ceiling on pricing.
- During CBM production, other challenges, such as getting the right permeability of gas from coal beds, developing the pipeline infrastructure near the block, and resolving land acquisition issues, are also faced.

Shale Gas Potential in India:

Shale Gas refers to the natural gas which is trapped within Shale formations. Shale gas and oil are usually found at the depths of 2500-5000 m. The shale gas resources are trapped under low permeable rocks. Therefore, a shale fluid which is a mixture of pressurised water, chemicals and sand is forcefully injected into the ground in order to fracture the low permeable rocks. This process is called hydraulic fracturing. The shale gas/oil is produced commercially when sufficient fracture conductivity is induced by hydraulic fracturing.

In India, the assessment of the shale gas potential has been carried out by different organisations. In 2011, the United States Geological Survey (USGS) estimated the technically recoverable shale gas as 6.1 tcf for 3 basins: Cambay, Krishna-Godavari and Cauvery. In 2013, ONGC estimated shale gas resources of 187.5 tcf from 5 sedimentary basins: Cambay, Krishna-Godavari, Cauvery, Ganga and Assam.[129] According to US Energy Information Administration report of 2015, India has around 96 tcf of technically recoverable shale gas.[130] However, despite of the presence of huge shale gas potential in India, the production has not been able pick up due to several challenges associated with its extraction:

- Around 5 to 9 million litres of water is used per attempt of extraction (fracturing) activities. The commercial production of shale gas requires multiple fracking activities in each well. Therefore, the fracturing attempts is likely to deplete huge water resources. Countries that are pursuing shale gas extraction have made fracking-specific water regulations. The Indian regulations still need to come up with clear identification of the amount of water usage.[131]
- The shale rocks are found adjacent to rocks containing useable water known as aquifers. While fracking, the shale fluid could possibly penetrate aquifers leading to methane poisoning of groundwater used for drinking and irrigation purposes.
- The fracking process poses another challenge of recycling and leakage issues associated with the flowback water which is usually methane contaminated.[132]

Apart from the challenges above, there hasn't been any success for the Indian companies in their recent shale gas exploration activities. ONGC did not see success on its shale gas exploration in 2019 after drilling 26 wells in three hydrocarbon basins of Cambay, Krishna-Godavari and Assam-Arakan due to lack of commercially extractable reserves.[133] Despite of the presence of some potential for shale gas in India, the challenges related to land and water access are expected to make the large-scale production unlikely.

2.6.3.2 Supply projection for imports

The supply from four of the six existing LNG regasification terminals rose gradually to reach 90 percent. The Dahej and Hazira terminals have been projected to reach a utilisation of 95 percent as these have seen high utilisation historically. The high utilisation will be supported by the increasing transmission and distribution infrastructure that is being built across the country.

Supply from existing terminals is expected to increase up to 134 mmscmd in FY 2030 and FY 2040.

For upcoming terminals, supply has been considered from 12 terminals accounting for a capacity addition of 43 MMTPA. An additional 6 MMTPA has been considered to account for any unannounced upcoming terminal. The start of supply was considered from the year of expected completion of the terminal and the connecting natural

[129] *"India Hydrocarbon Outlook" by DGH*
[130] *https://energy.economictimes.indiatimes.com/energy-speak/shale-in-india/3826*
[131] *https://www.thehindubusinessline.com/opinion/columns/shale-gas-exploration-addressing-water-issues/article29086003.ece*
[132] *https://www.thehindu.com/opinion/op-ed/the-shale-gas-challenge/article24822864.ece*
[133] *https://economictimes.indiatimes.com/industry/energy/oil-gas/ongc-ends-shale-exploration/articleshow/72233370.cms?from=mdr*

gas pipeline. The utilisation was gradually ramped up for the upcoming terminals. Terminal utilisation was capped at 100 percent on considering the increasing natural gas demand and supplying natural gas to other countries as well.

Supply from upcoming terminals was projected to increase up to 150 mmscmd in FY 2030 and 176 mmscmd in FY 2040.

2.6.3.3 Total supply projection

The total supply is projected to increase from 180 mmscmd in FY 2022 to 361 mmscmd in FY 2030 and 352 mmscmd in FY 2040 (supply decreases because of a decline in domestic production). Imports from LNG terminals will account for 79 percent and 88 percent of the total supply in FY 2030 and FY 2040, respectively.

Table 55 Projection for supply availability from domestic production and imports (in mmscmd)

Segment	Gas supply (mmscmd)		Share in FY 2039-40 (%)
	FY 2029-30	FY 2039-40	
Net production from existing fields	44	31	8.8%
Production from upcoming fields (Announced)	33	11	3.1%
Imports from existing terminals	134	134	38%
Imports from upcoming terminals	150	176	49.9%
Total	**361**	**352**	

2.7 Demand-supply model

2.7.1 Integrated demand-supply model

The following table shows the demand-supply situation for India until FY 2040.

Table 56 Overall demand and supply projections in India from FY 2022 to FY 2030 for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Demand	163	197	211	252	265	281	291	306	316
Supply	180	210	243	293	304	325	341	354	361
Deficit (-)/surplus (+)	17	12	32	41	39	44	49	49	45

Table 57 Overall demand and supply projections in India from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Demand	333	352	367	379	393	403	414	426	437	448
Domestic supply	367	367	364	360	359	358	356	355	353	352
Deficit (-)/surplus (+)	34	15	-3	-20	-34	-46	-57	-72	-84	-96

The increasing deficit after FY 2033 will require either increase in domestic production or augmentation of additional LNG imports. India will require building new RLNG terminals of capacity ~28 MMTPA (apart from the existing and upcoming ones) operating at full utilisation to meet the demand deficit in FY 2040.

3 Pakistan

3.1 Country overview – Pakistan

3.1.1 Economy (GDP), population, primary energy consumption, and fuel mix

Pakistan had a population of ~221 million people[134] in 2020. According to the IMF data, its GDP in 2020 was ~264 billion US dollars.[135] Primary energy supplies by source for Pakistan in FY 2020 was ~81 Mtoe[136] according to Pakistan Energy Yearbook. This primary energy supply does not include supplies from biomass. According to IRENA, in 2018, energy consumption in Pakistan from biomass was ~22.2 Mtoe.[137]Pakistan's dependence on natural gas in the overall energy mix was about 43 percent in FY 2020. Though Pakistan has the second-highest per capita gas consumption in the SAR, the overall growth rate of Pakistan's gas consumption from 2009-19 has been quite low (i.e., ~1.4 percent). In the country, natural gas consumption from domestic supplies is on the decline; this may be attributed to declining natural gas reserves and introduction of imported LNG since 2015. Pakistan's primary energy mix consists of 85 percent fossil fuels (43 percent natural gas, 24 percent oil, and 18 percent coal), and 15 percent supplies from electricity.

Figure 40 Pakistan: Primary energy consumption by source (2020)

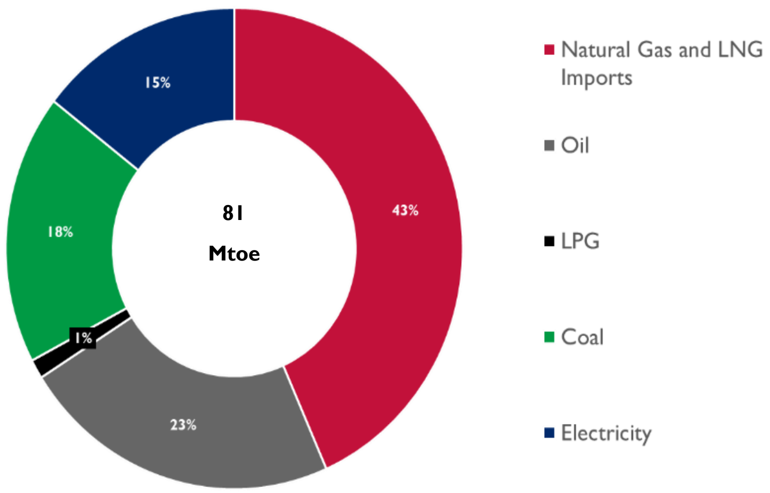


Table 58 Pakistan: Primary energy consumption by source (in Mtoe)

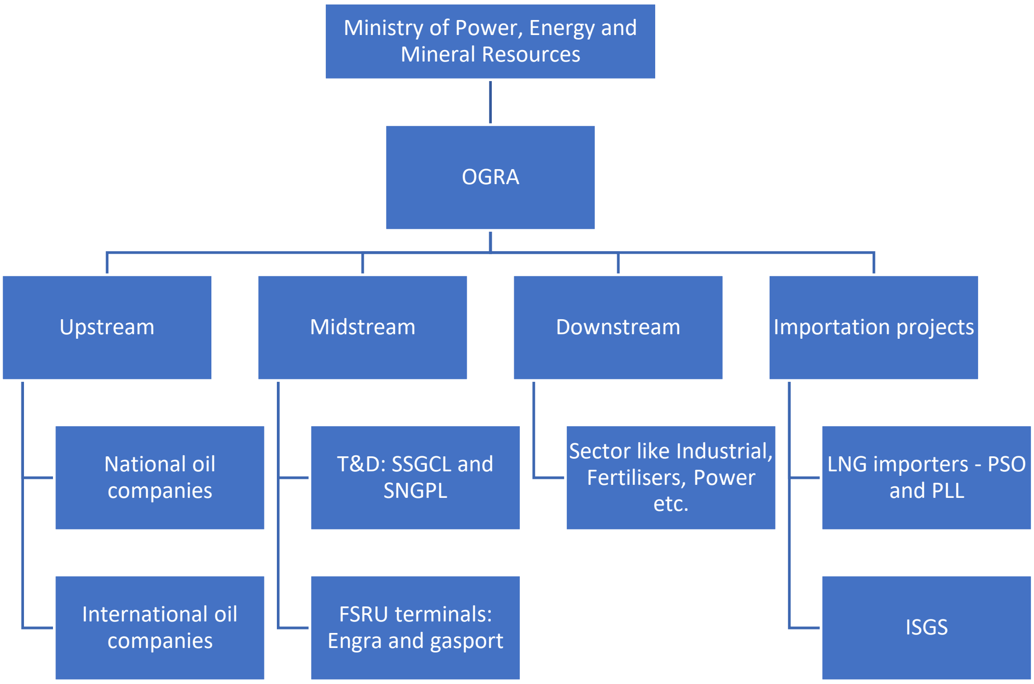
Source	Energy consumption (in Mtoe)
Natural gas and LNG (43%)	34.8
Oil (23%)	18.6
LPG (1%)	0.8
Coal (18%)	14.6
Electricity (15%)	12.2

[134] https://data.worldbank.org/indicator/SP.POP.TOTL?locations=PK
[135] https://www.imf.org/external/datamapper/NGDPD@WEO/WEOWORLD/PAK
[136] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf (Page 10)
[137] https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Pakistan_Asia_RE_SP.pdf

3.1.2 Gas value chain

The Ministry of Petroleum and Natural Resources (MoPNR) controls each activity in the value chain. MoPNR makes policies pertaining to upstream oil and gas production, along with awarding exploration and production licences. The Oil and Gas Regulatory Authority (OGRA) governs midstream and downstream activities. OGRA basically has an objective of seeking private-sector investment, along with increasing competition in midstream and downstream activities. There are various players in the oil and gas value chain in the country. The following figure shows an organogram of the gas sector in the country:

Figure 41 Organogram of the gas sector in Pakistan



Source: Emerging Asia LNG Demand, ADB

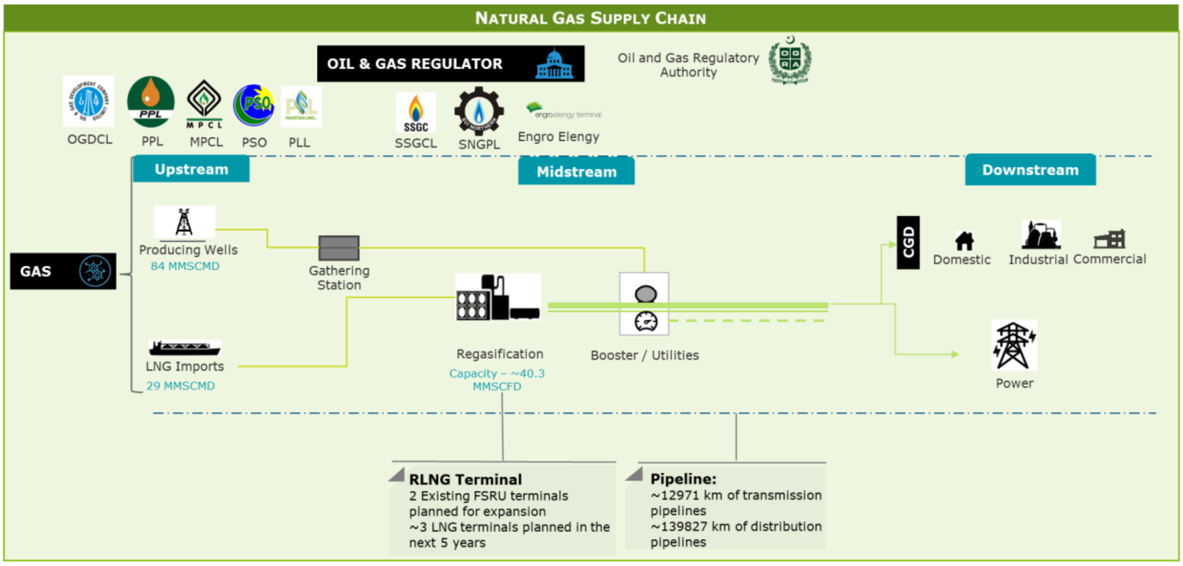
Table 59 Major players in the gas value chain of Pakistan

Extraction phase	Major players
Upstream	• There are 15 domestic companies; of which top three are mentioned below: ○ Oil and Gas Development Corporation Ltd. (OGDCL, 29 percent) ○ Pakistan Petroleum Ltd. (PPL, 19 percent) ○ Mari Petroleum Company Ltd. (MPCL, 18 percent) • Major foreign players operating in the upstream segment are mentioned below: ○ United Energy Pakistan Ltd. (UEPL, 13 percent) ○ Pakistan Oil and Gas Company (MOL, 8 percent) ○ ENI Pakistan Ltd. (6 percent)

Extraction phase	Major players
Midstream and downstream	• Two state-owned companies are involved in transmission and distribution of natural gas – Sui Northern Gas Pipelines Ltd (SNGPL) and Sui Southern Gas Company Ltd. (SSGCL)

LNG imports	• Two state-owned companies – Pakistan State Oil (PSO) and Pakistan LNG Ltd. (PLL) – import gas
	• Re-gasification of imported LNG is carried out at the Qasim port
	  ○ LNG imported by PSO is re-gasified by Engra Elengy Terminal Ltd. (EETL)
	  ○ LNG imported by PLL is re-gasified by Pakistan GasPort Consortium Ltd. (PGPCL)
	• Inter State Gas Systems (ISGS) is responsible for the construction of cross-country pipelines.

Figure 42 Natural gas value chain in Pakistan



3.1.3 As-is assessment and challenges in the gas sector

Pakistan is one of the highest gas dependent countries and 19th largest gas consumer in the world. According to Pakistan Energy Yearbook, Pakistan's energy imports were equivalent to ~43 percent of the total primary supplies in FY 2020. Oil and gas play a prominent role in the energy matrix of Pakistan. The country was once self-sufficient in natural gas production and meeting domestic gas demand. However, it witnessed declining gas reserves, along with a shrinking reserves to production ratio, because of which it has to rely on imports to meet its demand.

<u>Challenges around upstream exploration and production</u>

In Pakistan, the gas industry started in 1952 with the discovery of a major gas field in Sui, Balochistan. The field supplied gas to power stations in Karachi. Subsequently, the industrial areas of Karachi were given priority followed by domestic and commercial consumers. Later on, other significant discoveries of natural gas were made in Uch (in 1955), Mari (in 1957), and Kandhkot (in 1959).Within the past few decades, Pakistan has made significant progress in the upstream oil and gas sector. The country produced ~100 mmscmd of indigenous natural gas and imported ~26 mmscmd of LNG in FY 2020.[138] Pakistan's domestic gas production comes from 42 onshore fields, mainly located in southeast and central Pakistan. As of 2019, the country had more than 1,066 exploratory wells and 1,384 development wells. The country's overall success rate in the discovery of gas stands at 1:3 wells drilled; this rate is better than the global standards (1:10).[139]According to the Pakistan Energy Yearbook, the country had ~20.9 tcf of balance recoverable reserves in FY 2020.

According to the current assessment, several challenges could be observed in upstream exploration for the oil and gas sector:[140]

- The rules that have been defined for state-owned oil companies do not offer many incentives for investing in new technologies for carrying out exploration and drilling in tough terrains.
- COVID-19 has significantly affected the sector's supply side (discontinuation of oil and gas drilling activities).
- The remaining basins in Pakistan are perceived offering higher risk, lower reward returns, especially in terms of security conditions in those areas. Security protocols are difficult in oil and gas drilling activities for Balochistan and Khyber Pakhtunkhwa (KPK). Safety in those untapped areas needs to be improved for exploration activities to proceed.
- Various offshore campaigns have not yielded any significant results for the country. Moreover, the cost of doing business is quite high for new companies (given that offshore drilling is extremely costly).
- Small oil companies in Pakistan have been facing civil trials and litigations pertaining to their interpretation of the terms of contracts and taxes. These civil trials have still not resulted in more clear outcomes for these small companies.

In addition, a recent gas supply disruption occurred in Pakistan in June 2021 after two state-owned companies (SSGCL and SNGPL) announced the complete closure of gas supply until 5 July 2021 to industries and CNG stations. The disruption was caused due to decline in gas availability that occurred because of low pressure in the system, and dry docking of an LNG terminal.[141]

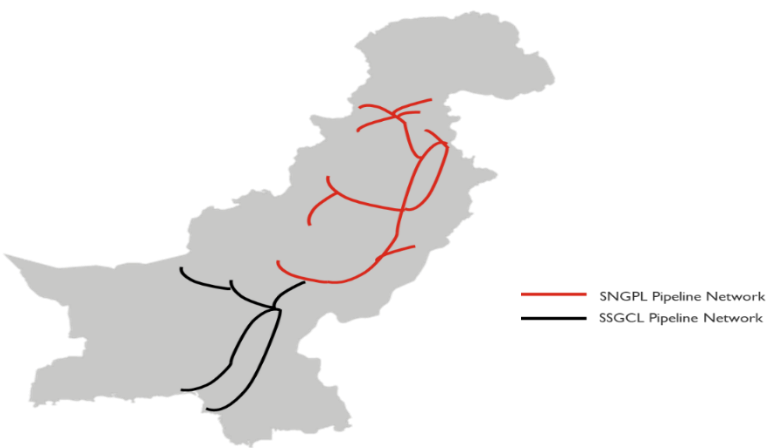
3.2 Gas infrastructure analysis

3.2.1 Existing pipeline and LNG terminal infrastructure

Pipeline Infrastructure

According to the data published in Pakistan Economic Survey 2019-20, the country has a gas network of ~12,971 km transmission pipelines, 139,827 km distribution pipelines, and 37,058 services gas pipelines to cater to the requirement of more than 9.6 million consumers across the country.[142]

Figure 43 Existing pipeline network in Pakistan



[138] Pakistan Energy Yearbook
[139] https://www.globalvillagespace.com/pakistan-energy-mix-overview-of-gas-sector-upstream/
[140] Source: https://pide.org.pk/Research/Gas-and-Petroleum-Market-Structure-and-Pricing.pdf
[141] Source: https://www.livemint.com/news/world/pakistan-suffers-severe-gas-crisis-as-companies-halt-supply-till-july-5-11624936264788.html
[142] Source: Pakistan Economic Survey (Energy), 2019-20

LNG infrastructure

The existing LNG import infrastructure in Pakistan consists of two FSRUs – the Engra Elengy and Gasport LNG terminals. Both of them are located at Port Qasim (Karachi) and have a combined capacity of 1440 mmscfd. The Engra Elengy terminal (operated by Excelerate Energy) has a capacity of 690 mmscfd (~19.3 mmscmd) and regasifies the LNG imported by Pakistan State Oil. PSO has signed a government-to-government, long-term contract with Qatar Gas for a period of 15 years. The Gasport LNG terminal has a capacity of 750 mmscfd (~21 mmscmd) and regasifies the LNG imported by Pakistan LNG Ltd. PLL has shorter-term, LNG contracts with Gunvor and Shell.[143] Both the terminals usually operate at a capacity of 85 percent or higher due to massive gas demand in the country.[144]

3.2.2 Upcoming and planned infrastructure

Pipeline infrastructure

For the pipeline infrastructure, two pipelines are planned in Pakistan: the Iran-Pakistan pipeline[145] (expected to be completed by 2024) and the TAPI pipeline[146] (expected to be delayed or not get completed due to political matters in Afghanistan).

In case of the Iran-Pakistan gas pipeline, Inter State Gas Systems (ISGS) of Pakistan and the National Iranian Gas Company (NIGC) have negotiated a revised agreement for its construction. Under the agreement, neither Iran would approach any court nor Pakistan will pay any fine if there is any delay in the pipeline construction. The project has been delayed when Pakistan faced a threat of international sanctions from the US. At present, both Iran and Pakistan are intending to come up with a mutual solution to complete the pipeline construction by 2024.[147]

For the TAPI pipeline, the delay has been extended due to the recent political matters that came up in Afghanistan. The project has also failed to attract any significant investments from international oil companies. According to the publicly available news sources, the new Afghan government will prioritise the project. The spokesperson from the newly formed government stated TAPI as a “long-term priority project” in August 2021 that they fully support. In addition, new government officials have had meetings with Turkmenistan on the project revival.[148]However, the uncertainty around the completion of the project still prevails.

LNG infrastructure

For both the existing terminals, expansion projects were announced that will be completed by 2022. However, supply from those terminals is expected to take place from the North South Gas Pipeline project, which is slated for completion by end-2023. Moreover, three new terminals have been announced in Pakistan for 2024. The details of upcoming projects have been described in section 3.6.3 of the report.

3.3 Policy, regulatory enablers, and emerging trends

3.3.1 Policy and regulatory support and incentives to promote the sector

The Ministry of Energy − Petroleum Division (MEPD) is the primary regulator for oil and gas related policies in Pakistan. The Directorate General of Gas (DG Gas) regulates sales of gas to SNGPL and SSGCL. Oil and Gas Regulatory Authority (OGRA) regulates midstream and downstream activities in the oil and gas sector.

In Pakistan, regulations for the natural gas sector are mentioned below:

- MEPD allocates import of natural gas and domestic production of natural gas from gas fields.
- The government of Pakistan has the first right to purchase gas produced in the country (directly or indirectly) through SNGPL and SSGCL.
- Selling price of gas is stated in the relevant contract with the government. It is linked to international crude oil price.

The current pricing and incentive regime for petroleum exploration and production has been defined under the Petroleum Exploration and Production Policy 2012. It is based on formulae linked to international crude prices

[143] *Gas and Petroleum Market Structure and Pricing by Pakistan Institute of Development Economics*
[144] https://www.dawn.com/news/1639229
[145] https://www.gem.wiki/Iran-Pakistan_Pipeline
[146] https://www.ogj.com/pipelines-transportation/pipelines/article/14188134/turkmenistan-to-start-afghan-tapi-construction-in-2021
[147] https://tribune.com.pk/story/2058009/1-isgs-nigc-ink-revised-accord-ip-gas-pipeline-project
[148] https://www.tribuneindia.com/news/nation/taliban-leaders-discuss-tapi-gas-pipeline-mining-projects-318727

and high sulphur fuel oil (HSFO). Exploration and production concessions are granted primarily through a competitive bidding process. The Directorate General of Gas allocates gas from new sources to gas utility companies (SSGCL and SNGPL) and executes gas price agreements with producers and gas sales agreements between producers and government-nominated buyers.

The Pakistani government is looking forward to prioritising offshore exploration in the nation. Within 2019, an offshore drilling activity was carried out at the Kekra-1 well in deep sea near Karachi with companies such as ExxonMobil, OGDCL, and PPL; Italy's ENI is also involved in the project. However, any oil and gas reservoirs could not be found in the area. Petroleum exploration and development companies in the country are seeking shifts in policies to bring about improvement in the working environment of exploration and production by addressing issues relating to security coverage, revocation of their existing blocks, and procurement rules. There are several areas in Pakistan where the local environment does not support exploration activities. Hence, companies need security coverage to mitigate the risks associated. They have also demanded amendment in Public Procurement Regulatory Authority (PPRA) rules for oil and gas companies in the public sector to reduce the time period of any procurement of the goods and services needed for exploration activities.

In 2018, the government of Pakistan launched a gas allocation policy and following priority has been given to various sectors for supply of domestic natural gas:

- Domestic and commercial sectors
- Power and zero-rated industry
- General industry, fertilisers, and captive power
- Cement and its captive power
- CNG

3.3.2 Emerging trends with respect to alternative fuels

In August 2020, Pakistan announced a new energy plan aiming a gradual shift towards the renewable forms of energy. The plan aims for 30 percent renewable energy generation, mainly from wind and solar energy; this will be a significant increase from the current levels of 4 percent.[149] The same thing has been mentioned in Indicative Generative Capacity Expansion Plan 2021-30 as well by NEPRA that the government of Pakistan through ARE Policy 2019 aims to include at least 20 percent and 30 percent of the renewable energy generation by capacity by 2025 and 2030, respectively.[150]However, this would also require an appropriate amount of backup generation to provide for reserve requirements of the system.

The government of Pakistan has been trying to lay emphasis on using indigenous and environmentally clean energy generation resources. Pakistan has developed the Alternative Energy Development Board (AEDB) to undertake and submit a request for proposals to potential bidders for projects in Pakistan for energy generation through renewable technologies.

Additionally, a new Alternative and Renewable Energy Policy (ARE Policy 2019) has been formulated in Pakistan. The policy aims at creating an environment for growth of sustainable and renewable energy sources in the country. Some salient features of this new policy include the following:

- The policy has an expanded scope compared with the previous one. It encompasses alternative and renewable energy sources and their competitive procurement from different sources. It addresses areas such as distributed generation systems, off-grid solutions, B2B methodologies, and rural energy services.
- It aims to develop large-scale ARE projects, with active participation of provinces, in each part of the country.
- Provinces are also part of the Steering Committee envisaged in the policy that will plan ARE induction. Provincial energy departments will carry out a competitive bidding process according to the annual ARE procurement plan approved by the AEDB board on recommendations of the Steering Committee. Therefore, the new policy aims to promote participation of stakeholders in the decision-making process.

[149] *Source: https://ieefa.org/new-pakistani-energy-plan-aims-for-30-renewable-generation-by-2030/*
[150] *Source: https://nepra.org.pk/Admission%20Notices/2021/06%20June/IGCEP%202021.pdf*

- The policy's most significant feature is that it makes a transition from the traditional methods of procurement based on cost plus and upfront tariffs to competitive bidding. New RE projects, specifically wind and solar power projects, will be developed through competitive bidding.[151]

3.4 Pricing assessment

3.4.1 Gas pricing mechanism

The price of natural gas in countries is usually determined by demand and supply. However, in Pakistan, prices are regulated in the domestic market. Even at the exploratory stage, prices are determined upfront and there is no price competition. The policy and current process for setting gas prices has two steps. In the first step, producer prices are determined and based on these prices consumer prices are determined using cost plus methodology.

Producer gas prices

- There are currently 55 gas fields in Pakistan and each field has its separate price. The current weighted average wellhead prices are ~US$3.5/mmbtu.[152]
- Gas prices for producers in Pakistan are determined by their revenue requirement that is indexed to international prices of crude oil specifying floor and ceiling according to the pricing agreements between the government and producers. Any change in cost is being regulated by Oil and Gas Regulatory Authority (OGRA).
- Gas pricing has seen several changes over the years. In 1950s and 1960s, it was determined on a cost-plus basis. Since 1985, gas prices have been revised intermittently according to the government policy. In the current scenario, the government is using its Petroleum Production and Exploration Policy (2012) to determine gas prices.
- According to the policy, offshore and onshore fields have been segregated to account for the risk levels associated with exploration and production activities. Under this policy, the government has set well-head gas prices as US$6 per mmbtu in Zone 3, US$6.3 per mmbtu in Zone 2, and US$6.6 per mmbtu in Zone 1 (for onshore zones).[153]
- However, prices received by companies are different for each gas field they have. These prices are set under the petroleum policy applicable at the time when they were discovered.

Consumer gas prices

- Based on gas companies' revenue requirements, OGRA determines the prescribed price (i.e., price to be retained by companies) for each category of consumers. End-consumer prices are decided for SNGPL and SNGCL based on the returns on value of their fixed assets and meeting the efficiency benchmarks being prescribed by OGRA. The Consumer Price of Natural Gas in Pakistan comprises the prescribed price for gas companies and Gas Development Surcharge (GDS). For consumers, gas prices are bundled and there is no segregation between different elements.
- OGRA fixes the 'prescribed price' for gas utilities after conducting public hearings where stakeholders express their views. The prescribed price for consumers has the following elements:
    - Producer gas prices linked with international prices of crude oil and HSFO
    - Transmission and distribution costs
    - Depreciation
    - Return to SNGPL and SSGCL (17.43 percent on net operating fixed assets)
- End-users are charged prices that consist of a fixed component and a variable component. They do not differentiate between transmission and distribution charges of gas.

Price to end-consumer: Fixed min. charge (INR/mmbtu) + gas tariff (INR/mmbtu)[152]

- The fixed minimum charge in Pakistan differs from segment to segment. According to the data from 1 July 2019, the following were the fixed minimum charges levied from different segments of consumers:

[151] Source: https://www.finance.gov.pk/survey/chapter_20/14_Energy.pdf
[152] Gas and Petroleum Market Structure and Pricing by Pakistan Institute of Development Economics
[153] https://www.globalvillagespace.com/pakistan-energy-mix-overview-of-gas-sector-upstream/

Table 60 Fixed gas tariff for different categories of Pakistani consumers (as of 1 July 2019)[152]

Segment	Fixed tariff (in US$/month)
Domestic	1.04
Government and semi-government	10.08
Special commercial	1.04
Commercial	35.28
Ice factory	35.28
General industry	157.81
Textile	121.39
CNG	198.27
Cement	197.26
Power (WAPDA and K1-Electric)	127.26
Liberty power gas turbine	259.67
Independent power producers	127.26
Captive power	157.81

(The conversion rate used was based on the exchange rate as on 1 July 2019: US$1 = PKR0.062)

- Variable charges for different segments have been broken down into slabs. Slabs for domestic gas prices have been defined in terms of consumption in hundred m^3 of gas. The following table shows six slabs in Pakistan for domestic gas consumers (according to the latest data from SNGPL):[154]

Table 61 Domestic gas slabs by SNGPL in Pakistan (as on 1 July 2019)[154]

Gas consumption	Variable tariff (in US$/mmbtu)
Upto 0.5 Hm^3	0.75
Upto 1 Hm^3	1.86
Upto 2 Hm^3	3.43
Upto 3 Hm^3	4.58
Upto 4 Hm^3	6.86
Above 4 Hm^3	9.05

(The conversion rate used was based on exchange rate as on 1 July 2019: US$1 = PKR0.062)

- For other segments, tariffs have been defined without any slabs. For other segments, the country has the following variable tariffs:

Table 62 Variable tariff for other segments in Pakistan (as of 1st July 2019)[152]

Segment	Variable tariff (in US$/mmbtu)
Commercial	7.95
Ice factory	7.95
General industry	6.33
Textile	4.87
CNG	7.95
Cement	7.92
Fertilisers	1.86

154 https://www.sngpl.com.pk/web/page.jsp?pgids=3531&pgname=PAGES_NAME_a&secs=ss7xa852op845&cats=ct4567123378&artcl=artuyh709123465

Segment	Variable tariff (in US$/mmbtu)
Independent power producers	5.11
Captive power	6.33

(The conversion rate used was based on exchange rate as on 1 July 2019: US$1 = PKR0.062)

RLNG pricing

- For RLNG, two major state-owned companies in Pakistan are allowed to import LNG – Pakistan State Oil (PSO) and Pakistan LNG Ltd. (PLL). PSO has signed a government-to-government contract with Qatar Gas for a period of 15 years at about 13.35 percent of Brent crude in 2016.[155]PSO also signed a new, long-term LNG contract with Qatar Gas to supply up to 3 MTPA of LNG per annum from FY 2022 to FY 2031.[156]PLL has shorter-term LNG contracts with Gunvor and Shell.
- Pakistan gets more than half of its LNG under long-term contracts. However, the country still relies on spot shipments to meet its LNG demand during winter. For November 2021, the weighted average sale provisional price for SNGPL for LNG transmission was US$14.77/mmbtu and LNG distribution was US$15.67/mmbtu. For SNGCL, the weighted average sale provisional transmission and distribution prices were US$14.48/mmbtu and US$15.42/mmbtu, respectively.[157]The following table shows RLNG pricing breakup for SNGPL:

Table 63 Weighted average RLNG price for SNGPL for November 2021[157]

Serial No.	Particulars	Calculation	Unit	Transmission		Distribution	
				PSO	PLL	PSO	PLL
1	Quantity received		mmbtu	25600000	6400000	25600000	6400000
2	Percentage losses		Percentage	1.1%	0.88%	6.97%	6.77%
3	Quantity available for sale	(1) * (2)	mmbtu	25319100	6343802	23814492	5966816
4	LNG price (DES)		US$/mmbtu	9.67	24.09	9.67	24.09
5	PSO/PLL other import-related costs			0.69	1.61	0.69	1.61
6	PSO/PLL margin (@2.5%)	2.5% * (4)		0.24	0.6	0.24	0.6
7	Terminal charges			0.4	0.74	0.4	0.74
8	RLNG cost	(4) + (5) + (6) + (7)		11.01	27.05	11.01	27.05
9	Retainage volume adjustment			0.08	0.13	0.08	0.13
10	T&D volume adjustment			0.04	0.1	0.04	0.1
11	LSA management fee			0.03	0.03	0.03	0.03
12	Cost of supply - SNGPL			0.25	0.25	0.25	0.25
13	Cost of supply - SSGCL			0.12	0.12	0.12	0.12
14	Total RLNG price without GST	(8) + (9) + (10) + (11) + (12) + (13)		11.53	27.69	12.23	29.41
15	Quantity available for sale	(3)	mmbtu	25319100	6343802	23814492	5966816
16	Total cost of RLNG	(14) * (15)	US$	292009114	175679424	291414491	175530498
17	Sum of total quantity	PSO (15) + PLL (15)	mmbtu	31662902		29781308	
18	Sum of total cost (PSO and PLL)	PSO (16) + PLL (16)	US$	467688538		466944989	
19	Weighted average cost	(16) / (15)	US$/mmbtu	14.77		15.67	

[155] https://tribune.com.pk/story/1150077/energy-solutions-govt-import-gas-exclusively-power-plants
[156] https://www.upstreamonline.com/lng/pakistan-to-import-more-lng-from-qatar/2-1-971345
[157] https://www.sngpl.com.pk/web/download/rlng_price_august06_2021.pdf

3.4.2 Pricing of alternative fuels and comparison with natural gas

In Pakistan, the pricing mechanisms for other fuels are mentioned below:

1. Coal: Pakistan meets a majority of its coal requirements through imports. With a high dependence on imports for its two-thirds of coal requirements, its coal prices follow international pricing trends.
2. Petroleum products: Price for domestically produced crude oil that has to be delivered at the nearest local refinery is equal to the cost and freight (C and F) price of a comparable kind of crude oil with addition or subtraction of a price differential (due to the quality difference). In addition, there is another windfall levy applicable on crude oil. Pricing of petroleum products at an ex-refinery level is based on import parity pricing, which implies the price applicable to the refiner if fuel was imported. Import parity pricing includes free on-board price, customs duty, and freight. To this, the refiner adds own charges and provides fuel to oil marketing companies. These companies then add their profit margins, dealer margins, and sales tax to arrive at the ex-depot selling price of the petroleum product. In the current scenario, the following are final prices for end consumers[158]:

Table 64 Prices of POL fuels in Pakistan (as of August 2021)

Fuel	Retail selling price (as of January 2022) in US$/mmbtu
Gasoline	28 (147.8 PKR/L)
Diesel	22 (144.6 PKR/L)
Kerosene	18.2 (116.5 PKR/L)

(Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for 1 January 2022)

Calorific value of LNG = 12500 kcal/kg; 1 mmbtu = 252000 kcal; US$ to PKR for 1 January 2022 = 178.25; calorific value of diesel = 10800 kcal/kg; calorific value of petrol = 10500 kcal/kg; calorific value of kerosene = 11,100 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L; and density of kerosene = 0.82 kg/L)

Cost economics of natural gas is clearly more favourable in Pakistan compared with other POL fuels as gasoline and diesel prices are more than US$22/mmbtu, whereas imported prices of RLNG are US$14.4-15.7/mmbtu.

3.5 Demand analysis

3.5.1 Existing demand

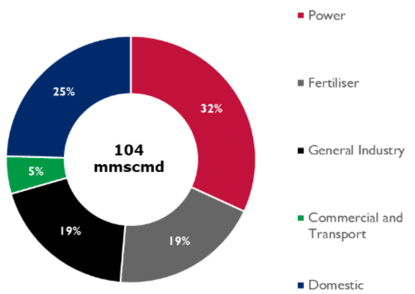
For FY 2020, Pakistan used ~102 mmscmd of natural gas and the gas consumption was ~104 mmscmd for July-February in FY 2021[159]. Gas consumption from the residential segment has increased due to price differential vis-a-vis other competing fuels (i.e., LPG, firewood, and coal). Demand for gas increases considerably during the winter season.

In Pakistan, the government allocates gas according to the gas allocation policy to the residential and commercial, power, fertiliser, cement and CNG sectors. For FY 2020, gas consumption by province was led by Punjab (56 percent), followed by Sindh (33 percent), Khyber Pakhtunkhwa (9 percent), and Baluchistan (2 percent). The CNG sector had been one of the major gas consumers. However, natural gas consumption in the transport sector has gradually declined over the years due to shortages in domestic supplies.

Natural gas consumption in Pakistan has followed almost a constant trend from 2009-15. After that, it saw an upward trend until 2019. Consumption from most sectors has remained almost constant across the years; the power sector has been the major gas consumer. The commercial and CNG sectors have contributed the least across the years in the overall gas consumption in Pakistan.

Figure 44 Natural gas consumption in Pakistan for different sectors for FY 2021 (in mmscmd)

[158] https://www.globalpetrolprices.com/Pakistan/
[159] Pakistan Energy Yearbook, HDIP, Pakistan Economic Survey



Sector	Gas consumption (in mmscmd)
Power (32%)	33.3
Fertiliser (19%)	19.8
General Industry (19%)	19.8
Commercial and CNG (5%)	5.2
Domestic (8%)	26

Figure 45 Trend for natural gas consumption in Pakistan (in mmscmd)

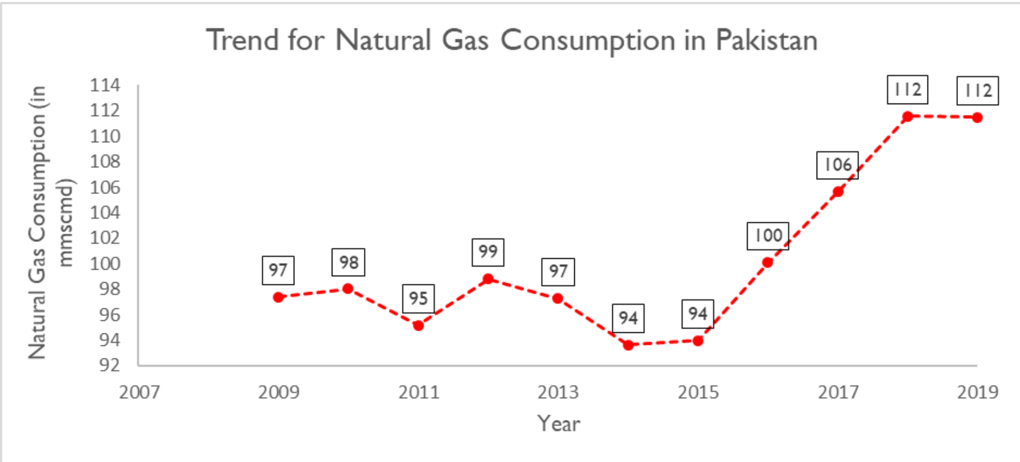
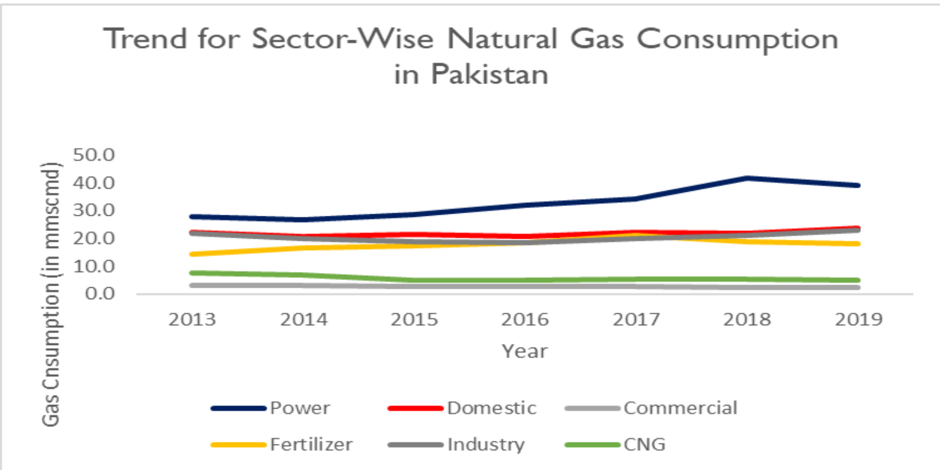


Figure 46 Trend for natural gas consumption, by sector, in Pakistan (in mmscmd)



3.5.2 Key drivers for demand

The key demand drivers for natural gas in Pakistan are mentioned below:

- The domestic sector plays a significant role in driving demand for natural gas, primarily due to the policy framework by the government of Pakistan; the domestic sector has been given a priority in the gas allocation mechanism.
- The industrial and power sectors have also traditionally been the major demand drivers for natural gas in Pakistan. Another important aspect that has driven natural gas demand within the country has been setting up of the China-Pakistan Economic Corridor (CPEC). The corridor is a US$62 billion transport corridor project that would entail construction of roads, power projects, and different types of

infrastructure across Pakistan.[160]The project aims to connect Pakistan's Gwadar port with China's North-western region by 2030. The CPEC development is expected to boost the natural gas demand in Pakistan in the following ways:

- The corridor aims to boost industrialisation in Pakistan. Nine special economic zones characterised by specific products or services, will be established in each province in Pakistan along the corridor. Various infrastructural projects under CPEC, such as stainless steel, power, and petrochemicals, are energy focused. They will, therefore, drive demand for natural gas.
- The road and rail networks being built under the CPEC project will be able to facilitate energy transportation with ease. They will also have the potential to stretch across to Afghanistan, Tajikistan, Kyrgyzstan, Kazakhstan, Russia, and even to Mongolia.
- The CPEC may help Pakistan reduce its dependence on imports from Saudi Arabia and improve its connectivity with Iran by facilitating the Iran–Pakistan gas pipeline. Iran has always wanted to build a natural gas pipeline connecting the country to Nawabshah and Gwadar in Pakistan. However, due to financial constraints, the Pakistan portion of the pipeline has not been built up. China had expressed its willingness to finance the pipeline construction in 2015. First, a 700 km long RLNG pipeline was expected to be built up between Gwadar and Nawabshah. After that, only 70 km of the pipeline segment between the Gwadar and Iranian border would be left.[161]As of now, there has not been any update. However, with the further development of the corridor, the construction of the pipeline can also pick pace.
- A RLNG terminal has also been planned up at the Gwadar port. Although CPEC energy projects have faced a delay due to COVID-19, the Chinese and Pakistani governments have been mulling over investments for the prospective RLNG terminal at Gwadar.[162]

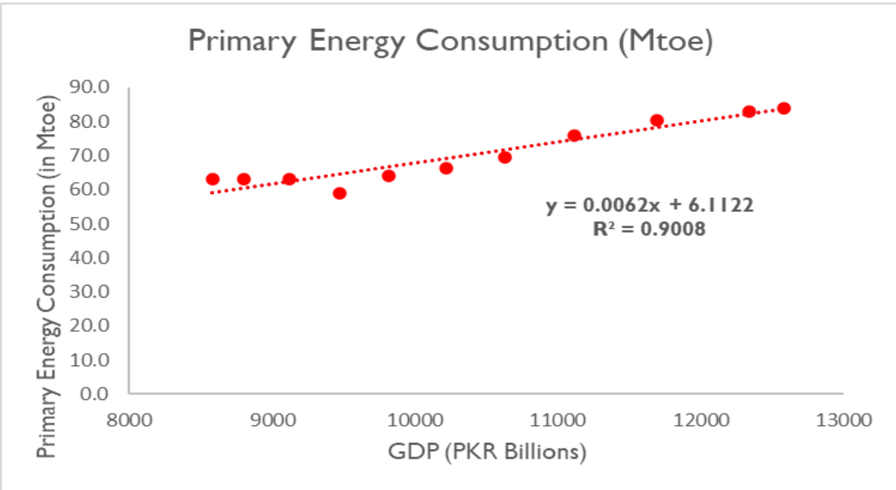
- The existing gas-based power plants will continue to need additional gas. According to the merit order of power generation plants, 13 of the top 15 power plants are based on gas (which is an affordable fuel).

3.5.3 Top-down approach

For this approach, a correlation has been drawn by creating a regression model using the constant-price GDP. This approach has been considered to estimate natural gas demand through regression of primary energy consumption by GDP of Pakistan and further considering the share of natural gas in the total primary energy mix.

After drawing in a correlation analysis between GDP and energy consumption data for Pakistan, the following regression equation was obtained:

Figure 47 Regression equation for GDP versus Energy Consumption

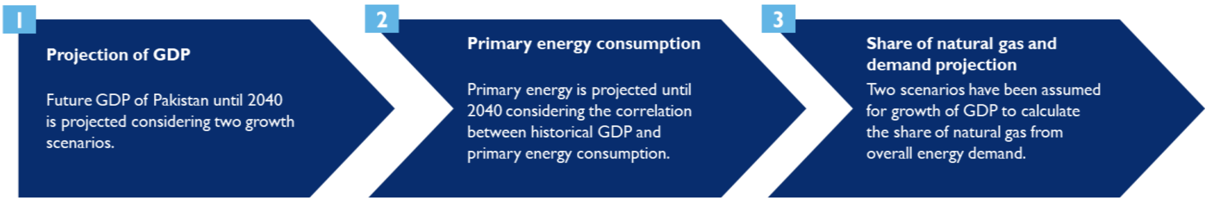


[160] https://www.thenews.com.pk/print/917411-62-billion-infrastructural-and-energy-projects-being-developed-under-cpec-scholars
[161] https://nation.com.pk/28-Mar-2016/gwadar-nawabshah-lng-project-part-of-cpec
[162] https://www.geo.tv/latest/363186-govt-mulls-construction-of-large-scale-lng-terminal-pipeline-network-at-gwadar-port

*Primary energy consumption (in Mtoe) = 6.1122 + 0.0062*GDP (in billions of PKR)*

GDP of Pakistan from 2009 to 2019 calculated by IMF has been used for this analysis. The GDP and growth rates, by year, have been provided in Annexure 17.2.1. Primary energy consumption data for Pakistan was taken from the BP Statistical Review. The R^2 value of this model came out as 0.90, implying that 90 percent of the variation in the primary energy consumption is being explained by GDP data.

Figure 48 Overview of methodology for top-down estimation of natural gas demand in Pakistan



<u>Detailed methodology</u>

1. Step 1 – Projection of GDP of Pakistan
   a. The historical GDP of Pakistan from 2009 to 2019 was collated.
   b. The GDP from 2020 to 2026 was sourced from IMF.
   c. After 2026, two scenarios have been used to project GDP until 2040.
      i. The first scenario took a five-year CAGR between 2021 and 2026 and projected GDP numbers after 2026 at a calculated growth rate. Within this scenario, the GDP growth of Pakistan has been considered as ~4.7 percent.
      ii. The second scenario took a seven-year CAGR between 2019 and 2026 and projected GDP numbers after 2026 at a calculated growth rate. This was considered as the most plausible scenario. Within this scenario, the GDP growth of Pakistan has been considered at ~3.5 percent.[163]
2. Step 2 – Projection of primary energy consumption
   a. Regression analysis of primary energy consumption with respect to historical GDP had been conducted. A correlation of 90 percent was observed between primary energy and GDP that can be considered as a pretty good statistical fit.
   b. Using correlation between GDP and primary energy, and future GDP projections, primary energy consumption was projected until 2040 considering the two scenarios of GDP growth in Pakistan.
3. Step 3 – Projection of natural gas demand
   a. The government of Pakistan has projected use of ~72 bcf natural gas in the country's primary energy mix by 2030 (according to the numbers published by OGRA in 2018-19).[164]
   b. Current share of natural gas consumption in Pakistan is ~44 percent.
   c. Natural gas share has increased linearly over 2021-30 to obtain percentage share in total energy consumption by 2030.
   d. The share has been constant thereafter until FY 2040 on account of the following reasons:
      i. Decline in domestic gas production and an increased dependency on gas imports
      i. Pursuit of alternative energy sources aggressively to achieve an optimal energy mix

<u>Analysis</u>

Gas demand under various scenarios is projected to increase from 196.44 mmscmd in 2030 to 305.8 mmscmd in 2040 in the first scenario and 273.1 mmscmd in the second scenario. The second scenario considering seven-year CAGR of GDP growth between 2019 to 2026 seems the most plausible one. Within the scenario, natural gas will have ~51.7 percent share in the energy mix by 2030 and CAGR of GDP growth would be 3.5 percent.

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[163] *The 7-year CAGR of GDP has been considered as ~3.5% per the IMF data. However, per IGCEP 2021-39, the 7-year CAGR from 2019-26 for Pakistan has been 3.86%. This was due to the actual GDP growth of 3.94% in 2020-21 which had been higher than the targeted growth rate of 2.1% for the year per the Pakistan Economic Survey.*
[164] https://www.gem.wiki/Pakistan_and_fossil_gas

Table 65 Summary of natural gas demand in Pakistan under the top-down approach

Scenario	Gas demand (mmscmd)				Remarks
	2025	2030	2035	2040	
Scenario - I	146.3	196.4	244.8	305.8	~49.4 percent share of natural gas by 2030 and GDP projected on the basis of a five-year CAGR between 2021 and 2026
Scenario – 2 (most plausible scenario)	150.2	196.44	231.5	273.1	~51.7 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR between 2019 and 2016 (most plausible scenario)

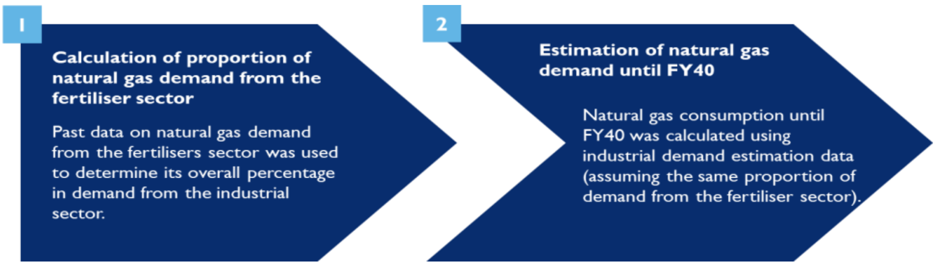
3.5.4 Bottom-up approach

3.5.4.1 Fertiliser sector

It is somewhat standing in a scenario where despite providing a substantial contribution in the process of boosting crop productivity in Pakistan, its potential is being challenged. Fertiliser-responsive crop varieties, supplementary irrigation water, and a favourable policy environment in Pakistan have induced fast growth in fertiliser demand; this would also continue in the future. However, recently the shortage of domestic natural gas production, along with the increased dependence on imports, has led to a decrease in the overall efficiency and utilisation in the supply side of the sector.

Demand for natural gas for the Fertiliser sector has been calculated and accounted for while doing the calculation of industrial demand later in the CGD sector in 3.3.4.3.

Figure 49 Overview of methodology for projecting natural gas demand for fertilisers sector in Pakistan



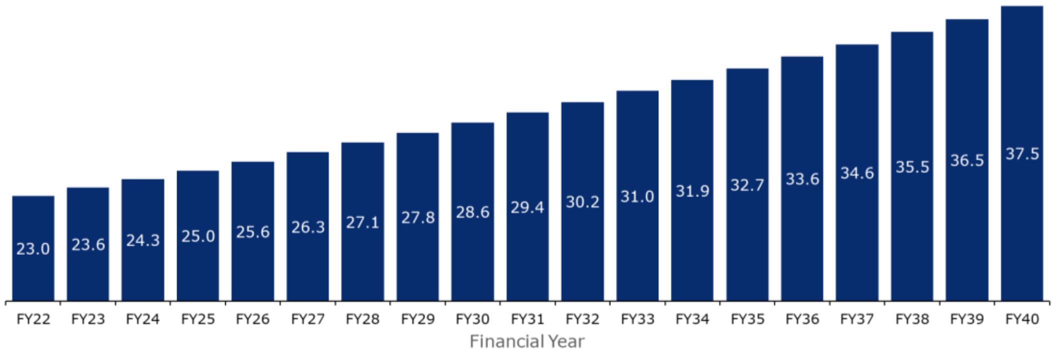
Detailed methodology

1. Step 1 – Calculation of the total natural gas demand for the fertilisers sector as a percentage of natural gas demand of the industrial sector
    a. After calculating the overall demand for the CGD sector for industrial, domestic and commercial connections until FY 2040, the industrial sector was used to calculate demand for the fertiliser sector.
    b. The past data for demand for natural gas for the fertiliser sector was collated through secondary research. This data was compared with the overall natural gas demand for industrial use. The fertiliser sector constituted ~39 percent of the overall natural gas demand for the industrial sector.
2. Step 2 – Calculation of natural gas demand from the fertiliser sector until FY 2040
    a. For calculation of natural gas demand, 39 percent was considered as the benchmark. After calculating data of the overall natural gas demand from the industrial sector in the next few years, 39 percent of it was considered as demand for the fertiliser sector.

Assumptions: Natural gas demand for the fertiliser sector from FY 2022 onwards would be in the same proportion with the overall industrial sector demand as it was in the previous years, for calculating future values.

Analysis: Natural gas demand from the fertiliser sector in Pakistan is expected to increase from 23 mmscmd in FY 2022 to 37.5 mmscmd in FY 2040.

Figure 50 Projected natural gas demand in Pakistan from the fertiliser sector (in mmscmd)

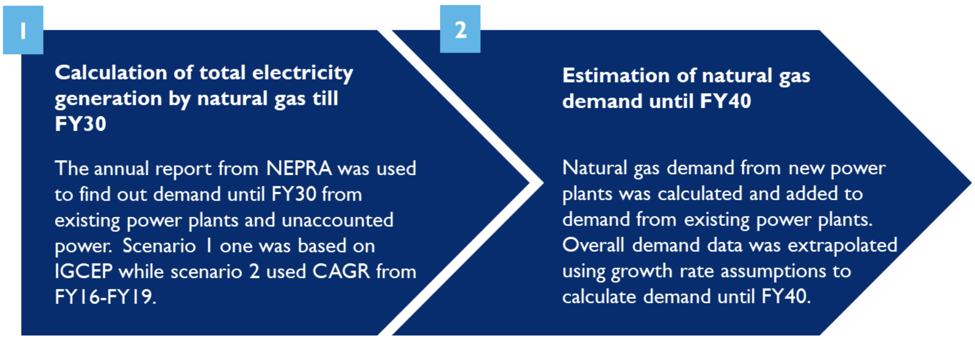


3.5.4.2 Power sector

National Electric Power Regulatory Authority (NEPRA) is the sole regulator of electric power services in the country. The power sector accounts for about ~32 percent natural gas demand in Pakistan. At present, it is one of the major demand drivers for the country. However, according to Indicative Generation Capacity Expansion Plan 2021-30 (IGCEP) released by NEPRA; the country aims to reduce the power reliance on imported fuels that also includes RLNG. According to IGCEP, by 2030, hydropower, coal, and nuclear energy will be dominant sources of power generation with ~84 percent of the overall power being generated from these three sources alone[165]. The indigenisation ratio of the country (ratio of power produced by indigenous generation sources to power produced by generation sources) was ~59 percent in 2020; this is expected to reach up to ~90 percent by 2030 due to inclusion of local coal, hydro, wind, and solar based power plants.[166]

The calculation of energy demand in the power sector is done by doing secondary research using data and inputs published by NEPRA. The list of power plants being used for the analysis has been provided in Annexure 17.2.2.

Figure 51 Methodology of calculation of gas demand by the power sector in Pakistan under the bottom-up approach



Detailed methodology

1. Step 1 – Estimation of total gas-based generation and gas demand until FY 2030
    a. In its annual report, NEPRA provides electricity generation, by plant, for gas-based power plants. The data is also available for gas consumption of these power plants. Overall, there were 41 gas-based existing power plants using either natural gas or RLNG considered for the analysis.
    b. Unaccounted electricity generation from natural gas and the corresponding gas consumption was calculated through total gas-based power generation given by NEPRA. The total power

[165] IGCEP 2021-30
[166] IGCEP 2021-30

generated by plants was subtracted from both RLNG and gas-based generation capacity to take unaccounted power into consideration.

  c. Based on the above data, two scenarios were considered for gas demand in the future:
     i. Scenario – 1 (most plausible scenario): This scenario was based on IGCEP 2020-39. According to this scenario, the gas-based generation in Pakistan is going to decrease by a growth rate of ~-18 percent up to 2030 as the country is more likely to focus on more indigenous sources of power generation and transition towards share of renewable energy in the overall power generation. Therefore, the growth rate of -18 percent was used to project gas demand until FY 2030.
     ii. Scenario – 2: Within this scenario, the overall gas demand for the gas-based power plants was calculated based on the historical gas demand growth rate between FY 2016-19. The growth rate came out as ~1.7 percent and was used to project gas demand until FY 2030.

2. Step – 2 Estimation of natural gas demand until FY 2040
   a. New gas power plants expected to come up in the next few years were identified through secondary research. Two plants were found after the research – Trimmu Barrage Power Plant Project[167] (1263 MW) and Bin Qasim Power Plant[168] (900 MW). For both these power plants, the pipeline constraints were also checked and verified. Per the latest news articles and reports, for both the power plants, the pipeline construction had been timely sanctioned. It is still ongoing. Hence, the construction and commencement of these power plants has been assumed to begin on time.
   b. The total natural gas demand was calculated as the sum of the natural gas demand from the existing power plants and the new power plants by extrapolating the current data with the CAGR factor.

<u>Assumptions</u>

1. For new gas power plants, the gas demand has been projected through a gradual increase in the PLF in the upcoming years and an average gas consumption of 0.0045 mmscmd for 1 MW power generation. Within the first scenario, the PLF of both the upcoming power plants was capped at 25 percent whereas in the second scenario, the PLF of the power plants was gradually increased to reach the maximum utilisation.
2. The growth rate (CAGR) for the overall natural gas demand from FY 2021 – FY 2030 was used for the purpose of projecting further gas demand in power. Within Scenario-1, this growth rate came out as ~-14.6 percent and in scenario-2, the growth rate came out as 3.7 percent. For projection of demand from FY 2031- FY 2040, the growth rate for gas demand in the second scenario was given a reducing trend with a cap of 2 percent and in the first scenario, the negative CAGR was reduced every year till FY 2040. This assumption was made as the visibility beyond 2030 is limited.

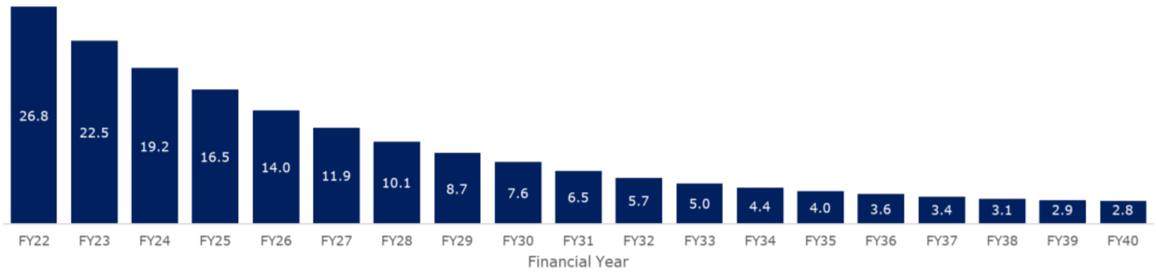
<u>Analysis</u>

Within scenario – 1 (based on IGCEP), demand for natural gas is expected to decrease from 26.8 mmscmd in FY 2022 to 7.6 mmscmd in FY 2030 and 2.8 mmscmd in FY 2040. Also, from the existing power plants, the demand is expected to reduce up to 3.4 mmscmd by FY 2030. Additionally, unaccounted power is expected to contribute ~1.7 mmscmd demand by FY 2030 in this scenario. This scenario is expected to be the most plausible scenario.

The natural gas demand from the power sector in Pakistan within Scenario – 2 is expected to increase from 40.9 mmscmd in FY 2022 to 54.4 mmscmd in FY 2030. The demand is expected to be 30.2 mmscmd by 2030 from the existing gas-based power plants and 8.83 mmscmd from the new upcoming power plants. Also, the unaccounted power will contribute 15.3 mmscmd to natural gas demand. On extrapolating the figures further, the overall natural gas demand from the power sector is expected to be 67.9 mmscmd by FY 2040.

[167] https://s3.us-west-2.amazonaws.com/backupsqlvis/RatingReports/OP_01077101002_00010771.pdf
[168] https://www.pipeline-journal.net/news/pakistan-build-short-distance-gas-pipeline-power-generation

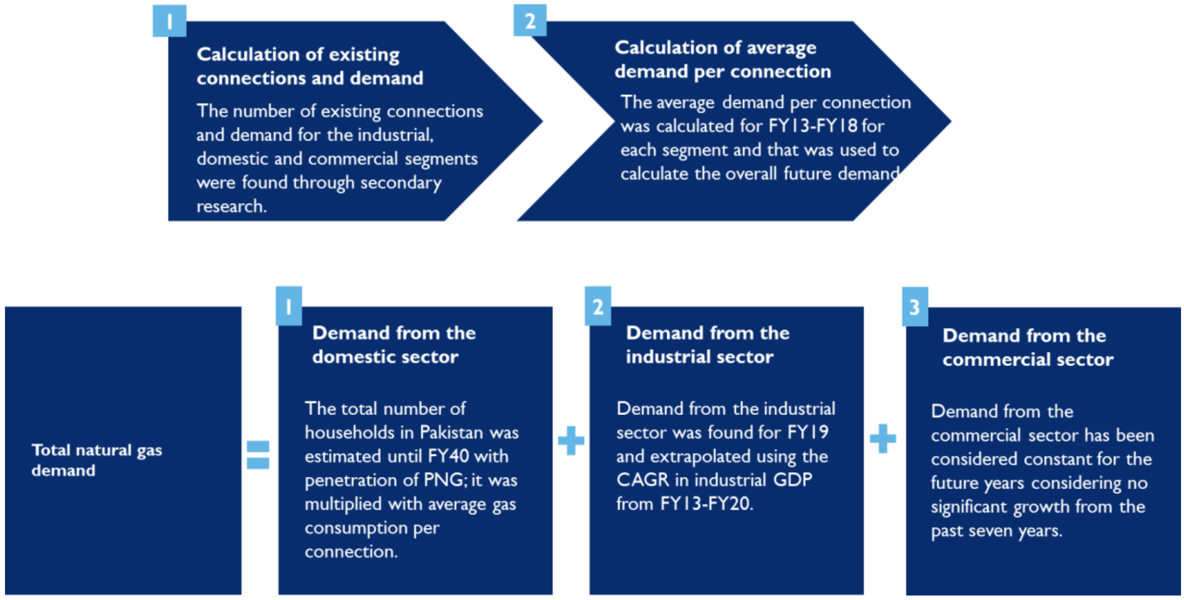
Figure 52 Projected natural gas demand in Pakistan from power sector in the most plausible scenario (in mmscmd)



3.5.4.3 CGD sector

It has been broken down into the industrial, domestic, and commercial segments. The demand from the sector was calculated on the basis of the number of PNG connections that were provided by the two state-owned companies to these different segments.

Figure 53 Methodology of calculation of gas demand by the CGD sector in Pakistan under the bottom-up approach



<u>Detailed methodology</u>

1. Step 1 – Calculation of the existing segment-wise CGD gas connections and CGD gas demand
    a. The two gas distribution companies of Pakistan − Sui Northern Gas Pipeline Ltd. (SNGPL) and Sui Southern Gas Pvt. Ltd. (SSGCL) − provided the number of segment-wise CGD connections through pipelines in the industrial, commercial, domestic, and CNG sectors from FY 2013–2018 from annual reports.
    b. The two gas distribution companies of Pakistan provided gas demand data by segment in the industrial, commercial, domestic, and CNG sectors from FY 2013-2018 from annual reports.
    c. Using the number for each segment for connections and natural gas demand, demand per connection was calculated for each one.
    d. To calculate demand for FY 2019, average demand per connection was considered from FY 2013-2018 and multiplied with the number of connections in FY 2019.
2. Step 2 – Calculation of future demand estimation
    a. Domestic sector
        i. Total number of households in Pakistan was projected to FY 2040.

   ii. Percentage of households with PNG connections was determined and projected until FY 2040.
   iii. Average gas consumption per household was determined and multiplied with the projected number of connections to get the total gas demand.

b. Industrial sector
   i. CGD gas demand from the industrial sector includes three sub segments – industries (such as ceramics), fertiliser plants, and the CNG sector.
   ii. Future projections of CGD industrial demand were done at the same CAGR as the growth in GDP from the industrial sector from FY 2013-2020.

c. Commercial sector: Demand from the commercial sector has been taken as constant for the future years.

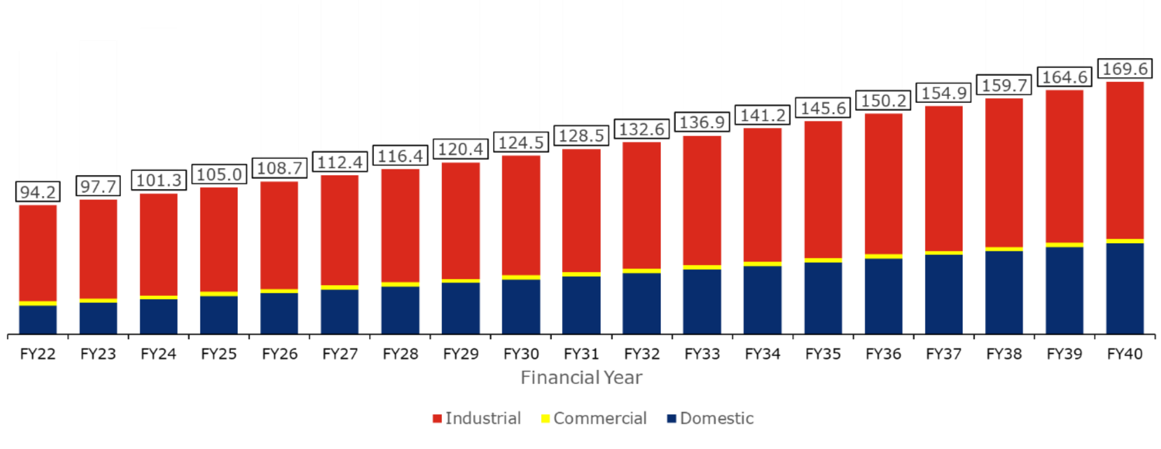
Assumptions

1. Percentage of households with PNG connections was projected with an increasing percentage until FY 2040 based on the past data of the percentage of households with domestic connections.
2. A direct correlation has been assumed in the industrial demand for natural gas and the industrial GDP for calculation of demand from the industrial sector until FY 2040.
3. Demand per connection for both SSGCL and SNGPL has been assumed to be the same, considering it is the average demand from different sections for City Gas Distribution.
4. Demand from the commercial sector is expected to remain constant, considering no significant growth in gas demand from the commercial sector in the past seven years.

Analysis

Natural gas demand from the CGD sector is expected to increase from 94.2 mmscmd in FY 2022 to 124.51 mmscmd in FY 2030 and 169.64 mmscmd in FY 2040. Initially, the industrial sector will be the highest contributor to CGD demand. However, with time as the number of households keeps on increasing in Pakistan, demand from the domestic sector is expected to occupy a significant portion as well. Within the industrial sector, demand is expected to rise from 58.9 mmscmd in FY 2022 to 96 mmscmd in FY 2040, whereas in the domestic sector, it is expected to increase from 32.7 mmscmd in FY 2022 to 71 mmscmd in FY 2040.

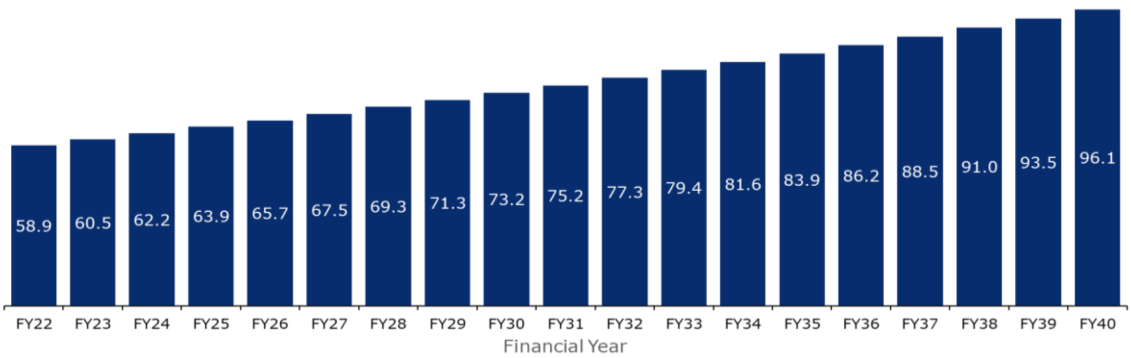
Figure 54 Projected natural gas demand in Pakistan from the CGD sector (in mmscmd)



3.5.4.4 Industry sector

Demand for the industrial sector has been accounted for in the CGD sector in 3.3.4.3 while doing the overall calculation. For the industry sector, net demand is expected to increase up to 73 mmscmd in FY 2030 and 96 mmscmd in FY 2040.

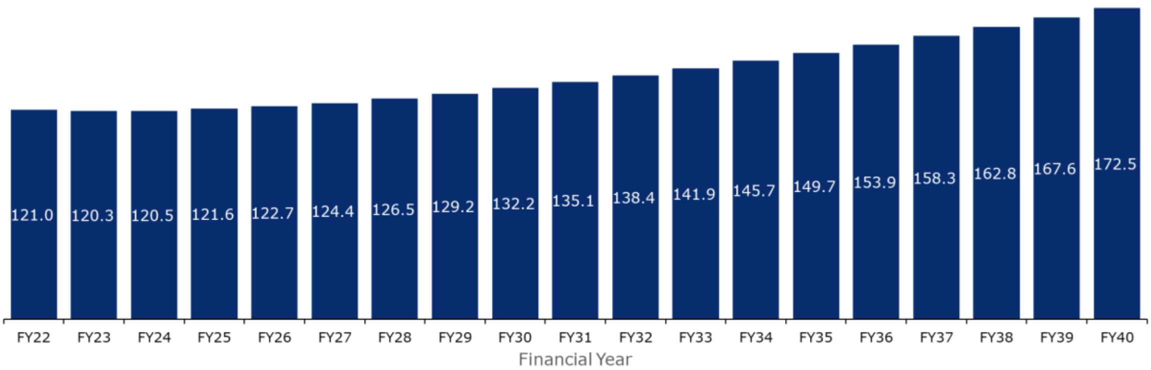
Figure 55 Projected natural gas demand in Pakistan from the industrial sector (in mmscmd)



3.5.5 Total demand projection until 2040

The total demand projection for natural gas in Pakistan is expected to increase to 132.2 mmscmd in FY 2030 and 172.5 mmscmd in FY 2040.

Figure 56 Projected natural gas demand in Pakistan from all sources for most plausible scenarios (in mmscmd)



The following is the breakup for the overall demand from each sector in the country:

Table 66 Overall summary of gas demand, by sector, in Pakistan from FY 2022 to FY 2030 for most plausible scenarios (in mmscmd)

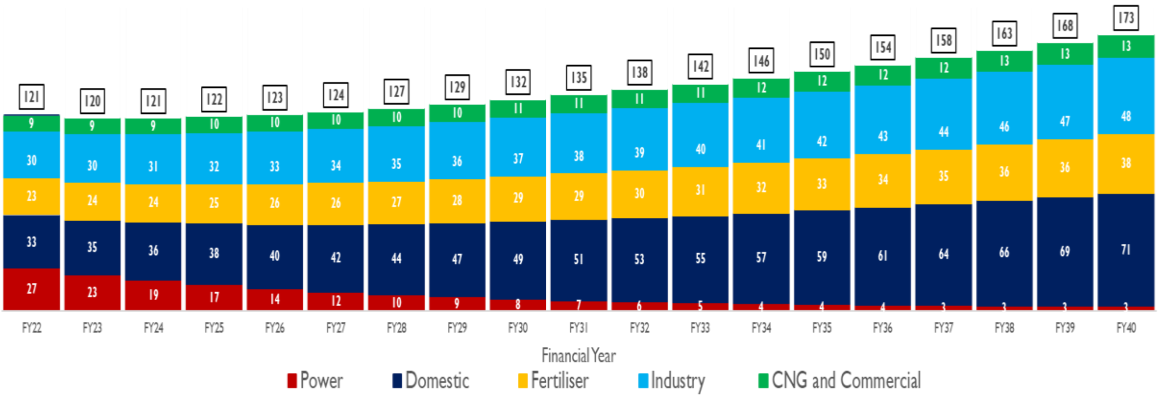
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	26.8	22.5	19.2	16.5	14.0	11.9	10.1	8.7	7.6
Domestic	32.7	34.5	36.4	38.4	40.4	42.3	44.4	46.5	48.7
Commercial	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Fertiliser	23.0	23.6	24.3	25.0	25.6	26.3	27.1	27.8	28.6
Industry	29.5	30.3	31.2	32.0	32.9	33.8	34.7	35.7	36.7
CNG	6.4	6.6	6.8	6.9	7.1	7.3	7.5	7.7	8.0
Total	121.0	120.3	120.5	121.6	122.7	124.4	126.5	129.2	132.2

Table 67 Overall summary of gas demand, by sector, in Pakistan from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	6.5	5.7	5.0	4.4	4.0	3.6	3.4	3.1	2.9	2.8
Domestic	50.7	52.7	54.8	57.0	59.2	61.4	63.7	66.1	68.5	71.0
Commercial	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Fertiliser	29.4	30.2	31.0	31.9	32.7	33.6	34.6	35.5	36.5	37.5
Industry	37.7	38.7	39.8	40.9	42.0	43.2	44.3	45.6	46.8	48.1
CNG	8.2	8.4	8.6	8.9	9.1	9.4	9.6	9.9	10.2	10.4
Total	135.1	138.4	141.9	145.7	149.7	153.9	158.3	162.8	167.6	172.5

Figure 57 Projections of sector-wise demand in Pakistan for most plausible scenarios (in mmscmd)



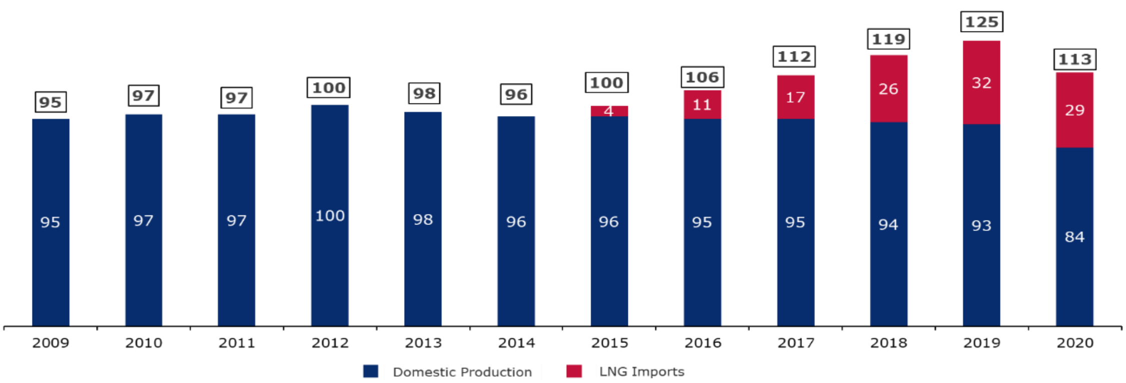
3.6 Supply analysis

3.6.1 Existing domestic production

Within Pakistan, the major gas fields for domestic production are - Sui (PPL), Uch (OGDCL), Qadirpur (OGDCL), Sawan (ENI, PPL), Kandhkot (PPL), and Mari (MPCL). These represent more than 50 percent of the country's proven gas reserves.[169] After analysing the trends of domestic natural gas production over the past decade, we identified that there is no significant change in supply from domestic fields and across the years, the proportion of gas supply from the existing fields is gradually declining. Moreover, dependence on LNG imports by FY 2020 increased to ~26 percent of the total gas supply[170].

Pakistan's recent efforts for offshore oil and gas exploration through Eni and ExxonMobil did not see outcomes.[171] Past efforts too by other foreign players, such as Shell, have not led to discovery of any additional natural gas reserves to meet domestic demand. The country has also given indications to auction 30 onshore gas blocks to improve supply situation. According to the BP Statistical Review and other industry reports, the country had 0.4 tcm of proven reserves of natural gas by end-2020.

Figure 58 Trend of natural gas production and consumption in Pakistan (in mmscmd)



[169] https://www.globalvillagespace.com/pakistan-energy-mix-overview-of-gas-sector-upstream/
[170] BP Energy Statistics
[171] https://apnews.com/article/9db1ddc83d7f4e518a35a48fb838fb4a

3.6.2 Existing supply through imports

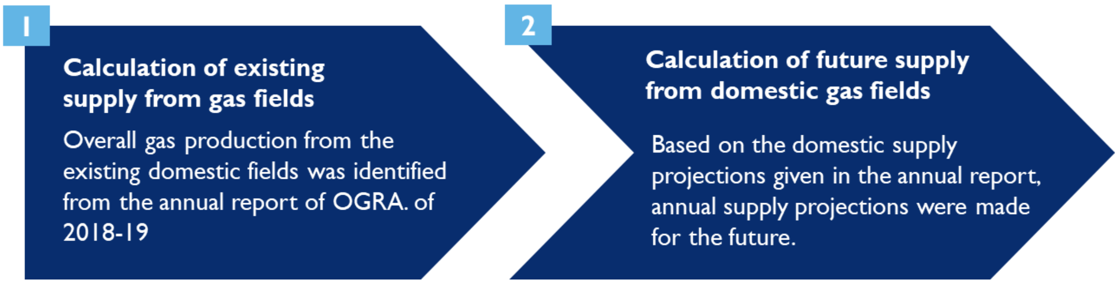
About ~26 percent of the natural gas demand in Pakistan is being met from LNG imports. Two LNG terminals are being considered currently – Engra Elengy Terminal and Gasport LNG Terminal with existing capacities of 690 mmscfd and 750 mmscfd, respectively.[172]

3.6.3 Upcoming expansion

3.6.3.1 Supply projection for domestic production

The supply projection for domestic production has been considered based on the following methodology:

Figure 59 Methodology for calculating the supply through domestic production in Pakistan



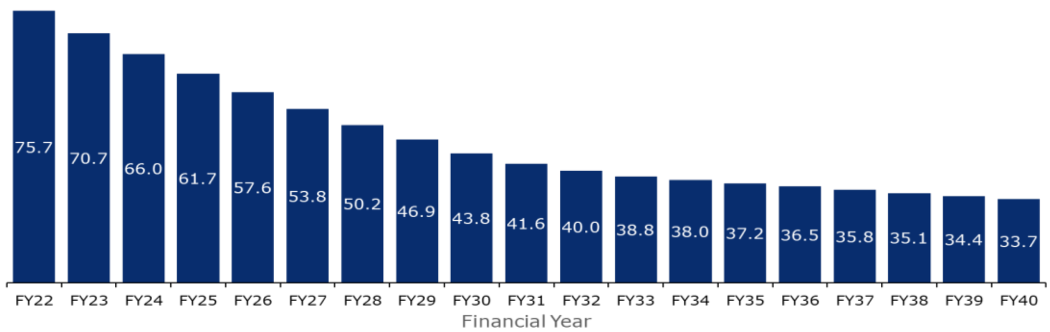
Detailed methodology

1. Gas production from existing domestic gas fields was identified through Annual Report 2018-19 by OGRA and the Ministry of Petroleum and Natural Resources. The existing fields of Sui, Uch, Qadirpur, Sawan, Zamzama, Badin, Bhit, Kandhkot, Mari and Manzalai were considered to calculate gas production.
2. Gas supply was projected through FY 2022-2040 based on the historical and expected decline in gas production based on Annual Report 2018-19 of OGRA. According to the projections given by OGRA in its 2018-19 annual report, the potential of domestic energy supply for Pakistan will be 16 bcm by FY 2030.[173] Based on that and the historical gas supply data, the CAGR of domestic gas supply was found to be ~-6.5 percent. This was used to calculate supply until FY 2030 for Pakistan.

