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Market study for identification of gas based generating assets for peak power supply.

WEC India

July 2025

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Abbreviations

Abbreviation	Full form
2D	2-Dimensional
3D	3-Dimensional
3X	3 times
AP	Andhra Pradesh
APGDC	Andhra Pradesh Gas Distribution Corporation
APM	Administered Pricing Mechanism
Approx.	Approximately
AS	Ancillary Services
BCD	Basic Customs Duty
BEE	Bureau of Energy Efficiency
BESS	Battery Energy Storage System
BOG	Boil-Off Gas
BPCL	Bharat Petroleum Corporation Limited
C&I	Commercial and Industrial
CAPEX	Capital Expenditure
CBM	Coal Bed Methane
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
C-form	Concessional Form (used for inter-state sales under CST Act)
CGD	City Gas Distribution
CNG	Compressed Natural Gas
CNG (T)	Compressed Natural Gas (Transport)
COG	Cost of Generation (in INR/kWh)
CSS	Cross Subsidy Surcharge
CTU	Central Transmission Utility
CUF	Capacity Utilization Factor
D1-D6	Gas fields in Krishna-Godavari Basin (KG-D6 Block)
DAE	Department of Atomic Energy
DAM	Day Ahead Market
DEEP	Discovery of Efficient Electricity Price
DES	Delivered Ex Ship
DGH	Directorate General of Hydrocarbons
DISCOM	Distribution Company
DSF	Discovered Small Fields
DTTILLP	Deloitte Touché Tohmatsu India LLP
E&P	Exploration and Production
e-bid	Electronic Bidding
EEZ	Exclusive Economic Zone
EoI	Expression of Interest
ESCOM	Electricity Supply Company

Abbreviation	Full form
ESO	Energy Storage Obligation
ESS	Energy Storage System
FC	Fixed Charges
FDRE	Federal Democratic Republic of Ethiopia
FGD	Flue Gas Desulphurization
FM	Force Majeure
FY	Financial Year
GAIL	Gas Authority of India Limited
GAs	Geographical Areas
GBS	Gross Budgetary Support
GCV	Gross Calorific Value
GIGL	GSPL India Gasnet Limited
GoI	Government of India
GSPC	Gujarat State Petroleum Corporation
GSPL	Gujarat State Petronet Limited
GST	Goods and Services Tax
GW	Gigawatt
GWh	Gigawatt-hour
HELP	Hydrocarbon Exploration and Licensing Policy
HPCL	Hindustan Petroleum Corporation Limited
HPDAM	High Price Day Ahead Market
HPHT	High Pressure High Temperature
HPPL	Hazira Pipeline Pvt Ltd
HT	High Tension
IDC	Interest During Construction
IEX	Indian Energy Exchange
IGGL	Indradhanush Gas Grid Limited
INR	Indian Rupee
IOCL	Indian Oil Corporation Limited
IPP	Independent Power Producer
ISTS	Inter-State Transmission System
JKM	Japan Korea Marker
JV	Joint Venture
kcal	Kilocalorie
KG	Krishna-Godavari
KM	Kilometer
kVA	Kilovolt-Ampere
kWh	Kilowatt-hour
LCOE	Levelized Cost of Electricity
LKm	Line Kilometer
LNG	Liquefied Natural Gas

Abbreviation	Full form
MA	Marketing Authorization (under PNGRB guidelines)
MBAS	Market-Based Ancillary Services (used in DSF or OALP rounds by DGH)
MJ	Megajoule
MM	Million
MMBTU	Million British Thermal Units
MMSCM	Million Standard Cubic Meters
MMSCMD	Million Standard Cubic Meters per Day
Mn	Million
MNRE	Ministry of New and Renewable Energy
MoP	Ministry of Power
MoPNG	Ministry of Petroleum and Natural Gas
MU	Million Units
MW	Megawatt
MWP	Megawatt Peak
NDR	National Data Repository
NELP	New Exploration Licensing Policy
NEP	National Electricity Plan
NG	Natural Gas
NHPC	National Hydroelectric Power Corporation
NOC	No Objection Certificate
NPA	Non-Performing Asset
OA	Open Access
OAL	Open Access Licensee
OALP	Open Acreage Licensing Policy
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation
PCRA	Petroleum Conservation Research Association
PHS	Pumped Hydro Storage
PIL	Pipeline Infrastructure Limited
PLF	Plant Load Factor
PMT	Panna-Mukta-Tapti
PNG	Piped Natural Gas
PNG (D)	Piped Natural Gas (Domestic)
PNGRB	Petroleum and Natural Gas Regulatory Board
PPA	Power Purchase Agreement
PPAC	Petroleum Planning and Analysis Cell
PSC	Production Sharing Contract
PSP	Pumped Storage Project
PSU	Public Sector Undertaking
PVT	Private
Pvt.	Private

Abbreviation	Full form
RE	Renewable Energy
RE+ESS	Renewable Energy plus Energy Storage System
REIA	Renewable Energy Implementation Agency
RIL	Reliance Industries Limited
RLNG	Regasified Liquefied Natural Gas
RPO	Renewable Purchase Obligation
RSC	Resource Scheduling Centre
RTC	Round-the-Clock
RTM	Real-Time Market
RUVITL	Rajasthan Urja Vikas IT Ltd
RUVNL	Rajasthan Urja Vikas Nigam Limited
SCM	Standard Cubic Meter
SECI	Solar Energy Corporation of India
SERC	State Electricity Regulatory Commission
SHR	Station Heat Rate
SPV	Special Purpose Vehicle
Sqkm	Square Kilometer
STU	State Transmission Utility
TBCB	Tariff-Based Competitive Bidding
TE	Technical Evaluation (used in bid/tender processes)
ToD	Time of Day
TPP	Thermal Power Plant
UFT	Unscheduled Flow Transmission
UK	Uttarakhand / United Kingdom (context dependent)
UN	United Nations
UOM	Unit of Measurement
US	United States
USD	United States Dollar
VAT	Value Added Tax
VC	Variable Cost
w.e.f	With Effect From
WEC	World Energy Council

1 Executive Summary

India's natural gas sector has undergone significant fluctuations in recent years, marked by phases of sharp decline and subsequent resurgence. Following a notable dip in consumption during the global energy crisis of 2022, gas demand in India rebounded strongly, culminating in record-high consumption in FY2024–25. This growth signals a pivotal moment for the sector and presents an opportunity to reposition natural gas as a key component of India's energy transition.

This report examines the critical role of natural gas in supporting India's energy transition and evaluates pathways to achieve the Government of India's target of increasing the share of natural gas to 15% in the overall energy mix by 2030[1]. With the current share standing at approximately 7%, meeting this ambitious goal will require a coordinated approach involving infrastructure expansion, policy and regulatory reforms, improved fuel accessibility for power and industrial sectors, and enhanced investment in both domestic production and LNG sourcing. The report places particular emphasis on the gas-to-power (G2P) segment as a key enabler in this transition, given its ability to provide flexible, quick-response generation to support grid stability alongside growing renewable energy penetration.

The projected growth in the G2P sector is underpinned by multiple factors, including ongoing infrastructure expansion, modest recovery in domestic production, policy interventions such as Section 11 mandates for peak demand management, and the expiry of legacy LNG contracts creating room for flexible long-term sourcing. However, despite these positive developments, the sector continues to face significant challenges. Domestic production, though improving (notably from KG-D6 and ONGC basins), remains insufficient to meet demand, leading to over 50% reliance on pricier imported LNG—exposing power plants to international price volatility. Reforms such as the Revised Domestic Gas Pricing Guidelines (2023) and the Unified Tariff Policy have stabilized pricing to some extent, while mechanisms like quarterly pooling ensure continuity for critical sectors like CGD.

In FY2024–25, the CGD sector accounted for ~29% of domestic gas allocation, followed by the power sector at ~18%. LNG imports, meanwhile, were primarily consumed by the fertilizer sector (~49%), with power plants accounting for a relatively small share (~8%). Gas-based power generation remains underutilized, with an installed capacity of ~20 GW (*down from 24GW to 20.132 GW effectively operating as of July 2025*[2]), yet only 31,580 MUs were generated during FY2024–25, resulting in a low PLF of 14.47%. A significant portion of this capacity—14.3 GW—is classified as stranded, primarily in the private sector (9.6 GW), concentrated in states like Gujarat

[1] PIB Press Release
[2] CEA Installed Capacity June 2025

and Andhra Pradesh. These assets, commissioned largely between 2005 and 2015, were originally aligned with KG-D6 gas sourcing but now face operational uncertainty due to supply constraints.

Nevertheless, renewed policy attention, rising renewable penetration[3] (~220 GW), and the urgent need for flexible peaking capacity are reviving interest in gas as a transition fuel. Compared to emerging storage solutions like BESS and PSP, gas-based assets offer competitive advantages in terms of lower capital expenditure (INR 45–50 Mn/MW), faster deployment timelines (6–12 months for reviving stranded gas assets), and flexible ramp-up times—making them ideal for bridging peak power deficits. Recent interventions, such as the April 2024 Section 11 directive, temporarily boosted PLFs to 38%, demonstrating the untapped potential of gas plants in peak demand scenarios.

Key technical and commercial analyses presented in the report include:

- IEX Price Band Analysis, determining the domestic gas price needed to match traded electricity prices.
- Peak Power Demand Assessment, which evaluates the role of gas plants in balancing load during non-solar hours.
- Asset Shortlisting Framework, based on techno-commercial and locational criteria.

A financial model was developed to optimize asset utilization while ensuring zero net profit/loss over five years. The analysis shows that gas-based assets could serve as a viable alternative to energy storage systems, particularly over the next 4–5 years.

To realize the government's vision of 15% gas share in India's energy mix by 2030, the report outlines a comprehensive set of recommendations, categorized into short-, medium-, and long-term measures. These include demand aggregation, flexible RTC models, exemption of ISTS charges for gas-based plants, supply chain transparency, and a strategic gas contracting strategy. A central recommendation is the establishment of a dedicated Single Planning Agency (or SPV) to coordinate planning, fuel supply, dispatch, and market access, ensuring integrated development of gas-based assets.

Following is the snapshot of recommendations for improving the utilization of stranded gas-based assets in the G2P sector divided into

- Wave-0: Short term measures (potential time for implementation 0-6 months)
- Wave-1: Medium term measures (potential time for implementation 6-12 months)
- Wave-2: Long term measures (potential time for implementation >1 year)

[3] PIB Press release July 2025

Category	Recommendations	Wave-0	Wave-1	Wave-2
Demand side	Minimum Gas offtake	Y		
Supply side	Transparency in gas pipeline capacity booking & utilization	Y		
Supply side	Coordination between power scheduling, gas trading agencies & gas plants	Y		
Supply side	Supply diversity in IGX trading	Y		
Demand side	Gas demand aggregation		Y	
Demand side	RTC power from gas-based assets and Gas Purchase Obligations		Y	
Gas Pricing	Exemption ISTS charges and introduction of environmental cess on coal-based generation		Y	
Supply side	Pipeline infrastructure access		Y	
Supply side	Re-invent PSDF 2015-17 like schemes and Revival of RLNG e-Bid Reverse Auction		Y	
Demand side	Ancillary service revenue and accelerating fuel switching measures			Y
Gas Pricing	LNG Contracting strategy			Y
Gas Pricing	Double taxation issue and GST taxation regime			Y
Supply side	Unbundling transport and sales & marketing operations			Y
Supply side	Securing Gas supply- strategic gas storage reserves, SHR based domestic gas allocation			Y

The strategic implementation of these measures will be critical in unlocking the full potential of gas-based power generation in India, enabling it to act as a reliable bridge fuel in the transition to a cleaner, more resilient energy future.

2 Engagement Context

2.1 About World Energy Council

World Energy Council (WEC) is a global forum for thought leadership and tangible engagement with the mission *'To promote the sustainable supply of and use of energy for the greatest benefit of all people'*. Formed in 1923, the council is the UN-accredited global energy body, representing the entire energy spectrum with more than 3000 member organizations located in over 90 countries. WEC hosts the World Energy Congress, which is the world's largest and most influential energy event covering all aspects of the energy agenda. It informs global, regional and national energy strategies by hosting high-level events, publishing authoritative studies, and working through its extensive member network to facilitate the world's energy policy dialogue.

World Energy Council India (WEC-India) is a country member of the WEC, a global and inclusive body in the pursuit of sustainable energy. WEC-India functions under the patronage of Ministry of Power and has support of Ministries of coal, MNRE, P&NG and external affairs. DAE, CEA, DGH, PCRA, BEE and leading energy PSUs are among its esteemed members.

3 Overview of Gas to Power Market

3.1 Overview of Indian Natural Gas Market

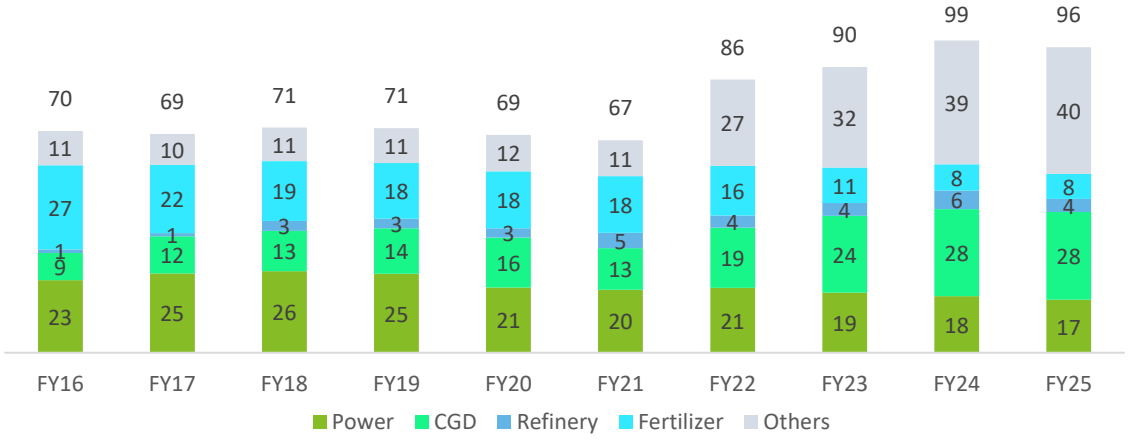
India's natural gas sector is entering a pivotal phase of transformation, backed by an assertive policy vision that aims to elevate its share in the country's energy mix from ~6–7% today to 15% by 2030. According to the International Energy Agency (IEA), domestic gas consumption is projected to rise by nearly 60% to around 103 billion cubic meters annually by 2030—driven by rapid urbanization, industrial expansion, and infrastructure scale-up—while dependence on imported liquefied natural gas (LNG) is expected to more than double to meet demand given modest domestic production growth[4]. This strategic pivot is reinforced by a suite of government initiatives, from expanding the national gas grid and LNG terminals, to broadening City Gas Distribution networks under the 'One Nation, One Gas Grid' strategy, and ongoing market reforms ongoing in gas pricing and marketing that are aimed at enhancing accessibility, affordability, and reliability of gas supply across sectors. By positioning natural gas as a cleaner transition fuel—targeting decarbonization goals and integrating with renewables—India is reshaping its energy future amidst both global climate pressures and domestic growth imperatives

Aligned with this trajectory, the Government of India unveiled ambitious plans in 2016 to elevate the share of natural gas in its primary energy mix from 6.14% (in 2016) to 15% by 2030, aiming to foster a "gas-based economy." Despite a promising start, as of FY24 end, the natural gas share stands at 7.15%[5]. Various steps have been taken by the Government in this direction to reach the 15% target.

3.2 Natural Gas Consumption

Natural gas sectoral consumption can be further divided into 2 categories – Domestic gas supply and LNG import.

Figure 1: Natural Gas sectoral consumption – Domestic supply (MMSCMD)

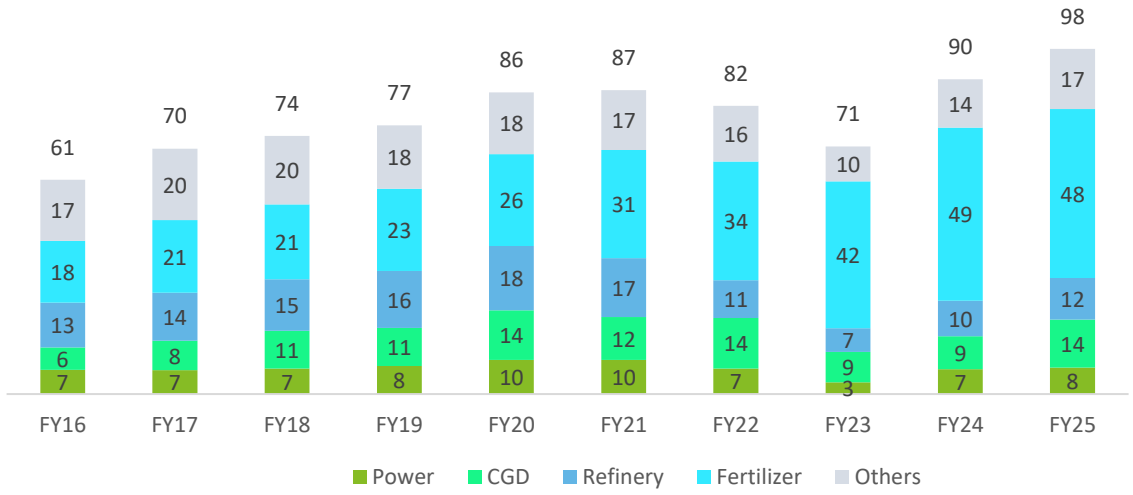


Source: ICED NITI Aayog Dashboard; PPAC Sectoral consumption. Others includes - Agriculture (Tea Plantation), Industrial, Manufacturing, Petrochemical, Misc., etc.

[4] News article Feb-25 (access here)
[5] ICED Portal (access here)

Out of total natural gas consumption from domestic supply in FY25, CGD sector consumed ~29% followed by power sector at ~18%. Even though domestic gas supply is expected to be allocated to CGD sector (transport and domestic segment), it has been used by other sectors as well.

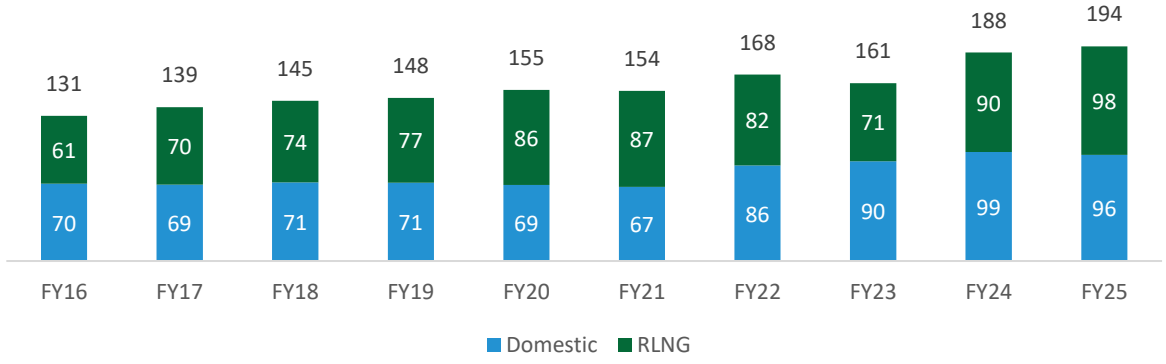
Figure 2: Natural Gas sectoral consumption – LNG Import (MMSCMD)



Source: ICED NITI Aayog Dashboard; PPAC Sectoral consumption
Others includes - Agriculture (Tea Plantation), Industrial, Manufacturing, Petrochemical, Misc., etc.

Out of total natural gas consumption from LNG import in FY25, fertilizer sector consumed ~49%, followed by CGD at ~15%, refinery at ~12%, and power sector at ~8%.

Figure 3: Total consumption of Natural Gas (in MMSCMD)



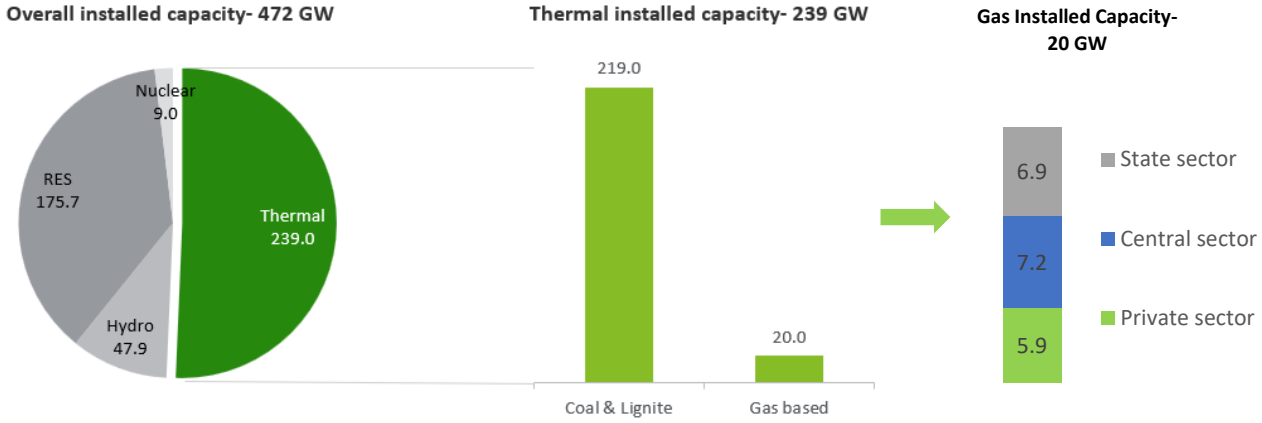
Source: ICED NITI Aayog Dashboard; PPAC Sectoral consumption

So, out of total natural consumption from both domestic supply and LNG import in FY25, fertilizer sector consumed ~29%, followed by CGD at ~22%, power sector at ~13% and refinery at ~8%. Total sectoral consumption of natural gas has seen an upward trend majorly driven by sectors such as CGD and fertilizers – due to demand from fertilizer which has remained strong, CGD sector has benefited from the priority allocation policy, etc.

3.3 Stranded Assets

Out of the total thermal capacity of 239 GW, ~20 GW is gas-based (*recently gas capacity reduced to 20 GW from ~25GW in April 2025*), with the central and states holding the largest share of 7 GW each, and privately-owned facilities accounting for 6 GW.

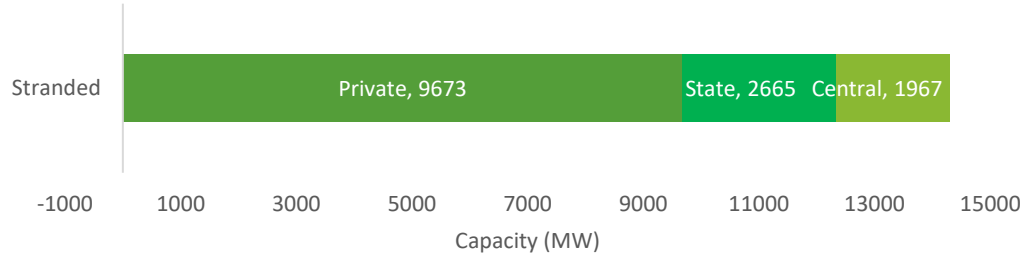
Figure 4: Share of gas in the overall installed capacity.



Source: CEA, MOP

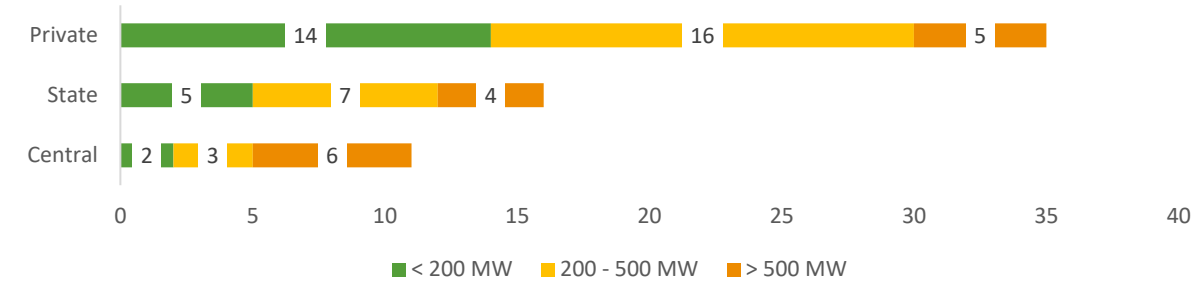
India currently grapples with 14.3 GW of stranded gas assets, primarily due to the unavailability of affordable fuel. Of this, the private sector bears the brunt, with 9.6 GW of capacity, concentrated notably in Andhra Pradesh and Gujarat. Most of these stranded plants were commissioned between 2005 and 2015, aligned with planned fuel sourcing from KG D-6 fields.

Figure 5: Sectoral distribution of 14.3 GW stranded gas power projects.



Source: CEA reports

Figure 6: Capacity split of stranded assets as per CEA List.

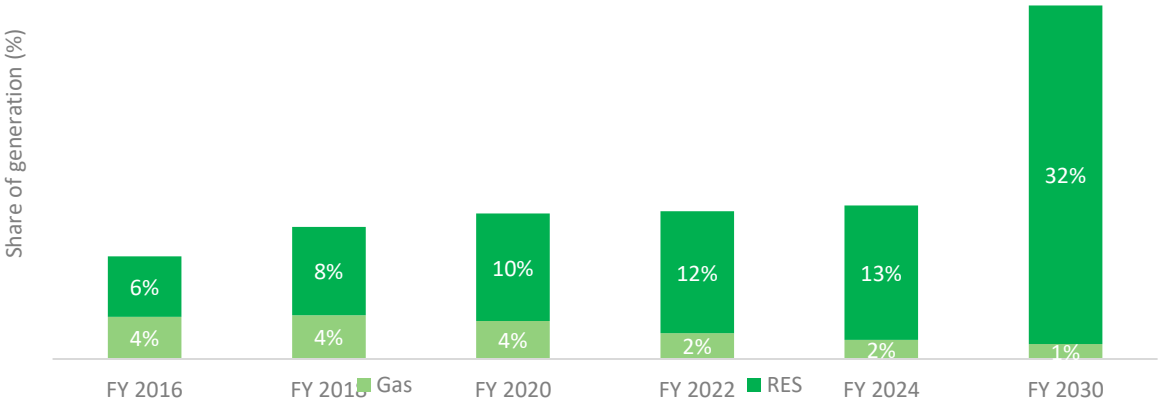


Source: CEA, Lok Sabha Notification on stranded assets 2019 (Link access)

1. *Stranded capacity is considered from list of NPA referred to as "stranded" by MoP, GoI*
2. *Installed capacity data is as of 30th April 2024, CEA report.*

The share of gas in the total generation mix has been on the decline since 2018, with the rapid adoption and advancement of renewable energy sources. As per the CEA report for optimal generation mix, Gas generation would account to 1.4% in total generational mix by FY30.

Figure 7: Share of gas generation in total mix.



Source: NITI Aayog Dashboard

The decline in gas-based power production stems largely from the lack of domestic gas supply. Additionally, the proliferation of coal-based thermal plants and overestimation of electricity demand growth contributed to the gas-based power plants being stranded. Notably, since 2013, the Indian government prioritized allocating domestic gas to the city gas distribution (CGD) sector, leaving gas-based power plants reliant on liquefied natural gas (LNG) imports, rendering them less competitive compared to other fuel-based and renewable energy sources.

Domestic gas, including APM (Administered Price Mechanism), PMT (Panna-Mukta-Tapti), and Non-APM, is distributed to consumers, including power plants, based on allocations by MoPNG, contingent upon availability from upstream suppliers. However, over time, the availability of domestic gas, particularly from upstream sources like ONGC, PMT gas from PMT JV etc., has

dwindled, resulting in a decreased supply to customers, including the power sector. The country's natural gas production has declined, exacerbating the shortfall in gas supplies.

During FY-24, the overall PLF of gas-based plants was ~14% due to less availability of domestic gas and high price of imported RLNG. However, the projects which were able to secure steady gas supply at a subsidized rate from domestic sources were able to maintain more than 55% PLF.

Table 1: Domestic gas supply source can maintain higher PLF%

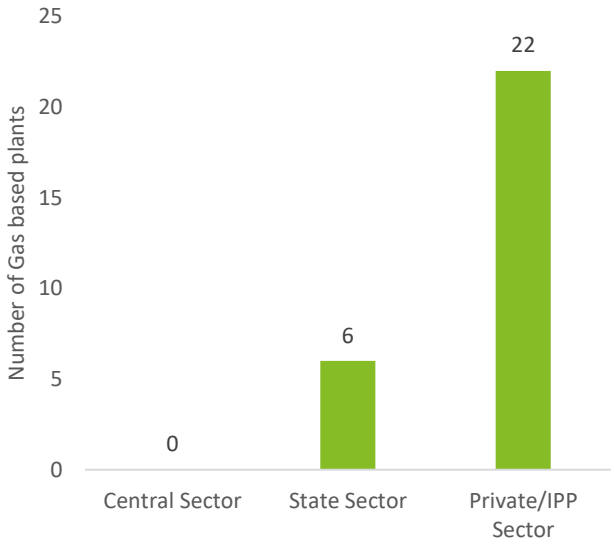
Selected gas plants	Sector	Installed Capacity (in MW)	State	Annual Generation-FY25 (in MU)	Gas supplied/ allocated %	PLF for FY25
MONARCHAK (NEEPCO)	Central	101	Tripura	489.29	92.0%	55.30%
TROMBAY CCPP	Private	180	Maharashtra	1475.20	46%	93.56%
KUTTALAM (TANGEDCO)	State	101	Tamil Nadu	648.85	73.33%	74.0%
KARAIKAL CCPP (PPCL)	State	32.5	Puducherry	204.95	80.0%	71.99%
TRIPURA CCPP (ONGC)	Central	726.6	Tripura	3882.76	99.25%	61.0%
VALUTHUR CCPP	State	186.20	Tamil Nadu	966.92	70%	59.28%
All India Average					**14%**	**14.47%**

Source: NPP Monthly Generation Reports FY25; CEA

The steadily declining availability of domestic natural gas at competitive prices has significantly undermined the viability of gas-based power generation in India. With natural gas production from key domestic sources like ONGC and PMT blocks witnessing a consistent downturn, the power sector has been increasingly deprived of affordable fuel supply. This has led to a sharp fall in plant load factors (PLFs), with gas-based plants operating at an average PLF of only ~14% in FY24, except for a few that managed to secure subsidized domestic gas and maintained PLFs above 55%. The strategic diversion of limited domestic gas toward the CGD sector since 2013 further compounded the issue, pushing power plants toward costlier imported LNG and eroding their competitiveness. Consequently, the role of gas in the power generation mix has plummeted and is projected to drop to a mere 1.4% by FY2030[6], as per the CEA, underscoring the critical need for policy and supply-side interventions to revive the segment. Hence, it can be concluded that availability of domestic gas supply at a competitive price determines the operability of asset.

[6] CEA Optimal Generation Mix Report

Figure 8: Project distribution for Nil generation in FY25.

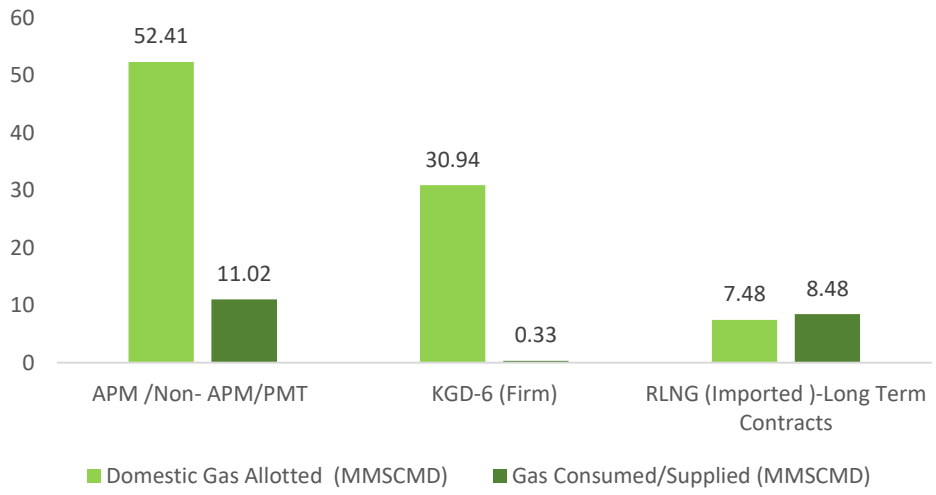


Source: NPP Monthly Generation data FY25, Deloitte Analysis

As per the CEA[7], a total of 28 gas-based power plants recorded zero generation in FY2024–25, representing a combined installed capacity of 9,285 MW. Notably, this figure remains unchanged from FY2023–24[8], when the same number of plants had nil generation. A significant proportion of these non-operational assets—22 out of 28 in FY25—belong to the private sector, with the remaining six attributed to state sector utilities. These projects, predominantly developed by private players and Independent Power Producers (IPPs), continue to face operational challenges due to the lack of firm gas allocation from central agencies and inadequate domestic fuel availability. This persistent underutilization of installed capacity highlights a critical gap in fuel supply planning and indicates a compelling opportunity for targeted investments in both captive and utility-scale gas-based infrastructure, particularly within the private sector. Addressing fuel supply constraints through policy interventions and supply tie-ups could unlock stranded capacity and support a more resilient energy mix.

[7] CEA Fuel Consumption Report 2024 (access here)
[8] PIB press release 2023 (access here)

Figure 9: Allocation vs actual gas consumption by power projects FY-25.



Source: CEA Annual Gas Consumption FY-25

In FY2024–25, of the total 83.35 mmscmd of domestic gas allocated, only 13.6% was consumed by the power sector, indicating a continued reliance on imported RLNG to meet fuel requirements. Power plants utilized approximately 21% of the total APM and non-APM domestic gas reserves, with minimal drawdown from the KG-D6 basin, which accounted for just 0.33 mmscmd. Additionally, RLNG consumption by power plants stood at 8.48 mmscmd—exceeding the allocated quantity of 7.48 mmscmd for the fiscal year. Despite this, the sector's dependence on imported RLNG remains constrained by its higher cost structure, which undermines the commercial viability of gas-based power generation. As a result, imported gas can only play a supplementary role in addressing the domestic supply shortfall, unless appropriate price rationalization or viability gap support mechanisms are introduced.

Table 2: Pipeline and isolated gas plants

Gas allotted and consumption (mmscmd)	Gas grid connected (45 plants)			Isolated fields (17 plants)	
	Domestic	Imported RLNG (Long term)	Imported RLNG (SPOT)	Isolated (Domestic)	Isolated RLNG (Imported)
Gas Allotted	69.574	7.48		13.8	-
Gas consumed/ supply	3.9	3.26	5.22	7.4	-

Source: CEA report on Annual Gas consumption FY25

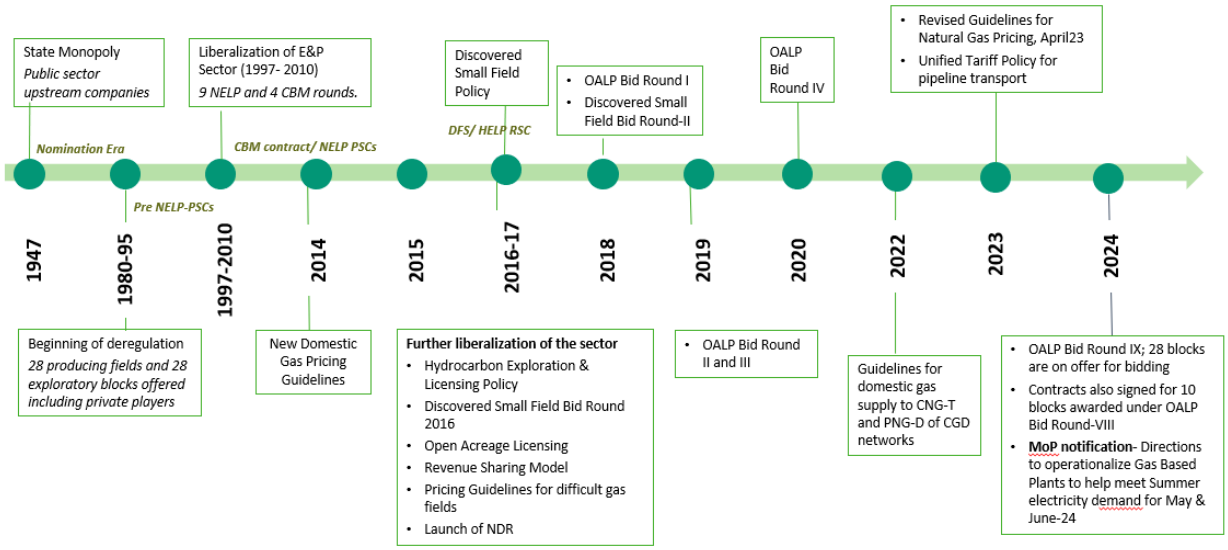
As per the data presented, a stark contrast is observed in the consumption patterns between pipeline-connected and isolated gas-based power plants in FY2024–25. Pipeline-connected plants utilized only 5.6% of their allotted domestic gas, indicating significant underutilization of allocated resources. In contrast, these plants exhibited a disproportionately high dependence on imported RLNG, consuming 8.48 mmscmd—exceeding their allotted 7.48 mmscmd. This over-reliance on imported fuel underscores the challenges posed by the limited availability or

allocation of domestic gas and highlights the commercial pressures resulting from the higher cost of RLNG. Conversely, isolated gas-based power plants—typically located in regions not connected to the national pipeline network—consumed approximately 54% of their domestic gas allocation without any reliance on imported RLNG. This reflects a more balanced and localized use of available domestic resources. The contrasting consumption dynamics underscore the need for a region-specific fuel supply strategy, optimized infrastructure planning, and pricing interventions to improve utilization and reduce dependence on costly imports.

3.4 Government support towards Natural Gas market

The government implemented various policies such as HELP, DSF, Gas pricing guidelines etc. in the last decade to boost domestic production of natural gas. Below are the notable government interventions and schemes issued in recent past years.

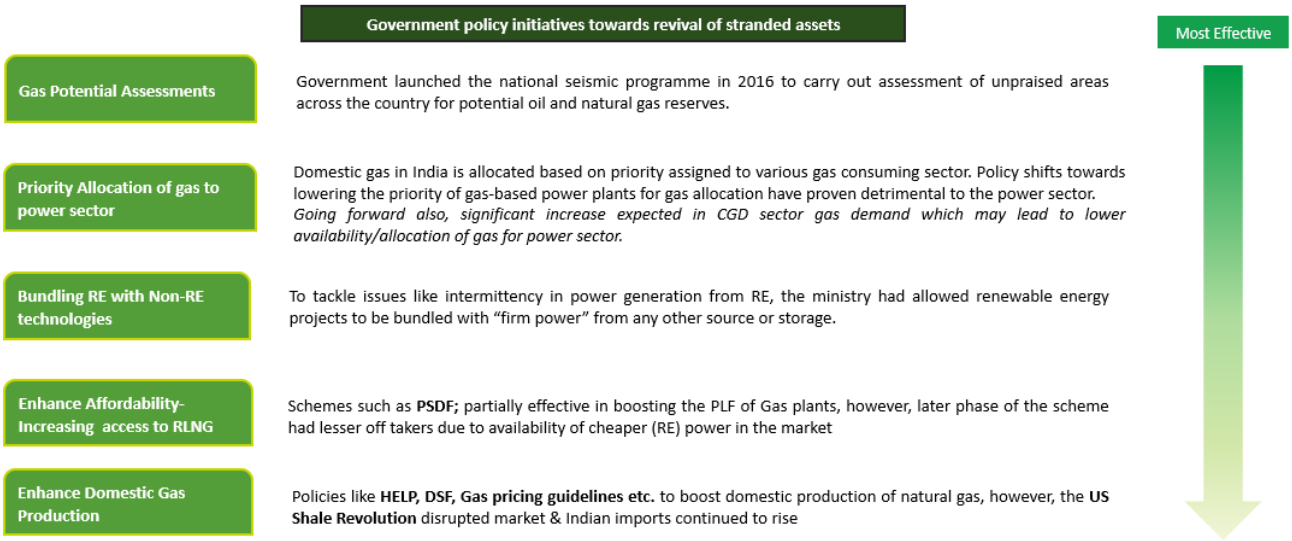
Figure 10: Timeline of government interventions.



3.5 Policy summary

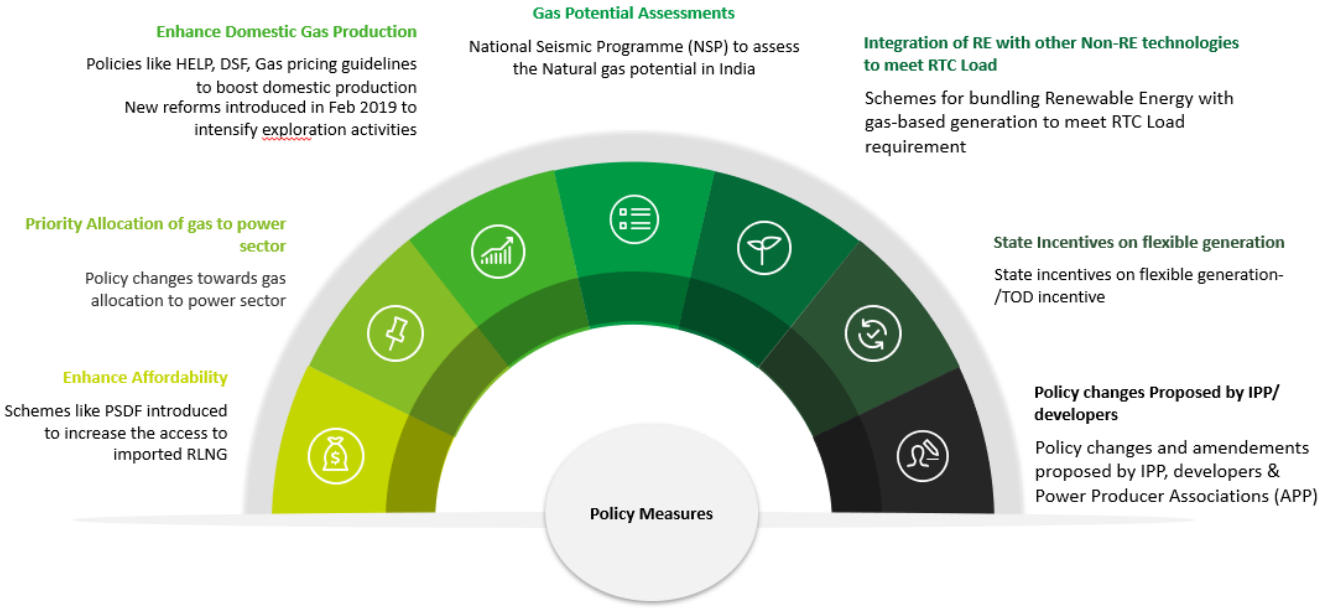
Below figure summarizes the government's policy initiatives towards revival of stranded assets based on their effectiveness.

Figure 11: Government's policy intervention towards revival of stranded assets.



Below figures illustrates various policy measures taken to review the stranded assets

Figure 12: Various policy measures.



3.6 Recent government interventions - MoP Guidelines under Section-11

The Ministry of Power (MoP) on 24th April of 2024, issued an order for directions to Gas Based Generating Stations (GBS) under section 11. This was issued as directions to imported gas based

generating stations to ensure they are running, and their capacity is being utilized. Earlier MoP also issued similar directions to imported coal-based generation stations in 2023.

Context

The order stated that presently 85% of non-solar hour demand is being met through coal and lignite generation. Primarily due to commercial considerations, significant portion of GBS is utilized during crunch period to optimize the availability of power during high demand period

Grid Directions

The directions stated that, Grid India would notify GBSs the number of days they are required to generate in a **week, at least 14 days before**. GBSs shall be guaranteed for dispatch at a **minimum 50% capacity** during hot weather and high demand periods. GBSs shall prioritize their offer of power to DISCOMs.

Figure 13: Actual vs Target generation in May 2024 due to MoP guidelines.

Date	1-May-24	5-May-24	10-May-24	15-May-24	20-May-24	25-May-24	31-May-24
Target (MU)	97.41	97.41	97.98	97.98	97.77	97.98	97.58
Actual (MU)	134.36	120.48	190.08	195.85	144.02	152.50	202.17

Source: National Power Portal

It has been observed that, GBS were able to generate 5,053.71 MUs whereas the target for the whole month of May is 3,030 MUs. It has been observed that following the directions of MoP, the PLF has increased from 13% to 38% in May-24.