Assumptions: The negative CAGR of -6.5 percent has been assumed to reduce gradually for projecting the supply beyond FY 2030 considering the fact that beyond 2030 in a long term, the visibility of supply from domestic production is limited

Analysis: Gas supply from domestic production is expected to decrease from 75.7 mmscmd in FY 2022 to 43.8 mmscmd in FY 2030 and further up to 33.7 mmscmd in FY 2040.

Figure 60 Projected natural gas supply in Pakistan from domestic fields (in mmscmd)



Shale Gas Potential in Pakistan:

[172] *Gas and Petroleum Market Structure and Pricing by Pakistan Institute of Development Economics*
[173] *Source: https://www.gem.wiki/Pakistan_and_fossil_gas#cite_note-:6-10*

According to a study conducted by US Energy Information Administration, Pakistan has estimated shale gas reserves of 105 tcf. Currently in Pakistan, OGDCL had started with the exploration of shale oil and gas reserves in December 2019. However, it had to suspend its drilling activities in May 2020 because of different reasons like high drilling costs and lack of machinery.[174] A study had been conducted by Weatherford for OGDCL in 2018 to assess the shale and tight gas deposits in the Indus Basin in Pakistan. According to that study, the best shale gas potential was estimated in lower Indus basin at 7.8 tcf over an area of 146 km. Despite of the potential, there hasn't been any success for Pakistan in extraction of shale gas due to the various challenges associated with it.[175]

3.6.3.2 Supply projection for imports

There is increasing dependence on LNG imports in Pakistan due to decline in domestic supply. Several new LNG terminals have been planned in the country considering the declining production. The following are the currently proposed new LNG terminals:[176]

Table 68 Upcoming LNG terminals in Pakistan

Project name	Location	Capacity	Expected commencement date	Pipeline	Expected pipeline completion year
Energas LNG terminal	Port Qasim	1000 mmscfd	2024	Ongoing (Pipeline has been licensed by OGRA)	2024
Fatima LNG terminal	Port Qasim	5.23 mtpa	2022	NSGPP (North South Gas Pipeline Project)	2023
Tabeer energy LNG terminal	Port Qasim	5.23 mtpa	1st quarter, 2023	Ongoing (Pipeline has been licensed by OGRA)	2024
Engro FSRU expansion	Port Qasim	1.05 mtpa	Winter 2020	NSGPP (North South Gas Pipeline Project)	2023
Gasport FSRU energy terminal expansion	Port Qasim	0.63 mtpa	December, 2021	NSGPP (North South Gas Pipeline Project)	2023

Apart from LNG terminals, two new natural gas pipelines are also a part of upcoming projects in Pakistan:

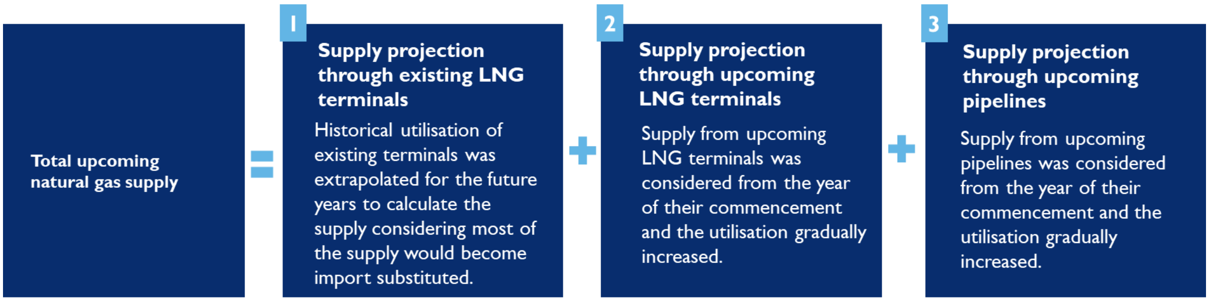
Table 69 Upcoming natural gas pipelines in Pakistan

Pipeline name	Capacity	Expected start	Length (in km)
Iran-Pakistan gas pipeline[177]	21.4 mmscmd	2024 (based on the news articles)	1100 km

[174] https://tribune.com.pk/story/2214954/ogdc-stops-search-shale-oil-gas-reserves
[175] https://www.thenews.com.pk/print/781552-ogdcl-plans-study-to-classify-shale-reservoirs-in-indus-basin
[176] Source: https://www.gem.wiki/Pakistan_and_fossil_gas#cite_note-28
[177] https://www.gem.wiki/Iran-Pakistan_Pipeline

Pipeline name	Capacity	Expected start	Length (in km)
Turkmenistan Afghanistan Pakistan India (TAPI) pipeline	1325 mmscfd	Pipeline has been assumed not to complete based on geopolitical dynamics	1814 km

Figure 61 Demand methodology for calculating the supply projection through imports in Pakistan



<u>Detailed methodology</u>

1. Step-1 Supply projection through existing LNG terminals
    a. The existing LNG terminals were identified as Engro LNG Terminal and Gasport LNG Terminal.
    b. The utilisation of both these terminals was extrapolated and used to calculate supply from the LNG imports in the next few years.
2. Step-2 Supply projection through upcoming LNG terminals and pipelines
    a. Upcoming LNG terminals, along with their connecting pipelines and capacities, were identified. A total of five new LNG terminals are coming up in Pakistan. For the Energas and Tabeer LNG terminals, the construction of pipelines has been sanctioned by OGRA and is still ongoing.[178] For the other three LNG terminals – Fatima and the expansions of Engro and Gasport – the pipeline infrastructure currently does not exist. From these terminals, supply is expected to be there through the North South Gas Pipeline Project (NSGPP). Therefore, the supply from the 3 terminals is projected to commence from the year NSGPP gets operational.[179]
    b. Two upcoming pipelines were also identified in Pakistan through secondary research – the Iran-Pakistan pipeline and the TAPI gas pipeline. For these pipelines, two scenarios have been considered:
        i. Scenario – 1 Completion of pipelines: The Iran–Pakistan pipeline is expected to be completed by FY 2024 after signing a recent deal between stakeholders from both the countries. The TAPI pipeline has been delayed because of a political matter in Afghanistan and lack of investments from international companies. However, if the governments of respective countries are able to collaborate in future and continue with the project, then the TAPI pipeline might reach its completion. For that, the pipeline commencement has been assumed from FY 2026 onwards.
        ii. Scenario – 2 Pipelines remain incomplete: Considering the uncertainty regarding both the pipelines, another alternative scenario has been assumed where no supply has been considered from each of these pipelines.
        iii. Within the most plausible scenario, the Iran-Pakistan pipeline has been assumed to get completed and the TAPI pipeline has been assumed to not get completed.
    c. Supply from the LNG terminals has been considered after the year of completion of the connecting pipeline. Also, the utilisation of these terminals and pipelines was gradually increased considering the time of operation and an increase in domestic demand that would be fulfilled by imports.

[178] https://profit.pakistantoday.com.pk/2021/08/01/ogra-issues-pipeline-construction-and-operation-licenses-to-energas-tabeer/
[179] https://www.argusmedia.com/en/news/2235619-pakistan-russia-sign-gas-pipeline-agreement

d. Overall supply from upcoming LNG terminals and pipelines was calculated for each year based on the product of their capacity and utilisation percent.

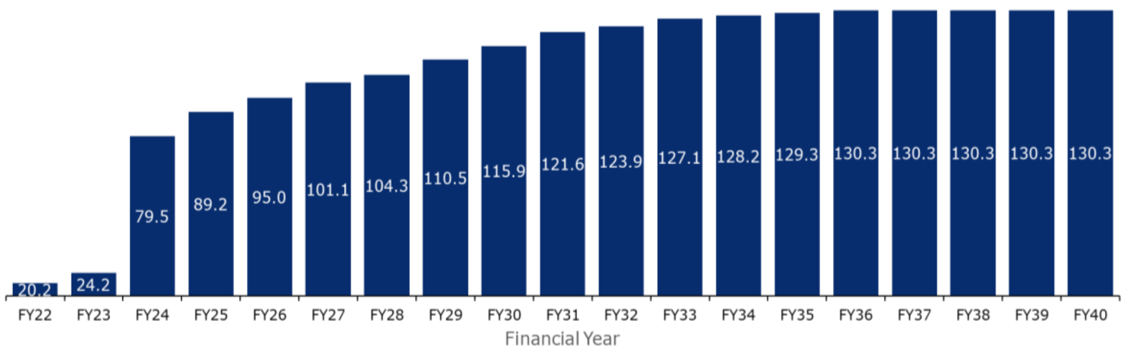
Assumptions

1. The assumption has been made that both the existing terminals will eventually reach their full utilisation with a cap of 90 percent. This is because the existing domestic production is not able to meet current natural gas demand in the country; eventually, imports will have to fill up the deficit.
2. Utilisation has been gradually increased from the starting year for new LNG terminals considering they would be slowly achieving their optimum utilisation with a cap of 90 percent.
3. For pipelines, utilisation will be gradually increased in the next few years until FY 2040 based on the expectations of long-term contracts formed by the government with other countries to meet domestic demand.

Analysis

The combined imports for both the terminals are expected to be 36.3 mmscmd until 2040 on the basis of the fact that both LNG terminals are able to reach up to their 90 percent utilisation. From the upcoming LNG terminals, supply for imports is expected to reach up to ~73 mmscmd as terminals reach their maximum utilisation by FY 2031. Also, for the upcoming pipelines, within the most plausible scenario (when the Iran-Pakistan pipeline is completed and TAPI pipeline is not completed), supply from pipeline imports is expected to be 11 mmscmd in FY 2030 and 21.4 mmscmd in 2040. Within the most plausible scenario, overall supply from imports is expected to increase up to 116 mmscmd by FY 2030 and 130 mmscmd by FY 2040. However, if both the pipelines are not completed, supply is expected to reach up to 109 mmscmd by FY 2031 and stay constant thereafter provided that the upcoming FSRUs operate at maximum assumed utilisation to cater to demand. Moreover, if both the pipelines get completed in the most optimistic scenario, the supply is expected to reach 135 mmscmd by FY 2030 and 167 mmscmd by FY 2040.

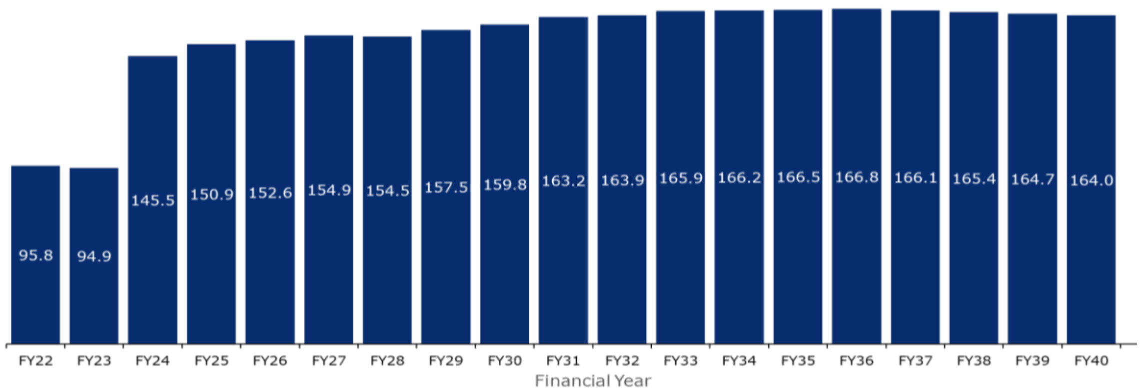
Figure 62 Projected overall natural gas supply in Pakistan from imports in most plausible scenario (in mmscmd)



3.6.4 Total supply projection until 2040

The overall supply projection in the basecase scenario is expected to reach 160 mmscmd in FY 2030 and 164 mmscmd in FY 2040, considering supply from the existing infrastructure and imports, and the upcoming projects in Pakistan. Within the basecase scenario, only the Iran-Pakistan pipeline is expected to get completed and the TAPI pipeline is not expected to be completed. After FY 2036, the overall supply is expected to decline because supply from domestic production would decline and the supply from imports would stagnate as the infrastructure reaches its full utilisation.

Figure 63 Projected natural gas supply in Pakistan from all sources in most plausible scenario (in mmscmd)



3.7 Demand-supply model

3.7.1 Integrated demand-supply model

The following tables show the projection and summary for the overall demand and natural gas supply in Pakistan from FY 2022-40.

Table 70 Demand and supply projections for Pakistan from FY 2022 to FY 2030 for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Demand	121.0	120.3	120.5	121.6	122.7	124.4	126.5	129.2	132.2
Domestic supply	75.7	70.7	66.0	61.7	57.6	53.8	50.2	46.9	43.8
Imports	20.2	24.2	79.5	89.2	95.0	101.1	104.3	110.5	115.9
Deficit (-)/surplus (+)	-25	-25	25	29	30	31	28	28	28

Table 71 Demand and supply projections for Pakistan from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Demand	135.1	138.4	141.9	145.7	149.7	153.9	158.3	162.8	167.6	172.5
Domestic supply	41.6	40.0	38.8	38.0	37.2	36.5	35.8	35.1	34.4	33.7
Imports	121.6	123.9	127.1	128.2	129.3	130.3	130.3	130.3	130.3	130.3
Deficit (-)/surplus (+)	28	26	24	21	17	13	8	3	-3	-8

The above-mentioned two tables indicates that once import-related projects in Pakistan are operational with unconstrained supplies of LNG imports and IPP project getting completed, the country is expected to have excessive supply of natural gas up to FY 2038. However, if LNG prices will increase, utilisation of terminals is expected to be affected, which in turn, will change supply numbers as well as deficit. Moreover, if TAPI pipeline gets completed, it would further increase the gas supplies in Pakistan.

4 Bangladesh

4.1 Country overview – Bangladesh

4.1.1 Economy (GDP), population, primary energy consumption, and fuel mix

Bangladesh is one of the direct neighbouring countries of India. It is surrounded by India on three sides, along with Myanmar and the Bay of Bengal on its south side. Bangladesh had a population of about ~165 million people in 2020.[180]The country's overall GDP was about ~US$324 billion in 2020.[181]According to the Energy & Mineral Resources Division, primary commercial energy consumption in the country was ~40.5 Mtoe in FY 2020.[182]The following was the fuel mix of primary energy consumption in Bangladesh for FY 2020.

Figure 64 Bangladesh: Primary energy consumption by source (2020)

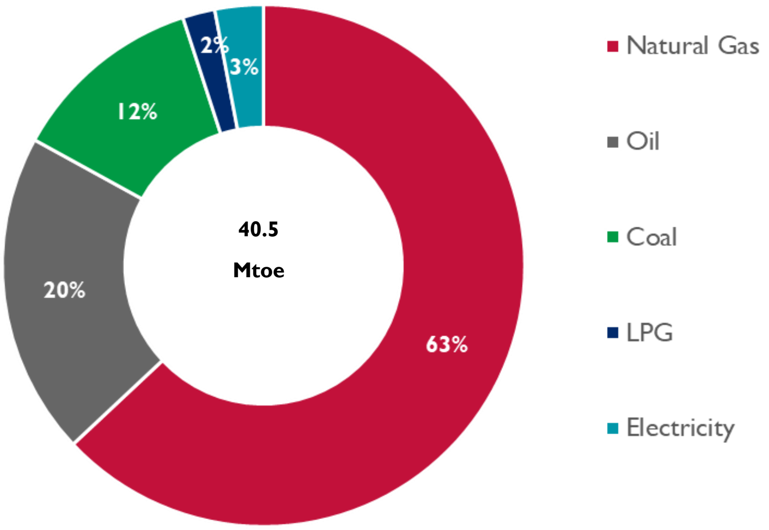


Table 72 Bangladesh: Primary energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Natural gas (63%)	25.5
Oil (20%)	8.1
Coal (12%)	4.9
LPG (2%)	0.8
Electricity (3%)	1.2

According to the latest data, Bangladesh has five primarily energy sources – natural gas, oil, coal, LPG, and electricity. Of these, natural gas fulfilled a significant portion (~63 percent) of energy demand past year. Natural gas has been the most economical fuel in the country (compared with petrol, diesel and LPG) and its shortage has curbed increase in demand across the years. Renewable energy's (RE) share is close to negligible as no new large-scale hydro projects or distributed solar and wind power projects have been planned in the country.

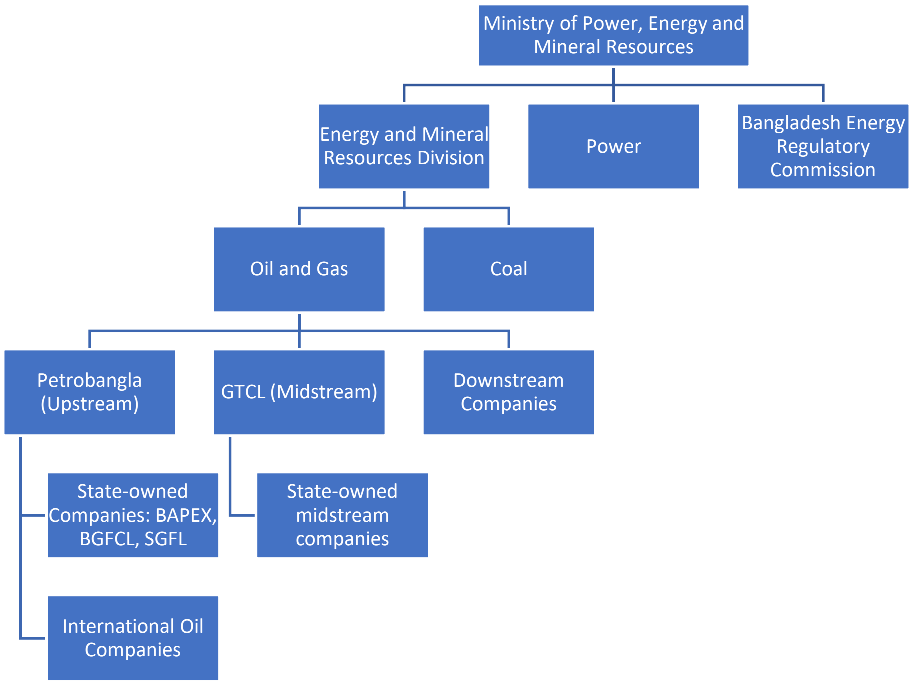
[180] https://data.worldbank.org/indicator/SP.POP.TOTL?locations=BD
[181] https://www.imf.org/external/datamapper/NGDPD@WEO/WEOWORLD/BGD
[182] Energy Scenario of Bangladesh, EMRD

However, energy consumption from non-commercially traded sources, such as biomass, is still significant. According to IRENA data of 2018, energy consumption from biomass was ~14 Mtoe.[183]

4.1.2 Gas value chain

In Bangladesh, gas value chain comprises several stakeholders. The Ministry of Power, Energy, and Mineral Resources (MOPEMR) overlooks at the whole energy scenario within the country. Petrobangla is the government-owned national state oil and gas company. It reports to the MOPEMR division. Petrobangla also acts as the upstream regulator for gas supply. It acquires gas from international oil companies at contract prices, mixes it with its own gas from subsidiaries, transmits the gas, and then distributes it to customers. Bangladesh Energy Regulatory Commission is the oil and gas regulator that decides natural gas tariffs for different segments. The following figure shows an organogram of the petroleum and natural gas sector in the country:

Figure 65 Organogram of the oil and gas sector in Bangladesh



Source: SAARC Energy Outlook, 2030

The following table shows major players in the gas value chain in Bangladesh:

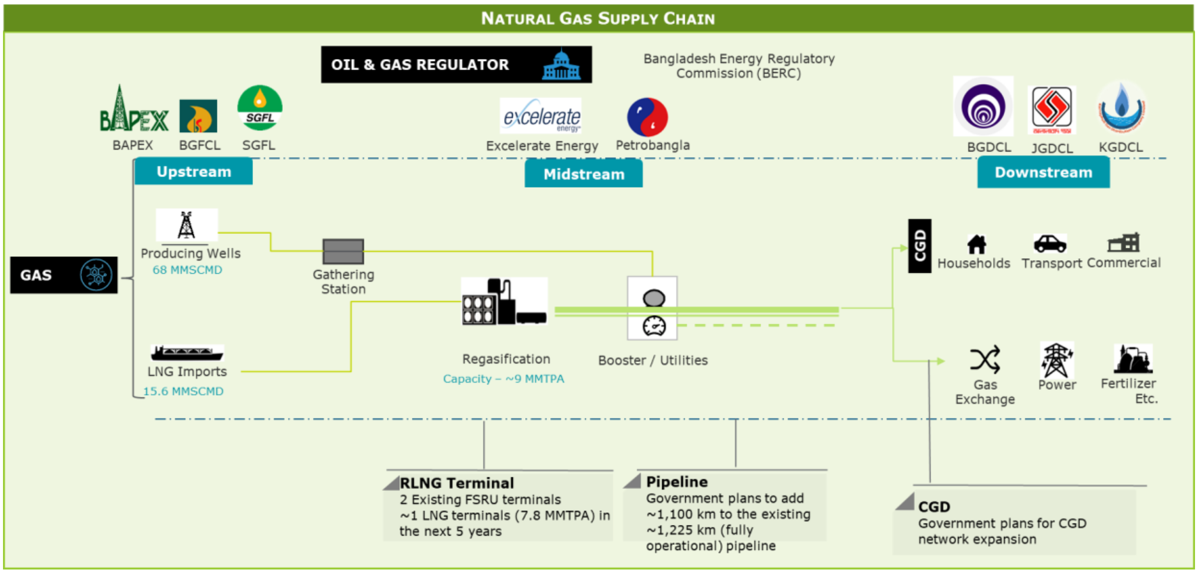
Table 73 Major players in gas value chain of Bangladesh

Extraction phase	Major players
Upstream	• Major players operating in this segment are: ○ BAPEX - Bangladesh Petroleum Exploration and Production Company Ltd. ○ BGFCL – Bangladesh Gas Fields Company Ltd. ○ SGFL – Sylhet Gas Fields Ltd.
Midstream	• GTCL (Gas Transmission Company Ltd.) is responsible for transportation of gas through the pipeline infrastructure • Several companies distribute gas:

[183] https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Bangladesh_Asia_RE_SP.pdf

Extraction phase	Major players
	○ TGTDCL – Titas Gas Transmission and Distribution Company Limited (62 percent market share) ○ BGDCL – Bakhrabad Gas Distribution Company Limited ○ JGTDSL – Jalalabad Gas Transmission and Distribution Systems Limited ○ PGCL – Pashchimanchal Gas Company Limited ○ KGDCL – Karnaphuli Gas Distribution Company Limited ○ SGCL – Sundarban Gas Company Limited
LNG	• For LNG import and processing, government-owned company Petrobangla and Excelerate Energy from the US have signed an agreement for FSRUs at Moheshkhali. • Summit Energy has also recently built a FSRU at Moheshkhali that is now operational.
Downstream	• Various downstream segments, such as power, CGD, fertilisers, and the general industry, constitute major demand for natural gas.

Figure 66 Schematic representation of natural gas value chain in Bangladesh



4.1.3 As-is assessment and challenges

<u>Upstream exploration and production scenario in Bangladesh</u>

The first gas exploration in the country took place in 1908 by Burmah Oil Company. After that, until the independence of India and Pakistan, exploration activities took place in a discontinuous fashion in the country. After attaining independence in 1951, exploration activities resumed in Bangladesh with technical assistance from Soviet Union. The first discovery of gas was made in Sylhet (1951-55) and later on in Chattack in 1959 by Pakistan Petroleum Limited. Production from Titas and Habiganj gas fields started in 1968. During the past few decades, gas discoveries in the country have been made by both national and international gas exploration companies.

As of 2019-20, Bangladesh had about 20 gas fields which produced ~68 mmscmd gas.[184] About 112 wells produced gas and 63 wells were suspended. The Bibiyana gas field, managed by Chevron Bangladesh, accounted for the highest production of ~34.2 mmscmd of gas. On a cumulative level, as of 2020, ~17.8 tcf of natural gas reserves have been exhausted and the remaining reserves are ~12.3 tcf. The list of fields, along with their cumulative gas production until 2019, and the remaining 2P (Proved plus Probable) reserves has been mentioned in Annexure 17.3.3.

Challenges around upstream exploration and production

Bangladesh remains one of the least explored countries amongst prospective gas basins in the world. It drilled only 28 exploratory wells in the past 20 years, reaching an average drilling rate of ~1.4 wells per year. The country has consumed ~13 tcf of gas during the past 20 years but made new discoveries of less than ~2 tcf of gas.[185] The country faced the following challenges around upstream production and exploration:

1. The exploration progress for any natural gas basin usually crosses three milestones – discovering simple types of oil gas reserves, moving towards the complex type of reserves and then progressing towards deep sea exploration. Bangladesh is yet to cross even its first milestone. The country has not yet discovered its simple types of oil-gas reserves. Consequently, lesser exploration has been done with respect to the second milestone. Deep ocean exploration, as of now, has not even started.
2. The simple types of oil gas reserves are present in anticlinal structures at places such as Patya, Sitapahar, and Kasalong in the Chittagong Hill Tracts. However, these anticlinal structures present a risk of seal breach, along with drilling challenges, due to overpressure caused by massive vertical relief on structures. Moreover, there is a risk of low-saturation 'fizz-gas' due to overpressure.[186]
3. Bangladesh is yet to explore any deep-sea natural gas resources. As of now, the country's natural gas production comes from onshore gas fields after the closure of Santos-operated offshore Sangu gas field in October 2013. Deep sea exploration also presents various technical challenges, such as tidal statics and feathering of streamers in tidal channels. Seafloor acquisition and transition zone technologies are required to counter these challenges. The following offshore exploration campaigns have either been or would be undertaken by the country:[187]
    a. In 1996, Cairn Energy discovered the Sangu gas field that produced gas until 2013. It was awarded block 16 in 1993; but Cairn later relinquished the block except the ring-fenced offshore Magnama structure that was transferred to Santos. After drilling two exploratory wells in Magnama without success, Santos relinquished the ring-fenced area in 2017. In the 1993 bidding round, Oakland-Rexwood was awarded blocks 17 and 18 that were relinquished in 2010.
    b. In the 2008 bidding round, the government signed a production sharing contract for two deep sea blocks, DS-10 and DS-11, with ConocoPhillips. The company conducted a total 5,750-line-kilometer of 2D seismic survey in 2012 and 2013. After interpretation, ConocoPhillips identified a few prospects. However, the company relinquished the blocks considering its investment was not feasible.
    c. Bangladesh now focuses on exploration in the shallow and deep offshore sea basins in the Bay of Bengal. In 2012, the country received a favourable verdict from International Tribunal for the Laws of the Seas (ITLOS) in its dispute with Myanmar over maritime rights in offshore basins in the Bay of Bengal. In 2014, it received another favourable verdict in a similar four-decade long dispute with India, awarding it nearly four-fifths of the disputed maritime area. These verdicts have bolstered the country's exploration plans.
    d. In 2012 Offshore Bidding Round, production sharing contracts were signed for blocks SS-04 and SS-09. These blocks were awarded to a consortium of OVL (45 percent), OIL (45 percent), and BAPEX (10 percent) with ONGC as the operating partner. In both the blocks measuring about 7000 square kilometer each, about 2700 line-kilometer(lkm) of 2D seismic survey has been completed. The MWP for SS04 included one exploratory well, while that for SS09 had two exploratory wells. Moreover, Santos, KrisEnergy, and BAPEX signed a contract for SS-11. Bangladesh has recently begun gas drilling in block SS-04 in the Bay of Bengal, under the contract between BAPEX and OVL. In SS-11, Santos has completed 3146 lkm of a 2D seismic

[184] *HCU, Annual Report on Gas Production, Distribution and Consumption*
[185] https://www.thedailystar.net/opinion/news/bangladesh-running-out-gas-resources-2095805
[186] https://www.geoexpro.com/articles/2020/12/bangladesh-upstream-delayed-but-not-out
[187] *Petrobangla Annual Report*

survey and identified seven potential leads. However, Santos' decision of wrapping up overall activities from the Asian region led them relinquish SS-11.

e. In 2017, Bangladesh has signed a production sharing contract for deep sea block DS-12 with South Korea's Posco Daewoo Corporation. About five leads were identified; of which, two were quite promising. However, the company left Bangladesh without completing the project because of the disagreement over revised terms of production sharing contract.

4. The licensing round for gas exploration slated in 2020 was further delayed due to COVID-19. The round would have concentrated on deep-water blocks prospective for gas close to the maritime border with Myanmar but now the licensing rounds have been postponed indefinitely. For the 2020 bidding round, Bangladesh had about 14 deep sea and 8 shallow sea blocks on offer that would have given some impetus to offshore gas exploration in the country.

Other challenges

The sector also faces several challenges within the country:

1. In Bangladesh, natural gas demand has been consistently increasing over the years, whereas supply from domestic fields has been declining. Hence, Bangladesh's dependence on natural gas import to meet demand has increased. The dominance of gas usage in gas-intensive sectors such as power is expected to get threatened because of higher prices of imported gas.
2. The infrastructure coverage for transmission pipelines has not been adequate to service the country's key market areas as most gas supply points are in the northeast and central regions, while delivery points are in the central, south, and west regions.
3. In Bangladesh, natural gas tariff has been the lowest compared with other SAR countries.[188] Though there was a weighted average increase of ~32.8 percent in gas tariffs for sectors in 2019.[189]However, they are still amongst the lowest in the world. Due to such low tariffs, there is supply shortage in different sectors and unmet demand in sectors such as CNG, domestic, and captive power. This could further lead to transition towards alternative fuel sources in these sectors in the next few years.
4. The oil and gas sector has witnessed government control on supply, distribution, and pricing. Therefore, if supply costs are high, the government resorts to subsidies. The country is a net importer of petroleum products and gas. In addition, according to an article by Wood Mackenzie, the country is expected to double its fossil fuel imports between 2020 and 2030.[190]Demand for fossil fuels will be fuelled by working-age population, urbanisation, electrification needs and also, the industrial sector. In the short term, the government might use surplus foreign exchange to meet the immediate energy crisis. However, the increased import dependence of the country will not be sustainable in the longer run. The cumulative cost of large amounts of coal and LNG imports on a long-term basis, along with large-scale imported power, is likely to raise cost of power and industrial products.

4.2 Gas infrastructure analysis

4.2.1 Existing pipeline and LNG terminal infrastructure

Pipeline infrastructure

Gas Transmission Company Limited (GTCL) is responsible for transportation of natural gas within the country. GTCL owns and operates major gas transmission pipelines throughout the country. Gas transmission pipelines built by other companies before the creation of GTCL have been integrated with the GTCL system.

In December 2019, the pipeline network infrastructure in the country was about ~24,336 km. This included about ~2,872 km of transmission pipelines, ~2,381 km of distribution pipelines, ~236 km of lateral lines, and ~16,738 km feeder main and service lines. The remaining ~2,110 km pipelines were constructed under customer financing.[191]

The table below shows a list of major operational pipelines in Bangladesh:

[188] Source: https://cpd.org.bd/wp-content/uploads/2019/03/The-Power-and-Energy-Sector-of-Bangladesh.pdf
[189] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/070219-analysis-biggest-ever-gas-price-hike-in-bangladesh-to-foot-lng-import-bill
[190] https://www.woodmac.com/press-releases/bangladesh-to-double-its-fossil-fuel-imports-in-a-decade/
[191] Source: Petrobangla Annual Report 2019-20

Table 74 Existing major gas pipelines in Bangladesh

Name	Size	Length
Ashuganj-Bakhrabad gas pipeline project	30-inch	58.50-km
Paschimanchal gas project (a)Bangabandhu (B-B) Bridge (b) Elenga-Nalka (c) Nalka-Baghabari	(a) 30-inch (b) 24-inch (c) 20-inch	(a) 9-km (b) 28.5-km (c) 35.5-km
Beanibazar-Kailashtila gas project	20-inch	18-km
Rashidpur-Ashuganj gas pipeline (1st phase): Rashidpur-Habigonj	30-inch	28-km
Rashidpur-Ashuganj gas pipeline (2nd Phase): Habigonj-Ashuganj	30-inch	54-km
Nalka-Bogra gas pipeline (a) Nalka-Hatikumrul (b) Hatikumrul-Bogra	(a) 30-inch (b) 20-inch	(a) 6-km (b) 54-km
Ashuganj-Monohordi gas pipeline	30-inch	37-km
Dhaka Clean Fuel (GTCL Part) gas pipeline	20-inch	60-km
Titas gas field (location-G)-AB pipeline gas pipeline	24-inch	8-km
Monohordi-Dhanua and Elenga-Bangabandhu Bridge East gas pipeline	30-inch	51-km
Bonpara-Rajshahi gas pipeline	12-inch	53-km
Bibiyana-Dhanua gas pipeline	36-inch	137.00-km
Titas Gas Field (locations - C, B, and A) To Titas-AB gas pipeline	10-inch	7.7-km
Bheramara-Khulna gas pipeline	20-inch	163.03-km
Hatikumrul-Ishardi -Bheramara gas pipeline	30-inch	84-km
Gas capacity expansion - Ashuganj to Bakhrabad gas pipeline	30-inch	61-km
Moheshkhali-Anwara gas pipeline project	30-inch	91-km
Bakhrabad Siddirgonj pipelines	30-inch	60-km
Anwara-Fouzdarhat gas pipeline project	42-inch	30-km
Maheshkhali Zero Point (Kaladiar Char) – CTMS (Dhalghat Para) gas pipeline project	42-inch	7-km
Maheshkhali-Anowara gas parallel pipeline project	42-inch	79-km

LNG infrastructure

At present, Bangladesh has two existing FSRU terminals at Moheshkhali. One is operated by Excelerate Energy, and another is by Summit LNG Terminal Co. Pvt. Ltd. Bangladesh has been importing LNG under long-term deals from Qatargas and Oman Trading International Ltd. (OTI) from these terminals.[192]Each terminal has a capacity of ~4.28 MMTPA. The utilisation of both the terminals has been constrained by the limited quantities of firm LNG supply agreements, and more dependence on spot LNG cargoes; these cargoes have become difficult to source on account of a high price volatility in the past year.

There was some delay in 2019 within the pipeline system in the Summit LNG terminal. The pipeline that would connect the FSRU to the coastal city of Chattogram had not been fully built. This would restrict the flow of RLNG from this import facility to the transmission network.[193]The delay was quickly addressed through government interventions. State-run GTCL completed the Chattogram-Feni-Bakhrabad gas transmission pipeline that is 181

[192] https://www.hellenicshippingnews.com/oti-signs-deal-with-petrobangla-to-supply-lng/
[193] Source: https://www.offshore-energy.biz/summit-lng-terminal-in-bangladesh-facing-constraints-on-pipeline-delays/

km long in April 2020.[194]The pipeline was ready to carry LNG at full capacity to end-users. It was earlier working on half of its capacity, but now the constraints associated with the pipeline have been removed.

4.2.2 Upcoming and planned infrastructure

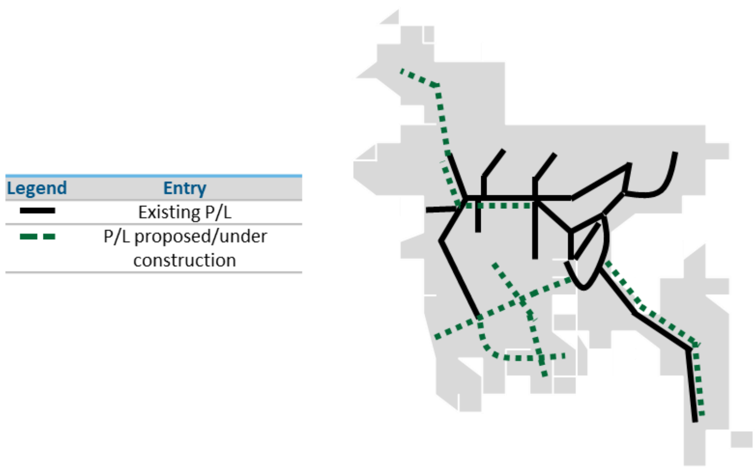
Pipelines

The government of Bangladesh focuses on completion of national gas grid extending pipelines across the country and connecting the North-Eastern region. Hence, a number of pipelines are work-in-progress within the country. The following table shows a list of partially commissioned or under construction pipelines in Bangladesh:

Table 75 List of partially commissioned or under-construction pipelines in Bangladesh

Name	Size	Length	Expected completion year
Bogra–Rangpur–Sayedpur gas pipeline project	30″	150 km	2021
Dhanua-Elenga and West Bank of Bangabandhu Bridge-Nalka Km gas pipeline project	30″	67 km	2021
Bakhrabad-Meghnaghat-Haripur gas pipeline project	42″	50 km	2022
2nd Bangabandhu Bridge (Railway Section) gas pipeline project	36″	12 km	2023
Satkhira (Bhomra)–Khulna (Aronghata) gas pipeline project	30″	65 km	2022
Langolbandh-Maowa and Janjira-Tekerhat gas pipeline project	30″	70 km	2023
Khulna-Gopalgonj-Tekerhat gas pipeline project	30″	80 km	2023
Bhola-Barishal gas pipeline project	30″	60 km	2025
Tekerhat-Faridpur and Tekerhat-Barishal gas pipeline project	30″	115 km	2028
Payra-Barishal gas pipeline project	42″	87 km	2034
Khulna-Bagerhat-Pirojpur-Jhalokathi-Barishal gas pipeline project	36″	110 km	2035
Hatikumrul-Bogura gas pipeline project	30″	55 km	2036

Figure 67 Existing and proposed pipeline infrastructure in Bangladesh



[194] Source: https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/042820-bangladesh-overcomes-pipeline-hurdles-to-boost-lng-re-gasification-capacity

LNG

In case of Bangladesh, ~7.8 MMTPA LNG terminals are under construction or in planning stage, resulting in good opportunity to import gas.[195] According to latest announcements, one LNG terminal called the Kutubdia terminal has been cancelled. However, the government is expected to come up with more initiatives in the future, considering the increasing demand for LNG in the country. The following table shares a summary of new LNG terminals:

Table 76 Upcoming LNG terminals in Bangladesh

LNG terminal	Developer	Status	Capacity (MTPA)
Matarbari land terminal	Petrobangla	2023	7.78
Kutubdia terminal	Petronet LNG	Cancelled	8.40
Payra port LNG terminal	Saudi Aramco	Cancelled	7.5

4.3 Policy, regulatory enablers, and emerging trends

4.3.1 Policy and regulatory support and incentives to promote the sector

The shortage of natural gas supply has started affecting economic activities and the country's growth. To address this situation, the government of Bangladesh has been making efforts to ensure energy supply and accelerate the economic development. The government has been working on short-, mid-, and long-term plans for gas and coal extraction, development, and production.

The government undertakes the following strategies and initiatives to promote the sector:[196]

- Adopting a time-based action plan for discovering new gas fields and development of producing gas fields to improve domestic supplies
- Making BAPEX more effective in exploring oil and gas through acquiring new rigs and its ancillaries
- Increasing LNG import, along with the development of LNG infrastructure, to meet domestic demand
- Increasing financial capacity of BAPEX by forming a separate gas development fund
- Putting efforts to ensuring proper pricing of gas to conserve energy and improve the gas sector's financial operations

4.3.2 Emerging trends with respect to alternative fuels

There are several emerging trends with respect to usage of alternative fuels in the country. Other forms of energy generation are also coming into prominence in Bangladesh because of depleting domestic gas production and increasing reliance on LNG imports. Coal use was expected to increase manifold to reach ~12 million tonne by FY 2030 due to massive build-up of coal-fired based thermal plants in the country (~6,000 MW).[197] However, recently the government has officially cancelled 10 coal-based power plant projects because of the government's commitment to reduce carbon emissions. As of now, the use of renewable energy within the country is limited as only about 3.5 percent of the country's power comes from renewable energy and no new significant projects have been announced. With the cancellation of coal-based plants, the country aims to achieve 40 percent of power generation from renewable energy by 2041[198].

The country not only focuses on conventional fuels but also makes research and development efforts for alternative unconventional energy sources. Different forms of unconventional energy, such as CBM, shale gas,

[195] https://www.gem.wiki/Bangladesh_and_fossil_gas
[196] Petrobangla Annual Report, 2019-20
[197] https://www.SARenergy.org/wp-content/uploads/2019/05/SAR-Energy-Outlook-2030-Final-Report-Draft.pdf
[198] https://www.reuters.com/article/us-bangladesh-energy-climate-change-coal-idUSKCN2E410H

and unconventional gas, are being explored. Petrobangla has undertaken a project to assess the potentiality of CBM in the Jamalganj coal deposit, the largest and deepest coal deposit in the country. Moreover, a preliminary study on the feasibility of shale gas potential in Bangladesh has also been prepared by the country's hydrocarbon unit.[199] The unit has prepared another research report titled "Action Plan and Guidelines for CBM, UCG, and Hard Rock Development in Bangladesh."

4.4 Pricing assessment

4.4.1 Gas pricing mechanism

Gas distribution companies in the country compute their gas tariffs for different consumer categories on the basis of two factors - future sales forecast and average revenue requirements. Petrobangla and BERC take into account inputs from stakeholders, including market participants, sector experts, and independent research bodies. Thereafter, it takes a stance on price revisions in case they need to be made. To account for disparity in income levels within different categories, consumers are cross subsidised in many cases.

Producer gas prices

The Energy Division of the Ministry of Power Energy and Mineral Resources (MOPEMR) has set a weighted average of the price of gas produced by Petrobangla and that purchased by Petrobangla from international oil companies. Bangladesh's wellhead gas prices have varied between US$1.3-2.6/mmbtu.[200]Upstream exploration companies in Bangladesh get thin margins for their operations from end-consumers.

Consumer gas prices

BERC regulates natural gas prices for end-consumers. The methodology used for this pricing is the cost-plus pricing. The price for end-consumers is set considering gas cost (for Petrobangla) and additional margins (a return and costs associated with transmission and distribution of natural gas). According to GSMP, the table shows gas tariff breakdown by sector in Bangladesh for Petrobangla in 2017:

Table 77 Gas tariff breakup for different sectors in Bangladesh for 2017 (in US$/mmbtu)

Serial no.	Price category	Power	Fertiliser	CNG	Captive power	Industry	Tea Garden	Commercial	Domestic
1	Wellhead margin	0.10	0.10	0.13	0.10	0.10	0.10	0.10	0.10
2	Deficit wellhead margin for BAPEX	0.02	0.02	0.09	0.02	0.02	0.02	0.02	0.02
3	BAPEX margin	0.02	0.00	0.05	0.02	0.02	0.02	0.02	0.02
4	Price deficit fund margin	0.14	0.12	2.56	0.19	0.32	0.32	0.56	0.30
5	Gas development fund	0.04	0.07	1.32	0.09	0.12	0.12	0.23	0.12
6	Energy security fund	0.05	0.02	0.84	1.05	0.55	0.46	1.05	0.63
7	Transmission margin	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
8	Distribution margin	0.12	0.12	0.07	0.07	0.11	0.11	0.11	0.11
9	Support for shortfall	0.14	0.06	2.09	0.53	0.42	0.41	2.38	1.76
10	Government taxes	0.65	0.60	6.23	1.93	1.55	1.49	2.62	1.61
	Total	**1.33**	**1.16**	**13.43**	**4.06**	**3.27**	**3.10**	**7.16**	**4.73**

(The conversion factor was done from US$ per Mcf to US$ per mmbtu, dividing with 1.037 per the rate provided by the US Energy Information Administration.)[201]

For the sectors, government taxes are in the range of ~35-50 percent. Gas development funds are used to carry out gas exploration and development and enhance capacity of national exploration and production companies. Although BAPEX and wellhead margins are low, they are covered by price deficit fund margins and deficit wellhead margins for BAPEX; this go straight to exploration and production activities that Petrobangla is undertaking. Transmission and distribution margins are ~2 percent and ~4 percent, respectively. Other funds are

[199] https://hcu.portal.gov.bd/sites/default/files/files/hcu.portal.gov.bd/publications/753d455d_3c37_43df_9ce6_6f80bdc0e982/2021-06-14-16-02-17701 8e29eac5e789f4322e1a17d9be3.pdf
[200] https://tribune.com.pk/story/2176787/review-gas-sector-prices
[201] https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

put aside for shortfall and energy security; this constitute ~10-40 percent of end consumers' price depending on the sector.

However, Petrobangla subsidises the prices offered to end consumers. In addition, gas tariffs saw a significant increase from 2017 to 2019 because the country started importing LNG from 2018; this LNG was supplied after mixing with domestic gas. According to Petrobangla's annual report, the following were an increase in gas tariffs for different sectors from 2017 to 2019:

Table 78 Gas prices in Bangladesh for different sectors for 2017 and 2019 according to Petrobangla annual report

Sectors	Tariff in 2017 (in $/mmbtu)	Tariff in 2019 (in $/mmbtu)	% change
Power	1.04	1.46	40.8%
Fertiliser	0.89	1.46	64.2%
Industry	2.54	3.51	37.9%
Commercial (hotels and restaurants)	5.58	7.54	35.0%
Commercial (cottage industry)	5.58	5.58	0.0%
Tea estate	2.43	3.51	44.2%
Captive power	3.15	4.54	44.0%
CNG feed gas	10.49	11.47	9.4%
Domestic (metered)	2.98	4.13	38.5%
Domestic (single burner)	8.68	10.70	23.3%
Domestic (double burner)	9.26	11.28	21.9%

(The conversion factor of 1 Taka/Mcf = 0.0115 $/mmbtu was used per the rate provided by US Energy Information Administration 1 Mcf = 1.037 mmbtu and using the currency conversion rate from Taka to Dollar as on 1 July 2019)

Petrobangla had also issued gas utilisation guidelines for Bangladesh in 2013. According to these guidelines, the following prioritisation for domestic natural gas supply, by sector, had been allotted to different sectors in the situation of gas shortage:

1. Fertilisers
2. Electricity
3. Industry/tea gardens
4. Captive power
5. Residential/commercial
6. CNG

RLNG pricing

Bangladesh imports LNG with a mix of long-term contracts and spot market prices. The country imports LNG under long-term deals from two global suppliers − Qatar's Qatargas and Oman's Oman Trading International (OTI). The Excelerate LNG terminal has contracts with Qatargas - a five-year contract of 1.8 MMTPA ending in 2022 and a 15-year contract of 2.5 MMTPA ending in 2032. In the contract, the purchase price has been set at about 12.65 percent of the three-month average price of brent crude oil plus US$0.50 constant per mmbtu.[202] The purchase agreement has been signed with Oman Trading International to import 1 MTMPA of LNG for 15 years starting 2019. The purchase price with OTI has been set at 11.9 percent of the three-month average of brent crude oil prices plus US$0.40 per mmbtu. Several firms, such as Vitol Asia Private Ltd., AOT Trading, and Excelerate Energy, provide LNG to Bangladesh through spot contracts.

[202] https://thefinancialexpress.com.bd/trade/global-lng-suppliers-seek-long-term-deals-with-bangladesh-1618974943

For May 2022, import price of LNG for long-term contracts was US$14/mmbtu.[203] A 15 percent VAT is applicable for import price and value addition (through regasification) being done to LNG. The following is the overall price breakup for Petrobangla for LNG imports:

Table 79 Price breakup of imported LNG in Bangladesh, as of May 2022

Component	Unit	Price
Import price	$/mmbtu	14
Value addition to LNG	$/mmbtu	1.51
VAT	$/mmbtu	2.8
Total	**$/mmbtu**	18.3

Despite Petrobangla bearing costs in the range of ~US$18/mmbtu, LNG is sold to customers at BERC subsidised rates, and the company pays US$0.2-0.3/mmbtu as VAT to the National Board of Revenue[204] (NBR). It has been unable to pay VAT on the original import price to NBR due to huge subsidies provided on the sales price of natural gas. The company received a subsidy of ~US$290 million from the government for LNG operations in 2019 according to its annual report.

4.4.2 Pricing of alternative fuels and comparison with natural gas

Imported coal attracts taxes in the range of 24-29 percent depending upon its type and grade. For petrol-related products, National Energy Policy of 2004 determines the rules that are applicable for crude oil and LPG. The price of locally produced LPG is linked to international kerosene price on British Thermal Units (BTU) with appropriate discount and subsidies to encourage consumption and local production. Moreover, value of oil from each production area is determined based on market value comparable with Asia Pacific Petroleum Price Index (APPI). The government controls other POL product prices in Bangladesh with revision being regularly undertaken on a constant basis. According to the latest data, the following are the prices of major POL products in Bangladesh:[205]

Table 80 POL fuel prices in Bangladesh

Fuel	Retail selling price (as of May 2022) in US$/mmbtu
Gasoline	32.8 (89 Taka/L)
Diesel	23.7 (80 Taka/L)
Kerosene	24.3 (80 Taka/L)

(Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for May 2022)

Calorific value of LNG = 12500 kcal/kg; 1 mmbtu = 252000 kcal; US$ to Taka for May 2022 = 91.76; calorific value of diesel = 10800 kcal/kg; calorific value of petrol = 10500 kcal/kg; calorific value of kerosene = 11,100 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L; density of kerosene = 0.82 kg/L)

For each category of end consumers, cost economics is favourable for natural gas compared with other POL fuels.

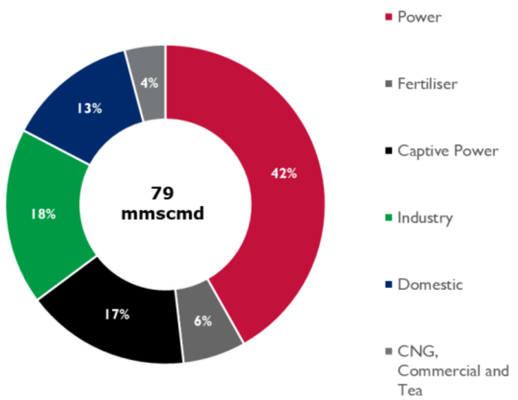
[203] https://thefinancialexpress.com.bd/trade/bangladesh-to-expand-lng-sourcing-amid-energy-dearth-1652410398
[204] https://thefinancialexpress.com.bd/economy/petrobangla-owes-nbr-tk-213b-vat-arrears-1628390568
[205] https://www.globalpetrolprices.com/Bangladesh/

4.5 Demand analysis

4.5.1 Existing demand

According to the Bangladesh Hydrocarbon Unit's report for FY 2021, gas consumption in Bangladesh was ~79 mmscmd. Lower gas prices and lack of other significant fuel sources, such as oil and coal, have fuelled demand for natural gas in the power sector (which accounted for ~59 percent of the gas supplied[206] that includes both power plants and captive power). To tide over the shortage and meet demand for a large gas-based power sector, Bangladesh began importing LNG in 2018. Apart from the power sector, the industrial sector constituted about 16 percent of the overall natural gas demand in the country followed by the domestic sector.

Figure 68 Gas consumption in Bangladesh by sector (FY 2021) according to Bangladesh Hydrocarbon Unit report (in mmscmd)



Sector	Gas consumption (in mmscmd)
Power (42%)	33
Fertiliser (6%)	4.7
Captive power (17%)	13.4
Industry (18%)	14.2
Domestic (13%)	10.3
CNG, commercial, and tea (4%)	3.1

Bangladesh has also shown a constant upward trend in natural gas consumption. Although the growth rate of the gas consumption over the years has been low (~4.6 percent), the country's per capita gas consumption is still the highest amongst SAR nations. Most sectors have shown almost a constant gas consumption over the years with a minor increase.

Figure 70 Trend of natural gas consumption in Bangladesh over the years (in mmscmd)

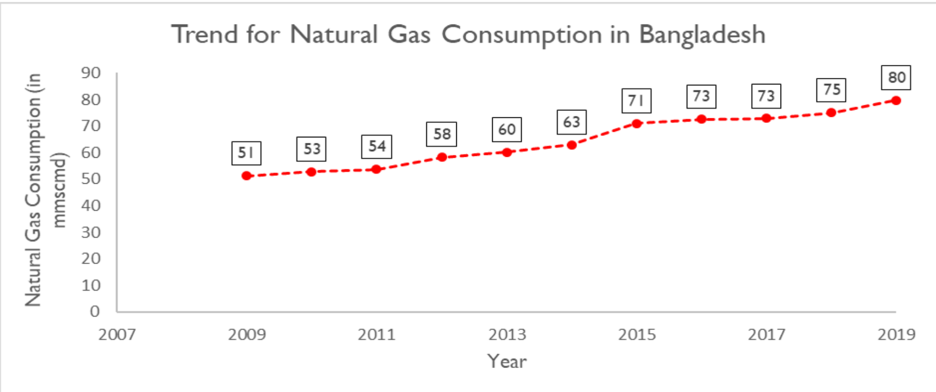
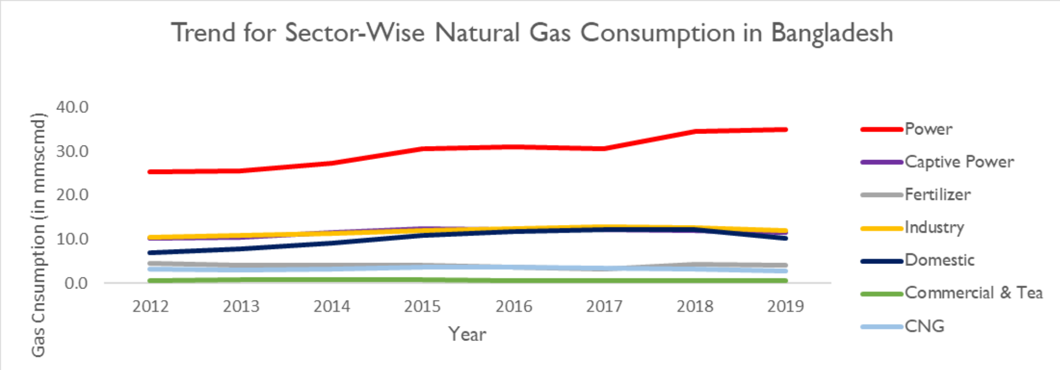


Figure 69 Trend of natural gas consumption, by sector, in Bangladesh (in mmscmd)

[206] *Bangladesh Energy Scenario Report, 2019-20 by Hydrocarbon Unit*



4.5.2 Key drivers for demand

Natural gas demand is expected to increase from most sectors, driven by the following factors:

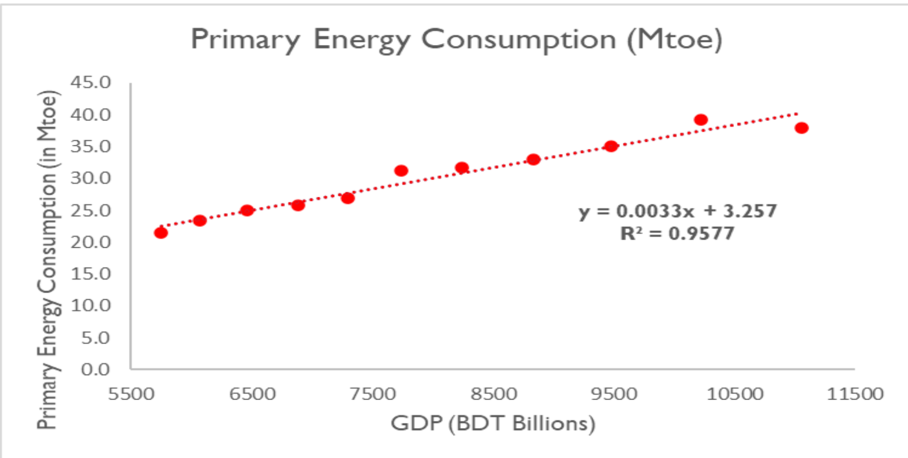
1. The major demand driver in Bangladesh will be the government's "electricity for all" mission that aims to electrify 100 percent of the country in the future. Hence, the power sector will be one of the major demand drivers for natural gas in the country.
2. The government of Bangladesh aims to achieve the status of a middle-income country by 2021[207] and a high-income country by 2041; This means that the government's policy initiatives will focus on things such as consistent economic growth, poverty eradication, infrastructure development, and energy security. Natural gas will play a significant role in economic growth activities, infrastructure development, and energy security. In addition, there has been a revision of PSMP (Power Sector Master Plan) 2016. According to this revision, the share of gas will be 40-45 percent in electricity generation.
3. Energy demand has also been fuelled by rapid urbanisation and social development in the country.
4. The current efficiency of natural gas use in fertiliser plants is pretty low compared with global benchmarks. This presents a potential for improvement in the sector if stakeholders involved take steps in the right direction to revamp fertiliser plants. The gas that can be saved after improving the plants' efficiency can be used in other sectors.
5. Many power plants that operate on alternative non-renewable energy sources (such as coal) are raising increasing concerns for environmental sustainability in the country. This can also give a push to gas-based power plants.

4.5.3 Top-down approach

To estimate natural gas demand, this approach draws a correlation between primary energy consumption and GDP in Bangladesh. After calculating primary energy consumption (based on assumptions and published reports by the government), the share of natural gas has been calculated in the primary energy mix.

After drawing in a correlation analysis between GDP and energy consumption data for Bangladesh, the following regression equation was obtained:

Figure 71 Chart showing GDP v/s Primary Energy Consumption for Bangladesh



[207] http://unohrlls.org/news/bangladesh-on-track-to-achieve-middle-income-status-by-2021/

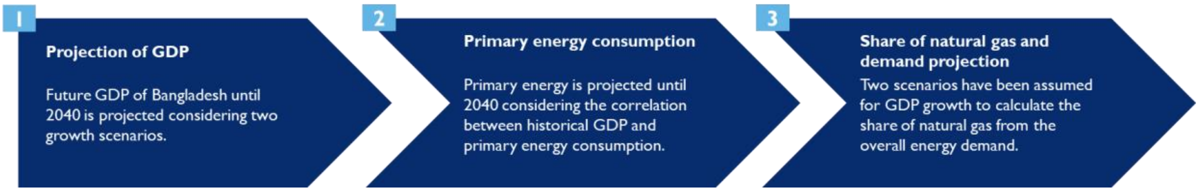
*Primary energy consumption (in Mtoe) = 3.257 + 0.0033*GDP (in billions of BDT)*

Historical GDP of Bangladesh from 2009 to 2019 by IMF has been used for this analysis. The GDP data for each year, along with growth rates, has been provided in Annexure 17.3.1. Primary energy consumption data for Bangladesh was taken from the BP Statistical Review. This model's R2 value came out as 0.957, implying that ~96 percent of the variation in primary energy consumption is being explained by GDP data.

Bangladesh has grown at a remarkable rate of 7.4 percent CAGR in the past five years (2014-2019). The country's economy has not contracted in FY 2021 despite the impact of COVID-19. Also, the growth rate of Bangladesh is expected to be sustained in the long term. Apart from that, the country has a huge potential to maintain its existing growth rate of GDP. Its growth story has been driven by three factors - exports, social-progress, and fiscal prudence. Between 2011 and 2019, Bangladesh's exports grew at 8.6 percent[208] every year compared with a global average of 0.4 percent. Government interventions have translated into improvements in children's health and education.

Therefore, for future projections of primary energy demand in Bangladesh, two scenarios were considered – a five-year CAGR of GDP between 2021 and 2026 and a seven-year CAGR of GDP between 2019 and 2026 considering that a high growth rate of GDP for the country would be sustainable in the future as well.

Figure 72 Methodology of the top-down approach to calculate natural gas demand in Bangladesh



<u>Detailed methodology</u>:

1. Step 1 – Projection of GDP of Bangladesh
    a. The historical GDP of Bangladesh from 2009 to 2019 was collated.
    b. GDP from 2020 to 2026 was sourced from IMF.
    c. Beyond 2026, two scenarios have been used to project GDP until 2040.
        i. The first scenario took a five-year CAGR between 2021 and 2026 and projected GDP numbers beyond 2026 at the calculated growth rate. Within this scenario, the GDP growth of Bangladesh has been considered ~7.3 percent.
        ii. The second scenario took a seven-year CAGR between 2019 and 2026 and projected GDP numbers beyond 2026 at the calculated growth rate. This was considered as the most plausible scenario. Within this scenario, Bangladesh's GDP growth has been considered at ~6.5 percent.
2. Step 2 – Projection of primary energy consumption
    a. Regression analysis of primary energy consumption with respect to historical GDP was conducted. A correlation of 96 percent was observed between primary energy and GDP that can be considered an excellent statistical fit.
    b. Using the correlation between GDP and primary energy and future GDP projections, primary energy consumption was projected until 2040, considering the two scenarios of GDP growth in Bangladesh.
3. Step 3 – Projection of natural gas demand
    a. The government of Bangladesh has projected a share of ~38 percent of natural gas in the country's primary energy mix by 2040, according to the Power and Energy Sector Master Plan, 2016.[209]
    b. Current share of natural gas consumption in Bangladesh for 2019 was estimated at ~63 percent.[210]
    c. Natural gas share has been declined linearly to obtain a 38 percent share over a period of over 2020–2040.

[208] *https://www.bloombergquint.com/economy-finance/economic-survey-2021-why-bangladesh-has-beat-india-in-export-growth*
[209] *https://openjicareport.jica.go.jp/pdf/12269742.pdf (Page 1-29)*
[210] *HCU Energy Consumption Report*

d. The decrease in natural gas share can be attributed to the following reasons:
   i. Decline in domestic gas production and an increased dependency on gas import
   ii. Pursuit of alternative energy sources, such as coal, to achieve an optimal energy mix

Analysis

Gas demand under various scenarios was projected to increase from 126.4 mmscmd in 2030 to 190.8 mmscmd in 2040 in the first scenario and from 122.6 mmscmd in 2030 to 171.4 mmscmd in 2040 in the second scenario. The base case scenario – 2 that assumed an annual increase of ~6.5 percent in GDP from 2026 onwards and considered a seven-year CAGR of GDP growth between 2019 to 2026, seems the most plausible one.

Table 81 Summary of natural gas demand scenarios in Bangladesh using the top-down approach

Scenario	Gas demand (mmscmd)				Remarks
	2025	2030	2035	2040	
Scenario - 1	101.2	126.4	156.5	190.8	49.9 percent share of natural gas by 2030 and GDP projected on the basis of a five-year CAGR between 2021 and 2026
Scenario – 2 (most plausible scenario)	101.2	122.6	146.1	171.4	49.9 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR between 2019 and 2016 (most plausible scenario)

4.5.4 Bottom-up approach

4.5.4.1 Fertiliser sector

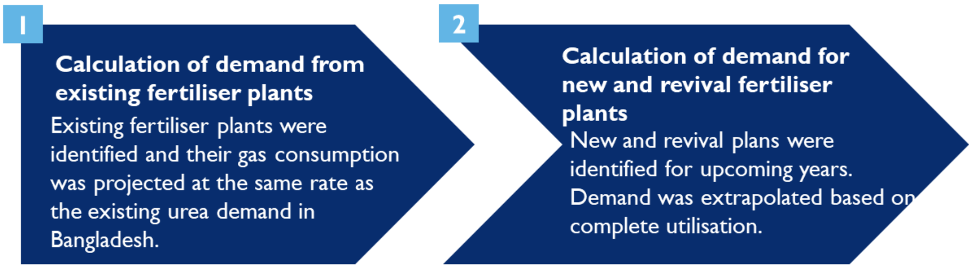
The fertiliser sector accounts for ~6 percent of the natural gas consumption in Bangladesh in 2020-21. At present, Bangladesh has five existing fertiliser plants that manufacture urea. Chittagong Urea Fertiliser Limited (CUFL) was on a temporary shutdown, but has resumed operations from September 2020.[211]Moreover, one more gas-based fertiliser plant, Ghorashal Polash, will come up in Bangladesh and start operations in 2023. Utilisation of fertiliser plants is expected to increase in the future considering that the government of Bangladesh plans to undertake the necessary steps to enable these plants to function on full capacity on account of increasing urea demand in the country. The following table shows a list of current and upcoming fertiliser plants in the country.[212]

Table 82 Current and upcoming fertiliser plants in Bangladesh

Fertiliser plant	Location	Status	Capacity (TMT)
JFCL – Jamuna Fertiliser Company Limited	Jamuna	Existing	561
AFCL – Ashuganj Fertiliser Company Limited	Ashuganj	Existing	528
KAFCO – Karnaphuli Fertiliser Company Limited	Karnaphulli	Existing	570
SFCL – Shahjalal Fertiliser Company Limited	Shahjalal	Existing	580
CUFL – Chittagong Urea Fertilisers Limited	Chittagong	Temporary shutdown	561
GPUFP – Ghorashal Polash Urea Fertiliser Project	Ghorashal Polash	2023	900

211 https://www.tbsnews.net/bangladesh/urea-production-resumes-cufl-127279
212 Petrobangla Daily Gas Report

Figure 73 Methodology for projecting natural gas demand from the fertiliser sector in Bangladesh



<u>Detailed methodology</u>

1. Step 1 – Demand estimation for existing fertiliser plants
    a. Existing fertiliser plants' current gas consumption was calculated using secondary data shared in Petrobangla's daily gas report.
    b. Due to the increasing demand for urea fertilisers in Bangladesh, gas consumption of these existing plants was projected at the same rate as the current utilisation of urea production plants.
2. Step 2 - Demand estimation from new and revival fertiliser plants
    a. Based on Bangladesh Gas Master Plan 2017, the standard gas consumption of new fertiliser plants and those that were on a temporary shutdown was identified. The starting year for gas consumption was based on the completion of the gas pipeline for these plants.
    b. The values were extrapolated for the future considering these plants were working at full capacity.

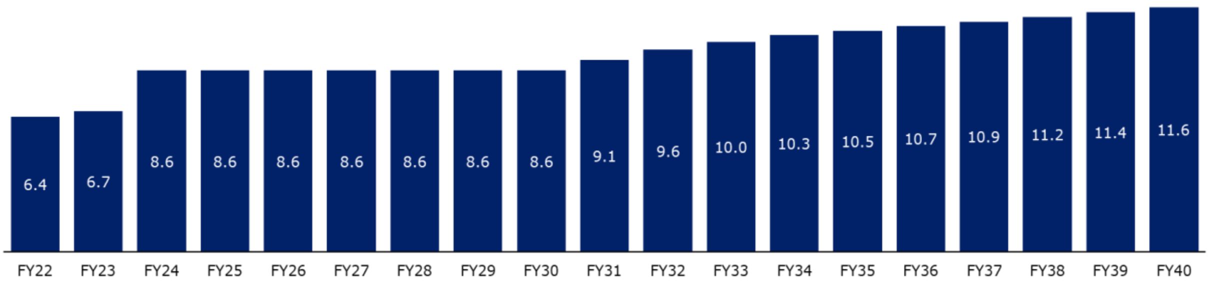
<u>Assumptions</u>

1. Existing and upcoming fertiliser plants using natural gas as feedstock have been considered to assess gas demand. Plants that use alternative fuels such as coal have not been considered for estimating natural gas demand.
2. Connectivity to a gas pipeline for upcoming fertiliser plants has been assessed. For plants that are not yet connected to a gas pipeline, the year of completion of natural gas pipeline has been considered based on announcements in the public domain. Natural gas consumption for these plants was consequently commenced from the respective year.
3. For gas demand from FY 2031 to FY 2040, CAGR for demand from FY 2021 to FY 2030 was calculated. This demand was gradually reduced after FY 2030, subject to a floor of ~2 percent as the visibility for future plant additions and expansions is limited after 10 years.
4. Fertiliser plants have been expected to fulfil gas demand and reach full utilisation. The government has been making necessary machine repairs and providing full capacity to meet urea demand in the country.

<u>Analysis</u>

Fertiliser plants' capacity is expected to reach 3.7 MMTPA by FY 2030. Natural gas demand from gas-based fertiliser plants is expected to increase from 6.4 mmscmd in FY 2022 to 11.6 mmscmd in FY 2040.

Figure 74 Projected natural gas demand from the fertiliser sector in Bangladesh (in mmscmd)

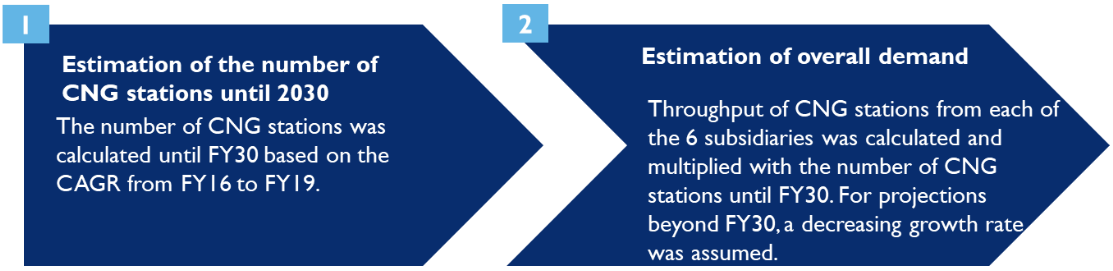


4.5.4.2 CGD sector

CNG demand estimation

CNG constituted about ~3.5 percent of the total gas demand in Bangladesh for 2020-21. The country has close to 600 CNG filling stations and about half million vehicles that run on CNG. Due to gas shortage, the government had compelled people to use less CNG. However, according to a report by IRADe and an analysis by ExxonMobil, the CAGR of natural gas demand from the CNG sector will be ~4.5 percent. One of the key enablers for this growth will be the increasing LNG supply through imports and switching of gas-intensive sectors to alternative fuels. This can spare more natural gas for the CNG sector. Moreover, import-related constraints with respect to the pipeline infrastructure have been addressed. However, CNG is also one of the least priority sectors for natural gas allocation in Bangladesh. Many times, supply to the sector is burdened to service demand from other sectors in the country. Therefore, the possibility of a slowdown in gas demand from this sector cannot be ruled out, because of the increasing gas demand from other sectors.

Figure 75 Methodology for natural gas demand estimation from CNG in Bangladesh



Detailed methodology

1. Step – 1: Estimation of the number of CNG stations until 2030
    a. For the existing CNG stations, six gas distribution companies of Petrobangla provide the number of CNG stations currently set up across Bangladesh by each subsidiary. The number was found out through secondary research.
    b. Upcoming CNG stations were projected at a same rate as a historical five-year CAGR from FY 2015-19. They were distributed across six subsidiaries in the same proportion as FY 2019. For these companies, growth in the number of CNG stations has been assumed on account of improving LNG import infrastructure in the country.
2. Step – 2: Estimation of demand and consideration of scenarios
    a. Throughput of each of these six subsidiaries was calculated from FY 2015-19. It did not tend to show a significant increase because of the government's push towards alternative sources of transport fuels due to supply constraints for natural gas.
    b. After the calculation of the throughput, two scenarios were considered:
        i. Scenario – 1 (base case and most plausible scenario): Within this scenario, demand is expected to increase from the CNG sector over the years. The throughput was multiplied with the number of CNG stations to arrive at total CNG demand until FY 2030. This scenario assumes that the average throughput of CNG stations will remain

constant. Within this scenario, the growth rate (CAGR) for demand from FY 2026-2030 was used for the purpose of projecting further domestic demand after FY 2030. This came out as ~3 percent (for the analysis, a more conservative figure had been used than the one that had been projected by ExxonMobil).

ii. Scenario – 2 (constrained demand scenario): This scenario assumes that CNG stations will face supply shortage in the future due to priority gas allocation for other sectors. Within this scenario, the throughput of CNG stations had been assumed to decrease due to constrained supplies that would affect overall demand. The decreasing throughput was multiplied with the number of CNG stations to arrive at total CNG demand until FY 2040.

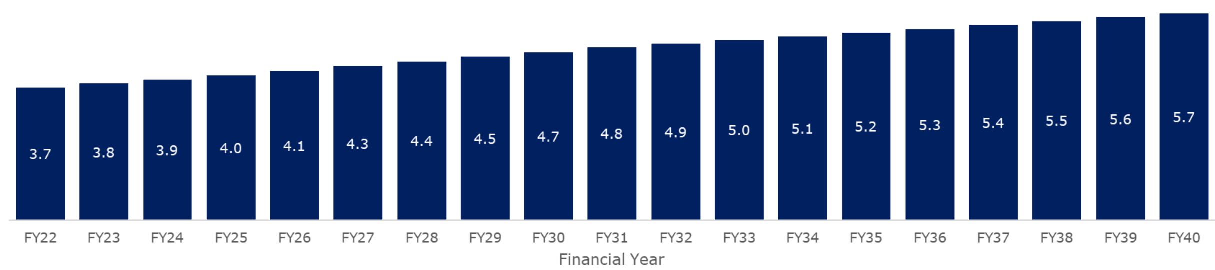
Assumptions

1. The throughput of each of these six subsidiaries is higher than the average throughput of a typical CNG station of 70.2 TMSCM/month (650 SCMH for 12 hours at 30 percent utilisation). Hence, the same throughput was assumed for a period from FY 2021 to FY 2040 for the respective subsidiaries within the first scenario.
2. In the first scenario, the demand from FY 2031-40 was projected at a reducing growth rate due to limited visibility beyond 2030. The CAGR of FY 2026-30 was reduced by 1 percent year-on-year beyond FY 2030 with a minimum cap of 2 percent.
3. In the second scenario, the throughput of CNG stations was assumed to decrease by 5 percent year-on-year.

Analysis

Demand for natural gas from the CNG sector is expected to reach from 3.7 mmscmd in FY 2022 to 4.7 mmscmd in FY 2030, and 5.7 mmscmd in FY 2040 in the first (most plausible) scenario based on the above analysis. In the second pessimistic scenario, demand from the CNG sector is expected to decrease from 3.2 mmscmd in FY 2022 to 2.7 mmscmd in FY 2030, and 2.1 mmscmd in FY 2040.

Figure 76 Projected natural gas demand in Bangladesh from the CNG sector within most plausible scenario (in mmscmd)



Industrial demand estimation

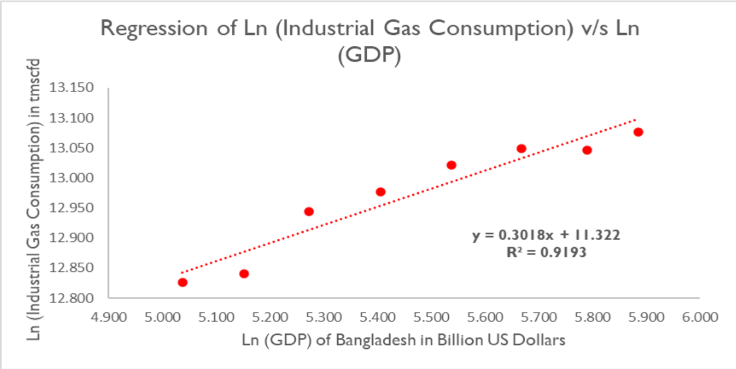
The industrial sector is again a major contributor to natural gas demand in Bangladesh. According to the latest data, the sector constituted ~18 percent demand in Bangladesh. To calculate industrial demand for natural gas, the past demand for natural gas from industrial sector has been taken to build a regression model using GDP. The model has been built considering the fact that with an increase in GDP, economic activity for the industrial sector will have a significant increase because of which natural gas demand will rise from the sector.

Detailed methodology

1. Step – 1: Secondary research for historical gas consumption and GDP
    a. Historical industrial gas consumption from FY 2013 to FY 2020 was identified for Bangladesh using secondary research.
    b. Historical GDP of Bangladesh (at current prices) was identified from FY 2013 to FY 2020 using the IMF data.
2. Step – 2: Overall demand estimation

a. Historical industrial gas consumption in tmscfd (as Ln) was plotted against historical GDP (as Ln). The following equation was obtained for regression between both the variables:

Figure 77 Regression of industrial gas demand versus GDP of Bangladesh



*Ln (industrial gas consumption) = 0.3018*Ln (GDP) + 11.32*

b. A correlation of 91.93 percent existed between the two variables implying that ~92 percent of the variance in industrial gas demand could be explained by GDP.

c. Gas demand was projected according to the following three different scenarios:

   i. Scenario – 1 (constrained demand scenario): GDP in Bangladesh was expected to grow at its seven-year CAGR in the future from 2019−2026 based on IMF projections of GDP data. Demand for natural gas from the industrial sector was calculated on the basis of the values of GDP using the regression equation.

   ii. Scenario – 2 (most plausible scenario): Based on the gas master plan, the industrial sector is expected to witness a higher growth on account of various factors, such as a rise in textile industries and the government's seventh five-year plan. As a result, to take into account the increased gas demand from higher growth in the industrial sector, the slope of correlation between both the variables gradually increased from 0.3 in FY 2022 to 0.42 in FY 2030. The gradually increasing slope was used to calculate demand with a seven-year CAGR for growth in GDP. In this scenario, industrial gas demand between FY 2026 and FY 2030 was estimated to increase at ~11.5 percent. This growth rate was extrapolated with a reducing trend from FY 2031 to calculate demand after FY 2030.

   iii. Scenario – 3: Within this scenario, from FY 2022 – FY 2030, industrial gas demand was calculated at an increasing slope from 0.3-0.42 similar to Scenario - 2. However, the slope of the regression equation was kept constant at 0.42 from FY 2030 onwards and consequently demand was calculated until FY 2040 with a seven-year CAGR for growth in GDP using the equation.

<u>Assumptions</u>

1. Within scenario 2, growth rate has been taken with a reducing trend after FY 2030 because the visibility of growth data beyond that year is limited.

<u>Analysis</u>

Within scenario 1, growth is the lowest with a constant slope and reaches up to 20.1 mmscmd in FY 2040. Considering scenario 2 as the most likely scenario, gas demand from the industrial sector is expected to increase from 15.3 mmscmd in FY 2022 to more than 70 mmscmd in FY 2040 considering that there is going to be growth in demand after FY 2030 as well. However, it would gradually slow down. Within scenario 3, the increasing slope has been taken as constant after FY 2030. After using a constant slope of 0.42 post FY 2030, the demand comes out as 46.9 mmscmd.

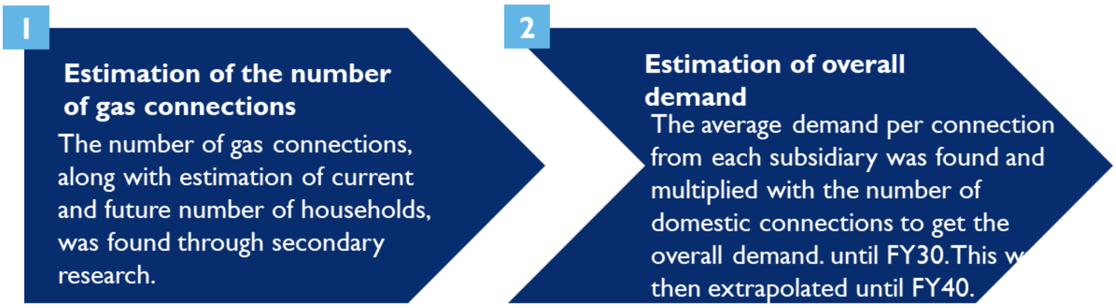
Table 83 Different scenarios for industrial CGD demand in Bangladesh

Scenario	Gas demand (mmscmd)		Remarks
	2030	2040	
Scenario - I	16.6	20.1	GDP has been projected on the basis of a seven-year CAGR between 2021 and 2026
Scenario – 2 (most plausible scenario)	36	70.7	GDP has been projected on the basis of a seven-year CAGR with an increasing slope until FY30; after post FY30, demand is expected to grow at a reducing CAGR (most plausible scenario)
Scenario – 3	36	46.9	GDP has been projected on the basis of a seven-year CAGR with an increasing slope until FY30; after FY30, the slope remains constant

Domestic demand estimation

Six gas distribution subsidiaries of Petrobangla – TGTDCL, BGDCL, JGTDSL, PGCL, KGDCL, and SGCL – cater to domestic demand in Bangladesh. Currently, the majority of domestic gas is being supplied by these companies on a fixed fee monthly basis. For demand estimation from the domestic sector, the increase in the number of households in the next few years, along with consumption per household, has been estimated.

Figure 78 Methodology to estimate natural gas demand from the domestic sector in Bangladesh



Detailed methodology

1. Step – 1: Estimation of the number of domestic connections
    a. Existing domestic connections have been considered for demand estimation (they were researched from annual reports of each of the six gas distribution subsidiaries of Petrobangla).
    b. Total current and future households in Bangladesh were identified through data provided by the Ministry of Planning, Bangladesh.
    c. Percentage of households covered under PNG was calculated using projection of growth rate.
2. Step – 2: Estimation of overall demand
    a. Average consumption per household had been assumed based on average household consumption calculated for each gas distribution subsidiary of Petrobangla.
    b. This was multiplied with the projection for domestic connections to get the overall demand from the domestic sector until FY 2030.
    c. For demand calculation after FY 2030, the data was extrapolated based on overall CAGR of gas demand from FY 2026-30.

Assumptions

1. The increase in households covered under PNG in Bangladesh was assumed to be constant based on Gas Sector Master Plan, 2017, on the account of the following reasons:

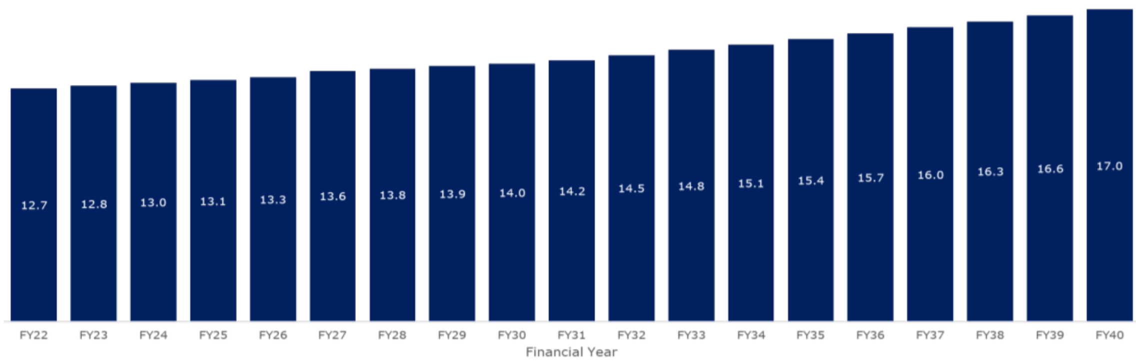
a. The government's initiatives to cap gas supply to users and promote LPG to control wasteful use of gas by users as they are charged on a fixed monthly basis.
b. Difficulties and economical inefficiency to make new connections in suburban areas of Bangladesh.

2. For demand projection from FY 2031-40, growth rate for domestic demand was reduced by 1 percent year-on-year from the CAGR of FY 2026-30, with a minimum growth rate cap of 2 percent because there is limited visibility of demand after 2030.

Analysis

Natural gas demand from the domestic sector in Bangladesh is expected to increase from 12.7 mmscmd in FY 2022 to 17 mmscmd in FY 2040.

Figure 79 Projected natural gas demand from the domestic sector in Bangladesh (in mmscmd)

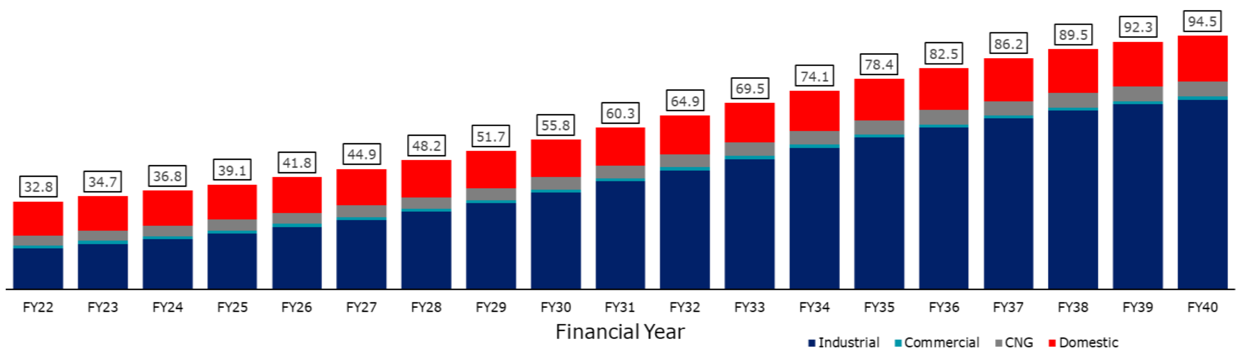


Aggregated demand

Total gas demand from the CGD sector is expected to increase from 32.8 mmscmd in FY 2022 to 94.5 mmscmd in FY 2040. A comparison by segment shows that:

- Almost 50 percent of the CGD demand comes from the industrial segment. Various industries, such as cement, ceramics, and steel, use natural gas for their operations. This sector contributes about 47 percent to the total CGD consumption.
- The industrial sector is followed by the domestic segment (39 percent).
- The remaining 15 percent of the CGD gas is consumed by the CNG and commercial segment.

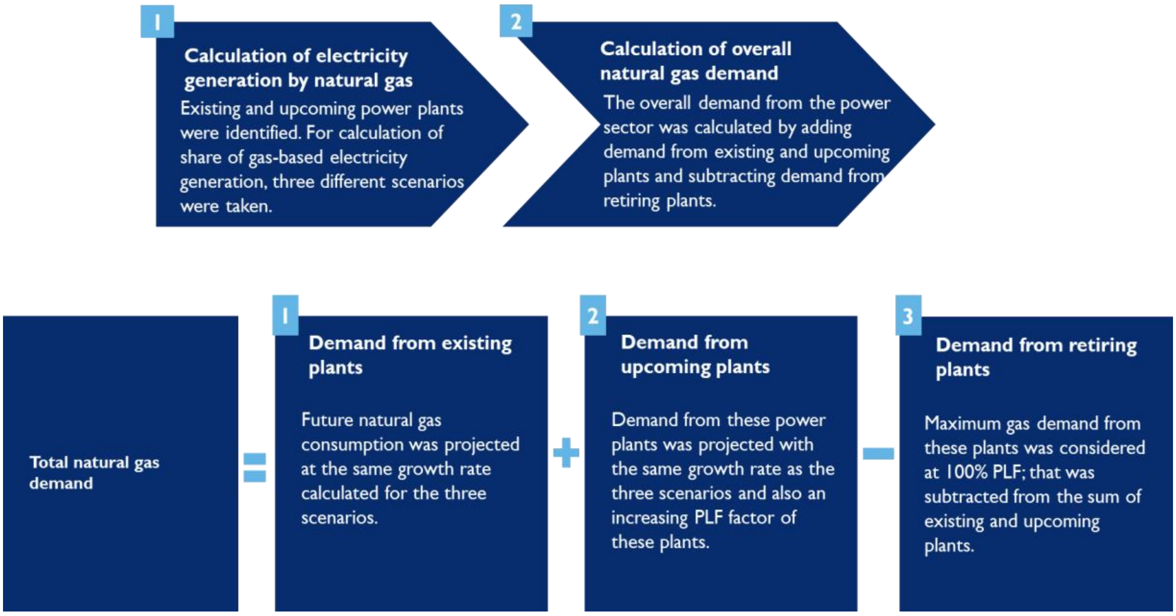
Figure 80 Projected natural gas demand in Bangladesh from the CGD sector considering most plausible scenarios (in mmscmd)



4.5.4.3 Power sector

The power sector accounted for the maximum proportion of gas consumption (~59 percent in 2020-21 that consisted of both utilities and captive power) in Bangladesh. The domestic sector is the largest power consumer in the country. Gross power demand increased from 37,441 MU in FY 2013 to 64,990 MU in FY 2018 at a CAGR of ~11.7 percent.[213] Moreover, the government of Bangladesh has been taking various steps to make electricity accessible for a larger population of Bangladesh. For FY 2020, according to the BPDB annual report, 70 percent of the overall power generation in Bangladesh was through natural gas. More than 72 percent of the rural areas in Bangladesh have already been added to the electricity grid through government initiatives. The power demand will continue to show strong growth in the future as government initiatives intend to electrify 100 percent of the country under the 'electricity for all' vision. The detailed list of power plants in Bangladesh, along with their capacity and maximum demand, is provided in Annexure 17.3.2.

Figure 81 Methodology for projecting natural gas demand from the power sector



<u>Detailed methodology</u>

1. Step – 1: Calculation of electricity generation by natural gas
    a. For finding out the total electricity demand generation, the list of existing and new upcoming power plants, along with their installed capacity, was identified in Bangladesh. The overall electricity generation according to Bangladesh Power Development Board in FY 2020 was ~71400 MU. The overall electricity generation from FY 2022 to FY 2040 was projected according to three cases:
        i. Case – 1 SAARC Energy Outlook (most plausible case): According to this report, the growth in the annual electricity generation in Bangladesh was ~9 percent from FY 2013 to FY 2017. A growth rate of 9 percent was used to project the total electricity generation up to FY 2030 starting from FY 2020. From FY 2030 onwards, the growth rate slowed down to 6 percent considering limited visibility after that year.
        ii. Case – 2 Modified PSMP: According to modified PSMP, the overall generation is expected to reach up to ~270 TWh by FY 2040. This accounts for a CAGR of ~6.9 percent that was used to project electricity generation up to FY 2040.
        iii. Case – 3 High GDP growth: This case has been considered according to GSMP 2016. Within this case, GDP growth rate in Bangladesh was considered ~8 percent and consequently, the total electricity generation was expected to reach up to ~352 TWh by FY 2040. This accounts for a CAGR of ~8.3 percent that was used to project electricity generation up to FY 2040.
    b. The SAARC Energy Outlook was taken as the most plausible case because the actual electricity generation had been on the lower side compared with what had been projected under the other two cases in GSMP 2016. To calculate the share of electricity that would be generated using natural gas, three possible scenarios were considered for the given case:

[213] *SAARC Energy Outlook 2030 Report*

i. Scenario 1 (constrained demand scenario) - It is assumed that Bangladesh is expected to pursue alternative energy sources, such as coal. In this scenario, share of gas-based power generation in the total generation decreases from 70 percent in FY 2020 to 20 percent in FY 2040.
ii. Scenario 2 (most plausible scenario) – Share of gas-based power generation in total generation decreases gradually from 70 percent in FY 2020 to 45 percent in FY 2040 assuming a gradual shift to alternative fuels considering the fact that import dependency for natural gas in Bangladesh will increase in the next few years. This scenario had been considered on the basis of the revised PSMP 2016 (Power Sector Master Plan, 2016) report.
iii. Scenario 3 – Share of gas-based power generation in total generation remains constant at 70 percent from FY 2020 through FY 2040, assuming no change in fuel mix.

c. The detailed list of three scenarios has been provided in Annexure 17.3.2. Scenario 2 has been considered as the most plausible scenario considering a potential increase in LNG prices in Bangladesh (due to increased import dependency).

2. Step – 2: Calculation of natural gas demand
   a. For the existing gas-based power plants
      i. Petrobangla's daily gas report provides current as well as maximum natural gas consumed by each power plant on a daily basis. These data points were found out through secondary research.
      ii. For the existing plants, future natural gas consumption was projected at the same year-on-year growth rate as the change in gas-based power generation was based on the three scenarios mentioned above.
   b. For the upcoming gas-based power plants
      i. Through secondary research done from BPDB (Bangladesh Power Development Board), the list of new upcoming plants, along with their capacity, in the next few years was identified.
      ii. Demand from these new gas-based power plants was calculated using an increasing PLF rate for the next few years by multiplying with gas consumption per MW of power generation.
   c. For retired gas-based power plants
      i. Through secondary research done from Bangladesh Power Development Board, the list of retiring gas-based power plants, along with the total capacity that would not be available, was found out; these plants would be non-operational in the next few years.
      ii. Maximum gas demand from these plants at 100 percent PLF was calculated through the installed capacity of these plants and gas consumption per MW.
      iii. This gas demand was reduced from the projected gas demand.

<u>Assumptions</u>

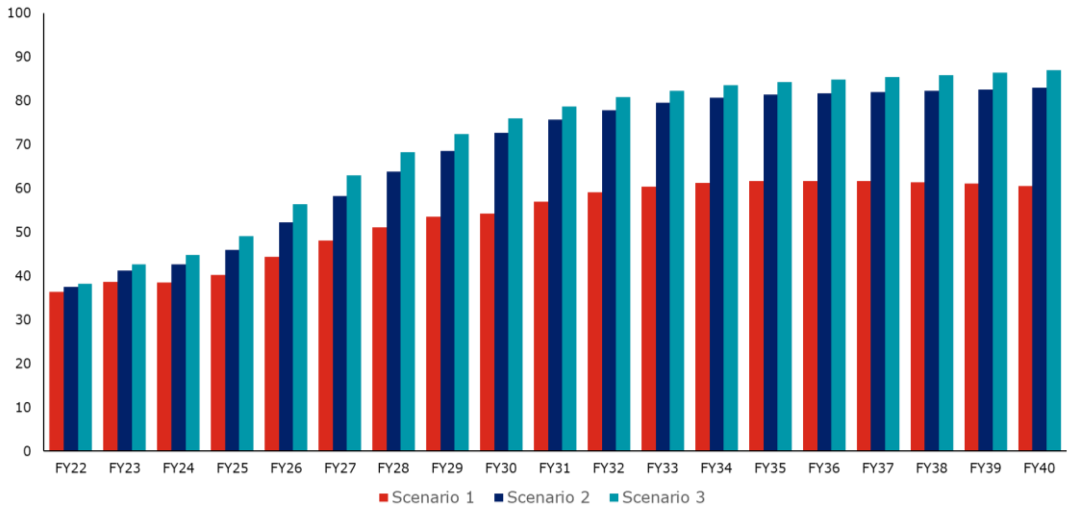
1. While the daily gas consumption remained largely same throughout the year (with minor seasonal variations), a few gas power plants received gas interchangeably. As a result, if a particular gas plant had no current gas consumption, it has been projected through a gradual increase in PLF starting from ~10 percent and average gas consumption of 0.0045 mmscmd for 1 MW power generation. Consumption of the existing plants was capped to increase up to 50 percent beyond their maximum gas demand.
2. For new gas power plants, gas demand has been projected through an increase in PLF from ~10 percent to up to 80 percent and an average gas consumption of 0.0045 mmscmd for 1 MW power generation. This has been done due to increased power demand, along with higher efficiency and lower heat rates of gas-based power plants, in the next few years.

<u>Analysis</u>

- The SAARC Energy Outlook was taken as the most plausible case for the growth rate of the total electricity generation. Within that case, the total natural gas demand from the power sector lies in the range of 61– 87 mmscmd by FY 2040. For generation according to modified PSMP, gas demand from power plants lies in the range of 55–85 mmscmd by FY 2040. For electricity generation according to a high GDP growth rate, demand lies in the range of 62–88 mmscmd by FY 2040.

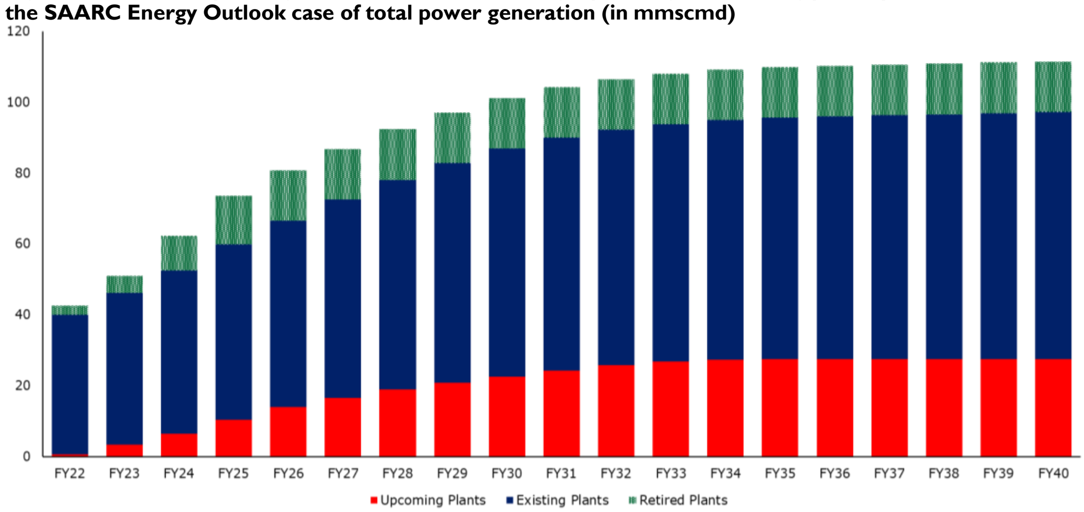
- Within the most plausible case of the total power generation, in scenario 1 where Bangladesh is expected to pursue other alternative sources of power generation significantly, gas demand from the power sector increases from ~38 mmscmd in FY 2022 to about 61 mmscmd by FY 2040. In scenario 2 where shift to other electricity sources, such as coal or renewable energy, is expected to be gradual, gas demand is expected to increase to about 83 mmscmd by FY 2040. In scenario 3 where a share of gas-based power generation remains constant, gas demand is expected to increase up to 87 mmscmd by FY 2040.

Figure 82 Projected demand for natural gas from the power sector for different scenarios in the SAARC Energy Outlook case (most plausible case) of total power generation (in mmscmd)



- Scenario 2 has been assumed to be the most plausible one considering the current demand situation.
- Within scenario 2, total gas-based power generation, capacity of more than 7500 MW is expected to be added in the next five years. Demand from upcoming gas-based power plants is expected to reach ~28 mmscmd by FY 2040.
- Amongst the existing gas-based power plants, gas demand is expected to reach up to 70 mmscmd by FY 2040. However, considering retirement of old gas power plants, demand is expected to be decreased to ~56 mmscmd.

Figure 83 Gas-based power generation from the existing, upcoming, and retiring power plants based on Scenario-2 within the SAARC Energy Outlook case of total power generation (in mmscmd)



Captive power plants

According to the Gas Master Plan 2017, industries using captive power plants shall gradually shift to grid power as the latter becomes available in the future. This is expected to reduce gas demand from captive power plants. Consequently, projections for gas demand from captive power plants have been carried out according to the EMRD report on gas production, distribution, and consumption for FY 2019-20. Within FY 2019, natural gas demand from the captive power plants was ~480 mmscfd. This demand is expected to decrease in the future up to ~186 mmscfd in FY 2030 as Bangladesh becomes more dependent on imports for its natural gas demand and different industries gradually start shifting towards the alternative sources.[214]After FY 2030, we have assumed demand from captive power plants to be constant for the analysis as a minimum number of industries will still be dependent on captive power.

4.5.5 Total demand projection until 2040

The overall demand projection until FY 2030 is for 142.2 mmscmd and until FY 2040 is for 194.2 mmscmd. Here, within this table, demand from the commercial sector has also been considered and assumed to be constant based on the Energy Scenario of Bangladesh report (2019-20).

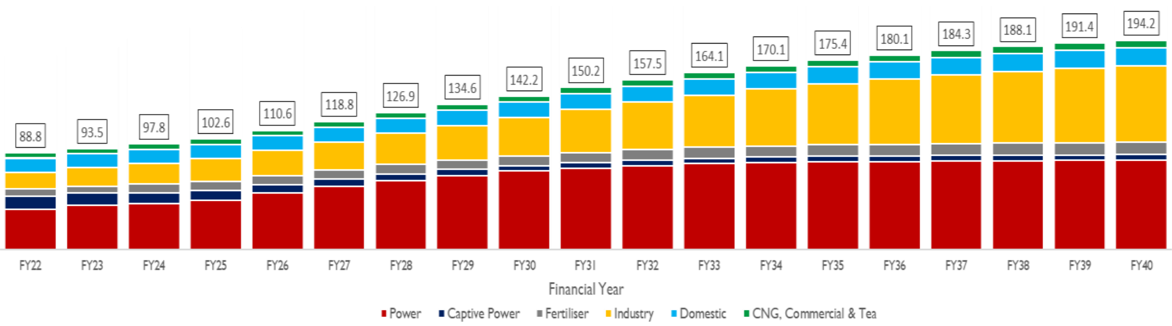
Table 84 Overall projected natural gas demand in Bangladesh from FY 2022 to FY 2030 for most plausible scenarios (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	37.5	41.2	42.6	46	52.2	58.2	63.8	68.5	72.6
Captive power	12.1	10.9	9.8	8.8	7.9	7.1	6.4	5.8	5.2
Fertiliser	6.4	6.7	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Industry	15.3	17.0	18.8	20.9	23.3	25.9	28.9	32.2	36.0
Domestic	12.7	12.8	13.0	13.1	13.3	13.6	13.8	13.9	14.0
Commercial and tea	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
CNG	3.7	3.8	3.9	4.0	4.1	4.3	4.4	4.5	4.7
Total	**88.8**	**93.5**	**97.8**	**102.6**	**110.6**	**118.8**	**126.9**	**134.6**	**142.2**

Table 85 Overall natural gas demand in Bangladesh from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	75.6	77.9	79.5	80.6	81.3	81.7	82.0	82.3	82.6	82.9
Captive power	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Fertiliser	9.1	9.6	10.0	10.3	10.5	10.7	10.9	11.2	11.4	11.6
Industry	40.2	44.4	48.6	52.8	56.7	60.4	63.7	66.6	69.0	70.7
Domestic	14.2	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.6	17.0
Commercial and tea	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
CNG	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7
Total	**150.2**	**157.5**	**164.1**	**170.1**	**175.4**	**180.1**	**184.3**	**188.1**	**191.4**	**194.2**

Figure 84 Projections of sector-wise demand in Bangladesh for most plausible scenarios (in mmscmd)



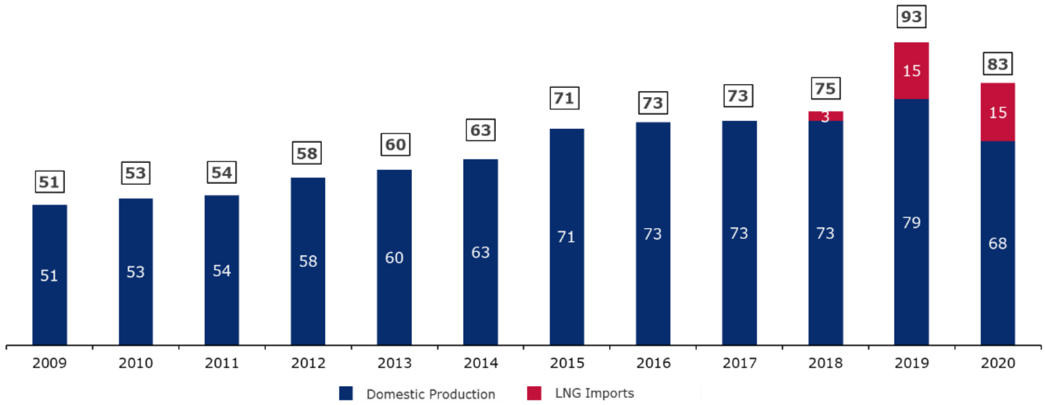
4.6 Supply analysis

[214] *Source: Energy Scenario of Bangladesh, 2019-20 by Hydrocarbon Unit*

4.6.1 Existing domestic production

At present, Bangladesh has domestic reserves of 0.11 trillion cubic meters. The gas fields in the country are primarily located in the north-eastern Sylhet, Chittagong, and Dhaka divisions; a dozen offshore blocks are located in the Bay of Bengal.[215]Of the 27 fields, only two fields are located offshore. With a 63 percent share of natural gas in the primary energy consumption basket, Bangladesh is a gas-intensive economy. Production in Bangladesh has steadily increased over the years; however, it is faced with rapidly dwindling reserves. Bangladesh, once self-sufficient in natural gas, began importing LNG in 2018. Petrobangla and Chevron are the major producers of natural gas with the later accounting for 55 percent of domestic gas produced in the country.

Figure 85 Trend of natural gas production and LNG imports in Bangladesh (in mmscmd)



4.6.2 Existing supply through imports

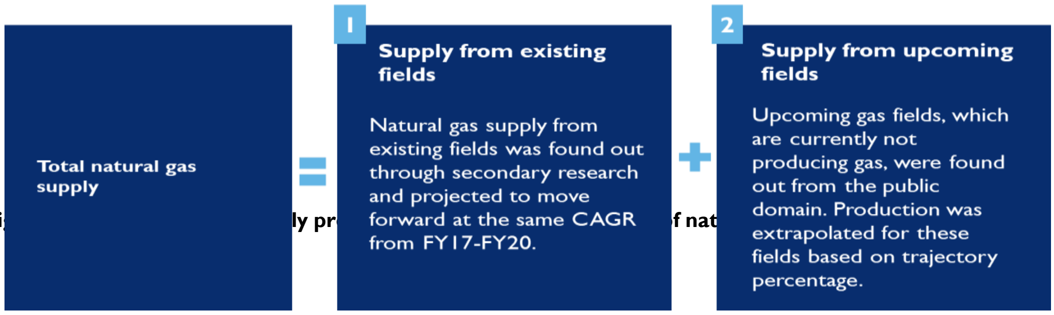
Bangladesh has been one of the fastest-growing LNG import markets as the country began to import LNG in 2018. Several dual-fuel power plants in the country with a total electricity generation capacity of about 650 MW, which had been running on gasoil, have recently been converted to gas-fired ones. This resulted in the need for increased LNG imports.[216] Moreover, imports might be needed for new gas-powered and fertiliser plants that are coming up in the future.

In FY 2021, Bangladesh imported ~20 percent of its natural gas to meet domestic demand. This import volume will gradually increase in the upcoming future due to the mounting demand from various sectors, including industries, power plants, and fertiliser plants as domestic gas reserves are depleting fast.

4.6.3 Upcoming expansion

4.6.3.1 Supply projection for domestic production

The supply projection from domestic production was based on six major gas producing companies in the upstream sector – BAPEX, BGFCL, SGFL, Chevron, Tullow, and Santos. For FY 2019-20, according to the annual report on gas production, distribution, and consumption, only five of these companies produced gases from the existing gas fields except Santos. Hence, operations of Santos have been considered to be suspended for the current time and the upcoming years as well.[217]The CAGR of production has reduced for these companies the



215 *Source: Present status of Bangladesh gas fields and future development: A review - https://rb.gy/y5cevd*
216 *Source: https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/012221-bangladesh-aiming-to-boost-lng-imports-by-a-third-in-2021-via-spot-purchases-official*
217 *Source: Annual Report on Gas Production, Distribution and Consumption 2019-20*

previous years; this can be attributed to the declining gas reserves in Bangladesh. The supplies from existing fields in Bangladesh are also declining at a fast pace. According to the Energy Scenario Report of Bangladesh, as of June 2020, Bangladesh had ~12.26 tcf remaining reserves for proven + probable (2P) resources. Production from domestic gas fields started declining from 2016-17 onwards; this can be verified from supply trends as well. The data of remaining reserves, by field, according to the Petrobangla annual report has been mentioned in Annexure 17.3.3.

Detailed methodology

1. Step – 1: Gas production from domestic fields
    a. Gas production from existing domestic gas fields of BAPEX, BGFCL, SGFL, and other private companies was identified through the annual gas production, distribution, and consumption report 2019-20 by Energy and Mineral Resources Division (EMRD), Ministry of Power, Energy and Mineral Resources.
    b. Gas supply was projected through FY 2022-2040 based on the historical and expected future decline in gas production based on the EMRD report and Petrobangla annual report 2019-20.
2. Step – 2: Gas production from upcoming gas fields
    a. Gas production from upcoming domestic gas fields has been projected based on information available in the public domain from the Petrobangla annual report and news articles. According to overall information, ~503.32 is the total 2P (proven + probable) capacity for the upcoming fields that are not producing gas currently. These include the Bhola North gas field and the recently discovered new gas field in the Sylhet region.[218]
    b. The pipeline that would supply gas from the field was identified. The supply from the Bhola North-1 gas field is expected to be there through Bhola Bharishal Gas Pipeline project that would get completed by 2025. Hence, supply from this field has been assumed to commence from FY 2026 onwards. For the newly discovered gas field in the Sylhet region, a pipeline already exist. Supply from that field has been assumed from FY 2023.
    c. Gas production from the fields was calculated based on the trajectory and percentage of the gas present in the gas field.
3. Step – 3: Consideration of scenarios: Three scenarios were considered for domestic production from the current and upcoming fields:
    a. CAGR (most plausible scenario): The CAGR scenario was based on the projection of historical decline percentage of domestic production in the future, along with the consideration of supply from two upcoming fields mentioned above. The actual decline in domestic production from 2018-19 to 2019-20 was observed to be around ~8%. However, this scenario has considered an average decline of ~3% in year-on-year production from the domestic fields since the workovers are being intensively pursued for augmenting the gas production from the existing wells. Along with that, some production may seep in from thin beds also.
    b. GSMP realistic scenario: This scenario was considered based on the Gas Sector Master Plan, 2017. The scenario considered domestic production projected in the plan according to the 3P (proven, probable, possible) production + 6.4 tcf yet-to-find resources.
    c. GSMP high-production scenario: This was another high-domestic production scenario considered in the Gas Sector Master Plan (according to Gustavson's report). The scenario considered domestic production as projected in the plan according to the 3P production + 34 tcf yet-to-find resources.

Assumptions

1. Gas production from the existing fields is expected to decline based on the availability of natural gas reserves in the country.
2. For the production from upcoming gas fields, natural gas production has been expected to first increase and then decrease as the overall capacity of the field is exhausted.

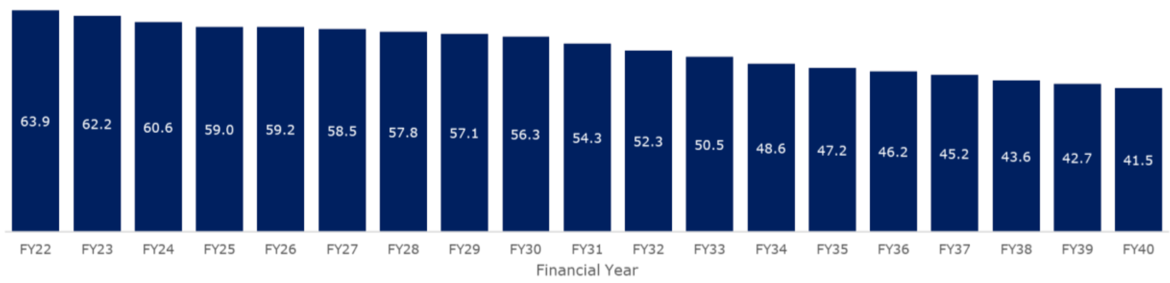
Analysis

The overall gas supply from the current and upcoming gas fields is expected to decline up to 56.3 mmscmd in FY 2030 and 41.5 mmscmd in FY 2040. Per the GSMP realistic scenario, gas supply in Bangladesh from domestic production is expected to decrease from 93 mmscmd in FY 2022 to 14 mmscmd in FY 2040. According to GSMP

[218] https://thefinancialexpress.com.bd/economy/bangladesh-announces-discovery-of-28th-gas-field-1628521212

high-production scenario, domestic gas production is expected to increase from 74 mmscmd in FY 2022 to 84.6 mmscmd in FY 2040 with supply peak coming as 136.8 mmscmd in FY 2032.

Figure 87 Projected natural gas supply in Bangladesh from domestic production per CAGR (most plausible) scenario (in mmscmd)



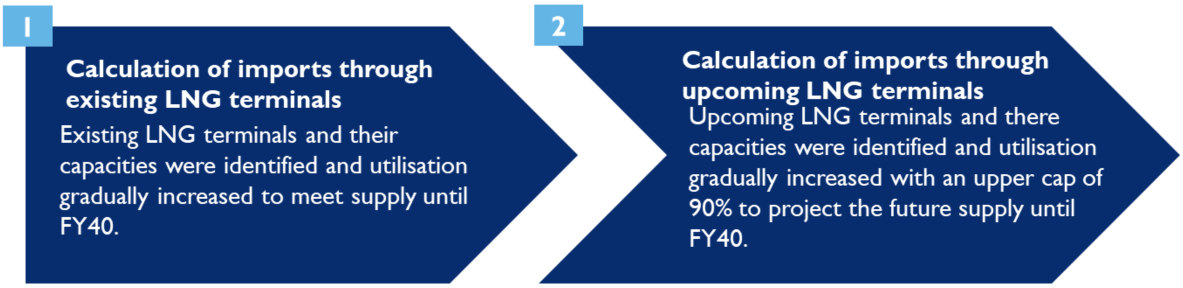
<u>Shale Gas Potential in Bangladesh</u>

According to Energy Scenario of Bangladesh report, Bangladesh is still in the process of exploration of different forms of energy like coal bed methane and shale gas. A preliminary study had been published by Hydrocarbons Unit Bangladesh on the potential of shale gas in the country. The study concluded that no valid shale gas resources exist in Bangladesh (Page 55 of the report). The shale resources might be present in certain sediments, but they are not commercially viable for extraction.[219]

4.6.3.2 Supply projection for imports

As natural gas supply from the existing fields shows a declining trend, imports are expected to take up their place to meet domestic demand for natural gas in Bangladesh. Initially both the existing LNG terminals faced delays in building pipeline infrastructure and were not operating at their full capacity. However, delays in laying down the pipelines for transporting gas from the existing terminals have been overcome.[220] Hence, these terminals can now operate at ~90 percent capacity. The overall supply from imports might depend on a mix of the spot and long-term contracts of the government to import LNG. However, as supply deficit will rise in the next few years with domestic production not being able to catch up, the utilisation of the LNG terminals would increase. The utilisation of the terminals has been ramped up with a conservative approach (keeping maximum cap of 90%) to calculate the total supply.

Figure 88 Methodology for supply projection from imports



<u>Detailed methodology</u>

1. Step – 1: Calculation of imports through existing LNG terminals
    a. The existing LNG terminals and their capacities were identified. At present, only two LNG terminals exist in Bangladesh – one is operated by Excelerate Energy and second is operated by Summit LNG.
    b. Historical utilisation of these terminals was also identified.

[219] *"Preliminary Study on Shale Gas Potentiality in Bangladesh", Hydrocarbons Unit, Bangladesh*
[220] *Source: https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/042820-bangladesh-overcomes-pipeline-hurdles-to-boost-lng-re-gasification-capacity*

   c. The utilisation of terminals gradually increased annually to project imports supply. The government of Bangladesh rectifies pipeline constraints associated with both these terminals. Hence, both the terminals are expected to operate at the maximum utilisation in the future.
2. Step – 2: Calculation of imports through upcoming LNG terminals
   a. Natural gas supply not served by any of the three previous means (existing fields, upcoming fields, and existing LNG terminals) was calculated.
   b. Upcoming LNG terminals and their capacities were identified. Two scenarios were considered for upcoming import related infrastructure:
      i. Scenario – 1 (most plausible scenario): According to the current data, two terminals are coming up in the future for LNG imports – Matarbari Terminal and Payra Terminal. However, there has not been any latest update for the Payra LNG terminal; it is presumed to be cancelled. Hence, supplies from the Payra LNG terminal have not been considered for the analysis.
      ii. Scenario – 2: Within this scenario, apart from the Matarbari terminal, additional LNG import terminals or FSRUs of capacity ~7.8 MMTPA at Payra (~3.9 MMTPA) and Moheshkhali (~3.9 MMTPA) have been assumed to get built in Bangladesh by FY 2025 based on discussions with stakeholders from Bangladesh. In addition, some amount of production has been assumed to come from domestic offshore fields by considering certain volumes for offshore production from FY 2028. This scenario has not been considered as the most plausible one due to 2 reasons. Firstly, there is a lack of visibility for Bangladesh around the LNG volumes tied up in long-term contracts for existing as well as upcoming infrastructure. Due to volatility in the spot LNG prices, the utilisation of the FSRUs or LNG import terminals can get affected if adequate volumes in long-term contracts are not tied up. Secondly, there hasn't been any offshore production in Bangladesh post the closure of Sangu offshore field in 2013 and there is no publicly available data validating the possibilities of additional commercially viable offshore discoveries in Bangladesh.
   c. The utilisation of the upcoming terminals increased gradually considering a gap in natural gas demand and supply.

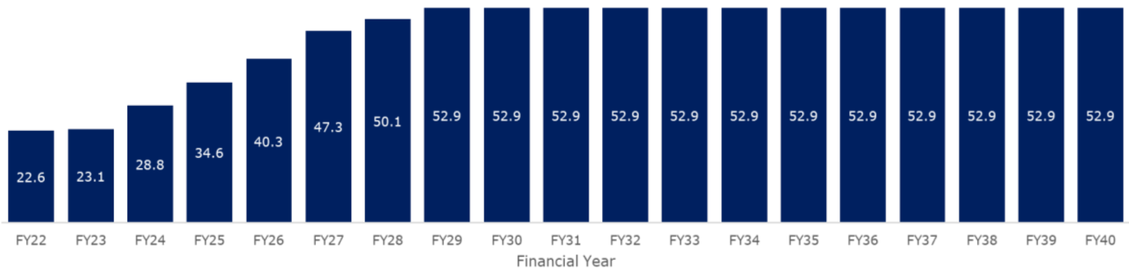
Assumptions

1. The utilisation of existing and new terminals gradually rose to reach full utilisation with a cap of 90 percent, considering that import dependency of natural gas will subsequently increase (due to a decline in supply from domestic production).
2. The offshore production has been assumed to start with ~2 mmscmd in FY 2028 and increase upto ~10 mmscmd in FY 2040.

Analysis

Within the most plausible scenario (Scenario-1), natural gas supply from LNG imports is expected to increase gradually from 22.6 mmscmd in FY 2022 to 52.9 mmscmd in FY 2030 and FY 2040. Within Scenario-2, the supply from LNG imports is expected to increase from 22.6 mmscmd in FY 2022 to 75.3 mmscmd in FY 2030 and 78.1 mmscmd in FY 2040. After FY 2031, imports become constant in both the scenarios as the LNG terminals reach upto their maximum utilisation. In addition, there is no data on upcoming LNG terminals for such a long term. Moreover, there will be a gradual shift towards other alternative energy sources

Figure 89 Projected natural gas supply in Bangladesh from imports until 2040 (in mmscmd) within Scenario-I (most plausible scenario)



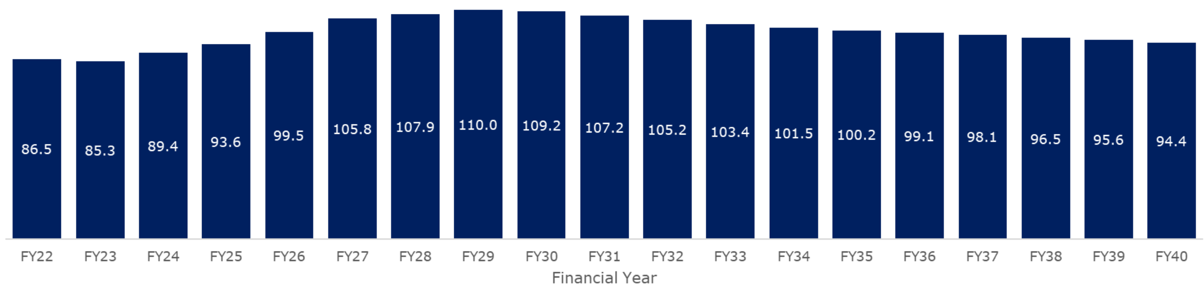
4.6.4 Total supply projection until 2040

The total supply projection for Bangladesh within the most plausible scenario shows an estimate of 109.2 mmscmd by FY 2030 and 94.4 until FY 2040. Moreover, peak supply is expected to be 110 mmscmd in FY 2029; after which, it is expected to decrease because of a decline in domestic production. However, if Scenario-2 plays out according to Section 4.6.3.2 with additional import infrastructure and offshore domestic production getting introduced in Bangladesh, the overall supply is expected to reach ~136 mmscmd by FY 2030 and ~130 mmscmd by FY 2040. Following is the summary of the scenarios that have been considered for supply:

Table 86 Summary of gas supply in Bangladesh under different scenarios

Supply scenarios	Gas supply (mmscmd)			
	2025	2030	2035	2040
Domestic: CAGR Scenario **Imports:** Scenario 1 (Most plausible scenario for supply)	93.6	109.2	100.2	94.4
Domestic: CAGR Scenario **Imports:** Scenario 2	93.6	135.6	131.4	129.6

Figure 90 Projection of overall natural gas supply in Bangladesh by 2040 in most plausible scenarios (in mmscmd)



4.7 Demand-supply model

4.7.1 Integrated demand-supply model

The following tables show the projection and summary for the overall demand and supply for natural gas in Bangladesh from FY 2022 to FY 2040 in the most plausible scenario.

Table 87 Overall demand and supply projections of natural gas for Bangladesh from FY 2022 to 2030 within most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	88.8	93.5	97.8	102.6	110.6	118.8	126.9	134.6	142.2
Domestic supply	63.9	62.1	60.3	58.7	57.1	55.6	54.1	52.7	51.4
Production from upcoming fields	0.0	0.2	0.3	0.4	2.1	2.9	3.7	4.4	4.9
Imports	22.6	23.1	28.8	34.6	40.3	47.3	50.1	52.9	52.9
Total supply	86.5	85.3	89.4	93.6	99.5	105.8	107.9	110.0	109.2
Deficit (-)/surplus (+)	-2.2	-8.1	-8.4	-9.0	-11.0	-13.0	-19.0	-24.6	-33.0

Table 88 Overall demand and supply projections of natural gas for Bangladesh from FY 2031 to FY 2040 within most plausible scenario (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	150.2	157.5	164.1	170.1	175.4	180.1	184.3	188.1	191.4	194.2
Domestic supply	50.1	48.9	47.8	46.6	45.6	44.5	43.6	42.6	41.7	40.8

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Production from upcoming fields	4.1	3.4	2.7	1.9	1.7	1.7	1.7	1.0	1.0	0.7
Imports	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Total supply	107.2	105.2	103.4	101.5	100.2	99.1	98.1	96.5	95.6	94.4
Deficit (-)/surplus (+)	-43.0	-52.3	-60.7	-68.7	-75.2	-80.9	-86.2	-91.6	-95.8	-99.8

The analysis shows that Bangladesh is most likely to experience a major deficit in the future after FY 2030, with the current state of existing supply from both the domestic production and the imports. In case, Scenario-2 plays out per section 4.6.3.2 with respect to offshore production in the country and additional import infrastructure being constructed, following would be the projections and summary for overall demand and supply for natural gas in Bangladesh:

Table 89 Overall demand and supply projections of natural gas for Bangladesh from FY 2022 to 2030 according to Scenario-2 of section 4.6.3.2 (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	88.8	93.5	97.8	102.6	110.6	118.8	126.9	134.6	142.2
Domestic supply	63.9	62.1	60.3	58.7	57.1	55.6	54.1	52.7	51.4
Production from upcoming fields	0.0	0.2	0.3	0.4	2.1	2.9	3.7	4.4	4.9
Production from offshore fields	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	4.0
Imports	22.6	23.1	28.8	37.4	44.5	55.7	62.7	72.5	75.3
Total supply	86.5	85.3	89.4	96.4	103.7	114.2	122.5	131.6	135.6
Deficit (-)/surplus (+)	-2.2	-8.1	-8.4	-6.2	-6.8	-4.6	-4.4	-3.0	-6.6

Table 90 Overall demand and supply projections of natural gas for Bangladesh from FY 2031 to 2040 according to Scenario-2 of section 4.6.3.2 (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	150.2	157.5	164.1	170.1	175.4	180.1	184.3	188.1	191.4	194.2
Domestic supply	50.1	48.9	47.8	46.6	45.6	44.5	43.6	42.6	41.7	40.8
Production from upcoming fields	4.1	3.4	2.7	1.9	1.7	1.7	1.7	1.0	1.0	0.7
Production from offshore fields	4.0	6.0	6.0	6.0	6.0	8.0	8.0	10.0	10.0	10.0
Imports	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
Total supply	136.4	136.4	134.6	132.7	131.4	132.3	131.3	131.7	130.8	129.6
Deficit (-)/surplus (+)	-13.8	-21.1	-29.5	-37.5	-44.0	-47.7	-53.0	-56.4	-60.6	-64.6

5 Nepal

5.1 Country overview – Nepal

5.1.1 Economy (GDP), population, overall energy consumption, and fuel mix

Nepal had a population of 29 million people in FY 2020.[221] According to IMF data, the country's GDP in FY 2020 was ~US$34 billion.[222] The overall energy consumption of Nepal in 2018 was ~14 Mtoe. Nepal is rich in fuels such as biomass (from firewood) and hydro reserves. However, it has small quantities of coal reserves and no proven petroleum reserves. As of 2018, traditional fuel and biomass (mainly fuel wood) met the most (about 72 percent) of the country's energy demand. Nepal mainly depends on imports from India to meet its energy requirements. According to the IRENA data for 2018, the country's energy mix consisted of 72 percent biomass, 19 percent POL products, 6 percent coal, and 3 percent from hydroelectricity, and other renewable energy resources.

Figure 91 Nepal: Overall energy consumption by source (2018)

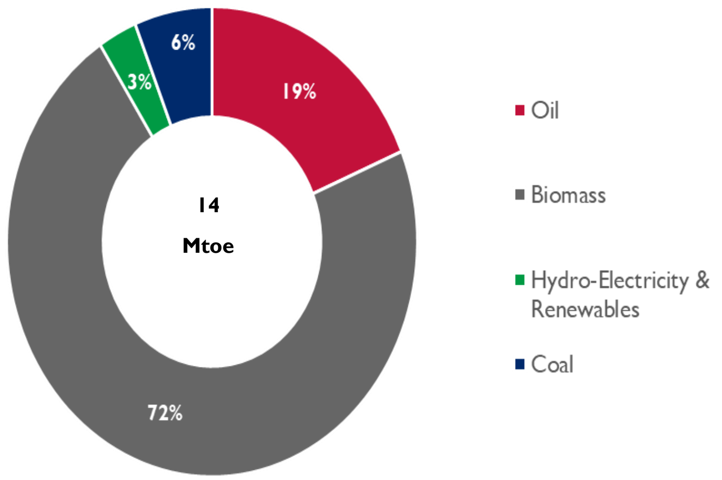


Table 91 Nepal: Overall energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Oil (19%)	2.7
Biomass (72%)	10.1
Coal (3%)	0.8
Hydro-electricity and renewables(6%)	0.4

5.1.2 Hydrocarbon value chain

Natural gas consumption is quite low compared with other fuels in the primary energy mix. It has no large-scale reserves of natural gas or oil. It is largely dominated by consumption of traditional energy sources, i.e., biomass (such as firewood and agricultural residue) for domestic energy requirements. The country's energy sector is managed by the Ministry of Energy, Water Resource, and Irrigation (or MoE). It is responsible for formulating policies for power and energy sector alongside the Ministry of Industries (MoI) (takes care of policies and regulations for coal and POL products). The Department of Mines and Geology, under the Ministry of Industry, set up an independent unit called Petroleum Exploration Promotion Project (PEPP) in 1982 to promote activities

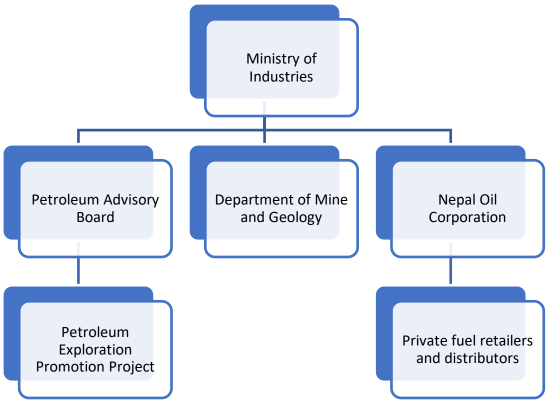
[221] https://www.imf.org/en/Countries/NPL
[222] https://www.imf.org/external/datamapper/NGDPD@WEO/OEMDC/ADVEC/WEOWORLD/CHN/NPL

pertaining to petroleum exploration. It is the responsible authority for undertaking necessary arrangements for negotiation with petroleum companies regarding petroleum agreements, along with monitoring ongoing exploration and production activities. The Petroleum Advisory Board, comprising senior officials of most ministries, has broad powers and responsibilities for petroleum-related activities.

Nepal Oil Corporation (NOC), a public enterprise under the Ministry of Industry, is responsible for managing imports, storage, and distribution of petroleum products throughout the country.

Nepal Gas industries Pvt. Ltd. and Trishul Gas Pvt. Ltd. are the major companies that are into the business of importing, bottling, and marketing of LPG across Nepal.

Figure 92 Organogram for the hydrocarbon sector



Source: SAARC Energy Outlook 2030 Report

5.1.3 As-is assessment and challenges

Petroleum is the second-largest energy source in Nepal after fuelwood, accounting for ~19 percent of the country’s primary energy supply. Roughly two-thirds of the oil imported by Nepal is used for transport. The rest is used mostly for household lighting, cooking, and heating; agriculture and forestry; and commercial and public services. Apart from some minor coal production, the oil and coal used in the country is imported. The share of natural gas is not significant compared with other fuels in Nepal’s energy mix.

According to the current assessment, Nepal faces the following challenges in the gas sector:

- Nepal has no known large-scale fossil fuel reserves.
- One of the biggest factors that acts as a challenge in the gas sector is the instability of the government. Moreover, earlier, there was a political unrest in the country following the introduction of the new constitution in September 2015. This resulted in a trade blockade in the Terai region due to which all imports, including POL products, were affected.
- Looking at the geographical coverage, Nepal is prone to earthquakes. Nepal was already recovering from the impact of an earthquake in April 2015. The cumulative effect of the earthquake and the blockade due to the political unrest resulted in a fall in overall gas and POL product demand in fiscal 2016.
- There has been an atmosphere of mistrust between India and Nepal over border issues for a short span of time.
- The pandemic has also significantly affected the supply side of the sector and imports.

5.2 Gas infrastructure analysis

5.2.1 Existing infrastructure

There is an existing 69 km petroleum products pipeline from Motihari (Bihar, India) to Amlekhgunj (Nepal). This Motihari–Amlekhgunj pipeline project is South Asia’s first cross-border oil project. It has already started commercial operation from September 2019.

Recently, a seismic survey was conducted in the Dailekh district of Nepal to explore petroleum and natural gas as per an agreement between Nepal and China. Amongst the surveyed locations, four places had shown in positive results for the presence of petroleum and natural gas reserves. Natural gas reserves were found in the

Padukasthan, Sirsethan, Muktinath and Navisthan areas of Dailekh. Some studies earlier showed seepage of natural gas in these areas; this has been officially confirmed after carrying out necessary tests. However, the exact potential of reserves and commercial viability of extraction has still not been determined. This would be done in the next few months.[223]If the report from China is positive regarding commercial viability, another study will be commissioned to look into further details of these reserves.

Moreover, the government is still in the process of exploring other opportunities associated with natural gas. It has recently discovered 300 MCM of a proven gas reserve in the Kathmandu Valley, which the country plans to exploit for use as a cooking fuel in a pilot project. As on date, there is no gas grid/existing pipeline infrastructure dedicated towards transportation and distribution of natural gas in Nepal. Moreover, being a land-locked country, Nepal does not have a scope for developing FSRU infrastructure for LNG import.

5.2.2 Upcoming and planned infrastructure

Nepal and India have agreed to study the feasibility of liquefied natural gas pipeline stretching from Gorakhpur in India to Rupandehi in Nepal. This pipeline would be operated by Indian Oil and Nepal Oil Corporation in a joint partnership. Moreover, there are discussions to build an LPG bottling plant at Jhapa in Nepal.[224]

The country has been estimated as a potential market for LNG. Amongst other sectors, natural gas imports through the natural gas pipeline from Gorakhpur to Rupandehi are expected to be used in the fertiliser sector in the country. The RLNG import terminal in Dhamra (Odisha), which is currently under construction, could be a potential source to provide gas to Nepal from India. The Nepalese Ministry of Industry, Commerce and Supplies has decided to build urea production plant in Bardaghat and Nawalparasi. Natural gas shall be provided through imports to these plants. There can also be potential to serve Nepal from India through Small Scale LNG (ssLNG).

5.3 Policy, regulatory enablers, and emerging trends

5.3.1 Policy and regulatory support and incentives for promoting the sector

The government is encouraging the use of natural gas in the country through various measures, such as collaborating with the Indian government and setting up a Joint Working Group (JWG). The JWG has deliberated on several projects related to setting up LPG bottling plants, as well as laying cross-border LPG pipelines, LNG pipelines, petroleum products pipelines, etc. The JWG also deliberated a larger role for India in building oil production storage capacities in Nepal. However, the policy on natural gas is yet to be formulated.

On the indigenous front, a limited amount of natural gas has been found in some pockets of Kathmandu Valley.[225] Per secondary research, there is a tentative gas reserves close to 42 bcm (1482.6 bcf).[226]However, probable reserves identified so far needs further confirmation to be of any use for commercial exploitation. If the proven reserves can be used economically even for a limited number of years, it is worth exploring in view of total dependence on imported gas.

5.3.2 Emerging trends with respect to alternative fuels

The Ministry of Energy, Water Resources, and Irrigation of Nepal has set up an Alternative Energy Promotion Centre (AEPC), whose main objectives are to:

- Popularise and promote the use of alternative/renewable energy technology
- Develop the commercially viable alternative energy industries in the country

Use of bio Compressed Natural Gas (bio CNG) is increasing to reduce dependence on fossil fuels. The Climate Investment Funds (CIF) is funding off-grid biogas energy generation. It is helping to build biogas capacity across 10 municipalities; construct 340 new biogas plants supplying community facilities and commercial establishments with clean energy; and produce enough biogas to replace equivalent of about 131,000 cylinders of imported LPG and some 5,000 tons of imported fertiliser per year.[227]

Envipower Energy and Fertilisers Pvt Ltd. and Gandaki Urja Pvt. Ltd. have established a commercial scale biogas plant to distribute bio CNG in Nepal.

[223] *https://english.onlinekhabar.com/study-proves-gas-and-petrol-in-dailekh.html*
[224] *https://kathmandupost.com/money/2020/08/25/nepal-india-in-talks-to-build-oil-pipelines-gas-plant-and-storage-facilities*
[225] *Report on National Energy Strategy of Nepal*
[226] *https://openjicareport.jica.go.jp/pdf/10603785_02.pdf*
[227] *https://www.climateinvestmentfunds.org/CIF10/nepal/bhairahawa*

Nepal is also making various provisions to boost EV use in the country. The budget for the fiscal year 2021-22 has abolished excise duty on import of EV and reduced customs duty from 40 percent to 10 percent to increase the internal consumption of electricity and promote use of environment-friendly transportation means.[228]

5.4 Pricing assessment

5.4.1 Gas pricing mechanism

As natural gas is not being consumed, the authorities have made no provision that demonstrates gas pricing strategy. However, considering the potential demand in the future, the country can be supplied natural gas from India from the nearby areas on the eastern side. The primary sources of carrying out trade with Nepal will be through road transportation and pipeline infrastructure as Nepal is a landlocked country. There is no scope of building up FSRU infrastructure for LNG import through carrier ships.

- **Pipeline infrastructure:** Natural gas can be supplied to Nepal from a take-off/carrier pipeline from the CGD regions of India that includes Gorakhpur (which is ~243 km from Amlekhgunj in Nepal) and Barauni (which is ~271 km from Amlekhgunj). The governments of both countries also intend to conduct a feasibility analysis of an LNG pipeline stretching from Gorakhpur in India to Rupandehi in Nepal. The following will be the major cost levers involved in transportation of natural gas through the pipeline in Nepal:
  i. DES price of LNG assumed 12.5 percent of crude oil price plus US$0.5 as a fixed constant charge
  ii. Custom duty of 2.5 percent and 10 percent cess on the custom duty
  iii. We shall consider that LNG will be regasified at the Dhamra RLNG terminal on the eastern coast. The regasification charges of the terminal, according to secondary research, US$ 0.78/mmbtu;[229]rupee to dollar conversion factor considered 0.013 based on latest data
  iv. 18 percent GST on the terminal charges
  v. We shall consider the sub-transmission pipeline transportation from Barauni in India to Amlekhgunj in Nepal; Barauni to be connected to the Dhamra LNG terminal from the JHBDPL pipeline through its extension of the Barauni Guwahati pipeline; per government orders, transportation tariff for the pipeline shall be INR 63.46/mmbtu that will be converted into US$0.82/mmbtu
  vi. 12 percent GST on the pipeline transportation tariff in India
  vii. For transportation from India to Amlekhgunj in Nepal through a sub-transmission pipeline, the distance covered will be ~300 km for transportation of up to 6 mmscmd of gas; for the pipeline construction, capex cost of ~INR 4 crore/km has been assumed (this would be incurred in two years). Along with that, operational expenses were assumed at 2.5 percent of capex and the increase in opex costs was assumed at an inflation rate of 5 percent; for getting a 15 percent rate of return, the pipeline's levelised tariff broadly stands at ~$ US1/mmbtu.
  viii. Nepal has a royalty tax of 12.5 percent for petroleum and crude oil products.[230]The same has been considered for natural gas transportation.
  ix. Retail distribution cost assumed to be US$10/mmbtu (infrastructure, O&M cost, and margins). This is a high-level estimation and would vary depending on capex, opex, demand, etc., of a particular region.

  Considering these assumptions, the following tables shows an illustrative landed cost of pipeline transportation for natural gas in Nepal at different crude oil prices:

Table 92 Illustrative cost for supply of natural gas from India to Nepal through pipeline transportation

	Crude price	$/Barrel	40	50	60	70	80	100	120
(i)	DES (12.5%)	$/MMBTU	5.50	6.75	8.00	9.25	10.50	13.00	15.50
(ii)	Custom duty (@2.75%)	$/MMBTU	0.15	0.19	0.22	0.25	0.29	0.36	0.43
(iii)	Terminal regasification charges for the Dhamra Terminal	$/MMBTU	0.78	0.78	0.78	0.78	0.78	0.78	0.78
(iv)	GST on terminal charges	$/MMBTU	0.14	0.14	0.14	0.14	0.14	0.14	0.14

[228] https://kathmandupost.com/national/2021/06/21/nepal-to-switch-to-light-electric-vehicles-by-2031-as-fossil-fuel-import-balloons
[229] http://loksabhaph.nic.in/questions/QResult15.aspx?qref=6265&lsno=17
[230] http://www.asianlii.org/np/legis/laws/npa2040180/

	Crude price	$/Barrel	40	50	60	70	80	100	120
(v)	Tariff for JHBDPL pipeline	$/MMBTU	0.82	0.82	0.82	0.82	0.82	0.82	0.82
(vi)	GST on JHBDPL Tariff	$/MMBTU	0.10	0.10	0.10	0.10	0.10	0.10	0.10
(vii)	Proposed pipeline tariff (from India to Nepal)	$/MMBTU	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Transportation cost from India (sum from (i) – (vii))	**$/MMBTU**	8.50	9.78	11.06	12.35	13.63	16.20	18.77
(viii)	Royalty tax for Nepal (@12.5%)	$/MMBTU	1.06	1.22	1.38	1.54	1.70	2.03	2.35
	Overall bulk consumer costs	**$/MMBTU**	**9.56**	**11.00**	**12.45**	**13.89**	**15.34**	**18.23**	**21.12**
	Retail Distribution Costs	$/MMBTU	10.00	10.00	10.00	10.00	10.00	10.00	10.00
(ix)	**Overall End Consumer Costs**	**$/MMBTU**	**19.56**	**21.00**	**22.45**	**23.89**	**25.34**	**28.23**	**31.12**

- **Small Scale LNG:** Small-scale LNG (ssLNG) systems transport LNG in cryogenic containers and re-gasify the LNG at the consumer site. ssLNG containers require less initial capital costs and provide greater mitigation of risks associated with supply contracts. However, they are prone to risks involved in the road transportation like delays and losses due to tolls, thefts etc. In addition, the road transportation costs are more volatile in nature as they are directly proportional to the fuel prices of the carrier vehicles. ssLNG can be supplied to Amlekhgunj in Nepal from either Dhamra LNG Terminal (~978 km) or Kukrahati LNG Terminal (~868 km). For an illustrative cost calculation for the landed cost of gas for bulk consumers in Nepal, following will be the major cost components involved in the supply:
  i. The DES price of LNG which has been assumed as 12.5 percent of Crude Oil price plus $ 0.5 as a fixed constant charge.
  ii. Custom Duty of 2.5 percent and 10 percent cess on the custom duty.
  iii. Loading Charges for LNG – The terminal will levy an additional charge for loading it into cryogenic tankers. The loading charge has been considered as $ 0.8/mmbtu that also includes $ 0.2/mmbtu margin based on the cost economics for ssLNG calculated by a report published by Council on Energy, Environment and Water (CEEW)[231].
  iv. GST on the loading charges @18 percent.
  v. The road transportation to Nepal would be carried out through a fleet of cryogenic tanks. The cost of transportation would primarily include the capex for the trucks and the containers, the operating expenses per kilometre, the cost of the fuel for two-way transportation, the wages of the drivers and taxes. On making broad assumptions, the cost of transporting and meeting the demand in Nepal from Dhamra comes out as $ ~1.8/mmbtu.
  vi. Costs for Satellite Storage Plant: The satellite storage plant will be consisting of a small storage tank, pumps and vaporisers for regasification for bulk usage. According to CEEW, the cost for a satellite storage plant consisting of a vaporiser (operating at utilisation of 80 percent), storage system, and other costs assuming a lifetime of 20 years gets calculated as $ 0.45/mmbtu. The capex involved for the setup of Satellite Plant would be $ ~2.14 Mn and the operating costs are expected to be $ ~0.24 Mn.
  vii. Nepal has a royalty tax of 12.5 percent for all petroleum and crude oil products. The same has been considered for the transport of ssLNG.
  viii. The retail distribution cost has been assumed to be $10/mmbtu (infrastructure, O&M cost and margins). This is a high-level estimation and would vary depending on the capex, opex, demand etc. of the particular region.

  Considering the assumptions mentioned above, following is an illustrative landed cost of ssLNG in Nepal according to different crude oil prices:

Table 93 Illustrative cost for supply of natural gas from India to Nepal through ssLNG

	Crude price	$/Barrel	40	50	60	70	80	100	120
(i)	DES (12.5%)	$/MMBTU	5.50	6.75	8.00	9.25	10.50	13.00	15.50
(ii)	Custom duty	$/MMBTU	0.15	0.19	0.22	0.25	0.29	0.36	0.43

[231] https://www.ceew.in/sites/default/files/CEEW-SsLNG-expansion-26Mar21.pdf

	Crude price	$/Barrel	40	50	60	70	80	100	120
(iii)	Truck Loading Charge	$/MMBTU	0.80	0.80	0.80	0.80	0.80	0.80	0.80
(iv)	GST on Loading Charge (18%)	$/MMBTU	0.14	0.14	0.14	0.14	0.14	0.14	0.14
(v)	Road Transportation Costs	$/MMBTU	2.00	2.00	2.00	2.00	2.00	2.00	2.00
	Overall Transportation Costs (Sum from (i) – (v))	**$/MMBTU**	8.60	9.88	11.16	12.45	13.73	16.30	18.87
(vi)	Satellite Storage Plant Costs	$/MMBTU	0.45	0.45	0.45	0.45	0.45	0.45	0.45
(vii)	Royalty Tax for Nepal (@12.5% of transportation and satellite storage plant cost)	$/MMBTU	1.13	1.29	1.45	1.61	1.77	2.09	2.42
	Overall Bulk Consumer Costs	**$/MMBTU**	**10.18**	**11.62**	**13.07**	**14.51**	**15.96**	**18.85**	**21.74**
	Retail Distribution Costs	$/MMBTU	10.00	10.00	10.00	10.00	10.00	10.00	10.00
viii	**Overall End Consumer Costs**	**$/MMBTU**	**20.18**	**21.62**	**23.07**	**24.51**	**25.96**	**28.85**	**31.74**

5.4.2 Pricing of alternative fuels and comparison of economics with natural gas

Table 94 Pricing of different POL products in Kathmandu

Petroleum Products	Retail Selling Price (as of May'2022) in US$/mmbtu
Petrol (MS)	34 (NRs 160.00/L)
Diesel (HSD)	31.5 (NRs 143.00/L)
Kerosene (SKO)	32.3 (NRs 143.00/L)
LPG cylinder	19.4 (NRs 1600.00/cyl)

(Source: Nepal Oil Corporation
Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for May 2022

Calorific value of LNG = 12500 kcal/kg; 1 mmbtu = 252000 kcal; US$ to NPR for May 2022 = 123; calorific value of diesel = 10800 kcal/kg; calorific value of petrol = 10500 kcal/kg; calorific value of kerosene = 11100 kcal/kg; calorific value of LPG = 11900 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L; density of kerosene = 0.82 kg/L; density of LPG = 0.51 kg/L)

Nepal Oil Corporation (NOC) has monopoly and is the main player that manages and meets fuel requirements of Nepal. The increase in prices are also attributed to higher import duties considering that a majority of the POL products are imported in Nepal due to lack of indigenous production. The overall estimated cost of natural gas comes in the range of US$19.5-31.2/mmbtu in case of pipeline transportation and US$20-32 in case of ssLNG. Therefore, switching to natural gas may prove to be more economical considering the present rates of other fuels. This could only be possible if adequate infrastructure is developed for gas transportation.

5.5 Demand analysis

5.5.1 Existing demand

The annual demand for petrol, diesel, and LPG was 1.1 million kL, 2.9 million kL, and 0.54 million tonnes, respectively, before disruptions caused by COVID-19. Role for gas-based power in Nepal is non-existent as it has huge hydropower potential. However, the recent floods and blackouts due to forced shut-down of several hydro-power stations exposed the need for a back-up generation source in which natural gas can prove to be one important fuel. Share of industry and transport sector in the final energy consumption is small at ~20 percent but it is expected to grow fast in future at ~4 percent annually and ~3.5 percent annually respectively. Natural gas may have a limited role to play in the transport and industrial sector. Nepal is exploring the feasibility of introducing natural gas through a pipeline from India for supply to industries.

5.5.2 Key drivers for demand

Some of the drivers which can lead to increase in demand are as under:

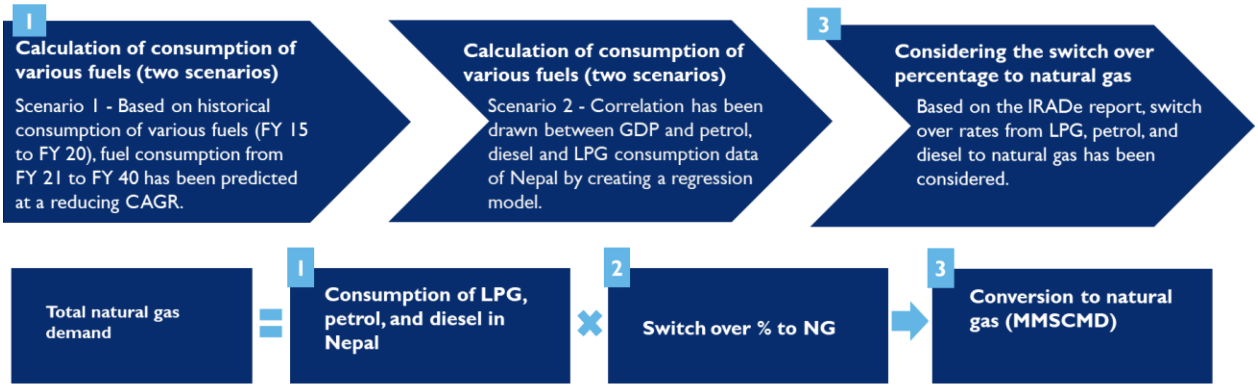
- Setting up of urea factories (in Bardaghat and Nawalparasi) and other industries at a large scale that are dependent on natural gas.
- The domestic/household sector plays a significant role in driving the demand. Nepal has been relying on biomass and wastes for long. But recently, the trend is shifting towards use of cleaner fuel i.e., LPG.
- Pricing of natural gas is considered to be as more economical as compared to other alternative fuels (e.g., diesel, petrol, and LPG). This can also act as one of the key drivers for increasing demand of natural gas.

5.5.3 Bottom-up approach

5.5.3.1 CGD sector

The CGD sector in Nepal has been broken down into the industrial, transport, and other segments. Demand for the CGD sector is calculated based on the data provided by NOC for the historical consumption of LPG, petrol, and diesel in Nepal.

Figure 93 Methodology of calculation of gas demand by the CGD sector in Nepal under the bottom-up approach



Detailed methodology

1. Step 1 – Calculation of consumption of LPG, petrol, and diesel in Nepal
    a. NOC provides the historical consumption of LPG, petrol, and diesel in Nepal.
    b. Two scenarios are considered:
        i. Scenario 1 - Based on historical consumption of above-mentioned fuels (FY 2015 to FY 2020), fuel consumption from FY 2021 to FY 2040 has been predicted at a reducing CAGR with a minimum growth cap of 8 percent.
        ii. Scenario 2 - A correlation has been drawn between GDP and petrol, diesel, and LPG data of Nepal by creating a regression model. This approach has been considered to estimate the consumption of petrol, diesel, and LPG.
        The detailed list of the consumption data for both the scenarios has been provided in Annexure 17.4.1. After drawing a correlation between GDP and consumption data for Nepal, the following regression equations were obtained:

        *Petrol consumption (in KL) = 609.79 - 867294.39 * GDP (in billions of NPR)*
        *Diesel consumption (in KL) = 1691.79 - 2263837.30 * GDP (in billions of NPR)*
        *LPG consumption (in MT) = 439.69 - 584288 * GDP (in billions of NPR)*

        The R2 value and p-values of this model for petrol, diesel, and LPG consumption were as under:

Table 95 Regression analysis of Nepal

Fuel type	R^2 value	p-values	
		Intercept	x-variable
Petrol	0.95	0.002	0.0004
Diesel	0.86	0.02	0.004
LPG	0.95	0.004	0.0008

Historical GDP of Nepal from FY 2015 to FY 2020 by IMF has been used for this analysis. The R^2 value of this model for petrol consumption came out as 0.95 implying that 95 percent of the variation in the petrol consumption is being explained by the GDP data. Similarly, the R^2 value for diesel and LPG consumption came out as 0.86 and 0.95, respectively. Moreover, p-values are less than 5 percent, indicating that there is a strong correlation between GDP and consumption of the above-mentioned fuels.

2. Step 2 – Considering the switch over percentage to natural gas
    a. The demand for natural gas was considered to progressively increase from FY 2022 onwards based on the penetration rates for conventional fuels. The following switch over rates from LPG, petrol, and diesel to natural gas has been considered based on the IRADe report that appeared plausible:

Table 96 Switch over rates to natural gas for Nepal

	2025	2030	2035	2040
Petrol	10%	20%	20%	20%
Diesel				
Transport	5%	15%	15%	15%
Industries	75%	75%	75%	75%
Others	50%	50%	50%	50%
LPG	15%	25%	35%	40%

<u>Assumptions</u>

1. For the calculation of consumption of LPG, petrol, and diesel, reducing CAGR has been capped at 8 percent after FY 2030. The main reason for doing so is that in case of developing economies such as Nepal, the growth in consumption of petroleum products will be higher in initial years, However, as economies mature, consumption may not increase at the same rate in the future. Hence, a cap on CAGR has been considered.
2. Based on the different calorific fuel conversion rates for each fuel and switch over rate, natural gas demand for the CGD sector has been predicted from FY 2021 to FY 2040.

<u>Analysis</u>

The demand for natural gas from the CGD sector is expected to increase from 1.74 mmscmd in FY 2025 to 4.11 mmscmd in FY 2030 and 10.30 mmscmd in FY 2040 in the first scenario and from 1.83 mmscmd in FY 2025 to

4.11 mmscmd in FY 2030 and 9.39 mmscmd in FY 2040 in the second scenario. Initially, the industrial sector will be the highest contributor towards the CGD demand but with time, as the no. of vehicles keeps on increasing in Nepal, the demand from the transport sector is expected to occupy a significant portion as well. Within the industrial sector, the demand is expected to rise from 0.3 mmscmd in FY 2021 to 1.05 mmscmd in FY 2040 whereas in domestic, it is expected to increase from 0.27 mmscmd in FY 2021 to 2.81 mmscmd in FY 2040.

Table 97 Summary of natural gas demand in Nepal under the bottom-up approach (in mmscmd)

Scenario	Gas demand (mmscmd)			
	2025	2030	2035	2040
Scenario – 1 (most plausible scenario)	1.74	4.11	7.01	10.30
Scenario – 2	1.83	4.11	6.71	9.39

5.5.4 Total demand projection until 2040

The total demand projection in Nepal has currently been considered only from the CGD sector. Within Scenario-1, demand is expected to reach up to 4.1 mmscmd in FY 2030 and 10.3 mmscmd in FY 2040. On the other hand, within Scenario-2, it is expected to reach up to 4.1 mmscmd in FY 2030 and 9.4 mmscmd in FY 2040.

Figure 94 Projected natural gas demand in Nepal in Scenario-1: most plausible scenario (in mmscmd)

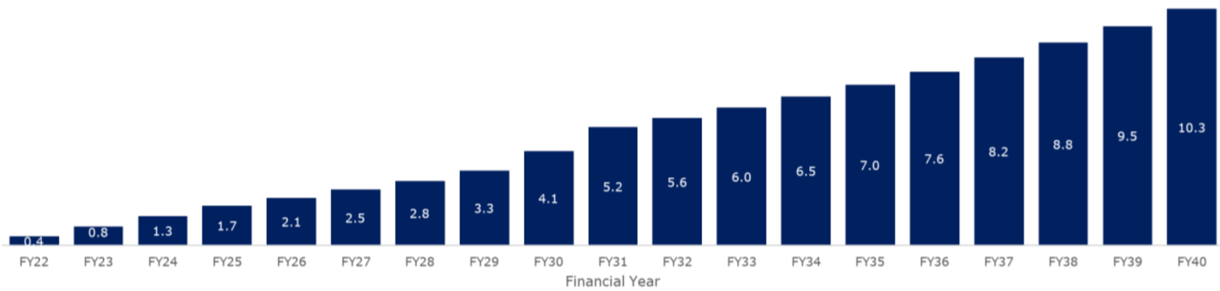
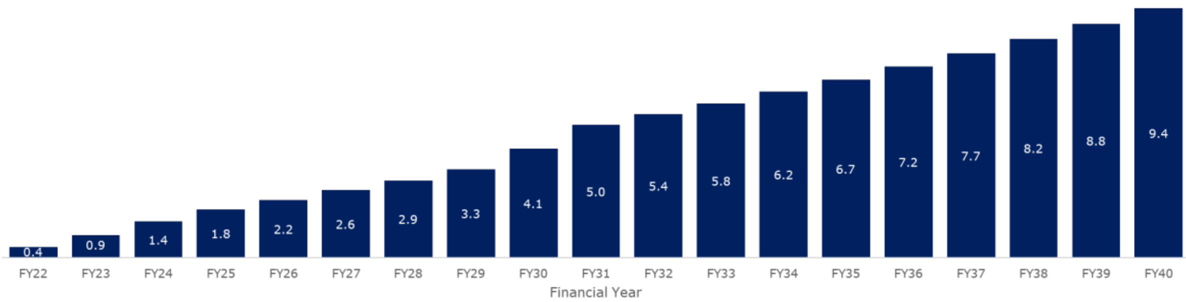


Figure 95 Projected natural gas demand in Nepal in Scenario 2 (in mmscmd)



Further analysis was carried out for Nepal to calculate overall demand by region. To calculate region-wise demand, the latest sales of POL fuels were considered in major locations of Nepal based on the sales data that is available with Nepal Oil Corporation.[232] Using that data, the percentage demand from each major location was calculated and the same percentage was used to project the overall natural gas demand from these locations. The following table shows a summary of projected demand for each location:

[232] http://noc.org.np/import

Table 98 Expected demand by location for natural gas in Nepal for most plausible scenario (in mmscmd)

Location	Fuel consumption (in kL)	% Fuel consumption	Scenario-1				Scenario-2			
			FY25	FY30	FY35	FY40	FY25	FY30	FY35	FY40
Biratnagar	1230	18.2%	0.32	0.75	1.28	1.88	0.33	0.75	1.22	1.71
Bhadrapur	7	0.1%	0.00	0.00	0.01	0.01	0.00	0.00	0.01	0.01
Janakpur	370	5.5%	0.10	0.23	0.38	0.56	0.10	0.23	0.37	0.52
Amlekhgunj	1475	21.9%	0.38	0.90	1.53	2.25	0.40	0.90	1.47	2.05
Birgunj	488	7.2%	0.13	0.30	0.51	0.75	0.13	0.30	0.49	0.68
Kathmandu	1290	19.1%	0.33	0.79	1.34	1.97	0.35	0.79	1.28	1.80
Pokhara	283	4.2%	0.07	0.17	0.29	0.43	0.08	0.17	0.28	0.39
Bhairahawa	527	7.8%	0.14	0.32	0.55	0.80	0.14	0.32	0.52	0.73
BHW Pump	16	0.2%	0.00	0.01	0.02	0.02	0.00	0.01	0.02	0.02
Nepalgunj	488	7.2%	0.13	0.30	0.51	0.75	0.13	0.30	0.49	0.68
Surkhet	126	1.9%	0.03	0.08	0.13	0.19	0.03	0.08	0.13	0.18
Dang	220	3.3%	0.06	0.13	0.23	0.34	0.06	0.13	0.22	0.31
Dhangadi	203	3.0%	0.05	0.12	0.21	0.31	0.06	0.12	0.20	0.28
Dipayal	20	0.3%	0.01	0.01	0.02	0.03	0.01	0.01	0.02	0.03

The above table shows that Biratnagar, Amlekhgunj, and Kathmandu are expected to constitute over 50 percent of the natural gas demand in Nepal by 2040. Therefore, for the purpose of providing any gas supplies and building up additional infrastructure, these areas need to be targeted and given a higher priority.

5.6 Supply analysis

5.6.1 Future initiatives

A limited amount of natural gas reserves has been found in some pockets of the Kathmandu Valley. Probable reserves identified so far needs further confirmation to be of any use for commercial exploitation. More data on expansion plans is not available in the public domain.