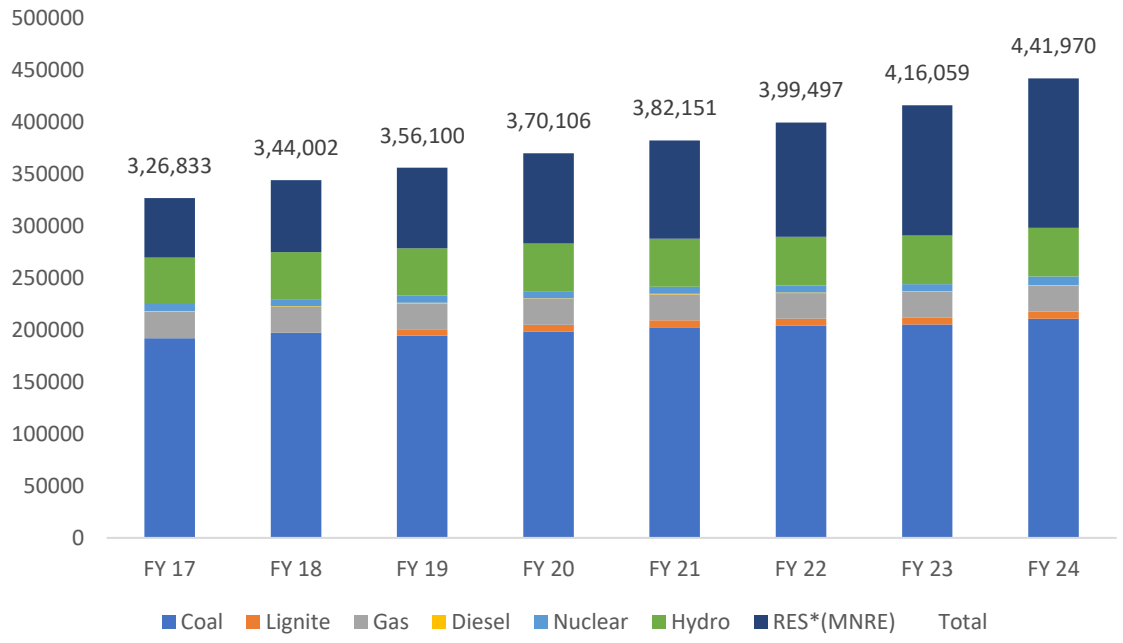
These types of guidelines/schemes can be replicated to utilize stranded assets and finally achieve the target of 15% natural gas in the energy mix by 2030.

4 Technological Assessment

4.1 Overview of Available Technologies

The current mix of energy sources in India's energy portfolio includes Coal (49%), Gas (6%), Diesel (0.15%), Nuclear (2%), Hydro (11%), RES (33%) as of FY 24[9] in a total installed capacity mix of ~450 GW. To meet the deficit of supply and considering the constraints of each technology, different technology combinations are being explored for a techno-economic optimal solution.

Figure 14: Source wise mix of Installed Capacity in India (MW)



Source: CEA

4.2 Technology Comparison

Energy storage systems like BESS, PSP have been introduced in India to bridge the deficit of supply in peak hours. However, these technologies come with their limitations as well, majorly in terms of financial and technical viability.

Table 3: Comparison of technologies based on technical and commercial parameters.

Parameter	BESS	PSP	Gas	Coal
CAPEX	~INR 20-25 Mn/MW	~ INR 45-60 Mn/MW	~ INR 45-50 Mn/MW	~ INR 100-120 Mn/MW
Development period	~ 12-15 months	~ 4-6 years	~ 6-12 months*	~ 4 – 5 years
O&M cost	~ 1-1.5% of CAPEX	~ INR 1-1.2 Mn/MW	~ INR 1.2 Mn/MW, 4% escalation	~ INR 1.4 Mn/MW, 4% escalation

[9] CEA

Parameter	BESS	PSP	Gas	Coal
Startup time	Instant	Instant	5 – 10 min (Open) 1 – 4 hours (Closed)	Cold start: 20-22 hours Hot start: 4-6 hours
Discharge duration	2 hours	4 – 8 hours	-	-
Efficiency	85-90%	75-80%	~30% (Open) ~50% (Closed)	~ 35-44% (sub critical to ultra super critical)
Green component	100% green energy	100% green energy	Cleaner source than coal	Not clean energy source, needs FGD
Technology maturity	Maturing & evolving	Mature	Mature	Mature

Source: Deloitte Analysis, Secondary Research, Past precedencies
** Timeframe for gas is considering reviving a stranded gas asset*

The table above illustrates a comparison of the balancing sources basis technical and commercial parameters. It is to be noted that the comparative numbers of gas-based assets have been considered for targeted stranded assets to be revived.

Comparative Overview of BESS, PSP, Gas, and Coal-Based Power Solutions:

A comparative view of four key power generation and storage technologies—Battery Energy Storage Systems (BESS), Pumped Storage Projects (PSP), Gas-based power, and Coal-based thermal generation—with focus on key operational, financial, and environmental parameters relevant to policy makers and infrastructure planners.

A- Capital Investment & Deployment Timeline

- BESS is the most capital-efficient storage technology with INR 20–25 Mn/MW and can be deployed rapidly within 12–15 months.
- PSP requires INR 45–60 Mn/MW and has a long development period of 4–6 years due to land, topography, and civil works.
- Gas plants have comparable CAPEX (INR 45–50 Mn/MW) but benefit from short lead times (6–12 months) considering the revival of stranded gas asset.
- Coal projects involve the highest capital outlay (INR 100–120 Mn/MW) and long development cycles (4–5 years), posing financial and execution risks.

B- Operational Flexibility & Efficiency

Startup Time:

- BESS and PSP offer instant ramp-up, ideal for peak shaving and frequency regulation.
- Gas: Fast startup (5–10 min for open cycle, 1–4 hrs for closed), enabling flexible operations.
- Coal: Limited flexibility with long cold starts (20–22 hrs) and moderate hot starts (4–6 hrs).

Efficiency:

- BESS: Highest at 85–90%.
- PSP: Moderate at 75–80%.
- Gas: Varies between 30–50% depending on cycle type.
- Coal: Typically, 35–44%, depending on technology (subcritical to ultra-supercritical).

C- O&M Costs

- BESS: Low, ~1–1.5% of CAPEX annually.
- PSP: ~INR 1–1.2 Mn/MW.
- Gas: ~INR 1.2 Mn/MW, with 4% annual escalation.
- Coal: Highest, ~INR 1.4 Mn/MW, with 4% escalation.

D- Environmental & Strategic Relevance

- BESS & PSP: Run on 100% green energy; essential for renewable integration.
- Gas: Cleaner than coal, suitable as a transition fuel in decarbonization pathways.
- Coal: High emissions; requires mitigation infrastructure like FGD units and remains the least sustainable.

E- Technology Maturity

- BESS: Rapidly evolving, with falling costs and improving performance.
- PSP, Gas & Coal: Mature, proven technologies, already integrated into national energy systems.

The above-mentioned data broadly reflects on the following, **allowing a window of 4-5 years:**

- The cost of operationalizing a stranded asset for gas is considerably lower than the remaining technologies.
- The development period for gas-based asset is 6-12 months as compared to the higher timelines for remaining technologies (except BESS)
- Gas based assets have the flexibility of shorter start up time over coal plants.

These act as preliminary indicators of advantages of acquiring the gas-based assets as compared to others.

A comparative analysis has been done based on secondary research to analyze the economic feasibility of gas-based plants when compared to RE + Coal, Solar + BESS and FDRE tenders. The total cost of generation for each technology has been determined and corresponding to the determined cost of generation, the DES price of gas has been estimated if that technological component was replaced by the power produced by Natural Gas.

Table 4: Range of Price of Gas in $/MMBtu for matching Potential COG

Technology	Cost of Generation (INR/kWh)	Key Assumptions	Price of Gas* ($/MMBtu)
RE + Coal	4.5 – 5.2	• ~55-60% energy to be met from RE at ~ INR 4.62/kWh (considering recent FDRE tender results; guarantee of 50% in 15 min time block) • ~40-45% energy to be met from coal-based generation at ~ INR 5.7/kWh (Levelized FC: 2.7 & levelized VC: 3)	6 – 6.5
Solar + BESS	3.2 – 3.6	• Recent Solar plus BESS tenders issued by major REIAs (1200MW NHPC, 2000MW SECI etc.), the winning tariff has been in these ranges during July 24 to the most recent Jan-25. • Considering 28% solar CUF at 2.8 INR/kWh COG and 2-hr discharge BESS cumulatively making CUF 35%.	5 – 7
FDRE tenders	5 – 5.6	• FDRE tenders tariff vary as per the tender conditions such as 90% demand fulfilment in a 15-min time block, RTC supply, FDRE dispatch during specific peak demand, hence the broader range of winning tariffs. • Recent SECI FDRE VI 8000MWh (Jan-25) went up to 8.5 INR/kWh.	8.4 – 11.5

Source: Deloitte Analyses
*Considered after adding Fixed cost of 1 INR/kWh to the CoG and then back calculating the DES price of gas

From the above table, it can be observed that –

- In case of FDRE bids, gas-based generation can be looked like an alternate cleaner source for coal or BESS till the time storage costs gets cheaper.
- Additionally, owing to high cost of energy storage, gas can be a lucrative source for RTC power (than Coal & BESS) due to higher ramp rate (~3X faster than coal) and fractional start up time (~1.6% that of coal)
- Currently, ESS costs (BESS as well as PSP) are high, and hence gas priced < $ 8/MMBtu offers a commercial advantage for servicing consumer requirements as compared to FDRE dispatch.

This analysis presents a comparative assessment of key generation technologies—Renewable Energy (RE) + Coal, Solar PV with Battery Energy Storage Systems (BESS), and Flexible Dispatchable Renewable Energy (FDRE)—based on recent market data, cost trends, and operational assumptions.

- RE (Hybrid) + Coal systems offer a levelized cost of generation ranging from INR 4.5 to 5.2/kWh, assuming a 55–60% RE share and 40–45% coal-based generation. This model provides a balanced mix of cost efficiency and firm power delivery.

- Solar + BESS solutions are increasingly cost-competitive, with tariffs between INR 3.2 to 3.6/kWh, driven by falling storage costs and recent tender outcomes. These systems ensure dispatchable clean power with enhanced reliability.
- FDRE projects, designed to deliver high firmness and flexibility, show higher tariffs ranging from INR 5.0 to 5.6/kWh, and in some cases up to INR 8.5/kWh, reflecting stringent performance criteria and integration of firming technologies.

While each technology has its merits, gas-based power generation emerges as a strategic and underutilized alternative. With quick ramping capability, lower emissions than coal, and significant idle capacity in existing plants, gas-based power can provide flexible, responsive generation. **When gas prices remain within a moderate range (USD 5–7/MMBtu), it can match or outperform FDRE in cost and dispatchability.**

In conclusion, integrating gas-based generation into India's evolving power mix offers a practical bridge between the variability of renewables and the reliability of conventional sources. It can play a critical role in supporting peak demand, ensuring grid stability, and enabling a smoother energy transition.

4.2.1 ToD Generation flexibility of Gas based power – sample state of Gujarat

Deployment of different technologies at different time slots of the day, primarily driven by the tariff deferential advantages of gas-based power generation over other technologies.

Gas provides greater flexibility to balance the intermittent RE, due to its high ramp rate (~3X faster than coal) and fractional start up time (~1.6% that of coal). Additionally, gas is a cleaner source of power than conventional coal-based operation, making it more lucrative for clean energy strategies of Utilities/ C&I.

To meet the RTC power requirement, generators can integrate RE, and Gas based operation with some transactions on IEX. Different technology can be opted at different ToD slots depending on the most lucrative option available for that time slot.

Figure 15: ToD Tariff for different sale avenue.

Sale avenue	Morning Peak Hours 0600-1000 hrs.	Normal Hours 1000-1700 hrs.	Evening peak hours 1700-2300 hrs.	Off-peak hours 2300-0600 hrs.
RE (Solar)*	INR 3.5-4/kWh	INR 3.5-4/kWh	Minimal generation	Solar Not Available
IEX^	INR 7-8 /kWh	INR 6-7/kWh	INR 9.5-11 /kWh	INR 7.5-8.5 /kWh
Gas$	INR 9.5-10.5 /kWh	INR 9.5-10.5 /kWh	INR 9.5-10.5 /kWh	INR 9.5-10.5 /kWh
Discom@	INR 10-11 /kWh	INR 9-10 /kWh	INR 10-11 /kWh	INR 9-10 /kWh

Source: Deloitte Analysis

**RE (Solar)- STU charges & losses are added to solar cost of generation to get the Landed cost of solar power assumed for Gujarat state*
^ IEX – ISTS charges & losses, STU charges & losses, CSS, AS, IEX transaction charges are added to IEX Price to calculate the Landed cost of IEX (DAM) power for FY25
$ GAS - STU charges & losses are added to Gas LCOE at DES price of $ 8.5 /MMBtu.
@Discom - ISTS charges & losses, STU charges & losses, CSS, AS are added to HT industrial tariff (>2500 kVA) and time of use charges for two peak periods similar to Gujarat - FY25

- Rely on RE generation during daytime, meet the peak power requirement from gas and procure power from Exchange/generate from gas (depending on tariff differential) during off peak hours
- Currently, as battery storage is expensive and not economically feasible, gas plants shall be utilized to meet the peaking requirements.

5 Sectoral Challenges & Mitigation measures

5.1 Sectoral Challenges

Given the reduction in domestic gas production along with reduction in LNG import in recent few years, various sectors are facing challenges.

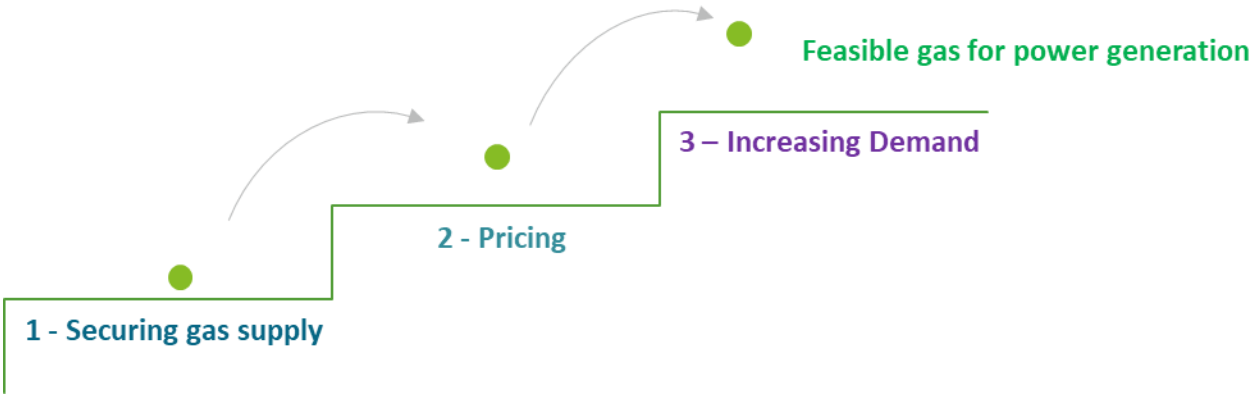
Table 5: Challenges faced by various sectors.

Sector	Challenges
Power	• Declining domestic natural gas allocation • Lower priority in gas allocation • High gas price leading to higher power tariff and non-dispatching of the plant
Fertilizer	• Volatile natural gas prices put burden on fertilizer subsidy. • Pricing of fertilizer is regulated and highly energy intensive process.
CGD	• Lower achievement of MWP targets • Industrial and commercial consumers are dependent on LNG/deep water gas and are subject to market fluctuations leading to swings in demand/fuel switching by customers. • Litigations challenging regulations /authorizations have surfaced slowing infra development and competition
Refinery	• Dependence on imported LNG • High cost of gas as feedstock for petrochemical products puts Indian players at disadvantage

5.2 Mitigation measures

These challenges in power sector can be overcome by focusing on following 3 broad levers through which feasible gas for power generation can be acquired.

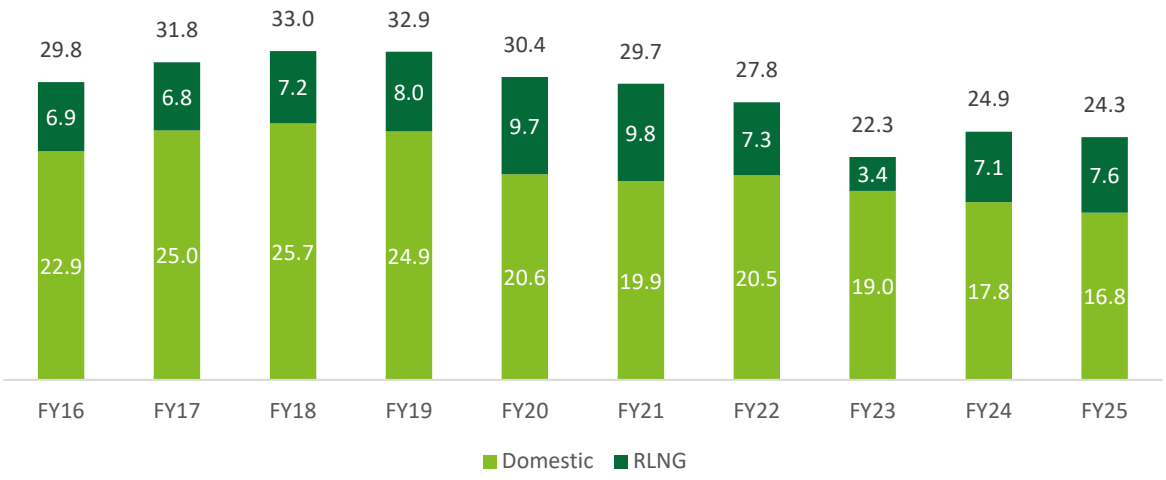
Figure 16: Key drivers for promoting Gas to Power market.



5.2.1 Securing Supply

Natural Gas consumption in power sector has been constantly declining over the past decade which once had a share of 50% in FY11 and now having only 13% consumption in FY24. The below table represents total natural gas consumption in power sector in MMSCMD terms.

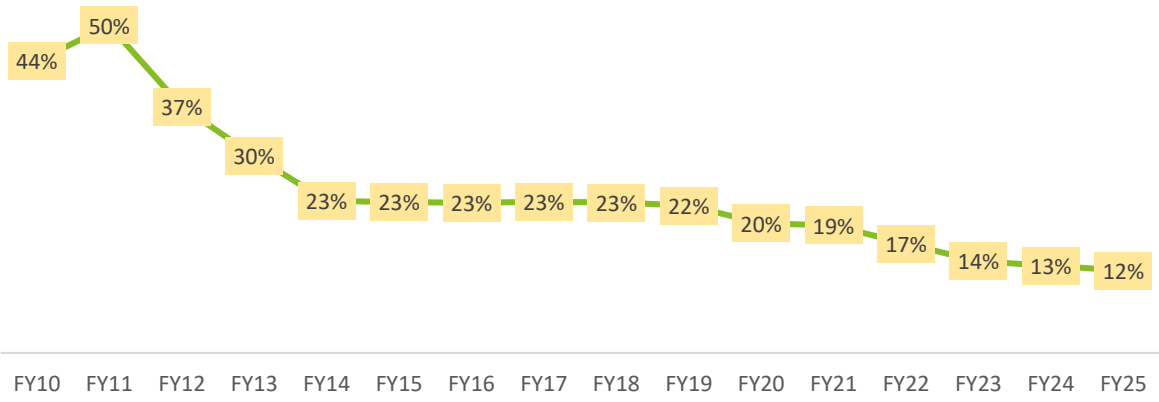
Figure 17: Total natural gas consumption in power sector (in MMSCMD)



Source: ICED NITI Aayog Dashboard

The below figure represents total natural gas consumption in power sector in % terms.

Figure 18: Total natural gas consumption in power sector (in %)



Source: ICED NITI Aayog Dashboard

In 2010, gas-based power plants were put above the CGD entities for domestic and transport requirements (CNG for transport and PNG for domestic use). As per the guidelines, Urea manufacturing fertilizer plants had 1st priority over the domestic gas produced, followed by LPG Plants and then the Gas Power Plants followed by the CGD entities.

However, as per the 2014 revised guidelines, CGD Projects were moved up to 1st priority for allocation of natural gas which were previously ranked 4th. CGD were given priority to meet the growing requirement of the sector as city gas projects were rolled out in newer cities considering CNG & PNG clean fuels and would help replace subsidized diesel in automobiles & households.

Three-fold increase in natural gas consumption is anticipated after the conclusion of 12th CGD bidding round. In future, CGD sector gas demand is expected to increase as Government has

recently bid out 8 CGDs in the 12th CGD bidding round, with the addition of 250 GAs within last 10 years. This may lead to lower availability of gas for power sector.

Currently, only 18 MMSCMD of Natural Gas consumption is domestic supply for 24GW gas based installed capacity having PLF of 14.26% in FY24.

5.2.2 Pricing

Natural gas pricing reforms in India have undergone significant changes to promote transparency, encourage investments, and align domestic prices with global energy trends. These reforms reflect the government's commitment to creating a competitive market while ensuring the affordability and accessibility of natural gas for diverse sectors.

Table 6: Landed cost of domestic gas

Price component	Unit	Value
Domestic Gas Price	$/MMBTU	6.5
Pipeline Tariff (Zone-1)	$/MMBTU	0.48
12% GST on transport (Pipeline Charges)	$/MMBTU	0.06
State VAT	%	15%
Total	**$/MMBTU**	**8.09**

Note: Calculations are considered for Gujarat as a consumer state

Source: Deloitte Analysis

Below mentioned table is an illustrative of the cost components on LNG:

Table 7: LNG- Landed Cost of gas

Price component	Unit	Value
DES Price	$/MMBTU	8.50
Custom Duty (0%, waived off for power generation)	$/MMBTU	0
Terminal Charges	$/MMBTU	1
Pipeline Tariff (Zone-2)	$/MMBTU	0.95
12% GST on transport (Pipeline & Terminal)	$/MMBTU	0.23
State VAT	%	5%
C-form VAT	%	2%
Total	**$/MMBTU**	**12.57**

Note: Calculations are considered for Gujarat as a source state and UP as a consumer state

Source: Deloitte Analysis

The landed cost of Liquefied Natural Gas (LNG) refers to the total cost incurred to deliver LNG from its source to the destination, typically at a regasification terminal in the importing country. The following cost components are involved in determining the landed cost:

Figure 19: Cost components imposed on Gas

Cost Component	Description
DES price (Delivered Ex-Ship) Cost	• The DES price is the price of LNG at the export terminal, excluding transportation and insurance costs. • It depends on the contractual terms (long-term, spot market, or index-linked pricing) and global benchmarks like Henry Hub, JKM (Japan-Korea Marker), or Brent crude oil.
Transportation Costs (Shipping Charges)	• These costs include the chartering of LNG tankers and depend on: • Shipping distance: Longer routes result in higher costs. • Market dynamics: Freight rates fluctuate based on demand for LNG carriers. • Transportation costs may also include fuel costs for the vessel.
Boil-Off Gas (BOG) Losses	• LNG, while being transported, naturally evaporates due to temperature variations, leading to boil-off gas losses. • These losses are factored into the shipping cost and vary depending on voyage duration and containment technology.
Insurance Charges	• LNG cargo is insured against risks during transportation, such as accidents, piracy, or natural calamities. Insurance premiums vary based on geopolitical risks, route safety, and cargo value
Regasification Cost	• After delivery to an LNG terminal, the LNG must be converted back into its gaseous form for transportation through pipelines. • Regasification costs depend on terminal efficiency, technology, and operational expenses
Port Charges and Terminal Fees	• These charges include fees for docking, unloading, and storage at the receiving port and LNG terminal. • They vary based on terminal infrastructure and handling capacity.
Customs Duties and Taxes	• Imported LNG is subject to customs duties and applicable taxes, which vary by country and trade agreements. In India, this includes Basic Customs Duty (BCD) and additional levies, if applicable.
Pipeline Transportation Cost	• Post-regasification, LNG is transported via pipelines to end users. • This cost depends on the distance and pipeline tariff structure, including unified or zonal tariffs
Exchange Rate Variations	• As LNG transactions are typically denominated in U.S. dollars, exchange rate fluctuations between the dollar and the Indian rupee impact the landed cost significantly.
Miscellaneous Costs	• These include administrative charges, handling fees, and demurrage charges (in case of delays in unloading). • Any additional contractual penalties or fees may also be included.