Further, the Nepalese Ministry of Supplies has decided to build a urea factory in Bardaghat and Nawalparasi. These upcoming projects can boost natural gas consumption that can be provided through imports. The annual capacity of urea plants is expected to be 700,000 tonnes; this would require 1.33 million scm of natural gas daily.[233]

5.7 Integrated demand-supply model

Table 99 Overall demand-supply estimates for Nepal from FY 2022 to FY 2030 for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.39	0.83	1.29	1.74	2.07	2.45	2.81	3.26	4.11
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.39	-0.83	-1.29	-1.74	-2.07	-2.45	-2.81	-3.26	-4.11

Table 100 Overall demand-supply estimates for Nepal from FY 2031 to FY 2040 for most plausible scenario (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	5.15	5.56	6.01	6.49	7.01	7.57	8.17	8.83	9.53	10.30
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-5.15	-5.56	-6.01	-6.49	-7.01	-7.57	-8.17	-8.83	-9.53	-10.30

[233] *https://kathmandupost.com/money/2017/04/06/rs72b-urea-plant-to-be-set-up-in-nawalparasi*

6 Sri Lanka

6.1 Country overview – Sri Lanka

6.1.1 Economy (GDP), population, primary energy consumption, and fuel mix

Sri Lanka is an island nation of area ~65,610 km^2 and about ~55 km to the south of India. It had a population of ~22 million people in 2020.[234] The country's overall GDP was ~81 billion dollars in 2020.[235]Moreover, per the BP Statistical Review, its primary energy consumption was ~7.88 Mtoe in 2020.[236]The country's primary energy requirement has been rising steadily over the years. Moreover, most of the primary energy requirements for Sri Lanka are met through imports. Non-renewable energy sources such as oil and coal form the major backbone of the energy supplies in the country. Sri Lanka is also a huge user of biomass with ~3.6 Mtoe of biomass energy used in the country in 2018, according to IRENA.[237]

Figure 96 Sri Lanka: Primary energy consumption by source (2020)

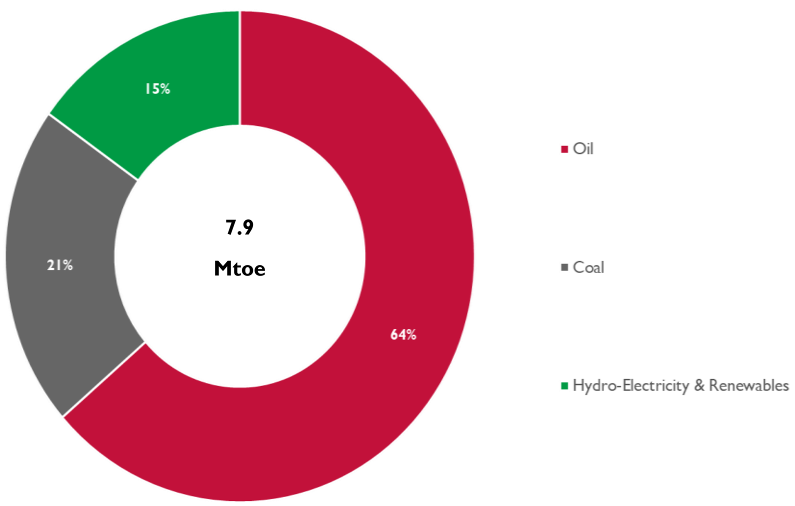


Table 101 Sri Lanka: Primary energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Oil	5.0 (64%)
Coal	1.7 (21%)
Hydroelectricity and renewables	1.2 (15%)

6.1.2 Gas value chain

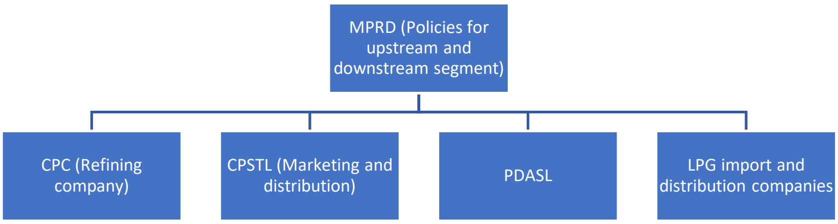
As of now, there is no usage of natural gas within the country, hence, the exact value chain of natural gas cannot be defined for Sri Lanka. However, the government of Sri Lanka has carried out several exploration and production activities for oil and natural gas resources in the country; this have been discussed further. Besides, the government has also published a "National Policy on Natural Gas," which aims to facilitate the transition towards natural gas from conventional energy sources.

MPRD (Ministry of Petroleum Resources Development) is responsible for formulation of policies for both upstream and downstream sector in the country. The hydrocarbon sector is largely managed by public sector

[234] https://data.worldbank.org/indicator/SP.POP.TOTL?locations=LK
[235] https://www.imf.org/external/datamapper/NGDPD@WEO/WEOWORLD/LKA
[236] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf
[237] https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Sri%20Lanka_Asia_RE_SP.pdf

enterprises; however, the private sector is engaged in petroleum distribution, bunker supplies, LPG distribution, and oil exploration. MPRD supervises the following institutions – Ceylon Petroleum Corporation (CPC), Ceylon Petroleum Storage Company Ltd. (CPSTL) which is a company with joint ownership between CPC and Lanka

Figure 97 Organogram of hydrocarbon sector in Sri Lanka



Indian Oil Corporation (LIOC), and Petroleum Development Authority of Sri Lanka (PDASL). Following is the organogram of hydrocarbon sector in Sri Lanka:

Source: Sri Lanka energy sector assessment, strategy, and roadmap by ADB

6.1.3 As-is assessment and challenges

<u>Challenges around upstream exploration and production</u>

Following are the challenges pertaining to carrying out the upstream exploration and production activities in Sri Lanka:

1. Due to the absence of a natural gas market and related policy implementations in Sri Lanka, PDASL has faced several difficulties in attracting investors for gas exploration. The environment in the country is still not easily conducive for it.
2. The oil and gas industry is still at its inception stage in Sri Lanka. The exploration activities entail a large overall financial risk. During exploration, there is always a risk of sunk cost for developers even if they do not find a producible quantity that is commercially viable. The government is still not ready to take this up at a large scale. To further de-risk exploration activities, it needs to take initiatives in development of a multi-client depository of seismic and other regional exploratory data. This would encourage marginal players to participate in exploration and mitigate financial risks.
3. The country faces technological challenges in getting the necessary data. For example, there is a thick volcanic layer within sediments that covers around two-thirds of the Mannar basin. The existing 2D and 3D seismic data in the area had been unable to image the sub-volcanic potential of the basin due to this layer. The country also requires more advanced seismic technologies to map the exact potential of the natural gas basins, along with the exact estimation of proved, probable, and possible reserves.
4. Evaluation of gas export potential, infrastructure development, preparation of flexible contracts, and project execution in ecologically sensitive areas, are some challenges, apart from the ones mentioned above, that PDASL faces in oil and gas exploration in Sri Lanka.

<u>Other challenges</u>

The natural gas sector in Sri Lanka also faces the following challenges:

1. The country, as of now, has not used natural gas as a fuel source for its energy requirements. Therefore, significant infrastructural investments will have to be made to help different sectors transition towards natural gas. Natural gas use in the domestic and industrial sectors is expected to be unlikely because of investment requirements in making grid pipeline infrastructure.
2. Natural gas will also compete in the future with other upcoming renewable energy sources, such as solar power.
3. Commercialisation of the gas resources that were discovered in the country.

6.2 Gas infrastructure analysis

6.2.1 Upcoming and planned infrastructure

As of now, no natural gas has been produced or imported within Sri Lanka over the past few years. While currently there is no domestic production of oil and natural gas, Sri Lanka has undertaken various exploration and production activities of oil and natural gas over the past few years. The first bidding round for gas was held for Mannar Basin in 2007 and two gas discoveries were made in one exploration block in 2011. Following the two discoveries, the government took strategic measures to expedite exploration activities in all three basins - Mannar, Cauvery and Lanka along with development of gas discoveries. The following is a list of some upstream activities for natural gas that were carried out in the country in recent past post the two discoveries:

Table 102 Timeline of exploration and production activities in Sri Lanka

Timeline	Exploration and production	Details	Location	Status	Company
Feb 2016 and restated in Aug 2019	Exploration	Joint study to explore two offshore ultra-deep blocks	North-East Lanka Basin blocks JS-5	Complete	Total Equinor
Jul 2018	Exploration	Multi-client 2D seismic data acquisition, processing, imaging, and marketing and licensing services	Selected data acquisitions in all three basins completed. Marketing & licensing of processed & reprocessed data in process	Complete	Eastern Echo DMCC (subsidiary of Schlumberger)
Jan 2019	Production	Bid round for appraisal and development of gas discoveries and additional hydrocarbon prospects in block M2	Mannar basin block M2	Complete	Three bids received in 2019 and no suitable operator was selected. Planned to commence offering the re-demarcated blocks in 2022.
May 2019	Production	Bid Round for the exploration and production of oil and gas in blocks M1 and C1	Mannar and Cauvery basin	Evaluation of sole bid is in process	NA
Aug 2019	Exploration	Multi-client airborne acquisition, processing, marketing, and licensing of Gravity, Gravity Gradiometry, and magnetic data	Cauvery Basin, shallow and coastal areas of Mannar basin	Completed acquisition in 2021 and processing in process	BellGeospace

The years 2020 and 2021 have seen the major initiatives and changes to the national upstream oil and gas framework in the country. Some of these initiatives include publication of new National Policy on Natural Gas (2020), revised offshore exploration block map (2021), policy initiative to offer all three of Sri Lanka's basins on joint study basis (2020), putting forward a new Petroleum Resources Act and establishment of PDASL as the upstream regulator (October 2021).

Pearl Energy Ltd. has signed an agreement to launch the Hambantota LNG hub. Various other private companies are in discussions on investment within this project to import LNG in Sri Lanka. Moreover, a US-based company called New Fortress Energy has signed a framework agreement with Sri Lanka's government to construct a new offshore LNG terminal. These upcoming projects will play a significant role in supplying natural gas and meeting the future demands for this fuel in Sri Lanka.

6.3 Policy, regulatory enablers, and emerging trends

6.3.1 Policy and regulatory support and incentives for promoting the sector

For promoting the sector, the following initiatives in terms of policy and regulatory support, need to be taken:

1. According to the Long-Term Generation Expansion Plan (LTGEP) base case in Sri Lanka, LNG will be one of the major power-generating sources in the upcoming power plants within the country.
2. The National Policy on Natural Gas (NPNG) was published by Ministry of Energy in October 2020. The policy introduces a definite vision for the country to introduce natural gas as a new energy source and industrial feedstock to a wide range of economic sectors in Sri Lanka.[238]The following is a list of goals that have been envisaged in NPNG to develop this sector in Sri Lanka:
    - The share of natural gas reaches at least one-third of the mix of the total fossil fuel consumption in the country by 2030.
    - The dependency on imported fossil fuels needs to be reduced to at least half of the present level by 2030.
    - Penetration of natural gas in sectors maintaining minimum 30 percent of the total energy mix, needs to be increased.
    - Profitable avenue of foreign exchange earnings established through exportation, exploitation, and bunkering of indigenous gas resources
    - Emission of greenhouse gasses will be minimised so that emission targets set by the country's NDCs to Paris Agreement on Climate Change can be achieved.
    - A robust framework of legal, regulatory, and institutional arrangements is planned to be developed for inculcating positive responses of producers, suppliers, and consumers of natural gas in place by 2020.
    - Progressive growth of skilled employment and business opportunities will be generated through a steady stream of foreign and local investments on natural gas.
3. NPNG also defines the following implementation steps to build up gas value chains and introduce the natural gas industry in the country:
    - Preliminary coordinating and cooperation building measures by nomination of different stakeholders in the process
    - Undertaking the communication activities with stakeholders along with all the planning measures
    - Initiating the interventions feasible within the existing legal and institutional frameworks with the help of stakeholders who have been identified
    - Identification of structural changes in the legal, institutional, and regulatory frameworks
    - Preparation of Gas Utilisation Master Plan (GUMP) to identify sector-specific, near-term actions and strategic interventions to promote the use of natural gas; the GUMP to also define specific activities and recommendations, along with their timelines, to promote long-term use of natural gas in the country
    - Full implementation of NPNG with the required changes in place
4. The government of Sri Lanka is considering negotiating government-to-government deals to procure long-term LNG; range between 0.3-0.8 MMTPA depending on wet or dry conditions in the country.

6.3.2 Emerging trends with respect to alternative fuels

The following are the emerging trends for use of alternative fuels in Sri Lanka:

1. Due to environmental concerns and negative public sentiments, along with a decreasing cost of renewable energy generation, Ceylon Energy Board has discarded construction plans for any coal-based

[238] https://www.pucsl.gov.lk/wp-content/uploads/2019/02/NG_Policy-Draft.pdf

power plants in the country. However, the country intends to use a super-critical coal technology to contain environmental concerns and meet emission requirements per the Paris Agreement.

2. Demand for POL fuels is expected to increase at a higher rate in the future, considering growth in the transportation sector and economic activities within the country. At present, Sri Lanka's vehicle market is under-penetrated and with the rise in per capita income, demand for vehicles will increase. This will be a major driver for petrol demand. However, growth might also get moderated because of the introduction of EVs and switching over of some percentage of current petrol-based vehicles to LNG once it gets introduced.
3. For diesel and furnace oil, demand might increase as the country's industrial GDP improves. However, it is also expected to show a marginal slow-down due to increased environmental concerns and fuel prices.
4. Naphtha demand is expected to decline, with its consumption falling to a minimal by 2030. No new naphtha-based thermal power capacities are expected in the future and existing capacities might get retired.
5. The government of Sri Lanka had established the Sustainable Energy Authority (SEA) in 2007 to develop indigenous renewable energy resources and attain sustainability in energy generation. The private sector is being encouraged to set up Other Renewable Energy (ORE) plants. Moreover, through bidding processes and constant support from the government to promote this sector, purchasing tariffs have fallen by up to 50 percent for solar and wind projects.
6. The National Policy Framework in Sri Lanka envisions to grow the contribution of large hydro and renewables to 80 percent of electricity generation by 2030 from the prevailing ~45 percent share. It also identifies the development of both utility-scale generation (solar and wind) as well as rooftop solar as the integral components in country's RE capacity expansion plans.
7. The "Soorya Bala Sangramaya" program aims to deploy 1 GW of rooftop solar capacity by 2025. The rooftop solar deployment in Sri Lanka is currently supported by 3 schemes under this program namely "Net-metering scheme", "Net-accounting scheme", and "Net-plus scheme". While all consumer categories are eligible for all schemes, the Net-accounting and Net-plus schemes focus on encouraging industrial and small residential consumers to set up rooftop solar systems.[239]

6.4 Pricing assessment

6.4.1 Gas pricing mechanism

At present, there is no public data for gas pricing mechanism in the country. This is because natural gas has not been produced or imported within the country. However, it can be supplied to Sri Lanka from India through ssLNG cargoes. From LNG terminals in India, fuel will have to be transported to Sri Lanka through a breakbulk facility using a special type of containers. An LNG hub and spoke distribution model can be used to facilitate LNG trade between India, Sri Lanka, and even Maldives. Supply can be made to New Fortress Energy's offshore LNG receiving, storage, and regasification terminal from either Kochi, Dahej, or Ennore RLNG terminals. For an illustrative cost calculation for the landed cost of gas through ssLNG in Sri Lanka, the following major cost components will be considered:

i. The DES price of LNG assumed 12.5 percent of crude oil price plus US$0.5 as a fixed constant charge
ii. Custom duty of 2.5 percent and 10 percent cess on custom duty
iii. Port handling charges of US$0.03/mmbtu have been assumed
iv. Loading charges for LNG; the terminal will levy an additional charge for loading it into ssLNG carrier vessels; the loading charge has been considered as US$0.8/mmbtu that also includes 0.2/mmbtu margin based on the cost economics for ssLNG calculated by a report published by Council on Energy, Environment and Water (CEEW)[240]
v. GST on the loading charges @18 percent
vi. LNG transportation would be carried out using specialised ssLNG carrier vessels from the LNG terminals with a break-bulk facility; after consulting with industry experts, transportation charges for ssLNG to Sri Lanka have been considered as US$1.2/mmbtu
vii. The terminal regasification and port handling charge for the New Fortress RLNG terminal has been considered US$1/mmbtu

[239] https://www.ceew.in/cef/solutions-factory/publications/accelerating-investments-in-renewable-energy-in-sri-lanka-drivers-risks-and-opportunities
[240] https://www.ceew.in/sites/default/files/CEEW-SsLNG-expansion-26Mar21.pdf

viii. Applied ports and airports development levy on imports; the PAL rate for fuel imports is ~7.5 percent[241]

ix. Retail distribution cost assumed to be US$10/mmbtu (infrastructure, O&M cost, and margins); it is a high-level estimation and would depend on capex, opex, demand, etc., of a particular region

Considering the assumptions mentioned above, the following is an illustrative landed cost of ssLNG in Sri Lanka according to different crude oil prices:

Table 103 Illustrative cost for supply of natural gas from India to Sri Lanka through ssLNG

	Crude price	$/Barrel	40	50	60	70	80	100	120
(i)	DES (12.5%)	$/MMBTU	5.50	6.75	8.00	9.25	10.50	13.00	15.50
(ii)	Custom duty	$/MMBTU	0.15	0.19	0.22	0.25	0.29	0.36	0.43
(iii)	Port handling charges	$/MMBTU	0.03	0.03	0.03	0.03	0.03	0.03	0.03
(iv)	Loading charges for new cargoes	$/MMBTU	0.80	0.80	0.80	0.80	0.80	0.80	0.80
(v)	GST on loading charges	$/MMBTU	0.14	0.14	0.14	0.14	0.14	0.14	0.14
(vi)	LNG shipping charges to Sri Lanka	$/MMBTU	1.20	1.20	1.20	1.20	1.20	1.20	1.20
(vii)	Terminal regasification and port handling charges at Sri Lanka	$/MMBTU	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Landed cost at Sri Lanka (Sum from (i) – (vii))	**$/MMBTU**	**8.83**	**10.11**	**11.39**	**12.68**	**13.96**	**16.53**	**19.10**
(viii)	PAL taxes (@ 7.5%)	$/MMBTU	0.66	0.76	0.85	0.95	1.05	1.24	1.43
	Overall landed cost	**$/MMBTU**	**9.49**	**10.87**	**12.25**	**13.63**	**15.01**	**17.77**	**20.53**
	Retail distribution costs	$/MMBTU	10	10	10	10	10	10	10
(ix)	**Overall end-consumer costs**	**$/MMBTU**	**19.49**	**20.87**	**22.25**	**23.63**	**25.01**	**27.77**	**30.53**

6.4.2 Pricing of alternative fuels and comparison with natural gas

The pricing of alternative fuels in Sri Lanka is given below:

1. Coal: It is primarily imported in Sri Lanka from different countries. Sri Lanka levies three types of taxes on coal: VAT, PAL charges (port and airports development levy) and NBT charges (nation building tax). The percentage being charged on imports depends on the variety of coal being imported.
2. Petroleum: In Sri Lanka, the government determines prices for petrol, diesel, and kerosene sold by Ceylon Petroleum Corporation (CPC) – the major distributor of these fuels in the country. It can revise the pricing formula every two months. However, LPG price increases require prior approval to be given by the Consumer Affairs Authority. Lanka Indian Oil Corporation (LIOC) has been given the right to set its prices. However, given that CPC controls two-thirds of the market and is the primary price setter, CPC's prices effectively determine Lanka IOC's prices as well. According to the latest data for August 2021, different POL fuels had the following prices:

Table 104 Pricing for POL fuels in Sri Lanka

Petroleum products	Retail selling price (as of May 2022) in US$/mmbtu[242]
Petrol (MS)	42 (LKR 450.00/L)
Diesel (HSD)	31.6 (LKR 400.00/L)
Industrial Kerosene (SKO)	30.7 (LKR 399.00/L)

[241] https://static1.squarespace.com/static/55697ab8e4b084f6ac0581ef/t/60d411990b9058635e0c70da/1624510882486/Advocata+Sri+Lanka+Fuel+Price+Analysis.pdf

[242] https://www.globalpetrolprices.com/Sri-Lanka/

(Price conversion has been done to US$/mmbtu based on calorific values of the respective fuels and using the exchange rate for May 2022.)

Calorific value of LNG = 12,500 kcal/kg; 1 mmbtu = 2,52,000 kcal; US$ to LKR for May 2022 = 362; calorific value of diesel = 10,500 kcal/kg; calorific value of petrol = 10500 kcal/kg; calorific value of kerosene = 11,100 kcal/kg; calorific value of LPG = 11,900 kcal/kg; density of diesel = 0.84 kg/L; density of petrol = 0.71 kg/L; density of kerosene = 0.82 kg/L)

3. Dendro: Apart from the above-mentioned fuels, Sri Lanka is also trying to focus on Dendro-based power plants, which is also a form of energy generation from biomass. In 2019, Sri Lanka commissioned a 3.3MW Dendro power plant that was connected to the national grid in May 2019.[243]Sri Lanka had introduced in a feed-in tariff policy to promote renewable energy technologies, for power plants with a capacity of less than 10 MW. Here, within the policy, there were two tariff structures defined for the generation of power from renewable energy sources. For Dendro-based power plants, the price of electricity generation under a fixed structure was ~ LKR20.7/kWh.[244]

The estimated price of natural gas is in the range of US$19.5-30.5/mmbtu, making it more economical compared with petrol, diesel, and industrial kerosene for Sri Lanka.

6.5 Demand analysis

6.5.1 Existing demand

Sri Lanka meets its demand for petroleum through crude oil import and finished products. It does not consume natural gas. Sri Lanka last built a power plant in 2014. It is seeing an increase in power demand in the past few years. There had been frequent load-shedding in the country as planned electricity generation projects were not implemented.[245]However, the country's electricity board has now started to methodically plan its development activities through generation expansion plans. This will help make a gradual shift towards cleaner sources of power and reduce dependence on fossil fuels. The country has now taken a firm call over moving towards ensuring a proper mix of power generation to ensure increased energy generation from cleaner sources. The Ceylon Electricity Board of Sri Lanka releases generation expansion plans every two years to identify the optimal selection of plant addition in the future. Within the latest LTGEP 2020-39, due consideration has been given to natural gas and LNG as imports sources with ~24 percent share of gas-based power expected to be generated in Sri Lanka by 2030.[246]

To comply with LTGEP plans, Sri Lanka is looking to build up LNG-based power plants in the future. In addition, an LNG trading hub is planned for bunkering, using its proximity to a busy shipping lane and supply to neighbouring regions. Transport and industry account for 33 percent and 26 percent of the total final energy consumption, respectively.[247]Given these dynamics, demand exists for at least ~10 mmscmd to meet the gas requirements from planned power plants, transport (CNG) sector, and industries.[248]

6.5.2 Key drivers for demand

The key drivers for natural gas demand in Sri Lanka are mentioned below:

1. Sri Lanka imports its fertiliser requirements from other nations. In 2019, it spent ~INR 26 billion on fertiliser import to meet domestic requirements.[249]The production of urea fertilisers within the country will save the government from import-related costs. Hence, as the Sri Lankan government has plans for domestic production of fertilisers, the sector will have demand for natural gas.
2. Power consumption will be another major demand driver for the country with growth in electricity demand targeted to grow at ~4.9 percent annually.[250]In addition, capacity additions of ~1,500 MW gas-

[243] https://economynext.com/sri-lanka-commissions-3-3mw-dendro-power-plant-14275/
[244] https://www.adb.org/sites/default/files/publication/354591/sri-lanka-power-2050v2.pdf (Page 105)
[245] Sri Lanka - Energy Sector, Assessment, Strategy, and Road Map - ADB
[246] LTGEP 2020-39
[247] IEA - 2018
[248] Economic Times, January 2018 - https://rb.gy/f6drwt, Deloitte analysis
[249] http://www.colombopage.com/archive_20B/Dec22_1608616421CH.php
[250] SAARC Energy Outlook Report

fired power plants are planned by FY 2030 and overall ~3,000 MW by FY 2040 in the future, according to LTGEP.[251]

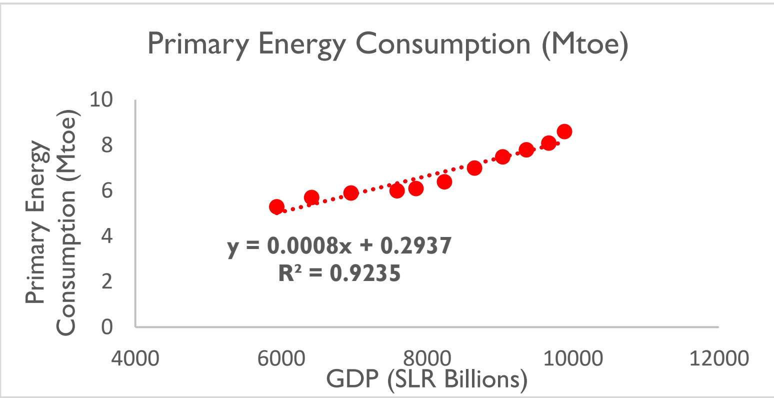
3. Sri Lanka's Energy Sector Development plan aims to reduce carbon footprint from the energy sector by 5 percent by 2025. Hence, to achieve that target, switching towards natural gas as a fuel source will play a significant role.[252]
4. In 2016, the government of Sri Lanka also made commitments under an agreement during the 21st session of the Conference of Parties to the United Nations Framework Convention on Climate Change. In those commitments, the country has aimed for 20 percent GHG emission reduction targets from 2020-2030 and one of the contributors of this target included conversion of fuel oil-based power plants to LNG-based power plants. Hence, this will also drive LNG demand in the country.
5. Shift from Dendro as a source of fuel for expansion of the forest cover in the nation is also being given priority. The forest cover in Sri Lanka reduced from 29.7 percent in 2017 to 16.5 percent in 2019.[253]The government has made a commitment to increase Sri Lanka's forest cover by 30 percent. Due to such concerns for climate change and dwindling rains in the country, a gradual shift towards alternative fuel sources, such as natural gas, has been considered.

6.5.3 Top-down approach

The top-down approach for estimation takes into account the fact that the primary energy consumption in Sri Lanka will be directly proportional to GDP growth because of the increase in economic activities and improvement in people's living standards. To estimate the top-down demand, a correlation has been drawn between the primary energy consumption in Sri Lanka and the country's GDP. After calculating primary energy consumption, based on the estimation number by the government, the share of natural gas has been calculated in the primary energy mix. According to government estimates, the share of natural gas within Sri Lanka's primary energy mix will be one-third of the total fossil fuels' consumption by 2030.[254]Using that estimate, the percentage share for natural gas has been increased year on year.

After drawing in a correlation analysis between GDP and the energy consumption data for Sri Lanka, the following regression equation was obtained:

Figure 98 Chart showing GDP v/s primary energy consumption for Sri Lanka



*Primary energy consumption (in Mtoe) = 0.2937 + 0.0008*GDP (in billions of SLR)*

Historical GDP of Sri Lanka from 2009 to 2019 by IMF has been used for this analysis. The primary energy consumption data for Sri Lanka was taken from the BP Statistical Review. The R2 value of this model came out as 0.924, implying that ~92 percent of the variation in the primary energy consumption is being explained by the GDP data. For future projections, two scenarios were considered for a five-year CAGR of GDP between 2021 and 2026 and a seven-year CAGR of GDP between 2019 and 2026. The seven-year CAGR scenario has been considered as the most plausible scenario in the given case. The five-year CAGR and seven-year CAGR for Sri Lanka's GDP growth were 4.1 percent and 3.1 percent, respectively. The details of the GDP data and growth rate have been provided in Annexure 17.5.1.

[251] LTGEP 2020-39 (Page E-8, E-9)
[252] https://www.adb.org/sites/default/files/institutional-document/547381/sri-lanka-energy-assessment-strategy-road-map.pdf (Page 74)
[253] https://thediplomat.com/2020/10/fighting-deforestation-in-sri-lanka/
[254] https://www.pucsl.gov.lk/wp-content/uploads/2019/02/NG_Policy-Draft.pdf (Page 9)

Figure 99 Methodology of top-down for calculation of natural gas demand in Sri Lanka

Detailed methodology

1. Step 1 – Projection of GDP of Sri Lanka
    a. The historical GDP of Sri Lanka from 2009 to 2019 was collated.
    b. The GDP from 2020 to 2026 was sourced from IMF.
    c. Beyond 2026, two scenarios have been used to project GDP until 2040.
        i. Scenario – 1: The first scenario took a five-year CAGR between 2021 and 2026 and projected GDP numbers beyond 2026 at the calculated growth rate. Within this scenario, the GDP growth of Sri Lanka has been considered ~4.1 percent.
        ii. Scenario – 2 (most plausible scenario): The second scenario took a seven-year CAGR between 2019 and 2026 and projected GDP numbers beyond 2026 at the calculated growth rate. This was considered as the most plausible scenario. Within this scenario, the GDP growth of Sri Lanka has been considered ~3.1 percent.
2. Step 2 – Projection of primary energy consumption
    a. Regression analysis of primary energy consumption with respect to historical GDP had been conducted. A correlation of ~92.4 percent was observed between primary energy and GDP that can be considered as a pretty good statistical fit.
    b. Using the correlation between GDP and primary energy and future GDP projections, primary energy consumption was projected until 2030, considering the two scenarios of GDP growth in Sri Lanka.
3. Step 3 – Projection of natural gas demand
    a. Current share of natural gas consumption is nil.
    b. According to the National Policy on Natural Gas, the share of natural gas in Sri Lanka is expected to reach up to one-third of the share of fossil fuels consumption by 2030. The share of energy consumption of fossil fuels, according to the latest data for Sri Lanka, was ~85 percent of the total energy mix. Therefore, the share of natural gas is expected to be ~28 percent of the total primary energy mix by 2030. Natural gas share has been projected linearly from 2021 to 2030 to obtain 28 percent share in 2030.
    c. According to NPNG, natural gas needs to maintain a minimum of 30 percent share in the overall energy mix. From 2031 to 2040, the share of gas in the primary energy mix has been increased at 1 percent year-on-year to ensure an optimal energy mix (representing different fuels, including renewable energy and meeting the minimum target of 30 percent).

Analysis

Gas demand under various scenarios is projected to increase from 12.23 mmscmd in 2030 to 23.70 mmscmd in 2040 in the first scenario and from ~10 mmscmd in 2030 to ~18 mmscmd in 2040 in the second scenario. The base case scenario – 2, which assumes ~3.1 percent annual increase in GDP from 2026 onwards considering a seven-year CAGR of GDP growth between 2019 to 2026, seems the most plausible one.

Table 105 Summary of natural gas demand scenarios in Sri Lanka using the top-down approach

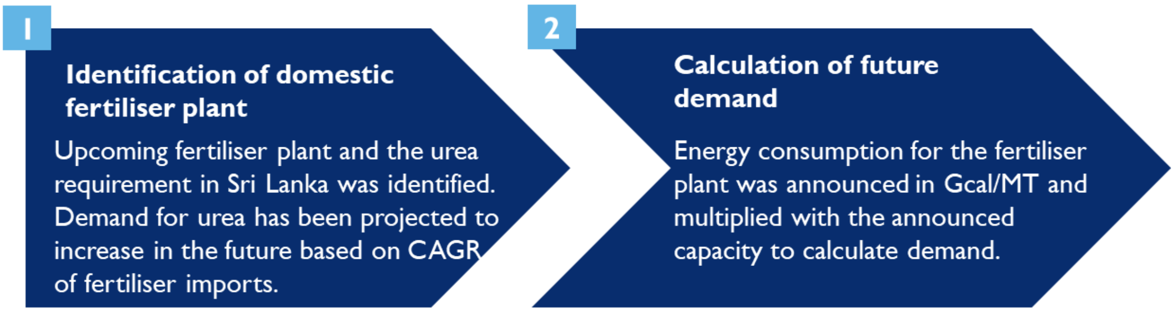
Scenario	Gas demand (mmscmd)				Remarks
	2025	2030	2035	2040	
Scenario - 1	4.3	10.4	14.9	21	28 percent share of natural gas by 2030 and GDP projected on the basis of a five-year CAGR between 2021 and 2026
Scenario – 2 (most plausible scenario)	4.3	10	13.5	18	28 percent share of natural gas by 2030 and GDP projected on the basis of a seven-year CAGR between 2019 and 2016 (most plausible scenario)

6.5.4 Bottom-up approach

6.5.4.1 Fertiliser sector

In the current scenario, there is no indigenous fertilisers production in Sri Lanka. All the demand for fertilisers is being met with the help of imports. The government of Sri Lanka now prepares to produce the urea fertiliser locally and a study is being conducted to assess its feasibility; for this, Paranthan Chemicals Ltd. has submitted a proposal, along with Ceylon Institute of Nanotechnology.[255]

Figure 100 Methodology to calculate natural gas demand in Sri Lanka from the fertiliser sector



Detailed methodology

1. An upcoming urea-based fertiliser plant that has been announced was considered on the basis of published secondary data. Moreover, urea demand has been considered to increase at ~2.5 percent based on industry estimates.
2. Energy consumption for an equivalent fertiliser plant has been considered on the basis of industry experience in Gcal/MT. This has been multiplied with announced capacities and converted into mmscmd to arrive at natural gas demand.

Assumptions

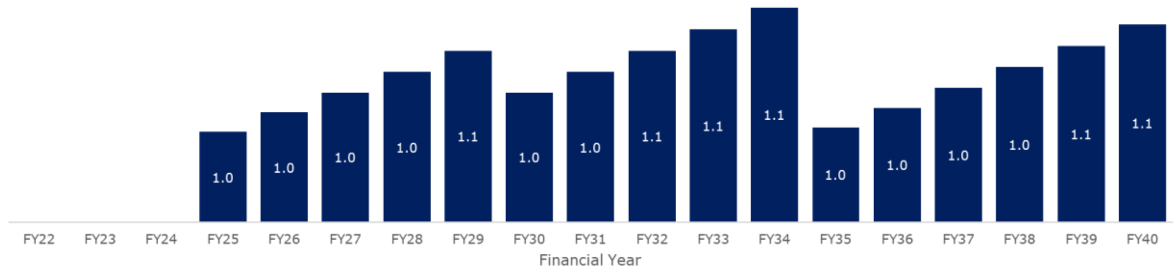
1. The assumption has been made on the basis of industry experience that energy consumption for the fertiliser plant in Gcal/MT will decrease in the future as the plant's efficiency increases.

Analysis

Demand for natural gas from the fertilisers sector in Sri Lanka is expected to increase from 0.96 mmscmd in FY 2025 to 1.09 mmscmd in FY 2040 based on the urea consumption. This increase in demand is not significant enough because energy consumption for fertiliser production is expected to become more efficient in the future. Moreover, the plant is expected to start operations from FY 2025. Hence before that, demand from fertilisers sector has been considered nil.

[255] http://www.colombopage.com/archive_20B/Dec22_1608616421CH.php

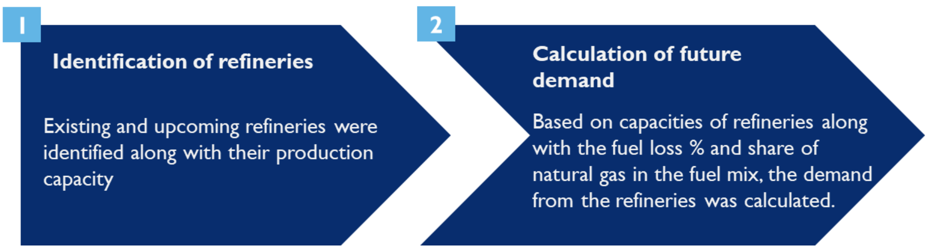
Figure 101 Projected natural gas demand from the fertiliser sector in Sri Lanka (in mmscmd)



6.5.4.2 Refining sector

A refinery consumes fuel gas, fuel oil, naphtha, and natural gas either as feed and/or fuel for hydrogen generation and gas turbines. The primary consumers of fuel in a refinery are process heaters, hydrogen generators and utilities. For the refining sector, currently two refineries in Sri Lanka have been considered to estimate natural gas demand – Sapugaskanda Refinery operated by the Ceylon Petroleum Corporation and Hambantota Refinery. Both of these refineries are expected to get connected with pipelines by about 2025; after that, demand from refineries has been estimated.

Figure 102 Methodology to calculate natural gas demand from the refining sector in Sri Lanka



Detailed methodology

1. Step 1 – Identification of refineries
   a. The existing and upcoming refineries in Sri Lanka were identified, along with their refining capacity
2. Step – 2 Estimation of natural gas demand
   a. Natural gas demand has been estimated by multiplying refining capacity with the percentage of natural gas in the overall fuel mix and fuel loss percentage.
   b. Demand from refineries was estimated from the expected year of completion of gas pipelines until FY 2040.

Assumptions

1. Connectivity to a gas pipeline for both the upcoming refineries has been assessed. After the commencement to the gas pipeline, demand has been estimated.
2. The fuel and loss percentage of both the refineries has been estimated ~10 percent considering that they would be energy-intensive refineries.
3. Considering a number of fuels (fuel oil, fuel gas, naphtha, and natural gas) are consumed in both the refineries, the share of natural gas consumption has been assumed 25 percent.

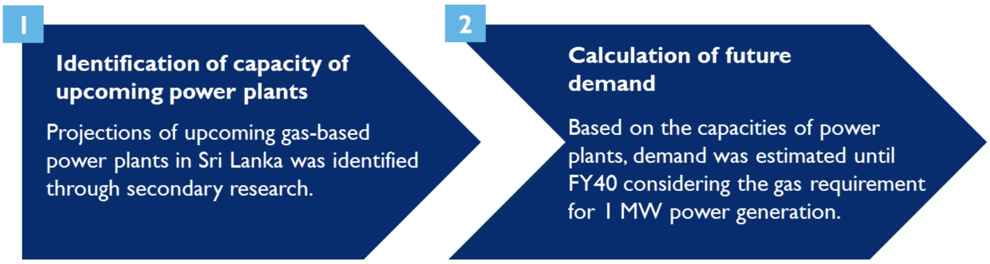
Analysis

Gas demand for the refining sector in Sri Lanka is expected to be 0.9 mmscmd from FY 2026-40 (after the expected year for completion of the gas pipeline), considering the publicly available data for the existing and upcoming refineries in Sri Lanka. However, it might increase in case more refinery projects are announced in the future.

6.5.4.3 Power sector

The power sector in Sri Lanka is expected to generate significant demand for natural gas in the upcoming years. West Coast and Kelanithissa Combined Cycle Plants are likely to be converted to natural gas with the development of LNG infrastructure. In addition, around 10 gas-based fire power plants are expected to come up in Sri Lanka in the future based on secondary research done from LTGEP 2020-39. Hence, for these power plants, the requirement of natural gas was identified based on 1 MW of power generation. Around 900 MW of gas-based power plants are planned by 2025 and expected to increase to 3000 MW by 2040. The details of the new upcoming power plants have been provided in Annexure 17.5.2.

Figure 103 Methodology for calculation of demand from Power Sector in Sri Lanka



<u>Detailed methodology</u>

1. Step – 1: Calculation of total capacity of upcoming power plants
    a. LTGEP 2020-39 provides projections of upcoming natural gas-based power plants in Sri Lanka until 2040. The plants and their total upcoming capacity were identified until FY 2040.
    b. In addition, the plants that are likely to be converted into natural gas were considered. According to LTGEP 2020-39, the Sojitz Kelanithissa power plant will be converted into a combined cycle gas-based power plant from 2023 onwards. Moreover, the West Coast and Kelanithissa combined cycle plants are likely to be converted to natural gas.
    c. The gas-based power plants retiring after FY 2030 were considered and their gas demand was made 0.
2. Step – 2: Calculation of natural gas demand for 1 MW power generation
    a. The PLF of the power plants across the years was determined from the estimates provided in LTGEP 2020-39.
    b. Based on capacities of upcoming gas-based power plants, natural gas demand has been estimated and predicted from FY 2021-40 after multiplying the capacity of power plants with the PLF and gas required for 1 MW power generation.

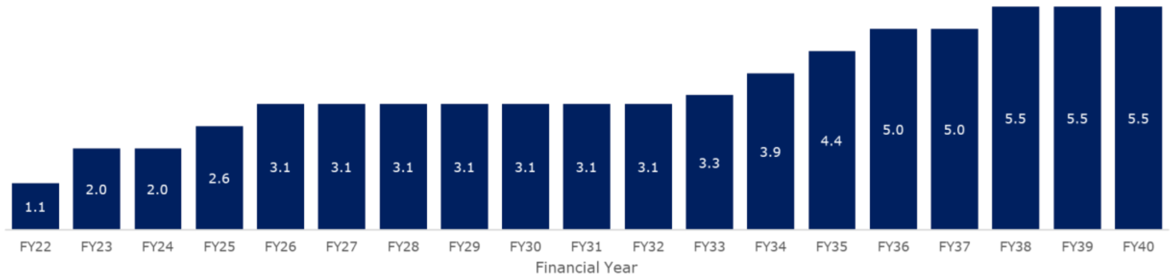
<u>Assumptions</u>

1. The PLF was assumed to be constant across the years taking the average of the PLF across the years that has been considered for power generation from gas-based power plants in LTGEP 2020-39.
2. As there is no natural gas consumption in the country, consumption per MW of power plant was calculated considering a typical consumption of natural gas per MW of power plant (e.g., 1 MW of power plant will consume gas in the range of 3000-4100 scmd for PLF ranging between 60-90 percent considering Station Heat Rate (SHR) of say 1900 kcal/Kwh and taking conversion to equivalent gas requirement with gross calorific value of gas).

<u>Analysis</u>

The natural gas demand from gas-based power plants is expected to rise from 1.1 mmscmd in FY 2022 to 3.1 mmscmd in FY 2030 and 5.5 mmscmd in FY 2040.

Figure 104 Projected natural gas demand in Sri Lanka from the power sector (in mmscmd)

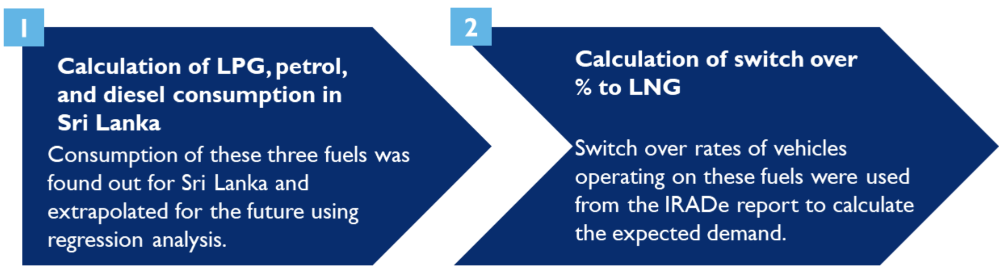


6.5.4.4 CGD sector

Currently, within CGD sector, there hasn't been any usage of natural gas in Sri Lanka. However, with the govt. initiatives to push towards cleaner fuels, a number of vehicles running in Sri Lanka on petrol and diesel are expected to convert to CNG which is going to drive the demand for natural gas from the CGD sector. The natural gas can be introduced for the vehicles in the form of CNG, LNG OR DME (Dimethyl Ether). CNG can be used in light vehicles like the 3-wheelers and 4-wheelers while LNG can be used in heavy vehicles including buses. The DME option can be used as a substitute for diesel. Natural gas might prove to be a more economical option than the other POL fuels and also cause less environmental pollution. With the development of the necessary infrastructure, the prices and transition towards natural gas could be governed by the market forces. The Government can also try to give a push towards this fuel by giving concessions on purchase of CNG-fitted vehicles and encouraging the use of LNG in public transport and luxury buses that are plying on the long-distance routes.

For the domestic sector, the demand may be catered to by supplying natural gas in future in clusters of the individual households through the local pipeline networks that are serviced by a central storage unit and receive their gas supply from CNG/LNG bulk carriers. Public-Private Partnership model can be incorporated in the country to supply the gas to individual consumers and also undertake the installation and maintenance of the network. The gas distribution in Sri Lanka might not be able to commence immediately and it might take a few years for the people to get comfortable with this new kind of fuel. Moreover, from the supply side as well, developing the relevant infrastructure and ensuring the appropriate safety standards within those central storage units might consume time. Hence, the penetration of natural gas for this sector has been assumed to begin from FY 2025 onwards.

Figure 105 Methodology for calculation of natural gas demand from the CGD sector in Sri Lanka



<u>Detailed methodology</u>

1. Step – 1: Calculation of consumption of LPG, petrol, and diesel in Sri Lanka
    a. Central Bank of Sri Lanka provides the historical consumption of LPG, petrol, and diesel in Sri Lanka.[256]
    b. Based on historical consumption of above fuels (FY 2015 to FY 2020), regression analysis has been performed with GDP and fuel consumption from FY 2021 to FY 2040 has been predicted for these fuels. The following were the regression equations for the three fuels:

[256] https://www.cbsl.gov.lk/sites/default/files/cbslweb_documents/publications/otherpub/publication_sri_lanka_socio_economic_data_folder_2020_e.pdf (Page 55)

*LPG consumption (in kL) = -1363 + 0.1848*GDP (in billions of SLR)*
*Petrol consumption (in kL) = -3178 + 0.4661*GDP (in billions of SLR)*
*Diesel consumption (in kL) = 93.74 + 0.216*GDP (in billions of SLR)*

Table 106 Regression analysis for fuel consumption in Sri Lanka with GDP

Fuel type	R^2 value	p-values	
		Intercept	x-variable
Petrol	0.87	0.02	0.007
Diesel	0.35	0.95	0.21
LPG	0.86	0.01	0.008

c. After doing the regression analysis for growth in the consumption for LPG and Petrol, the R2 value of the models came out as ~0.86 and ~0.87 implying that a significant variation in the consumption of LPG and Petrol can be explained by the growth in the GDP of the country. Moreover, the p-value of both the intercept and x-variable was also checked to confirm that whether they are significant or not in case of Petrol and LPG. The p-value indicates the probability that the value of the intercept and x-variable is 0 in the regression equation and it needs to be less than 0.05. Here, for both Petrol & LPG, the p-value was less than 0.05, hence, the regression model only was used to project further demand.
d. After doing the regression analysis for diesel, the value of R2 metric came out as ~0.36 implying that the variation in demand for diesel in Sri Lanka could not be explained from the GDP data. Moreover, the p-values of the intercept and the x-variable are also not significant. Therefore, for diesel the CAGR from FY15 to FY20 was used to project the further growth in the use (that was ~2.06 percent).

2. Step – 2: Switch over percent to natural gas
   a. 2 scenarios for switching over to natural gas were considered.
   b. Scenario – 1 (Most plausible scenario): Switch over rates of vehicles from petrol, diesel, and LPG to natural gas were considered from the IRADe report in order to estimate the overall demand. For switch over from LPG, petrol, and diesel to natural gas, the following conversion rates had been considered based on the IRADe report:[257]

Table 107 Switch over rates for different types of vehicles towards natural gas in Sri Lanka

	2025	2030	2035	2040
Petrol and diesel	10%	20%		25%
LPG	15%	25%	35%	40%

   c. Scenario – 2: The second scenario has been considered from the natural gas utilisation roadmap report by Sri Lanka Carbon Fund Ltd. Within that, the penetration of LPG to natural gas will start from 2026 at 4 percent and increase 4 percent every year until 2040 to reach up to 60 percent. Moreover, for petrol and diesel, the penetration will start from 2023 at 2 percent and increase by 2 percent every year to reach up to 36 percent by 2040.

<u>Analysis</u>

The total demand for natural gas in Sri Lanka from the CGD sector is expected to increase from 2 mmscmd in FY 2025 to 5.28 mmscmd in FY 2030 and 12.06 mmscmd in FY 2040 under Scenario 1, which is the most plausible

[257] *Gas and RLNG Environment in BBINS region (Page 168)*

scenario. Within Scenario-2, the overall demand from 0.3 mmscmd in FY 2023 to around 5.2 mmscmd in FY 2030 and 17.6 mmscmd in FY 2040. Also, the majority contribution in the demand from the CGD sector is going to be from petrol vehicles.

Figure 106 Projected natural gas demand in Sri Lanka from the CGD sector in Scenario-1 – most plausible scenario (in mmscmd)

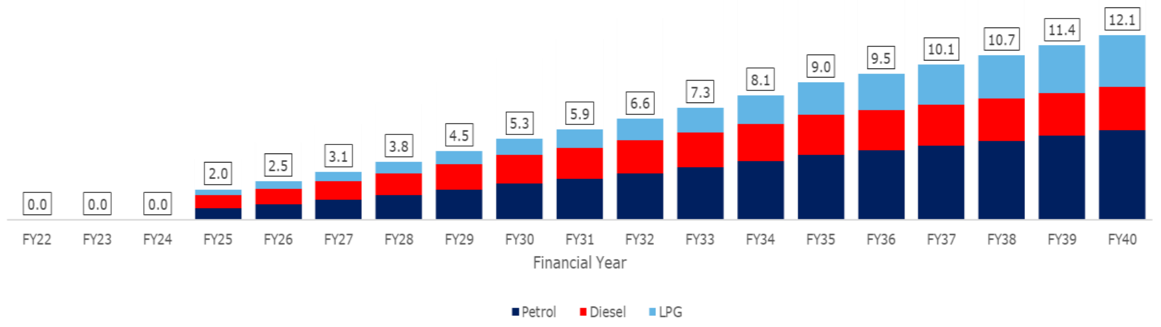
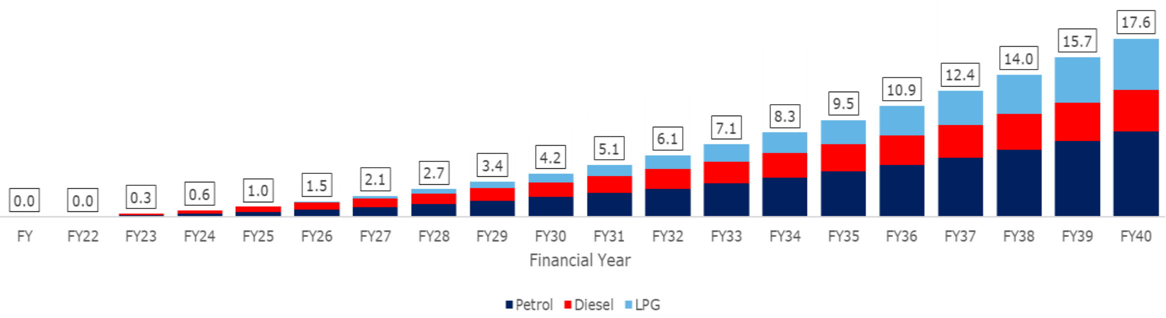


Figure 107 Projected natural gas demand in Sri Lanka from the CGD sector in Scenario-2 (in mmscmd)



6.5.5 Total demand projection until 2040

The overall demand for the natural gas sector in Sri Lanka is expected to increase from 1.1 mmscmd in FY 2022 to 10.3 mmscmd in FY 2030 and 19.6 mmscmd in FY 2040 within the most plausible scenario.

Figure 108 Overall projected natural gas demand in Sri Lanka for most plausible scenario (in mmscmd)

The following is the breakup for the overall sector-wise demand in the country:

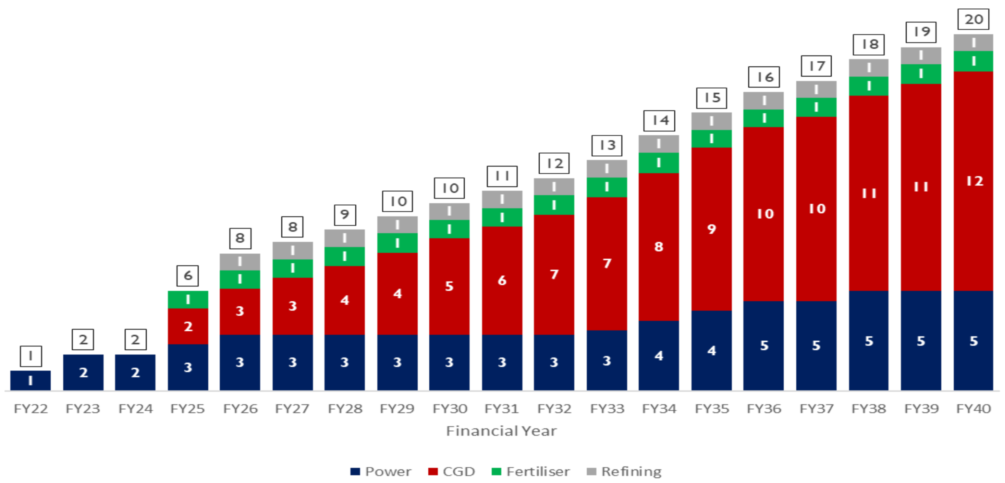
Table 108 Summary of sector-wise demand in Sri Lanka from FY 2022 to FY 2030 for most plausible scenario (in mmscmd)

Sector	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Power	1.1	2.0	2.0	2.6	3.1	3.1	3.1	3.1	3.1
CGD	0	0	0	2.0	2.5	3.1	3.8	4.5	5.3
Fertiliser	0	0.0	0.0	1.0	1.0	1.0	1.0	1.1	1.0
Refining	0	0	0	0	0.9	0.9	0.9	0.9	0.9
Total	**1.1**	**2.0**	**2.0**	**5.5**	**7.6**	**8.2**	**8.9**	**9.6**	**10.3**

Table 109 Summary of sector-wise demand in Sri Lanka from FY 2031 to FY 2040 for most plausible scenario (in mmscmd)

Sector	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Power	3.1	3.1	3.3	3.9	4.4	5.0	5.0	5.5	5.5	5.5
CGD	5.9	6.6	7.3	8.1	9.0	9.5	10.1	10.7	11.4	12.1
Fertiliser	1.0	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.1	1.1
Refinery	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**11.0**	**11.7**	**12.7**	**14.0**	**15.3**	**16.4**	**17.0**	**18.2**	**18.9**	**19.6**

Figure 109 Projections of sector-wise demand in Sri Lanka for most plausible scenario (in mmscmd)



6.6 Supply analysis

6.6.1 Planned supplies

6.6.1.1 Future initiatives

There are a number of upcoming plans and agreements that have started to come into picture for addressing the upcoming demand for natural gas in Sri Lanka. In order to address the demand in the next few years, Sri Lanka is increasingly looking towards FSRU based LNG distribution. Pearl Energy (Pvt) Ltd. signed an agreement with the Board of Investment of Sri Lanka to launch 'Hambantota LNG Hub' - a floating storage LNG trading facility at the Port of Hambantota, bringing LNG to Sri Lanka. The strategic location of the Hambantota port makes it the one of the most ideal locations for facilitating the trade[258]. The State Oil Company of Azerbaijan Republic (SOCAR) is also looking forward to joining hands in this project by partnering with Pearl Energy.[259]The initial capacity of the LNG trading facility is expected to be 1 MMTPA. For projecting the future supplies of Sri Lanka, LNG trading facility has been assumed to be operational from FY 2025 onwards at its maximum utilisation considering the push towards gas-based initiatives in the country.

Moreover, New York-based New Fortress Energy has signed a framework agreement with Sri Lanka's government to construct a new offshore LNG terminal. New Fortress will supply LNG to the existing 300 MW Yugadanavi power plant[260]. New Fortress has also signed a MoU with Lakdhanavi Ltd. (LTL) to collaboratively develop a gas-fired power plant in in the Kerawalapitiya Power Complex. Hence, there are a lot of future upcoming opportunities and plans for development of supply mechanisms of natural gas to Sri Lanka.

The Government of Sri Lanka has aligned its goals to reduce their dependence on imports and utilise all the reserves and resources that are locally available within the country. However, the goal to produce gas domestically for meeting majority of the country's needs will depend on the discoveries translating into

258 https://www.lankabusinessonline.com/pearl-energy-to-set-up-lng-hub-in-hambantota-aims-lng-trading-in-the-region/
259 https://www.maritimegateway.com/socar-trading-and-pearl-energy-to-develop-hambantota-lng-hub/
260 https://www.businesswire.com/news/home/20210713005674/en/New-Fortress-Energy-to-Develop-New-350-MW-Power-Plant-in-Sri-Lanka

production assets and securing of investors that often involve a long gestation period. Petroleum Development Authority of Sri Lanka (PDASL) has estimated that the Mannar basin alone could have the potential to generate 2 billion barrels of oil and 9 trillion cubic feet of natural gas, which is sufficient for meeting its needs for next 60 years.[261] To date, oil and gas production is yet to commence in the country. The country continues to depend on imports of crude oil and LNG to meet the demand at least in the short term.

6.7 Integrated demand-supply model

Table 110 Overall demand-supply estimates for Sri Lanka from FY 2022 to FY 2030 for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	1.1	2.0	2.0	5.5	7.6	8.2	8.9	9.6	10.3
Total supply	0	0	0	3.6	3.6	3.6	3.6	3.6	3.6
Deficit (-)/surplus (+)	-1.1	-2.0	-2.0	-1.9	-4.0	-4.6	-5.3	-6.0	-6.7

Table 111 Overall demand-supply estimates for Sri Lanka from FY 2031 to FY 2040 for most plausible scenarios (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	11.0	11.7	12.7	14.0	15.3	16.4	17.0	18.2	18.9	19.6
Total supply	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Deficit (-)/surplus (+)	-7.4	-8.1	-9.1	-10.4	-11.7	-12.8	-13.4	-14.6	-15.3	-16.0

[261] https://www.news.lk/fetures/item/27867-oil-and-gas-in-sri-lanka-are-we-on-track

7 Afghanistan

7.1 Country overview – Afghanistan

7.1.1 Economy (GDP), population, overall energy consumption, and fuel mix

Afghanistan had a population of ~39 million people in 2020.[262]According to the IMF data, the country's GDP in 2020 was ~US$20 billion.[263]The overall energy consumption of the country ~3.4 Mtoe in 2018, per the IRENA report.[264]The majority of the energy consumption in Afghanistan is met through imports. In 2018, non-renewable energy sources, such as oil, gas, and coal constituted ~75 percent of the overall energy consumption in the country. In the past two decades, Afghanistan's energy consumption has increased significantly, mainly due to population growth and changing lifestyle patterns. The following pie chart shows the energy consumption mix in Afghanistan according to IRENA:

Figure 110 Afghanistan: Overall energy consumption by source (2018)

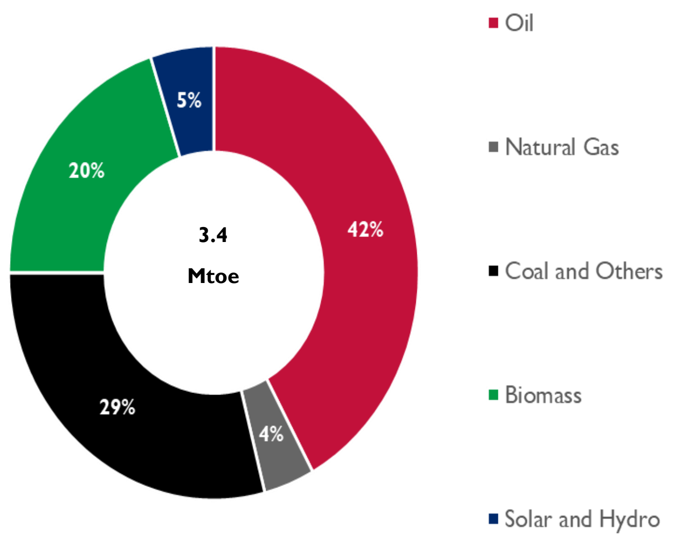


Table 112 Afghanistan: Overall energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Oil (42%)	1.4
Natural gas (4%)	0.14
Coal and others (29%)	0.99
Biomass (20%)	0.68
Solar and hydro (5%)	0.17

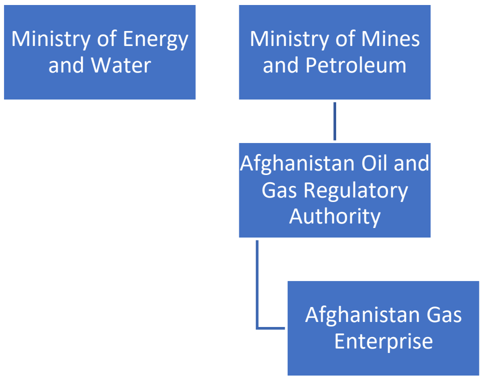
7.1.2 Gas value chain

The Ministry of Energy and Water (MEW) mainly manages Afghanistan's energy sector. MEW is responsible for formulating policies for power, coal, and gas and other primary fuels except POL products. MEW collaborates with the Ministry of Mines and Petroleum (MOMP) to formulate policies and attract investments for the energy

[262] https://data.worldbank.org/indicator/SP.POP.TOTL?locations=AF
[263] https://www.imf.org/external/datamapper/NGDPD@WEO/WEOWORLD/AFG
[264] https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Afghanistan_Asia_RE_SP.pdf

sector. Afghanistan Oil and Gas Regulatory Authority (AOGRA) is the oil and gas regulator. Afghanistan Gas Enterprise (AGE) is primarily responsible for upstream gas exploration and production in the country. AGE is a state-owned enterprise that comes under the MOMP. AGE was established in 1967 to implement and oversee natural gas operations. It is responsible for enhancing extraction and transmission capacities and selling spare parts and machinery. AGE is the sole upstream and midstream player in Afghanistan responsible for delivering gas to end consumers (fertiliser and power plants). It generates 90 percent of its revenue from the Kode-e-Barq fertiliser plant. In addition, a small part of the revenue comes from supplying natural gas to Mazar inhabitants. The following is the organogram of the gas sector in Afghanistan:

Figure 111 Organogram of the gas sector in Afghanistan



7.1.3 As-is assessment and challenges in the gas sector

In Afghanistan, years of conflicts and war have hindered economic development and progress which has been one of the major challenges for the country.

7.2 Gas infrastructure analysis

7.2.1 Existing infrastructure

The country currently has an 89 km gas pipeline (built in 1974) that connects Sherberghan gas fields to the Mazar-e-Sharif fertiliser plant for the direct supply of natural gas for urea production. However, the pipeline is unable to support the pressure required for a gas-fired power plant. Moreover, Afghanistan recently started extracting gas from a newly discovered field in the Sherberghan gas fields only.[265]Construction of a new 94.5 km pipeline from Sherberghan to Mazar-e-Sharif is in process; of which, 45 km has already been completed. A small network of pipelines also exists to fulfil demand from domestic consumers near the Sherberghan gas fields. However, gas supply through those pipelines is insignificant.

7.2.2 Upcoming and planned infrastructure

The major upcoming infrastructure for gas imports expected in Afghanistan is the TAPI (Turkmenistan-Afghanistan-Pakistan-India) pipeline. This would be an 1,814 km trans-country natural gas pipeline running across four countries. A special-purpose consortium known as TAPI Pipeline Company (TPCL) was incorporated in November 2014 by Turkmengaz (a majority stakeholder with an 85 percent interest), Afghan Gas Enterprise (5 percent), Inter State Gas Systems (5 percent), and GAIL (5 percent) to execute project for the four countries, with Turkmengaz leading the consortium. The pipeline was expected to be operational from late 2022. However, the expected completion might get delayed, or the pipeline might also stay incomplete due to a political matter in the country.

7.3 Policy, regulatory enablers, and emerging trends

7.3.1 Policy and regulatory support and incentives to promote the sector

Afghanistan did not have any laws and regulations for the oil and gas sector until 2005. Afghanistan's first hydrocarbon law was adopted in 2009, under which two exploration and production-sharing contracts were awarded. The hydrocarbon law was further amended in September 2018 to further reform the subsector. The

[265] https://www.aa.com.tr/en/asia-pacific/afghanistan-starts-gas-extraction-after-4-decades/1789496

new hydrocarbon law led to the formation of AOGRA in March 2019 that was responsible for promoting private investments and regulate upstream, midstream, and downstream activities.

No public data revealing any latest policies for promoting natural gas, is available.

7.3.2 Emerging trends with respect to alternative fuels

Afghanistan's government had formed in a policy to promote the use of renewable energy sources – "Afghanistan National Renewable Energy Policy". This policy aimed to introduce renewable energy in the national energy sector plans through commencement of different RE projects in the country. It was aligned to the power sector master plan for setting up a framework to increase the use of renewable energy in the country.[266]The following were the plan's salient features:

- Target to deploy 350-450 MW of renewable power capacity by 2032
- Support the involvement of the private sector, government, and non-government organisations, donors, and the people of Afghanistan in transitioning towards renewable energy resources
- Optimally deploy and use renewable energy resources in all possible manners

7.4 Pricing assessment

7.4.1 Gas pricing mechanism

No legal framework is available in the country to regulate gas pricing. A few methodologies had developed but were not adopted because of lack of consensus. Pricing for current customers is being decided by the AGE Board of Directors.[267]

7.4.2 Pricing of alternative fuels and comparison with natural gas

The Afghanistan Ministry of Commerce and Industries supervises the fuel sector in the country. It plays a major role in determining prices. However, no public data is available on the pricing mechanism of alternative fuels in Afghanistan. Moreover, the country largely depends on imports for its energy demands. Hence, duties are levied on imports for different fuels; this acts as a good source of revenue for the government. The following table shows the prices of alternative fuels as of January 2022.[268]

Table 113 Prices of alternative fuels in Afghanistan

Fuel	Retail selling rice (as of January 2022) in US $/mmbtu
Gasoline	29.9 (92 Afghani/L)
Diesel	19.6 (75 Afghani/L)
LPG	36.2 (90 Afghani/L)

(Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for 1 January 2022.

Calorific value of LNG = 12,500 kcal/kg; 1 mmbtu = 2,52,000 kcal; US$ to AFG for 1 January 2022 = 103.75; calorific value of diesel = 10,800 kcal/kg; calorific value of petrol = 10,500 kcal/kg; calorific value of kerosene = 11,100 kcal/kg; calorific value of LPG = 11900 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L; density of kerosene = 0.82 kg/L; density of LPG = 0.51 kg/L)

7.5 Demand analysis

7.5.1 Existing demand

In Afghanistan, about 34 percent population has access to grid electricity. However, due to a severe shortage, power cuts last up to 15 hours a day. About 200 MW of gas-based power plant is planned in Sheberghan using

[266] https://www.SARenergy.org/wp-content/uploads/2019/05/SAR-Energy-Outlook-2030-Final-Report-Draft.pdf (Page 56)
[267] ADB Assessment of Gas and Power Subsector in Afghanistan
[268] https://www.globalpetrolprices.com/Afghanistan/

the country's domestic natural gas.[269]This will require 0.8-1 mmscmd of natural gas. In addition, demand for natural gas is also generated from the Mazar-e-Sharif (Kod-e-Barq) fertiliser plant in Afghanistan. No public data for natural gas demand from other sectors, is available.

7.5.2 Key demand drivers

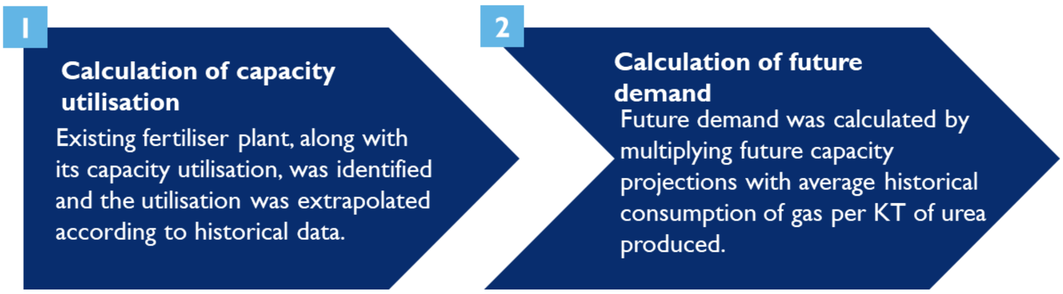
Given the lack of electricity access to a large section of the population in the country, there is a significant potential to expand gas-based power generation once the gas fields are developed in the country or the TAPI pipeline is operational. According to the Afghanistan Power System Master Plan for 2013, gross power demand would increase approximately seven times to reach 15,909 MU in 2032 in the base case.[270]The upcoming two gas-based power plants are expected to address domestic power demand and boost gas demand in the country. The country also depends on imports to meet its urea-related demands as the current urea plant in Afghanistan does not function at its full efficiency. As new fertiliser plants are announced in the country, gas demand would subsequently increase in the future.

7.5.3 Bottom-up approach

7.5.3.1 Fertiliser sector

The current analysis of demand from the fertiliser sector has been made based on the data available in the public domain.[271]For analysing the natural gas demand from the fertiliser sector, data from only one plant (the Kod-e-Barq fertiliser plant) was available in the public domain. The plant has a production capacity of 105,000 tonnes of urea and is a gas-based plant. In addition to plant, most of the fertiliser demand in the country is met through imports through the China Pakistan Economic corridor (from Gwadar Port in Pakistan). No data regarding announcements for any new fertiliser plants was available for Afghanistan.

Figure 112 Detailed methodology for natural gas demand estimation from fertiliser sector



<u>Detailed methodology</u>

1. Step – 1: Calculation of capacity utilisation
    a. The existing fertiliser plant and its urea production capacity was identified.
    b. The plant utilisation for the future was projected based on the same rate as growth in historical fertiliser plant utilisation.
2. Step – 2: Calculation of future demand
    a. Future demand for natural gas from the fertiliser plant has been calculated by multiplying the future projections of plant capacity with the average historical gas consumption per KT urea production.
    b. Demand was calculated until FY 2030 using this methodology.

<u>Assumptions</u>

1. The utilisation of the plant capacity has been expected to increase in the future at the historical growth rate.
2. The current analysis of the demand from the Fertiliser sector has been made based on the data that is available in the public. It considers that the fertiliser demand will increase in the next few years.

[269] SARI/EI, IFC, Diesel and gas turbine worldwide - https://rb.gy/kb4td4
[270] *https://www.SARenergy.org/wp-content/uploads/2019/05/SAR-Energy-Outlook-2030-Final-Report-Draft.pdf (Page 60)*
[271] *Note: All the analysis for demand and supply for Afghanistan was carried out before the political matters in the country*

7.5.3.2 Power sector

The penetration of electricity within the households of Afghanistan has been close to ~35 percent[272] and most of the un-electrified households in the country live in the rural areas. Imports from the neighbouring countries fulfil the majority of power requirements of the country. The transmission system is fragmented, consisting of isolated grids or islands supplied by different power systems (including different generating stations and different import sources). About 80 percent of the power requirements are met through imports from countries such as Tajikistan, Uzbekistan, Turkmenistan, and Iran. For domestic power generation, the country had ~57 percent of the renewable energy capacity and 43 percent of the non-renewable energy capacity in 2020. Within renewable energy, hydroelectricity and solar power have been the primary sources of power generation. For non-renewable power generation, the country had 14 diesel-based and two oil-based power plants, as of FY 2018. However, the capacity utilisation within both renewable and non-renewable power sources has been quite low. As of 2019, the capacity utilisation of hydroelectric generation plants was 39 percent and solar power generation plants was 18 percent, whereas for fossil fuels-based generation, it was ~7 percent.[273]Within Afghanistan, Da Afghanistan Breshna Sherkat (DABS) is the sole company responsible for power transmission and distribution in the country. It also determines tariffs for different sectors and is a responsible for overseeing the power generation systems, including substations, transformers, cable networks, and dispatch and control systems. According to the latest data, the following were electricity tariffs for different entities decided by DABS:[274]

Table 114 Price of power for different consumer segments in Afghanistan

Entity	Power price (in US$/kWh)
Apartments	0.03 (0-200 kWh) 0.04 (201-400 kWh) 0.07 (401-700 kWh) 0.10 (701-2000 kWh) 0.11 (2001 kWh or higher)
Commercial	0.14
Government	0.15
NGOs	0.14
Registered factories	0.07
Unregistered factories	0.14

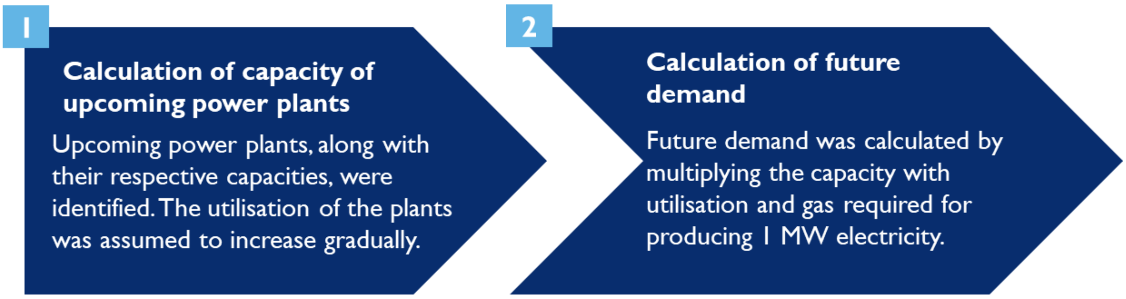
The conversion rate used has been 1 Afghani = 0.011 US $

The transmission system in Afghanistan is divided into four major groups connecting different supply sources to the grid: the first group is the North East Power System (primarily connecting Kabul, Mazar-e-Sharif and Jalalabad with Uzbekistan and Tajikistan); second group is the South East Power System (consists of Kandahar and links with the hydro power project at Kajaki); the third one is the Herat System (links with Iran and Turkmenistan); the final one is the Turkmenistan system. The North East Power System is the major transmission system that receives power from Uzbekistan and Tajikistan as well as several domestic generation plants. As of 2018, DABS had signed five power purchase agreements with private developers that included two gas-fired power plants, two solar power generation plants in Kandahar, and the capacity expansion of the hydro-power project in Kajaki, along with its operation and maintenance.

272 *SAARC Energy Outlook*
273 https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Afghanistan_Asia_RE_SP.pdf
274 https://main.dabs.af/KabulElectricitytariff

According to the Afghanistan Power Master Plan 2013, gross power demand in the country will reach up to ~16000 MU by 2032.[275] The main demand centres for Power in Afghanistan are capital Kabul, followed by Herat, Balkh, Kandahar, Kunduz, and Parwan. From FY 2018, gross demand in the power sector is expected to increase at a rate of ~6.2 percent. In lieu of the increasing demand, the utilisation of gas-based power plants in Afghanistan is also expected to increase in the near future. For our analysis, we have considered two power plants – Mazar gas plant[276] and Sherberghan Gas Power plant.[277] The Mazar gas plant was commissioned in 2020 and expected to be completed by end of 2021.[95] For the Sherberghan gas power plant, the Bayat Energy Company has been provided a five-year contract starting from 2019.[96] Moreover, the PLF of these plants has been considered to improve gradually considering the increasing power demand in Afghanistan.

Figure 113 Detailed methodology for calculation of demand from the power sector



<u>Detailed methodology</u>

1. Step – 1: Calculation of capacity of the upcoming power plants
   a. Currently Afghanistan does not have any gas-based power plants operating in the country. The capacity and year of commencement for the two upcoming gas-based power plants was found through secondary research.
   b. The plant utilisation for the future was expected to increase gradually for making future projections.
2. Step – 2: Calculation of future demand
   a. Future demand of natural gas from power plants has been calculated based on the data of gas consumption for 1 MW power generation and the respective utilisation of the power plant.

<u>Assumptions</u>

1. The commencement of the power plants has been delayed by one year considering the political matters in Afghanistan. For the Mazar gas plant, the commencement year has been considered 2023; for Sherberghan Power, it has been taken as 2026.
2. The utilisation of the plant capacity has been expected to increase gradually in the future until it reaches its maximum utilisation due to the increasing power demand in Afghanistan.

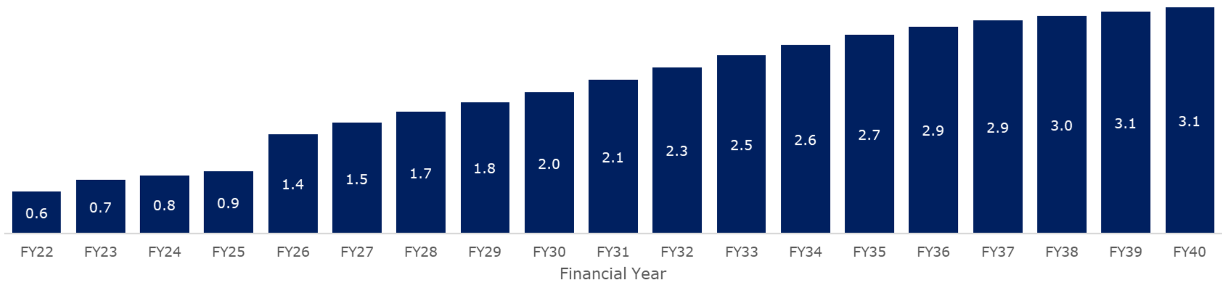
7.5.4 Total demand projection until 2040

For demand projection from FY 2031-40, the increase in the overall demand (~9 percent) was calculated from FY 2026-30. This growth rate was further extrapolated at a reducing trend to calculate the overall demand until FY 2040. The extrapolation was done at a reducing rate as the visibility of the overall scenario of the country beyond FY 2030 is limited.

The total demand projection using the bottom-up approach for Afghanistan is expected to increase from 0.58 mmscmd in FY 2022 to 1.95 mmscmd in FY 2030 and 3.13 mmscmd in FY 2040. These demand projections will depend on stability in the country in the future.

Figure 114 Overall projection of natural gas demand in Afghanistan (in mmscmd)

[275] *SAARC Energy Outlook*
[276] https://www.nsenergybusiness.com/projects/mazar-e-sharif-gas-to-power-project/
[277] https://momp.gov.af/work-progress-%C2%A0bayat%C2%A0power-plant-production-electrical-energy-natural-gas



7.6 Supply analysis

7.6.1 Existing domestic production

According to the data from the Ministry of Mines of Afghanistan, the country currently has about 0.42 trillion cubic meters of unexplored natural gas reserves. Major gas reservoirs are located in the north and northwest regions near the Uzbekistan and Turkmenistan borders. According to intergovernmental agreements concluded between the government of Afghanistan and the Soviet Union, starting from 1958, surveys were conducted in the territories of northern Afghanistan to discover oil and gas reserves. From 1960-1983, several oil and gas fields were discovered in the northern provinces of Sheberghan, Sar-e-Pul, and Faryab. Until 1989 when the Soviet Union withdrew from the country, the gas produced in the country was exported to the Soviet Union. Following the Soviet military's withdrawal, natural gas production and operations in Afghanistan dropped drastically.

Additional exploration and development were not carried out during the Afghan civil war and also by the Taliban government. However, after the American invasion and removal of the Taliban government, exploration and production activities for natural gas were able to resume slowly. As of 2011, the country had 34 natural gas wells in the three producing gas fields. Afghan Gas Enterprise successfully rehabilitated a well in the Shakarak gas field in early 2011. According to a recent re-assessment by USGS Petroleum Resource Assessment, the country has an undiscovered 16 trillion cubic feet of natural gas and 0.5 billion barrels (0.8 billion tonne) of the natural gas liquids in the country. The technically recoverable gas reserves in Afghanistan according to the study were in the range of ~444 bcm.[278]Most of the technically recoverable natural gas reserves are located in two basins in northern Afghanistan - the Amu Darya basin and the Afghan Tajik oil and gas fields.

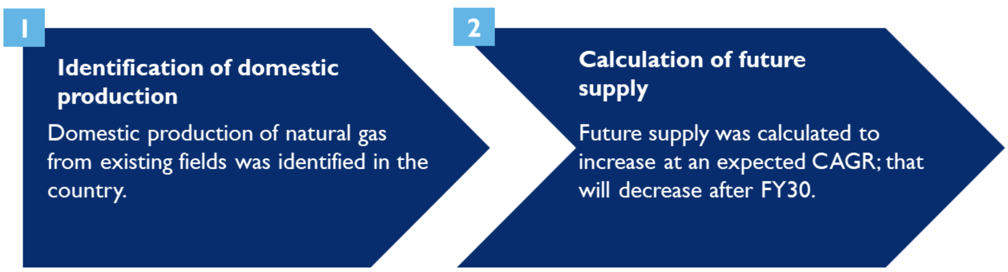
Eight gas reservoirs have been discovered in the Amu Darya basin.[279]However, gas production of 411 scmd commenced[280] in 2020 after nearly four decades from the Jawzjan province near gas rich Turkmenistan border. The country currently produces only 5 percent of its domestic fuel demand and rest of the fuel demand is fulfilled by imports from other countries.

7.6.2 Upcoming and planned expansion

7.6.2.1 Supply projection for domestic production

Afghanistan Gas Enterprise is responsible for the production and supply of natural gas. The AGE's natural gas supply mostly goes to the Kod-e-Barq fertiliser plant in Afghanistan. For projections regarding domestic production, production from AGE has only been considered.

Figure 115 Methodology for projection of natural gas supply in Afghanistan



278 https://www.adb.org/projects/47018-001/main
279 Revised estimates of Oil and Natural Gas Reserves in Afghanistan - https://rb.gy/wjtub2
280 https://www.aa.com.tr/en/asia-pacific/afghanistan-starts-gas-extraction-after-4-decades/1789496

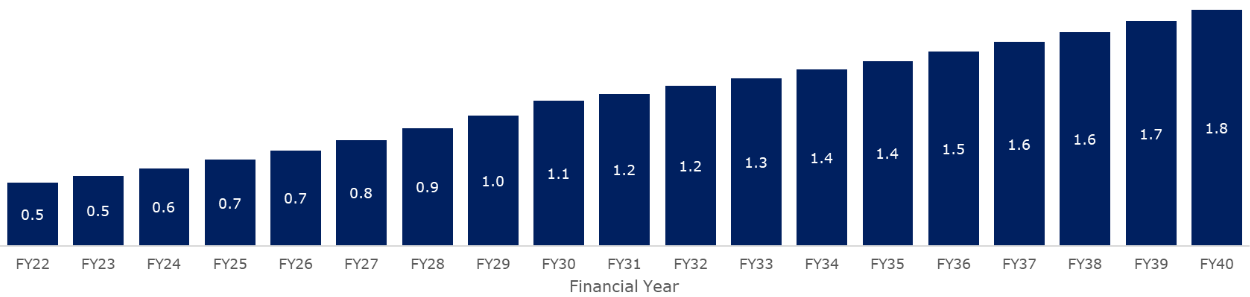
Detailed methodology

1. Gas production from existing domestic gas fields was identified through the annual report by the Ministry of Mines and Petroleum.
2. Gas supply was projected through FY 2022-30 at a CAGR of ~11 percent considering discovery of new domestic resources in the next few years. For domestic supply projection from FY 2031–40, the CAGR was reduced to 5 percent considering the depletion of the domestic natural gas resources.

Analysis

Natural gas supply in Afghanistan from domestic production is expected to increase from 0.5 mmscmd in FY 2022 to 1.1 mmscmd in FY 2030 and 1.8 mmscmd in FY 2040. This is taking into consideration of the fact that a plethora of natural gas reserves which are there in the country will be explored in future and used to extract the natural gas.

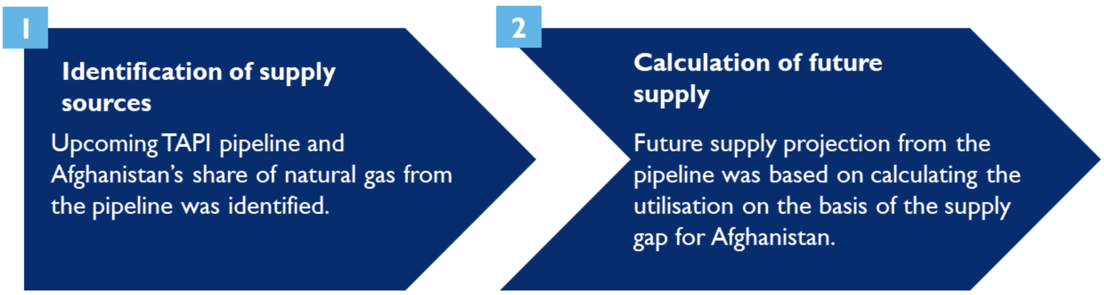
Figure 116 Projected natural gas supply in Afghanistan from domestic production (in mmscmd)



7.6.2.2 Supply projection for imports

The supply through imports for Afghanistan is expected to be majorly through the TAPI (Turkmenistan, Afghanistan, Pakistan, and India) pipeline. Afghanistan is expected to purchase 16 percent of the gas being transferred through the pipeline, which approximates to 5.11 bcm[99] per year. The country would also receive a transit fee for the pipeline, which will also facilitate gas import to Pakistan and India.[281]

Figure 117 Methodology for projecting natural gas supply from imports in Afghanistan



Detailed methodology

1. The upcoming Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline and Afghanistan's share of gas volume (~14 mmscmd) in the pipeline were identified.
2. For the TAPI pipeline, two scenarios were considered:
   a. Scenario – 1: Completion of Pipeline: The TAPI pipeline has been delayed because of the political matters in Afghanistan and lack of investments from international companies. However, the new government in Afghanistan is expected to push the project forward and hence, the commencement has been assumed with a delay.

[281] https://www.hydrocarbons-technology.com/projects/turkmenistan-afghanistan-pakistan-india-tapi-gas-pipeline-project/

b. Scenario – 2: Pipeline remains incomplete (most plausible scenario): Considering the uncertainty regarding the TAPI pipeline, another alternative scenario has been assumed where no supply has been considered.

3. Within the most plausible scenario (Scenario – 2), the pipeline has been assumed to remain incomplete. For Scenario – 1, the utilisation of the pipeline has been determined by considering a number of factors such as the year of starting operations and a gap in natural gas supply to meet the deficit demand.

Assumptions

1. The TAPI pipeline was expected to be completed by 2021 in Afghanistan. Overall, the project had to be completed by late 2022.[282]Considering the recent political matters in Afghanistan, a two-year delay had been assumed in laying down the pipeline in Afghanistan. Hence the overall pipeline was assumed to be completed by 2024 for Scenario-1.[283]
2. The pipeline utilisation percentage during each year was determined to ensure fulfilling natural gas demand of the country.

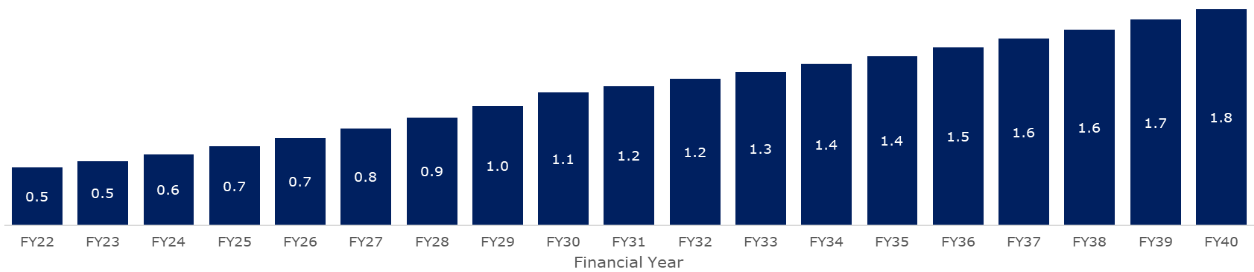
Analysis

Within the most plausible (Scenario – 2), the expected gas supply from imports for Afghanistan has been considered as 0 since the TAPI pipeline is not expected to get completed. However, within Scenario-1, Afghanistan's supply of gas from the TAPI pipeline is expected to rise from 0.3 mmscmd in FY 2025 to 0.8 mmscmd in FY 2030 and a maximum of 1.3 mmscmd in FY 2035. The imports from the TAPI pipeline would fulfil the overall natural gas supply deficit in Afghanistan until FY 2040 if it gets completed. In addition, within that case, Afghanistan would also have additional capacity as well to purchase and use natural gas being transported through the pipeline to meet an increase in demand in the country.

7.6.3 Total supply projection until 2040

Natural gas supply in Afghanistan is expected to increase from 0.5 mmscmd in FY 2022 to 1.8 mmscmd in FY 2040 considering the supplies from domestic production. If the TAPI pipeline is completed, the overall supply is expected to be 1.1 mmscmd by FY 2030 and 3.2 mmscmd by FY 2040.

Figure 118 Overall supply projection for natural gas in Afghanistan for most plausible scenario (in mmscmd)



7.7 Demand-supply model

7.7.1 Integrated demand-supply model

The following table provides integrated demand-supply projection for natural gas in Afghanistan. Within the basecase scenario when the pipeline is not completed, a supply deficit is expected of 0.8 mmscmd by FY 2030 and 1.3 mmscmd by FY 2040. However, if the TAPI pipeline commences in the country, then from FY 2025 onwards, the deficit is expected to reach zero until FY 2040.

[282] https://www.ogj.com/pipelines-transportation/pipelines/article/14188134/turkmenistan-to-start-afghan-tapi-construction-in-2021
[283] https://www.upstreamonline.com/production/taliban-tapi-gas-pipeline-is-a-priority-project/2-1-1053761

Table 115 Overall demand-supply projections for Afghanistan from FY 2022 to FY 2030 for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total Demand	0.58	0.75	0.81	0.86	1.38	1.53	1.69	1.82	1.95
Total Supply	0.5	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1
Deficit (-)/Surplus (+)	-0.1	-0.2	-0.2	-0.2	-0.6	-0.7	-0.8	-0.8	-0.8

Table 116 Overall demand-supply projections for Afghanistan from FY 2031 to FY 2040 for most plausible scenario (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	2.13	2.30	2.46	2.61	2.74	2.86	2.94	3.00	3.06	3.13
Total supply	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8
Deficit (-)/surplus (+)	-1.0	-1.1	-1.2	-1.3	-1.3	-1.4	-1.4	-1.4	-1.3	-1.3

8 Bhutan

8.1 Country overview – Bhutan

8.1.1 Economy (GDP), population, overall energy consumption, and fuel mix

Bhutan is a landlocked country located in the eastern Himalayas. It is bordered by China to the north and west, and India to the south and the east. Bhutan had a population of 0.745 million people in 2020.[284]According to IMF data, the country's GDP in 2020 was US$2.48 billion.[285]The overall energy consumption of Bhutan was ~1.8 Mtoe for 2018.[286]Bhutan is rich in fuels such as biomass (from firewood, biogas, and briquettes) and hydro reserves. However, it has small quantities of coal reserves and no proven petroleum reserves. The domestic and industrial sectors have the largest share in the primary energy mix accounting for ~79 percent of it. The balance 21 percent was consumed largely by the transport sector. Bhutan mainly depends on imports from India for meeting its energy requirements. The country's energy mix consists of 49 percent of biomass followed by 33 percent energy obtained through hydroelectricity according to the data published by IRENA.

Figure 119 Bhutan: Overall energy consumption by source (2018)

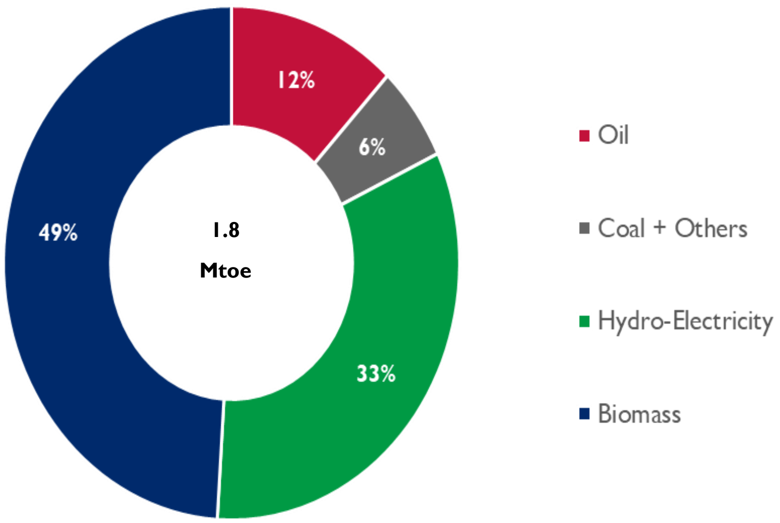


Table 117 Bhutan: Overall energy consumption by source (in Mtoe)

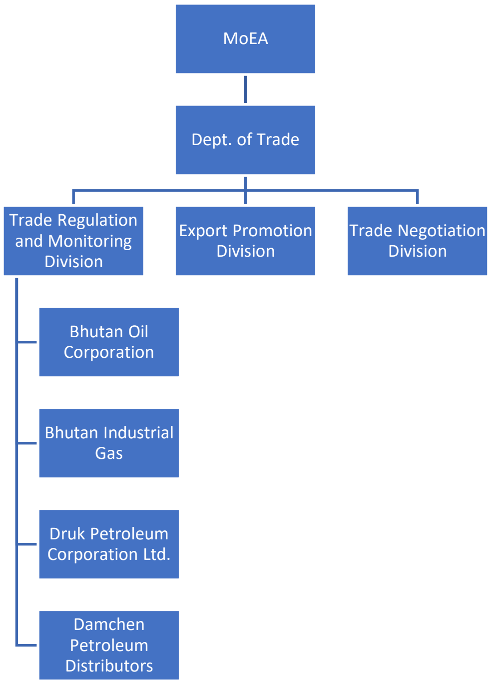
Source	Energy consumption (in Mtoe)
Oil (12%)	0.22
Coal and others (6%)	0.11
Solar and hydro (33%)	0.59
Biomass (49%)	0.88

8.1.2 Hydrocarbon value chain

Petroleum reserves have not been explored in Bhutan yet. The country does not have any refinery for crude oil processing. The Department of Trade under the Ministry of Economic Affairs (MoEA) oversees the refinery's operations. The Department of Trade (DoT) oversees the import of oil and petroleum products and their distribution. An organogram of the oil and gas sector is given below:

[284] https://www.imf.org/en/Countries/BTN
[285] https://www.imf.org/external/datamapper/NGDPD@WEO/OEMDC/ADVEC/WEOWORLD/BTN
[286] https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Bhutan_Asia_RE_SP.pdf

Figure 120 Organogram for the Ministry of Economic Affairs in Bhutan



Source: MoEA Organogram[287] and SAARC Energy Outlook

The Royal Government of Bhutan (RGoB) has a long-term agreement with the government of India for supplying petroleum products. Under the agreement, public sector oil companies in India, IOCL and BPCL supply petroleum products to Bhutan. Petroleum products are imported directly by distributors in Bhutan. At present, these products are distributed in Bhutan through Bhutan Oil Distributor (a part of the Tashi Group of Companies), Damchen Petroleum, Druk Petroleum Corporation Limited, and Bhutan Industrial Gas. The petroleum product market is regulated by the POL section under the Department of Trade, Ministry of Economic Affairs, RGoB.

8.1.3 As-is assessment and challenges

Bhutan does not consume natural gas due to unavailability of proven domestic sources and lack of pipelines from India or China (as Bhutan is landlocked country). It has significant hydropower potential and only a fraction of it has been tapped. Power generation is seasonally dependent, and shortfalls are met through imports from India.[288]The power generated throughout the year depends on the run-of-the river that fluctuates seasonally. Power generation is typically high during June to October because of snow melting and monsoon, while November to April is the lean season. Natural gas may have a role to play in the transport sector and industry depending on the development of gas ecosystem in the country. In the future, introduction of natural gas in Bhutan will depend on supply from neighbouring country India – either through extension of the North East grid pipeline or LNG trucks (subject to feasibility of demand and infrastructure).

8.2 Gas infrastructure analysis

8.2.1 Upcoming and planned infrastructure

At present, Bhutan does not have any planned infrastructure for transportation and distribution of natural gas.

However, several opportunities can be tapped into in the future to supply natural gas to Bhutan:

- Natural gas can be supplied to Bhutan through the Barauni-Guwahati pipeline that is expected to be completed by November 2021.[289]The point for this sourcing can be from Jalpaiguri, which is about 250 km from Thimphu, the capital city of Bhutan.

[287] https://www.moea.gov.bt/?page_id=25#tabs_desc_1191_2
[288] *IRENA - 2019*
[289] *https://economictimes.indiatimes.com/news/politics-and-nation/assam-is-moving-towards-gas-based-economy-chandra-mohan-patowary/articleshow/80450475.cms*

- In addition, the districts of Darjeeling, Jalpaiguri, and Kalimpong are included in the GAs to be covered in the ninth bidding round for City Gas Distribution by PNGRB.[290]These GAs are bordering Bhutan. As a result, implementation of piped natural gas in these GAs can further facilitate gas import in Bhutan.
- Bhutan also could be tapped through the CNG cascades. Dhamra could be used for ssLNG. Bhutan can also be served from India through ssLNG.

8.3 Policy, regulatory enablers, and emerging trends

8.3.1 Policy and regulatory support and incentives to promote the sector

In the 2020/21 budget, the government of Bhutan focused on hydro projects and diversifying its electricity mix to other forms of renewables.

The government has introduced several policy updates, including the National Energy Efficiency and Conservation Policy and a National Waste Management Strategy released in 2019. At present, Bhutan aims to remain carbon neutral, building upon a commitment already made in 2009.[291]

The Alternative Renewable Energy Policy (AREP) 2013 provided a comprehensive set of guidelines on suitable policy instruments, deployment pathways, and capacity developments. The AREP 2013 also laid the foundations for establishing a Renewable Energy Development Fund (REDF) as the central financing instrument for renewable energy projects in Bhutan.[292]

8.3.2 Emerging trends with respect to alternative fuels

The government is encouraging people to use EVs to reduce dependency on fuel imports. The 12th Five-Year Plan (2019-2024)[293]also identifies promotion of EVs to address environmental issues and reduce dependency on fossil fuels as one of the key programmes envisaged for the transport sector. This plan will also contribute to National Key Results Area 6 – carbon neutral, and climate and disaster resilient development enhanced.[294]

Bhutan had about 118 EVs as of February 2020. The Ministry of Information and Communication, as part of a GEF/UNDP project, has planned to roll out 300 electric taxis as part of the subsidy scheme for 2019-2021.[295]

Popularity of biogas is also increasingly in rural Bhutan. There are already 5,003 biogas plants in villages across the country, installed in collaboration with the Department of Livestock.[296]The units that have already been installed are collectively producing about 5,000 cubic metres of biogas per day (the equivalent of nearly 60,000 cylinders of LPG per year). The savings from fuel replacement was recently estimated at NT 31.4 million (US$ 419,000) per year.[297]

8.4 Pricing assessment

8.4.1 Gas pricing mechanism

As Bhutan completely depends on imports with no domestic reserves, no policy pertaining to gas pricing could be ascertained. However, natural gas can be supplied to Bhutan from India through two primary sources: road transportation through ssLNG and pipeline infrastructure.

- **Pipeline infrastructure:** Natural gas can be supplied to Bhutan from a take-off/carrier pipeline from the CGD regions of India that includes Bongaigaon (which is ~270 km from Thimphu) and Jalpaiguri (which is ~250 km from Thimphu). However, demand for natural gas in Bhutan is expected to be less than even 1 mmscmd in the future. To construct a pipeline from Bongaigaon to Thimphu for a period of 25 years, capex of ~INR 3 crore/km distributed in 2 years; opex of ~2.5 percent; and inflation of ~5 percent are considered, for getting a favourable return on investments. The levelised tariff for gas transportation using these assumptions will be ~US$18-19.5/mmbtu because of low gas demand in the country.

290 www.pngrb.gov.in
291 https://climateactiontracker.org/countries/bhutan/
292 IRENA 2019
293 https://policy.asiapacificenergy.org/node/2376
294 Report on Second Nationally Determined Contribution by the Royal Government of Bhutan (https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Bhutan%20Second/Second%20NDC%20Bhutan.pdf)
295 https://www.thethirdpole.net/en/energy/during-pandemic-bhutan-pushes-for-alternative-to-carbon-imports/
296 https://www.thethirdpole.net/en/energy/during-pandemic-bhutan-pushes-for-alternative-to-carbon-imports/
297 https://www.thethirdpole.net/en/energy/biogas-makes-big-waves-in-rural-bhutan/

Therefore, supply of natural gas to Bhutan through pipeline infrastructure might not be a viable alternative in the future because that would make it more expensive than other POL fuels.

- **Small-scale LNG:** The ssLNG systems transport LNG in cryogenic containers and re-gasify LNG at the consumer site. Small-scale LNG can be a better option to supply gas across Bhutan. Supply through ssLNG has lower initial investments and at the same time is more scalable. In addition, ssLNG offers less risk in terms of the complexities of transportation and the flexibility of the despatch schedules per the requirement at the demand centre. LNG can be supplied to Thimphu from either the Dhamra LNG terminal (~1100 km) or the Kukrahati LNG terminal (~960 km). For an illustrative cost calculation for the landed cost of gas for bulk consumers in Bhutan, the following major cost components will be involved in supply:

  i. The DES price of LNG has been assumed 12.5 percent of crude oil price, plus US$0.5 as a fixed constant charge.
  ii. Custom duty is 2.5 percent and cess on the custom duty is 10 percent.
  iii. Loading charges for LNG – The terminal will levy an additional charge for loading it into cryogenic tankers. This charge can be compared with the regasification charge being levied on pipeline transport. Loading charge has been considered US$0.8/mmbtu that also includes a US$0.2/mmbtu margin based on cost economics for ssLNG calculated by a report published by the Council on Energy, Environment and Water (CEEW).[298]
  iv. GST on the loading charges is @18 percent.
  v. Road transportation to Bhutan would be carried out through a fleet of cryogenic tanks. Transportation cost would primarily include capex for trucks and containers, operating expenses per kilometre, fuel cost for two-way transportation, and drivers' wages and taxes. On making broad assumptions, cost of transporting and meeting demand in Bhutan from Dhamra is ~US$2.5/mmbtu.
  vi. Costs of satellite storage plant: The plant will need to be included near to the demand site to re-gasify LNG for its use. A satellite storage plant will consist of components such as a small storage tank, pumps, and vaporisers for regasification for bulk use. Per CEEW, cost of a satellite storage plant consisting of a vaporiser (operating at 80 percent utilisation), a storage system, and other costs assuming a lifetime of 20 years is estimated at US$0.45/mmbtu.
  vii. Bhutan levies a 5 percent sales tax and 5 percent green tax on the fuels being sold in the country.[299]
  viii. Retail distribution cost has been assumed to be US$10/mmbtu (infrastructure, O&M cost, and margins). This is a high-level estimation and would vary depending on capex, opex, demand, etc. in a particular region.

  The following table shows an illustrative landed cost of ssLNG in Bhutan, considering the assumptions mentioned above:

Table 118 Illustrative cost for supply of natural gas from India to Bhutan through ssLNG

	Crude price	**$/Barrel**	**40**	**50**	**60**	**70**	**80**	**100**	**120**
(i)	DES (12.5%)	$/MMBTU	5.50	6.75	8.00	9.25	10.50	13.00	15.50
(ii)	Custom duty	$/MMBTU	0.15	0.19	0.22	0.25	0.29	0.36	0.43
(iii)	Truck loading charge	$/MMBTU	0.80	0.80	0.80	0.80	0.80	0.80	0.80
(iv)	GST on loading charge (18%)	$/MMBTU	0.14	0.14	0.14	0.14	0.14	0.14	0.14
(v)	Road transportation costs	$/MMBTU	2.50	2.50	2.50	2.50	2.50	2.50	2.50
	Overall transportation costs (sum from (i) – (v))	**$/MMBTU**	**9.10**	**10.38**	**11.66**	**12.95**	**14.23**	**16.80**	**19.37**

[298] https://www.ceew.in/sites/default/files/CEEW-SsLNG-expansion-26Mar21.pdf
[299] https://kuenselonline.com/tax-cut-on-fuel-in-india-will-not-reduce-fuel-prices-in-bhutan/

	Crude price	$/Barrel	40	50	60	70	80	100	120
(vi)	Satellite storage plant costs	$/MMBTU	0.45	0.45	0.45	0.45	0.45	0.45	0.45
(vii)	Bhutan sales tax (@5% of transportation and storage plant)	$/MMBTU	0.48	0.54	0.61	0.67	0.73	0.86	0.99
(vii)	Bhutan green tax (@5% of transportation and storage plant)	$/MMBTU	0.48	0.54	0.61	0.67	0.73	0.86	0.99
	Overall bulk consumer costs	**$/MMBTU**	**10.50**	**11.91**	**13.33**	**14.74**	**16.15**	**18.98**	**21.80**
	Retail distribution costs	$/MMBTU	10	10	10	10	10	10	10
	Overall end-consumer costs	**$/MMBTU**	**20.50**	**21.91**	**23.33**	**24.74**	**26.15**	**28.98**	**31.80**

8.4.2 Pricing of alternative fuels and comparison with natural gas

The Department of Trade, Ministry of Economic Affairs, regulates and determines prices of POL products across various regions of Bhutan. Price variation is seen in different districts on the basis of transportation cost. India is the only supplier of main POL products and prices are directly correlated by the market price in India. The following table shows prices of key POL products in Thimphu, Bhutan:

Table 119 Pricing of different POL products in Thimphu, Bhutan

Petroleum Products	Retail Selling Price (as of May 2022) IN US $/mmbtu
Petrol (MS)	40.1 (Nu 92.08 per litre)
Diesel (HSD)	38.2 (Nu 109.29 per litre)

(Source: Global Petrol Prices
Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for May 2022.

Calorific Value of LNG = 12,500 kcal/kg; 1 mmbtu = 2,52,000 kcal; US$ to Nu for May 2022 = 77.6; calorific value of diesel = 10,800 kcal/kg; calorific value of petrol = 10,500 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L)

Excise duty is exempted on fuel imports at source in India due to which prices of petrol and diesel are lower than those in India. The approximate end-consumer prices of LNG are expected to fall in the range of US$20-32/mmbtu in Bhutan. Therefore, LNG might prove to be a more viable alternative for use compared with petrol and diesel.

8.5 Demand analysis

8.5.1 Existing demand

Bhutan imported 0.11 million kL of diesel, 0.03 million kL of petrol, 3418 kL of kerosene, and 8454 MT of LPG in FY 2020.[300] Trucks and buses are the largest diesel consumers, with taxis accounting for the largest share of petrol. The transport and industrial sectors accounted for 19 percent and 37 percent of the total energy consumption[301]. Energy demand in industry and the transport sector has doubled in the past decade, making them the fastest-growing sectors in terms of energy consumption.

[300] *Statistical Yearbook of Bhutan, 2021*
[301] *Bhutan Energy Data Directory 2015 and IRENA's 2019 Report on Renewables Readiness Assessment: Kingdom of Bhutan*

8.5.2 Key demand drivers

Some of the drivers which can lead to increase in gas demand are as under:

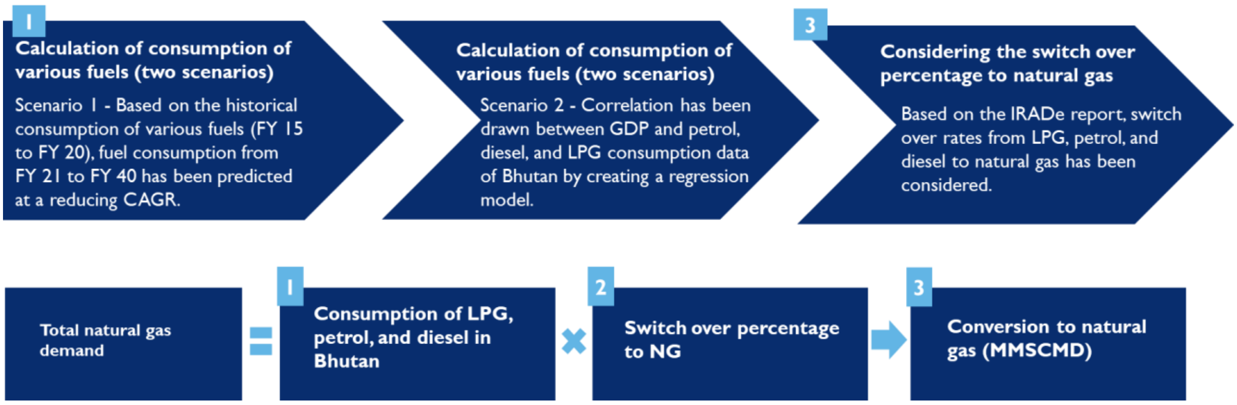
- At present, Bhutan aims to remain carbon neutral, building upon a commitment already made in 2009.[302]Natural gas can play a key role in maintaining this target.
- Gas demand is expected to come up majorly from the transport sector through introduction of CNG vehicles.
- Gas demand can also come up from replacing LPG as fuel with potential introduction of CGD networks in Bhutan. Domestic piped natural gas has comparatively been more affordable than LPG in other nations of the SAR. Hence, natural gas can replace LPG as cooking fuel especially within those areas where the pipeline network is created. Moreover, Bhutan has demand only for the subsidised LPG cylinders that are supplied from India. Non-subsidised cylinders are comparatively very expensive and sold in little volumes. As of 2019, the price of refilling a subsidised 14.2 kg LPG cylinder in Bhutan was 530 Nu compared with a non-subsidised cylinder that was 840 Nu.[303] With the potential pipeline connectivity with the nearby CGD GAs of India or through ssLNG supply from India, the introduction of natural gas can take place in the country. With the introduction of gas, the switch over from LPG can take place in the domestic segment. In addition, for industrial use as well, CNG/LNG might be able to provide more potential benefits compared with LPG. Within an industrial scenario, LPG might be difficult to disperse in case of a spill. It can have more dangerous outcomes during the accidents because of its higher calorific value.

8.5.3 Bottom-up approach

8.5.3.1 CGD sector

The CGD sector in Bhutan can be broken down into the industrial, transport, and other segments. Demand for the CGD sector is calculated using the data on historical consumption of LPG, petrol, and diesel in Bhutan provided by the National Statistics Bureau.

Figure 121 Methodology to calculate gas demand by the CGD sector in Bhutan under the bottom-up approach



<u>Detailed methodology</u>

1. Step 1 – Calculation of consumption of LPG, petrol, and diesel in Bhutan
    a. The National Statistics Bureau provided the historical consumption of LPG, petrol, and diesel in Bhutan; this was found out through secondary research.
    b. Two scenarios are considered:
        i. Scenario 1 - Based on historical consumption of above fuels (FY 2015 to FY 2020), fuel consumption from FY 2022 to FY 2040 has been predicted at a reducing CAGR with a minimum growth cap of 5 percent.
        ii. Scenario 2 – A correlation has been drawn by creating a regression model using the macroeconomic indicator of GDP of Bhutan. This approach has been considered to

[302] *https://climateactiontracker.org/countries/bhutan/*
[303] *https://thebhutanese.bt/chronic-shortage-of-subsidised-lpg-in-the-country/*

estimate the consumption of petrol, diesel, and LPG assuming that primary energy consumption will also change in proportion to a change in GDP.
The detailed list of the consumption data for both the scenarios has been provided in Annexure 17.7.1. After drawing in a correlation analysis between GDP and the consumption data for Bhutan, the following regression equations were obtained:

*Petrol consumption (in KL) = 1314.21 – 42358.2 * GDP (in billions of Nu)*
*Diesel consumption (in KL) = 2506.54 – 15978.7 * GDP (in billions of Nu)*
*LPG consumption (in MT) = 223.27 - 5711.29 * GDP (in billions of Nu)*

The R2 value and p-values of this model for petrol, diesel, and LPG consumption are as under:

Table 120 Regression analysis of Bhutan

Fuel type	R^2 value	p-values	
		Intercept	x-variable
Petrol	0.90	0.07	0.01
Diesel	0.88	0.65	0.01
LPG	0.88	0.15	0.01

Historical GDP of Bhutan from FY 2015 to FY 2020 by IMF has been used for this analysis. This model's R^2 value for petrol consumption was 0.90, implying that 90 percent of the variation in the petrol consumption is being explained by the GDP data. Similarly, R^2 value for diesel and LPG consumption was 0.88807 and 0.88402, respectively. This implies a strong correlation between GDP and the consumption of above-mentioned fuels.

2. Step 2 – Considering the switch over percentage to natural gas
    a. Demand for natural gas was considered to progressively increase from FY 2022 onwards based on penetration rates for conventional fuels. The following rates to switch over from LPG, petrol, and diesel to natural gas has been considered based on the IRADe report; this appeared plausible:

Table 121 Switch over rates to natural gas in Bhutan

	2025	2030	2035	2040
Petrol	0%	0%	0%	0%
Diesel	5%	10%	15%	15%
LPG	10%	15%	20%	25%

Assumptions

1. Gas demand is expected mainly from the transport sector through introduction of CNG vehicles. However, this is only expected to replace diesel due to price competitiveness with petrol. Hence, the switch over rates for petrol have been considered as zero. Moreover, Bhutan plans to replace its cars and taxis with EVs. For both LCVs and HCVs, the replacement of diesel with natural gas has been considered.

2. Gas demand has also been created by replacing LPG as fuel with any potential introduction of CGD networks in Bhutan.
3. To calculate consumption of LPG, petrol, and diesel, a reducing CAGR has been capped at 5 percent after FY 2030. This is because in case of developing economies (such as Bhutan), consumption growth in petroleum products will be higher in initial years. However, as economies mature, consumption will not rise at the same rate in the future. Hence, a cap in CAGR has been factored in.
4. Based on the different calorific fuel conversion rates for each fuel and switch over rate, natural gas demand in the CGD sector has been predicted from FY 2021 to FY 2040.

Analysis

In the first scenario, natural gas demand from the CGD sector is expected to increase from 0.04 mmscmd in FY 2025 to 0.09 mmscmd in FY 2030 and 0.22 mmscmd in FY 2040. In the second scenario, demand will increase from 0.03 mmscmd in FY 2025 to 0.09 mmscmd in FY 2030 and 0.25 mmscmd in FY 2040. The highest contributor of this rise in natural gas demand can be attributed to the replacement of diesel used for transportation purpose. The demand for gas in place of diesel will rise from 0.03 mmscmd in FY 2025 to 0.22 mmscmd in FY 2040.

Table 122 Summary of natural gas demand in Bhutan under the bottom-up approach

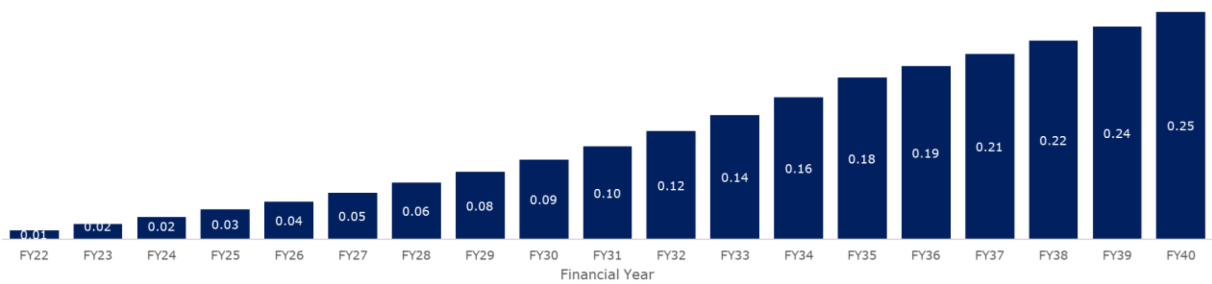
Scenario	Gas demand (mmscmd)			
	2025	2030	2035	2040
Scenario – 1 (most plausible scenario)	0.04	0.09	0.17	0.22
Scenario – 2	0.03	0.09	0.18	0.25

8.5.4 Total demand projection until 2040

The total demand projection for natural gas in Bhutan is expected to increase to 0.09 mmscmd in FY 2030 and 0.22 mmscmd in FY 2040 for scenario 1 and 0.25 mmscmd for scenario 2.

Figure 122 Projected natural gas demand in Bhutan from all sources in Scenario 1: most plausible scenario (in mmscmd)

Figure 123 Projected natural gas demand in Bhutan from all sources in Scenario 2 (in mmscmd)



8.6 Supply analysis

8.6.1 Future initiatives

Several mechanisms can be considered to supply natural gas to Bhutan. The Barauni-Guwahati pipeline, which is under construction in India, can be one of the options that would be completed by November 2021.[304] Jalpaiguri (West Bengal, India), which is about 250 km from Thimphu (the capital of Bhutan), can be the sourcing point of this pipeline. Moreover, the districts of Darjeeling, Jalpaiguri, and Kalimpong are included in GAs to be covered in the 9th bidding round for City Gas Distribution by PNGRB.[305]These GAs are bordering Bhutan that presents the opportunity to facilitate the trade of piped natural gas with Bhutan through small diameter take-off pipelines. Bhutan also could be tapped through CNG cascades. The upcoming Dhamra LNG terminal in India could be used for ssLNG.

8.7 Integrated demand-supply model

Table 123 Overall demand-supply estimates for Bhutan from FY 2022 to FY 2030 for most plausible scenario (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.08	0.09
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.01	-0.02	-0.03	-0.04	-0.04	-0.05	-0.06	-0.08	-0.09

Table 124 Overall demand-supply estimates for Bhutan from FY 2031 to FY 2040 for most plausible scenario (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	0.10	0.12	0.13	0.15	0.17	0.18	0.19	0.20	0.21	0.22
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.10	-0.12	-0.13	-0.15	-0.17	-0.18	-0.19	-0.20	-0.21	-0.22

[304] *https://economictimes.indiatimes.com/news/politics-and-nation/assam-is-moving-towards-gas-based-economy-chandra-mohan-patowary/articleshow/80450475.cms*
[305] *www.pngrb.gov.in*

9 Maldives

9.1 Country overview – Maldives

9.1.1 Economy (GDP), population, primary energy consumption, and fuel mix

Maldives comprises 1,192 dispersed small islands in the Indian Ocean, grouped into 26 geographical atolls. It has a population of 0.52 million people in 2020.[306]According to the IMF data, the country's GDP in 2020 was ~US$4 billion.[307]The overall energy consumption of Maldives was 0.58 Mtoe in 2018, per IRENA.[308]At present, the energy mix of Maldives comprises of oil as the single-largest only energy source. The energy mix includes consumption of POL products (diesel, petrol, and cooking gas), with miniscule involvement from RE. Amongst POL products, diesel is the single-largest energy source, accounting for ~86 percent of the energy supply in 2018.[309]The power sector is the largest consumer of diesel, with no other power generating sources in the country.

Figure 124 Maldives: Overall energy consumption (2018)

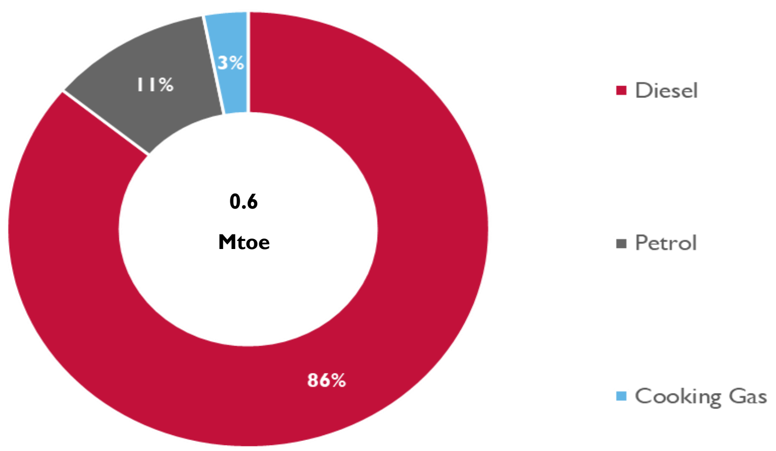


Table 125 Maldives: Overall energy consumption by source (in Mtoe)

Source	Energy consumption (in Mtoe)
Diesel (86%)	0.5
Petrol (11%)	0.06
Cooking gas (3%)	0.02

9.1.2 Hydrocarbon value chain

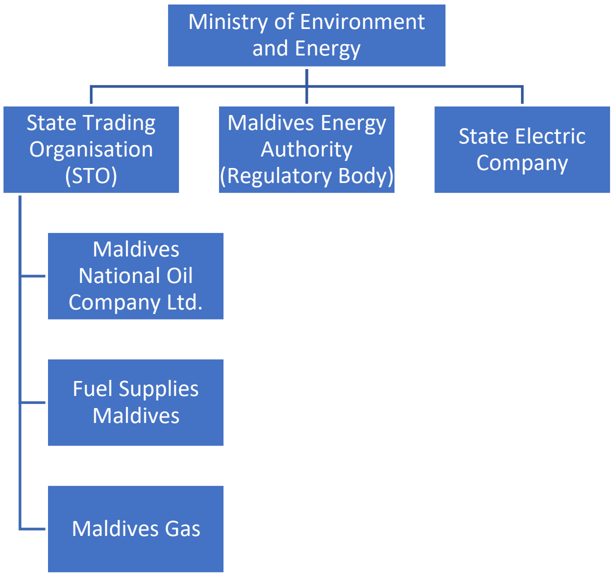
Due to lack of indigenous fossil fuels reserves, Maldives fully depends on imported POL to meet its energy needs. The Ministry of Environment and Energy is the primary body responsible for the government's environmental, energy, and climate policy.[310]The energy department oversees formulating policies related to the energy sector. It strengthens international cooperation to boost both investment and knowhow in the sector. It is committed to raise awareness on energy resources and consumption. The State Trading Organisation PLC (STO) is responsible for undertaking trading and commercial activity on behalf of the Maldivian government.[311]It undertakes the trade and import of POL products.

[306] *https://www.imf.org/en/Countries/MDV*
[307] *https://www.imf.org/external/datamapper/NGDPD@WEO/OEMDC/ADVEC/WEOWORLD/CHN/NPL*
[308] *https://www.irena.org/IRENADocuments/Statistical_Profiles/Asia/Maldives_Asia_RE_SP.pdf*
[309] *Source: SAR, Energy Data Book, Maldives Custom Services*
[310] *https://www.environment.gov.mv/biodiversity/about-us*
[311] *https://sto.mv/AboutUs*

- Maldives National Oil Company (MNOC) is a 100 percent owned subsidiary of STO. It was incorporated to explore potential and oversee production, refining, and transport of hydrocarbons, gas, and POL products.
- Fuel Supplies Maldives Ltd. (FSM) deals in providing fuel-related services, including sales, distribution, and maintenance of storage facilities across the country.
- Maldives Gas is the distributor of cooking gas in the nation and supplies LPG to more than 40,000 customers.[312]

Following is the organogram of the hydrocarbons sector in Maldives:

Figure 125 Organogram of hydrocarbons sector in Maldives



Source: SAARC Energy Outlook, 2030

9.1.3 As-is assessment and challenges

Maldives stands out on the electricity front compared with other SAR nations. It has achieved a provision of providing 24-hour electricity supply throughout the country since 2008.[313]However, to date, diesel acts as the main fuel source for power generation. Over-reliance on diesel imports to meet power demand makes Maldives highly vulnerable to global fuel price fluctuations; this affects the government's control over fiscal and current account deficits. The share of natural gas is not quite significant compared with other POL products in the country's energy mix.

According to the current assessment, a few of the challenges for Maldives in the gas sector are mentioned below:

- Maldives has no proven large-scale gas reserves.
- It one of the most vulnerable nations to climate change, particularly to natural disasters and environmental hazards.
- Geographically being an island country consisting of several dispersed islands, Maldives finds it difficult to lay pipeline infrastructure for connecting islands with natural gas.
- The country mainly depends on international tourism and global trade means that even the tiniest fluctuations in the world market are felt across the Maldivian economy.
- The government was trying to reduce the impact of these external factors through diversification. However, COVID-19 has also significantly affected the sector's supply side and imports. The main sector, tourism, came to a standstill in 2020. After that, it is yet to pick up and come to the pre-COVID levels.

[312] https://sto.mv/Subsidiaries
[313] https://www.worldbank.org/en/news/feature/2020/12/11/maldives-building-back-better-through-clean-energy

9.2 Gas infrastructure analysis

9.2.1 Existing infrastructure

As on date, no gas grid/existing pipeline infrastructure is dedicated towards transportation and distribution of natural gas in Maldives. Moreover, the country does not have any indigenous proven gas reserves, and is completely dependent on imports to meet its POL demand.

9.2.2 Upcoming and planned infrastructure

LNG can be sourced to Maldives from the following possible supply locations:

- Dahej LNG terminal – LNG can be sourced from the Dahej LNG terminal in Gujarat, India
- Kochi LNG terminal – LNG can be sourced from the Kochi LNG terminal in Kerala, India
- Colombo, Sri Lanka – Upcoming LNG terminal by New Fortress Energy[314]

Distributing LNG within Maldives would involve transporting LNG at a small scale. LNG would be brought to Maldives from conventional LNG import terminals or mid-sea LNG carriers or FSRUs. It would be then distributed in smaller-sized parcels directly to end-users using a combination of sea and land transport.

Within the Greater Male region, gas can be distributed through a pipeline. For islands outside Male, ssLNG can be distributed through small-scale LNG carriers. Outside the Greater Male region, LNG could represent a cost reduction opportunity for large resort islands that ship small amounts of LNG from Male for a resort's semi-industrial processes and power production.

Small-scale LNG can be built as modular structures with options to build upon existing infrastructures (e.g., harbors, jetty, and access roads).

Figure 126 Possible LNG supply chain through small scale LNG (ssLNG) in Maldives

9.3 Policy, regulatory enablers, and emerging trends

9.3.1 Policy and regulatory support and incentives to promote the sector

Maldives has played a coherent and prominent role in international climate change discussions. Maldives' Nationally Determined Contribution (NDC) submission to the United Nations Framework Convention on Climate Change (UNFCCC) has established the country's intention to reduce its greenhouse gas emissions by 10 percent compared with business-as-usual by 2030 unconditionally[315]. Additionally, the country intends to reduce greenhouse gas emissions by 24 percent under the condition of sufficient availability of financial resources and international support for technology transfer and capacity building. In addition, the increasing climate change presents an existential threat for Maldives. Given the small, low-lying and dispersed nature of its islands, along with its high import dependency and vulnerabilities to extreme events, the country would be one of the severely impacted ones in case of a disaster. Therefore, the island nation remains active on international forums, such as the United Nations Framework Convention on Climate Change (UNFCCC), and tries to abide by targets set for the country. The efforts made by the government of Maldives in the future are expected to be based on strategies and sectoral action plans designed for the energy, tourism, waste, water, and building sectors.[316]

The policy instruments supporting Maldives' vision for its energy sector are the Energy Policy and Strategy 2016 and the Strategic Action Plan (SAP) 2019–2023. The Energy Policy and Strategy 2016 has established five guiding principles:

1. Strengthen the institutional and regulatory framework of the energy sector
2. Promote energy conservation and efficiency
3. Increase the share of renewable energy in the national energy mix

[314] https://www.offshore-technology.com/news/new-fortress-lng-terminal-sri-lanka/
[315] https://www4.unfccc.int/sites/NDCStaging/Pages/All.aspx
[316] Road map for the energy sector in Maldives 2020–2030

4. Improve the reliability and sustainability of electricity service and maintain universal access to electricity
5. Increase national energy security

The SAP identifies development priorities, steers national efforts, and outlines achievable targets for a five-year period.

The government considers that investing in renewable energy is crucial to improve energy security and reverse the country's dependence on imported fossil fuels.

9.3.2 Emerging trends with respect to alternative fuels

For harnessing biomass energy, biomass resources (mostly coconut shells and coconut oil) are also available. However, biomass resources are constrained because they are distributed in much dispersed small quantities across Maldives. However, the amounts are too small for local solutions, and their collection would be too complex and carbon-intensive to bring them to a place with large energy demand.[317]

One of the key areas for the government is the transport sector. Cars that are older than five years are banned from being imported and only motorcycles with a certain engine capacity allowed into the country.[318]

Use of EVs is on the rise in Maldives. To further boost the use, EVs are allowed into the Maldives tax-free, while petrol and diesel vehicles face a 200 percent import duty.[319]

The World Bank has supported the government through the Accelerating Sustainable Private Investment in Renewable Energy (ASPIRE) project, which began in 2014, and the recently launched Accelerating Renewable Energy Integration and Sustainable Energy (ARISE) project (approved in 2020)[320]

9.4 Pricing assessment

9.4.1 Gas pricing mechanism

As natural gas is not being consumed, the authorities have made no provision for the gas pricing strategy.

9.4.2 Pricing of alternative fuels and comparison with natural gas

Table 126 Pricing of different POL products in Maldives

Petroleum products	Retail selling rice (as of May 2022) in US$/mmbtu
Petrol (MS)	31.9 (MVR 14.6 per litre)
Diesel (HSD)	26 (MVR 14.8 per litre)
LPG cylinder	27.4 (MVR 200.00 for refilling of 10 kg cylinder)

(Source: https://sto.mv/Media/Details/revision-of-fuel-prices--ref-news-fuel-2021 https://maldivegas.com/pages/prices

Price conversion has been done to US$/mmbtu based on the calorific values of the respective fuels and using the exchange rate for May 2022.

Calorific value of LNG = 12,500 kcal/kg; 1 mmbtu = 2,52,000 kcal; US$ to MVR for May 2022 = 15.5; calorific value of diesel = 10,800 kcal/kg; calorific value of petrol = 10,500 kcal/kg; calorific value of kerosene = 11,100 kcal/kg; calorific value of LPG = 11,900 kcal/kg; density of diesel = 0.86 kg/L; density of petrol = 0.71 kg/L; density of kerosene = 0.82 kg/L; and density of LPG = 0.51 kg/L)

Maldives Gas is the distributor of cooking gas in the nation and supplies LPG to more than 40,000 customers.

[317] Report - A Brighter Future for Maldives Powered by Renewables
[318] https://www.ccacoalition.org/en/partners/maldives-republic#:~:text=Further%2C%20electric%20vehicles%20are%20allowed,a%20200%20percent%20import%20duty.andtext=To%20reduce%20overall%20passenger%20vehicle,%2C%20bicycle%20lanes%2C%20and%20footpaths.
[319] https://bit.ly/3DUzSi7
[320] https://www.worldbank.org/en/results/2021/03/31/derisking-solar-projects-to-catalyze-private-investment-in-maldives#:~:text=In%20December%202020%2C%20the%20World,time%20supporting%20improved%20power%20system

9.5 Demand analysis

9.5.1 Existing demand

Demand for POL products in Maldives was ~561,433 MT before the disruptions caused by the pandemic.[321] Diesel serves as the primary energy fuel source, accounting for ~82 percent of the total POL imports in the country in 2018.[322] The power sector accounted for ~80 percent of diesel consumption. To meet residential demand, the overall installed diesel-based power capacity in the inhabited islands is estimated to have risen from 141 MW in 2012 to 214 MW in 2017. Demand for diesel is rising from resorts to undertake tourism activities (such as tourist ship excursions and fishing). Demand for petrol also rose significantly led by rising number of motorcycles and passenger cars and the speed boats segment utilised for tourist transit.

According to import data, cooking gas demand in Maldives rose from 14,483 tons in 2017 to 16,885 tons in 2019,[323]with residential consumption contributing more than 60 percent to the total demand. The remaining demand came from resorts and the fishing segment. The emphasis on clean energy has led to a rising conversion from kerosene to LPG as cooking fuel.

9.5.2 Key demand drivers

Setting up infrastructure for LNG use in the Greater Male region would be relevant for the following applications:

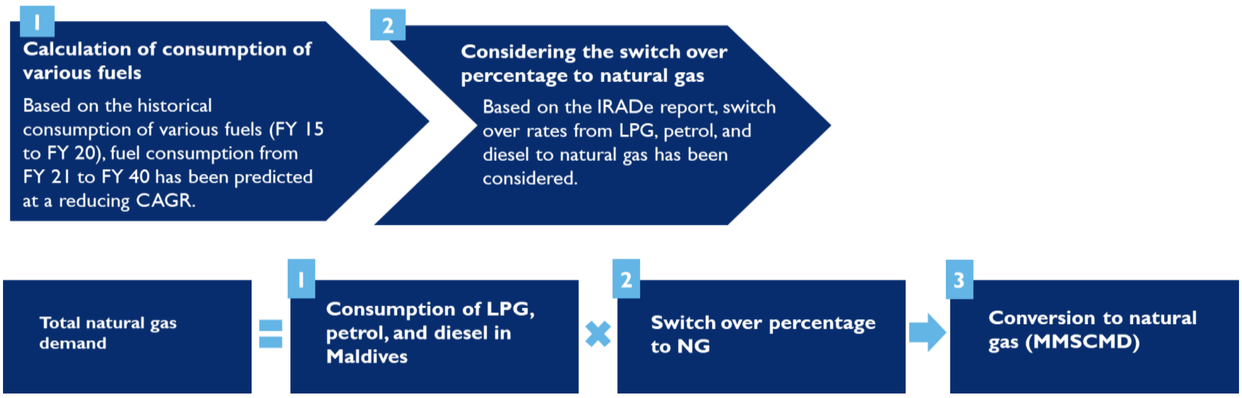
- **Power -** In its effort to reduce dependence on imported fuel, the government is pushing for power generation through other energy sources. Replacing diesel with natural gas can help increase the share of natural gas in the energy mix.
- **Industry and resorts** - Natural gas distributed through pipelines could substitute the fuel used in the co-generation (power and heat), heating, and cooling processes used in industries and resorts.
- **Sea transport** – Being a tourism dominated country, Maldives relies on tankers, container vessels, and cruises. LNG and dual fuel engines are an option for this segment. Use of LNG will also be encouraged through the IMO 2020 rule. This limits sulphur content in fuel oil used on ships to 0.5 percent m/m, down from the previous 3.5 percent limit.[324]Ocean-Going Vessels (OGVs) can use LNG as a bunker fuel that can provide both the environmental benefits and attractive fuel prices for stakeholders. Installing small-scale LNG infrastructure in the Greater Male region can provide an opportunity to install an LNG filling station close to Male's main port.[325]

9.5.3 Bottom-up approach

9.5.3.1 CGD sector

In Maldives, the CGD sector can be broken down into the industrial, transport, and other segments. Demand in the CGD sector is calculated based on the data of the historical consumption of LPG, petrol, and diesel provided by Maldives Customs Services.

Figure 127 Methodology for calculation of natural gas demand in Maldives



[321] *SAARC Energy Outlook Report*
[322] *https://www.orfonline.org/expert-speak/what-does-energy-security-mean-maldives/*
[323] *Report - A Brighter Future for Maldives Powered by Renewables*
[324] *https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx*
[325] *Report by Asian Development Bank on "A BRIGHTER FUTURE FOR MALDIVES POWERED BY RENEWABLES"*

Detailed methodology

1. Step 1 – Calculation of consumption of LPG, petrol, and diesel in Maldives
    a. Maldives Customs Services provides the historical consumption of LPG, petrol, and diesel in the country.
    b. Two scenarios are considered:
        i. Scenario 1 - Based on historical consumption of above fuels (FY 2015 to FY 2020), fuel consumption from FY 2022 to FY 2040 has been predicted at a reducing CAGR with a minimum growth cap of 5 percent.
        ii. Scenario 2 – Correlation was drawn by creating a regression model using the macroeconomic indicator of GDP of Maldives. The detailed list of the consumption data for both the scenarios has been provided in Annexure 17.8.1. This approach has been considered to estimate the consumption of petrol, diesel, and LPG. Historical GDP of Maldives from FY 2015 to FY 2020 was used for this analysis. The following table shows R^2 value and p-values of this model for petrol, diesel, and LPG consumption:

Table 127 Regression analysis of Maldives

Fuel type	R^2 value	p-values	
		Intercept	x-variable
Petrol	0.40	0.66	0.17
Diesel	0.10	0.27	0.53
LPG	0.87	0.05	0.006

The above-mentioned analysis clarifies that R^2 values for petrol and diesel consumption were 40 percent and 10 percent, respectively. This implies that variation in petrol and diesel consumption is not being explained by variation in GDP data. Here, p-values for variables also need to be considered. The p-value of the independent variables in a regression model tests the hypothesis that there is no correlation between the independent and dependent variables. In statistical terms, the p-value of independent variable needs to be less than 0.05 to conclude with 95 percent confidence that it is significant in determining the value of the dependent variable. In the given case, the p-values for petrol and diesel consumption were 17 percent and 53 percent, respectively; both was higher than 5 percent. Therefore, this metric was also not significant at a 5 percent level of confidence. As two of the three regression models were not able to make good predictions for consumption data, we did not consider this approach to calculate the total natural gas demand.

    c. Gas demand is expected to come up from replacement of petrol, diesel, and LPG in the following sectors:
        i. Power – Diesel is used for electricity generation in Maldives. Natural gas/LNG can be a viable alternative for power generation provided new gas-based power plants come up in Maldives.
        ii. Industry and domestic – For the industrial sector, diesel is primarily used as fuel. LPG is used for cooking and water heating in the domestic sector. It has rapidly displaced the use of biomass as the main energy source for domestic purposes in small, inhabited islands.
        iii. Sea transport – Bunker fuels are being used for sea transport. Ships generally use three types of fuels ‐ heavy fuel oil, low sulphur fuel oil, and diesel oil. Within Maldives, only diesel oil is being used as bunker fuel. In the future, LNG can emerge as a viable alternative for bunker fuel in shipping as it causes less pollution.

iv. Road transport – Petrol is the major fuel being used for road transport. CNG can be an alternative for the use of petrol provided that the infrastructure is built up in the country in the next few years.

2. Step 2 – Considering the switch over percentage to natural gas
   a. Natural gas demand was considered to increase from FY 2022 onwards based on penetration rates for conventional fuels. The following switch over rates from LPG, petrol, and diesel to natural gas has been considered based on the IRADe report (appeared plausible):

Table 128 Switch over rates to natural gas in Maldives

	2025	2030	2035	2040
Petrol	5%	10%	15%	15%
Diesel	5%	10%	15%	15%
LPG	10%	15%	20%	25%

Assumptions

1. To calculate consumption of LPG, petrol, and diesel, a reducing CAGR has been capped at 5 percent after FY 2030. This is because in case of developing economies such as Maldives, the growth in consumption of petroleum products will be higher in initial years. As economies mature, consumption will not increase at the same rate in the future. Hence, a cap in CAGR has been factored.
2. Based on the different calorific fuel conversion rates for each fuel and switch over rate, natural gas demand for CGD sector has been predicted from FY 2021 to FY 2040.

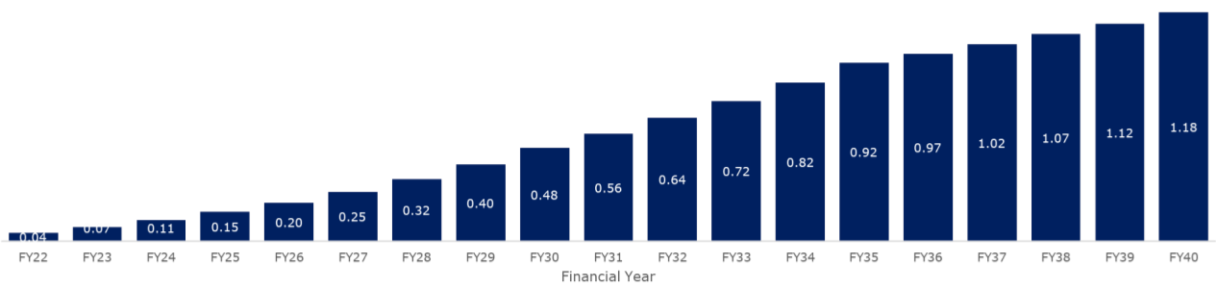
Analysis

Natural gas demand from the CGD sector is expected to increase from 0.15 mmscmd in FY 2025 to 0.48 mmscmd in FY 2030 and 1.18 mmscmd in FY 2040. The highest contributor of this rise can be the replacement of diesel used for power generation and other uses, such as transportation, cruises, and resorts. Demand for replacement of diesel to natural gas will rise from 0.13 mmscmd in FY 2025 to 1.06 mmscmd in FY 2040.

9.5.4 Total demand projection until 2040

The total demand projection for natural gas in Maldives is expected to increase to 0.48 mmscmd in FY 2030 and 1.18 mmscmd in FY 2040.

Figure 128 Overall demand projection for natural gas in Maldives (in mmscmd)



9.6 Supply analysis

9.6.1 Future initiatives

There are several opportunities to supply natural gas in Maldives. These are mentioned below:

- Petronet LNG Ltd. is exploring an opportunity to set up an LNG terminal in Maldives.[326]Moreover, Pearl Energy (Pvt) Ltd., which has signed an agreement to set up a floating storage LNG facility in Sri Lanka, plans to deploy small LNG carriers to redistribute LNG to Maldives, providing LNG as a clean and affordable alternative to industries.[327]Initially, it will have a capacity of 1 MMTPA that can be expanded later.[328]
- Small-scale LNG (ssLNG) can be built as modular structures with options to build upon existing infrastructures (e.g., harbors, jetty, and access roads). LNG would be brought to Maldives at conventional LNG import terminals or mid-sea LNG carriers or FSRUs. It would be then distributed in smaller-sized parcels directly to end users using a combination of sea and land transport.
- Within the Greater Male region, gas can be distributed through pipeline. For islands outside Male, ssLNG can be distributed through small-scale LNG carriers. Outside the Greater Male region, LNG could represent a cost reduction opportunity for large resort islands that ship small amounts of LNG from Male for a resort's semi-industrial processes and power production.[329]

9.7 Integrated demand-supply model

Table 129 Overall demand-supply estimates for Maldives from FY 2022 to FY 2030 (in mmscmd)

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Total demand	0.04	0.07	0.11	0.15	0.20	0.25	0.32	0.40	0.48
Total supply	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.04	-0.07	-0.11	-0.15	-0.20	-0.25	-0.32	-0.40	-0.48

Table 130 Overall demand-supply estimates for Maldives from FY 2031 to FY 2040 (in mmscmd)

	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Total demand	0.56	0.64	0.72	0.82	0.92	0.97	1.02	1.07	1.12	1.18
Total supply	0	0	0	0	0	0	0	0	0	0
Deficit (-)/surplus (+)	-0.56	-0.64	-0.72	-0.82	-0.92	-0.97	-1.02	-1.07	-1.12	-1.18

[326] *https://www.livemint.com/Industry/GzBJlonvBR5UYE2vNT9H5I/LNG-diplomacy-India-plans-to-build-terminals-in-4-nations.html*
[327] *https://www.lngindustry.com/liquid-natural-gas/25082020/agreement-signed-to-launch-a-floating-storage-lng-facility-in-sri-lanka/*
[328] *https://giignl.org/news/sri-lanka-launch-floating-storage-lng-facility*
[329] *Report - A Brighter Future for Maldives Powered by Renewables (https://www.adb.org/sites/default/files/publication/654021/renewables-roadmap-energy-sector-maldives.pdf)*

10 Potential economic benefits in switching to gas

Chapters 2-9 of the report made a country-wise analysis of the gas ecosystem in the SAR and also the expected landing costs of LNG to the countries where gas is not currently present. Since gas is cheaper compared to petrol, diesel and other alternate POL fuels, countries can derive additional potential savings in switching to gas from these fuels. The following tables provide the comparison of landed cost of gas for different SAR member states compared with alternative fuels, such as petrol and diesel:

Table 131 Comparison of LNG prices with other fuels for SAR member states

Country	Landed cost of LNG ($/mmbtu)	Price of petrol ($/mmbtu)	Price of diesel ($/mmbtu)
India	12-22.3	31-48	23-35
Pakistan	14.7-15.7	28	22
Bangladesh	18.3	35.1	25.3
Sri Lanka*	9.5-20.6	42	31.6
Nepal*	9-22	34	31.5
Bhutan*	10.5-22	40.1	38.2

Note: The prices that have been considered for petrol and diesel are for May 2022.

**: The price for these countries has been considered after analysing the possible supply sources. Calculations are based on an illustrative landed cost of gas from India.*

For the countries which do not have access to gas, the potential savings on switching to gas can be calculated in three steps:

1. The first step involves projecting the demands of the alternate fuels in future and multiplying it with the switch-over percentage indicating substitution of those fuels with gas. Using this approach, the demand calculation for gas was made for Nepal, Sri Lanka, Bhutan and Maldives in Chapters 5, 6, 8, and 9 respectively.
2. The second step involves calculating the price differential between gas and alternate fuels.
3. The third and final step involves multiplying the gas demand arriving from the switch-over of different fuels (post converting it from mmscmd to mmbtu) with the price differential to calculate potential savings.

Potential economic benefits in switching to gas for Nepal and Bhutan:

For Nepal and Bhutan, the following will be the potential savings in US$ per mmbtu on switching to gas from petrol and diesel:

Table 132 Potential savings in switching to gas from petrol and diesel for Nepal and Bhutan in US$ per mmbtu

Country	Retail cost of gas (in $/mmbtu)	Retail cost of petrol (in $/mmbtu)	Retail cost of diesel (in $/mmbtu)	Benefit in switching from petrol to gas (in $/mmbtu)	Benefit in switching from diesel to gas (in $/mmbtu)
	(A)	(B)	(C)	(D) = (B) - (A)	(E) = (C) - (A)
Bhutan	31.8	40.1	38.2	8.3	6.4
Nepal	31.1	34	31.5	2.9	0.4

According to the demand-supply projections made for Nepal and Bhutan, gas demand is expected to increase based on switch over rates for petrol and diesel. Considering the assumed switch over rates for petrol and diesel (discussed in sections 5.5.3 for Nepal and 8.5.3 for Bhutan) and the equivalent gas demand after switching, the following are expected to be the economic benefits for both the countries:

Table 133 Potential overall economic benefits on switching to gas for Nepal and Bhutan in the base case scenario

Year	Nepal						Bhutan					
	Petrol			Diesel			Petrol			Diesel		
	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)
2025	0.23	3331349.2	9.7	1.13	16367063.5	6.5	0.0	0.0	0.0	0.03	434523.8	2.8
2030	0.76	11007936.5	31.9	2.69	38962301.6	15.6	0.0	0.0	0.0	0.08	1158730.2	7.4
2035	1.11	16077381.0	46.6	3.95	57212301.6	22.9	0.0	0.0	0.0	0.15	2172619.0	13.9
2040	1.63	23609127.0	68.5	5.8	84007936.5	33.6	0.0	0.0	0.0	0.19	2751984.1	17.6

Note: *The expected benefits on switching to gas from alternative fuels have been projected for future considering the prices of May 2022. However, considering the future volatility in crude oil prices and alternative fuel prices, the extent of benefits might vary.*

For conversion from mmscmd to mmbtu, the calorific value of gas has been considered 10,000 kcal/scm.

Potential economic benefits in switching to gas for Sri Lanka and Maldives

Sri Lanka and Maldives have similar geographies; the landed cost of gas for both the countries is expected to be the same. Within both the countries, petrol is majorly used in the transportation segment. Hence, for switching from petrol, the retail cost of gas has been considered for analysis. However, diesel is being used as a major bulk fuel in the power sector for both the countries. As of 2019, Sri Lanka had the following composition of the fuel demand for power generation: 54 percent of fuel oil, 32 percent of auto diesel and 14 percent of naphtha.[330] Therefore, of the expected power sector gas demand in Sri Lanka, 32 percent has been assumed to come after replacement of diesel, which would provide savings to the country. In case of Maldives, diesel is used for power generation, and in industries and sea transport as a bulk fuel. The following table shows the potential savings in US$ per mmbtu on switching to gas from petrol and diesel:

Table 134 Potential savings in switching to gas from petrol and diesel for Sri Lanka and Maldives in US$ per mmbtu

Country	Retail cost of gas (in $/mmbtu)	Retail cost of petrol (in $/mmbtu)	Benefit in switching from petrol to gas (in $/mmbtu)	Landed cost of LNG (in $/mmbtu)	Cost of diesel (in $/mmbtu)	Benefit in switching from diesel to LNG for bulk usage (in $/mmbtu)
	(A)	(B)	(C) = (B) - (A)	(D)	(E)	(F) = (E) - (D)
Sri Lanka	30.5	42	11.5	20.5	31.6	11.1
Maldives	30.5	31.9	1.4	20.5	26	5.5

Based on the switch over rates for petrol in the CGD sector for Sri Lanka (Section 6.5.4.4) and switch over from diesel to bulk LNG in both Sri Lanka and Maldives, the following economic benefits are expected for both the countries:

Table 135 Potential overall economic benefits on switching to gas for Sri Lanka and Maldives in the base case scenario

Year	Sri Lanka						Maldives					
	Petrol (in the CGD sector)			Diesel (in the power sector)			Petrol (in the CGD sector)			Diesel (in all sectors)		
	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)	Switch to gas (in mmscmd)	Switch to gas (in mmbtu)	Expected benefit (in Mn $)
2025	0.8	11152777.8	128.3	0.8	12050793.7	133.8	0.02	289682.5	3.3	0.1	1882936.5	10.4
2030	2.4	34472222.2	396.4	1.0	14368254.0	159.5	0.04	579365.1	6.7	0.4	6228174.6	34.3
2035	4.3	61702381.0	709.6	1.4	20393650.8	226.4	0.08	1158730.2	13.3	0.8	12021825.4	66.1
2040	5.8	84442460.3	971.1	1.8	25492063.5	283.0	0.09	1303571.4	15.0	1.1	15353174.6	84.4

Note: *The expected benefits on switching to gas from alternative fuels have been projected for the future considering the considering the prices of May 2022. However, considering the future volatility in crude oil prices and alternative fuel prices, the extent of benefits might vary.*

For conversion from mmscmd to mmbtu, the calorific value of gas has been considered 10,000 kcal/scm.

Potential economic benefits in switching to gas for Bangladesh

[330] *Ceylon Petroleum Corporation Annual Report, 2019*

For Bangladesh, the gas that is expected to reach through cross-border trade will be used in the power sector. Within the power sector, gas is expected to replace furnace oil used for power generation. The following will be the potential savings in US$ per mmbtu on switching to gas:

Table 136 Potential savings in switching to gas from furnace oil for Bangladesh in US$ per mmbtu

Country	Landed cost of gas (in $/mmbtu)	Cost of furnace oil (in $/mmbtu)	Benefit in switching from furnace oil to gas (in $/mmbtu)
	(A)	(B)	(C) = (B) - (A)
Bangladesh	18	21	3

Note: *The expected benefits on switching to gas from alternative fuels have been projected for the future considering the considering the prices of May 2022. However, considering the future volatility in crude oil prices and alternative fuel prices, the extent of benefits might vary.*

For conversion from mmscmd to mmbtu, the calorific value of gas has been considered 10,000 kcal/scm.

The following table summarises the expected overall benefits in the region on switching to gas from alternative fuels in the base case demand and supply scenario:

Table 137 Potential annual savings, by country, in switching over to gas from alternative fuels for the base case scenario

Country	Potential annual economic benefit in Mn $(by FY 2025)	Potential annual economic benefit in Mn $(by FY 2030)	Potential annual economic benefit in Mn $(by FY 2035)	Potential annual economic benefit in Mn $(by FY 2040)
Nepal	16.2	47.5	69.5	102.1
Bhutan	2.8	7.4	13.9	17.6
Sri Lanka	262.0	555.9	935.9	1254.1
Maldives	13.7	40.9	79.4	99.4
Total	**~295**	**~652**	**~1099**	**~1473**

SECTION B: ASSESSMENT OF CROSS-BORDER TRADING OPPORTUNITIES AND POTENTIAL IN THE SOUTH ASIAN REGION

11 Drivers for CBNGT

Chapters 2-10 of the report share an assessment of natural gas demand and supply for each member country of SAR until 2040 along with the potential benefits to the countries on switching to gas. The Cross-Border Natural Gas Trade (CBNGT) amongst the SAR nations has a significant potential in the future based on the following key drivers:

- Benefits of gas
- Demand-supply dynamics
- Policy and regulatory enablers
- Requisite infrastructural development
- Optimum utilisation of infrastructure

1. **Benefits of gas:** The earlier sections of the report establish affordability of gas compared with other alternative fuels for major countries in the SAR. Gas is expected to be a more economical choice of fuels as compared to the alternatives in majority of the countries in the SAR. In addition, usage of gas is also expected to provide significant environmental and social benefits. Natural gas has one of the lowest emissions of CO_2, NO_2, and methane compared with conventional fossil fuels. Moreover, gas can serve as one of the potential transitioning fuels to renewable energy from the conventional fossil fuels. In terms of social benefits, pipeline gas can offer a steady supply of clean fuel to urban and rural households, thereby reducing the impact of respiratory diseases caused by burning of traditional fuels used for cooking and other purposes.

2. **Demand-supply dynamics:** For most SAR member states, the overall gas demand is expected to increase until FY 2040 per the following table:

Table 138 Expected demand for gas in SAR member states (in most plausible scenario)

Country	FY 2025	FY 2030	FY 2035	FY 2040	Growth CAGR (FY 2025-40)
India	252	316	393	448	4%
Pakistan	122	132	150	172	2%
Bangladesh	103	142	175	194	5%
Sri Lanka	6	10	15	20	8%
Nepal	1.7	4.11	7	10.3	13%
Bhutan	0.04	0.09	0.17	0.22	12%
Maldives	0.15	0.48	0.92	1.18	15%
Afghanistan	0.86	1.95	2.74	3.13	9%

In addition, the net supply in the region is expected to either stagnate or decrease post FY 2030 because of the dwindling domestic reserves.

Table 139 Expected supply for gas in SAR member states (in most plausible scenario)

Country	FY 2025	FY 2030	FY 2035	FY 2040	Growth CAGR (FY 2025-40)
India	293	361	359	352	1.2%
Pakistan	151	160	167	164	0.4%
Bangladesh	94	109	100	94	0.06%
Sri Lanka	3.6	3.6	3.6	3.6	0%
Nepal	0	0	0	0	NA
Bhutan	0	0	0	0	NA

Country	FY 2025	FY 2030	FY 2035	FY 2040	Growth CAGR (FY 2025-40)
Maldives	0	0	0	0	NA
Afghanistan	0.7	1.1	1.4	1.8	8.9%

The overall demand-supply deficit for the countries in the SAR is expected to shape up in the following manner:

Table 140 Expected demand-supply deficit for gas in SAR member states (in most plausible scenario)

Country	FY 2025	FY 2030	FY 2035	FY 2040
India	38	44	-33	-96
Pakistan	29	28	17	-8
Bangladesh	-9	-33	-75	-99
Sri Lanka	-1.9	-6.7	-11.7	-16
Nepal	-1.74	-4.11	-7	-10.3
Bhutan	-0.04	-0.09	-0.17	-0.22
Maldives	-0.15	-0.48	-0.92	-1.18
Afghanistan	-0.2	-0.8	-1.3	-1.3

It is expected that with the commencement of upcoming LNG receiving terminals, India has a potential of being surplus in gas supplies between 2024 and 2030. This would auger well for the initiation of cross-border trade in the region. Pakistan is also expected to have surplus on account of the upcoming LNG terminal projects and IPP pipeline along with the reduction in gas demand from the power sector (per IGCEP document).

3. **Regulatory and policy enablers:** SAR member states have initiated several policies to promote the use of gas. The Indian government has announced that it aims to increase the share of natural gas in the country's energy mix to 15 percent by 2030. Bangladesh is intending to adopt a time-based action plan to discover new gas fields in the country and increase the financial capacity of the state-owned upstream gas company. Sri Lanka has already drafted NPNG to introduce natural gas as a fuel in the energy mix and bring up its share up to one-third of the fossil fuel consumption by 2030. Countries such as Bhutan, Nepal, and Maldives are also expected to introduce new policy initiatives to encourage gas use. Nepal has set up joint working groups with India to study feasibility of gas supply and other means of energy trade. Bhutan is currently a carbon neutral nation and intends to maintain this status in the future. Maldives also needs to adhere to its emissions norms for its participation in international climate change programmes. Hence, it needs to transition towards cleaner energy sources.

4. **Requisite infrastructural development and utilisation:** Several initiatives have been taken around infrastructural development in the South-Asian region to encourage cross-border trading. The discussions to develop the TAPI (Turkmenistan-Afghanistan-Pakistan-India) pipeline and the IPP (Iran-Pakistan Pipeline) pipeline have recently started to pick pace. Bangladesh is undertaking plans to assess the feasibility of developing LNG terminals at several locations within the country. India's CGD distribution network has been expanding through new rounds of GAs because of which the major regions in Nepal and Bhutan have the potential to be serviced through pipeline connectivity. In the future, developing the Dhamra, Haldia, and Kukrahati LNG terminals would help supply gas to the eastern countries. In addition, innovations in making ssLNG an affordable supply chain option for consumers who are not connected by pipelines has opened up significant potential for penetration.

5. **Optimum utilisation of infrastructure:** The cross-border trade would provide higher utilisation for the existing infrastructure, particularly the LNG receiving terminals and the pipelines, where the capital

costs have already been invested. It would indeed be an attractive proposition for the investors to offer lower or competitive tariffs for optimal capacity utilisation of the existing infrastructure. Besides, this would also help in mitigating the capital risks for gas consuming while investing in installing new terminals/pipelines or expansions and upgradation of their existing infrastructure.

Given the drivers mentioned above, cross-border trade emerges to be a win-win option if tradable volumes are available at affordable and competitive prices. CBNGT would also help to fulfil the volatility in demand within the region with minimal investment in infrastructure. With maturity in cross-border trade and institutional framework, over a period of time, the region can aim to establish its own pricing benchmarks or index, which would further foster trade and establish liquid gas markets. The subsequent chapters of the report further breakdown the possibilities of cross-border trade through the analysis of global gas trade case studies, infrastructural requirements, trade potential and the potential benefits.

12 Global gas markets and key learnings

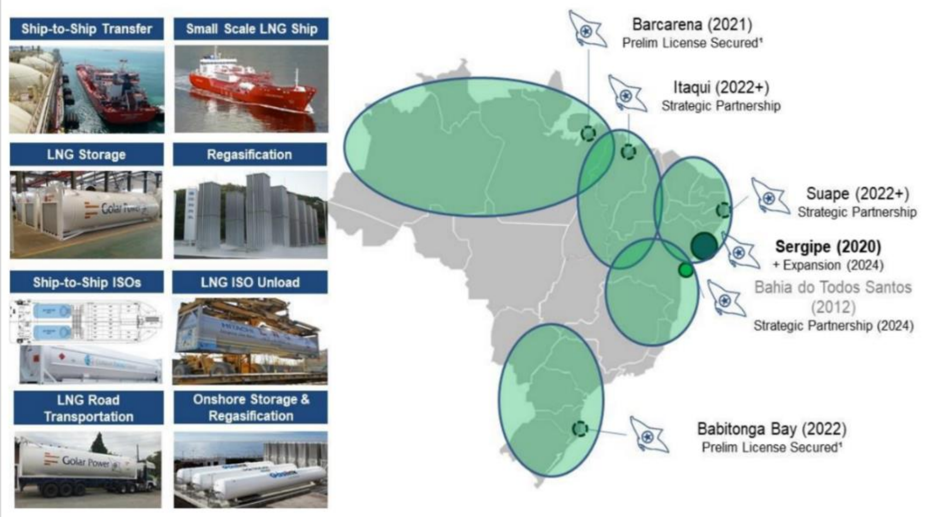
The chapter talks about some case studies on the global gas markets along with the key learnings from those in the context of South Asia. Regional gas trade is being pursued by various regions across the world, although a key difference for the SAR is that a majority of the countries are import dependent. Several key learnings can be adopted from the following global examples:

A. **Setting up regional/sub-regional LNG terminals:**[331]In 2008, private company Sempra Energy Mexico commissioned an LNG receipt terminal at Baja California, Mexico. The gas received by the terminal was first used to meet industries' needs locally with the excess gas being supplied into the Southwest US. The LNG project was built as an integrated project and the company also made investments into building related infrastructure (such as spur pipelines). The storage capacity in the terminal was available to market participants on a common carrier basis.

   Key learnings: A regional/sub-regional LNG terminal can allow aggregation of demand, which in turn, can be used to secure gas supplies at competitive rates. In addition, an interconnected gas grid would be a key enabler for setting up a regional LNG terminal, aggregating demand, and planning for optimum investment in gas/LNG infrastructure. Similarly, in India, the under-construction Dhamra terminal has the potential to "become a hub for supply to nations such as Bangladesh and Myanmar."[332]The terminal could also become a supply hub for Nepal and Bhutan.

B. **Breakbulk LNG terminals and associated infrastructure**: In several regions across the world, launching small-scale LNG reloading operations, such as at Zeebrugge and Gate Rotterdam in the North Sea, has increased availability of small-scale LNG supplies. The smaller cargo sizes enable more flexible commercial operations.[333]Similarly, ship-to-ship transfer has also been used by countries such as Myanmar to break larger cargoes and supply gas to remote locations.[334]Golar LNG is actively using the hub/terminal approach for extended distribution to inland and off-grid consumers in Brazil.[335]For example, Golar Power Brazil is developing the country's first private LNG import terminal within the Suape Port complex in Pernambuco. In addition to supplying LNG to a power generation plant in the Suape complex, the hub will also supply LNG to the industrial, residential, and commercial segments, and gas stations. Current and under-construction pipelines will partially drain LNG supply to end-users and consumers. IsoTank container trucks will then distribute LNG to the region within a 1,000-kilometre radius; cabotage will be the method used to carry LNG to other states. Smaller LNG vessels will move it to different hubs/ports throughout the Brazilian coast.[336]

Figure 129 Case study (hub and spoke model)



331 "SAR Regional Energy Trade Study (SRETS)", SAR Secretariat, Mar-2010
332 "Adani's Dhamra LNG terminal to help supply gas to Bangladesh, Myanmar", The Hindu, Apr-2018
333 "LNG Supply Chains and the Development of LNG as a Shipping Fuel in Northern Europe", Oxford Institute for Energy Studies, Jan-2019
334 "Myanmar LNG project developer conducts ship-to-ship transfer offshore Malaysia, S&P Platts", Jul-2020
335 Golar LNG Investor Presentation - SEB Nordic Seminar, Jan-2020
336 "Brazil LNG Import Terminal", Market Intelligence, Jun-2020

Key learnings: SAR countries, such as Maldives and Sri Lanka, with low gas requirements could benefit from a larger consumer (such as India) developing a breakbulk facility. Alternatively, the terminal could also be built in Sri Lanka on a hub-and-spoke model.[337]Developing a small-scale LNG regasification facility on the islands would increase access to natural gas while optimising capex costs.