5.2.3 Demand Increase

With India's energy demand projected to surge to 260 GW this year and an anticipated rise to 350 GW by 2030, ensuring an uninterrupted power supply is paramount. For ensuring uninterrupted supply, the central government is taking all measures possible. One such strategic approach involves allocating domestic gas to the power sector during peak demand periods, particularly in summers.

Ways to enhance demand for Gas based generation:

- Gas-Based Generation (GBS) offers a cost-effective alternative to Energy Storage Systems (ESS)
- Extending MoP's GBS optimization notification beyond summer to high-demand periods
- Floating tenders to integrate Renewable Energy (RE) with GBS in a single bid.

GBS offers a cost-effective alternative to ESS.

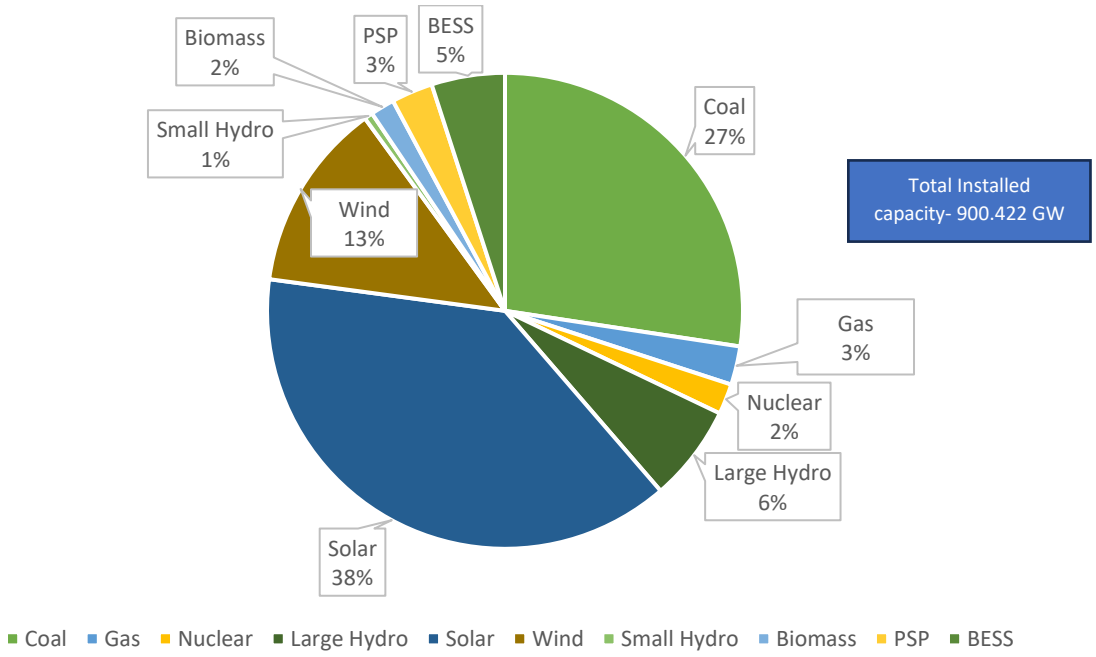
According to CEA's NEP (2023), the installed capacity for the year 2031-32 is likely to be 900,422 MW with Natural Gas at 24,824 MW, PSP at 26,686 MW and BESS at 47,244 MW as per the below table:

Table 8: NEP Projections for ESS

ESS Technology	2026-27	2031-32
BESS (GWh)	34.72	236.22
PSP (GWh)	47.65	175.18
Total (GWh)	**83.37**	**411.4**

Source: CEA's NEP

Figure 20: Installed capacity by 2031-32 (NEP)

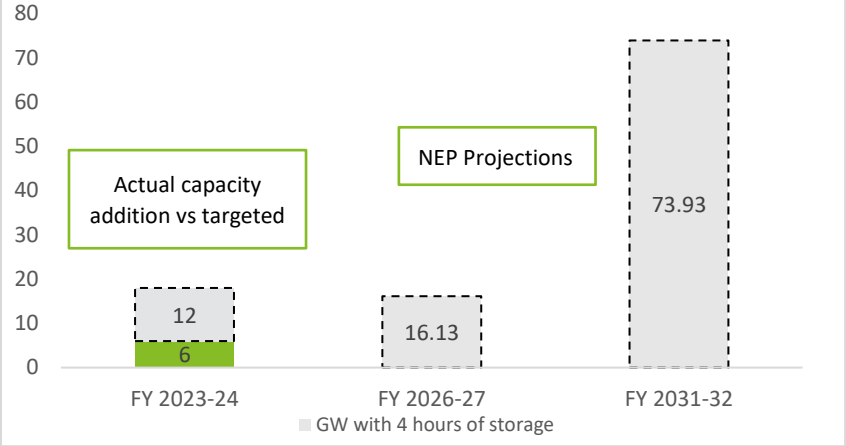


Source: National Electricity Plan

As of 2023, 4745.6 MW of PHS projects have been installed with 1500 MW under construction (as per MNRE) and 0.04 GW of BESS. Hence, ~6 GW ESS capacity has been installed.

It is expected that a significant transformation in the Indian energy sector will be driven by revised Renewable Purchase Obligations (RPO) and Energy Storage Obligations (ESO) norms, catalyzing 12 GW capacity expansion in FY24. However, only around 50% of the targeted 12 GW assuming 4 hours of storage per GW ESS addition has been achieved, creating an opportunity for gas-based generation to bridge the gap and meet energy demand.

Figure 21: ESS requirements by 2031-32.



Source: NEP 2031-32

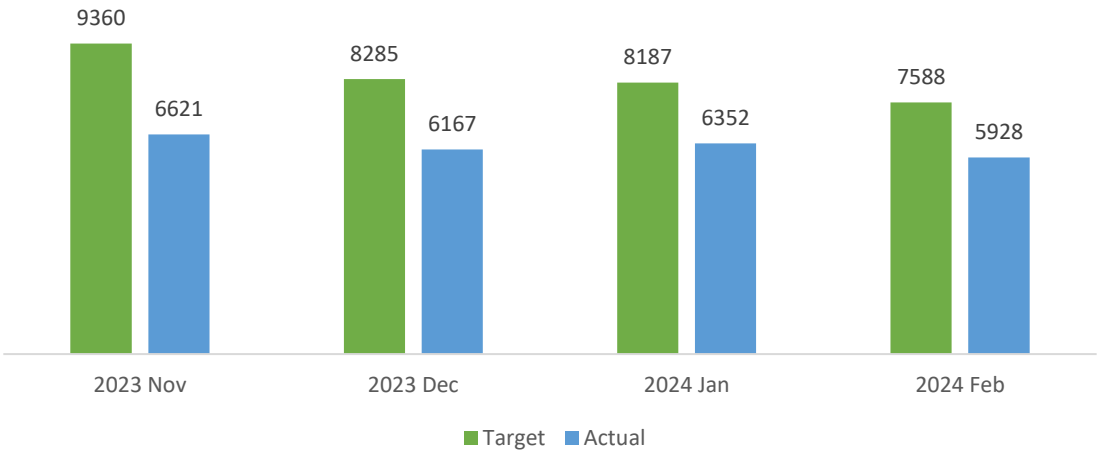
Assuming 4 hours of storage per GW, India requires ~12 GW storage capacity in FY24, which is likely to increase further to ~70 GW by FY30 and ~ 74 GW by 2032. Only around 50% of the targeted 12GW ESS addition i.e. 6GW has been achieved in FY24 (As of 2023, 6 GW of PSP and 40 MW of BESS have been installed).

Extending MoP's GBS optimization notification beyond summer to high-demand periods

To address peak electricity demand during summer, the Government of India will operationalize gas-based power plants. This directive aims to maximize power generation from GBS, aligning with similar measures for imported-coal-based plants. Effective from May 1 to June 30, 2024, the order mandates GBSs to operate as per government direction. GRID-INDIA will coordinate with GBSs, prioritizing power allocation to Power Purchase Agreement (PPA) holders before offering surplus power to the market.

Extending this notification to include winter months is essential. India's energy demand sees ups and downs, like in September 2023, when it peaked at 239.9 GW due to unpredictable weather from El Niño. Agriculture also affects demand, with Punjab needing more power in the Kharif season and Madhya Pradesh in rabi season. Gas-based generation can step in to meet demand during winter, balancing out the drop in hydro power and the needs of agricultural demand.

Figure 22: Target vs Actual Hydro Generation (GWh)



Source: CEA

Floating tenders to integrate Renewable Energy (RE) with GBS in a single bid.

Central government has issued guidelines for resource adequacy planning framework for power sector, establishing an institutional framework from the national level down to Discoms. These guidelines ensure that sufficient resources are available at each level to meet demand reliably.

Rajasthan Urja Vikas and IT Service Limited (RUVITL) intends to tie-up procurement of thermal power up to capacity of 3200 MW and solar power up to capacity of 8000 MW through Tariff based Competitive Bidding Process.	
Tender release date	**02.05.2024**
Bid Submission date	08.07.2024
Location	Jaipur, Rajasthan

Source: Electronic Tender Portal

Procurement of 1600 MW Coal Based Power Project and 5000 MW Solar Project through Tariff based bidding process	
Tender release date	**13.03.2024**
Bid Submission date	18.06.2024
Location	Maharashtra

Source: Electronic Tender Portal

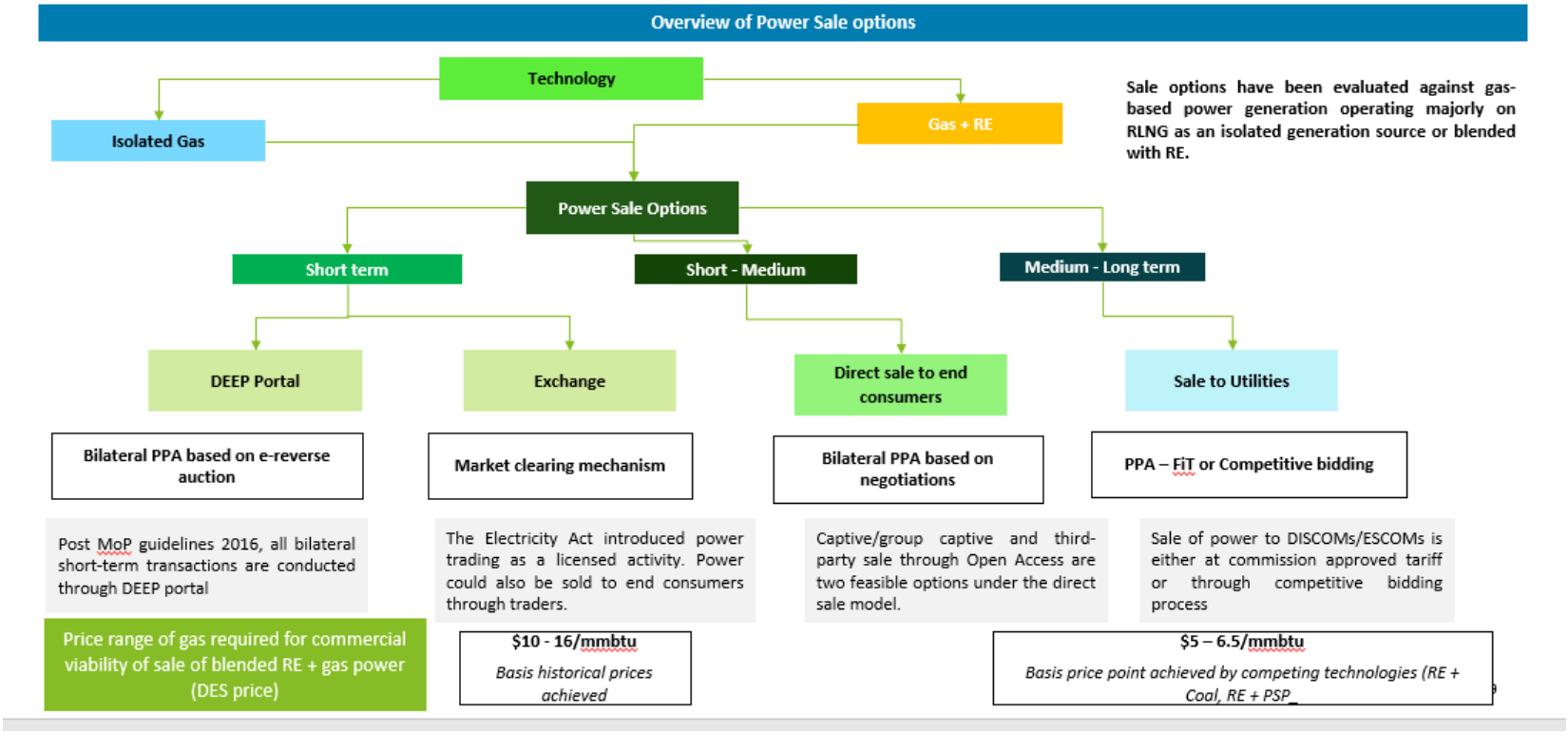
In line with these directives, renewable energy (RE) and thermal power tenders adhere to MoP and CEA guidelines, guaranteeing resource adequacy without resorting to load shedding. Furthermore, to address challenges posed by aging thermal plants and stranded gas assets, these tenders offer a combined bid for both solar and thermal capacities, providing a strategic approach to meet current and future energy demands efficiently.

6 Offtaker Assessment

Power market has traditionally been dominated by long term contracted sale. But over the recent years there has been an increasing shift toward medium term contracts, markets and C&I.

6.1 Overview of power sale options

Figure 23: Overview of Power Sale Options

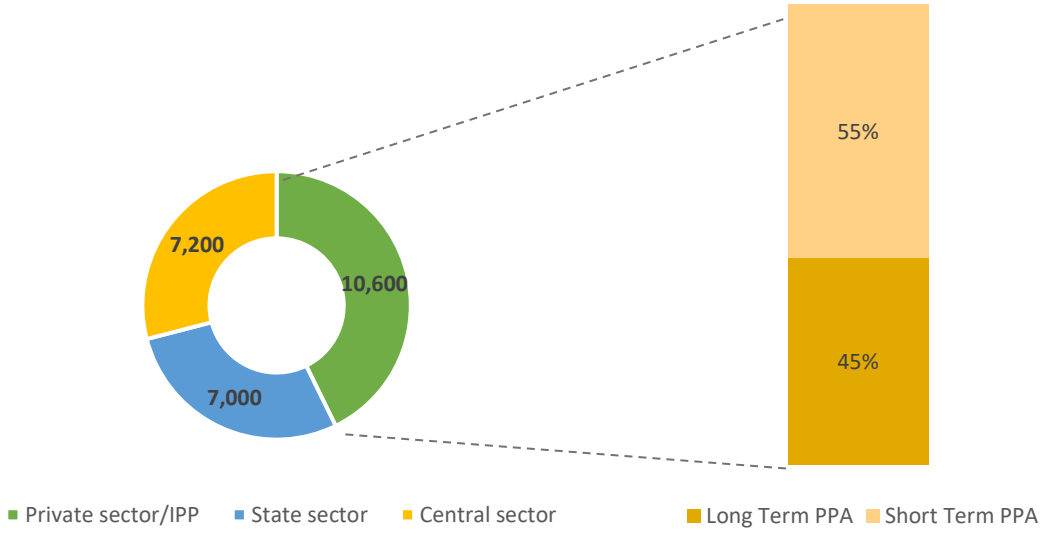


Source: Deloitte Analysis

6.2 Sale to Utility

As of 2024, approximately 45% of the private sector's gas capacity is contracted with long-term PPAs. However, despite the PPA, DISCOMs are not procuring power from these plants due to their failure to meet commercial dispatch requirements. 50% of these plants, which are tied up with historic 5-year PLF of less than 5%, are unable to secure demand.

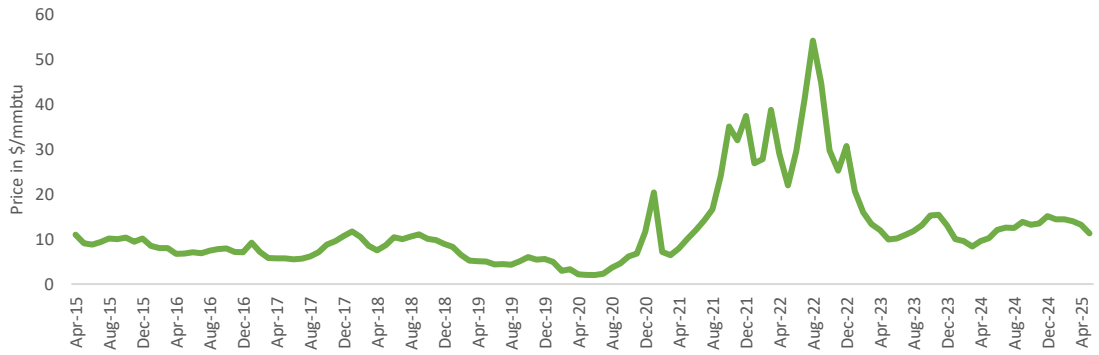
Figure 24: Share of installed gas-based capacity in FY 24 (MW)



Source: CEA

However, the recent decline in international gas prices (compared to spikes in April 2022, July 2022 and January 2023), prompted by geopolitical tensions, has created opportunities for electricity suppliers to offer power at reduced rates. This development enhances competitiveness against RE coupled with ESS or other peaking supply sources.

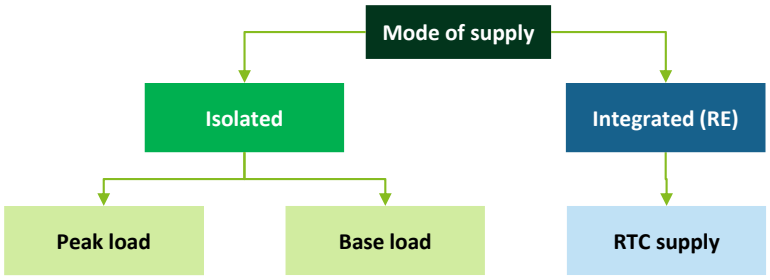
Figure 25: JKM Price index of Natural Gas



Source: Niti Ayog ICED Portal

The sale of power to DISCOMs/ESCOMs occurs either at commission approved tariff or through competitive bidding processes. Utilities may procure power to meet various load demands, including peak, base, or RTC loads. Considering the cost dynamics of RLNG-based generation, dispatching power becomes economically feasible, particularly during peak demand periods or RTC supply scenarios, possibly blended with RE sources.

Figure 26: Mode of supply from gas projects.

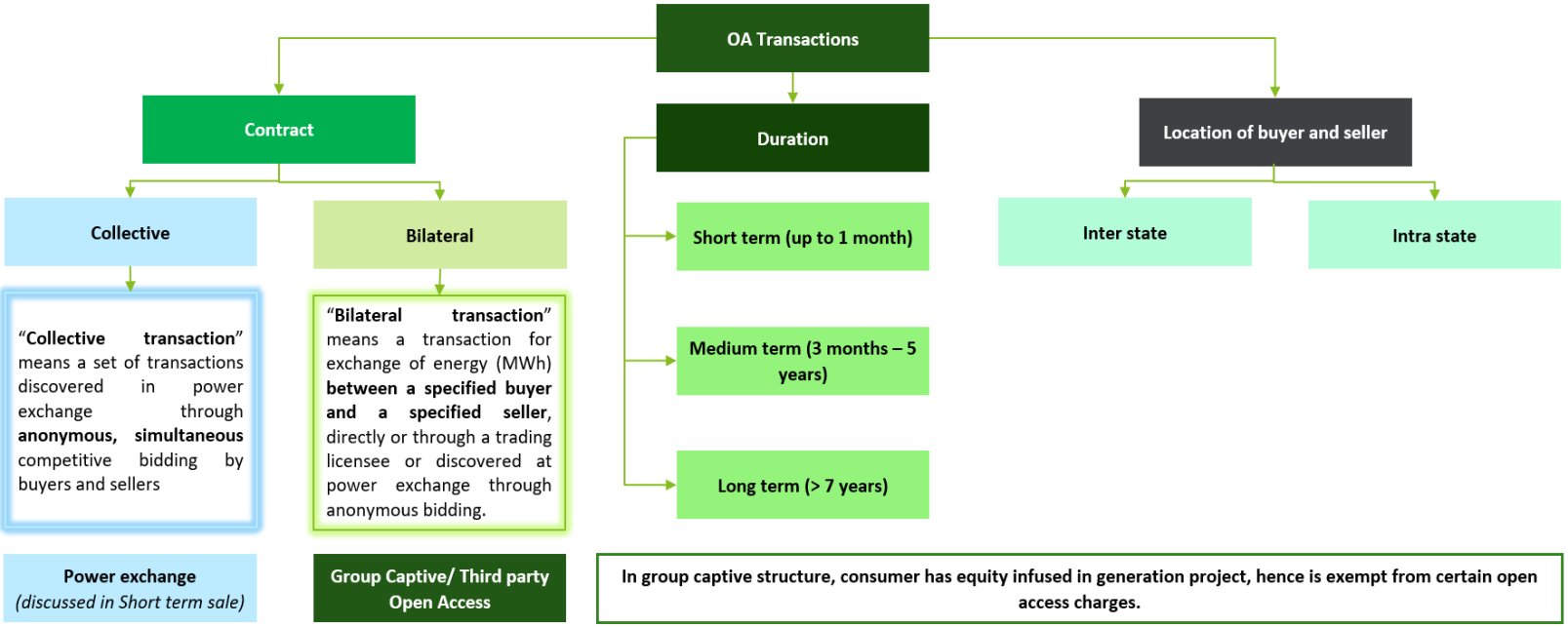


Capacity developed by the Central/State sectors is typically tied up under long-term agreements to fulfill the demands of respective states. Moreover, private sector's installed capacity that lacks a long-term PPA, leads to either non-operational status or is reliant on short-term power sales through exchanges.