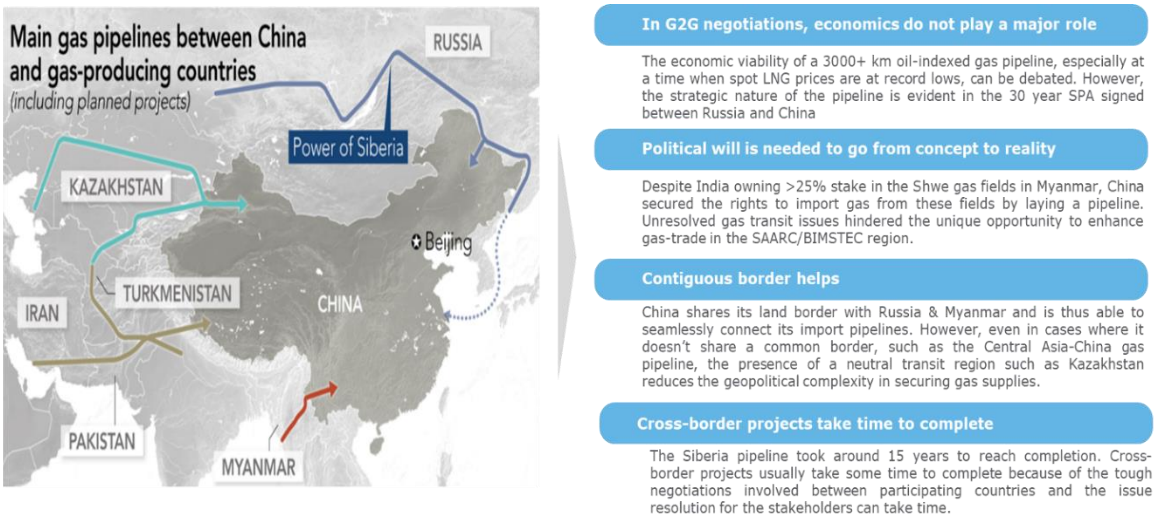
C. Joint gas exploration: In November 2018, China and the Philippines signed an agreement to carry out joint oil and gas development in the South China Sea. The countries previously had a strained relationship due to a long-standing territorial dispute over the South China Sea.[338]

Key learnings: Similarly, India and Sri Lanka can jointly explore natural gas in the Mannar basin, along with increasing exploration activities with Bangladesh in the Bay of Bengal.

D. Pipeline development (Siberia pipeline): China's focus on gas trade, especially via the new Power of Siberia pipeline, offers profound lessons in energy diplomacy. The pipeline was discussed and debated on for over 15 years before coming to fruition. Although once the supply agreement was signed, the +3,000-km pipeline was executed in about five years despite inhospitable terrain and technological challenges. It was a win-win deal as Russia's Gazprom and Chinese oil giant PetroChina have signed a 30-year contract – the pipeline at its peak will supply 38 billion cubic meters (bcm) annually. This offers Russia a large energy export market, while China gets clean fuel for its rapid growth.

Key learnings: The following were the key learnings from this case study:

Figure 130 Key learnings from the Siberia pipeline case study



E. Pipeline development (BTC pipeline): The Baku–Tbilisi–Ceyhan (BTC) oil pipeline, which runs via Turkey, is the main artery of Caspian oil exports and plays an important role in oil delivery from Azerbaijan, Turkmenistan, and Kazakhstan. The pipeline carries crude oil across a distance of 1,768 km from the Azeri-Chirag Deepwater Gunashli field and condensate from Shah Deniz in Azerbaijan across Georgia and into Turkey. The BTC pipeline became operational in 2006. It was built by a company operated by British Petroleum (BP) and is owned by a consortium of 11 energy companies. The major challenge being faced by BP in the region was to ensure the social safeguards for local communities in the regions with autocratic regimes. However, BP was able to address concerns and build a consensus on the issues pertaining to human rights through discussions with the relevant stakeholders and inclusion of certain standards to be followed within operational documents.

The Voluntary Principles on Security and Human Rights were referenced in both the joint statement and the security protocol for the East-West Energy Corridor of the BTC pipeline. Other human rights measures incorporated under the project's legal requisites included the legally binding human rights undertaking. BP

[337] *"ADB Funds Feasibility Study on Setting Up an LNG Hub in Sri Lanka", Sasec, Jun-2019*
[338] *"China and Philippines sign joint oil and gas exploration MoU", Offshore Technology, Nov-2018*

trained the security forces in charge of guarding the BTC pipeline on human rights issues and created an independent monitoring body to assess the impact of the pipeline on local communities.

Key learnings: Similar to the BTC pipeline, several social challenges were faced while constructing the TAPI pipeline. Similar to the BTC pipeline, the TAPI pipeline is also expected to impact the livelihood of several communities in the participating countries. An impact assessment of the pipeline showed that the construction process might affect agricultural land and heritage sites in Afghanistan and Pakistan, resulting in the resettlement of a number of households. The project is also expected to affect the access to natural resources for local communities during the construction phase and provide only marginal employment opportunities. Many stakeholders have objected to the fact that ethnic minorities in Pakistan and Afghanistan have been excluded from participating in and benefiting from transnational energy and connectivity projects. This might also create challenges pertaining to safety and sabotaging of the infrastructure within the region. The policies created during the construction of the BTC pipeline can also be contextually applied to the TAPI project. Upholding the human rights of local communities can discourage attempts to sabotage the pipeline and encourage greater international investment in cross-border infrastructure in South Asia. Forming a stronger consortium, inviting participation from major international players, and addressing local communities' concerns are needed to drive project towards successful completion. Moreover, construction of cross-border pipelines involving more than one nation can take time upto one or two decades. Each country negotiates very hard for its stake in the entry-exit fees (or tariffs and taxes) as well as in the construction process. In multi-nation pipeline projects, a consortium with a lead by an international oil major is a major requirement to resolve issues of the stakeholders.

F. **Pipeline development (TANAP and TAP gas pipelines):** The TAP and TANAP pipeline projects are two parts of Southern Gas Corridor built to carry natural gas from the Shah Deniz field in the Caspian Sea to Italy through Azerbaijan, Georgia, Turkey, Greece, and Albania. The project also envisaged adding pipelines to Bulgaria and provide additional gas sourcing option to south - eastern Europe and further to the remaining parts of Europe.

The TANAP project involved the construction of an 1,850 km-long pipeline to supply gas from Azerbaijan to Turkey. Started in March 2015, the pipeline construction was completed in June 2018. The TANAP project was announced in 2011 after an intergovernmental MoU was signed to form a consortium. In 2012, the heads of state of Turkey and Azerbaijan signed a binding agreement. In 2015, after resolving the remaining issues, the heads of state of Turkey, Georgia and Azerbaijan together laid the foundation for the construction of this pipeline. A comprehensive community consultation programme had been carried out for the TANAP project since 2013; feedback was taken from more than 4,000 stakeholders across the pipeline route to prepare the environmental and social impact assessment report.

The TAP is an 878-km long pipeline that connects directly to TANAP on the Turkish-Greek border and transports natural gas via Greece and Albania, across the Adriatic Sea to southern Italy. The TAP pipeline began its commercial operations in 2020. The TAP project had been conceived in 2003 and the feasibility report had been completed in 2006. In 2012, the key consortium partners BP, Total SA, and SOCAR signed a funding agreement with TAP's shareholders. In 2013, the project received the EU Third Party Access exemption to enter into 'Ship-or-Pay' transportation contracts with the shippers of the Shah Deniz II gas via the TANAP pipeline. The governments of Italy, Greece, and Albania signed a tri-lateral Inter-Governmental Agreement (IGA) in 2013 to implement the TAP project on time.

Both these pipelines took years of sustained and tough negotiations amongst nations and could be finalised only after firm governmental interventions.

Key learnings: Similar to the BTC pipeline, construction of TAP and TANAP cross-border pipelines involving more than one nation took nearly a decade and a half to be completed. It also called for sustained efforts by the lead consortium partners with the respective government agencies and local communities. The key role played by heads of state underpins the stakes in such projects. The TAPI pipeline project involves four countries and will need to undergo tough negotiations between the concerned governments despite the tensions between them. Currently, India's concerns regarding the project's safety and security have increased with the new government's rule in Afghanistan. TPCL had been incorporated in 2014 with India's

GAIL, Pakistan's Interstate Gas Systems (ISGS), and Afghanistan's AGE having a 5 percent stake each, along with Turkmenistan's Turkmengaz having the remaining 85 percent. The structure of the consortium with four separate pipeline companies (one for each country constructing and operating their own segment of the pipeline), might bring conflict of interests in the future. In addition, the governments from respective countries will need to collaborate and support the consortium to ensure further progress of the project.

G. **Innovative infrastructure models for island nations:** The Karadeniz Powership Osman Khan is a floating power plant with a capacity of 470 MW. It supplied 26 percent of Ghana's generated power to Tema (a city in Ghana). In the initial stages, the power plant was not welcomed in Tema because the vessel occupied a prime spot at the busy Tema harbour where the fishermen earned their daily catch. However, the benefits of a steady power supply quickly began to transform industry in the region as there was continuous power supply; fishermen could now use refrigerant systems to attract bulk buyers for their fish. The mobile power plant was moved to a different location in Ghana in mid-2019, highlighting the model's flexibility. The Osman Khan uses dual-fuel engines offering specific advantages for floating power ships over gas turbines. These ships are modular, and can provide ancillary, black start, durability, voltage, and frequency control. According to the company, because of their compact design and seawater cooling, they are even more efficient than land-based power plants that can be constructed with the same technology. As ships are at the sea level and contracts are typically for baseload power, production suffers minimal derating.

Key learnings: Innovative infrastructure models, such as floating power plants, can help island economies, including Sri Lanka and Maldives, to transition towards cleaner fuels, such as LNG. In a country such as Maldives that comprises only small islands, this approach can help link the isolated regions to the gas economy. A similar type of models has also been deployed in Indonesia and Cuba. In addition, involving the local people will be critical to the adoption of such flexible models.

Therefore, from all the major case studies of the world, it is quite evident that the cross-border trade for natural gas/LNG involves several stakeholders from the national governments to the local populations. The commencement of these projects is bound to take some time given the different types of complexities involved. The discussions for cross-border trading projects, particularly in the SAR, need to happen at a consortium level. These discussions have to be driven from the top by interventions from the head of states for any viable output to come out that can benefit all the participating nations.

13 Infrastructural requirements for development of gas trade in the SAR

Gas being a fungible resource, needs containment for its transportation. The bulk trade of gas is well diversified across LNG and pipeline projects. Pipelines, in particular the cross-border pipelines, have traditionally witnessed a very long gestation period due to the time consumed in resolving the conflicting interests of the respective stakeholder nations before financial closure and award of the project.

In the midstream and downstream segments, pipelines have always considered as are the most popular and plausible solution for transportation and supply of gas. However, in recent years, transportation of small volumes of LNG by road tankers, rail wagons and barges have emerged as an alternative to pipelines.

13.1 Development of regional/sub regional natural gas pipeline networks

The major challenges in pipeline construction are Right-of-Way (RoW) and a higher construction cost that varies with type of terrain, length, and volume of gas. Some advantages and limitations with respect to development of pipeline infrastructure for cross-border trading are mentioned below:

Advantages of gas pipelines for cross-border trading: Several advantages can be served by transportation of natural gas through pipelines:

- Uninterrupted supply to neighbouring countries
- Safety and quality of gas

Limitations of gas pipelines for cross-border trading: Despite various advantages, development of cross-country pipelines faces several limitations.

- Initial capital expenditure and the time requirement for constructing a pipeline is high.
- Acquiring land for RoW, especially through private and agricultural land, and habited areas, is difficult. The rights of the affected communities need to be considered while constructing a pipeline.
- Adequate demand is required to make the pipeline economically feasible.
- Geopolitical risk in terms of the security concerns in laying down the pipelines across countries, needs to be considered.

One of the major pipeline projects in the SAR for boosting intra-regional connectivity has already been underway – the TAPI gas pipeline. However, several challenges are being faced in the completion of the pipeline. The major concern for the TAPI pipeline has been the absence of participation of private-sector players. In addition, there has been lack of financial support due to which the pipeline has not been able to reach its completion.

However, pipelines could be a suitable means of transport from India to other high-demand countries, such as Nepal and Bangladesh, which are near to the eastern coastline of India. In case of cross-border pipelines, the delivery point for the pipeline will depend on demand coming from the particular segment or the regions in the country (which will have to be taken into consideration while conducting the feasibility study). In addition, the economics of laying undersea pipelines to connect Sri Lanka and Maldives could also be explored to enable trade with the island nations.

Investments: The details of investments in cross-border pipeline projects in the SAR are given below:

- In case of the TAPI pipeline, the overall estimated capital cost of the project is US$7.7 billion for the construction of ~1,800 km pipeline spanning across the four nations.[339]
- The IP pipeline entails an approximate capital cost of US$7.5 billion for construction of ~1,900 km of the pipeline.[340]
- The gas sector master plan of Bangladesh proposes the construction of a 36-inch and 70-km long gas pipeline from India to Khulna to meet the supply shortage in the country. Capex for the pipeline was estimated at US$150 million.

[339] https://www.adb.org/sites/default/files/project-documents/52167/52167-001-cp-en.pdf
[340] https://www.gem.wiki/Iran-Pakistan_Pipeline

- In India, GAIL has planned a capex of US$6.5 billion to build a 7, 000-km pipeline in the next five years.[341]

13.2 ssLNG: An emerging supply chain solution for consumers not connected by pipelines

13.2.1 Overview of the ssLNG market

ssLNG can transport natural gas through unconventional transportation mediums, such as cryogenic containers and vessels in a liquid state. The transported LNG can be re-gasified for end-use. The supply through ssLNG can primarily cater to the following categories of consumers:

- Providing supply to small industrial consumers that are not connected to any natural gas pipeline
- Providing supply to organisations for the research purpose as well as to large industrial consumers with specific fuel requirement (constant calorific values or where constant flame temperature is required), such as glass industries and ceramic tiles
- Supply to LNG dispensing/refuelling stations on the Indian Highways across the country for LNG supporting heavy-duty vehicles
- Providing LNG supply to City Gas Distribution companies to develop an authorised GA at a faster pace via the LNG route instead of waiting for natural gas trunk pipelines to come to their area.

Compared with diesel, use of LNG could improve efficiency in the power generation, heating, or cooling processes, and combustion engines. ssLNG has the capability to provide temporary access to gas to the potential consumers. It can further help create demand and feasibility for pipeline construction. Using the scalable, modular, and movable assets to target small demand nodes, ssLNG can play a major role in diversifying the natural gas consumer base. The typical supply chain of the ssLNG system will consist of LNG receiving a terminal, transport system, and satellite regasification station:[342]

A. **Receiving terminal:** Tanker ships carrying LNG arrive at the receiving terminal. The receiving terminals need to have truck loading facilities to offload LNG from ships to cryogenic containers for transport.

B. **Transport system:** Transporting LNG for small-scale consumers is possible via road, rail, or waterways. Several configurations are possible for transporting LNG ‐ the terminal operator having its own fleet of transport vehicles, the consumer bringing in his own transport fleet to the terminal site; or a third-party logistics provider arranging LNG transport.

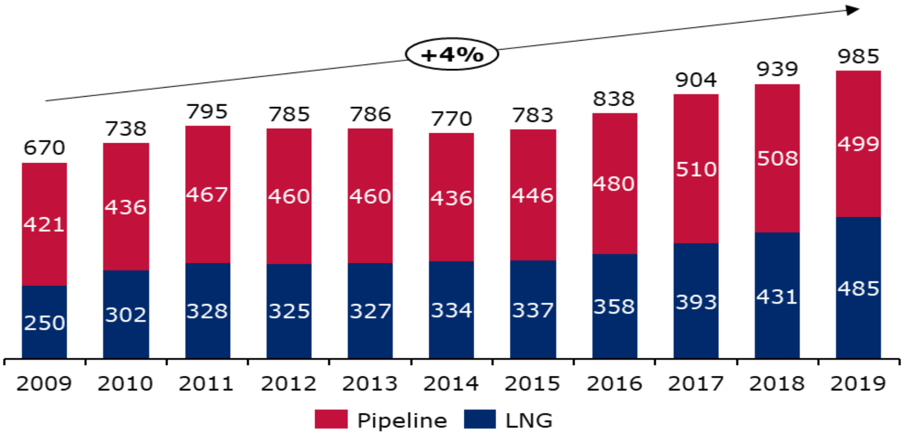
C. **Satellite storage plants:** LNG is transported to the storage and regasification plant located near the demand node that usually caters to several industrial consumers. The following are the components of a satellite storage plant:
    i. Storage tanks: The transport ssLNG is offloaded into storage tanks. Tank size can depend on the daily demand of the system.
    ii. Pumps: Different types of pumps can be used to pump LNG into vaporisers for regasification.
    iii. Vaporisers: These perform the regasification of LNG. In the regasification process, LNG is heated from cryogenic to atmospheric conditions through a heat exchange process, typically with ambient air. The vaporisation is done to low, medium, or high pressure depending on use cases of gas.

13.2.2 Global ssLNG market

The LNG and gas industry has stood resilient during the COVID-19-induced slowdown. It is expected to grow at a steady pace on the back of strong global trends. With new Net Zero Emission (NZE) targets being set at regional levels, gas and LNG are increasingly sought after as a fuel that can help decarbonise the world economy. Per the data from the BP Statistical Review, natural gas trade in the world has grown at a CAGR of ~4 percent over the past 10 years. The following graph represents the amount of global gas trade (in bcm) from 2009-19:[343]

[341] https://economictimes.indiatimes.com/industry/energy/oil-gas/gail-to-invest-rs-1-05-lakh-cr-to-create-infra-for-gas-based-economy/articleshow/74280928.cms?from=mdr
[342] *ssLNG for expanding Natural Gas Access in India (CEEW)*
[343] *BP Statistical Review*

Figure 131 Global Gas Trade (in bcm) from 2009-19

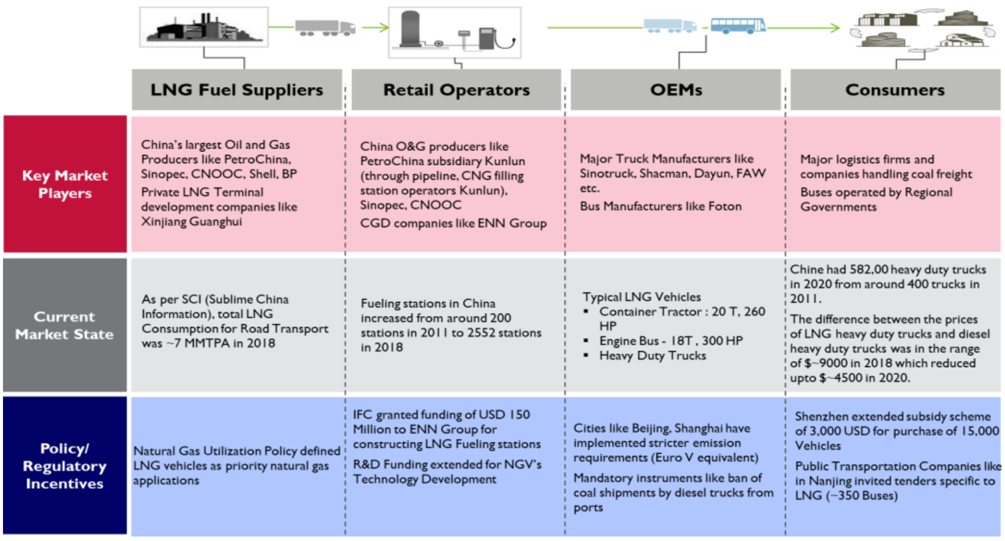


Natural gas trade increased from 670 bcm in 2009 to more than 985 bcm in 2019. This indicates a major uptake in the natural gas market globally during the past decade. While inter-regional trade through pipelines constituted almost two-third of the total trade in 2009, it has reduced to almost 50 percent with growth in LNG trade across the globe. This indicates that LNG shipping has opened significant growth opportunities for countries where pipeline transfer is a challenge. While Asian countries have been the major importers of LNG, Qatar, Australia, the US, and Russia have been amongst the major natural gas exporting nations.

LNG growth has led to technological developments in the end-user markets, especially in the US and China for growth of ssLNG. Both the US and China have revamped policies and regulations in the form of rebates, tax exemptions, loans, and purchase criteria in tenders to promote LNG as a transport fuel.

China: It has achieved success in LNG with strong central policy directives aimed at increasing the use of natural gas as a vehicle fuel, displacing diesel from larger trucks as part of their efforts to improve air quality in cities. The country was able to develop an extensive cryogenic supply chain to provide low-cost LNG. LNG is shipped by trucks from both import terminals and domestic small-scale liquefaction plants to industrial users and LNG fuelling stations. The overview of the LNG market in China is given below:

Figure 132 Overview of the LNG market in China



In China, vehicles running on natural gas were initially developed in inland provinces with rich gas resources. Later, the coastal provinces with LNG accessibility were targeted. In addition, the number of LNG dispensing stations increased almost 12 times from 200 in 2011 to ~2,550 in 2018.[344] Multiple subsidies amounting to half of purchase price difference between LNG and diesel vehicles were provided at national, municipal, and district

[344] https://www.gti.energy/wp-content/uploads/2019/10/22-LNG19-03April2019-Yuan-Yuan-paper.pdf

government levels by the Chinese government. Public transportation companies were encouraged to invite tenders specific to LNG. The Port of Tianjin banned the use of diesel trucks to transport coal to reduce air pollution leading to higher LNG sales.[345]The efforts pertaining to ssLNG have been quite successful in China. Therefore, the Chinese government is looking to repeat the programme for marine transport for inland river traffic.

US: Fuelling stations in the US were first established along main interstate highway on the west coast connecting major ports. The majority of current fuelling infrastructure to support LNG-powered vehicles is located in California. In addition, many recent developments in ssLNG production in the US are taking place in Florida around interconnected markets in port and rail infrastructure.[346]Stricter emissions regulations in the marine sector stimulated the use of LNG as a bunker fuel as well. The International Maritime Organization's (IMO) 2020 regulations played a significant role in creating investment opportunities in the LNG fuelling infrastructure. In 2020, the country had ~114 LNG fuelling stations per the US Energy Information Administration. The following figure gives an overview of the LNG market in the US:

Figure 133 Overview of the LNG market in the US

	LNG Fuel Suppliers	Retail Operators	OEMs	Consumers
Key Market Players	Leading Oil and Gas Producers like Shell	Shell – O&G producer, supplier), Clean Energy Group –CNG Station operator, Blu – a JV of Chinese NG Supplier and ENN, a small US CNG Fueling station operator	All major Truck Manufacturers like Peterbilt, Freightliner, Volvo, Mack Trucks Bus Manufacturers like ElDorado National	Large delivery companies like UPS Major FMCG firms via own or leased fleet Waste collection firms Enviro Express
Current Market State	Total LNG Consumption for Road Transport was around 1.3 MMTPA till 2017	As per US EIA, number of LNG filling stations in USA increased from 39 to 114 (in 2020) with an annual CAGR of 11.3%.	Typical LNG vehicles ▪ Long Haul Trucks : 36T, 400 HP ▪ Delivery trucks : 30T, 320 HP ▪ Bus: 30T, 300 HP	LNG Vehicles increased from 17,850 in 2013 to 25,000 in 2016 (<0.005% of heavy-duty vehicles)
Policy/ Regulatory Incentives	LNG fuel used for public transportation is exempted from state gross retail tax NG used for transportation was exempted from state, local sales, public utility taxes	Low interest loans on production facilities and infrastructure. Income tax credit of up to 25% of total costs associated with Fueling Infrastructure Infrastructure Loan up to 75% of costs with interest exemption for first 2 years	Funding of around 15% for R&D, deployment projects involving public transportation vehicles LNG Vehicle allowed to exceed GVW restriction by up to 3 Tonnes	Funding of up to 50% of differential cost between LNG and diesel vehicle Revolving loan program with zero Interest Loans up to $300,000 Income tax credit for up to 50% of incremental cost

13.2.3 ssLNG development in India

India has been amongst the earliest countries to pursue and commence the ssLNG model by road trucks. However, ssLNG still has limited penetration in India. Major gas consumers are traditionally supplied through the pipeline networks whose development is being prioritised by the government. Per India Infrastructural Research, LNG is being supplied to 50 industrial/LCNG (Liquid-to-Compressed Natural Gas) operators from existing terminals – Dahej, Ennore, and Kochi. In 2019, about 90 TMT of LNG in the country was supplied through road tankers from the three terminals.[347]India has eight truck loading facilities in these terminals with the possible LNG send out capacity of 0.4 mtpa.

India also presents significant opportunities for LNG demand in the transport sector. This can play a major role in boosting the overall ssLNG ecosystem. However, several market, infrastructure, and regulatory-based constraints limit demand. The following are the different constraints limiting the use of LNG in the transport sector in India:

A. **Market-based constraints:** The following are different market-based constraints:
   i. Engine constraints:
      - Current technology for LNG tank size and engine type allows a certain segment (~7.5T to 25T GVW) of vehicles to shift to LNG.
   ii. Retrofit challenges:
      - Lack of standards for retrofit of existing vehicles
      - Ageing fleet (average age >10 years)
   iii. Dedicated routes:

[345] https://www.theguardian.com/world/2017/sep/11/china-to-ban-production-of-petrol-and-diesel-cars-in-the-near-future
[346] http://gasprocessingnews.com/features/201608/market-development-is-key-to-success-for-small-scale-lng.aspx
[347] Small Scale LNG Market, 2020 (India Infrastructure Research)

- LNG infrastructure to initially come up in only the top few traffic routes to maximise utilisation
- Only limited routes targeted in initial years

B. Infrastructure and regulatory constraints:

i. LNG fuel suppliers:
   - LNG tank and customisation approvals
   - Clarity needed on the policy roadmap

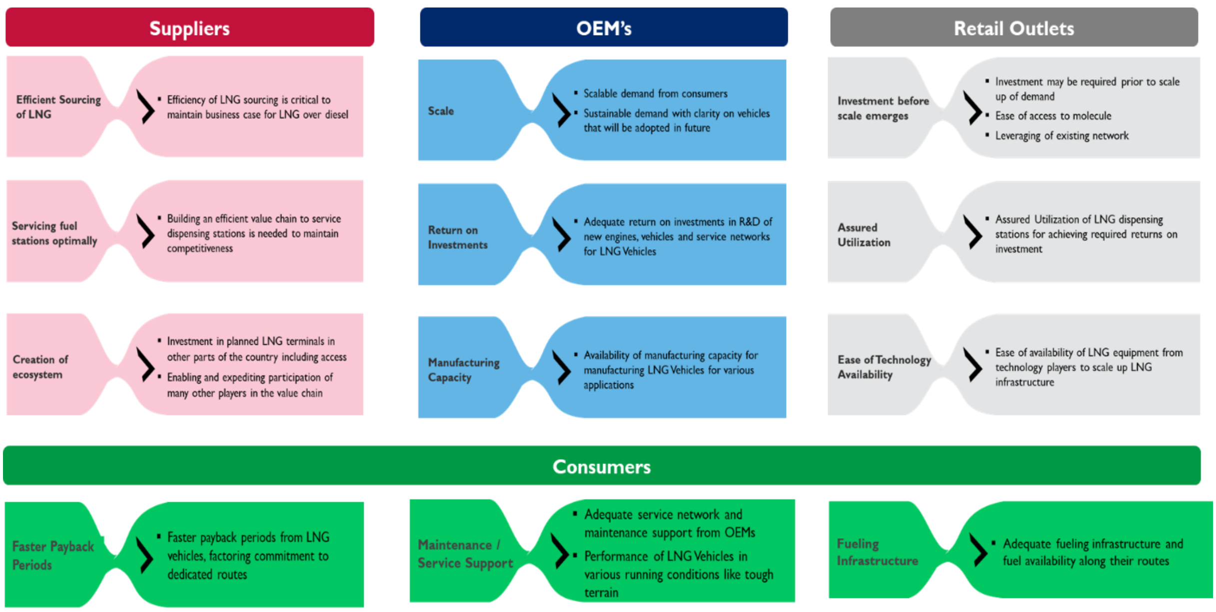
ii. Potential consumers:
   - Low awareness of technology
   - Low availability of dispensing stations
   - Performance apprehension

iii. OEMs:
   - Economical transport of fuel from terminals
   - High capital costs for entry
   - Requires long-term commitment

iv. Retail operators:
   - Challenge in financing retail infrastructure due to low utilisation
   - Land for setting up dispensing stations at key locations could be a bottleneck

Despite market constraints for use of LNG in the transport sector, there are a few enablers as well for different stakeholders in the value chain.

Figure 134 Enablers for development of the LNG road transport ecosystem in India



Apart from the above-mentioned enablers, other initiatives are taken in the country for the development of ssLNG:

- Both public and private companies in India have started to transition towards ssLNG through installation of truck-loading units on the LNG terminals. In April 2021, Japan's Mitsui signed a memorandum of understanding with Indian cryogenic technology equipment company Inoxcva to invest in India's ssLNG infrastructure, including logistics and receiving facilities.[348] In India, several CGD companies, including Indraprastha Gas, GAIL, and Think Gas, plan to develop LCNG (Liquified Compressed Natural Gas) or satellite stations.

- According to a report by India Infrastructure Research, about 15 upcoming truck loading bays are planned in the country to send out 0.75 MMTPA of LNG. With the upcoming facilities coming in, a total

[348] https://www.energyvoice.com/oilandgas/asia/314632/japans-mitsui-eyes-small-scale-lng-in-india/

1.15 MMTPA of LNG send out would be possible. Moreover, at least 7-10 MMTPA of demand from ssLNG is expected by 2025.

- Government-led initiatives, such as recognition of LNG as an automotive fuel (the 2017 Amendment to Central Motor Vehicle Rules Act, 1989), amendments in gas cylinder rules, and Static and Mobile Pressure Vessels (SMPV) rules to support the supply chain of LCNG stations, etc., have been positive enablers in creating an efficient ecosystem for ssLNG development. Further, for the 11th City Gas Distribution round, PNGRB aims to promote natural gas supply through trucks in geographical areas that lack pipeline connectivity. India also plans a network of LCNG/LNG fuelling stations along its 6,000 km long golden quadrilateral highways to build an effective ecosystem for LNG-fuelled vehicles in the country. The government has laid the foundation of first 50 LNG fuelling stations across key national highways. It plans to invest close to US$1.4 billion in the next three years in setting up 1,000 LNG stations.[349]

13.3 Development of ssLNG through LNG hub and spoke model in the SAR

13.3.1 ssLNG transportation through a hub and spoke model

In an LNG hub and spoke model, a centralised LNG hub/facility will be developed to distribute LNG to the demand destinations through different means of transportation. Within the SAR, the possibility of hub and spoke model can exist either through roadways (LNG trade of India with the eastern countries, such as Bangladesh, Nepal, and Bhutan) or through waterways (LNG trade of India with southern countries, such as Sri Lanka and Maldives). The following are the different advantages and limitations in using ssLNG for cross-border trading.

Advantages of ssLNG for cross-border trading: There are several advantages of carrying out cross-border trade through ssLNG in an LNG hub and spoke model:

- ssLNG can be used to serve demand centres with lower demand that cannot be connected to a pipeline network.
- Capex requirements for commencing a ssLNG based model are significantly lower compared with pipeline-based transportation. In addition, operations can commence faster compared with the commencement of a pipeline connectivity.
- There has also been a significant reduction in costs of vaporisers and LNG storage facilities that provide more viability to this means of transportation.
- As pipelines are fixed, non-scalable assets, they must be sized appropriately to have sufficient capacity to meet any increases in demand. However, there is risk of demand stagnating at a lower capacity and pipeline assets getting stranded. Such risks are not faced with ssLNG. The transportation quantities can be scaled up later to the desired capacity per demand from spokes.
- Small-scale LNG can serve those consumers better who have intermittent, irregular, or seasonal requirements.
- ssLNG provides more flexibility in the risks pertaining to “take-or-pay” supply contracts. The excess can be resold and transported easily to other demand centres.

Limitations of ssLNG for cross-border trading: The limitations presented by the ssLNG mode of trade in cross-border trading are as follows:

- As the ssLNG model will rely on road or waterways transport, cargoes are susceptible to disruptions to any of these modes of transport caused from natural events (flooding, cyclones, and earthquakes). Moreover, they can be susceptible to the accidents that delay travel and human-made events, such as strikes or public disorder.
- Small-scale LNG will be able to primarily benefit end-users who require a small volume. In addition, end-users will also require investments satellite regasification facilities consisting of vaporisers and storage tanks.
- LNG road carriers need to be retrofitted to manage cryogenic cargoes and therefore, will cost more. They have to be contracted on a hire-lease basis.
- Operational costs consisting of personnel, maintenance, and fuel costs are high for ssLNG.

[349] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/020121-indias-small-scale-gas-potential-gives-lng-by-trucks-a-boost

13.3.2 ssLNG hub and spoke model in South Asia: Options and investments

In a hub and spoke model, ssLNG transportation can support investments from several stakeholders. LNG terminal operators can benefit by providing the transport and regasification service to enhance their reach to new places and improve their capacity utilisation. Small and medium-sized enterprises at demand locations in other countries can gain from this model with a local micro-grid network for gas delivery. Third-party companies could also engage in volume aggregation of small consumers' demand and provide doorstep delivery of LNG from the terminal to consumer sites.

The model can be used to primarily serve Bhutan (where demand will be low) and certain remote locations in Nepal and Bangladesh where pipeline construction is not feasible. To facilitate trade on the eastern coast, India offers three possible options for the LNG hub: the Dhamra LNG terminal (Orissa), the Haldia LNG terminal (West Bengal) and the Kukrahati LNG terminal (West Bengal). The Dhamra LNG terminal is the most feasible hub for trade because of its higher capacity. Pearl Energy (Pvt) Ltd. signed an agreement with the Board of Investment of Sri Lanka to launch the Hambantota LNG hub,[350]which can be a potential hub for an LNG hub and spoke model amongst India, Sri Lanka, and Maldives. India and Sri Lanka can also collaborate to operate a joint LNG terminal facility at the Hambantota hub.

The Gwadar deep seaport has also been proposed as one of the potential sites for a physical natural gas trading hub, by virtue of geography. It is in close proximity to the Strait of Hormuz, and the oil and gas rich Middle East. The TAPI and IP pipeline projects both traverse the site; the China-Pakistan Economic Corridor infrastructure projects include an LNG terminal at Gwadar.[351]However, development of pipeline connectivity to India and onwards would have to be considered in that scenario for the Gwadar Port to become a trading hub in the region.

Investments: The following are investment details in LNG terminal construction projects in the SAR:

- The Maldives Renewable Energy Roadmap described the differences between the construction of a conventional LNG terminal and a small-scale LNG terminal in Maldives. To construct a conventional LNG terminal of 5-10 MMTPA capacity, the investment amount is expected to be US$1-1.5 billion. For construction of a small-scale LNG terminal of 0.1-1 MMTPA capacity, the expected investment amount is in the range of US$50-100 million.
- For the Hambantota LNG terminal in Sri Lanka whose capacity will be 1 MMTPA, capex investment is expected to be US$100 million.[352]
- According to the LTGEP report from Ceylon Electricity Board, construction of an FSRU with 1 MMTPA capacity in Sri Lanka is expected to incur US$174 million.
- The Gas Sector Master Plan of Bangladesh provided a comparison of construction costs between a land-based LNG terminal and an FSRU. According to the plan, approximate capex for construction of a 3 MMTPA land-based LNG terminal would be US$750 million, whereas for an FSRU, it would be US$450 million.
- Transportation through ssLNG will include costs of LNG trucks and cryogenic tankers. As per a research report by the Council of Energy, Environment, and Water, capex investment for a diesel truck is expected to be US$0.03-0.05 million and capex investment for a cryogenic container to be US$0.12-0.14 million.

ssLNG hub and spoke model can be implemented in shorter timelines for initiating cross-border trade with low volumes and lower capital and business risks and provide scalable solutions as the demand picks up.

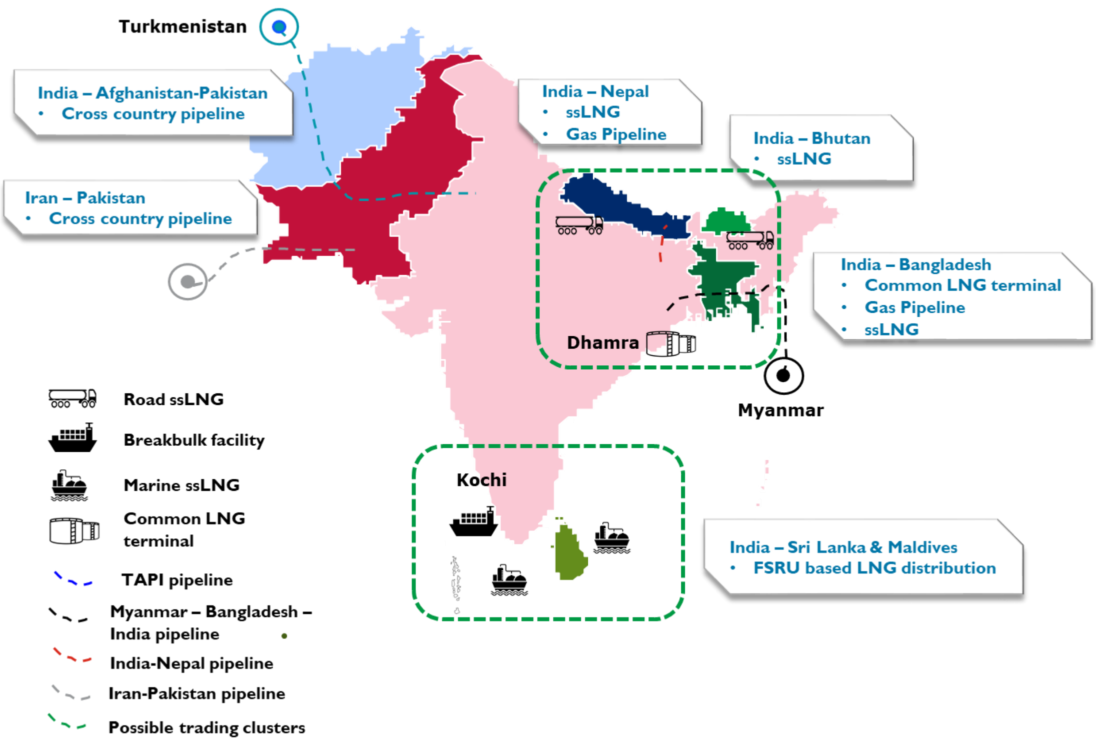
[350] *"Floating storage trading facility in H'tota from Pearl Energy", Daily News, Aug-2020*
[351] *"Dynamics of Natural Gas Pricing: The Critical Need for a Natural Gas Hub in South Asia", Journal of International Affairs – Columbia University, Jan-2016*
[352] *https://www.maritimegateway.com/socar-trading-and-pearl-energy-to-develop-hambantota-lng-hub/*

13.4 Infrastructure options for cross-border trade

Given the diverse geography and geopolitical considerations embedded in energy discussions in the SAR, a regional pipeline network can be combined with an LNG hub and spoke model.

The Island nations could be supplied using a central breakbulk facility. It might be preferable to encourage gas trading between land-locked neighbours via a pipeline or ssLNG with a company such as Petronet LNG playing the role of an LNG aggregator. The Dhamra LNG terminal could serve as the hub for supplying LNG in the hub and spoke model to the eastern countries. LNG tolling could be considered to increase trade opportunities between India and Bangladesh as electricity markets are developing at a quicker pace. Bangladesh could also be supplied via a breakbulk facility at the Dhamra LNG Terminal. The following is the summary of various opportunities of cross-border trade between the SAR countries:

Figure 135 Summary of infrastructure options, by country, in the SAR region



In addition to the opportunities mentioned above, the joint gas exploration programmes are already making their way. These partnerships can also be commenced amongst other neighbouring countries, such as India-Nepal, India-Sri Lanka, and Afghanistan-Pakistan. Forming a regional hub in the region will require political will and market liberalisation as in the case of the European and US markets. However, the commencement of Indian Gas Exchange has already initiated a step towards the same.

13.5 Potential trade options for regional gas trade

Developing cross-border infrastructure forms one half of the equation in facilitating cross-border trade. The other half of the equation is associated with introducing different types of gas trade arrangements. Several feasible arrangements can be introduced in the SAR:

- **LNG sales purchase agreements:** These are typically made for long-term LNG trade between buyers and sellers. For spot or short-term LNG sales, LNG master sales agreements are signed that are slightly different from the standard sales purchase agreements. These contracts need to address the following things associated with LNG trade:
    - Contract term
    - Fixed annual purchase quantity
    - Pre-agreed pricing

- Transportation and delivery
- Firm take or pay obligations for LNG buyers
- Firm deliver or pay obligations for LNG sellers

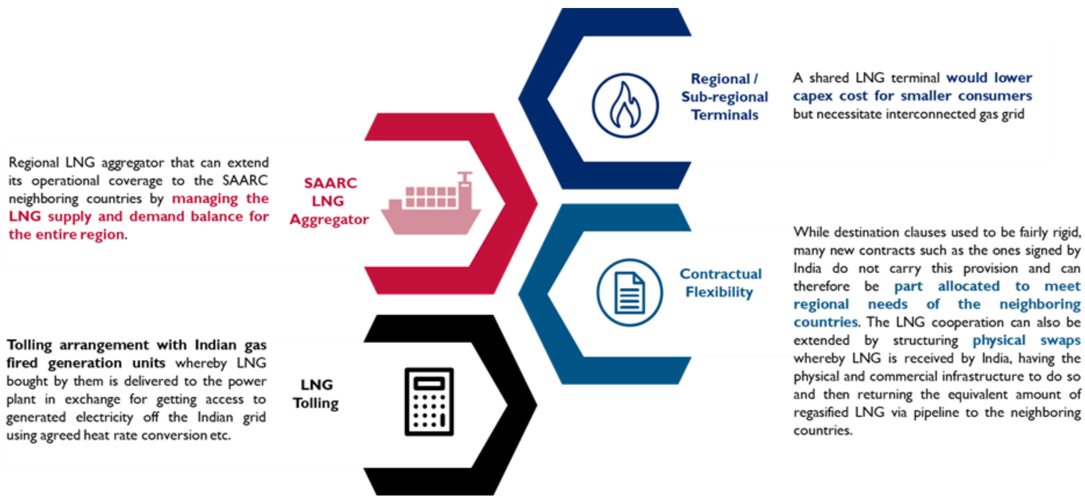
Within the SAR, India, Pakistan, and Bangladesh have their own long-term contracts for LNG import. Many new contracts being signed by India do not have any destination provisions. Hence, they can be used flexibly to promote regional LNG trade. Indian companies with LNG contracts not having any destination clauses can reroute certain LNG volumes to neighbouring countries, such as Bangladesh, Sri Lanka, and Maldives, to fulfil their needs. This also provides flexibility for these countries to spend less time and efforts in negotiating individual LNG contracts.

- **Third-party access for LNG tolling:** In general manufacturing processes, a tolling agreement is a contract to supply an agreed amount of raw material to be put through industrial processes and in return providing a payment for using those processes. Tolling is a relatively recent model for LNG plant operations where the customer pays a toll to convert gas into liquid in a liquefaction plant or vice-versa. The plant owner provides liquefaction/regasification services and collects the toll for provision of those services. Tolling arrangements are made on a "use or pay" basis. Customers bear the risk of volatile gas prices. In India, LNG terminals such as Dhamra, can provide third-party access to buyers from neighbouring countries (such as Bangladesh) on a tolling arrangement. There is a possibility of another type of a tolling arrangement involving Indian gas-fired generation units whereby the LNG bought by Bangladesh, Bhutan, or Nepal is delivered to Indian power plants in exchange for getting access to generated electricity off the Indian grid.

- **LNG swaps and regional LNG aggregator:** LNG swaps are prominent in the global LNG marketplace as they help reduce shipping and logistics costs for buyers. In a typical LNG swap, the buyer will swap an LNG cargo produced in one part of the world with LNG sourced from a location that is closer to where the buyer wants LNG to be delivered. Such type of an arrangement through physical swaps is feasible with countries such as Nepal and Bhutan where the LNG is received for them by India through any of the operational terminals. Then an equivalent amount of LNG can be supplied to them either in a regasified form or through ssLNG. This can be managed through a regional LNG aggregator that can extend its operational coverage to the SAR neighbouring countries by managing demand and supply for the countries in the region. This would enable the LNG aggregator to have a greater flexibility in its contracts and lower procurement costs for the region.

- **Third-party access for gas exchanges:** India launched the Indian Gas Exchange in 2020 to create a common digital platform for both buyers and sellers to trade in the spot and forward markets for imported natural gas. After establishing gas infrastructure connectivity with neighbouring countries (such as Bangladesh, Bhutan, and Nepal), India can provide third-party access of the exchange to buyers and sellers from these countries. This would help create a common regional marketplace for gas trade and be a major step in the formation of a regional LNG hub.

Figure 136 Summary of cross-border trade options in the SAR region



14 Cross-border natural gas trade in the SAR: benefits, trade potential, and options

14.1 Potential benefits of cross-border trade in the SAR

The potential cross-border trading in the SAR is expected to bring several economic, environmental, and social benefits to the member states.

14.1.1 Economic benefits

The commencement of cross-border gas trade amongst countries will help in switching over to affordable gas compared with alternative fuels, thus resulting in economic benefits for nations. The following tables provide the comparison of landed cost of gas for different SAR member states compared with alternative fuels, such as petrol and diesel:

Table 141 Comparison of LNG prices with other fuels for SAR member states

Country	Landed cost of LNG ($/mmbtu)	Price of petrol ($/mmbtu)	Price of diesel ($/mmbtu)
India	12-22.3	31-48	23-35
Pakistan	14.7-15.7	28	22
Bangladesh	18.3	35.1	25.3
Sri Lanka*	9.5-20.6	42	31.6
Nepal*	9-22	34	31.5
Bhutan*	10.5-22	40.1	38.2

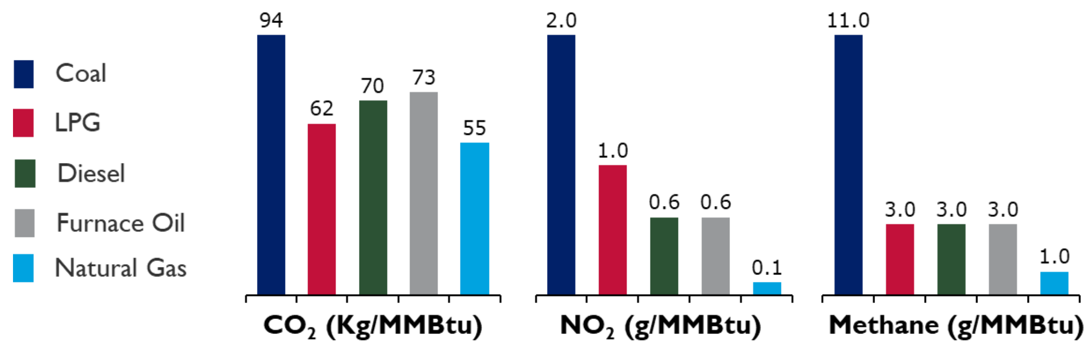
Note: The prices that have been considered for petrol and diesel are for May 2022. For Pakistan, the prices have been considered for November 2021.

**: The price for these countries has been considered after analysing the possible supply sources. Calculations are based on an illustrative landed cost of gas from India.*

14.1.2 Environmental benefits

Environmental benefits of intra-regional gas trade: Natural gas trade in the SAR will provide significant environmental benefits through its increased use in various sectors. Natural gas has one of the lowest emissions of CO_2, NO_2, and methane compared with conventional fuels, such as coal, diesel, and FO. As per IEA, CO_2 emissions (per unit of energy produced) from gas are about 40 percent lower than coal and nearly 20 percent lower than oil. Moreover, emissions are ~95 percent less for NO_2 and ~90 percent less for methane compared with coal. Moreover, the combustion of gas causes negligible emissions of fine particulate matter ($PM_{2.5}$) and sulphur dioxide (SO_2).[353]Given below is the comparison of emissions caused by combustion of gas and other conventional fuels:[354]

Figure 137 Emissions caused on combustion of Gas and other conventional fuels



Moreover, the increasing climate change concerns across the globe have highlighted the need of transitioning towards cleaner energy sources that cause less greenhouse gas emissions. In December 2015, the countries

[353] https://www.iea.org/commentaries/the-environmental-case-for-natural-gas
[354] https://www.epa.gov/sites/default/files/2018-03/documents/emission-factors_mar_2018_0.pdf

across the globe committed to create a new international climate agreement by the conclusion of the U.N. Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP21). As a result, the countries agreed to publicly outline the climate actions they intend to take after 2020 under a new international agreement, known as their Intended Nationally Determined Contributions (INDCs). The SAR nations also gave their individual conditional and unconditional INDC targets, by country.

Figure 138 Overall summary of INDCs of SAR countries

	INDCs for SAR countries
India	• To reduce the emissions intensity of its GDP by 33–35% by 2030 from the 2005 level • To adopt a climate-friendly and a cleaner path than the one followed hitherto by others at the corresponding level of economic development • To create an additional carbon sink of 2.5–3 billion tons of CO2 equivalent through additional forest and tree cover by 2030 • To build capacities, create a domestic framework, and international architecture for quick diffusion of cutting-edge climate technology in India and joint collaborative R&D for such future technologies
Pakistan	• Pakistan intended to reduce up to 20% of its 2030 projected GHG emissions, subject to availability of international grants to meet the total abatement cost amounting to US$40 billion
Bangladesh	• An unconditional contribution to reduce GHG emissions by 5% from Business as Usual (BAU) levels by 2030 in the power, transport, and industry sectors, based on existing resources • A conditional 15% reduction in GHG emissions from BAU levels by 2030 in the power, transport, and industry sectors, subject to appropriate international support in the form of finance, investment, technology development and transfer, and capacity building • Implementation on programmes on gas exploration and reservoir management to enhance energy security and ensure low-emission development
Sri Lanka	• Sri Lanka intended to reduce GHG emissions against the Business-As-Usual scenario unconditionally by 7% (the energy sector 4%, and 3% from other sectors) and conditionally 23% (the energy sector 16% and 7% from other sectors) by 2030 • Establishment of energy efficient and sustainable transport systems by 2030 and introduction of low emission vehicles into the transport system • Modernising and facilitating the industries to reduce their GHG emissions per the international ISO standards
Nepal	• Nepal to formulate the Low Carbon Economic Development Strategy that would promote economic development through low carbon emission with a particular focus on: (i) energy; (ii) agriculture and livestock; (iii) forests; (iv) industry; (v) human settlements and wastes; (vi) transport; and vii) commercial sectors • By 2050, Nepal to achieve 80% electrification through renewable energy sources having an appropriate energy mix. It will also reduce its dependency on fossil fuels by 50%. • By 2025, Nepal to strive to decrease the rate of air pollution through proper monitoring of sources of air pollutants, such as wastes, old and unmaintained vehicles, and industries
Bhutan	• Bhutan to remain carbon neutral where emission of greenhouse gases will not exceed carbon sequestration by the country's forests • Promotion of a low carbon transport system by improving efficiency and emissions from existing vehicles through standards and capacity building, along with promotion of non-fossil fuel powered transport • • Improvement of manufacturing processes in existing industries through investments and adoption of cleaner technology to move towards carbon neutral and sustainable development
Afghanistan	• Afghanistan to achieve 13.6% reduction in GHG emissions by 2030 compared with a business as usual (BAU) 2030 scenario, conditional on external support.
Maldives	• Maldives to reduce unconditionally 10% of its Greenhouse Gases (below BAU) for 2030 • The reduction could be increased up to 24% in a conditional manner in the context of sustainable development, supported and enabled by availability of financial resources, technology transfer, and capacity building.

Natural gas can serve as one of the potential transitioning fuels from conventional fossil fuels for the SAR nations to move towards achievement of their INDC targets of lower GHG emissions.

14.1.3 Social benefits

Primary social benefits of intra-regional trade are expected in terms of the direct and indirect employment expected to be generated due to gas demand and creation of gas infrastructure. Direct jobs are expected to be involved in development and operation of upstream exploration, pipeline transportation, and distribution of gas apart from construction and operation of LNG terminals and cross-country pipelines. Moreover, this would lead to creation of additional jobs in other industries that supply goods and services to the natural gas industry.

In addition, unlike the LPG cylinders that need to be refilled time and again, pipeline gas will offer a steady supply of clean fuel to urban and rural households. The supply of piped gas to the rural households will not only ensure a healthy lifestyle but also save significant time usually spent on collecting firewood. The social benefits of gas trade and usage can also be assessed in terms of the positive externalities through the less harmful emissions by gas usage. The increased usage of gas is expected to reduce the levels of environmental pollution in the region, which in turn, would reduce the mortality and respiratory infections rate amongst the population.

14.2 Demand-supply deficit and cross-border trading potential for natural gas

The major contributors in the facilitation of cross-border trade are expected to be: (i) Increasing gas demand in the SAR; (ii) Surplus and deficit amongst member nations; (iii) Benefits of gas usage over other fuels; and (iv) Widening demand-supply gap. Due to the rise in gas demand in the next few years from different sectors, each member country is likely to face higher dependence on LNG imports to meet domestic gas demand. The imports accounted for 60 percent, 26 percent, and 18 percent of the natural gas consumption in case of India, Pakistan, and Bangladesh, respectively, for FY 2020.[355]

14.2.1 Cross-border trading potential amongst the SAR nations

Amongst the SAR nations, India is expected to be the main facilitator of cross-border natural gas trade within the region and supply gas/LNG to other member countries. The major reasons for this are: capacity and scale of upcoming LNG projects, completion of gas pipeline grids across the country, new CGD rounds to provide gas supplies to remote areas, and impetus given by the government to increase the share of gas in the fuel mix. Apart from India, Bangladesh can also act as a facilitator of cross-border trade to countries on the eastern side like Nepal and Bhutan given that Bangladesh's government is able to build up sufficient new capacity of LNG terminals. As of now, for assessment of cross-border trade in the SAR, only the gas trade from India to other countries has been considered. Potential cross-border trade with Pakistan and Afghanistan has not been considered in the assessment due to factors such as faraway geographical proximity of both the nations from other SAR countries, and the possibility of both countries not facing a supply deficit in the scenario of completion of TAPI and IPP pipelines.

For Sri Lanka, the Hambantota LNG terminal with 1 MMTPA capacity, is expected in the future. New Fortress Energy has also signed a framework agreement with Sri Lanka's government to construct a new offshore LNG terminal to supply gas to power plants in Sri Lanka. In addition, the government of Sri Lanka has the goal to produce gas domestically for meeting a majority of the country's needs because of which several exploration and production activities are underway in the Mannar and Cauvery basins. Therefore, for Sri Lanka, 10 percent of the supply deficit has been assumed to be met through cross-border trade.

In case of Bangladesh, the overall supply deficit is expected to be quite high. Most of this deficit is expected to be met by the country through the unannounced LNG terminals post FY 2025 and new domestic gas exploration programmes. Only a certain percentage of the supply deficit could be met through cross-border trade. For the initial years, the percentage of supply deficit to be met by cross-border shall be high as any new announced projects post FY 2025 might take some time in completion and reach full utilisation. In addition, the gas requirement through cross-border trade might decrease in future if there are additional indigenous gas discoveries through both onshore and offshore production. Therefore, in the initial years for Bangladesh, 50 percent and 25 percent of the total deficit has been assumed to be fulfilled by cross-border trade in FY 2025 and FY 2030 respectively. Post FY 2030, Bangladesh is expected to come up with further avenues of supply given the rising gas demand in the country. Therefore, the percentage of deficit expected to be met by cross-border trade has been assumed to further reduce upto 12.5 percent, and 10 percent for FY 2035 and FY 2040 respectively.

For calculation of the overall cross-border trade potential, 2 scenarios of supply deficit in Bangladesh have been considered.

14.2.1.1 Scenario – A: Overall trade potential in basecase demand and supply for Bangladesh (most plausible scenario)

Scenario A considers the supply from imports and overall demand-supply deficit for Bangladesh according to Scenario-1 of Section 4.6.3.2 in the report. Within this scenario, along with the 2 existing terminals, only Matarbari LNG terminal has been assumed to commence in future within Bangladesh per the publicly available data. According to this scenario, the overall demand-supply deficit in Bangladesh reaches upto ~33 mmscmd by FY 2030 and ~100 mmscmd by FY 2040 (Table 68 and Table 69 of the report).

Within Scenario A, a summary of the overall cross-border trading potential until FY 2040 for Bangladesh, Bhutan, Sri Lanka, Nepal, and Maldives with India has been shown below:

Table 142 Potential for cross-border trade in the SAR within Scenario-A for basecase demand and supply in Bangladesh

Countries	FY25	FY30	FY35	FY40
Bangladesh gas supply deficit (Scenario-1 of supply according to Section 4.6.3.2)	-4.5*	-8.2*	-9.4*	-10*
SL gas supply deficit	-0.19	-0.67**	-1.17**	-1.60**

[355] *PPAC, BP Energy Statistics*

Countries	FY25	FY30	FY35	FY40
Bhutan gas supply deficit	-0.04	-0.09	-0.17	-0.22
Nepal gas supply deficit	-1.74	-4.11	-7.01	-10.3
Maldives gas supply deficit	-0.15	-0.48	-0.92	-1.18
India gas supply surplus	38	44	-33***	-96***
Cross-border trading potential with India (in mmscmd)	**6.6**	**13.6**	**18.7**	**23.3**
Range of trade potential (in mmscmd)	**5-10**	**10-15**	**15-20**	**20-25**

**: The combined deficit of Bangladesh is expected to be more than the deficit mentioned in the table above. However, some natural gas demand is also expected to be fulfilled by new LNG terminals currently unannounced in the country post FY 2025 or additional enhancements in both onshore and offshore domestic production. Hence, 50 percent, 25 percent, 12.5 percent, and 10 percent of the total deficit has been assumed to be fulfilled by cross-border trade in FY 2025, FY 2030, FY 2035, and FY 2040, respectively.*

***: Sri Lanka is expected to come up with the Hambantota LNG terminal whose capacity would be 1 MMTPA. In addition, the New Fortress LNG terminal is expected to provide supply to the gas-fired power plants. The domestic exploration and production activities are also picking up pace in the country. Hence, 10 percent of the supply deficit has been assumed to be fulfilled by the cross-border trade.*

****: India is expected to have gas surplus until FY 2030. After FY 2030, there is limited visibility of new LNG terminals and new domestic sources of production. Hence, the overall supplies have been projected to plateau after FY 2030 despite an increase gas demand from sectors. Therefore, India is expected to have a demand deficit from FY 2033 onwards. There is an overall demand deficit for FY 2035 and FY 2040.*

The combined trading potential of India with Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives within this scenario is expected to reach up to ~10-15 mmscmd by FY 2030; this could be met from India considering there would be optimal utilisation of the existing and upcoming LNG terminals. Net combined supply deficit for Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives is expected to reach up to ~127 mmscmd by FY 2040. However, as Bangladesh and Sri Lanka can negotiate import contracts with other countries outside the SAR, the overall trading potential in the region is expected to be ~20-25 mmscmd.

14.2.1.2 Scenario – B: Overall trade potential for increased supply in Bangladesh from additional import infrastructure and offshore production

Scenario B for cross-border trade considers the supply from imports and overall demand-supply deficit for Bangladesh according to Scenario-2 of Section 4.6.3.2 in the report. This scenario assumes commencement of offshore production in Bangladesh from FY 2028 along with additional import infrastructure of ~7.8 MMTPA being constructed in the country by FY 2025. According to this scenario, the overall demand-supply deficit in Bangladesh reaches upto ~7 mmscmd by FY 2030 and ~65 mmscmd by FY 2040 (Table 70 and Table 71 of the report). The percentage of demand-supply deficit for Bangladesh to be met by cross-border trade has been considered equivalent to Scenario A only.

Within Scenario B, a summary of the overall cross-border trading potential until FY 2040 for Bangladesh, Bhutan, Sri Lanka, Nepal, and Maldives with India has been shown below:

Table 143 Potential for cross-border trade in the SAR within Scenario-B for additional supply from offshore production and imports in Bangladesh

Countries	FY25	FY30	FY35	FY40
Bangladesh gas supply deficit (Scenario-2 of supply according to Section 4.6.3.2)	-3.1*	-1.6*	-5.5*	-6.5*
SL gas supply deficit	-0.19	-0.67**	-1.17**	-1.60**
Bhutan gas supply deficit	-0.04	-0.09	-0.17	-0.22
Nepal gas supply deficit	-1.74	-4.11	-7.01	-10.3
Maldives gas supply deficit	-0.15	-0.48	-0.92	-1.18
India gas supply surplus	38	44	-33***	-96***

Countries	FY25	FY30	FY35	FY40
Cross-border trading potential with India (in mmscmd)	**5.2**	**7**	**14.8**	**19.7**
Range of trade potential (in mmscmd)	**~5**	**5-10**	**10-15**	**15-20**

**: The combined deficit of Bangladesh is expected to be more than the deficit mentioned in the table above. However, some natural gas demand is also expected to be fulfilled by new LNG terminals currently unannounced in the country post FY 2025 or additional enhancements in both onshore and offshore domestic production. Hence, 50 percent, 25 percent, 12.5 percent, and 10 percent of the total deficit has been assumed to be fulfilled by cross-border trade in FY 2025, FY 2030, FY 2035, and FY 2040, respectively.*

***: Sri Lanka is expected to come up with the Hambantota LNG terminal whose capacity would be 1 MMTPA. In addition, the New Fortress LNG terminal is expected to provide supply to the gas-fired power plants. The domestic exploration and production activities are also picking up pace in the country. Hence, 10 percent of the supply deficit has been assumed to be fulfilled by the cross-border trade.*

****: India is expected to have gas surplus until FY 2030. After FY 2030, there is limited visibility of new LNG terminals and new domestic sources of production. Hence, the overall supplies have been projected to plateau after FY 2030 despite an increase gas demand from sectors. Therefore, India is expected to have a demand deficit from FY 2033 onwards. There is an overall demand deficit for FY 2035 and FY 2040.*

The combined trading potential of India with Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives within this scenario is expected to decrease and reach up to ~5-10 mmscmd by FY 2030; this could be met from India considering there would be optimal utilisation of the existing and upcoming LNG terminals. Net combined supply deficit for Bangladesh, Sri Lanka, Nepal, Bhutan, and Maldives is expected to reach up to ~93 mmscmd by FY 2040 considering there would be additional sources of supply in Bangladesh through offshore discoveries and import infrastructure. However, for the remaining deficit, as Bangladesh and Sri Lanka can negotiate import contracts with other countries outside the SAR, the overall trading potential in the region within this scenario is expected to be ~15-20 mmscmd by FY 2040.

14.2.2 Economic benefits for SAR countries from cross-border trading and switching to gas

The cross-border trading of gas between SAR countries can result in potential annual savings for individual member nations. Considering a potential benefit of US$1/mmbtu after commencement of intra-regional trade and the calorific value of gas as 10,000 kcal/scm, ~US$14.5 million of savings can be achieved each year on doing 1 mmscmd of gas trade. The following can be the potential annual savings by country for both the scenarios of cross-border trade considering the above-mentioned assumptions:

Table 144 Potential annual savings by country for Scenario A in cross-border trade

Country	Potential annual economic benefit in Mn US$ (by FY 2025)	Potential annual economic benefit in Mn US$ (by FY 2030)	Potential annual economic benefit in Mn US$ (by FY 2035)	Potential yearly economic benefit in Mn US$ (by FY 2040)
Bangladesh	64.9	119.5	136.4	144.6
Sri Lanka	2.8	9.7	17	23.2
Bhutan	0.5	1.3	2.4	3.2
Nepal	25.3	59.5	101.6	149.4
Maldives	2.2	7.0	13.4	17.1
Total savings in the region	**~96**	**~197**	**~271**	**~338**

Table 145 Potential annual savings by country for Scenario B in cross-border trade

Country	Potential annual economic benefit in Mn US$ (by FY 2025)	Potential annual economic benefit in Mn US$ (by FY 2030)	Potential annual economic benefit in Mn US$ (by FY 2035)	Potential yearly economic benefit in Mn US$ (by FY 2040)
Bangladesh	44.6	23.8	79.8	93.6
Sri Lanka	2.8	9.7	17	23.2

Country	Potential annual economic benefit in Mn US$ (by FY 2025)	Potential annual economic benefit in Mn US$ (by FY 2030)	Potential annual economic benefit in Mn US$ (by FY 2035)	Potential yearly economic benefit in Mn US$ (by FY 2040)
Bhutan	0.5	1.3	2.4	3.2
Nepal	25.3	59.5	101.6	149.4
Maldives	2.2	7.0	13.4	17.1
Total savings in the region	**~75**	**~101**	**~214**	**~287**

In addition to the consumer countries, the cross-border trading is also expected to provide considerable benefits to the terminal and pipeline operators in India (the supplier country) as well. Commencement of cross-border gas trading would result in creation of additional markets for companies operating LNG terminals and pipelines. This would eventually lead to improvement in their capacity utilisation and opportunities for the government to get attractive long-term contracts for LNG procurement from global markets. In the long run, as India supplies gas to other countries, this would help in the formation of a gas trading hub in South Asia that would be spearheaded by India. Moreover, this will also help in the maturity of IGX as more buyers and sellers from the other countries would come onboard for intra-regional gas trade. Along with that, this would be a major booster for the development of ssLNG supply chain in India. In addition, intra-regional trade would provide incentives to both private and public players to invest in expansion of LNG terminal and pipeline capacities. This would create additional opportunities for infrastructural investments and employment which would have a positive impact on the economic growth. Overall, cross-border trading would be a major step for the expansion of the gas ecosystem in the country and the whole region.

14.3 Natural gas trading infrastructure options within SAR nations

The SAR presents the challenge of varied geographies and sizes of the countries. Therefore, one single trade mechanism will not be possible for countries. In the future, India is expected to be at the forefront in carrying out trade between the countries and meeting supply deficit.

14.3.1 Potential gas trade between Bangladesh and India

Trading between India and Bangladesh is currently limited to POL fuels. At present, high-speed diesel is being supplied from the Siliguri terminal through rail rakes to the Parbatipur depot of Bangladesh Petroleum Corporation. The countries have also been in discussions for the construction of India Bangladesh Friendship Pipeline for transport of diesel from Siliguri to Parbatipur which is expected to get completed by 2022.[356] In addition, a pipeline to transport natural gas from Dattapulia in India to Khulna in Bangladesh had also been discussed. However, there has not been any progress. The potential opportunity for facilitating natural gas trade between India and Bangladesh can be carried out in the following ways:

- **Pipeline infrastructure**: Dedicated pipelines can be constructed from CGD GAs (awarded in 9th and 10th rounds) of India to high demand districts of Bangladesh for transportation of natural gas. The pipeline infrastructure can be built by connecting the already existing pipeline infrastructure in GAs through sub-transmission pipelines. A certain percentage of spare capacity of the already existing pipeline network would be required to be allocated for transportation of natural gas through the network. In case the pipeline is constructed, it can present significant potential of facilitating cross-border gas trade between India and Bangladesh. The development of a natural gas pipeline between India and Bangladesh could also lead to the growth of Indian Gas Exchange. After the pipeline development and establishment of gas networks, buyers and sellers in Bangladesh could be provided TPA to the Indian Gas Exchange. This would bring more participants onto the platform. This would be a major step for the SAR countries in transitioning towards a regional gas hub. India is currently exploring petroleum and natural gas in Tripura, and other neighbouring states of Bangladesh. In case, any gas is discovered within those areas by 2030, some amount of it can be traded with Bangladesh through small-diameter pipelines. In December 2021, the Adani Group in India submitted an expression of interest to construct a gas pipeline from Haldia to Panitar in West Bengal (to also be connected to the

[356] https://www.thedailystar.net/business/economy/news/development-works-now-90pc-complete-officials-3089461

JHBDPL pipeline). This is near to the Indo-Bangla border.[357]The following are a few other pipeline connectivity options between India and Bangladesh:

Table 146 Pipeline connectivity options between India and Bangladesh

Serial No.	From	To	Distance between source and destination
1	Silguri, Durgapur (North-Eastern Region of India)	Chittagong	~630 km
2	Haldia, Kolkata (extension of JHBDPL gas pipeline by Adani)	Boalia, Satkhira (connects Southern Bangladesh)	~135 km
3	Kishanganj, Bihar	Dinajpur, Bangladesh (connects Northern Bangladesh)	~120 km
4	Dattapulia, West Bengal	Jessore, Bangladesh	~70 km
5	Panitar, West Bengal (extension of JHBDPL gas pipeline by Adani)	Bhomra, Sathkira	~20 km
6	Panitar, West Bengal (extension of JHBDPL gas pipeline by Adani)	Khulna, Bangladesh	~85 km
7	Agartala, Tripura (Indradhanush Gas Grid)	Comilla, Bangladesh	~60 km
8	Panisagar, Tripura (Indradhanush Gas Grid)	Moulvi Bazaar, Bangladesh	~75 km

- **RLNG facility in the Bay of Bengal**: An LNG facility can be built on the Bay of Bengal coast with joint participation by India, Bangladesh, and possibly Nepal. New LNG terminals at Haldia, Dhamra, and Kukrahati are being developed. Additional support and investments for these terminals through development of a trilateral partnership can enhance economic viability. In addition, LNG can be supplied to Bangladesh through a breakbulk facility from LNG terminals in India on the eastern coast through a tolling arrangement in the form of ssLNG. Either the Dhamra LNG terminal or the Haldia LNG terminal can facilitate LNG supply to Bangladesh through the Bay of Bengal to FSRUs; these are located at the Moheshkhali Island in southern Bangladesh. The companies operating FSRUs in Bangladesh can pay a fixed toll for the liquefaction of gas at the Dhamra/Haldia terminal. Moreover, the Shibsa river in Khulna-Sathkira district presents another opportunity for cross-border trade with India through high sea sales of LNG from Dhamra/Haldia. Bangladesh can construct a FSRU at the Shibsa river, and subsequently, a 35 km gas pipeline can be laid down from the river to supply gas to the Western region in the country.

During the SAGE event in 2021, India has already announced plans to explore opportunities to supply refined-LNG through a cross-border pipeline and establish an LNG terminal with Bangladesh.[358]Players such as IOCL have been undertaking several initiatives in Bangladesh in coordination with Bangladesh Petroleum Corporation (BPC) and Petrobangla to explore opportunities in this regard.

14.3.2 Potential gas trade between Bhutan and India

India and Bhutan are already on the path of improving regional trade relations through the purchase of power from hydro-electric projects in Bhutan. Electricity flows between India and Bhutan depend on the prevailing

[357] https://pngrb.gov.in/pdf/public-notice/EoI31122021.pdf
[358] https://www.thedailystar.net/business/news/india-bangladesh-exploring-proposal-cross-border-refined-lng-pipeline-2058121

seasons in both the countries. Bhutan sells electricity to India in summers, and buys from India in winter. However, trade of fuel, including natural gas is yet to commence. The primary sources of carrying out trade with Bhutan will be through road transportation from ssLNG and pipeline infrastructure. However, as demand in Bhutan is not expected to go beyond 0.5 mmscmd, building a pipeline from India to Bhutan might not be economically feasible. Therefore, the most plausible scenario for trade between India and Bhutan could be through ssLNG. The entire gas trading between the two countries is expected to be carried out in the future through ssLNG considering the relatively low gas demand from Bhutan.

The government of India is establishing its policy support to grow ssLNG in India; this is important to tap into demand of consumers that are not connected to the gas grid and supply to neighbouring countries, such as Nepal and Bhutan. India plans to set up LNG infrastructure with an investment of INR 10,000 crore, along with 1,000 LNG fuel stations for long haul transportation. This infrastructure is expected to initially come up in top few traffic routes to maximise utilisation.[359]Cost of ssLNG used for bulk consumers in Bhutan from India (considering supply from the Dhamra terminal) is expected between US$10.5-21.8/mmbtu. With the inclusion of retail distribution costs, final costs of end-consumers are expected between US$20.5-31.8.

Following is the analysis of the major districts and their population density in Bhutan:

Table 147 District wise population density of Bhutan

Name	Capital	Area (km^2)	Population Census 2017-05-30	Population Density
Bumthang	Jakar	2667	17820	7
Chukha (Chhukha)	Chukha	1880	68966	37
Dagana	Dagana	1713	24965	15
Gasa	Gasa	2951	3952	1
Haa	Haa	1905	13655	7
Lhuentse (Lhuntse)	Lhuentse	2851	14437	5
Mongar (Monggar)	Mongar	1940	37150	19
Paro	Tshongdue	1287	46316	36
Pemagatshel	Pemagatshel	1022	23632	23
Punakha	Punakha	1110	28740	26
Samdrup Jongkhar	Samdrup Jongkhar	1877	35079	19
Samtse (Samchi)	Samtse	1256	62590	50
Sarpang (Geylegphug)	Sarpang	1655	46004	28
Thimphu	Thimphu	1792	138736	77
Trashigang	Trashigang	2198	45518	21
Trashiyangtse	Yangtse	1447	17300	12
Trongsa	Trongsa	1814	19960	11
Tsirang (Chirang)	Damphu	638	22376	35
Wangdue Phodrang	Wangdue	3977	42186	11
Zhemgang	Zhemgang	2416	17763	7

Source: Population and Housing Census of 2017, Bhutan

Thimphu, Chukha, and Samtse are the capitals of the districts with the highest population density in Bhutan.[360]The possible options for ssLNG transportation to these districts from India are mentioned below:

[359] https://www.business-standard.com/article/economy-policy/india-set-to-attract-rs-10-000-cr-for-1-000-lng-stations-in-three-years-120111900653_1.html
[360] *Population and Housing Census of 2017, Bhutan*

Table 148 Options for ssLNG transportation between India and Bhutan

Serial no.	From	To	Distance between source and destination
1	Kukrahati LNG Terminal	Thimpu District	~940 km
2	Haldia LNG Terminal	Thimpu District	~935 km
3	Dhamra LNG terminal	Thimpu district	~1160 km
4	Kukrahati LNG terminal	Chukha district	~880 km
5	Haldia LNG terminal	Chukha district	~875 km
6	Dhamra LNG terminal	Chukha district	~1095 km
7	Kukrahati LNG terminal	Samtse district	~755 km
8	Haldia LNG terminal	Samtse district	~750 km
9	Dhamra LNG terminal	Samtse district	~980 km

14.3.3 Potential gas trade between Nepal and India

India has been committed to explore the potential for energy trading opportunities with Nepal. In 2019, India and Nepal had inaugurated the first cross-border pipeline between Motihari (India) and Amlekhgunj (Nepal) for trading oil that was built through joint cooperation between IOCL and NOC.

The primary sources of carrying out trade with Nepal will be through road transportation and pipeline infrastructure as Nepal is a land-locked country. There is no scope of building FSRU infrastructure for import of LNG through carrier ships. The two key gas trading options for natural gas between India and Nepal are mentioned below:

- **Natural gas trading through pipelines:** Dedicated pipeline infrastructure can be built between India and Nepal and connected to the existing CGD network through sub-transmission pipelines. Within Nepal, several areas are in proximity of a few GAs under the CGD network of India. Nepal has seven provinces comprising 77 districts. The population density in the country is not evenly distributed. The following is the data of the population density in different provinces of Nepal according to Census 2021:

Table 149 Province wise population density of Nepal

Province	Population	Area	Population Density
Province 1	4,972,071	25,905	192
Madhes	6,126,288	9,661	634
Bagmati	6,084,042	20,300	300
Gandaki	2,479,745	21,504	115
Lumbini	5,124,225	22,288	230
Karnali	1,694,889	27,984	61
Sudurpaschim	2,711,270	19,539	139

According to the data from NOC, within the provinces with the highest population density, Amlekhgunj (Madhes province), Kathmandu (Bagmati province), and Biratnagar (Province 1) had the highest fuel demand for FY 2020. The landed cost of gas through pipeline transportation between India and Nepal is expected to fall between US$9-21.2/mmbtu and final cost for end-consumers (including retail distribution costs) is expected to be US$19-31.2/mmbtu. Considering that cross-border pipelines between India and Nepal would be able to function at their 100 percent capacity, 60-70 percent of the gas demand in Nepal is expected to get fulfilled through pipeline trade based on the analysis of the pipeline transportation costs. The following can be the possible options for pipeline connectivity between India and Nepal for high fuel demand areas:

Table 150 Pipeline connectivity options between India and Nepal

Serial no.	From	To	Distance between source and destination
1	Gorakhpur (extension of JHBDPL gas pipeline)	Amlekhgunj	~245 km
2	Barauni (extension of JHBDPL gas pipeline)	Amlekhgunj	~270 km
3	Darbhanga (small diameter pipeline from CGD network)	Janakpur	~60 km
4	Darbhanga (small diameter pipeline from CGD network)	Biratnagar	~175 km
5	Madhubani (small diameter pipeline from CGD network)	Janakpur	~80 km
6	Supaul (small diameter pipeline from CGD network)	Biratnagar	~100 km
7	Madhubani (small diameter pipeline from CGD network)	Biratnagar	~150 km
8	Sitamarhi (small diameter pipeline from CGD network)	Biratnagar	~230 km
9	Sitamarhi (small diameter pipeline from CGD network)	Amlekhgunj	~140 km
10	Motihari (small diameter pipeline from CGD network)	Amlekhgunj	~90 km
11	Motihari (small diameter pipeline from CGD network)	Kathmandu	~190 km
12	Muzaffarpur (small diameter pipeline from CGD network)	Amlekhgunj	~175 km
13	Muzaffarpur (small diameter pipeline from CGD network)	Biratnagar	~230 km

- **Natural gas trading through road transportation (ssLNG):** LNG supplies can be made to key demand areas of Nepal in the form of ssLNG from cryogenic trucks through LNG terminals that are coming up on the east coast. The landed cost of ssLNG use for bulk consumers in Nepal from India is expected to come between US$10-21.8/mmbtu. With the inclusion of retail distribution costs, overall costs for end-consumers is expected to come between US$20-31.8/mmbtu. Through the ssLNG route, Nepal is expected to meet its remaining ~30-40 percent of the natural gas demand. The following can be the possible options for ssLNG transportation between India and Nepal:

Table 151 Options for ssLNG transportation between India and Nepal

Serial no.	From	To	Distance between source and destination
1	Kukrahati LNG terminal	Amlekhgunj	~845 km
2	Haldia LNG terminal	Amlekhgunj	~840 km
3	Dhamra LNG terminal	Amlekhgunj	~950 km
4	Kukrahati LNG terminal	Kathmandu	~960 km
5	Haldia LNG terminal	Kathmandu	~955 km
6	Dhamra LNG terminal	Kathmandu	~1085 km
7	Kukrahati LNG terminal	Biratnagar	~635 km
8	Haldia LNG terminal	Biratnagar	~630 km
9	Dhamra LNG terminal	Biratnagar	~775 km

India, Nepal, and Bangladesh can negotiate a joint arrangement to build an LNG facility on the Bay of Bengal. Being in proximity to India compared with other neighbouring countries, the commencement of natural gas transportation between India and Nepal can possibly act as a fuel for growth of cross-border natural gas trade in the entire region.