6.3 Sale to C&I

The Electricity Act paved way for sale of power by the generator to the eligible end consumers by introducing open access to transmission and distribution system and liberalization of captive consumption. CERC notifies the applicable regulations at central level which is adopted by SERCs with necessary modifications. CERC regulates open access to inter-state transmission system (CTU) while SERCs regulate open access in their respective intra-state transmission (STU) and distribution (DISCOM) system. As of April 25, the total installed capacity of India stands at ~472 GW out of which the private sector's share is roughly 54%[10].

Figure 27: Transactions related to Open Access Power Sale Options

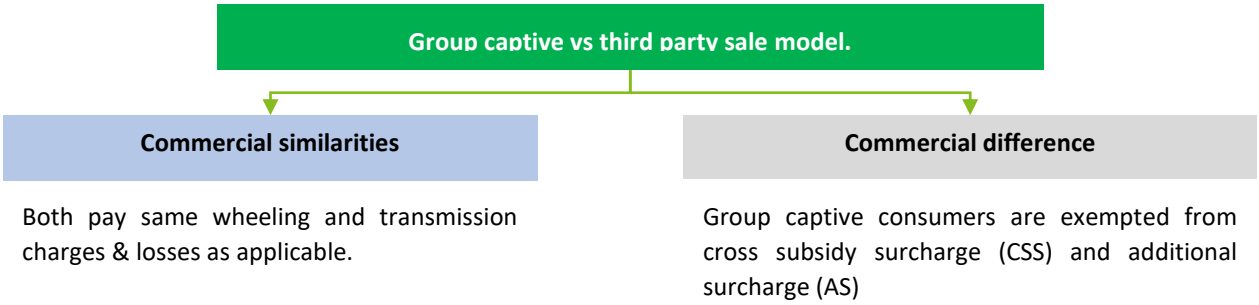


[10] CEA Installed Capacity (access here)

6.3.1 Overview of Third Party and Captive Gas Based Generation

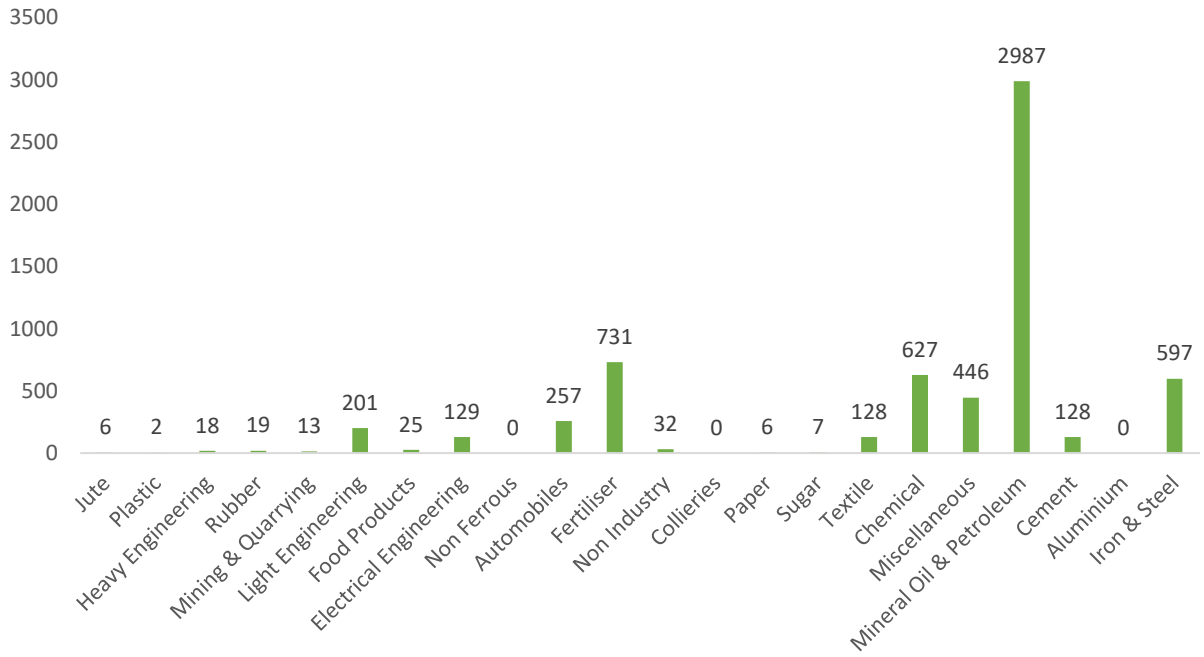
Electricity Act 2003 defines a "Captive Generating Plant" as a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such cooperative society or association.

Figure 28: Similarities and difference between group captive and third-party sale.



Captive gas-based generation at ~ 6.36 GW primarily services industries such as Mineral Oil & Petroleum, Fertiliser, Chemical, Iron & Steel, Cement, Textile, Automobiles and Miscellaneous.

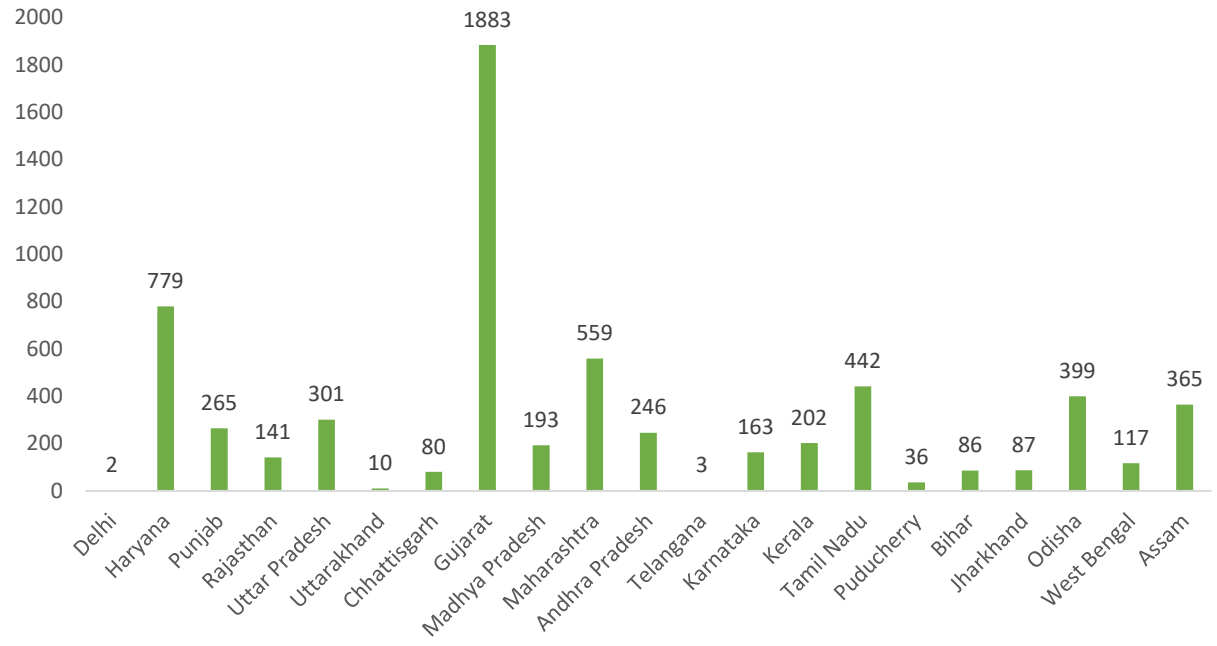
Figure 29: Gas-based Installed Capacity (in MW)



Source: CEA General Review 2024

Out of the total capacity installed under captive/group captive mechanism, majority captive-based generation is present in Gujarat (1.9 GW), Haryana (779 MW), Maharashtra (559MW), Tamil Nadu (442 MW), Odisha (399 MW), Assam (365 MW), Uttar Pradesh (301 MW), and Punjab (265MW). States with lucrative OA charges & industrial demand are attractive for contracting capacity based on group captive/TPP sale model.

Figure 30: Captive gas-based capacity – installation by State (in MW)



Source: CEA General Review 2024

Notably, states such as Gujarat, Haryana, Maharashtra, Tamil Nadu, and Odisha account for a substantial share out of 6.36 GW captive gas-based power generation capacity. The concentration of captive gas-based installations in these regions suggests a corresponding potential for enhanced Open Access (OA) transactions, particularly through third-party power purchase (TPP) arrangements. Industries in these states are more likely to channel surplus electricity into the grid via OA mechanisms, leveraging their captive generation assets for commercial benefit. Thus, high captive capacity can be considered a strong proxy for identifying active and emerging OA markets in the context of gas-based power generation.

6.3.2 Non-Utilities – Energy Intensive Industries

- Out of 22 Industries monitored by CEA, Iron & Steel, Aluminum, Cement, Mineral Oil & Petroleum, Miscellaneous, Chemical, Textile are the energy intensive industries based on consumption.
- Industries having a substantial captive gas-based generation are Fertilizers (74%) and Mineral Oil & Petroleum (54%), with industries such as Automobiles (25%), Chemical

(15%), Light Engineering (13%), Heavy Engineering (11%) and Jute (9%) having a decent gas based captive generation capacity.

- Out of the energy intensive industries, Iron & Steel, Aluminum, Cement, Textile and Sugar majorly meets their respective energy requirements from other captive generation sources, and **they don't rely on gas power for their captive consumption**. (Negligible consumption from GBS).

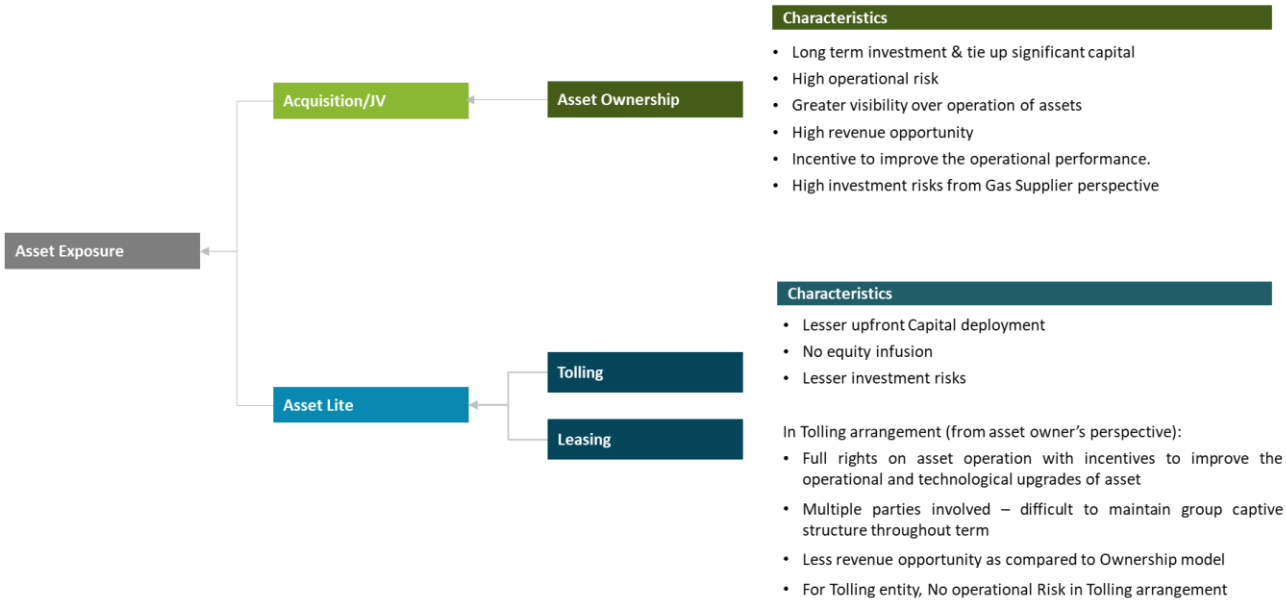
Table 9: Industry-wise consumption By Captive Power Plants having demand of 0.5MW & above.

Name of Industry	Gas-based energy generation (GWh)	Total energy generation (GWh)	% of total generation from Gas	Total energy consumption (GWh)	Energy intensiveness based on consumption (%)
Jute	3	33.50	9%	185.63	0.1%
Plastic	0	436.43	0%	1199.44	0.4%
Heavy Engineering	73	664.65	11%	1695.37	0.5%
Rubber	19	321.92	6%	2214.06	0.7%
Mining & Quarrying	15	1451.76	1%	3463.70	1.1%
Light Engineering	113	880.80	13%	3678.06	1.2%
Food Products	35	1021.23	3%	3823.49	1.2%
Electrical Engineering	93	2843.57	3%	3862.96	1.2%
Non-Ferrous	0	3574.43	0%	5283.63	1.7%
Automobiles	345	1353.01	25%	5837.50	1.9%
Fertilizer	3484	4714.50	74%	6154.12	2.0%
Non-Industry	26	725.00	4%	6929.22	2.2%
Collieries	0	285.74	0%	7035.40	2.3%
Paper	5	7252.26	0%	8320.06	2.7%
Sugar	20	13837.47	0%	8416.59	2.7%
Textile	139	4359.61	3%	16680.70	5.4%
Chemical	1377	8916.73	15%	18364.33	5.9%
Miscellaneous	552	8195.26	7%	19738.50	6.3%
Mineral Oil & Petroleum	13474	24823.60	54%	27221.46	8.7%
Cement	251	18276.32	1%	30103.49	9.7%
Aluminum	0	48093.78	0%	52967.20	17.0%
Iron & Steel	1063	59870.26	2%	77940.05	25.1%
Total	**21087.00**	**211931.83**		**311114.96**	100%

Source: CEA General Review 2024

6.4 Contractual Structures

Figure 31: Different contractual structures.

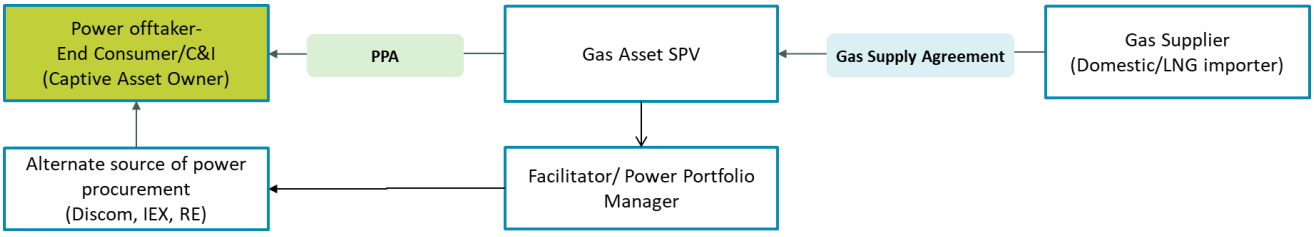


Based on the asset ownership as shown above, there can be two types of contractual structures, out of which asset lite can have further Tolling and Leasing ownership structures.

6.4.1 Structure-1: Asset ownership

Asset owner have stake in the Captive Gas Asset SPV along with the Gas Supplier for easing out the stranded gas asset.

Figure 32: Contractual structure - Asset ownership.



6.4.1.1 Key features:

- Gas Supplier basically supplies natural gas either from domestic sources or LNG imports as per mutually agreed Gas Supply Agreement.
- PPA will be executed between the End consumer/C&I Consumer and Captive Gas Asset SPV for the power offtake.

- A Facilitator/Power Portfolio manager may be included that will play a power optimizer role for the consumer under Energy Balancing Contracts.
- Facilitator may play a role of power optimizer for the consumer.
- Energy Balancing – Contract for scheduling dispatch from generation source basis power procurement cost optimization

6.4.1.2 Key Structural Parameters

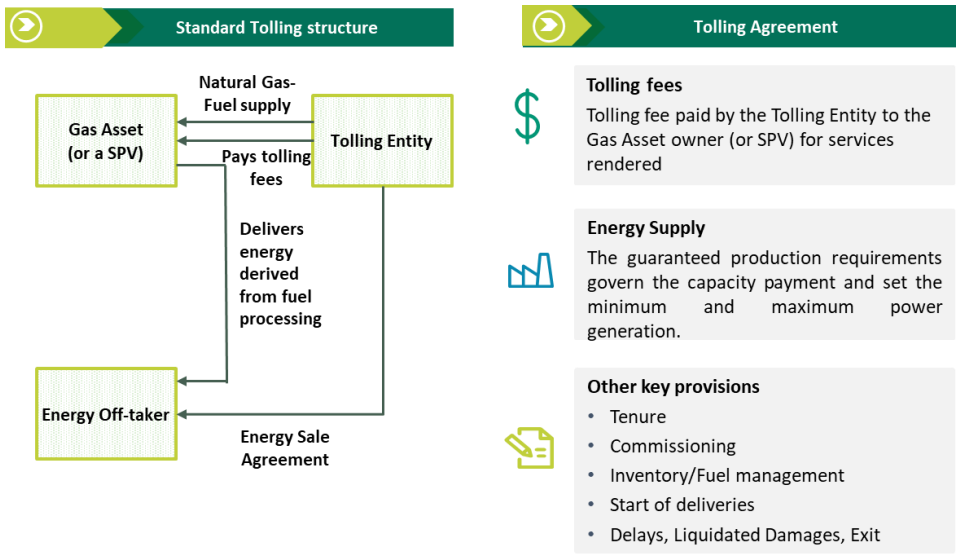
- Gas Supplier and consumer will form an SPV (with minimum 26% stake by the consumer) to enable the consumer to meet the captive criteria.
- Gas Supplier will enter into a Gas Supply Agreement with the Captive Gas Asset for sale of Natural Gas.
- Consumer will enter into PPA with the Captive Gas Asset for the purchase of power generated by the asset.
- Additionally, a Facilitator can be incorporated who will play the role of portfolio manager for both the consumer and the Project SPV– Forecasting & Scheduling power, power purchase optimisation, maintaining OA on behalf of consumer/SPV at an agreed tariff.
- **Key advantage to the consumer**: Upfront Equity infusion by Gas Supplier
- **Key advantage to Gas Supplier**: Pilot venture to gauge business & offering viability, assured gas offtake.

6.4.1.3 Risks considerations

- **Investment Risks-** Gas Supplier is making upfront investment against 74% equity stake. High risk in case the consumer may opt out of the deal before the contract expiry term. The exit clause in the PPA should be adequately defined to safeguard Gas Supplier against the risk.
- **Risk around Gas price fluctuations:** The variable tariff in the PPA should absorb the gas price fluctuations.
- **Power offtake risk from the consumer:** In case the consumer refrains from off taking the agreed quantum of power, adequate remedy clause may be built in the Contract.
- **Plant performance parameters not adhering to stipulated norms:** Due Diligence is required to form a view on these parameters (Heat rate and Aux risk) which leads to higher O&M costs over life of the plant and adopt technical upgradations.
- **Inadequate gas supply/ other FM event:** Deemed generation compensation in the PPA.

6.4.2 Structure-2: Tolling gas asset

Figure 33: Contractual structure – Tolling arrangement.



- Tolling Entity enters into Tolling Agreement with the Gas Asset owner (or a SPV) for plant operations.
- Tolling Entity procures Natural Gas & pays upfront tolling fees to the Gas Asset owner (or a SPV)

6.4.2.1 Key features of tolling a gas-based asset by a tolling entity

- All market risks relating to supply and the sales price of electric power, are taken on by the Tolling Entity, who sets up **agreements directly for fuel supply (NG) and transportation and for sale of electric power.**
- The Gas Asset owner (or SPV) in exchange for the **tolling fee** paid by the Tolling Entity, offers its **production capacity and provides the service of converting fuel into electricity.**
- Only **operating risk** is taken on by the Gas Asset owner (or SPV).
- The Gas Asset owner (or SPV) can rely on readily **predictable and constant cash flows** for the duration of the tolling agreement, regardless of the fluctuations in the power market or in the price of fuel used to produce electricity.

6.4.2.2 Key Structural Parameters

- Gas Asset owner (or SPV) will continue owning the asset.
- PPA is executed between Tolling Entity & energy offtaker. Market & Fuel related risk will be borne by Tolling Entity. Only operating risk will be taken on by the Gas Asset owner (or SPV).
- Tolling Entity will be paying upfront tolling fees to the Gas Asset owner (or SPV).

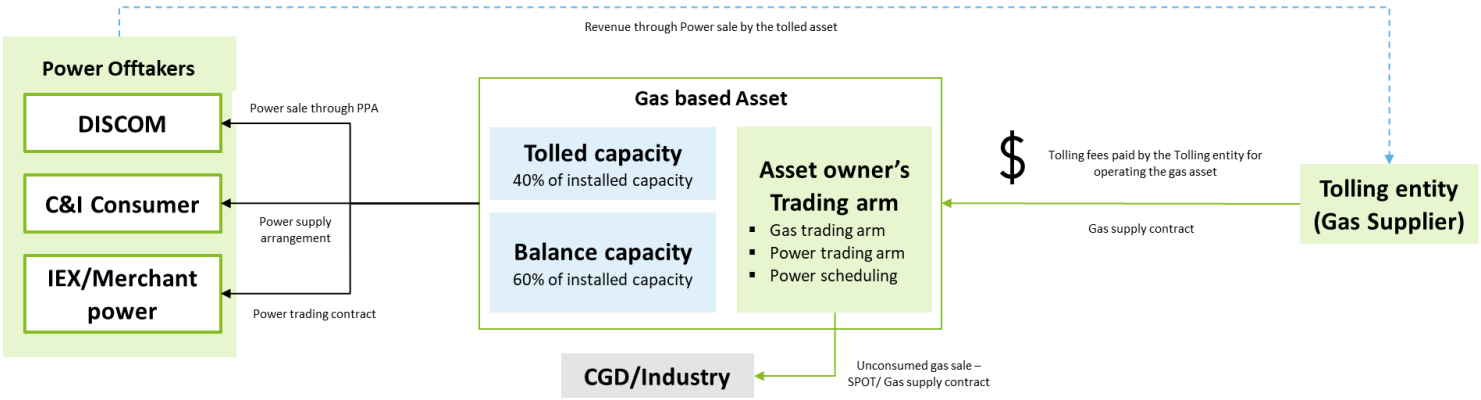
- Gas Asset owner (or SPV) will use its production capacity and convert fuel into electricity. The power generated from the facility will be supplied to an energy offtaker under a PPA or to the Gas Asset owner (or SPV) itself.
- **Revenue from Tolling Agreement**: Gas Asset owner (or SPV) earns a fee for the conversion service.
- **Key advantage to the** Gas Asset owner (or SPV): Upfront money as tolling charges, competitively priced gas supply for operating asset
- **Key advantage to Tolling Entity**: Asset lite model, Limited investment risks, revenue from sale of power to energy offtaker.

6.4.2.3 Risks considerations

- **Gas asset operational risk:** Inadequate performance of the gas asset (lower operational efficiency), leading to additional gas requirement than the agreed norms. Adequate adjustment to be brought in the tolling fees.
- **Risk around Gas price fluctuations:** The variable tariff in the Tolling Agreement should absorb the gas price fluctuations.
- **Inadequate gas supply/ other FM event:** Deemed generation compensation in the Tolling Agreement

6.4.2.4 Case study for tolling arrangement

Figure 34: Case study for Tolling arrangement.



Use case study for Tolling arrangement:

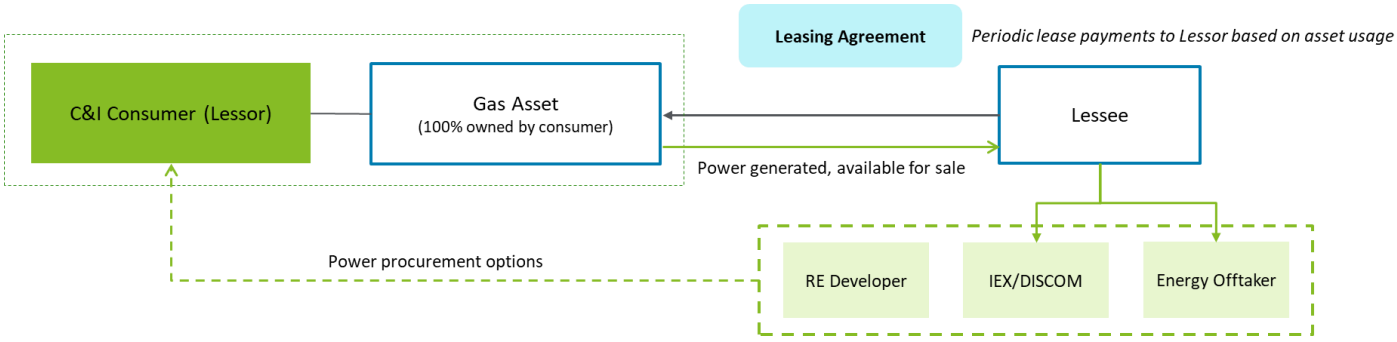
1. Asset owner's Trading arm (gas trading) plays an intermediary role of aggregating gas demand between gas-based plant (tolled and balance capacity) and other consumers such as CGD / industries / refineries.

2. Asset owner's Trading arm (power trading) plays an intermediary role of aggregating demand from Consumers and enabling dispatch of power from tolled and balance asset capacity.

3. Gas dispatch to end user's basis pre-determined priority, which may be factored in contract pricing.
4. Tolling arrangement between Asset owner's Trading (Gas and Power) arm and gas-based asset to reflect charges for
    1. Blocking generation capacity of gas-based asset for Trading arm to use at will.
    2. O&M charges for power plant

6.4.3 Structure-3: Leasing arrangement

Figure 35: Contractual structure - Leasing arrangement.



A contractual arrangement where the owner of the power plant (lessor) leases the power plant or specific equipment within the plant to another party (lessee).

This agreement allows the lessee to use the power plant or equipment for a specified period in exchange for periodic lease payments.

- Lessor: The owner of the power plant or equipment retains ownership throughout the lease term.
- Lessee: Gains the right to use the power plant or equipment but does not gain ownership.

Comparison of 3 type of contractual structures:

Table 10: Comparison of different contractual structures

Parameter	Ownership (PPA)	Tolling Agreement	Leasing Agreement
Nature of Contract	Sale-based: Purchase and sale of electricity	Service-based: Conversion of fuel to electricity	Use-based: Leasing of power plant or equipment
Ownership (Gas Asset - power plant)	Power plant owner retains ownership	Power plant owner retains ownership	Lessor (asset owner) retains ownership; lessee gains usage rights
Revenue Model	Power plant earns revenue from electricity sales	Power plant earns tolling fee	Lessor earns revenue from lease payments
Risks associated	Higher risk for power plant owner; bears fuel cost and market risks	Lower risk for power plant owner; fuel and market risks borne by off-taker	Risk depends on lease type; operational risk often on lessee
Capital Expenditure	High for power plant owner	Low for off-taker	Lower initial capital outlay for lessee
Operational Responsibility	Power plant owner operates plant	Power plant owner operates plant	Lessee often responsible for operation and maintenance (finance lease)
Contract Duration	Long-term (5 to 25 years)	Typically, medium to long-term	Can be short-term or long-term
Asset exposure	Asset owned by power plant owner	Asset lite model for Tolling entity	Asset lite model for Tolling entity for lessee
Fuel Supply (Natural gas supply)	Managed by power plant owner or through agreement with Gas Supplier	Managed by Tolling entity/ fuel supplier	Not applicable directly to fuel supply
Power Offtake (sale of electricity generated by gas asset)	Electricity is sold to the consumer/captive consumption/DISCOM	Electricity is sold to off-taker/DISCOM	Equipment or plant is returned to lessor or purchased by lessee

7 Analyses

7.1 IEX Price Band Analysis

A scenario has been created under an assumption in which the entire quantum of power traded on IEX is procured from gas-based assets. The price range at which power is traded for the last three financial years on IEX has been mapped from DAM and RTM data (FY 23, FY 24 and FY 25).

Approach

- The DAM and RTM Data has been extracted for FY 23, FY 24 and FY 25
- The price bands have been set at-

Table 11: Price bands for IEX analysis

>=5 to <5.5	>=5.5 to <6	>=6 to <6.5	>=6.5 to <7	>=7 to <7.5	>=7.5 to <8	>=8 to <8.5	>=8.5 to <9	>=9 to <9.5	>=9.5 to <10	>=10

- Based on the price bands the number of occurrences of each price band across the two financial years has been mapped
- Similarly, for each price band the volume of power traded in MUs is mapped.

Table 12: Total Volume Traded (DAM+RTM) Summary

Price range	All	>=5 to <5.5	>=5.5 to <6	>=6 to <6.5	>=6.5 to <7	>=7 to <7.5	>=7.5 to <8	>=8 to <8.5	>=8.5 to <9	>=9 to <9.5	>=9.5 to <10	>=10
FY23 BUs	75	5	4	3	2	2	2	2	1	1	1	12
FY24 BUs	83	4	3	2	1	1	1	1	1	0	1	14
FY25 BUs	100	4	2	1	1	1	0	0	0	0	0	11

Table 13: Cumulative Volume Traded (DAM+RTM) Summary

Price	All	>=5	>=5.5	>=6	>=6.5	>=7	>=7.5	>=8	>=8.5	>=9	>=9.5	>=10
FY23 BUs	75	37	31	27	24	21	19	18	16	14	13	12
FY24 BUs	83	28	24	21	19	18	17	16	16	15	15	14

Price	All	>=5	>=5.5	>=6	>=6.5	>=7	>=7.5	>=8	>=8.5	>=9	>=9.5	>=10
FY25 BUs	100	20	17	15	14	13	12	12	12	11	11	11

Estimate of Potential capacity of gas-based asset & DES price

The DES Price has been estimated for purchase of gas to match power procurement price through exchange. The following assumptions have been taken to arrive at the same.

Table 14: Assumptions for DES price calculations

Assumptions	Units	Values
MMBTU to SCM	-	25.2
GCV of gas	kcal/SCM	10000
SHR	kcal/kWh	2150
Dollar to rupee conversion	INR/USD	83.73
VAT	%	15.00%
GST on pipeline charges	%	12.00%
Regasification charges	USD/MMBTU	1
Pipeline charges	INR/MMBTU	40
Customs duty (exempted)	%	0.00%
Fixed cost component	INR/kWh	1
CUF	%	50%
Auxiliary consumption	%	2.50%

Based on the above assumptions, the capacity estimate required to operationalize for gas-based assets has been estimated. It must be noted that the major assumption here is that 100% of the volume traded on IEX in the past two years is expected to be generated from gas-based plants in the analysis.

Table 15: Gas based assets capacity for different price bands.

Description	Units	>=5	>=6	>=7	>=8	>=9	>=10
No of units in FY25	BUs	20.21	14.60	12.93	12.03	11.47	10.79
Auxiliary consumption	BUs	0.51	0.36	0.32	0.30	0.29	0.27
Total units to be generated	BUs	20.71	14.96	13.25	12.33	11.76	11.06

Description	Units	>=5	>=6	>=7	>=8	>=9	>=10
Weighted avg price	INR/kWh	8.27	8.91	9.36	9.59	9.73	9.84
Gas requirement	Mn MMBTU	176.73	127.67	113.06	105.20	100.33	94.32
Respective Gas based assets capacity	MW	4729	3416	3026	2815	2685	2524

Corresponding to the derived capacity of assets, the DES price has been calculated.

Table 16: DES price for different price bands

Description	Units	>=5	>=6	>=7	>=8	>=9	>=10
Weighted avg price	INR/kWh	8.27	8.91	9.36	9.59	9.73	9.84
Fixed cost component	INR/kWh	1	1	1	1	1	1
Variable cost component	INR/kWh	7.27	7.91	8.36	8.59	8.73	8.84
Landed cost of gas	USD/MMBTU	10.17	11.07	11.70	12.03	12.23	12.37
VAT imposed	USD/MMBTU	1.33	1.44	1.53	1.57	1.59	1.61
Regasification charges	USD/MMBTU	1.00	1.00	1.00	1.00	1.00	1.00
Pipeline charges	USD/MMBTU	0.48	0.48	0.48	0.48	0.48	0.48
GST on pipeline & regasification charges	USD/MMBTU	0.18	0.18	0.18	0.18	0.18	0.18
Gas price without customs duty	USD/MMBTU	7.19	7.97	8.52	8.80	8.98	9.10
Customs duty	USD/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00
Final DES price	**USD/MMBTU**	**7.19**	**7.97**	**8.52**	**8.80**	**8.98**	**9.10**

The above analysis reflects the DES price at which gas is required to be procured to match the price band at which the corresponding volume of electricity has been traded in IEX in the past three years.

7.2 Peak Power Analysis

Objective:

To assess the potential role of gas-based power assets in meeting peak electricity demand by 2030, considering their flexibility and rapid ramp-up capabilities.

Approach:

Installed Capacity of various power generation sources is estimated till 2030 based on their projected installed capacities by CEA and the existing average Capacity Utilization Factors (CUFs). This power supply is then mapped against anticipated peak power demand

scenarios for the years 2027 and 2030. The analysis incorporates planned capacity additions as outlined in the CEA's National Electricity Plan 2032, enabling an evaluation of supply-demand dynamics during peak load periods.

Estimating the installed capacity by 2030 (Supply):

Total installed capacity of various power generating sources have been considered as per following scenarios:

- Scenario 1: 26.9 GW of coal being added till 2030[11] from 2024 onwards.
- Scenario 2: 80 GW of coal being added till 2030[12] from 2024 onwards.

Installed capacities by 2027 and 2030 for other sources such as Hydro, Nuclear, Solar, Wind, Bio-power, BESS, PSP have been taken from CEA's NEP 2022-2032 projections. The total installed capacity till 2030 has been attached in the Annexure.

Estimating the peak power demand:

Peak power demand projections till 2030 have been considered from base year 2024 with the following growth rates:

- Case – a: 6.42% till 2027 & 5.74% from 2027 to 2030[13].

Peak power demand (GW)	2024	2027(P)	2030(P)
During Solar hours	250	301	356
During non-solar hours	234	282	334

- Case – b: 8% till 2030[14].

Peak power demand (GW)	2024	2027(P)	2030(P)
During Solar hours	250	315	397
During non-solar hours	234	295	372

[11] CEA National Electricity Plan (NEP)
[12] PIB notification
[13] CEA 20th EPS Report 2022
[14] Secondary research and Deloitte Analysis

The CUFs for each source of power generation has been considered as per Capacity factor for non-solar hours attached in annexure.

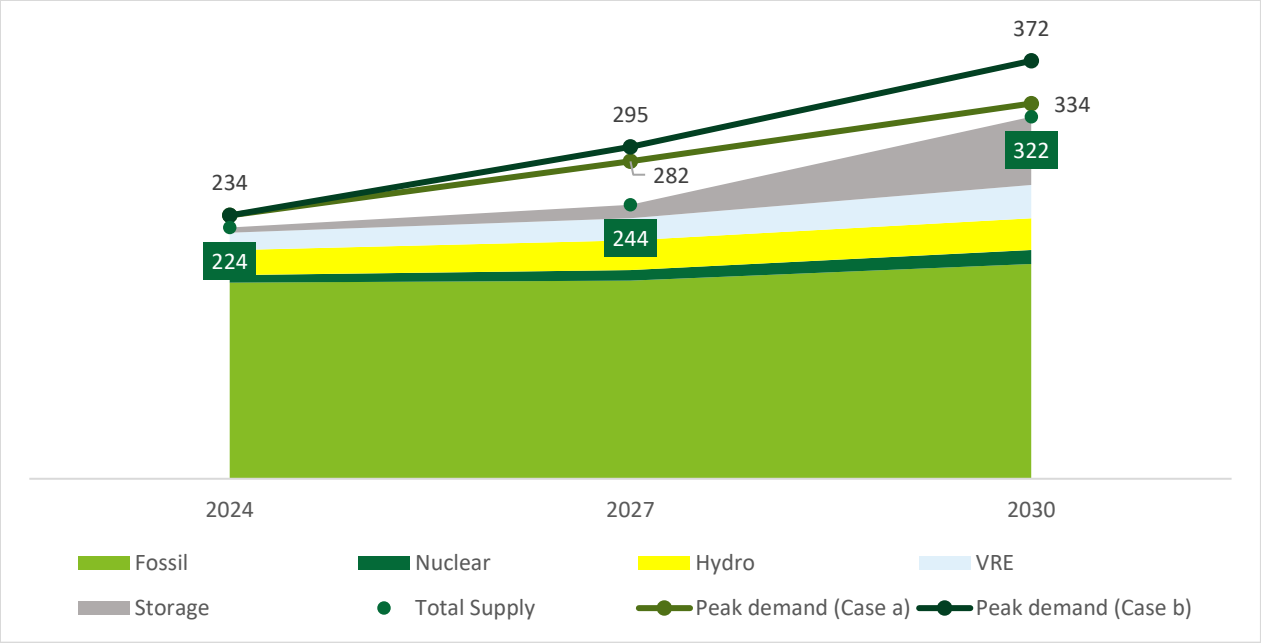
Output:

Based on these assumptions, the demand deficit has been estimated to calculate the maximum deficit that can be catered to by the 25 GW gas-based assets (assuming the gas plants run at 50% PLF).

Scenario 1: Coal based power addition of 26.9 GW till 2030

Supply at peak net demand (in GW)	2024	2027 (P)	2030 (P)
Fossil	175	176	191
Nuclear	7	9	12
Hydro	22	26	28
VRE	15	20	30
Storage	5	12	61
Total Supply in GW	**224**	**244**	**322**
Peak demand in GW (case a)	**234**	**282**	**334**
Peak demand in GW (case b)	**234**	**295**	**372**
Surplus/ Deficit	**-11**	**-39**	**-12**
Potential demand to be met through Gas (GW)	**9**	**13**	**12**

Figure 36: Graphical representation of scenario 1: Coal based power addition of 26.9 GW till 2030

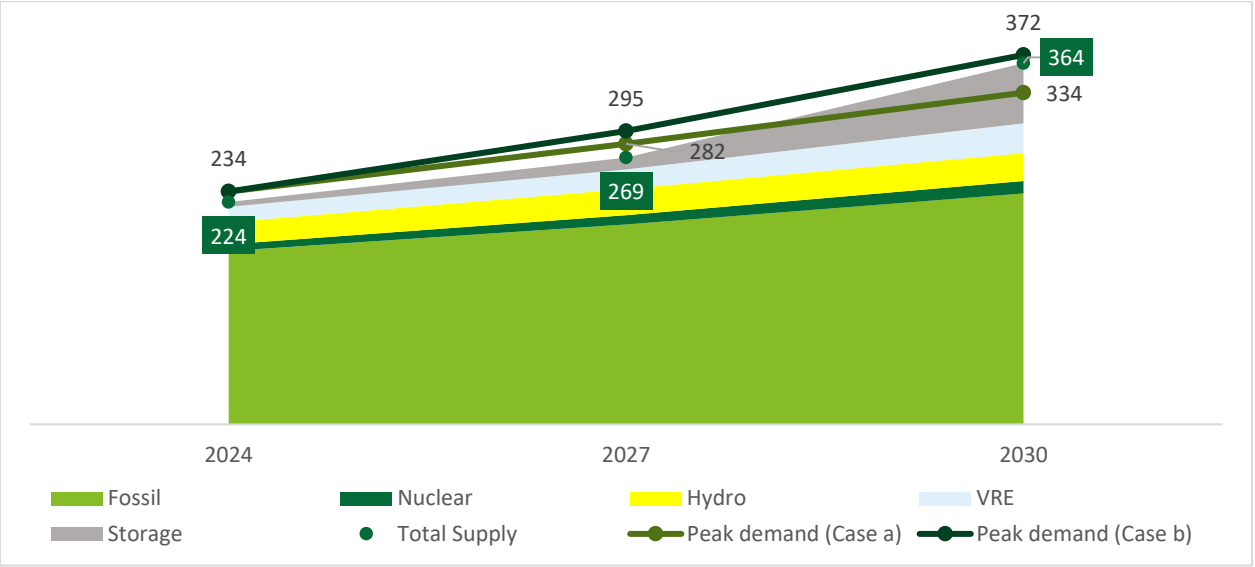


This shows that gas-based assets have a higher potential during non-solar hours to meet the demand deficit created in the market.

Scenario 2: Coal based power addition of 80 GW till 2030

Supply at peak net demand	2024	2027 (P)	2030 (P)
Fossil	175	201	233
Nuclear	7	9	12
Hydro	22	26	28
VRE	15	20	30
Storage	5	12	61
Total Supply in GW	**224**	**269**	**364**
Peak demand in GW (case a)	**234**	**282**	**334**
Peak demand in GW (case b)	**234**	**295**	**372**
Surplus/ Deficit	**-11**	**-14**	**30**
Potential demand to be met through Gas (GW)	**9**	**13**	**0**

Figure 37: Graphical representation of scenario 2: Coal based power addition of 80 GW till 2030



Under scenario 1, for both the cases the deficit of 12 GW for case a, and 50 GW for case b between total supply and peak demand exists which shall be met utilizing the gas-based assets.

Under scenario 2, for the case b the deficit of just 8 GW between total supply and peak demand exists which shall be met utilizing the gas-based assets.

Considering the factor that powering up the gas-based assets will not take longer than 6-8 months, and even coal power plant addition will take considerable time as typically a new plant construction takes up to 2 years, gas-based assets are the perfect alternative to cater to the deficit created against the projected demand by CEA. The quick ramp up ramp down ability shall further help to be a perfect alternative during non-solar hours. Even though it seems that gas-based assets won't be required by 2030, but according to CEA "India's peak power demand is set to reach 270 gigawatts (GW) in the next fiscal and is projected to soar to an estimated 446 GW by 2030"[15] which means that gas-based assets will be required by 2030 too.

[15] CEA projections (access here)

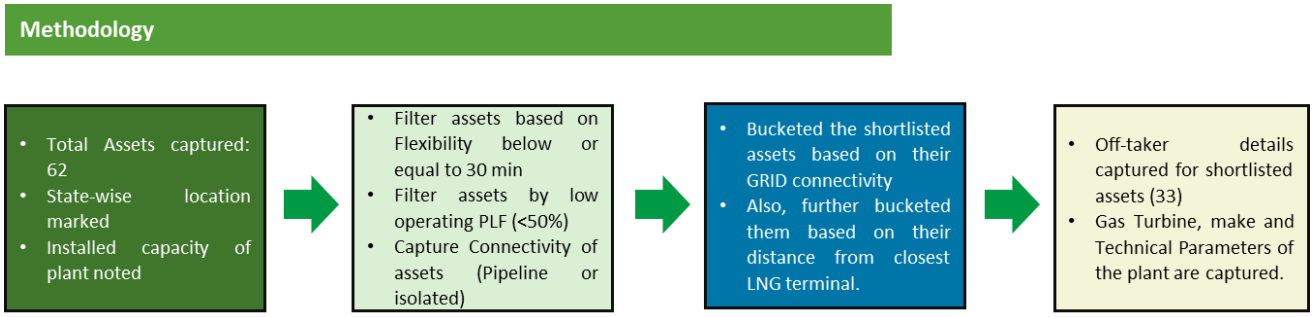
7.3 Shortlisting of assets

7.3.1 Methodology

- **Total Assets Captured:** 62 utility gas-based assets monitored by CEA.
- **State-wise Location Marked:** Each asset's geographic position was recorded.
- **Installed Capacity Noted:** Capacity details of all plants were captured.
- **Filtering Criteria:**
    - **Filter-1:** Flexibility (Turn on/off time) below or equal to 30 minutes.
    - **Filter-2:** Low plant load factor (PLF) in FY24 (<50%).
    - **Filter-3:** Gas connectivity (Pipeline only).
- **Shortlisted Assets:** 33 utility assets (~18 GW Installed Capacity).
- **Technical Parameters Captured:**
    - Gas Turbine, make, and technical specifications.
    - Off-taker details recorded for each shortlisted asset.

Note: Legal aspect for assets under NCLT proceedings are not considered and legal framework needs to be assessed.