14.3.4 Potential gas trade between Sri Lanka, Maldives, and India

Natural gas trade between India, Sri Lanka, and Maldives can be facilitated through ssLNG. From LNG terminals, LNG will have to be transported through a breakbulk facility. An FSRU-based LNG hub and spoke distribution model in Sri Lanka, Maldives, and India could be considered for carrying out natural gas trade amongst the nations. The following can be the potential routes of LNG supply amongst India, Sri Lanka, and Maldives:

Table 152 Options for ssLNG trade between India, Sri Lanka, and Maldives

Serial No.	From	To	Distance between source and destination (in nautical miles)	Distance between source and destination (in km)
1	Kochi LNG terminal	Colombo Port (Sri Lanka)	353 nm	654 km
2	Ennore LNG terminal	Hambantota Port (Sri Lanka)	535 nm	991 km
3	Kochi LNG terminal	Male Islands (Maldives)	493 nm	913 km
4	Colombo Port (Sri Lanka)	Male Islands (Maldives)	483 nm	895 km
5	Hambantota Port (Sri Lanka)	Male Islands (Maldives)	508 nm	941 km

The offshore LNG terminal by New Fortress at Colombo Port can be used to primarily carry out LNG trading with India. The LNG received at the terminal would primarily be used to fulfil demands of gas-based power plants in Sri Lanka. However, the terminal could be used to fulfil natural gas demands of other sectors as well in the future.

Developing the Hambantota LNG hub through an agreement between Pearl Energy and Board Investment of Sri Lanka can act as a facilitator for the country's LNG trading with both India and Maldives. Hambantota Port has the geographic advantage of being strategically located nearest to the world's busiest shipping lane. It also has a deep-water coastline. This allows the port to be capable of managing large container ships and super tankers, making it an ideal location for the hub formation for transhipment of goods and natural resources across the subcontinent. Pearl Energy already plans to deploy small-scale LNG carriers to conduct LNG trade with Maldives with the pre-condition that the receiving terminals are built up in Maldives with the storage and regasification facilities.

The receiving terminals in Maldives can most likely be built in the Greater Male region. After that within the Greater Male region, regasified LNG could then be distributed through pipelines. The inhabited islands in

Maldives are connected by a basic nationwide transportation network of ferries and jetties. For islands outside Male, ssLNG can be distributed through cryogenic LNG carriers that would be transported through these ferries and jetties. In addition, capacity of reception terminals might be increased at a later stage with a surge in demand.

The initial capacity of the Hambantota LNG terminal is expected to be ~1 MMTPA. However, with the LNG terminal becoming the trading hub for the nation with India and Maldives, increased investments will be needed for the capacity expansion of the terminal after construction.

14.3.5 Potential gas trade between Pakistan and Afghanistan

In case, the gas requirements of Afghanistan increase beyond the projected quantities, they can be met through ssLNG trade from Pakistan.

14.3.6 Potential gas trade between Myanmar and the SAR

Myanmar's gas production witnessed optimistic prospects with significant off-shore discoveries in 1990s of the Yadana and Yetagun fields (the production from these fields commenced in 1998 - 2000). Post that, the Shwe and Zawtika fields also got discovered in the country (production from these fields commenced in 2013 - 14). Around two-thirds of the gas being produced in Myanmar is exported to Thailand and China. The country's supply contract with Thailand will cease in 2028. The reserves of gas fields supplying gas to Thailand and China will decline by 2033 and 2035.

Within Myanmar, both domestic offshore and onshore reserves are facing decline in production. The onshore production is expected to be steady till 2028 post which it shall begin to decline. In addition, due to the growth in its internal gas demand, Myanmar is expected to retain production from its future offshore and onshore discoveries for its own domestic consumption. The country is bound with heavy export commitments and the declining domestic production is not being supported by upcoming new discoveries. Moreover, Myanmar has started to import LNG to meet its own domestic requirement and it would be difficult for the country to share its gas for cross-border trade.

According to a study done by World Bank, by 2025-26 the expected demand-supply deficit for gas in Myanmar is expected to go over 400 mmscfd because of its heavy export commitments.[361] If there can be pipeline connectivity for Myanmar with Bangladesh and India, the trade possibilities of Myanmar with the SAR can be explored. Another report had been published by the Oil and Gas Planning Department (Government of Myanmar) in which the average growth rate of gas demand in Myanmar is expected to be 4.2 percent by 2040 with the share of gas being 3.6 percent in the total final energy consumption. Moreover, the gas supply in the country is expected to be increase by 5.7 percent till 2040. However, the import dependency of the country is expected to go up from 14 percent in 2016 to 49 percent in 2040.[362] Therefore, if there are new discoveries in Myanmar with potential for exports, there are possibilities of supplying gas to Bangladesh and further to India as well. A pipeline connectivity from India or Bangladesh to Myanmar can be a vital factor for creating connectivity of South Asia with the South-East Asian countries.

14.4 Potential infrastructural investments for cross-border trade

The trade options mentioned above will require substantial investments in building up the cross-border infrastructure to facilitate trade. The following is the summary of infrastructural investments to facilitate cross-border gas trade in the region:

Nepal-India trade

Table 153 Estimated capex cost of infrastructure for facilitating India-Nepal gas trade

Cross-border infrastructure	Capex cost (in Mn US$)	Source
India-Nepal Cross Border Pipeline (Sub-Transmission Pipeline of 300 km, 24 inch with cost of INR 4 crore/km and capacity of upto 6 mmscmd)	160	Discussion with industry experts and research reports

[361] https://documents1.worldbank.org/curated/en/521291561526640149/pdf/An-Initial-Assessment-of-the-Economic-Costs-of-Natural-Gas-for-Myanmar-s-Domestic-Market.pdf
[362] https://www.eria.org/uploads/media/Research-Project-Report/RPR—Myanmar—2020/Myanmar-Energy-Oulook-2020-Full-Report.pdf

Cross-border infrastructure	Capex cost (in Mn US$)	Source
Cost of LNG Tankers (17.5 MT Cryogenic Bullet Trailer along with diesel truck like Tata Signa 4625.S which can travel for ~300 km per day; Approx. 350 tankers of cost INR 1.3 crore per tanker required to cater to 1 mmscmd of current demand with turnaround time of 8 days)	70	
ssLNG Satellite Plant Infrastructure (With regasification capacity of 0.1 mmscmd for upto 1 mmscmd of gas demand; Cost has been assumed as INR 15 crore for processing 0.1 mmscmd of gas)[363]	20	
Total	**250**	

Bhutan-India trade

Table 154 Estimated capex cost of infrastructure for facilitating India-Bhutan gas trade

Cross-border infrastructure	Capex cost (in Mn US$)	Source
ssLNG Satellite Plant Infrastructure (With regasification capacity of 0.1 mmscmd for upto 0.3 mmscmd of gas demand; Cost has been assumed as INR 15 crore for processing 0.1 mmscmd of gas)	6.0	Discussion with industry experts and research reports
Cost of LNG Tankers (17.5 MT Cryogenic Bullet Trailer along with diesel truck like Tata Signa 4625.S which can travel for ~300 km per day; Approx. 80 tankers of cost INR 1.3 crore per tanker required to cater to 0.23 mmscmd of current demand with turnaround time of 8 days)	16.0	
Total	**22.0**	

Sri Lanka-India trade

Table 155 Estimated capex cost of infrastructure for facilitating India-Sri Lanka gas trade

Cross-border infrastructure	Capex cost (in Mn US$)	Source
Hambantota LNG terminal (For taking supplies up to 1 MMTPA LNG)	100	https://www.maritimegateway.com/socar-trading-and-pearl-energy-to-develop-hambantota-lng-hub/
Additional expansion of Hambantota LNG terminal in Sri Lanka for cross-border trade (Required for up to 0.5 MMTPA of cross-border trade; general cost of developing a 1 MMTPA LNG terminal was considered US$ 100 million)	50	General cost for developing a conventional LNG terminal was mentioned in Maldives RE Roadmap (by ADB)
Total	**150**	

Maldives-India trade

Table 156 Estimated capex cost of infrastructure for facilitating India-Maldives gas trade

Cross-border infrastructure	Capex cost (in Mn US$)	Source
Small-scale LNG terminal in Maldives (Required for up to 0.3 MMTPA LNG trade; general cost for developing a small-scale LNG terminal of up to 1 MMTPA was considered US$ 100 million)	30	General cost of developing a small-scale LNG terminal was mentioned in Maldives RE Roadmap (by ADB)
Total	**30**	

Bangladesh-India trade

[363] *The satellite regasification plants can be of smaller capacities and located in different areas depending on the demand of that particular region.*

Table 157 Estimated capex cost of infrastructure for facilitating India-Bangladesh gas trade

Cross-border infrastructure	Capex cost (in Mn US$)	Source
India-Bangladesh cross-border pipeline (36-inch 70 km cross-border pipeline from India to Khulna)	150	GSMP Bangladesh
Total	**150**	

14.5 Collaboration opportunities for countries

The cross-border gas trading within the SAR nations can be beneficial for the participating nations in terms of both tangible and intangible benefits. However, countries such as Nepal, Bhutan, Sri Lanka, and Maldives are still at a nascent stage in the use of gas as a fuel and development of the gas ecosystem in their respective boundaries. Therefore, there is a requirement for collaboration between the member countries for the development of the gas value chain across the region. Both public and private sector companies could collaborate to develop infrastructure and enabling trade. The following are a few collaboration opportunities for individual SAR member countries:

Bangladesh-India

- ONGC Videsh Ltd. (OVL) and Oil India Ltd. (OIL) have already invested for upstream exploration in two shallow water blocks in Bangladesh. These companies can spearhead the initiatives to further enhance the joint offshore gas exploration between India and Bangladesh through technology transfer and capability development.

- In June 2021, H-Energy signed a Memorandum of Understanding (MoU) with Petrobangla to commence supply of RLNG to Bangladesh through the Kanai Chhata-Shrirampur gas pipeline to connect with the Bangladesh border.[364]Several small diameter take-off pipelines can be built by GTCL to supply gas to demand locations in Bangladesh.

- Petronet LNG had earlier proposed to build up an LNG Facility at the Moheshkhali Island in Bangladesh through a government-to-government deal, which was cancelled. The negotiations to build up the Moheshkhali LNG terminal can be again looked into given that Bangladesh is expected to face a gas deficit in the future with no additional import projects being announced.

- National Thermal Power Corporation (NTPC) and Bangladesh Power Development Board (BPDB) are in the process of jointly setting up the Rampal power plant which is expected to be operational by 2022[365]. Adani Power Limited and the Reliance Group have also signed MoUs with BPDB worth US$5.5 billion to build 4,600 MW power plants in the country. These collaborations can be further extended to generate gas-based power in Bangladesh and building additional infrastructure for gas transmission and distribution.

- IOCL has also undertaken several initiatives in Bangladesh in coordination with Bangladesh Petroleum Corporation (BPCL) and Petrobangla. A joint venture was formed between IOCL and Beximco (The Bangladesh Export Import Company Limited) in June 2020 to further expand its downstream business in Bangladesh and other countries. IOCL can further provide assistance to Bangladesh in promoting the overall gas ecosystem.

- In December 2021, the Adani Group in India submitted an expression of interest to PNGRB for constructing a gas pipeline from Haldia to Panitar in West Bengal; this can potentially be connected to the gas grid of western Bangladesh.[366]

[364] https://timesofindia.indiatimes.com/business/india-business/h-energy-inks-mou-with-petrobangla-for-lng-pipe-link/articleshow/83586982.cms
[365] https://www.gem.wiki/Rampal_power_station
[366] https://pngrb.gov.in/pdf/public-notice/EoI31122021.pdf

Nepal-India

- India-Nepal Joint Working Group had been discussing the feasibility analysis of constructing a gas pipeline from Gorakhpur to Rupandehi.[367]The feasibility assessment and construction of the pipeline needs to be taken up on priority to facilitate natural gas trade. State oil companies (IOCL and NOC) from both the countries are expected to oversee the whole project once Nepal assures a potential market for LNG.

- IOCL can further extend the pipeline collaboration support in building up a gas ecosystem in Nepal. IOCL can play a major role in providing the necessary training on handling of gaseous fuels and drive the creation of the necessary gas infrastructure in the country. For example, IOCL can assist NOC in creation of CNG pumps to promote the use of gas in the transport sector.

Bhutan-India

- India-Bhutan currently have strong relations; ~77 percent of the total imports to Bhutan in 2020 were from India.[368]In the present scenario, there are no collaboration projects between India and Bhutan for POL or other fuels. At present, Bhutan has ~2,100 MW of hydropower projects developed with the government of India assistance. The government assistance needs to be provided to Bhutan in identification of prospective sectors and building the necessary mechanisms for the use of gas similar to bilateral hydropower projects signed in 2008.

- BPCL currently commands a 46 percent share in the automotive fuels through its fuel stations in Bhutan.[369]The Bharat Petroleum Natural Gas company can similarly be a major driver for the use of gas in the automotive sector through knowledge and technology transfer.

- According to Bhutan's National Statistics Bureau, the country imported ~7,850 MT of LPG in 2020. Some portion of this LPG demand and its growth can be met from ssLNG through the ssLNG supply chain options developed in India from companies such as GAIL.

- HPCL commissioned its first petrol pump in Bhutan in 2020 in partnership with State Trading Corporation of Bhutan (STBCL). This was the first of the 22 outlets planned per the MoU between both the companies.[370]The similar partnership can be extended towards the development of CNG and LNG stations in the country.

Sri Lanka-India

- LIOC (Lanka IOC) is the subsidiary of IOCL in Sri Lanka. Lanka IOC operates 202 petrol and diesel stations in Sri Lanka. It also has a joint venture with Ceylon Petroleum Corporation (CPC) that operates 13 oil terminals in the country. LIOC can be the major facilitator for introduction of natural gas in the country along through support from IOCL.
- Indian companies such as GAIL, GSPCL and Reliance, have a rich experience in laying gas pipelines and compressor stations as well as establishing City Gas Distribution networks in India. These companies have opportunities to use this experience and collaborate with the Sri Lankan government to increase the penetration of gas in the CGD sector.
- India has pursued the establishment of an LNG-based power plant at Kerawalapitiya in Sri Lanka with an initial capacity of 300 MW through a joint venture between NTPC and Ceylon Electricity Board. The

[367] https://thehimalayantimes.com/business/nepal-india-to-study-feasibility-of-liquefied-natural-gas-pipeline-project
[368] https://www.indembthimphu.gov.in/pages.php?id=42
[369] https://www.bharatpetroleum.com/Speed-Goes-International.aspx
[370] https://www.business-standard.com/article/pti-stories/hpcl-commissions-its-first-petrol-pump-in-bhutan-120031801143_1.html

plant would be converted from coal to LNG once the government of Sri Lanka starts importing fuel into the nation. NTPC can similarly drive joint venture initiatives to introduce LNG-based power in the country.

- The Kerawalapitiya LNG terminal was intended to be established with a joint venture between Petronet LNG and another Japanese firm. However, the construction of the terminal was cancelled because of certain reasons. Petronet LNG can still consider undertaking construction of the LNG terminal in Sri Lanka considering the geographical connectivity advantages (offered by the country).

- Indian LNG receiving terminals of Kochi and Ennore, and Sri Lanka's Hambantota LNG terminal have entered into a cooperation deal to meet seasonal or contractual imbalances.

14.6 Summary of challenges and enablers of cross-border natural gas trading

Given all the key drivers, infrastructural options, benefits of gas, trade potential and country-wise opportunities, the SAR provides immense opportunities for facilitation of cross-border gas trading. However, challenges related to demand, supply, infrastructure development, and policy enablers are required to be addressed. For the countries that already have gas, the major challenges are declining domestic production and building up appropriate gas infrastructure in the country. For the countries that do not have access to gas of now, the major challenges are non-existence of the gas supply infrastructure and regulatory policies for gas usage. Moreover, there are several enablers in the SAR that could help overcome the challenges with respect to cross-border trade. The major enablers for infrastructural challenges are completion of different pipeline projects, such as IPP, TAPI, and Indradhanush Gas Grid, in the region, along with the feasibility assessment and development of trade routes (roadways or waterways) for gas trade between neighbouring countries. For challenges associated with demand and supply, the major enablers would be joint gas exploration, and exploration of unconventional gas supply options and LNG supplies from new upcoming terminals. For policy and regulatory challenges, major enablers would be increased energy cooperation and provision of appropriate incentives for switching to gas.

Various types of challenges and enablers for cross-border trading in the region are mentioned below:

1) **Demand-supply challenges and enablers:** The following is the summary of major demand-supply challenges and required enablers for the region:

Figure 139 Demand-supply challenges and enablers for cross-border trade in the SAR

	Key Challenges	Enablers
India	• Declining domestic production in the country. • Increased dependence on gas imports.	• Expected surplus from the upcoming RLNG terminals. • Joint offshore gas exploration in the regions of Bay of Bengal and Indian Ocean with Bangladesh and Sri Lanka. • Exploration and study of unconventional gas supply options. • Gas supplies from existing and upcoming RLNG terminals. • Expansion of pipeline networks of India near to the borders of neighboring countries.
Pakistan	• Declining domestic production in the country. • Curtailing of gas-supply to certain sectors because of the supply demand imbalance.	• Decline in the consumption of gas from the power sector. • Completion of cross-country pipelines – Turkmenistan-Afghanistan-Pakistan-India and Iran Pakistan Pipeline. • Improvement in domestic production through unconventional gas supply options and additional investments in gas exploration. • LNG supplies from upcoming terminals and expansion of existing terminals.
Bangladesh	• Declining domestic production in the country. • Curtailing of gas-supply to certain sectors because of the supply demand imbalance. • Huge investments in the new land-based upcoming Matarbari LNG terminal and getting it operational on time.	• Exploration and study of unconventional gas supply options. • Increased investments in the off-shore gas exploration; joint gas exploration programs with India. • LNG supplies from upcoming terminals like Matarbari. • Making RLNG terminals in India available on 'tolling' basis. • Expansion of Indradhanush gas grid in India close to country's borders. • Surpluses from India and access to India's LNG terminals, and pipelines.
Sri Lanka	• No significant discoveries of domestic Natural Gas in the country.	• Joint offshore gas-exploration initiatives with India. • LNG supplies from upcoming terminals like Hambantota. • Assessing feasibility of short-term trade to meet demand-supply imbalances from India's LNG terminals at Ennore and Kochi
Nepal	• No domestic sources of supply.	• Carrying out joint feasibility study to trade gas through pipelines and ssLNG with India along with identification of demand and supply locations. • Access to the upcoming gas infrastructure in the GAs bordering India.
Bhutan	• Low demand of gas expected in upcoming years because of small size of the country. • No domestic sources of supply.	• Promoting and incentivizing the usage of natural gas as compared to other alternate fossil fuels. • Carrying out a joint feasibility study to trade ssLNG with India. • Access to the upcoming gas infrastructure in the GAs bordering India
Afghanistan	• Low demand of gas expected in upcoming years. • Domestic gas production inadequate to meet the future demand.	• Additional investments in improving the Fertilizers and Power sectors and reducing dependency on imports • Building additional pipeline infrastructure to bring demand from CGD sector. • Completion of cross-country pipelines – TAPI.
Maldives	• Low demand of gas expected in upcoming years. • No domestic sources of supply.	• Promoting and incentivizing the usage of natural gas and LNG as compared to other alternate fossil fuels like in Bunker Fuels for shipping. • Carrying out joint feasibility study to trade gas through ssLNG with India and Sri Lanka along with identification of demand and supply locations.

2) **Policy and regulatory challenges and enablers:** The following is the summary of major challenges pertaining to policies and regulations and the required enablers for the region:

Figure 140 Policy and regulatory challenges and enablers for cross-border trade in the SAR region

	Key Challenges	Enablers
India	• Requirement of increased political consensus with neighbouring countries. • Pricing freedom for domestic gas is yet to be provided by the Government. • Lack of regional trade financing.	• Increasing energy cooperation between the countries as a peace-building mechanism. • Bringing market-based pricing of gas by allowing it to be traded on Indian Gas Exchange. • Formation of regional-trading financing institutions. • Incentivizing trade by relaxing taxation & tariffs for LNG received at RLNG terminals for re-exports. • Simplified tariff structure for gas pipelines under deliberation by the regulators.
Pakistan	• Requirement of increased political consensus with neighbouring countries. • Field-wise domestic gas pricing being regulated by the Government. • Complex policies for investments into upstream sector.	• Increasing energy cooperation with other countries. • Bringing more liberalization in domestic-gas pricing. • Improvement in ease of doing business for oil and gas sector. • Putting ban on polluting fuels and replacing them with gas.
Bangladesh	• Pricing freedom for domestic gas is yet to be provided by the government. • Tax rebate concerns for the state-owned Petrobangla company. • Cancellation of LNG terminal projects.	• Bringing more liberalisation and transparency in domestic-gas pricing. • Negotiating with Petrobangla for clarity on the taxes to be paid to the Government. • Improvement in ease of doing business in terms of building LNG infrastructure. • Resolving taxes on gas imports through bilateral government to government negotiations
Sri Lanka	• The country has formed a National Policy on Natural Gas. However, there is no clear action plan on utilization and any specific policies for natural gas exploration and production.	• A dedicated regulatory body needs to be established for policy formulation and development of the sector in the country. • Indian companies like IOCL can help in laying the gas supply and distribution pipeline infrastructure along with operations and maintenance.
Nepal	• No incentives in the country to switch from polluting fossil fuels for the major sectors.	• Carrying out a detailed analysis of potential savings in import bills from switching to Natural Gas and providing appropriate incentives for switching to gas through policy measures.
Bhutan	• No incentives in the country to switch from polluting fossil fuels for the major sectors.	• Carrying out a detailed analysis of potential savings in import bills from switching to Natural Gas and providing appropriate incentives for switching to gas through policy measures.
Afghanistan	• Recent political turmoil and political instability in the country.	• Establishment of a stable Government in the country with the focus towards improvement in the energy security and reducing dependency on imports.
Maldives	• No incentives in the country to switch from polluting fossil fuels for the major sectors.	• Carrying out a detailed analysis of potential savings in import bills from switching to Natural Gas and providing appropriate incentives for switching to gas through policy measures.

3) **Infrastructural and geographical challenges and enablers:** The following is the summary of major challenges pertaining to infrastructural and geographical limitations of different countries and the required enablers for the region:

Figure 141 Infrastructural and geographical challenges and enablers for cross-border trade in the SAR region

	Key Challenges	Enablers
India	• India has ~12650 km of operational pipelines and ~14300 km of pipelines is under construction. Therefore, there is limited supply to the demand centers till the national grid is completed. • Ensuring optimal utilisation of gas infrastructure in the country.	• Increased investments towards improving the gas pipelines connectivity in the country and expediting the under-construction pipelines. • Building up of LNG stations on the key travel routes. • Completion of the expansion of its pipeline network close to the borders of neighboring countries like Bangladesh. • Adoption of ssLNG and development of the ssLNG supply chain.
Pakistan	• Local community objections to the construction of TAPI pipeline. • Security concerns regarding the construction and completion of TAPI pipeline. • Ensuring optimal utilisation of gas infrastructure in the country.	• Upholding the human rights of the local communities affected by the pipeline. • Increased support from the Government in sensitive areas.
Bangladesh	• Limited connectivity of the country with pipelines. • Inadequate LNG imports infrastructure and cancelled LNG projects. • Ensuring optimal utilisation of gas infrastructure in the country. • Pipeline constraints for supplies to its western regions because of declining domestic production in Paschimanchal and Sunderbans fields. • Existing and future LNG terminals can come only in Cox Bazaar area which is in deep south and requires substantial investments in pipeline infrastructure.	• Investments in development of transport routes with India for ssLNG transport. • Completion of the national grid of pipelines in the North-Eastern region and other regions of proximity to get access to gas with lesser investments. • Operating a joint LNG terminal with India on Bay of Bengal.
Sri Lanka	• Presence of no infrastructure to scale up the supply of natural gas in upcoming years as per NPNG targets. • Imports to the country only possible through sea-routes or with pipeline connectivity from India.	• Assessment and preparation of a detailed action plan for construction of Gas Supply infrastructure in the country. • Increased investments and initiatives towards domestic gas exploration; commencement of joint gas exploration with India.
Nepal	• Landlocked location of the country. • Inadequate connectivity with India for trade. • No existing gas infrastructure in the country.	• Investments in development of transport routes with India and providing transit facilities. • Routes assessment for minimum transportation cost to trade gas with India. • Preparation of a gas sector roadmap in future for country's infrastructural needs.
Bhutan	• Landlocked location of the country. • Inadequate connectivity with India for trade. • No existing gas infrastructure in the country.	• Investments in development of transport routes with India and providing transit facilities. • Routes assessment for minimum transportation cost to trade gas with India. • Preparation of a gas sector roadmap in future for country's infrastructural needs.
Afghanistan	• Security concerns regarding the construction and completion of TAPI pipeline.	• Increased support and focus from the new Government in construction of pipeline and providing safety in the sensitive areas.
Maldives	• Inadequate connectivity with the other countries of the SAARC region. • No existing gas infrastructure in the country.	• Identification of the major demand centers where the LNG trading could be conducted with India and Sri Lanka. • Preparation of a gas sector roadmap in future for country's infrastructural needs.. • Investments towards building small regasification facilities in islands as the demand is less and will only be met through ssLNG.

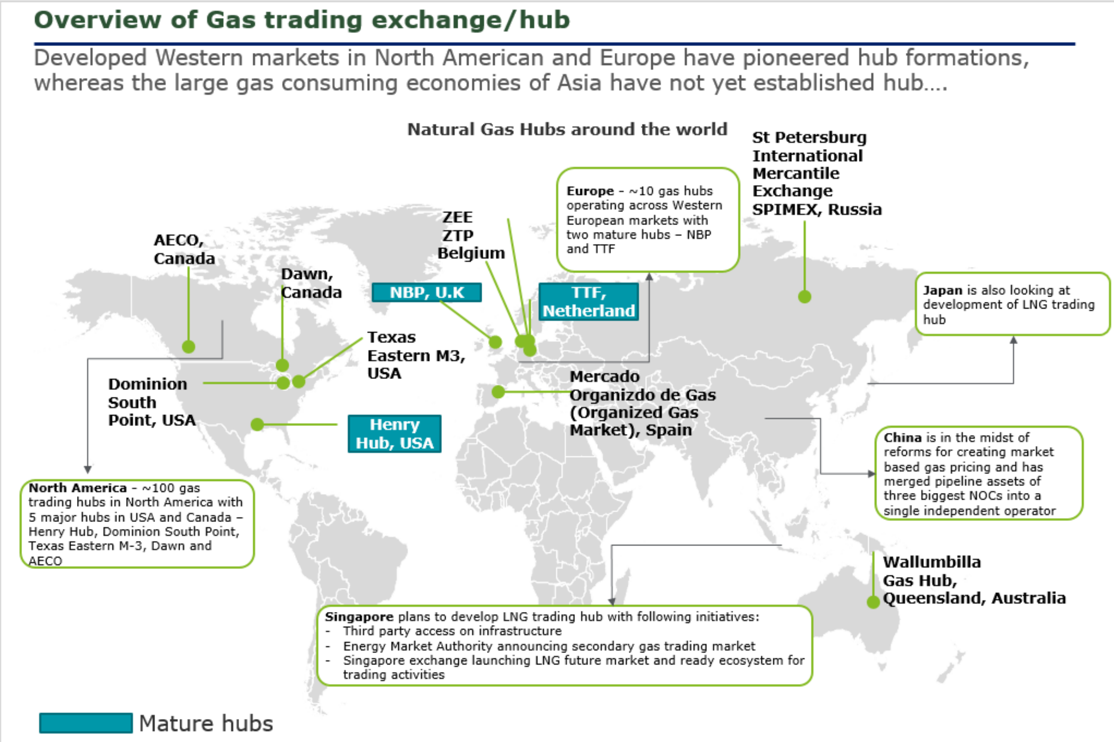
15 Gas hubs and exchanges in global markets

Gas trading hubs defined by the IEA[371]as "a single price zone accessible to incumbents and new entrants on equal terms and where trading is liquid. This will create a reliable price signal in the forward and spot markets that are not distorted" have been initially developed in the US in 1980s, the UK in 1990s, and more recently in Europe in 2000s.

15.1 Development of gas hubs in global markets

The figure below provides an overview of global gas trading exchange/hubs.

Figure 142 Overview of gas trading exchange/hubs



A common hub classification is into physical delivery points and virtual marketplaces. A physical hub is a geographical (centrally located and sufficiently interconnected) point in the network where a price is set for natural gas delivered at that specific location. This mostly exists in North America with the Henry Hub as a typical example. In case of a virtual hub, trading hubs can also be used interchangeably with Virtual Trading Points (VTPs). VTPs are associated with the entry-exit system (market area) from which point the same or other network users can transport gas to exit points. The differing structures of markets, where transport activities are fully privatised in North America but regulated in Europe, are believed to underlie two different approaches: hubs are used to facilitate trade in the US but are meant for daily balancing in Europe.[372]

Within the global markets, a set of benchmark hubs have emerged across time that offer the prices for other hubs and hence, are limited in number. A benchmark hub should have good liquidity from spot contracts to several years forward contracts. It should be accessible to a wide range of market participants. The following two are the major benchmark hubs in the US and Europe:

- **Henry Hub in the US:** The world's first gas market hubs appeared in the US in the 1990s and were a result of governmental reforms of the natural gas industry. Henry Hub was selected by the New York Mercantile Exchange as the site for trading natural gas futures contracts. Henry Hub offers natural gas shippers and marketers access to pipelines serving markets across the US as it is a meeting point of several natural gas interconnections. The local markets in the US tend to price their natural gas with a

[371] *"Developing a Natural Gas Trading Hub in Asia", OECD/IEA, 2013*
[372] *"Key elements for functioning gas hubs: A case study of East Asia", Natural Gas Industry B, Mar-2018*

differential to the Henry Hub. The differential accounts for regional market conditions, transportation costs, and available transmission capacity between locations. For 2019-20, the traded volumes of gas on Henry Hub have been in the range of 3000-5000 bcm every month.[373]

- **Title Transfer Facility (TTF) hub in Europe:** Within Europe, only two major gas hubs have emerged as the benchmark hubs for the region: The Netherlands' TTF and the UK's NBP (National Balancing Point). Only these two hubs (NBP and TTF) in Europe trade in quantities beyond the month ahead contracts. The Dutch TTF has seen a comparatively significant rise in the trading activity from 2014 onwards. The hub has the maximum number of active participants in Europe and the greatest number of product types. For 2019-20, the traded volumes of gas on TTF have been in the range of 300-500 bcm every month.[373]

15.2 Learnings from the gas hubs in global markets

Unlike the European and North American natural gas markets, the South Asian natural gas market is complex and fragmented i.e., it is not highly interconnected by high pressure pipelines. Despite significant changes in pricing mechanisms of the global LNG hubs, in case of South Asia, natural gas prices have remained linked to crude oil prices and do not reflect regional supply/demand fundamentals. Historically, the oil-linked pricing has largely prevailed for long, and the costs are passed on to the consumers. In the US, LNG competes with pipeline natural gas and is benchmarked against the Henry Hub prices for domestic spot and short-term transactions. In Europe, LNG price is benchmarked against fuel oil and natural gas spot prices. In South Asia, LNG prices within most nations have been benchmarked against Brent crude prices plus a premium for average costs of shipping through long-term contracts with countries such as Qatar and Oman.

Due to its diversity in nationality, governance, and culture, the European hub experience can offer valuable lessons for South Asia.[374]The figure below provides key insights from the European hub experience.

Figure 143 Key insights from the European hub experience

Gas Market Liberalization

In Italy and France, the hubs were not developed well due to a lack of government will to liberalize their gas markets. **A liquid hub was delayed in Italy due to the failure of creating a competition in middle and downstream sectors** to the extent seen in the Northwest European liberalized market in the 2000s

Additionally, **liberalization of national electricity markets also plays a major role in gas hub development**, as utilities are major gas consumers who are less likely to participate in wholesale gas trading if they can pass costs to consumers

Pricing Transition For LT Contracts

Owing to a price difference, and the freedom to choose their suppliers by consumers in a liberalized market, the traditional utilities that signed oil-linked long terms contract were often bypassed and consequently suffered financial loss as well as failure to meet the minimum take-or-pay levels.

Since most of the failure of take-or-pay happened with Gazprom, **the European utilities, renegotiated their contracts with Gazprom** by reducing prices and level of take-or- pay by 2012. **Gazprom did not accept hub prices initially,** but instead gave discounts to bring the oil indexation prices close to hub prices. **However, in September 2015, Gazprom Export conducted gas auctions for the first time.**

Policy Push & Regulations

UK was able to succeed in liberalization due to the aggressive nature of the government. On the contrary, **a poor political and regulatory framework to encourage trading contributed to the failure of Italian PSV** . Similarly, TTF was only kick-started after the implementation of the 'Gas Roundabout' in the mid-2000s . The gas market liberalization in Continental Europe was driven by the EU's political ambitions to create both a fair market for all consumers and an integrated energy market

The hubs can become functional from the initial stage when TPA is provided for trade (on an 'ex-hub' or 'delivered' basis). The SAR is in a primitive stage. Only a limited number of enablers would be required to commence a gas hub. However, several steps are needed for the transition of a primitive hub to a matured liquid hub. As history has shown us in North America, Britain, and now North-West Europe, the development of a liquid hub can result in disruption and financial cost to (particularly) the incumbent players who dominated the pre-liberalisation landscape. This also takes time and commitment.

15.3 Steps involved in the formation of a gas hub

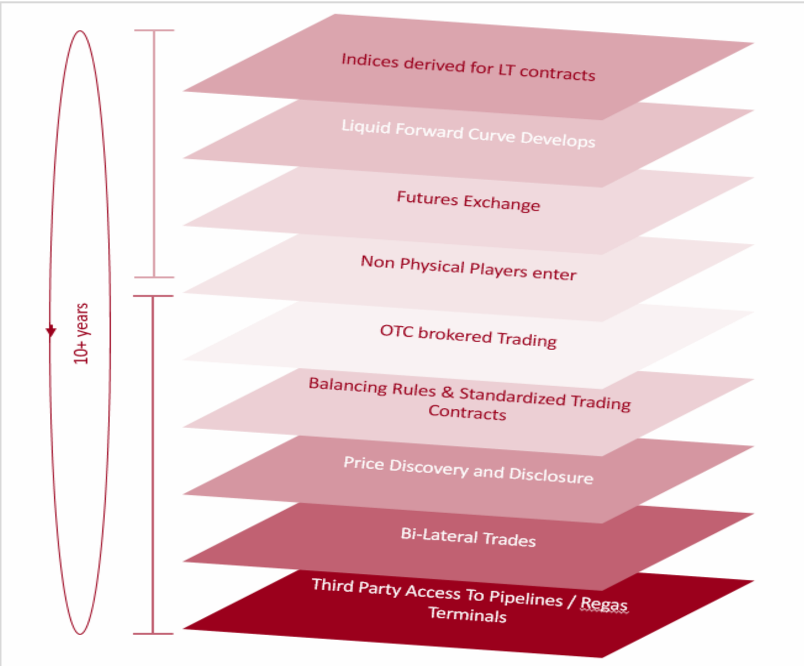
Based on the transition experience of the North American and British markets, the process can take some time. It now proves to be the case in Continental Europe.[375]The following are the steps involved in the formation of a gas hub in a region:

[373] https://www.iea.org/data-and-statistics/charts/traded-volumes-on-henry-hub-and-ttf-2019-2020
[374] *"Development of Europe's gas hubs: Implications for East Asia", Natural Gas Industry B, Nov-2016*
[375] *"The evolution of European traded gas hubs", Oxford Institute for Energy Studies, Dec-2015*

- Regulators mandate that the potential infrastructure users have access to the exchange platform under non-discriminatory commercial terms, known as TPA (Third-Party Access). This opens the hub network to new buyers and sellers.
- Multiple parties begin to contract with each other on their own terms and over the TPA facilities. Producers can trade directly with distributors and large end-users. The number of parties and transactions expands.
- Price Reporting Entities (PRE) begin publishing pricing information where prices and volumes are reported and published daily, weekly, or monthly, under rules to ensure accuracy. Reliable price information supports bilateral trading and reduces transaction costs.
- Regulators or an industry organisation, such as the North American Energy Standards Board (NAESB), ensures common use of terms, and standardised trading and transfer practices. This facilitates trading by reducing transaction costs and making trading more efficient.
- In addition to producers, distributors, and end-users, traders such as merchants, financial institutions, and brokers enter the market to trade gas and provide additional market liquidity.
- Liquidity at the hub increases to the point that PRE-reported prices at the hub become a reliable indicator of the market balance. The reported prices become a reliable index that parties will cite for future pricing in long-term contracts.
- Non-physical traders offering pure financial hedging instruments based on the hub index enter the market to take price risk and offer customised over-the-counter hedging services linked to the index.
- A commodity exchange, such as NYMEX, creates a standardised tradeable futures contract and offers a trading platform under the exchange rules.
- Parties trade large numbers of futures contracts for deliveries many months out, providing future price discovery and a means of managing price risk on future commitments.

The figure below provides key stages of the evolution of a hub.

Figure 144 Key stages of the evolution of a hub



Although, the development and maturity of gas hub in a region may appear to be a complex process, but the initial foundations for commencement of a hub have already been laid through the launch of India Gas Exchange (IGX). The hub formation process for the SAR is not expected to be a very complex one provided that the member countries can ensure liberalisation of domestic gas pricing, Third-Party Access (TPA) to infrastructure, and mutual collaboration for trading gas on the IGX.

15.4 Pre-requisites for successful development of regional gas hub in South Asia

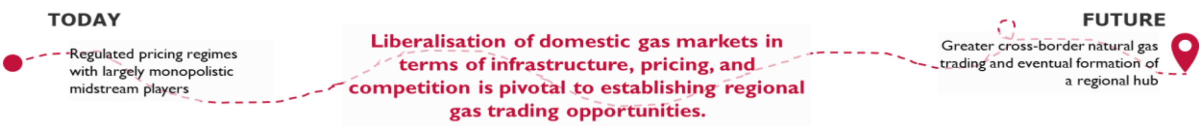
The SAR would also need to develop into a gas hub similar to those developed in the European market. Two basic buckets of requirements need to be established in South Asia to enable cross-border natural gas trading and eventual formation of a regional hub:

I. Institutional requirements: To support competition in a natural gas market, first some institutional requirements need to be met. These include the following:

- **Hands-off government approach to natural gas markets** (including wholesale gas price deregulation). This will involve a shift from direct influence on the gas market to only monitoring the market activities through independent regulators.
- **Separation of transport and commercial activities** through either full ownership unbundling or financial separation. This will allow the commercial and transport activities for gas to run as separate entities. Subsequently, the independent transport entity will be able to levy a fair and charge an indiscriminate transmission fee on a proportional basis for all shippers.
- **Support from the respective governments** of the member countries for providing the enabling policy support. The intervention from head of states would be needed to accelerate the formation of cross-border trade infrastructure and subsequently, enable a gas trading hub in the region.
- **Deregulation of allied sectors,** such as power (allowing generators to completely pass-through price risks in the gas sector to end-customers) reduces demand for risk mitigation trade.

II. Structural requirements: In addition to institutional requirements, participants need a minimum degree of certainty that a market is actually competitive and is functioning as such. The governmental role will then shift from active participant to regulator, setting rules and monitoring the sector. Structural requirements include the following:

- **Building sufficient network capacity and non-discriminatory access to networks** - To successfully implement a fully transparent and non-preferential access, the open access regime should satisfy the three conditions; the coverage should include monopoly assets along the supply chain. It must be managed by a dedicated system operator. The access to pipelines and pricing need to be supported by fair and transparent regulations. A regulator might not be required initially, but eventually the access must be overseen by an independent regulator.
- **Ensuring a competitive number of market participants** by lowering entry barriers through a well-regulated network code. This network code will need to be created by a regulator which would determine what number of market participants and proportion of market share would constitute true competition. The regulator will then have to enforce competition within the market.
- **Ensuring pricing transparency and standardisation of contractual arrangements** which would be able to reflect the current and the future state of the market. This would involve letting the market set the wholesale price level for natural gas. Therefore, the customers will be able to seek suppliers who can deliver the product that suits their needs at least possible cost.
- **Actively encouraging involvement of financial institutions** because these will be able to cover the financial/operational risks for parties involved in the natural gas trade. They will be able to reduce the counterparty risk and provide a clear, long-term price signal.



India is envisaged to be playing a central role in establishing a trade link amongst the SAR countries. Some prominent trade opportunities are mentioned below:

1. **Road-based ssLNG trading between India-Bhutan and India-Nepal**
2. **Pipeline inter-connection between India-Bangladesh and India-Nepal**
3. **Shared LNG import infrastructure with Bangladesh**
4. **Completion of the TAPI pipeline allowing greater integration of the Indian and Pakistan gas grid, and establishment of a shared gas exchange.**
5. **FSRU-based LNG hub and spoke distribution in Sri Lanka, Maldives, and the Andaman and Nicobar Islands**

For cross-border trade to occur, preconditions for a competitive market (separation of transport and commercial activities, wholesale price deregulation, etc.) need to be coupled with adequate build out of regional gas infrastructure. Innovative models, such as breakbulk and hub and spoke model, can be used to maximise penetration in underserved markets with the potential for India, as the largest regional consumer, to play the role of an aggregator.

15.5 Development of regional gas hub and exchange in South Asia

For the countries in the SAR, natural gas trading has traditionally been mostly dominated by the established market structures consisting of long-term contracts in which LNG has remained indexed based on crude oil price to keep both the fuels competitive in the market.

Gas trading hubs are well-advanced and mature in North-West Europe and North America but have just started in emerging markets, such as India. North American gas prices reflect gas supply-demand balances through gas-on-gas competition, while European prices are linked both to oil and gas hub prices. The European hub experience highlights market liberalisation. The transition of gas pricing to a mechanism that drives competitive markets is the major factor that allow effective functioning of natural gas hubs. Both of these major requirements need strong changes in cultures, regulations, and governance practices, along with a strong political will. The following basic elements need to be developed for a mature regional gas trading hub to exist:[376]

1. **Defined trading point:** The trading point in a hub can be a physical trading point i.e., an interconnection of the pipelines or a virtual trading point. A trading point needs adequate physical pipeline capacity for gas ownership exchange between suppliers and end buyers, along with a nearby gas storage and sufficient network capacity in pipelines. For prices in one hub to be accepted by market players outside the hub area, such as in the case of trading within SAR nations, inter-connectivity with other markets will also be needed.
2. **Hub operator:** The operator co-operates with market participants and undertakes administrative tasks. Most often, Transmission System Operator (TSO) is responsible for operating the infrastructure and dealing with the transportation network.
3. **Trading platform/exchange:** It is a place where both buyers and sellers aggregate and gas price at various physical locations is decided. The gas exchange will be a counterparty in each transaction.
4. **Standardisation of contracts:** These have to be defined by their place and time of delivery in a standard manner. The contracts can be standardised as intra-day, day-ahead, and month-ahead.
5. **Right mix of market participants** (buyers, sellers, and other stakeholders associated in the value chain)

Along with the above-mentioned components, a successful regional gas hub will also require a significant trading volume particularly in futures contracts to manage price risks and boost liquidity. At present, within Asia, Singapore, China, and Japan have undertaken the hub initiatives for natural gas. These hubs are yet to completely develop into the trading platforms similar to the ones in Europe and the US. One of the primary reasons that they have not completely been able to develop is that there is no competitive wholesale market for gas in these countries. India has already taken the first step towards formation of regional gas hub through Indian Gas Exchange (IGX). However, market liberalisation in India and the SAR will be the key factor for transitioning towards formation of a competitive regional gas hub.

15.6 Role of IGX in developing a regional gas exchange

In June 2020, the first gas exchange was launched in the country by IEX that deals in the business of power trading. The platform provided a common digital marketplace for both buyers and sellers making the trading process more convenient as buyers would not have to contact multiple dealers to ensure that they get the best price. The exchange allows for shorter contracts – for delivery on the next day, and up to a month along with ordinary contracts for natural gas supply which are as long as six months to a year. The lot size for bidding as of April 2022 is for 50 mmbtu/day. The IGX as of now facilitates two types of transactions:

1) **Delivered transaction:** IGX facilitates trade and physical delivery of gas by booking the necessary transmission facility, and financial settlement for the traded contracts.

[376] *Key Elements of Functioning Gas Hubs: A case study of East Asia", Natural Gas Industry B, March-2018*

2) **Ex-hub transaction:** IGX facilitates the trade and the financial settlement for the traded contracts. The necessary transmission facility is arranged by the shipper.

The following is the flow of the bidding process taking place on the exchange:[377]

1. **Bidding:** The buy/sell bids are submitted to the platform.
2. **Matching:** The provisional market clearing price and market clearing volume are calculated through the demand and supply curves.
3. **Pipeline availability:** The pipeline availability is confirmed with pipeline operators.
4. **Result:** The final market clearing price and market clearing volume are calculated.
5. **Confirmation:** The confirmation of pipeline capacity is received from operators.
6. **Scheduling:** The final scheduling is communicated to participants.

PNGRB amended Gas Exchange Regulations in May 2022 to provide revised definitions of 'gas hub' and 'delivery point' with respect to IGX. As per the definitions, 'delivery point' means location of delivery of gas against the traded contracts and 'gas hub' means a group of delivery points in regional proximity. PNGRB approved 6 regional gas hubs namely, Western Hub, Southern Hub, Eastern Hub, Central Hub, Northern Hub, and North-Eastern Hub across India. Each regional hub would have multiple delivery points on the exchange. The delivery points were identified based on the state and respective regional boundary. In the current scenario, IGX has Dahej, Hazira, Ankot, Mhaskal, Bhadbhut, Dabhol, and KG Basin as the delivery points. Apart from that, IGX is intending to have a platform to facilitate imbalances of shippers and has requested PNGRB for the same.

The Indian gas exchange platform is expected to play a significant role in discovering a price benchmark for gas appropriate for both buyers and sellers, address demand-supply gaps, and promote additional investments in the gas value chain. This will also reduce the premium on imported LNG that arises from dependence indexation to foreign gas or crude markers. Further, the gas trading platform is expected play a major role in the mitigation of sellers' counterparty default risk. The availability of natural gas in large quantities at a fair market price through the hub will also facilitate rapid expansion of fertilisers, gas-based power plants, pipeline infrastructure, and the industrial, petrochemical, and City Gas Distribution sectors.

The Indian gas sector is still short on many of the hallmarks of a typical gas-trading hub on supply, demand, infrastructure, and price. Unlike other mature gas hubs through which there are multiple sources of supply from domestic production, cross-border pipeline gas as well as LNG flows, the IGX presides only over spot LNG shipments. However, the IGX provides the potential act as a medium to facilitate the cross-border trade with other SAR nations at price determined by the exact demand and supply. The online gas trading platform can also strengthen India's energy ties with countries such as the US and reduce its import dependency on more volatile regions (such as the Middle East).[378] The regional SAR hub will emerge after the trade matures and reaches significant levels, in due course of time.

In the short term, the government can try to mandate a certain share of the domestic gas as well to be traded on the exchange hub. In the long term, several factors are critical for IGX to mature into a liquid gas trading hub - increase in supply of tradable gas, a competitive wholesale natural gas market, non-discriminatory third-party pipeline access, standardised contracts for both transportation and sale and purchase of gas, and liquid physical markets that encourage the development of a futures market and price reporting.[379]Eventually, there should not be any cross-subsidies or price caps, the hub would determine price on which gas for trade will be sold. With optionality in their hands, customers would drive the bargain.

[377] https://www.igxindia.com/wp-content/uploads/2020/06/IGX-Launch-Presentation.pdf
[378] https://adi-analytics.com/2020/07/10/indias-giant-leap-first-gas-trading-hub-launched/
[379] https://www.orfonline.org/research/india-natural-gas-exchange-one-small-step-or-a-giant-leap/

SECTION C: RECOMMENDATIONS FOR CROSS-BORDER TRADING IN THE SOUTH ASIAN REGION

16 Recommendations and proposed roadmap

16.1 Recommendations for cross-border trading

There is a potential of 10-15 mmscmd of cross border trade by 2030 between the SAR countries, which is expected to get enhanced to a level of 20-25 mmscmd by the FY 2040. We envisage India playing a central role in establishing an energy trade link amongst SAR countries. Apart from India, Bangladesh can also play the role of a contributor towards facilitation of cross-border trade with countries like Nepal and Bhutan provided the country is able to ramp up its gas supplies. The efforts to promote regional gas trading and hub formation are linked to supply and demand dynamics, improving infrastructure, regional policies and regulation, and pricing mechanisms.

16.1.1 Improvement in supply dynamics

The following key recommendations can improve supply dynamics in the SAR:

Immediate/near-future

- **Knowledge and technology sharing:** India and Bangladesh can potentially sign-up joint gas exploration and technology sharing agreements to explore more gas hydrates in the Bay of Bengal (in addition to blocks SS04 and SS09). Similarly, Indian companies can collaborate with the Sri Lankan government for doing joint oil and gas exploration in the Mannar and Cauvery basins.
- **Feasibility assessment for cross-border pipeline routes:** The potential trade locations for pipeline connectivity for India-Nepal and India-Bangladesh need to be identified for constructing a cross-border pipeline. Within India, 9th, 10th, and 11th round GAs closer to the Bangladesh and Nepal borders are expected to be major points of take-off from India.

Short/Mid-term

- **Expansion of regional connectivity:** The major pre-requisite for facilitating trade in the region is well-built regional roadways and waterways networks to minimise challenges and costs to gas transportation. Dhamra and Kukrahati/Haldia are expected to be major supply centres to the eastern countries from India. Hence, these terminals need to be connected with a well-established road network. Similarly, the Kochi and Ennore terminals need to augment a breakbulk facility and have a well-established sea transportation route with Sri Lanka and Maldives.

Long-term

- **Developing a regional energy database:** One of the major roadblocks for building cross-border trading infrastructure and joint energy cooperation between the SAR nations has been lack of data sharing in terms of the available supply resources. A common energy database through contribution from countries in the region will help estimate the commercial viability of investments in gas exploration.

16.1.2 Improvement in demand dynamics

The following are some key recommendations for improvement in the supply dynamics of the SAR:

Immediate/near-future

- **Demand assessment for countries:** India, Sri Lanka, and Maldives need to carry out joint natural gas demand assessment studies to identify anchor customers for gas. These customers are expected to consequently play a major role in establishing the use of gas for other sectors in both the island countries. Within Sri Lanka, the power sector is expected to be one of the major demand drivers. Building up small LNG supplies to power plants in Sri Lanka can assist in harnessing the demand potential in the country.

Short/mid-term

- **Creation of an ecosystem for LNG-fuelled vehicles:** New investments will be needed from both the government and private players in India to establish an ecosystem of LNG automotive vehicles in the future. For island nations, use of LNG as a bunkering fuel on ships is yet to take off and an increase in LNG-driven ships can drive demand for both internal use and facilitate cross-border demand.

- **Pilot projects:** Countries such as India-Bhutan and India-Nepal can collaborate to perform feasibility studies in identifying the most economically viable routes for LNG transportation, along with running small pilot projects.

Long-term

- **Use of newer technologies:** New technologies are needed to increase use of LNG as a cleaner fuel in the region. FSRUs have traditionally been proven as reliable and flexible solutions in terms of cost optimisation. They can also be developed at a smaller scale for island nations, such as Sri Lanka and Maldives. Floating LNG systems, which are water-based combined production, liquefaction, storage, and transfer plants, have also emerged in the past few years.

16.1.3 Infrastructural development

The following are some key recommendations in terms of infrastructural development in the region:

Short/mid-term:

- **Feasibility assessment for infrastructure development:** Joint feasibility studies can be carried out between India-Bangladesh and India-Nepal for the cost economics of construction of cross-border pipelines along with identification of the most viable demand and supply locations.

Long-term:

- **Pipeline development and inter-connected gas grid:** India is expected to be the primary supply centre from where cross-country gas pipelines are expected to be constructed. The following are a few recommendations for building an inter-connected pipeline network across the region:
    - The North-Eastern (NE) gas grid needs to be completed on time to create an inter-connected gas grid and facilitate trade across eastern countries with India. This would be a ~1,650 km gas-pipeline grid connecting 8 states in North-East India. Consequently, after the development of the NE grid, several nearby remote areas in countries such as Bangladesh, Bhutan, and Nepal could be supplied through small take-off carrier pipelines. This would also require interlinking of gas grids in India.
    - A pipeline regulatory body, such as South Asian Pipeline Consortium consisting of India, Bangladesh, Bhutan, and Nepal can be created to oversee the overall planning, implementation, and operation of cross-border pipelines between the nations. This body shall function under the regional regulatory body, which shall oversee the cross-border trading in the region.
    - Russia has designated 'Pipeline Troops' as part of its government services. These troops are trained to build and repair pipelines. A similar group of trained, technical professionals can be created to manage the inter-connected pipeline network.
    - Completing inter-regional pipelines, such as TAPI and IPP, can give an impetus to kick-start new cross-border pipeline projects in the region. In addition, electricity and petroleum product pipelines between India-Nepal, India-Bangladesh, and India-Bhutan can be used to push for gas pipeline initiatives.

- **Joint LNG terminal feasibility assessment:** The feasibility assessment of creating a joint LNG terminal viz-a-viz a dedicated terminal between India-Bangladesh and India-Sri Lanka-Maldives will need to be carried out in the region. Several factors need to be considered to determine the ideal location of a joint LNG terminal.[380]The major criteria will be whether port facilities will be flexible enough to manage a wide variety of LNG ships and hold breakbulk facilities to transport gas to smaller nations in the region. In addition, the location of the terminal site on a major LNG transit route will ensure lower shipping costs and easier delivery of LNG to the port. The ownership structure and financing options of the joint LNG terminal will also need to be considered. The LNG terminal could be structured as a joint holding of the participating countries through equity participation. It can also be considered to involve the private sector in building the LNG terminal and using the storage facility on a common carrier principle. The pricing of the LNG procured at the terminal can first be under a fixed charge arrangement (based on the price at which the LNG is procured). It can then subsequently transition towards market-based pricing. If the construction is not feasible, the potential supply terminals for trade to Nepal, Bhutan, Sri Lanka, and Maldives will have to be identified. Nepal and Bhutan will then most likely be supplied from the Dhamra, Haldia, or Kukrahati LNG terminal. Sri Lanka and Maldives will be supplied from either the Ennore or Kochi LNG terminal.

- **Private sector participation:** Traditionally, the public sector funds infrastructure investments in South Asia. The natural gas sector is mainly operated by government-owned companies in India, Pakistan, and Bangladesh under a subsidised domain. However, to facilitate cross-border trading, a significant amount of investments and participation will also be required from private companies. The private sector participation can be through PPP models in which the planning of infrastructure networks, provision of RoW, development of a regulatory framework, and managing political risks can be carried out by public-sector entities, whereas private companies would be responsible for the construction, operation, and securing financing for the project. However, this would also require deregulation of gas pricing from the respective governments to create a more open market for gas and hence, encourage the participation of private players. Two types of contracts can be undertaken in terms of roles of the private and public sectors:
    a) The first type of projects can have asset ownership for public-sector companies, while the management and operation of asset can be contracted out to a private company. This will include service contracts and lease arrangements.
    b) The second type of projects can involve temporary or partial private ownership of assets. This will include contracts such as Build-Own-Operate-Transfer (BOOT) or joint ownership.

16.1.4 Harmonisation of policies, regulations, and pricing

The following are a few recommendations in terms of pricing, policies, and regulations:

Short/mid-term

- **Policies for promotion of the gas sector:** The governments of the SAR member countries need to work on additional policies and incentives to promote the gas sector. A policy push in terms of a ban or fine on use of polluting fuels is required for key sectors, such as fertiliser, industrial, and transportation. For the power sector, use of gas-based power generation can be encouraged as a grid balancing mechanism for renewable power sources. Moreover, there is a need for open access policies for gas infrastructure in the midstream segment, along with policies pertaining to capacity allocation. The governments of the respective countries need to focus their attention on improving the ease of doing business to encourage investments from smaller companies in the gas sector's growth.

- **Unified gas tariffs in India and bringing gas under GST (Goods and Services Tax):** In 2020, PNGRB released a new tariff structure for 14 natural gas pipelines in which buyers would be charged a fixed tariff for the transport of gas within 300 km of the source and a fixed tariff for the transport of gas beyond 300 km on a single pipeline network.[381] This step aimed to reduce the cost of natural gas for

[380] *Feasibility Study for Setting up SAR Regional/Sub-regional LNG Terminals", SAARC Energy Centre, Dec-2016*
[381] *https://indianexpress.com/article/explained/explained-petroleum-boards-new-unified-tariff-structure-its-impact-and-challenges-in-implementation-7093848/*

the users who were further away from the sources of natural gas and LNG terminals along with the rationalization of transportation costs. This can be expanded further to have a single tariff for the whole system of each entity without any linkage to point of injection of gas. Another option is to implement an entry-exit tariff model in which the users will have to pay one tariff to enter into and another one to exit from the system which would also remove the complications of the contractual path. In addition, natural gas is still outside the ambit of GST (Goods and Services Tax) and existing taxes like central excise duty, VAT etc. are still applicable on the fuel. Inclusion of natural gas under GST is needed to provide uniform taxation and encourage free trade of the fuel across India along with the development of the gas exchange.

Long-term

- **Gas pricing deregulation in the region:** Long-term oil indexed contract arrangements for LNG imports in South Asia cause gas prices to not reflect in countries' own market fundamentals based on supply and demand. There needs to be pricing deregulation and transition from long-term contracts to ensure a market-driven and transparent pricing mechanism. This will involve a significant role shift from direct control on pricing and priority allocation of gas to just monitoring the functioning of the market. This should eventually lead to breaking the bundled and regulated natural gas prices into a transmission price and a wholesale price (including commodity, service, and profit margin). Progressive deregulation in the consumption end markets is also needed to provide incentives for efficient gas sourcing and diversifying import sources.

- **Development of a regional regulatory body:** In the initial phases, the respective member countries can try to find out a mid-path to have cross-border trade operations based on harmonious principles through the discussions between the concerned stakeholders. However, in the long term, a regional regulatory body will need to be developed to facilitate coordination amongst the SAR nations. This regulatory body will need to comprise stakeholders from the member nations to put forward their interests. Clear legitimacy can be provided to a consortium formed by independent regulators from each SAR member state, such as PNGRB, OGRA, and BERC, to define the rules and terms for natural gas trade in the region. The following will be expected responsibilities from the regional regulator:

    - **Developing a regional gas trading agreement:** Forming a regional gas trading agreement will be the major task for the regional regulator. The regulator will be required to facilitate communication between the member states on modes of trading, pricing, taxation, and other trade-related aspects for natural gas to consequently form a trade agreement approved by stakeholders. The gas trade agreement would be able to benefit the member countries through enabling seamless trade, removing barriers and enabling increased flow of gas across the borders. Although South Asian Free Trade Area (SAFTA) has already been in place to facilitate trade of different commodities in the region, it has not proved to be successful in improving cross-border. Intra-regional trade amongst SAR nations still lies below 5 percent. Therefore, a separate trading agreement for gas can be defined considering the trading potential and increasing requirements for each member nation. Through regional gas trade agreements, other member nations shall be able to receive cheaper imports of gas through India.

    - **Overseeing infrastructural development:** The regional regulator will have to oversee and track progress on the development of regional gas infrastructure, along with joint cooperation programmes (such as cross-border pipelines, joint gas exploration). It will also have to define the rules of private-sector participation for creating cross-border trade infrastructure. In addition, the regulator will need to decide the ownership structure and financing options of the joint infrastructure being operated in the region.

- **Supervision of gas pricing and gas trading exchange:** The regional regulator will have to keep supervision on natural gas prices as markets become more liberalised in the region. It will need to ensure a transparent pricing mechanism, driven by demand and supply of gas. It shall also be responsible for foreseeing trading contracts and defining the standard rules of trade on a common regional trading platform (such as IGX).

- **Ensuring harmony and dispute resolution:** The regional regulator will be required to ensure cohesiveness between regional and individual state policies and regulations to prevent any concerns and conflicts between the participating member states. Moreover, it will be responsible for resolutions of disputes in cross-border trade and enforcement of agreements.

- **LNG group buying:** The regulatory body can also play a major role in forming a separate consortium for joint purchase of LNG to exert more influence during negotiations and get better contracts from sellers using combined demand as a negotiating tool. However, this will require internal negotiations on the percentage and quantity of fuel that would be allocated to each member country.

16.2 Recommendations on regional gas hub

The initial steps towards forming a regional gas hub in South Asia have already been taken through the launch of IGX. The IGX platform might be able to bring in buyers and sellers from member states to a common marketplace for natural gas trading. However, several steps need to be taken for the eventual development of the platform to be able to create a regional gas hub in the South Asian region:[382]

1) **Identification of the optimum physical location of trading hub:** For the SAR, a physical hub with advanced infrastructure will be a better choice as multiple companies are operating pipelines and countries are currently not interconnected. The attributes needed at the chosen physical point shall be multiple supply sources able to feed into that point, closer proximity to major demand centres, sufficient and surplus pipeline capacity, and gas storage facilities nearby for short term load balancing. Dhamra can be one potential location for a trading hub to determine prices as it is on the eastern coast closer to Bangladesh, Nepal, and Bhutan. It is also connected to the JHBDPL gas pipeline.

2) **Creating the required institutional structure:** The initial phase of bilateral gas trade between countries needs to commence with minimal regulations. In the initial phases, the respective member countries can try to find out a mid-path to have cross-border trade operations based on harmonious principles through the discussions between the concerned stakeholders. However, with due course of time based on the experience and complexities of trade and a greater number of buyers and sellers joining IGX from other SAR countries, a platform regulator will be required. The regulator will have to be empowered with clear policy guidelines, stringent market rules, and power to enforce punitive damages for market abuse. It will be responsible for standardising trading rules and contracts. It will also monitor the market to ensure compliance with rules to regulate the gas hub and a commodities/securities body to regulate the gas exchange in the longer run.

3) **Synchronous operation of gas pipelines:** As the gas exchange will have to operate on a real-time basis, it will require real-time access to information from across the pipeline network that requires every element to work together as one single operation. Operators will need to collaborate and harmonise the rules and processes guiding their operations for the hub to function successfully.

4) **Movement of domestic gas to the hub:** Developing a mature trading hub will require changes in the policies pertaining to domestic gas allocation for priority sectors. As the gas sector in the SAR is expected to face gas shortage, removal of priority sector allocation or marketing freedom for new exploration and production of

[382] https://www.icf.com/insights/public-policy/well-functioning-gas-trading-hub-in-india

gas will make domestic gas prices equal to imports that might affect several downstream sectors. Feasibility analysis will need to be carried out for different options to allocate domestic gas towards the trading hub – (i) Allocating gas from newly discovered domestic fields to the hub; (ii) Domestic gas allocated to 1-2 priority sectors to be moved to the hub; (iii) All of the domestic gas produced to be moved to the hub – the benefits and implications for each of those will need to be figured out. As of now, PNGRB has approved trading of domestic gas on the IGX platform in which the domestic producers can sell upto 500 mmscm or 10 percent of their annual production on the gas exchange which can be further expanded in the future.[383] This would enable producers to have immediate opportunities for selling their gas, increase the liquidity on the platform, and would allow small buyers to procure gas at competitive prices.

5) **Trading through ssLNG:** At present, the IGX platform facilitates the trade of natural gas that is to be transported though pipelines. The platform will also need to account for the trade of smaller quantities of gas through ssLNG containers. This will eventually help in onboarding consumers from Bhutan, Sri Lanka, and Maldives to the platform as the primary mode of supply to those countries is expected to be only through ssLNG.

6) **Ensuring TPA (Third Party Access) to gas infrastructure (pipelines and LNG terminals) and making data of the pipeline capacity publicly available:** This is required to bring more transparency and competitiveness in the regional gas hub for operators from other countries to participate as well. Moreover, investments will be required to create additional pipeline infrastructure across the region in which the complexities pertaining to the pipeline tariff mechanism, the financing and business models, and ownership structure will need to be figured out.

7) **Changing the existing type of contracts:** In the South Asian region for major countries producing domestic gas, gas supply contracts between buyers and sellers combine the sale of gas and transmission services. Market reform and formation of a successful hub will require contracts to be unbundled to enable competition and allow anyone to book pipeline capacity.

8) **TSO (Transmission System Operator) and gas access bulletin board:** A TSO (Transmission System Operator) is an entity entrusted with the transportation of gas on regional level along with providing reliable data on pipeline capacity availability and utilisation. The TSO would be responsible for integration of various pipelines along with tasks like network planning, nomination, and scheduling for different types of pipelines. If the TSO would manage the entire pipeline capacity, it would bring more transparency to the pipeline system as the pipeline owners will also be subject to disciplinary charges for creating gas imbalances. Moreover, the TSO would also be responsible for showing the gas access bulletin board to give access to real-time information on gas and pipelines availability for all the players in the market.

9) **Stakeholder awareness and collaboration:** A robust stakeholder communication program will be required to create awareness about the benefits of cross-border trade and gas hub formation for the SAR, policies and regulations, pricing of gas as compared to alternate fuels, infrastructural requirements, and roles and responsibilities of stakeholders in the creation of a regional gas ecosystem. Along with strong communication, stakeholders will also need to be provided regular training and skill development for their specific roles in the gas-hub ecosystem.

16.3 Joint gas exploration programmes

Joint gas exploration programmes can also be carried out in the SAR. Over the past few years, Bangladesh faced several challenges with respect to oil and gas exploration. In 2018, South Korean conglomerate Daewoo made a natural gas discovery in Block D-12 in the Bay of Bengal.[384]Daewoo has a contract with the Bangladesh

[383] https://energy.economictimes.indiatimes.com/news/oil-and-gas/igx-gets-regulators-approval-for-trading-of-domestic-natural-gas/91516385
[384] https://www.indoasiancommodities.com/2018/08/30/india-bangladesh-discovers-gas-bay-bengal/

government that allows for exploration in deep seas until 2022. India had also discovered accumulations of natural gas hydrates in the Bay of Bengal in collaboration with the US Geological Survey Program (USGS) in 2018.

India and Bangladesh can potentially sign up similar joint gas exploration and technology sharing agreements to explore more gas hydrates in the Bay of Bengal. The biggest hurdle for exploring gas in the eastern region of SAR in land-locked countries, such as Bangladesh and Nepal, has been logistics requirements and tough terrain that drives up exploration cost. The joint gas exploration programmes can offer immense benefits, such as overcoming the hurdles of logistics mobilisation, poor connectivity, and a reduction in exploration cost. Both the countries can cooperate and use each other's expertise, territory for resource mobilisation, and equipment in the exploration sector to make the projects economically viable. A joint gas exploration project had already been signed in 2012 between India and Bangladesh to explore the potential offshore gas resources in the Bay of Bengal.[385]The SS-4 or Shallow Sea-4 block, located offshore in the Bay of Bengal, will be drilled under Production Sharing Contracts (PSCs) by Indian state-owned ONGC Videsh Ltd, Oil India Ltd, and Bangladesh Petroleum Exploration and Production Company Limited (BAPEX). The partnership had completed a 5,500-line-km 2D seismic survey in the block as the contract was signed. More such contracts need to be negotiated to fully assess the natural gas potential of the Bay of Bengal.

[385] https://www.dhakatribune.com/bangladesh/power-energy/2021/09/28/bangladesh-to-start-drilling-for-gas-in-bay-wednesday

17 Annexure

17.1 India

17.1.1 Existing domestic fields in India

Table 158 Existing domestic natural gas fields, by state, in India

Company	Location	State	Location/Asset	Production (in mmscm)			
				FY16	FY17	FY18	FY19
ONGC	Offshore	Maharashtra	Mumbai High	5083	5215	5330.53	5526.6
ONGC	Offshore	Maharashtra	Heera & Neelam	1068	1066	1054.83	921.99
ONGC	Offshore	Maharashtra	Bassein & Satellite	10043	10131	10857.58	11556.45
ONGC	Offshore	Maharashtra	Eastern offshore	212	470	548.22	1036.74
ONGC	Onshore	Gujarat	Ahmedabad	138	142	145.04	154.45
ONGC	Onshore	Gujarat	Mehsana	202	207	212.33	214.57
ONGC	Onshore	Gujarat	Ankleshwar	1050	1132	1163.74	954.85
ONGC	Onshore	Gujarat	Cambay	9	10	10.47	8.53
ONGC	Onshore	Assam	Assam	405	435	507.97	482.63
ONGC	Onshore	Tamil Nadu	Cauvery	1010	977	1193.67	1182.49
ONGC	Onshore	Andhra Pradesh	Rajahmundry	619	868	959.16	1076.72
ONGC	Onshore	Tripura	Tripura	1332	1430	1440.37	1554.3
ONGC	Onshore	Rajasthan	Jodhpur	5	5	5.56	4.31
OIL	Onshore	Assam	Greater Naharkatia field	301	257	312.84	255.97
OIL	Onshore	Assam	Greater Jorajan field	461	465	472.89	396.45
OIL	Onshore	Assam	Greater Shalmari field	22	39	40.86	48.36
OIL	Onshore	Assam	Greater Hapjan field	341	303	324.89	348.45
OIL	Onshore	Assam	Greater Chandmari field	446	591	535.84	587.53
OIL	Onshore	Assam	Tengakhat field	35	34	26.47	22.73
OIL	Onshore	Assam	Bhogpara field	10	13	18.6	19.61
OIL	Onshore	Assam	Greater Kathaloni field	31	29	29.65	27.96
OIL	Onshore	Assam	Greater Dikom field	252	210	175.93	154.49
OIL	Onshore	Assam	Western Satellite field	9	18	18.52	51.59
OIL	Onshore	Assam	Eastern Satellite field	93	83	42.84	10.57
OIL	Onshore	Assam	Central Small field	569	600	605.45	520.89
OIL	Onshore	Assam	Digboi	1	0	0.44	0.39
OIL	Onshore	Arunachal Pradesh	Kumchai field	11	12	11.57	12.24
OIL	Onshore	Rajasthan	Dandewala	202	226	201.78	208.43
OIL	Onshore	Rajasthan	Bagitibba	4	6	9.62	19.31
OIL	Onshore	Rajasthan	Tanot	0	0	0	0
Private/JVs	Onshore	Andhra Pradesh	KG-ONN-2003/1	0	0	0	4.58
Private/JVs	Onshore	Arunachal Pradesh	KHARSANG	18	16	17.95	15.57
Private/JVs	Onshore	Assam	AAP-ON-94/1	0	0	52.53	324.5
Private/JVs	Onshore	Gujarat	CB-ON/3	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ON/2	9	10	10.04	9.5
Private/JVs	Onshore	Gujarat	CB-ONN-2000/1	2	2	1.34	0.98
Private/JVs	Onshore	Gujarat	CB-ONN-2002/3	0	0	0.31	0.98
Private/JVs	Onshore	Gujarat	CB-ONN-2003/2	0	0	0.11	0.1

Company	Location	State	Location/Asset	Production (in mmscm)			
				FY16	FY17	FY18	FY19
Private/JVs	Onshore	Gujarat	Unawa	0	0	0	0
Private/JVs	Onshore	Gujarat	Sanganpur	0	0	0.01	0
Private/JVs	Onshore	Gujarat	Allora	0	0	0	0
Private/JVs	Onshore	Gujarat	Dholasan	0	0	0	0
Private/JVs	Onshore	Gujarat	Kanawara	10	9	9.18	9.78
Private/JVs	Onshore	Gujarat	North Kathana	0	0	0	0
Private/JVs	Onshore	Gujarat	Asjol	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ON/7	0	0	0.35	0.3
Private/JVs	Onshore	Gujarat	N. Balol	5	4	4.2	4.29
Private/JVs	Onshore	Gujarat	Dholka	12	13	12.71	14.07
Private/JVs	Onshore	Gujarat	Wavel	0	0	0.01	0
Private/JVs	Onshore	Gujarat	Hazira	42	42	26.09	16.91
Private/JVs	Onshore	Gujarat	Bhandut	0	2	0.17	0
Private/JVs	Onshore	Gujarat	Cambay	1	0	1.22	0.97
Private/JVs	Onshore	Gujarat	CB-ONN-2001/1	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ONN-2002/1	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ONN-2004/1	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ONN-2004/2	0	0	0	0
Private/JVs	Onshore	Gujarat	Bakrol	8	8	7.21	7.94
Private/JVs	Onshore	Gujarat	Indrora	0	0	0.14	0.12
Private/JVs	Onshore	Gujarat	Karjisan	0	0	1.89	3.63
Private/JVs	Onshore	Gujarat	Lohar	0	0	0.11	0.12
Private/JVs	Onshore	Gujarat	Baola	0	0	0	0
Private/JVs	Onshore	Gujarat	CB-ONN-2005/9	0	0	0	0.11
Private/JVs	Onshore	Gujarat	Modhera	0	0	0	0
Private/JVs	Onshore	Rajasthan	RJ-ON-90/1	699	686	813.36	985.39
Private/JVs	Onshore	Rajasthan	RJ-ON/6	428	354	411.61	265.81
Private/JVs	Onshore	Tamil Nadu	CY-ONN-2002/2	1	6	13.55	25.36
Private/JVs	Offshore	Andhra Pradesh	Ravva	260	192	214.06	220.72
Private/JVs	Offshore	Andhra Pradesh	PY-1	22	18	23.54	87.98
Private/JVs	Offshore	Andhra Pradesh	KG-DWN-98/3	3940	2862	1922.4	1029.44
Private/JVs	Offshore	Tamil Nadu	KG-OSN-2001/3	134	128	108.53	84.05
Private/JVs	Offshore	Gujarat	CB-OS/2	68	81	97.69	122.23
Private/JVs	Offshore	Maharashtra	Panna-Mukta	2050	1874	1853.25	1530.91
Private/JVs	Offshore	Maharashtra	M&S Tapti	131	0	0	0
Private/JVs	CBM	Jharkhand	Jharia	2	3	3.96	3.58
Private/JVs	CBM	Jharkhand	Sohagpur East	0	0	0	0.01
Private/JVs	CBM	Madhya Pradesh	Sohagpur West	1	6	199.77	356.65
Private/JVs	CBM	West Bengal	Raniganj East	236	385	328.45	197.66
Private/JVs	CBM	West Bengal	Raniganj West	153	170	202.62	152.56

Source: MOPNG Statistics Report 2019-20

17.1.2 Top-down approach

Table 159 Historical GDP and projections of GDP until FY 2040

Year	GDP (INR Bn)	GDP growth rate (Case I: 7-year CAGR)
2009	74,302	10.3%
2010	81,925	6.6%
2011	87,363	5.5%
2012	92,130	6.4%
2013	98,014	7.4%
2014	1,05,277	8.0%
2015	1,13,695	8.3%
2016	1,23,082	6.8%
2017	1,31,446	6.5%
2018	1,40,033	4.0%
2019	1,45,693	-8.0%
2020	1,34,089	12.5%
2021	1,50,912	6.9%
2022	1,61,373	6.8%
2023	1,72,373	6.7%
2024	1,83,907	6.6%
2025	1,96,087	6.5%
2026	2,08,901	6.7%
2027	2,22,938	5.3%
2028	2,37,919	5.3%
2029	2,53,905	5.3%
2030	2,70,967	5.3%
2031	2,89,174	5.3%
2032	3,08,605	5.3%
2033	3,29,342	5.3%

Year	GDP (INR Bn)	GDP growth rate (Case 1: 7-year CAGR)
2034	3,51,472	5.3%
2035	3,75,089	5.3%
2036	4,00,292	5.3%
2037	4,27,190	5.3%
2038	4,55,895	5.3%
2039	4,86,528	5.3%
2040	5,19,221	5.3%

Note –

1. GDP at constant prices
2. Source – IMF World Economic Outlook 2021 for GDP projections until 2026

Table 160 Primary energy demand and natural gas demand from the bottom-up approach

Year	Natural gas demand (mmscmd)			Natural gas share (%)			Primary energy demand (mtoe)
	Scenario - 1	Scenario - 2	Scenario - 3	Scenario - 1	Scenario - 2	Scenario - 3	
2009	132	132	132	9.6%	9.6%	9.6%	514.1
2010	143	143	143	10.6%	10.6%	10.6%	538.7
2011	166	166	166	10.3%	10.3%	10.3%	570.3
2012	148	148	148	8.7%	8.7%	8.7%	599.8
2013	134	134	134	7.8%	7.8%	7.8%	622.8
2014	129	129	129	7.1%	7.1%	7.1%	665.4
2015	131	131	131	6.0%	6.0%	6.0%	687.1
2016	139	139	139	6.2%	6.2%	6.2%	718.1
2017	145	145	145	6.2%	6.2%	6.2%	748.4
2018	148	148	148	6.2%	6.2%	6.2%	795.4
2019	155	155	155	6.0%	6.0%	6.0%	813.5
2020	151	159	166	6.2%	6.5%	6.8%	768.4
2021	169	189	203	6.3%	7.1%	7.6%	838.6
2022	183	214	237	6.5%	7.6%	8.4%	882.3

Year	Natural gas demand (mmscmd)			Natural gas share (%)			Primary energy demand (mtoe)
	Scenario - 1	Scenario - 2	Scenario - 3	Scenario - 1	Scenario - 2	Scenario - 3	
2023	198	241	274	6.7%	8.2%	9.3%	928.3
2024	214	271	313	6.9%	8.7%	10.1%	976.5
2025	232	303	357	7.1%	9.3%	10.9%	1027.4
2026	250	338	403	7.3%	9.8%	11.7%	1080.9
2027	267	372	450	7.4%	10.4%	12.5%	1127.0
2028	286	408	500	7.6%	10.9%	13.4%	1175.6
2029	305	448	554	7.8%	11.5%	14.2%	1226.7
2030	326	490	612	**8.0%**	**12.0%**	**15.0%**	1280.5
2031	343	519	652	8.1%	12.2%	15.3%	1337.1
2032	361	551	695	8.1%	12.4%	15.6%	1396.8
2033	379	585	742	8.2%	12.6%	15.9%	1459.6
2034	399	621	791	8.2%	12.8%	16.3%	1525.7
2035	420	659	844	8.3%	13.0%	16.6%	1595.3
2036	443	701	901	8.3%	13.2%	17.0%	1668.6
2037	466	744	962	8.4%	13.4%	17.3%	1745.7
2038	491	791	1028	8.4%	13.6%	17.7%	1826.9
2039	517	841	1098	8.5%	13.8%	18.0%	1912.5
2040	545	895	1174	8.5%	14.0%	18.4%	2002.5

17.1.3 Bottom-up approach

Table 161 Details of fertiliser plants in India

Sr. no.	Plant name	Location	Status	Production (TMT)					
				FY14	FY15	FY16	FY17	FY18	Avg. production
1	BVFCL	Namrup-II	Existing plant	71	98	66	60	58	**71**
2	BVFCL	Namrup-III	Existing plant	235	261	256	250	212	**243**
3	CFCL	Gadepan-I	Existing plant	991	976	1,091	966	1,138	**1,032**
4	CFCL	Gadepan-II	Existing plant	951	876	1,035	1,036	956	**971**
5	GNVFC	Bharuch	Existing plant	696	704	691	690	649	**686**
6	GSFC	Baroda	Existing plant	322	352	361	359	311	**341**
7	IFFCO	Kalol	Existing plant	600	597	601	602	602	**600**
8	IFFCO	Phulpur-I	Existing plant	620	578	758	632	726	**663**
9	IFFCO	Phulpur-II	Existing plant	951	884	1,054	992	955	**967**
10	IFFCO	Aonla-I	Existing plant	1,103	1,047	1,133	1,069	896	**1,050**
11	IFFCO	Aonla-II	Existing plant	1,074	1,021	1,123	1,034	931	**1,037**
12	Indo-Gulf	Jagdishpur	Existing plant	1,036	1,022	1,208	1,161	1,184	**1,122**
13	KFCL	Kanpur	Existing plant	313	641	717	723	723	**623**
14	Kribhco	Hazira	Existing plant	2,210	2,225	2,268	2,353	2,254	**2,262**
15	KSFL	Shahjahanpur	Existing plant	1,035	1,050	983	932	901	**980**
16	MCFL	Managalore	Existing plant	379	251	380	380	420	**362**
17	MFL	Madras	Existing plant	487	329	409	468	419	**422**
18	NFCL	Kakinada-I	Existing plant	647	348	631	788	798	**642**
19	NFCL	Kakinada-II	Existing plant	780	583	711	710	792	**715**
20	NFL	Nangal (*)	Existing plant	395	479	546	502	543	**493**
21	NFL	Bathinda	Existing plant	560	561	548	568	563	**560**
22	NFL	Panipat	Existing plant	511	512	567	543	560	**539**

Sr. no.	Plant name	Location	Status	Production (TMT)					
				FY14	FY15	FY16	FY17	FY18	Avg. production
23	NFL	Vijaipur-I	Existing plant	1,006	951	990	1,058	1,044	**1,010**
24	NFL	Vijaipur-II	Existing plant	1,162	1,138	1,146	1,139	1,088	**1,135**
25	RCF	Trombay-V	Existing plant	353	424	452	408	441	**416**
26	RCF	Thal	Existing plant	1,993	2,178	2,098	2,144	2,061	**2,095**
27	SFC	Kota	Existing plant	403	397	401	394	410	**401**
28	SPIC	Tuticorin	Existing plant	286	492	620	563	659	**524**
29	YFIPL	Babrala	Existing plant	1,137	1,250	1,231	1,214	1,248	**1,216**
30	ZIL	Goa	Existing plant	376	363	400	465	473	**415**
31	Matix fertilisers phase I	Panagarh	2021						**1,270**
32	CFCL	Gadepan III	Existing plant						**1,340**
33	RFCL	Ramagundam	2021						**1,270**
34	HURL	Gorakhpur	2022						**1,270**
35	HURL	Sindri	2022						**1,270**
36	HURL	Barauni	2022						**1,270**
37	Matix fertilisers phase 2	West bengal	2023						**1,300**
38	BVFCL	Namrup IV	2024						**1,240**
39	IFFCO	Kalol	2023						**75**
40	HFCL	Durgapur	2022						
41	FCIL	Talcher	Coal based						
42	Indo-Gulf	Jagdishpur	No news of extension- Plant sold						
43	NFCL	Kakinada	No announcement since 2012						
44	Kanpur fertilisers	Jabalpur	No announcement since 2015						
45	GSFC	Dahej	No announcement since 2015						

Table 162 Details of energy consumption by fertiliser plants

Sr. No.	Plant name	Location	Group	Energy consumption (Gcal/MT)						
				FY14	FY15	FY16	FY17	FY18	Avg. Cons.	Target 2018-19 NUP 2015
1	BVFCL	Namrup-II	1	14.3	14.9	17.8	18.6	18.9	16.9	5.5
2	BVFCL	Namrup-III	1	12.2	11.3	11.3	11.3	12.8	11.8	5.5
3	CFCL	Gadepan-I	1	5.6	5.5	5.5	5.6	5.4	5.5	5.5
4	CFCL	Gadepan-II	1	5.4	5.5	5.3	5.4	5.4	5.4	5.5
5	GNVFC	Bharuch	2	6.9	6.9	6.8	6.4	6.5	6.7	6.2
6	GSFC	Baroda	2	6.5	6.3	6.3	6.4	6.5	6.4	6.2
7	IFFCO	Kalol	2	5.8	5.8	5.6	5.7	5.8	5.7	6.2
8	IFFCO	Phulpur-I	3	6.8	6.6	6.6	6.7	5.9	6.5	6.5
9	IFFCO	Phulpur-II	1	5.5	5.5	5.6	5.6	5.3	5.5	5.5
10	IFFCO	Aonla-I	1	5.6	5.6	5.6	5.6	5.3	5.5	5.5
11	IFFCO	Aonla-II	1	5.5	5.4	5.3	5.3	5.2	5.4	5.5
12	Indo-Gulf	Jagdishpur	1	5.5	5.3	5.2	5.2	5.3	5.3	5.5
13	KFCL	Kanpur	3	7.2	7.0	7.1	7.0	6.9	7.0	6.5
14	Kribhco	Hazira	1	5.7	5.7	5.6	5.6	5.7	5.7	5.5
15	KSFL	Shahjahanpur	1	5.6	5.5	5.6	5.6	5.7	5.6	5.5
16	MCFL	Mangalore	3	6.5	6.4	6.5	6.4	6.4	6.4	6.5
17	MFL	Madras	3	7.4	8.1	7.6	7.5	7.8	7.7	6.5
18	NFCL	Kakinada-I	1	5.8	6.3	5.8	5.7	5.6	5.8	5.5
19	NFCL	Kakinada-II	1	5.7	5.8	5.7	5.7	5.6	5.7	5.5
20	NFL	Nangal (*)	3	7.4	7.0	7.0	7.0	6.8	7.1	6.5
21	NFL	Bathinda	3	7.2	7.1	7.0	6.9	6.8	7.0	6.5
22	NFL	Panipat	3	7.6	7.4	7.2	7.1	6.8	7.2	6.5
23	NFL	Vijaipur-I	1	5.9	5.9	5.8	5.8	5.8	5.8	5.5
24	NFL	Vijaipur-II	1	5.4	5.3	5.4	5.4	5.3	5.4	5.5
25	RCF	Trombay-V	3	6.8	7.1	6.9	6.9	6.7	6.9	6.5

Sr. No.	Plant name	Location	Group	Energy consumption (Gcal/MT)						
				FY14	FY15	FY16	FY17	FY18	Avg. Cons.	Target 2018-19 NUP 2015
26	RCF	Thal	2	6.3	5.9	5.9	5.9	5.9	6.0	6.2
27	SFC	Kota	3	7.3	7.2	7.3	7.1	7.1	7.2	6.5
28	SPIC	Tuticorin	3	7.0	7.0	6.8	6.7	6.8	6.9	6.5
29	YFIPL	Babrala	1	5.2	5.1	5.2	5.2	5.2	5.2	5.5
30	ZIL	Goa	3	6.9	6.9	6.6	6.7	6.7	6.7	6.5
31	Matix fertilisers phase 1	Panagarh	1							5.5
32	CFCL	Gadepan III	1							5.5
33	RFCL	Ramagundam	1							5.5
34	HURL	Gorakhpur	1							5.5
35	HURL	Sindri	1							5.5
36	HURL	Barauni	1							5.5
37	Matix fertilisers phase 2	West bengal	1							5.5
38	BVFCL	Namrup IV	1							5.5
39	IFFCO	Kalol	1							5.5
40	HFCL	Durgapur	1							5.5
41	FCIL	Talcher								
42	Indo-Gulf	Jagdishpur								
43	NFCL	Kakinada								
44	Kanpur Fertilisers	Jabalpur								
45	GSFC	Dahej								

Table 163 Natural gas consumption from the refinery sector

Sr. No.	Refinery name	Pipeline connectivity	Refinery capacity (MMTPA)				
			FY22	FY25	FY30	FY35	FY40
1	IOCL Panipat	Existing pipelines	15.0	25.0	25.0	25.0	25.0

Sr. No.	Refinery name	Pipeline connectivity	Refinery capacity (MMTPA)				
			FY22	FY25	FY30	FY35	FY40
2	IOCL Mathura	Existing pipelines	8.0	11.0	11.0	11.0	11.0
3	IOCL Koyali	Existing pipelines	13.7	18.0	18.0	18.0	18.0
4	IOCL Paradip	2024	15.0	21.0	21.0	21.0	21.0
5	CPCL Manali	Existing pipelines	10.5	10.5	10.5	10.5	10.5
6	IOCL Barauni	2024	9.0	9.0	9.0	9.0	9.0
7	IOCL Haldia	2024	8.0	8.0	8.0	8.0	8.0
8	IOCL Digboi	Existing pipelines	0.7	0.7	0.7	0.7	0.7
9	IOCL Guwahati	2024	1.7	1.7	1.7	1.7	1.7
10	IOCL Bongaigaon	2024	2.7	2.7	4.5	4.5	4.5
11	CPCL Chennai	Existing pipelines	1.0	9.0	9.0	9.0	9.0
12	HPCL Mumbai	Existing pipelines	9.5	9.5	9.5	9.5	9.5
13	BPCL Mumbai	Existing pipelines	12.0	12.0	12.0	12.0	12.0
14	BPCL Kochi	Existing pipelines	15.5	20.0	20.0	20.0	20.0
15	NRL Numaligarh	Existing pipelines	3.0	9.0	9.0	9.0	9.0
16	HPCL Visag	Sep-20	15.0	15.0	15.0	15.0	15.0
17	HMEL Bathinda	Mar-21	11.3	11.3	11.3	11.3	11.3
18	ONGC MRPL	Feb-22	15.0	18.0	18.0	18.0	18.0
19	ONGC Tatipaka	Existing pipelines	0.1	0.1	0.1	0.1	0.1
20	BPCL BORL	2026	7.8	15.0	15.0	15.0	15.0
21	HPCL Barmer	2026	-	9.0	9.0	9.0	9.0
22	RRPCL Mumbai	Existing pipelines	-	60.0	60.0	60.0	60.0
23	Nayara Vadinar	Existing pipelines	20.0	46.0	46.0	46.0	46.0
24	RIL DTA	Existing pipelines	33.0	40.5	40.5	40.5	40.5
25	RIL SEZ	Existing pipelines	35.2	35.2	35.2	35.2	35.2
26	**Grand total**		262.6	417.1	418.9	419.0	419.0

Table 164 Pipeline connectivity by GA

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
1	1st GA	Kota, Rajasthan	Rajasthan	Mahesana Bathinda Pipeline	Operational
2	1st GA	Sonipat, Haryana	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
3	1st GA	Mathura, Uttar Pradesh	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
4	1st GA	Kakinada, Andhra Pradesh	Andhra Pradesh	KG Basin network pipeline	Operational
5	1st GA	Meerut, Uttar Pradesh	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
6	1st GA	Dewas, Madhya Pradesh	Madhya Pradesh	VDPL	Operational
7	2nd GA	Allahabad, Uttar Pradesh	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
8	2nd GA	Jhansi, Uttar Pradesh	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
9	2nd GA	Chandigarh, India	Chandigarh	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
10	3rd GA	Ludhiana, Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
11	3rd GA	Jalandhar, Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
12	3rd GA	Jamnagar, Gujarat	Gujarat	GSPL High Pressure Network	Operational
13	3rd GA	Bhavnagar, Gujarat	Gujarat	GSPL High Pressure Network	Operational
14	3rd GA	Kutch-East, Gujarat	Gujarat	GSPL High Pressure Network	Operational
15	3rd GA	Kutch-West, Gujarat	Gujarat	GSPL High Pressure Network	Operational
16	4th GA	Bengaluru, Karnatka	Karnataka	Dabhol -Bengaluru	Operational
17	4th GA	Raigad, Maharashtra	Maharashtra	RGTIL	Operational
18	4th GA	Pune, Maharashtra	Maharashtra	RGTIL	Operational
19	4th GA	Thane, Maharashtra	Maharashtra	Uran-Trombay Pipeline	Operational
20	4th GA	Daman, Daman and Diu	Daman and Diu	Uran-Trombay Pipeline	Operational
21	4th GA	Dadra, Dadra and Nagar Haveli	Dadra and Nagar Haveli	Uran-Trombay Pipeline	Operational
22	4th GA	Panipat, Haryana	Haryana	Dadri-Panipat	Operational
23	4th GA	Amritsar , Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
24	4th GA	Ernakulam, Kerala	Kerala	Kochi-Koottanad bangalore Mangalore pipeline (Phase 1)	Operational
25	5th GA	East Godavari, Andhra Pradesh	Andhra Pradesh	KG Basin network pipeline	Operational
26	5th GA	Belgaum, Karnataka	Karnataka	Dabhol -Bengaluru	Operational
27	5th GA	Krishna, Andhra Pradesh	Andhra Pradesh	KG basin network pipeline	Operational
28	5th GA	West Godawari, Andhra Pradesh	Andhra Pradesh	KG basin network pipeline	Operational
29	5th GA	Tumkur, Karnataka	Karnataka	Dabhol -Bengaluru	Operational
30	5th GA	Haridwar, Uttarakhand	Uttarakhand	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
31	5th GA	Dharwad, Karnataka	Karnataka	Dabhol -Bengaluru	Operational
32	5th GA	Udham Singh Nagar, Uttarakhand	Uttarakhand	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
33	6th GA	Dhar, Madhya Pradesh	Madhya Pradesh	Dahej - Vijapur - Dadri	Operational
34	6th GA	Dahod, Gujarat	Gujarat	GSPL High Pressure Network	Operational
35	6th GA	Banaskantha, Gujarat	Gujarat	GSPL High Pressure Network	Operational
36	6th GA	Saharanpur, Uttar Pradesh	Uttar Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
37	6th GA	Ratnagiri, Maharashtra	Maharashtra	Dabhol -Bengaluru	Operational
38	6th GA	Amreli, Gujarat	Gujarat	GSPL High Pressure Network	Operational
39	6th GA	Bhatinda, Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
40	6th GA	Patan, Gujarat	Gujarat	GSPL High Pressure Network	Operational
41	6th GA	Yamunanagar, Haryana	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
42	6th GA	Rewari, Haryana	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
43	6th GA	North Goa, Goa	Goa	Dabhol -Bengaluru	Operational
44	6th GA	Rupnagar, Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
45	6th GA	Fatehgarh Sahib, Punjab	Punjab	Bathinda-Jammu-Srinagar	Operational
46	6th GA	Dahej, Gujarat	Gujarat	GSPL High Pressure Network	Operational
47	6th GA	Rohtak, Haryana	Haryana	Dahej - Vijapur - Dadri	Operational
48	6th GA	Ahmedabad, Gujarat	Gujarat	GSPL High Pressure Network	Operational
49	6th GA	Anand, Gujarat	Gujarat	GSPL High Pressure Network	Operational
50	6th GA	Panchmahal, Gujarat	Gujarat	GSPL High Pressure Network	Operational
51	7th GA	Solapur, Maharashtra	Maharashtra	RGTIL	Operational
52	8th GA	Karnal, Haryana	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
53	8th GA	Ambala, Haryana	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
54	8th GA	South Goa, Goa	Goa	Dabhol -Bengaluru	Operational
55	8th GA	Bulandshahr, Uttar Pradesh	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
56	8th GA	Baghpat, Uttar Pradesh	Uttar Pradesh	Dadri-Panipat	Operational
57	8th GA	Kolhapur, Maharashtra	Maharashtra	Dabhol -Bengaluru	Operational
58	9th GA	Srikakulam, Andhra Pradesh	Andhra Pradesh	KG Basin network pipeline	Operational
59	9th GA	Cachar, Hailakandi and Karimganj Districts	Assam	NEGG	2022
60	9th GA	Kamrup and Kamrup Metropolitan Districts	Assam	NEGG	2022
61	9th GA	Aurangabad, Kaimur and Rohtas Districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024

Sr. No.	**Round**	**GA**	**State**	**Nearest pipeline**	**Pipeline status**
62	9th GA	Begusarai District	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
63	9th GA	Gaya and Nalanda Districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
64	9th GA	Diu and Gir Somnath Districts	Daman and Diu	GSPL High Pressure Network	Operational
65	9th GA	Surendranagar District (Except areas already authorised)	Gujarat	GSPL High Pressure Network	Operational
66	9th GA	Barwala and Ranpur Talukas	Gujarat	GSPL High Pressure Network	Operational
67	9th GA	Navsari (except areas already authorised), Surat (except area already authorised), Tapi (except area already authorised) and The Dangs Districts	Gujarat	East West Pipeline	Operational
68	9th GA	Junagadh District	Gujarat	GSPL High Pressure Network	Operational
69	9th GA	Kheda (except areas already authorised), Morbi (except area already authorised) and Mahisagar districts	Gujarat	GSPL High Pressure Network	Operational
70	9th GA	Narmada (Rajpipla) district	Gujarat	GSPL High Pressure Network	Operational
71	9th GA	Porbandar district	Gujarat	GSPL High Pressure Network	Operational
72	9th GA	Panchkula (except areas already authorised), Sirmaur, Shimla, and Solan districts	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
73	9th GA	Bhiwani, Charkhi Dadri, and Mahendragarh districts	Haryana	Chhainsa-Jhajjar-Hissar Pipeline (CJPL)	Operational
74	9th GA	Hisar district	Haryana	Chhainsa-Jhajjar-Hissar Pipeline (CJPL)	Operational
75	9th GA	Jhajjar district	Haryana	Chhainsa-Jhajjar-Hissar Pipeline (CJPL)	Operational
76	9th GA	Sonipat (except areas already authorised) and Jind districts	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
77	9th GA	Nuh and Palwal districts	Haryana	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
78	9th GA	Bilaspur, Hamirpur, and Una districts	Himachal Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
79	9th GA	Bokaro, Hazaribagh, and Ramgarh districts	Jharkhand	Jagdishpur-Haldia Pipeline (Dobhi-Durgapur)	Operational
80	9th GA	Giridih and Dhanbad districts	Jharkhand	Jagdishpur-Haldia Pipeline (Dobhi-Durgapur)	Operational
81	9th GA	Chitradurga and Davanagere districts	Karnataka	Dabhol -Bengaluru	Operational
82	9th GA	Udupi district	Karnataka	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational
83	9th GA	Ballari and Gadag districts	Karnataka	Dabhol -Bengaluru	Operational
84	9th GA	Bidar district	Karnataka	Dabhol -Bengaluru	Operational
85	9th GA	Dakshina Kannada, Karnataka	Karnataka	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational
86	9th GA	Ramanagara district	Karnataka	Dabhol -Bengaluru	Operational
87	**9th GA**	**Kozhikode and Wayanad districts**	**Kerala**	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational
88	**9th GA**	**Malappuram district**	**Kerala**	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational
89	9th GA	Kannur, Kasaragod, and Mahe districts	Kerala	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational
90	**9th GA**	**Palakkad and Thrissur districts**	**Kerala**	Kochi-Koottanad bangalore Mangalore pipeline (Phase I)	Operational

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
91	9th GA	Bhopal, Madhya Pradesh	Madhya Pradesh	Mallawaram-Bhopal-Bhilwara	2026
92	9th GA	Guna district	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
93	9th GA	Rewa district	Madhya Pradesh	Shahdol Phulpur pipeline	Operational
94	9th GA	Satna and Shahdol districts	Madhya Pradesh	Shahdol Phulpur pipeline	Operational
95	9th GA	Ahmednagar, Maharashtra	Maharashtra	RGTIL	Operational
96	9th GA	Valsad (except area already authorised), Dhule and Nashik districts	Gujarat	East West pipeline	Operational
97	9th GA	Latur and Osmanabad districts	Maharashtra	RGTIL	Operational
98	9th GA	Sangli and Satara districts	Maharashtra	Dabhol -Bengaluru	Operational
99	9th GA	Sindhudurg district	Maharashtra	Jaigarh- Mangalore	2023
100	9th GA	Angul and Dhekanal districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
101	9th GA	Sundargarh and Jharsuguda districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
102	**9th GA**	**Balasore, Bhadrak, and Mayurbhanj districts**	**Odisha**	Jagdishpur-Haldia-Bokaro-Dhamra	2024
103	9th GA	Bargarh, Debagarh, and Sambalpur districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
104	9th GA	Ganjam, Nayagarh, and Puri districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
105	9th GA	Jagatsinghpur and Kendrapara districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
106	9th GA	Jajpur and Kendujhar districts	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
107	9th GA	Karaikal and Nagapattinam districts	Puducherry	Cauvery Basin pipeline network	Operational
108	9th GA	Puducherry district	Puducherry	Ennore-Tuticorin	2021
109	9th GA	SAS Nagar (except areas already authorised), Patiala, and Sangrur districts	Punjab	Dadri-Bawana-Nangal pipeline (DBPL)	Operational
110	9th GA	Ludhiana (except area already authorised), Barnala, and Moga districts	Punjab	Mahesana Bathinda pipeline	Operational
111	9th GA	Jalandhar (except areas already authorised), Kapurthala, and SBS Nagar districts	Punjab	Bathinda-Jammu-Srinagar	Operational
112	9th GA	Barmer, Jaisalmer, and Jodhpur districts	Rajasthan	Mahesana Bathinda pipeline	Operational
113	9th GA	Alwar (other than Bhiwadi) and Jaipur districts	Rajasthan	Mahesana Bathinda pipeline	Operational
114	9th GA	Kota (except area already authorised), Baran, and Chittorgarh (only Rawatbhata Taluka) districts	Rajasthan	Mahesana Bathinda pipeline	Operational
115	9th GA	Bhilwara and Bundi districts	Rajasthan	Dahej - Vijapur – Dadri	Operational
116	9th GA	Chittorgarh (other than Rawatbhata Taluka) and Udaipur districts	Rajasthan	Mahesana Bathinda pipeline	Operational
117	9th GA	Dholpur district	Rajasthan	Dahej - Vijapur – Dadri	Operational
118	9th GA	Kanchipuram, Tamil Nadu	Tamil Nadu	Ennore-Tuticorin	2021
119	9th GA	Chennai, Tamil Nadu	Tamil Nadu	Ennore-Tuticorin	2021

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
120	**9th GA**	**Coimbatore district**	**Tamil Nadu**	Kochi-Koottanad bangalore Mangalore pipeline (Phase 2)	2022
121	9th GA	Cuddalore, Nagapattinam, and Tiruvarur districts	Tamil Nadu	Cauvery Basin pipeline network	Operational
122	9th GA	Ramanathapuram district	Tamil Nadu	Ennore-Tuticorin	2021
123	9th GA	Salem, Tamil Nadu	Tamil Nadu	Ennore-Tuticorin	2021
124	9th GA	Tiruppur district	Tamil Nadu	Kochi-Koottanad bangalore Mangalore pipeline (Phase 2)	2022
125	9th GA	Bhadradri Kothagudem and Khammam districts	Telangana	East West pipeline	Operational
126	9th GA	Jagtial, Peddapalli, Karimnagar, and Rajanna Sircilla districts	Telangana	Mallawaram-Bhopal-Bhilwara	2026
127	9th GA	Jangaon, Jayashankar Bhupalpally, Mahabubabad, Warangal Urban, and Warangal Rural districts	Telangana	East West pipeline	Operational
128	9th GA	Medak, Siddipet and Sangareddy districts	Telangana	East West pipeline	Operational
129	9th GA	Medchal-Malkajgiri, Ranga Reddy and Vikarabad districts	Telangana	East West pipeline	Operational
130	9th GA	Nalgonda, Suryapet and Yadadri Bhuvanagiri districts	Telangana	East West pipeline	Operational
131	9th GA	Gomati district	Tripura	NEGG	2022
132	9th GA	West Tripura (except areas already authorised) district	Tripura	Agartala Regional Network	Operational
133	9th GA	Hathras districts	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
134	9th GA	Allahabad (except areas already authorised), Bhadohi, and Kaushambi districts	Uttar Pradesh	Shahdol Phulpur pipeline	Operational
135	9th GA	Amethi, Pratapgarh, and Raebareli districts	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
136	9th GA	Auraiya, Kanpur Dehat, and Etawah districts	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
137	9th GA	Faisabad and Sultanpur districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
138	9th GA	Gorakhpur, Sant Kabir Nagar and Kushinagar districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
139	9th GA	Meerut (except areas already authorised), Muzaffarnagar, and Shamli districts	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
140	9th GA	Moradabad (except areas already authorised) district	Uttar Pradesh	Dadri-Auraiya	Operational
141	9th GA	Unnao (except areas already authorised)	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
142	9th GA	Dehradun district	Uttarakhand	Dadri-Bawana-Nangal Pipeline (DBPL)	Operational
143	9th GA	Burdwan district	West Bengal	Jagdishpur-Haldia-Bokaro-Dhamra	2024
144	Old	Agartala CGD network	Tripura	Agartala Regional Network	Operational
145	Old	Upper Assam CGD network	Assam	AGCL's Assam regional netwrok	Operational
146	Old	Firozabad Geographical Area (Taj Trapezium Zone)	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
147	Old	Agra	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
148	Old	Hyderabad	Telangana	East West pipeline	Operational
149	Old	Indore including Ujjain	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
150	Old	Gwalior	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
151	Old	Ghandhinagar Mehsana Sabarkantha	Gujarat	GSPL High Pressure Network	Operational
152	Old	Pune	Maharashtra	East West pipeline	Operational
153	Old	Kanpur CGD Network	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
154	Old	Bareilly CGD Network	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
155	Old	Delhi CGD Network	Delhi	Dahej - Vijapur - Dadri	Operational
156	Old	Mumbai CGD Network	Maharashtra	Mumbai regional P/L network	Operational
157	Old	Vijaywada CGD Network	Andhra Pradesh	East West pipeline	Operational
158	Old	Mumbai CGD Network(GA-2)	Maharashtra	Mumbai regional P/L network	Operational
159	Old	Kolkata CGD Network	West Bengal	Jagdishpur-Haldia-Bokaro-Dhamra	2024
160	Old	Lucknow GA	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
161	Old	Vadodara GA	Gujarat	GSPL High Pressure Network	Operational
162	Old	Ghaziabad GA	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
163	Old	Anand	Gujarat	GSPL High Pressure Network	Operational
164	Old	Valsad	Gujarat	GSPL High Pressure Network	Operational
165	Old	Hazira	Gujarat	GSPL High Pressure Network	Operational
166	Old	Raj kot	Gujarat	GSPL High Pressure Network	Operational
167	Old	Surendranagar	Gujarat	GSPL High Pressure Network	Operational
168	Old	Navsari	Gujarat	Dahej-Uran-Panvel-Dabhol	Operational
169	Old	Nadiad	Gujarat	GSPL High Pressure Network	Operational
170	Old	Khurja	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
171	Old	Moradabad	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
172	Old	Surat-Bharuch-Ankleshwar	Gujarat	GSPL High Pressure Network	Operational
173	Old	Bhiwadi	Rajasthan	Dahej - Vijapur - Dadri	Operational
174	Old	Ahmedabad City and Daskroi	Gujarat	GSPL High Pressure Network	Operational
175	Old	Khordha CGD Network	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
176	Old	Cuttack CGD Network	Odisha	Jagdishpur-Haldia-Bokaro-Dhamra	2024
177	Old	Patna CGD Network	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
178	Old	Ranchi CGD Network	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
179	Old	East Singhbhum CGD Network	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
180	Old	Varanasi CGD Network	Uttar Pradesh	Jagdishpur-Haldia Pipeline (Phulpur-Varanasi)	Operational

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
181	10	Anantpur and Cuddapah Districts	Andhra Pradesh	Kakinada Vijaywada Nellore	2021
182	10	Nellore district	Andhra Pradesh	Kakinada Vijaywada Nellore	2021
183	10	Chitoor, Kolar, and Vellore districts	Andhra Pradesh, Tamil Nadu and Karnataka	Kakinada Vijaywada Nellore	2021
184	10	Araria, Purnia, Katihar, and Kishanganj districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
185	10	Arwal, Jehanabad, Bhojpur, and Buxar districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
186	10	Khagaria, Saharsa, and Madhepura districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
187	10	Lakhisarai, Munger, and Bhagalpur districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
188	10	Muzafarpur, Vaishali, Saran, and Samastipur districts	Bihar	Jagdishpur-Haldia-Bokaro-Dhamra	2024
189	10	Nawada and Kodarma districts	Bihar and Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
190	10	Deoghar, Sheikhpura, and Jamui districts	Bihar and Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
191	10	Kaithal district	Haryana	Dadri-Bawana-Nangal (DBPL) pipeline	Operational
192	10	Sirsa, Fatehabad, and Mansa (Punjab) districts	Haryana and Punjab	Mahesana Bathinda pipeline	Operational
193	10	Chhatra and Palamu districts	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
194	10	Seraikela-Kharsawan district	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
195	10	West Singhbhoom district	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
196	10	Bagalkot Koppal and Raichur districts	Karnataka	Dabhol -Bengaluru	Operational
197	10	Chikmagalur Hassan and Kodagu districts	Karnataka	Dabhol -Bengaluru	Operational
198	10	Gulbarga and Bijapur districts	Karnataka	Dabhol -Bengaluru	Operational
199	10	Mysore, Mandya and Chamarajnagar districts	Karnataka	Dabhol -Bengaluru	Operational
200	10	Uttar Kanada Haveri and Shimoga districts	Karnataka	Kochi-Koottanad bangalore Mangalore pipeline (Phase 1)	Operational
201	10	Allapuza, Kollam and Thiruvananthapuram districts	Kerala	Kochi-Koottanad bangalore Mangalore pipeline (Phase 1)	Operational
202	10	Ashoknagar district	Madhya Pradesh	Dahej - Vijapur - Dadri	Operational
203	10	Gwalior (Except already authorised) and Sheopur districts	Madhya Pradesh	Dahej - Vijapur - Dadri	Operational
205	10	Raisen Shajapur and Shehore districts	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur Pipeline	Operational
206	10	Shivpuri district	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
207	10	Sidhi and Singrauli districts	Madhya Pradesh	Shahdol Phulpur pipeline	Operational
208	10	Ujjain (except area already authorised), Dewas (except area already authorised) and Indore (except area already authorised) districts	Madhya Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
209	10	Anuppur, Bilaspur, and Korba districts	Madhya Pradesh and Chattisgarh	Surat-Paradip	Cancelled
210	10	Jhabua, Banswara, Ratlam, and Dungarpur districts	Madhya Pradesh and Rajashthan	Hazira-Vijaipur-Jagdishpur pipeline	Operational

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
211	10	Jhansi (except area already authorised), Bhind, Jalaun, Lalitpur, and Datia districts	Madhya Pradesh and Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
212	10	Firozpur, Faridkot, and Muktsar districts	Punjab	Mahesana Bathinda pipeline	Operational
213	10	Hoshiarpur and Gurudashpur districts	Punjab	Bathinda-Jammu-Srinagar	Operational
214	10	Ajmer, Pali, and Rajsamand districts	Rajasthan	Mahesana Bathinda pipeline	Operational
215	10	Jalor and Sirohi districts	Rajasthan	Mahesana Bathinda pipeline	Operational
216	10	Azamgarh, Mau, and Balia districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
217	10	Bareilly (except area already authorised), Pilibhit and Rampur districts	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
218	10	Basti and Ambedkarnagar districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
219	10	Farukhabad, Etah, and Hardoi districts	Uttar Pradesh	Dahej - Vijapur - Dadri	Operational
220	10	Gonda and Barabanki districts	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
221	10	Jaunpur and Ghazipur districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
222	10	Kanpur (except area already authorised), Fatehpur and Hamirpur districts	Uttar Pradesh	Bathinda-Jammu-Srinagar	Operational
223	10	Mainpuri and Kannauj districts	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
224	10	Mirzapur, Chandauli, and Sonbhadra districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2024
225	10	Shahjahanpur and Badaun districts	Uttar Pradesh	Hazira-Vijaipur-Jagdishpur pipeline	Operational
226	10	Bijnor and Nainital	Uttar Pradesh and Uttarakhand	Hazira-Vijaipur-Jagdishpur pipeline	Operational
227	10	Darjeeling , Jalpaiguri, and Uttar Dinajpur	West Bengal	Jagdishpur-Haldia-Bokaro-Dhamra	2024
228	10	Howrah (except area already authorised) Districts and Hoogly districts (except area already authorised)	West Bengal	Contai-Paradip-Dattapulia P/L	Cancelled
229	10	Nadia (except area already authorised) districts and North 24 Pargana districts (except area already authorised)	West Bengal	Contai-Paradip-Dattapulia P/L	Cancelled
230	10	South 24 Pargana (except area already authorised) district	West Bengal	Contai-Paradip-Dattapulia P/L	Cancelled
231	11	Kurnool, Guntur, and Prakasam districts	Andhra Pradesh	Kakinada Vijaywada Nellore	2022
232	11	Nagaon, Morigaon, Hojai, Karbi Anglong and West Karbi Anglong districts	Assam	NEGG	2022
233	11	North Lakhimpur, Dhemaji, Darrang, Udalgiri, Sonitpur and Biswanath Chariali districts	Assam	NEGG	2022
234	11	Kokrajhar and Dhubri districts	Assam	Barauni-Guwahati pipeline	2022
235	11	Baksa, Barpeta, Bongaigaon, Chirang, and Nalbari districts	Assam	Barauni-Guwahati pipeline	2022
236	11	Darbhanga, Madhubani, Supaul, Sitamarhi, and Sheohar districts	Bihar	Barauni-Guwahati pipeline	2022
237	11	Gopalganj, Siwan, West Champaran, East Champaran and Deoria districts	Bihar and Uttar Pradesh	Jagdishpur-Haldia pipeline (Phulpur-Varanasi)	2022
238	11	Baloda Bazar, Gariyaband and Raipur districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
239	11	Kabirdham, Raj Nandgaon and Kanker districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
240	11	Mungeli, Bemetara, Durg, Balod and Dhamtari districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
241	11	Jashpur, Raigarh, Janjgir-Champa and Mahasamund districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
242	11	Koriya and Surajpur districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
243	11	Garwa, Balrampur and Surguja districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
244	11	Kondagaon, Bastar and Sukma districts	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
245	11	Narayanpur, Bijapur and Dantewada	Chhattisgarh	Mumbai Nagpur Jharsuguda pipeline	2023
246	11	Mandi, Kullu, Kinnaur and Lahaul and Spiti districts	Himachal Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
247	11	Kangra and Chamba districts	Himachal Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
248	11	Jammu, Udhampur, Reasi, Samba and Kathua districts	UT of Jammu and Kashmir	Bathinda-Jammu-Srinagar	2022
249	11	Gumla, Latehar, Lohardaga, Simdega, Garhwa and Khunti districts	Jharkhand	Jagdishpur-Haldia-Bokaro-Dhamra	2024
250	11	Chikkballapur district	Karnataka	Dabhol -Bengaluru	2022
251	11	Idukki, Kottayam and Pattanamtitta districts	Kerala	Kochi-Koottanad bangalore Mangalore pipeline (Phase 1)	2022
252	11	Agar Malwa, Neemuch, Mandsaur and Jhalawar Districts	Madhya Pradesh and Rajasthan	Dahej - Vijapur - Dadri	2022
253	11	Burhanpur, Khandwa, Khargone and Harda districts	Madhya Pradesh	Dahej - Vijapur - Dadri	2022
254	11	Tikamgarh, Niwari, Chattarpur and Panna districts	Madhya Pradesh	Mallawaram-Bhopal-Bhilwara	2026
255	11	Betul, Chhindwara, Seoni and Balaghat districts	Madhya Pradesh	Mallawaram-Bhopal-Bhilwara	2026
256	11	Damoh, Jabalpur, Katni, Mandla, Umaria and Dindori districts	Madhya Pradesh	Shahdol Phulpur pipeline	2022
257	11	Hoshangabad, Narsinghpur, Sagar and Vidisha districts	Madhya Pradesh	Mallawaram-Bhopal-Bhilwara	2026
258	11	Buldana, Nanded and Parbhani districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
259	11	Beed, Jalgaon and Jalna districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
260	11	Akola, Hingoli and Washim districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
261	11	Amravati and Yavatmal districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
262	11	Chandrapur and Wardha districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
263	11	Nagpur district	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
264	11	Bhandara, Gondiya and Garchiroli districts	Maharashtra	Mumbai Nagpur Jharsuguda Pipeline	2023
265	11	Alirajpur, Nandurbar and Barwani districts	Maharashtra	Dahej-Uran-Panvel-Dabhol	2022
266	11	Koraput, Malkangiri, and Nabarangpur districts	Odisha	Angul Srikakulam Pipeline	2022
267	11	Gajapati, Kandhamal, Boudh and Sonepur districts	Odisha	Angul Srikakulam Pipeline	2022
268	11	Rayagada, Kalahandi, Bolangir and Nuapada districts	Odisha	Angul Srikakulam Pipeline	2022
269	11	Pathankot district	Punjab	Bathinda-Jammu-Srinagar	2022

Sr. No.	Round	GA	State	Nearest pipeline	Pipeline status
270	11	Tarn Taran district	Punjab	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
271	11	Fazilka (except area already authorised), Ganganagar and Hanumangarh districts	Punjab and Rajasthan	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
272	11	Bikaner and Churu districts	Rajasthan	Mahesana Bathinda Pipeline	2022
273	11	Jhunjhunu, Sikar and Nagaur districts	Rajasthan	Mahesana Bathinda Pipeline	2022
274	11	Dausa, Karauli, Sawai Madhopur and Tonk districts	Rajasthan	Mahesana Bathinda Pipeline	2022
275	11	Dharmapuri and Krishnagiri districts	Tamil Nadu	Kochi-Koottanad bangalore Mangalore pipeline (Phase 2)	2022
276	11	Tiruvannamalai and Villupuram districts	Tamil Nadu	Kochi-Koottanad bangalore Mangalore pipeline (Phase 2)	2022
277	11	Ariyalur and Perambalur districts	Tamil Nadu	Ennore-Tuticorin	2022
278	11	Namakkal and Tiruchirapalli districts	Tamil Nadu	Ennore-Tuticorin	2022
279	11	Pudukottai, Sivaganga and Thanjavur districts	Tamil Nadu	Ennore-Tuticorin	2022
280	11	Madurai, Theni and Virudhnagar districts	Tamil Nadu	Ennore-Tuticorin	2022
281	11	Kanyakumari, Thoothukudi and Tiruneveli Kattabo districts	Tamil Nadu	Ennore-Tuticorin	2022
282	11	Dindigul and Karur districts	Tamil Nadu	Ennore-Tuticorin	2022
283	11	Nilgiris and Erode districts	Tamil Nadu	Kochi-Koottanad bangalore Mangalore pipeline (Phase 2)	2022
284	11	Nisamabad, Adilabad, Nirmal, Mancherial and Kumuram Bheem Asifabad districts	Telangana	Mallawaram-Bhopal-Bhilwara	2026
285	11	Jogulamba Gadwal, Nagarkurnool, Mahabubnagar, Narayanpet, Wanaparthy and Yadgir districts	Telangana and Karnataka	Mallawaram-Bhopal-Bhilwara	2026
286	11	South Tripura and Sepahijala districts	Tripura	NEGG	2022
287	11	Dhalai, North Tripura, Unakoti and Khowai districts	Tripura	NEGG	2022
288	11	Amroha and Sambhal districts	Uttar Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
289	11	Kasganj district	Uttar Pradesh	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
290	11	Purulia and Bankura districts	West Bengal	Jagdishpur-Haldia-Bokaro-Dhamra	2024
291	11	East Mednipore, West Mednipore and Jhargram districts	West Bengal	Jagdishpur-Haldia-Bokaro-Dhamra	2024
292	11	Alipurduar and Koch Bihar districts	West Bengal	Barauni-Guwahati Pipeline	2022
293	11	Banda, Chitrakoot and Mahoba districts	Uttar Pradesh	Jagdishpur-Haldia-Bokaro-Dhamra	2022
294	11	Pauri Garhwal, Uttarkashi, Rudraprayag and Tehri Garhwal districts	Uttarakhand	Dadri-Bawana-Nangal Pipeline (DBPL)	2022
295	11	Pithoragarh, Champawat, Almora, Chamoli and Bageshwar districts	Uttarakhand	Dadri-Bawana-Nangal Pipeline (DBPL)	2022

Table 165 Household data for GAs in 11th round

S.No.	State	State	Households - Rural	Households - Urban
1	Kurnool, Guntur, and Prakasam districts	Andhra Pradesh	22,08,397	8,36,327
2	Nagaon, Morigaon, Hojai, Karbi Anglong, and West Karbi Anglong districts	Assam	8,33,951	1,25,836
3	North Lakhimpur, Dhemaji, Darrang, Udalgiri, Sonitpur, and Biswanath Chariali districts	Assam	9,10,787	89,695
4	Kokrajhar and Dhubri districts	Assam	5,40,434	55,321
5	Baksa, Barpeta, Bongaigaon, Chirang, and Nalbari districts	Assam	8,48,202	84,089
6	Darbhanga, Madhubani, Supaul, Sitamarhi, and Sheohar districts	Bihar	28,63,764	1,67,302
7	Gopalganj, Siwan, West Champaran, East Champaran, and Deoria districts	Bihar and Uttar Pradesh	28,62,152	2,46,876
8	Baloda Bazar, Gariyaband, and Raipur districts	Chhattisgarh	6,16,741	2,57,810
9	Kabirdham, Raj Nandgaon, and Kanker districts	Chhattisgarh	4,37,114	87,670
10	Mungeli, Bemetara, Durg, Balod, and Dhamtari districts	Chhattisgarh	9,93,012	3,26,151
11	Jashpur, Raigarh, Janjgir-Champa, and Mahasamund districts	Chhattisgarh	10,26,711	1,46,914
12	Koriya and Surajpur districts	Chhattisgarh	1,49,779	54,145
13	Garwa, Balrampur, and Surguja districts	Chhattisgarh	7,42,697	63,787

S.No.	State	State	Households - Rural	Households - Urban
14	Kondagaon, Bastar, and Sukma districts	Chhattisgarh	3,15,306	53,398
15	Narayanpur, Bijapur, and Dantewada	Chhattisgarh	85,035	33,957
16	Mandi, Kullu, Kinnaur and Lahaul, and Spiti districts	Himachal Pradesh	3,14,755	25,847
17	Kangra and Chamba districts	Himachal Pradesh	4,12,975	28,372
18	Jammu, Udhampur, Reasi, Samba, and Kathua districts	UT of Jammu and Kashmir	4,45,666	2,08,890
19	Gumla, Latehar, Lohardaga, Simdega, Garhwa, and Khunti districts	Jharkhand	5,82,166	64,062
20	Chikkballapur district	Karnataka	2,20,987	63,711
21	Idukki, Kottayam, and Pattanamtitta districts	Kerala	9,01,712	1,88,070
22	Agar Malwa, Neemuch, Mandsaur, and Jhalawar Districts	Madhya Pradesh and Rajasthan	6,26,414	1,59,815
23	Burhanpur, Khandwa, Khargone, and Harda districts	Madhya Pradesh	7,13,082	1,58,189
24	Tikamgarh, Niwari, Chattarpur, and Panna districts	Madhya Pradesh	7,35,186	1,45,936
25	Betul, Chhindwara, Seoni, and Balaghat districts	Madhya Pradesh	12,10,647	2,69,149
26	Damoh, Jabalpur, Katni, Mandla, Umaria, and Dindori districts	Madhya Pradesh	12,20,734	4,70,295
27	Hoshangabad, Narsinghpur, Sagar, and Vidisha districts	Madhya Pradesh	8,40,977	2,95,862
28	Buldana, Nanded, and Parbhani districts	Maharashtra	12,02,024	3,86,044

S.No.	State	State	Households - Rural	Households - Urban
29	Beed, Jalgaon, and Jalna districts	Maharashtra	13,81,066	4,50,113
30	Akola, Hingoli, and Washim districts	Maharashtra	6,64,818	2,19,204
31	Amravati and Yavatmal districts	Maharashtra	9,45,784	15,31,053
32	Chandrapur and Wardha districts	Maharashtra	5,68,721	3,05,833
33	Nagpur district	Maharashtra	3,39,997	7,01,547
34	Bhandara, Gondiya, and Garchiroli districts	Maharashtra	6,91,186	1,04,474
35	Alirajpur, Nandurbar, and Barwani districts	Maharashtra	5,90,556	1,00,042
36	Koraput, Malkangiri, and Nabarangpur districts	Odisha	6,62,216	86,483
37	Gajapati, Kandhamal, Boudh, and Sonepur districts	Odisha	3,79,395	42,328
38	Rayagada, Kalahandi, Bolangir, and Nuapada districts	Odisha	10,78,444	1,14,558
39	Pathankot district	Punjab	64,886	58,848
40	Tarn Taran district	Punjab	1,76,669	26,752
41	Fazilka (except area already authorised), Ganganagar and Hanumangarh districts	Punjab and Rajasthan	6,09,163	1,92,644
42	Bikaner and Churu districts	Rajasthan	5,00,839	2,33,089
43	Jhunjhunu, Sikar, and Nagaur districts	Rajasthan	11,22,697	2,85,125
44	Dausa, Karauli, Sawai Madhopur, and Tonk districts	Rajasthan	8,99,519	1,77,072

S.No.	State	State	Households - Rural	Households - Urban
45	Dharmapuri and Krishnagiri districts	Tamil Nadu	6,53,268	1,70,658
46	Tiruvannamalai and Villupuram districts	Tamil Nadu	11,51,536	2,37,668
47	Ariyalur and Perambalur districts	Tamil Nadu	2,99,848	46,485
48	Namakkal and Tiruchirapalli districts	Tamil Nadu	6,40,492	5,33,423
49	Pudukottai, Sivaganga, and Thanjavur districts	Tamil Nadu	9,36,000	3,95,980
50	Madurai, Theni, and Virudhnagar districts	Tamil Nadu	7,36,757	9,33,990
51	Kanyakumari, Thoothukudi, and Tiruneveli Kattabo districts	Tamil Nadu	7,39,984	10,21,093
52	Dindigul and Karur districts	Tamil Nadu	5,22,575	3,28,502
53	Nilgiris and Erode districts	Tamil Nadu	4,06,523	4,49,201
54	Nisamabad, Adilabad, Nirmal, Mancherial, and Kumuram Bheem Asifabad districts	Telangana	9,38,548	3,04,535
55	Jogulamba Gadwal, Nagarkurnool, Mahabubnagar, Narayanpet, Wanaparthy and Yadgir districts	Telangana and Karnataka	9,05,293	1,66,221
56	South Tripura and Sepahijala districts	Tripura	1,76,230	10
57	Dhalai, North Tripura, Unakoti, and Khowai districts	Tripura	2,13,749	11
58	Amroha and Sambhal districts	Uttar Pradesh	2,10,473	82,638
59	Kasganj district	Uttar Pradesh	70,402	24,540

S.No.	State	State	Households - Rural	Households - Urban
60	Purulia and Bankura districts	West Bengal	11,96,995	1,37,731
61	East Mednipore, West Mednipore, and Jhargram districts	West Bengal	21,31,659	2,84,121
62	Alipurduar and Koch Bihar districts	West Bengal	6,81,344	86,619
63	Banda, Chitrakoot, and Mahoba districts	Uttar Pradesh	5,46,201	1,00,429
64	Pauri Garhwal, Uttarkashi, Rudraprayag, and Tehri Garhwal districts	Uttarakhand	3,64,667	50,969
65	Pithoragarh, Champawat, Almora, Chamoli, and Bageshwar districts	Uttarakhand	3,98,231	58,039

Table 166 Minimum work programme for CNG (upto 10th round)

S.no.	State	CNG stations
1	Tamil Nadu	872
2	Karnataka	811
3	Uttar Pradesh	785
4	Kerala	763
5	Andhra Pradesh/Telangana	694
6	Rajasthan	576
7	West Bengal	480
8	Bihar	459
9	Madhya Pradesh	309
10	Punjab	278
11	Haryana	277
12	Andhra Pradesh, Tamil Nadu, and Karnataka	251
13	Maharashtra	225

S.no.	State	CNG stations
14	Kerala and Puducherry	185
15	Jharkhand	179
16	Maharashtra and Gujarat	156
17	Gujarat	140
18	Puducherry	130
19	Odisha	116
20	Uttar Pradesh and Uttarakhand	91
21	Assam	72
22	Haryana and Punjab	54
23	Madhya Pradesh and Rajasthan	54
24	Uttarakhand	50
25	Haryana and Himachal Pradesh	45
26	Bihar and Jharkhand	37
27	Daman and Diu and Gujarat	35
28	UP and MP	34
29	Puducherry and Tamil Nadu	27
30	Madhya Pradesh and Chhattisgarh	20
31	Tripura	12
32	Himachal Pradesh	10
33	Delhi	0
34	Chandigarh	0
35	Dadra and Nagar haveli	0
36	Daman and Diu	0
37	Goa	0
38	Gujarat and Dadra Nagar Haveli	0
39	**Total**	**8227**

Table 167 TCO calculations for CNG, petrol, and diesel vehicles

Car price	**CNG**	**Petrol**	**Diesel**	**Unit**
Car runtime	150 km per day for 300 days in a year			
Ex-showroom price	664,610	506,990	700,110	*INR*
+ RTO	55,043	44,009	69,780	*INR*
On-road price	719,653	550,999	769,890	*INR*
EMI (for 4 years)	17,738	13,581	18,976	*INR/month*
+ Insurance	29,907	22,814	31,504	*INR/year*
- Salvage value of car	107,948	82,650	115,483	*INR*
+ MDT + GPS device	30,000	30,000	30,000	*INR*
+ Other accessories	6,000	6,000	6,000	*INR*
+ PUC certification	80	80	100	*INR/year*
Capex (A)	**4.1**	**3.2**	**4.4**	***INR/km***
Running cost	**CNG**	**Petrol**	**Diesel**	
Avg. daily run	150	150	150	*km/day*
Mileage of the fuel	18	20.7	25.1	*km/kg or km/L*
CNG price	43.4	96.62	85.85	*INR/kg or INR/L*
+ Driver salary	20,000	20,000	20,000	*INR/month*
Running cost (B)	**7.7**	**10.0**	**8.8**	***INR/km***
Light motor vehicle permit	**CNG**	**Petrol**	**Diesel**	
National permit for LMV	5000	5000	5000	*INR/5years*
#time permit to be taken	2	2	2	
Total permit cost (C)	**0.04**	**0.04**	**0.04**	***INR/km***
Maintenance cost	**CNG**	**Petrol**	**Diesel**	
Battery cost				
Battery life	70,000	70,000	70,000	*km*
#batteries to be changed	3	3	3	*unit*
Battery cost	3700	3700	5200	*INR/battery*
- Salvage value	15%	15%	15%	%

Car price	CNG	Petrol	Diesel	Unit
Total battery cost	0.01	0.01	0.01	*INR/km*
Tyre cost				
Tyre life	60,000	60,000	60,000	*Km*
#times tyre-set to be replaced	3	3	3	*unit of tyre-sets*
Tyre cost	20,000	20,000	20,000	*INR/full-set*
Total tyre cost	0.3	0.3	0.3	*INR/km*
Servicing cost				
Cost of servicing for 50,000 km	13,600	13,600	18,126	*INR*
Overall servicing cost	0.3	0.3	0.4	*INR/km*
Other cost				
Repair cost	0.55	0.55	0.55	*INR/km*
Total maintenance cost (D)	**1.1**	**1.1**	**1.2**	***INR/km***
Overall TCO	**13.0**	**14.4**	**14.5**	***INR/km***

Assumptions

1. The car model considered for TCO analysis is Hyundai Grand i10 Nios for which all three variants - petrol, diesel, and LPG are there in the market.
2. Road tax and other price assumptions have been taken per Delhi prices.
3. Only commercial four wheelers have been considered with an average distance of 150 km per day and 300 days per year with a life tenure of five years.
4. The whole on-road price for the car has been assumed to be paid through a four-year car loan with 8.5 percent of annual interest.
5. The salvage value of 15 percent has been assumed for the car after the life tenure.
6. The costs associated with devices, services, and maintenance work have been assumed per the market standards available on different car websites.
7. The driver earning has been assumed as INR 20,000 per month.

17.2 Pakistan

17.2.1 Top-down approach

Table 168 Historical GDP of Pakistan and projections by five-year and seven-year CAGR

Year	GDP (PKR billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (PKR billion) – Scenario 2	GDP growth rate (7 year CAGR)
2015	10,632	3.9%	10,632	3.9%
2016	11,117	4.4%	11,117	4.4%
2017	11,697	5.0%	11,697	5.0%
2018	12,344	5.2%	12,344	5.2%
2019	12,580	1.9%	12,580	1.9%
2020	12,532	-0.4%	12,532	-0.4%
2021	12,719	1.5%	12,719	1.5%
2022	13,224	3.8%	13,224	3.8%
2023	13,824	4.3%	13,824	4.3%
2024	14,515	4.8%	14,515	4.8%
2025	15,245	4.8%	15,245	4.8%
2026	16,014	4.8%	16,014	4.8%
2027	16,769	4.7%	16,576	3.5%
2028	17,560	4.7%	17,157	3.5%
2029	18,387	4.7%	17,759	3.5%
2030	19,254	4.7%	18,382	3.5%
2031	20,162	4.7%	19,027	3.5%
2032	21,113	4.7%	19,694	3.5%
2033	22,108	4.7%	20,385	3.5%
2034	23,150	4.7%	21,100	3.5%
2035	24,242	4.7%	21,840	3.5%
2036	25,385	4.7%	22,606	3.5%
2037	26,582	4.7%	23,399	3.5%

Year	GDP (PKR billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (PKR billion) – Scenario 2	GDP growth rate (7 year CAGR)
2038	27,835	4.7%	24,220	3.5%
2039	5,870	4.7%	25,070	3.5%
2040	6,175	4.7%	25,949	3.5%

17.2.2 Bottom-up approach

Table 169 List of power plants in Pakistan

Plant	Gas consumption (in mmscfd)					
	Product	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
TPS Jamshoro (GENCO-I)	Natural Gas	31,095.6	14,085.2	8,782.0	6,474.9	886.9
SPS Faisalabad (GENCO- III)	Natural Gas	1,328.0	971.2	85.1	0.0	0.0
GTPS Faisalabad (GENCO-III)	Natural Gas	3,631.0	2,719.0	1,297.2	0.0	0.0
TPS Muzaffargarh (GENCO-III)	Natural Gas	4,641.0	11.0	384.1	0.0	7.5
TPS Nandipur (GENCO-III)	Natural Gas	0.0	4,822.6	2,133.6	14,299.3	12,030.5
GTPS Kotri (GENCO-I)	Natural Gas	7,139.0	4,203.3	1,258.9	552.0	0.0
TPS Guddu (Units 1-4) (GENCO-II)	Natural Gas	2,501.4	3,395.3	4,209.9	171.4	0.0
TPS Guddu (Units 5-10) (GENCO-II)	Natural Gas	24,331.6	29,803.5	43,758.6	43,384.4	20,020.7
TPS Guddu (Units 11-13) (GENCO-II)	Natural Gas	4,460.3	11,919.7	16,311.5	13,445.7	6,182.7
TPS Guddu (Units 14-16) (GENCO-II)	Natural Gas	32,113.1	40,375.6	39,464.5	44,942.7	41,643.0
TPS Quetta (Isolated Generation) (GENCO-II)	Natural Gas	1,914.5	934.5	0.0	0.0	0.0
Narowal Energy	Natural Gas	230	262	234	125	67
Fauji Kabirwala	Natural Gas	1419944	709502	404931	259336	59271
Habibullah Coastal	Natural Gas	4889875	6533436	7416480	6231700	1006228
Rousch Power	Natural Gas	23833821	19781549	0	0	0
TNB Liberty Power	Natural Gas	12003012	11611024	8776938	10910993	7946696

Plant	Gas consumption (in mmscfd)					
	Product	2015-16	2016-17	2017-18	2018-19	2019-20
Engro Power Gen. Qadirpur	Natural Gas	10196067	13923051	13221041	11258742	6077764
Davis Energen.	Natural Gas	691918	516629	85456	0	0
Sapphire Electric	Natural Gas	5409221	4414191	4883647	6252321	2337975
Saif Power	Natural Gas	6392115	3805865	5146932	6403632	3738827
Orient Power	Natural Gas	6421294	4366253	5270563	6795121	2735769
Foundation Power	Natural Gas	9539800	9830259	10818257	10526917	6578836
Halmore Power	Natural Gas	4087127	2172844	4953062	4849884	2846605
Uch Power	Natural Gas	32101860	33657865	33721523	29954223	31456577
Uch-II Power	Natural Gas	17423515	20340852	19524716	22553022	16349080
KAPCO	Natural Gas	9322082	22502701	36631183	30440566	21678499
Bin Qasim TPS-II	Natural Gas	31577	30153	25928.49	19118.21	19729
Korangi Town GTPS-II	Natural Gas	4769	3631	2699.01	2418.98	1900
Site GTPS-II	Natural Gas	3659	3517	3953.32	2174.2	2283
Korangi CCPP	Natural Gas	10525	8848	6562.04	6325.76	5593
Sindh Nooriabad-I	Natural Gas			1412024	3274096	2999996
Sindh Nooriabad-II	Natural Gas			1426212	3137925	2978275
Bin Qasim TPS I	Natural Gas	16353	8867	7710.67	8672.23	8552
TPS Jamshoro (GENCO-I)	RLNG			2145.5	1881.9	
GTPS Faisalabad (GENCO-III)	RLNG			1092.0	1801.9	
TPS Muzaffargarh (GENCO-III)	RLNG			1575.75	7.15	
Bin Qasim TPS-II	RLNG	0	0	1690.91	11868.6	13554
Korangi Town GTPS-II	RLNG	0	0	336.99	1222.94	1006
Site GTPS-II	RLNG	0	0	353.68	980.14	1292

Plant	Gas consumption (in mmscfd)					
	Product	2015-16	2016-17	2017-18	2018-19	2019-20
Korangi CCPP	RLNG	0	0	748.04	3334.39	3161
Bin Qasim TPS I	RLNG			847.74	4,362.57	5,821.00

17.3 Bangladesh

17.3.1 Top-down approach

Table 170 Historical GDP of Bangladesh and projections by five-year and seven-year CAGR

Year	GDP (BDT billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (BDT billion) – Scenario 2	GDP growth rate (7 year CAGR)
2015	8,249	6.6%	8,249	6.6%
2016	8,835	7.1%	8,835	7.1%
2017	9,479	7.3%	9,479	7.3%
2018	10,224	7.9%	10,224	7.9%
2019	11,058	8.2%	11,058	8.2%
2020	11,478	3.8%	11,478	3.8%
2021	12,056	5.0%	12,056	5.0%
2022	12,956	7.5%	12,956	7.5%
2023	13,902	7.3%	13,902	7.3%
2024	14,916	7.3%	14,916	7.3%
2025	16,005	7.3%	16,005	7.3%
2026	17,158	7.2%	17,158	7.2%
2027	18413	7.3%	18269	6.5%
2028	19759	7.3%	19452	6.5%
2029	21204	7.3%	20712	6.5%
2030	22755	7.3%	22054	6.5%
2031	24419	7.3%	23482	6.5%
2032	26205	7.3%	25003	6.5%
2033	28121	7.3%	26622	6.5%

Year	GDP (BDT billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (BDT billion) – Scenario 2	GDP growth rate (7 year CAGR)
2034	30177	7.3%	28347	6.5%
2035	32384	7.3%	30183	6.5%
2036	34753	7.3%	32138	6.5%
2037	37294	7.3%	34219	6.5%
2038	40021	7.3%	36435	6.5%
2039	42948	7.3%	38795	6.5%
2040	46089	7.3%	41308	6.5%

17.3.2 Bottom-up approach

Table 171 List of power plants in Bangladesh

Power plant	Existing/Upcoming year	Installed capacity (MW)	Pipeline	Pipeline completion year	Company	Max. demand
Ghorashal (1315 MW)	Existing	1315			TGTDCL	148
Max (G)-78 MW Rent	Existing	78			TGTDCL	20
Aggreeko (GSL)-145 MW Rent	Existing	145			TGTDCL	38
Siddhirganj (210 MW)	Existing	210			TGTDCL	30.0
Siddhirganj (2x120 MW)	Existing	240			TGTDCL	52
HPS (100 MW)	Existing	100			TGTDCL	16
HPS(EGCB) 412 MW	Existing	412			TGTDCL	68
Meghnaghat IPP 450 MW	Existing	450			TGTDCL	75
Summit Meghn. 335 MW	Existing	335			TGTDCL	55
Tongi (80 MW)	Existing	80			TGTDCL	26
RPCL (210 MW)	Existing	210			TGTDCL	40
Madhabdi (27+10 MW) REB	Existing	37			TGTDCL	9
Ashulia (24+10 MW) REB	Existing	34			TGTDCL	10
Doreen Tangail 22 MW SIPP	Existing	22			TGTDCL	5
Doreen Narsingdi 22 MW SIPP	Existing	22			TGTDCL	5
Maona 33 MW SIPP	Existing	33			TGTDCL	8
Rupganj 33 MW SIPP	Existing	33			TGTDCL	8
EGCB Shiddhirgonj 335 MW	Existing	335			TGTDCL	55
HPL (360 MW)	Existing	360			TGTDCL	55
Regent 108 MW	Existing	108			TGTDCL	27
Ashuganj 648 MW*	Existing	648			BGDCL	
Ashuganj 55 MW rental	Existing	55			BGDCL	192

Power plant	Existing/Upcoming year	Installed capacity (MW)	Pipeline	Pipeline completion year	Company	Max. demand
Ashuganj 53 MW rental	Existing	53			BGDCL	
Ashuganj -80 MW Rent	Existing	80			BGDCL	20
Ashuganj 225MW	Existing	225			BGDCL	40
Ashuganj 200 MW Modular	Existing	200			BGDCL	40
APS 450 MW CCPP S	Existing	450			BGDCL	62
APS 450 MW CCPP N	Existing	450			BGDCL	62
B-baria 70 MW rental	Existing	70			BGDCL	24
Feni-22 MW SIPP	Existing	22			BGDCL	5
Mohipal-11 MW SIPP	Existing	11			BGDCL	3
Jangalia-33 MW SIPP	Existing	33			BGDCL	8
Chandpur 150 MW CCPP	Existing	150			BGDCL	27
Comilla REB 24 MW	Existing	24			BGDCL	6
Midland Power 51 MW	Existing	51			BGDCL	12
Raozan (2x210) MW	Existing	420			KGDCL	95
Sikalbaha (40 MW)	Existing	40			KGDCL	12
Sikalbaha (225+150+65) MW	Existing	440			KGDCL	73
Barabkunda 22 MW SIPP	Existing	22			KGDCL	5
Shahjibazar 2x30 MW	Existing	60			JGTDSL	18
S.Bazar 3 yrs rental 50 MW	Existing	50			JGTDSL	12
S.Bazar 15 yrs rent 86 MW	Existing	86			JGTDSL	20
S.Bazar 330 MW	Existing	330			JGTDSL	47
S.Bazar 100 MW	Existing	100			JGTDSL	18
Fenchuganj CC1 90 MW	Existing	90			JGTDSL	17
Fenchuganj CC2 105 MW	Existing	105			JGTDSL	18
Kumargaon 20 MW	Existing	20			JGTDSL	2
K.gaon 3 yrs rent 50 MW	Existing	50			JGTDSL	12
K.gaon 15 yrs rent 10 MW	Existing	10			JGTDSL	3
K gaon 142 MW CCPP	Existing	142			JGTDSL	36
Habiganj 11 MW SIPP	Existing	11			JGTDSL	3
F.ganj 15 yrs rent 51 MW	Existing	51			JGTDSL	13
F.ganj 3 yrs rent 50 MW	Existing	50			JGTDSL	10
Shahjahanullah pgcl Rent	Existing				JGTDSL	5
Bibiyana-2 341 MW	Existing	341			JGTDSL	50
Bibiyana-3 400 MW	Existing	400			JGTDSL	40
Bibiyana-S,400 MW,PDB	Existing	400			JGTDSL	43
Khushiyara 163 MW	Existing	163			JGTDSL	28

Power plant	Existing/Upcoming year	Installed capacity (MW)	Pipeline	Pipeline completion year	Company	Max. demand
Baghabari (100+71 MW)	Existing	171			PGCL	50
Bogra 15 yrs rent (20 MW)	Existing	20			PGCL	5
Ullapara 11 MW SIPP	Existing	11			PGCL	3
Bogra 3 yrs rent (20 MW)	Existing	20			PGCL	5
NWPGCL Unit -1	Existing				PGCL	38
NWPGCL Unit -2	Existing				PGCL	38
NWPGCL Unit -3	Existing				PGCL	38
NWPGCL Unit -4	Existing				PGCL	70
Bhola 3 yrs rent 34.5 MW	Existing	34.5			SGCL	10
Bhola 225 MW	Existing	225			SGCL	35
Bheramara 360MW	Existing	360			SGCL	65
Aggreko 95MW	Existing	95			SGCL	26
NBBL220MW	Existing	220			SGCL	38
Ashuganj CCPP (East)	2021	400	Ashuganj-Bakhrabad Pipeline	Existing		
Khulna CCPP	2021	336	Bheramara-Khulna Pipeline	Existing		
Meghnaghat (Summit)	2022	583	Bakhrabad-Siddhirganj Pipeline	Existing		
Meghnaghat CCPP (Unique)	2022	584	Bakhrabad-Siddhirganj Pipeline	Existing		
Mymensingh	2022	360	Dhonua-Mymensingh Pipeline	Existing		
Raozan	2022	450	Chattogram-Raozan Pipeline	Existing		
Reliance CCPP Meghnaghat	2022	718	Bakhrabad-Siddhirganj Pipeline	Existing		
Haripur CCPP	2023	250	Bakhrabad-Siddhirganj Pipeline	Existing		
Meghnaghat (unlima)	2023	450	Bakhrabad-Siddhirganj Pipeline	Existing		
Rupsa CCPP	2023	880	Langalbandh-Mawa-Gopalganj-Khulna Transmission Pipeline	2021		
Anowara CCPP (United)	2024	590	Anowara-Fouzdarhat Pipeline	Existing		
Payra RLNG Power Plant	2024	1200	RLNG Terminal Payra port	2022		
Ghorasal 225 MW	2025	225	Narshingdi-Ghorasal Pipeline	Existing		
Siddirganj	2025	550	Bakhrabad-Siddhirganj Pipeline	Existing		

Table 172 Gas-based power generation scenarios in the most plausible case

Financial year	Total consumption	Gas-based power generation % Scenario 1	Gas-based generation (MU)	Gas-based power generation % Scenario 2	Gas-based generation (MU)	Gas-based power generation % Scenario 3	Gas-based generation (MU)
FY20	71419	70.0%	49993	70.0%	49993	70.0%	49993
FY21	75347	67.5%	50859	68.8%	53520	70.0%	52743
FY22	79491	64.0%	50874	67.5%	57276	70.0%	55644
FY23	83863	60.5%	50737	66.3%	61274	70.0%	58704
FY24	88476	57.0%	50431	65.0%	65529	70.0%	61933
FY25	93342	53.5%	49938	63.8%	70053	70.0%	65339
FY26	98476	50.0%	49238	62.5%	74861	70.0%	68933
FY27	103892	46.5%	48310	61.3%	79966	70.0%	72724
FY28	109606	43.0%	47130	60.0%	85384	70.0%	76724
FY29	115634	39.5%	45675	58.8%	91130	70.0%	80944
FY30	121994	35.0%	42698	57.5%	97218	70.0%	85396

Financial year	Total consumption	Gas-based power generation % Scenario 1	Gas-based generation (MU)	Gas-based power generation % Scenario 2	Gas-based generation (MU)	Gas-based power generation % Scenario 3	Gas-based generation (MU)
FY31	128704	33.5%	43116	56.3%	100811	70.0%	90093
FY32	135782	32.0%	43450	55.0%	104485	70.0%	95048
FY33	143250	30.5%	43691	53.8%	108237	70.0%	100275
FY34	151129	29.0%	43827	52.5%	112063	70.0%	105790
FY35	159441	27.5%	43846	51.3%	115958	70.0%	111609
FY36	168211	26.0%	43735	50.0%	119918	70.0%	117747
FY37	177462	24.5%	43478	48.8%	123935	70.0%	124223
FY38	187222	23.0%	43061	47.5%	128003	70.0%	131056
FY39	197520	21.5%	42467	46.3%	132112	70.0%	138264
FY40	208383	20.0%	41677	45.0%	136254	70.0%	145868

17.3.3 Existing domestic production

Table 173 Gas Fields in Bangladesh

Serial no.	Name of the field	Cumulative production (until December 2019)	Remaining reserve w.r.t 2P (1 Jan 2020) (in bcf)
1	Titas	4786.5	1580.5
2	Habiganj	2506.8	140.2
3	Bakhrabad	840.5	391
4	Kailashtilla	715.7	2044.3
5	Rashidpur	642.6	1790.4
6	Sylhet/Haripur	216.6	102.3
7	Meghna	74	Reserve Re-evaluation in process
8	Narshingdi	210.4	66.4
9	Beani Bazar	105.4	97.6
10	Fenchuganj	161.2	219.9
11	Shaldanadi	92.2	186.8
12	Shahbazpur	77.4	565.3
13	Semutang	13.3	304.4
14	Sundalpur Shahzadpur	14.7	20.4
15	Srikail	92.7	68.3
16	Begumganj	3.6	66.4
17	Jalalabad	1356.7	Reserve Re-evaluation in process
18	Moulavi Bazar	327.1	100.9
19	Bibiyana	4075	1680.4
20	Bangura	457	65
	Total	**16769.5**	**9490.3**

Source: Petrobangla Annual Report

17.4 Nepal

17.4.1 Bottom-up approach

Table 174 Historical GDP of Nepal and projections of GDP until FY 2040

Year	GDP (NPR billion)	GDP growth rate (5 year CAGR)
2015	1,862	4.0%
2016	1,870	0.4%
2017	2,038	9.0%
2018	2,194	7.6%
2019	2,340	6.7%
2020	2,296	-1.9%
2021	2,362	2.9%
2022	2,462	4.2%
2023	2,610	6.0%
2024	2,750	5.4%
2025	2,892	5.2%
2026	3,042	5.2%
2027	3,199	5.2%
2028	3,365	5.2%
2029	3,540	5.2%
2030	3,724	5.2%
2031	3,917	5.2%
2032	4,120	5.2%
2033	4,334	5.2%
2034	4,559	5.2%
2035	4,795	5.2%
2036	5,044	5.2%
2037	5,305	5.2%
2038	5,581	5.2%

Year	GDP (NPR billion)	GDP growth rate (5 year CAGR)
2039	5,870	5.2%
2040	6,175	5.2%

Note –

1. GDP at constant prices.
2. Source – IMF World Economic Outlook 2021 for GDP projections until 2026

Table 175 Consumption data of Nepal and projections until FY 2040

Year	Scenario – 1 (Considering historical consumption data and forecasting at a reducing CAGR)			Scenario – 2 (Considering correlation of consumption with GDP)		
	Petrol (in KL)	Diesel (in KL)	LPG (in MT)	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2015	283567	901393	258299	283567	901393	258299
2016	238578	782451	214194	238578	782451	214194
2017	402278	1297066	312928	402278	1297066	312928
2018	484781	1597551	370560	484781	1597551	370560
2019	562866	1702157	429609	562866	1702157	429609
2020	507786	1453592	449063	507786	1453592	449063
2021	570539.5	1599367	501584.6	573097.4	1732347	454326.2
2022	641048.3	1759762	560249	633765.7	1900663	498071.9
2023	720270.7	1936242	625774.7	724198	2151556	563279.3
2024	809283.6	2130420	698964.2	809880	2389270	625061.5
2025	909297	2344072	780713.7	896348.7	2629166	687410.9
2026	1000227	2579150	872024.6	987512.7	2882089	753145.9
2027	1100249	2837803	974015	1083729	3149028	822523.7
2028	1210274	3122395	1087934	1184935	3429813	895500.2
2029	1331302	3435528	1215177	1291392	3725164	972262.4
2030	1464432	3780064	1357302	1403371	4035837	1053007
2031	1581586	4082470	1465886	1521159	4362624	1137939
2032	1708113	4409067	1583157	1645057	4706364	1227278
2033	1844762	4761793	1709809	1775383	5067934	1321250
2034	1992343	5142736	1846594	1912468	5448261	1420098
2035	2151731	5554155	1994321	2056665	5848316	1524073
2036	2323869	5998487	2153867	2208342	6269124	1633441
2037	2509779	6478366	2326176	2367886	6711761	1748483
2038	2710561	6996636	2512271	2535707	7177359	1869493
2039	2927406	7556366	2713252	2712234	7667109	1996780

Year	Scenario – 1 (Considering historical consumption data and forecasting at a reducing CAGR)			Scenario – 2 (Considering correlation of consumption with GDP)		
	Petrol (in KL)	Diesel (in KL)	LPG (in MT)	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2040	3161599	8160876	2930312	2897918	8182265	2130669

17.5 Sri Lanka

17.5.1 Top-down approach

Table 176 Historical GDP of Sri Lanka and projections by five-year and seven-year CAGR

Year	GDP (SLR billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (SLR billion) – Scenario 2	GDP growth rate (7 year CAGR)
2015	8,648	4.8%	8,648	4.8%
2016	9,036	4.3%	9,036	4.3%
2017	9,359	3.5%	9,359	3.5%
2018	9,665	3.2%	9,665	3.2%
2019	9,883	2.2%	9,883	2.2%
2020	9,531	-3.7%	9,531	-3.7%
2021	9,912	3.9%	9,912	3.9%
2022	10,319	3.9%	10,319	3.9%
2023	10,742	3.9%	10,742	3.9%
2024	11,189	4.0%	11,189	4.0%
2025	11,654	4.0%	11,654	4.0%
2026	12,139	4.0%	12,139	4.0%
2027	12,641	4.1%	12,500	4.1%
2028	13,163	4.1%	12,873	4.1%
2029	13,708	4.1%	13,256	4.1%
2030	14,274	4.1%	13,651	4.1%
2031	14,865	4.1%	14,058	4.1%
2032	15,479	4.1%	14,477	4.1%
2033	16,120	4.1%	14,908	4.1%
2034	16,786	4.1%	15,353	4.1%

Year	GDP (SLR billion) – Scenario 1	GDP growth rate (5 year CAGR)	GDP (SLR billion) – Scenario 2	GDP growth rate (7 year CAGR)
2035	17,480	4.1%	15,810	4.1%
2036	18,203	4.1%	16,281	4.1%
2037	18,956	4.1%	16,766	4.1%
2038	19,740	4.1%	17,266	4.1%
2039	20,556	4.1%	17,780	4.1%
2040	21,406	4.1%	18,310	4.1%

17.5.2 Bottom-up approach

Table 177 Upcoming gas-based power plants in Sri Lanka

Upcoming gas-based power plants in Sri Lanka	Capacity	Year
1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region	300 MW	2021
1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region	300 MW	2021
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2022
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2024
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2025
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2032
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2033
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2034
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2035
1x300 MW Natural Gas fired Combined Cycle Power Plant	300 MW	2037
3x35 MW Gas Turbine operating on Natural Gas	105 MW	2021
Sojitz Kelantissa Conversion to Gas Based Power Plant	163 MW	2023
Sojitz Kelantissa Gas Based Power Plant Retirement	163 MW	2033
1x300 MW West Coast Combined Cycle Power Plant Retirement	300 MW	2035

17.6 Afghanistan

17.6.1 Bottom-up approach

Table 178 Upcoming power plants in Afghanistan

Upcoming power plants	Capacity	Expected year of completion
Mazar Gas Power Plant	58.5	2021
Sherberghan Gas Power Plant Phase 1	41	2025
Sherberghan Gas Power Plant Phase 2	159	2025

17.7 Bhutan

17.7.1 Bottom-up approach

Table 179 Historical GDP of Bhutan and projections of GDP until FY 2040

Year	GDP (Nu billion)	GDP growth rate (5 year CAGR)
2015	57	6.2%
2016	61	7.4%
2017	65	6.3%
2018	67	3.8%
2019	70	4.3%
2020	69	-0.8%
2021	68	-1.9%
2022	72	5.7%
2023	76	5.6%
2024	82	7.6%
2025	86	5.8%
2026	91	5.8%
2027	97	6.1%
2028	103	6.1%
2029	109	6.1%
2030	116	6.1%
2031	123	6.1%
2032	130	6.1%
2033	138	6.1%
2034	147	6.1%
2035	156	6.1%
2036	165	6.1%
2037	175	6.1%
2038	186	6.1%

Year	GDP (Nu billion)	GDP growth rate (5 year CAGR)
2039	197	6.1%
2040	209	6.1%

Note –

1. GDP at constant prices.
2. Source – IMF World Economic Outlook 2021 for GDP projections until 2026

Table 180 Consumption data of Bhutan and projections until FY 2040

Year	Scenario – 1 (Considering historical consumption data and forecasting at a reducing CAGR)			Scenario – 2 (Considering correlation of consumption with GDP)		
	Petrol (in KL)	Diesel (in KL)	LPG (in MT)	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2015	33846.6	126139.4	7289.7	33846.6	126139.4	7289.7
2016	36214.8	133851.3	7593.3	36214.8	133851.3	7593.3
2017	39119.5	144620.7	8078.9	39119.5	144620.7	8078.9
2018	46912.3	159722.5	9442.5	46912.3	159722.5	9442.5
2019	50958.5	154616.6	10198.1	50958.5	154616.6	10198.1
2020	56447.2	162688.7	11091.1	48745.2	157779.6	9766.7
2021	62091.9	171182.3	11978.4	46999.9	154450.9	9470.1
2022	68301.1	180119.2	12936.6	52064.9	164111.1	10330.7
2023	75131.2	189522.8	13971.6	57359.8	174210.0	11230.2
2024	82644.3	199417.3	15089.3	64961.2	188707.8	12521.7
2025	89255.8	209828.3	16296.4	71181.3	200571.2	13578.4
2026	96396.3	220782.9	17600.2	77761.5	213121.5	14696.4
2027	104108.0	232309.4	19008.2	85083.2	227085.8	15940.3
2028	112436.7	244437.6	20528.8	92851.1	241901.2	17260.0
2029	121431.6	257199.1	22171.1	101092.5	257619.8	18660.2
2030	127503.2	270626.8	23279.7	109836.2	274296.4	20145.7
2031	133878.3	284158.1	24443.7	119112.9	291989.4	21721.7
2032	140572.2	298366.0	25665.8	128955.0	310761.0	23393.8

Year	Scenario – I (Considering historical consumption data and forecasting at a reducing CAGR)			Scenario – 2 (Considering correlation of consumption with GDP)		
	Petrol (in KL)	Diesel (in KL)	LPG (in MT)	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2033	147600.8	313284.3	26949.1	139397.0	330676.7	25167.9
2034	154980.9	328948.5	28296.6	150475.5	351806.3	27050.1
2035	162729.9	345396.0	29711.4	162229.3	374223.8	29047.0
2036	170866.4	362665.7	31197.0	174699.4	398007.8	31165.6
2037	179409.8	380799.0	32756.8	187929.7	423241.4	33413.3
2038	188380.2	399839.0	34394.7	201966.4	450013.1	35798.1
2039	197799.3	419830.9	36114.4	216858.7	478416.7	38328.2
2040	207689.2	440822.5	37920.1	232658.7	508551.5	41012.5

17.8 Maldives

17.8.1 Bottom-up approach

Table 181 Historical GDP of Maldives and projections of GDP until FY 2040

Year	GDP (US$ billion)	GDP growth rate (7 year CAGR)
2015	4.11	11.1%
2016	4.38	6.6%
2017	4.75	8.4%
2018	5.30	11.6%
2019	5.64	6.4%
2020	4.03	-28.5%
2021	4.15	2.90%
2022	4.27	2.90%
2023	4.39	2.90%
2024	4.52	2.90%
2025	4.65	2.90%
2026	4.78	2.90%
2027	4.92	2.90%
2028	5.06	2.90%
2029	5.21	2.90%
2030	5.36	2.90%
2031	5.52	2.90%
2032	5.68	2.90%
2033	5.84	2.90%
2034	6.01	2.90%
2035	6.18	2.90%
2036	6.36	2.90%
2037	6.55	2.90%
2038	6.74	2.90%

Year	GDP (US$ billion)	GDP growth rate (7 year CAGR)
2039	6.93	2.90%
2040	7.13	2.90%

Note –

1. GDP at constant prices.
2. Source – https://bit.ly/2WUpwhi

Table 182 Consumption data of Maldives and projections until FY 2040

Year	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2015	31429.2	389967.7	13601.8
2016	47794.1	445035.6	13651.4
2017	57729.8	447555.5	14899.7
2018	68648.7	521597.9	15008.9
2019	84722.7	578994.3	17072.2
2020	63969.5	563027.0	13171.4
2021	70366.5	621499.3	13830.0
2022	77403.1	686044.1	14521.5
2023	85143.4	757292.2	15247.5
2024	93657.8	835939.6	16009.9
2025	101150.4	922754.8	16810.4
2026	109242.4	1018586.1	17650.9
2027	117981.8	1124369.8	18533.5
2028	127420.4	1241139.5	19460.1
2029	137614.0	1370036.1	20433.2
2030	144494.7	1512319.1	21454.8
2031	151719.4	1587935.1	22527.5
2032	159305.4	1667331.8	23653.9
2033	167270.7	1750698.4	24836.6

Year	Petrol (in KL)	Diesel (in KL)	LPG (in MT)
2034	175634.2	1838233.3	26078.5
2035	184415.9	1930145.0	27382.4
2036	193636.7	2026652.2	28751.5
2037	203318.6	2127984.8	30189.1
2038	213484.5	2234384.1	31698.5
2039	224158.7	2346103.3	33283.5
2040	235366.6	2463408.5	34947.6

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

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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:

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