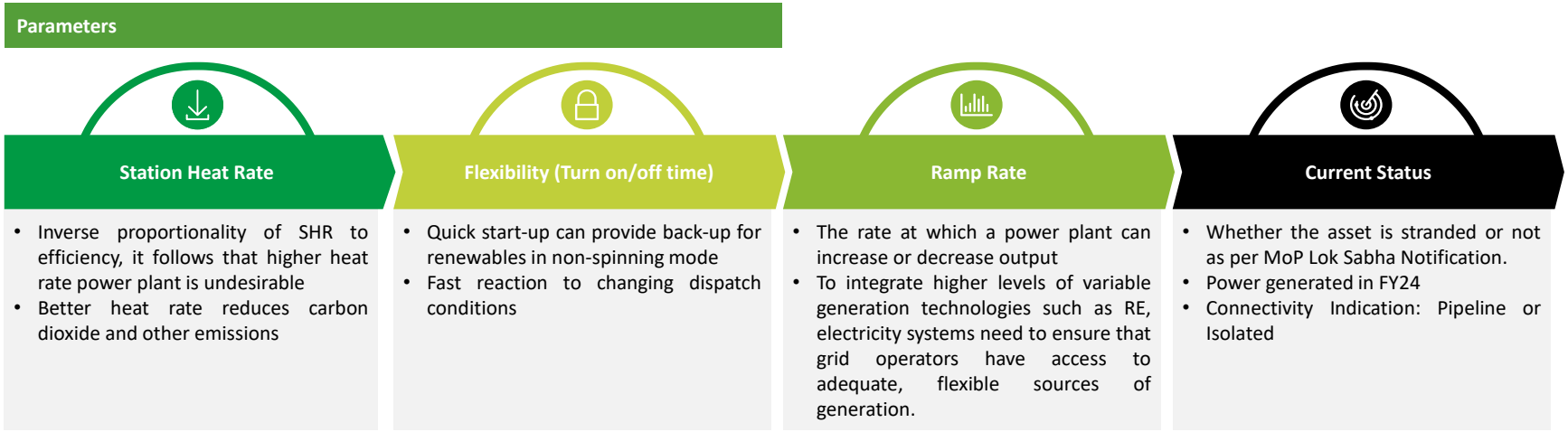
Figure 38: Methodology adopted for shortlisting of assets.



7.3.2 Key Parameters Considered

1. **Station Heat Rate (SHR)**
    - Higher SHR indicates lower efficiency, making such plants undesirable.
    - Better heat rate contributes to reduced carbon dioxide and other emissions.
2. **Flexibility (Turn on/off Time)**
    - Quick start-up enhances back-up capabilities for renewables in non-spinning mode.
    - Enables fast response to changing dispatch conditions.
3. **Ramp Rate**
    - Determines how quickly a plant can increase or decrease its output.
    - Essential for integrating higher levels of renewable energy by ensuring flexible generation sources.

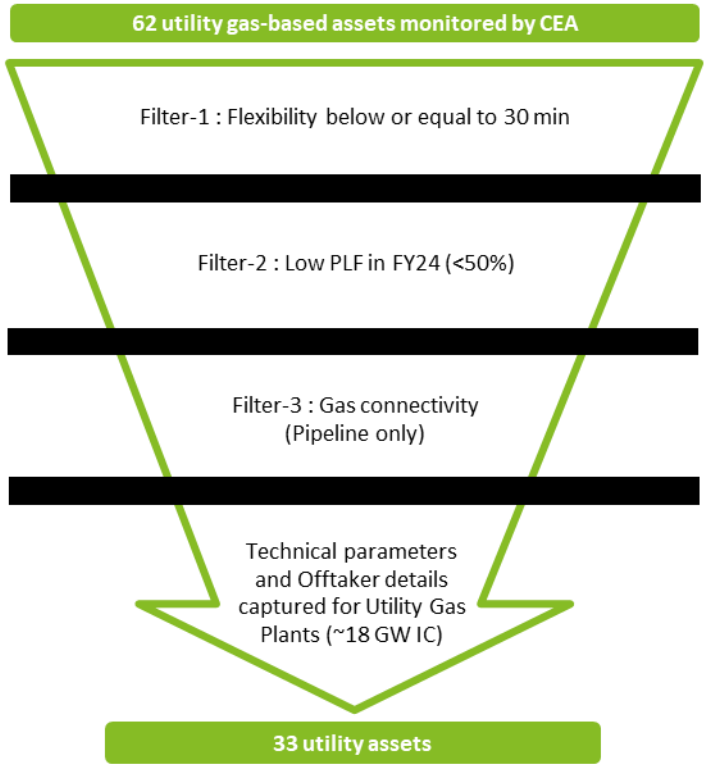
Figure 39: Key parameters considered for shortlisting of assets.



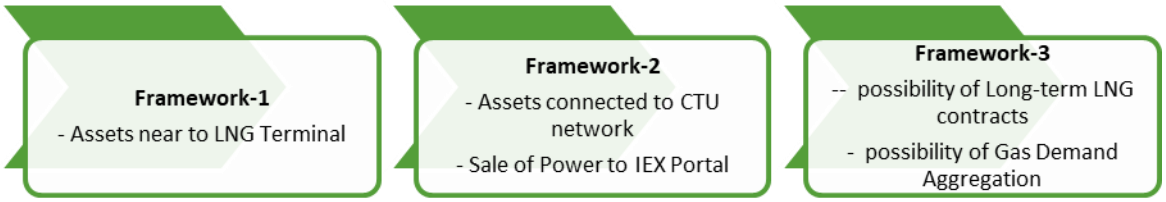
7.3.3 Frameworks for Categorizing Shortlisted Assets

- **Framework-1:** Assets located near an LNG terminal.
- **Framework-2:** Assets connected to the CTU network with potential for power sale via the IEX portal.
- **Framework-3:** Assets with possibilities for long-term LNG contracts and gas demand aggregation.

Figure 40: Frameworks for categorizing shortlisted assets.

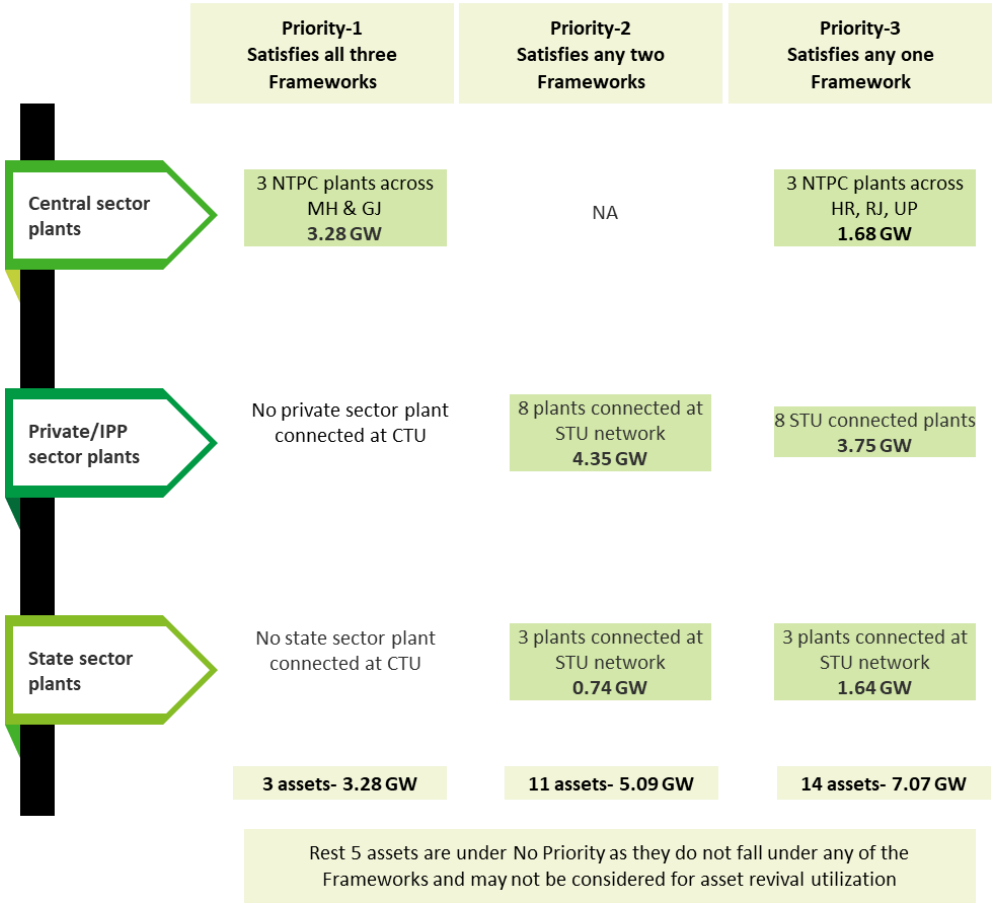


Frameworks for categorizing shortlisted assets based on stakeholder interactions:



7.3.4 Results

Figure 41: Prioritizing shortlisted assets.



Detailed list is attached as per “Shortlisted assets” in the Annexure.

7.4 Financial Model

7.4.1 Objective

- Maximize utilization across asset base, while achieving a zero profit/loss over the selected period (5 years).
- Utilizing gas-based power as an alternate to ESS over the next 5 years - this would enable Utilities/GRIDCo to defer **fresh investment** in **maturing** ESS technology (till price stability is achieved) by leveraging existing asset base.

7.4.2 Approach

- Gas based asset has been considered to be engaged in two modes of power sale:
    - Fixed price contract – This is a RE + Gas power supply contract, which achieves 100% round-the-clock firm supply. Gas power supplied in this contract is at a fixed price, enabling the end-consumer to enter a firm supply contract at a fixed price (similar to RE+ESS contract)
    - Exchange – Sale of gas-based power over electricity exchange in time slots where cost of generation is lower than sale price.

7.4.3 Rationale

- Fixed contract enables support for increasing asset utilization in a predictable manner (based on RE generation pattern). Additionally, it increases consumption of fuel across assets, which may create avenue for discounted fuel pricing from suppliers.
- Sale over exchange enables covering of losses incurred in servicing “fixed contract”, hence facilitating our zero profit/loss solution.

7.4.4 Key features of fixed contract

- Competitively priced 100% CUF contract, with ~55% generation from RE
- Enables Utilities/Consumers/Developers to defer high CAPEX investment in Energy Storage solutions till price and technology maturity are achieved.
- It has been considered that the contract will be serviced by Gas for 5 years. Post that, additional RE + ESS may be deployed to continue servicing firm energy requirement.

Table 17: Key parameters of financial model

Parameter	UOM	Value	Remarks
CUF	%	100%	RTC power with firm dispatch
Tariff	INR/kWh	~5.2 – 5.4/kWh	FDRE tenders with ~ 70% average utilization factors, and fulfilment of 80-90% demand requirement are priced at INR 4.8 – 5/kWh. The Fixed Contract has 100% utilization guarantee, with ~55% RE and the balance clean gas-based power, a premium of ~0.3 -0.5/kWh has been considered.
Cost of generation	INR/kWh	Solar: 2.5 Wind: 3.4 Gas: 8.0	RE considered to be priced considering purchase from developer at premium; The same may be negotiated for more competitive rates. Gas pricing has been considered to maximize utilization while minimizing losses.
Generation CUF	%	Solar: 27.5% Wind: 39% Gas: 44%	Assumption
Zone 1 & Zone 2	km	-	As per Unified Tariff Policy 2023, Zone 1: up to 300km; Zone 2: 300km to 1200km from gas source

7.4.5 Scenarios assessment to achieve zero profit/loss

Critical parameters impacting cost of generation from gas asset, and subsequently, impacting the overall viability of the venture were analyzed.

The following interventions may be considered to realize the results of the analysis. It includes key negotiated discounts on fuel price, terminal charges and OPEX of asset as well as policy intervention measures such as waiver on C-form VAT.

The following results are considering 4,000 MW of gas-based assets, for which 40% of capacity would be engaged in fixed contract and remaining would be available for exchange arbitrage.

Table 18: Scenario analysis for assets located in pipeline zone 2.

Parameter	UOM	1	2	3	4	5	6
Discount on FC + OPEX		No	Yes	Yes	Yes	Yes	Yes
Discount on Terminal charges		No	No	Yes	Yes	Yes	Yes
Discount on DES price		No	No	No	5%	5%	8.5%
Waiver on c-form VAT		No	No	No	No	No	Yes
Results							
Profit per year	INR Mn/year	-6,061	-4,683	-2,053	2,233	4,305	7,580
Average CUF	%	32%	32%	34%	36%	38%	40%
Fuel consumed	Mn MTPA	1.84	1.84	1.93	2.09	2.17	2.30

Table 19: Scenario analysis for assets located in pipeline zone 1.

Parameter	UOM	7	8	9	10	11	12
Discount on FC + OPEX		No	Yes	Yes	Yes	Yes	Yes
Discount on Terminal charges		No	No	Yes	Yes	Yes	Yes
Discount on DES price		No	No	No	5%	5%	8.5%
Waiver on c-form VAT		No	No	No	No	No	Yes
Results							
Profit per year	INR Mn/year	-1,514	-137	2,727	7,425	9,593	13,197
Average CUF	%	35%	35%	37%	40%	42%	44%
Fuel consumed	Mn MTPA	2.0	2.0	2.1	2.3	2.4	2.5

Scenario-8 is further iterated to understand the breakeven point and following are the outcomes under two assumed PPA tariffs:

Table 20: Further breakdown of scenario 8

At Gas PPA INR 8/kWh; RTC PPA @ INR 5.39/kWh and in assets located in pipeline zone 1

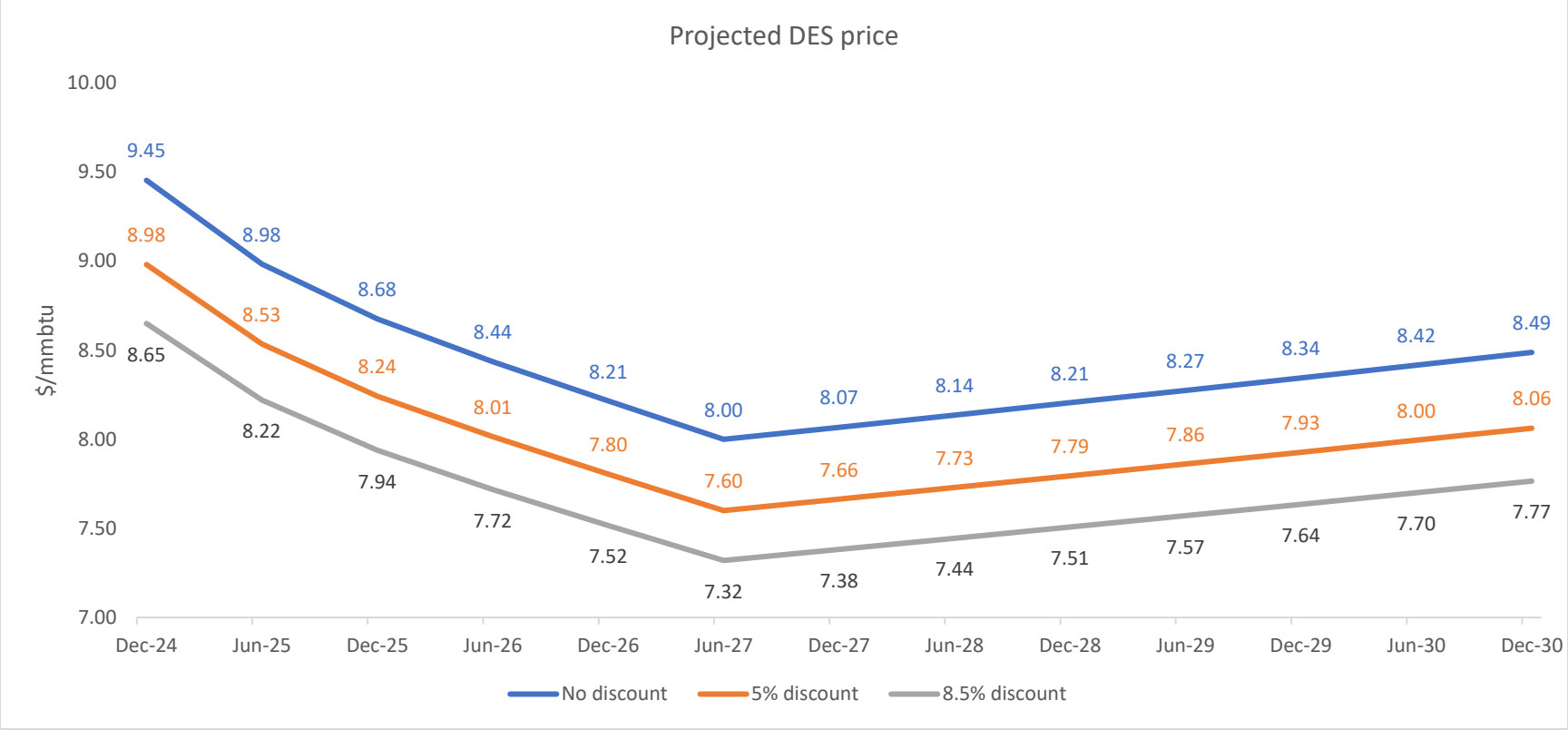
Discount on FC + OPEX (in %) \ DES Price (in USD/MMBTU)	7.5	8	8.5	9
0%	8,016	2,240	(2,983)	(7,755)
2%	8,199	2,424	(2,800)	(7,571)
4%	8,383	2,608	(2,616)	(7,388)
6%	8,566	2,791	(2,432)	(7,204)
8%	8,750	2,975	(2,249)	(7,020)
10%	8,934	3,158	(2,065)	(6,837)
12%	9,117	3,342	(1,881)	(6,653)
14%	9,301	3,526	(1,698)	(6,469)
16%	9,485	3,709	(1,514)	(6,286)
18%	9,668	3,893	(1,331)	(6,102)
20%	9,852	4,077	(1,147)	(5,918)

At Gas PPA INR 7.5/kWh; RTC PPA @ INR 5.17/kWh and in assets located in pipeline zone 1

Discount on FC + OPEX (in %) \ DES Price (in USD/MMBTU)	7.5	8	8.5	9
0%	4,846	(929)	(6,153)	(10,924)
2%	5,030	(746)	(5,969)	(10,741)
4%	5,213	(562)	(5,786)	(10,557)
6%	5,397	(378)	(5,602)	(10,374)
8%	5,580	(195)	(5,418)	(10,190)
10%	5,764	(11)	(5,235)	(10,006)
12%	5,948	172	(5,051)	(9,823)
14%	6,131	356	(4,867)	(9,639)
16%	6,315	540	(4,684)	(9,455)
18%	6,499	723	(4,500)	(9,272)
20%	6,682	907	(4,317)	(9,088)

The discounted DES price trajectory considered under 3 trajectories of 0%, 5% and 8.5% discount to DES price are as follows:

Figure 42: Discounted DES price under various discount rates to DES price

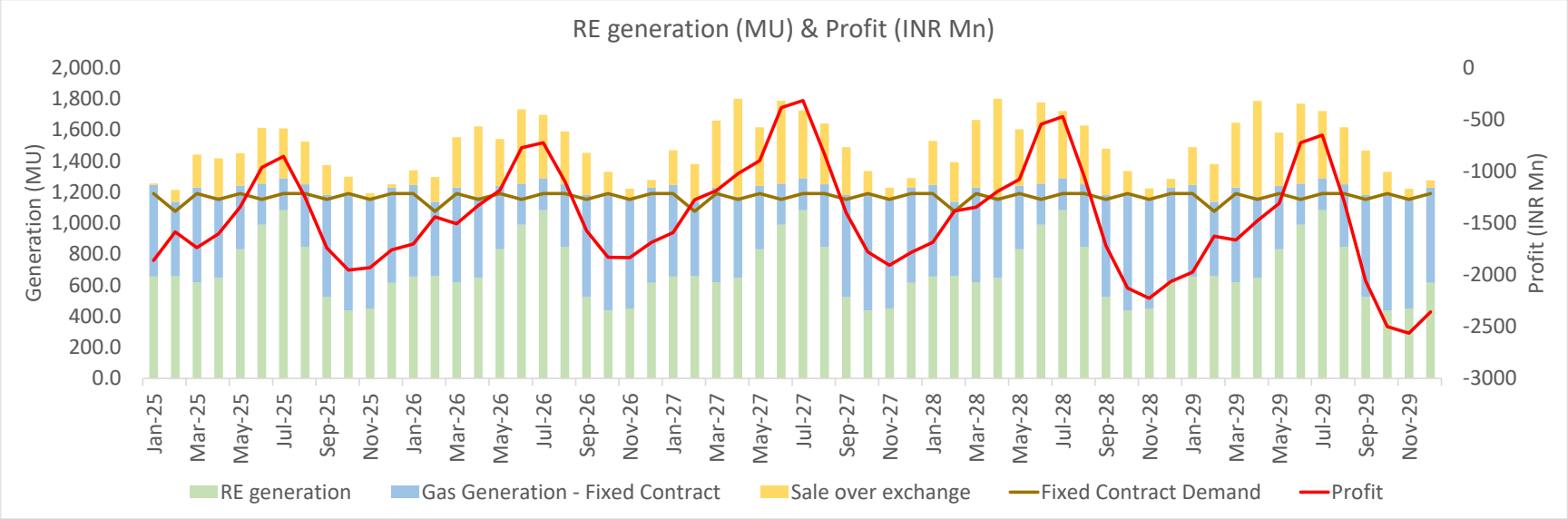


Source: Deloitte Analysis; Secondary research; Fitch & JK Morgan's Projections

Suggested contractual intervention:

Profitability is concurrent with lower RE generation months; hence a fixed contract may be sought with lower demand requirements in low RE months.

Figure 43: RE generation (MU) & Profit (INR Mn)



Fuel supply arrangement and fixed contract demand pattern may be optimized to factor RE generation pattern and seasonality of IEX power pricing, to maximize utilization and minimize losses.

Table 21: Key findings from financial model

	RE generation	IEX price	Illustrative months	Fuel supply	Gas based Power supply
1	High	High	May, Jun, Jul, Aug	High	High
2	Low	Moderate	Sep, Oct,	Moderate (exchange sale)	Low
3	Moderate	Low	Jan, Feb	Moderate (fixed contract)	High
4	Low	Low	Nov, Dec	Low	Low

Figure 44: Key output of financial model.

4 GW	Gas asset capacity that can be utilized
~37%	Capacity utilization to serve fixed contract (~56% RE) at INR 7.5/kWh and balance energy for sale on exchange
Upto 51%	Share of units sold on exchange (Sale on exchange considered **only** if sale in particular time slot is profitable)
106 Mn MMBTU/year	Average fuel consumption per year, considered in 5-year period (~2.1 Mn MTPA)

*At Gas PPA INR 7.5/kWh; RTC PPA @ INR 5.17/kWh and in assets located in pipeline zone 1

Key Parameters considered for 12 scenarios	Discount on FC + OPEX	0 – 20%
	Regasification charges	USD 0.75 – 1 per MMBTU
	DES price considered	USD 7 – 15 per MMBTU
	Waiver on c-form VAT	0 – 2%

8 Key Findings & Recommendations

8.1 Existing Practices in the Industry

- Fertilizers: this sector procures from SPOT through **monthly tendering process**. One of the NG producers recommended that the same can be replicated for power sector in which some volume of gas can be purchased under GSA (long term), and some can be for a shorter period (monthly, weekly)
- Limiting the magnitude of **offtake flexibility** will enable gas suppliers to supply efficiently and buyers will also incur **less default premiums**.
- Refinery: this sector is driven by variability & affordability and the gas is linked to Brent Index, which one of the LNG suppliers suggested that this economics of gas procurement for power sector might not work.
- CGD: Natural gas is majorly procured from domestic gas allocation and has seasonality variations. Despite increasing demand in the CGD sector, allocation ratios of domestic gas have broadly been maintained:
    - Q3 2024–25: 54.68% of projected demand allocated.
    - Q1 2025–26: 55.68% allocation
    - Q2 2025–26 (Projected): 54.74% allocation[16]

Given domestic natural gas is first allocated to priority sectors like the City Gas Distribution (CGD) sector for Compressed Natural Gas (CNG) and Piped Natural Gas (PNG), fertilizers, etc., and due to low availability of domestic natural gas, it cannot be allocated to power sector.

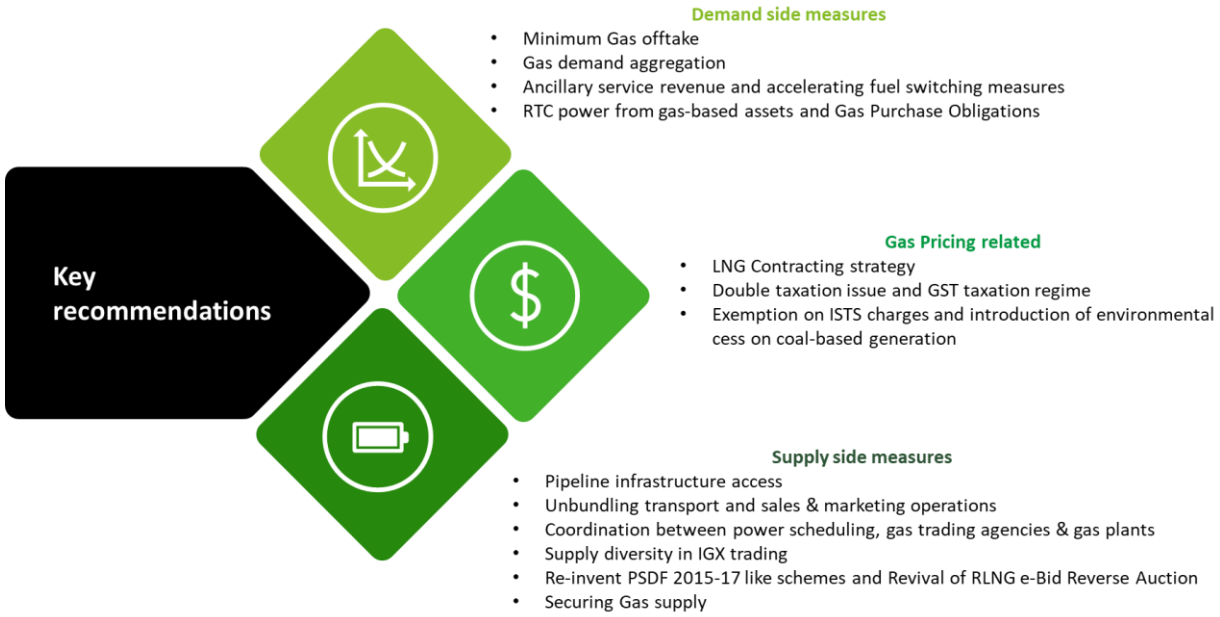
[16] Ministry of Petroleum & Natural Gas (access here)

8.2 Recommendations

8.2.1 Recommendations from stakeholder consultations

Stakeholder discussions provided various recommendations for reviving gas-based assets in India such as minimum power offtake, gas demand aggregation for power sector etc.

Figure 45: Key recommendations for G2P sector.



8.2.1.1 Demand side measures

Minimum Gas offtake

Incorporating seasonal variations ensures sustainable gas offtake commitments by balancing base loads with flexible peak demand adjustments effectively.

To ensure sustainability, gas-based assets can be operated at a **minimum base load** with the **flexibility to ramp up** during **peak demand periods**.

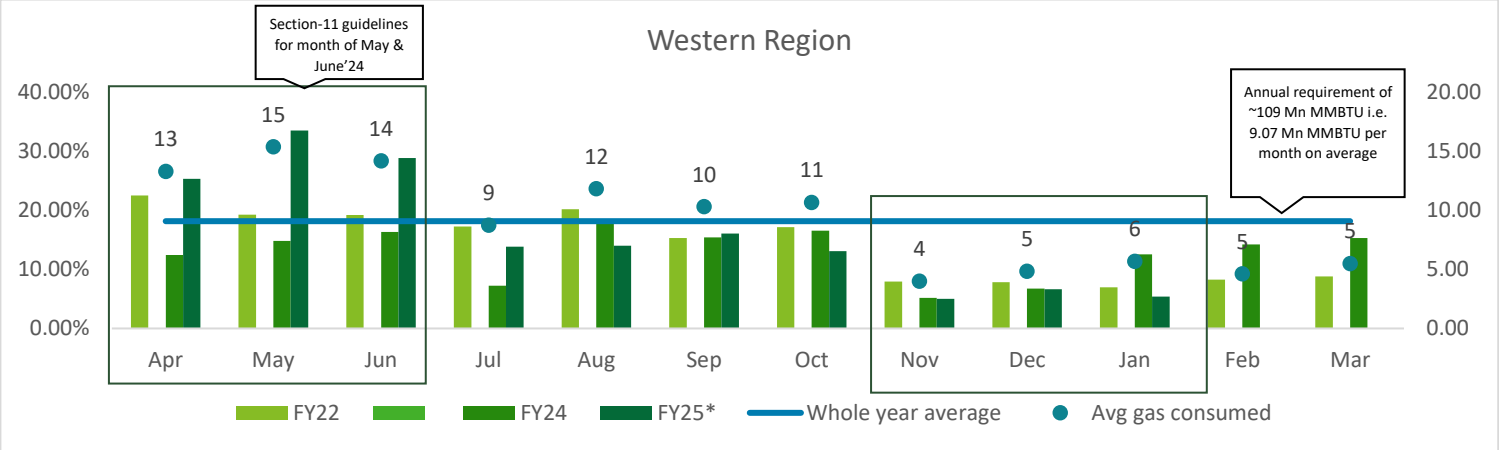
Seasonal variations (+-20%) can also be incorporated in the peak demand forecasts for ensuring **minimum contracting base loads** for a 3-5 years' timeframe.

Seasonal variations are accounted for:

- **Summer heatwaves** (April–June): Higher LNG requirement due to peak power demand.
- **Monsoon impacts** (July–September): Reduced LNG demand due to higher hydropower & wind generation.

- **Winter demand shifts** (November–February): Stable LNG demand, especially for North India's industrial heating.

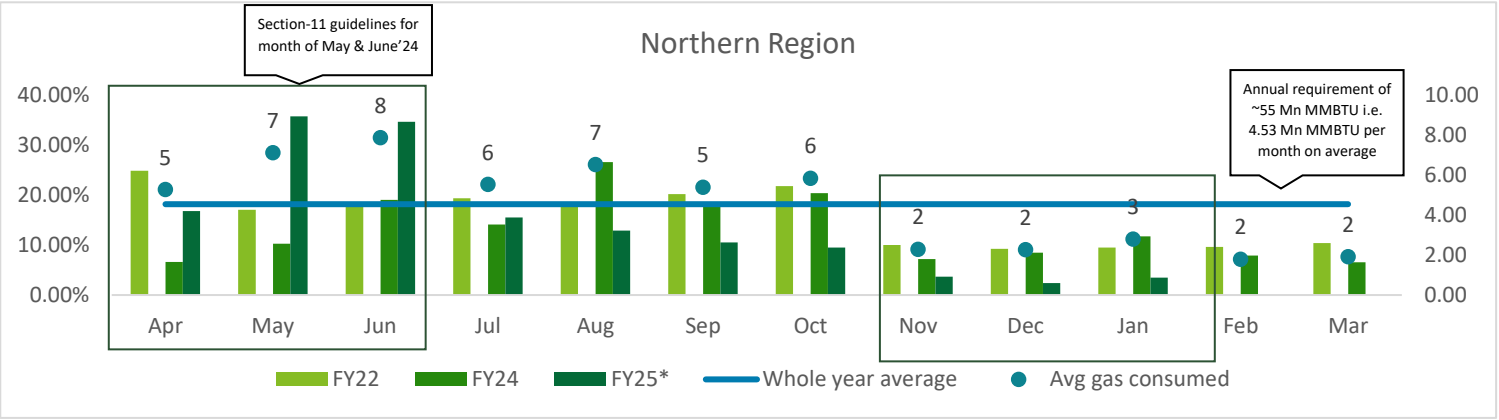
Figure 46: PLFs & Gas consumption.



Source: National Power Portal

Only pipeline connected CEA monitored utility assets considered.
FY23 data not considered due to global disruptions caused in the gas supply chain.

Figure 47: PLFs & Gas consumption.

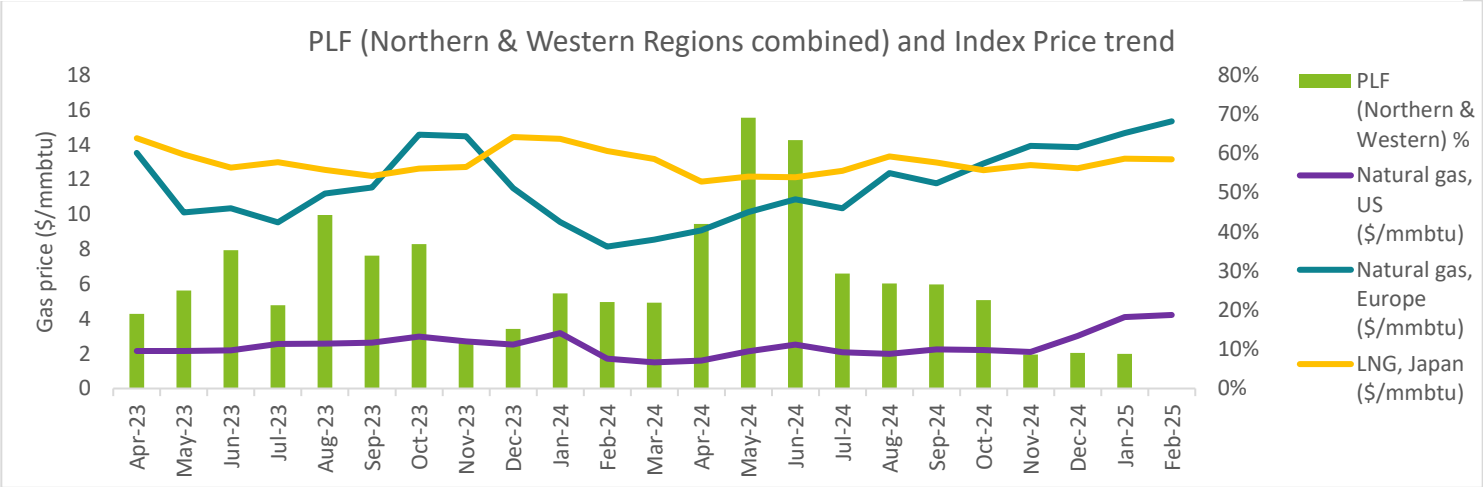


Source: National Power Portal

Region-wise monthly gas consumption can be interpreted using PLF variation of gas-based assets for last 4 financial years as shown in the above charts. The gas consumption by GBS is higher in summer months of April, May and June whereas it's on lower side in winter months of November, December & January and certain moderate spikes during monsoon months which should be considered while formulating contractual agreements.

LNG transportation costs are significant. Even if U.S. natural gas is cheaper, the cost of liquefying, shipping, and regasifying it can make the final price comparable to or even higher than buying from other suppliers closer to the market. PLF and Price trend is shown as below in the chart.

Figure 48: PLFs and Gas price trend (FY24-25)*



Source: Deloitte Analysis

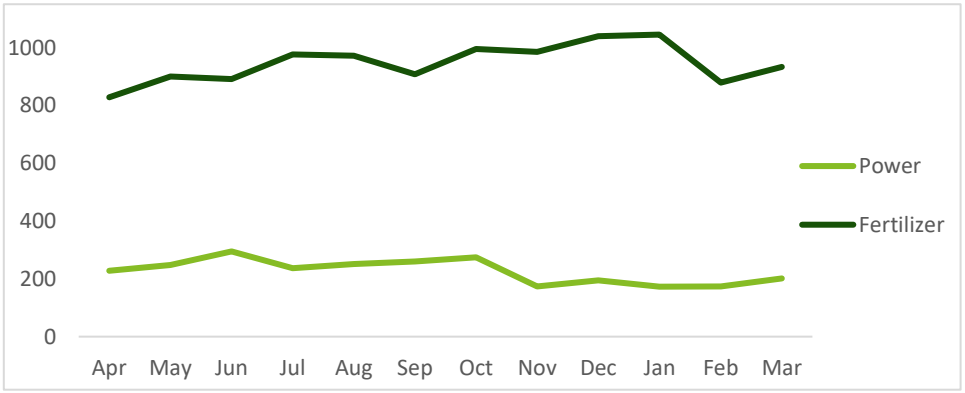
**Till Feb-25*

Gas Demand aggregation

Aggregating demand from various gas-based plants as well as the other sectors such as Fertilizers, CGD, Refinery etc. could streamline gas procurement for LNG suppliers, ensuring efficient and cost-effective supply. A Nodal Agency or Consortium could oversee this process, with the power sector **providing 3-4 months' advance notice** for optimized LNG ordering.

As per the above-mentioned recommendation by stakeholders, sectoral gas consumption data for last 9 FYs (FY16 to FY25[17]) were analyzed and it was found that Fertilizer and Power sector complements each other over seasonal peaks and troughs while other sectors such as Refinery, CGD, Agriculture, Industrial have a stable consumption pattern.

Figure 49: LNG Consumption Trend- Complementing Power sector (in MMSCM)



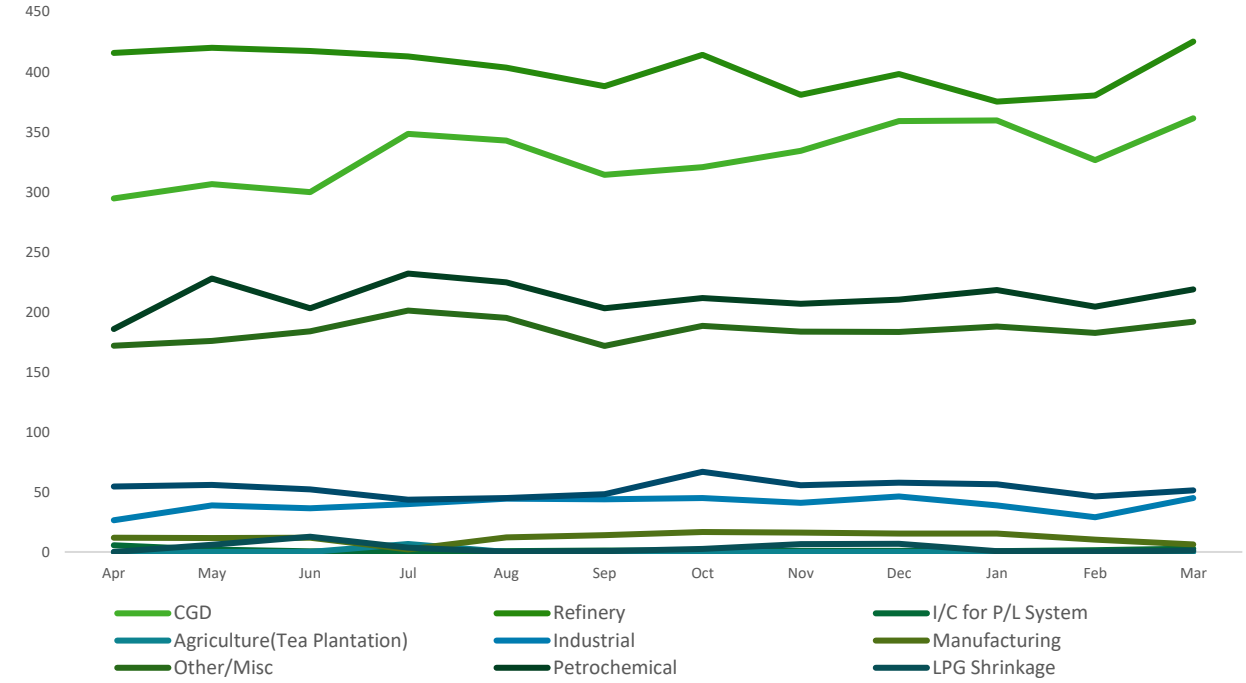
Duration	Power	Fertilizer
Summer (Apr-Jun)	↑	↑
Jul-Sep	↑	↓
Nov-Jan	↓	↑

Source: PPAC Sectoral Consumption

Fertilizer sector, having the largest gas demand, complements the power sector demand across seasonal variations and hence gas demand can be aggregated for both sectors.

[17] PPAC Sectoral Consumption Trend FY16 to FY25

Figure 50: LNG Consumption Trend- Stable wrt Power sector (in MMSCM)



Source: PPAC Sectoral Consumption

Ancillary services revenue retained by Generator in Tolling model.

Revenue Leakage for Tolling Entity (TE): The TE does not benefit from the additional revenue streams generated from the ancillary services[18].

No Upside from Market-Based Ancillary Revenue: Unlike coal-based generators that might receive Compensatory Tariff Adjustments under specific CERC guidelines, gas-based tolling entities do not receive similar compensation mechanisms.

Limited Participation in Market-Based Ancillary Services (MBAS): The TE is unable to benefit from the 2023 CERC's MBAS framework, which enables generators to earn through competitive bidding for ancillary services.

Potential solutions

- Revenue-Sharing Clause in Tolling Agreements
- Hybrid Payment Models: Instead of a purely tolling-based fee, the TE could opt for a capacity charge component linked to ancillary service earnings

[18] As per **CERC Ancillary Services Regulations, 2022**, ancillary services (frequency regulation, spinning reserve, etc.) are compensated separately from energy market payments.

Accelerating coal-to-gas switching through various govt schemes

Accelerating coal-to-gas switching could also be achieved by strengthening energy-saving targets for coal power plants under the Perform, Achieve, and Trade (PAT) scheme and broadening the Carbon Credit Trading Scheme (CCTS) to include thermal power plants.

Incorporating both energy efficiency and CO_2 emission reductions into these frameworks will create stronger incentives for fuel switching as natural gas plants offer higher efficiency and lower emissions compared to coal.

RE RTC bids to be specifically complemented with gas power generation from stranded assets

To boost stranded thermal assets, MoP had earlier issued guidelines for RTC generation by RE assets complementing with coal based thermal generation only. However, later, MoP amended the RTC Power procurement guidelines and allowed RE power to be complemented with power from any source.

Considering the advantages Gas has over other balancing power like coal, and the boost required to the stranded Gas assets, specific bids should be called for, for complementing RE power with power generation from stranded gas asset only.

This will result in increased uptake for Gas based power along with improved utilization of stranded gas-based assets.

- Increased utilization of stranded gas-based assets
- Lower carbon emissions
- Faster ramp-up and flexibility in power generation
- Efficient integration of RE sources

Gas Purchase Obligations

Gas Purchase Obligation similar to RPO considering gas being the clean source of energy. In 2022, MoPNG has suggested an obligatory purchase mechanism, along the lines of the Renewable Purchase Obligation, for reviving gas-based power plants. GPOs similar to RPOs can be introduced such that around 1% of the power must come from gas so that there can be an incentive to power off-takers as well as power generators.

This will potentially increase uptake for Gas based power from supply side.

- Enhanced Supply of Clean Energy
- Boost to Gas-Based Power Plant Utilization
- Improved Energy Security
- Alignment with Sustainability Goals

8.2.1.2 Pricing Strategies

LNG Contracting strategy.

Given India's growing reliance on imported LNG, declining contract coverage post-2028, and recent experiences with sharp demand swings due to price spikes and extreme weather events, the country would benefit from a more strategic approach to managing gas supply security.

LNG contracting strategy considering market trends and growing LNG requirements.

The global LNG market is expected to ease significantly later in the decade, while India's exposure to spot market dynamics is set to increase after 2028 with the **expiration of legacy LNG contracts.** Considering these trends, India's LNG contracting strategy may adapt to ensure long-term gas supply security and mitigate market risks such as:

- State-controlled importers to ensure that **all new LNG contracts are destination flexible** (at least within Indian LNG Terminals) and exploring joint LNG procurement for smaller city gas companies to help them negotiate better terms.
- Leveraging a period of lower international prices in the latter half of the decade could also provide an opportunity to lock in favorable LNG contracts.

Double taxation issue under "Barter system"

Globally, LNG can be sold upon reaching the destination terminal through a practice that allows for flexible transactions, though this is not currently followed in India due to double taxation concerns.

A potential solution for Indian gas-based power plants could be exploring "Barter system," which could provide similar flexibility without the tax complications.

Benefits of "Barter system" in Indian context

- Avoids double taxation, unlike direct LNG resale.
- Enhances flexibility in LNG supply without requiring physical re-transportation.
- Optimizes LNG utilization, preventing underutilization of procured cargoes.
- Supports grid reliability, ensuring plants procures gas when needed without delays.
- Reduces logistics costs, avoiding unnecessary transportation expenses.

Gas under GST regime

Gas is currently under VAT, and not GST regime, which makes it costly. There's a push to bring natural gas under GST.

The inclusion of natural gas under GST would eliminate the unequal and often unfavorable – tax treatment compared to coal and LPG. However, this reform would lead to a loss of VAT revenues currently collected by state governments on natural gas.

Benefits of under GST regime

- Seamless credit flow under GST
- Abdication of the following 2 cost components currently under VAT regime:
  - additional VAT charges applicable on Intra-state transactions (reversal of input tax credit by end consumer)
  - applicability of CST on inter-state transactions (C-form)

ISTS Charges and Losses levied on gas power to be exempted for C&I sale.

GoI has extended the ISTS charge exemptions to RE generators till 2025. To give special incentives to BESS, pump hydro projects, ISTS waive offs are provided to battery storage and pump hydro projects as well along with solar and wind. Similar waive off can be sought for gas projects for C&I sale as well. This will improve the opportunity to revive the stranded gas asset which already has capital invested.

This will result in waivers to provide fiscal benefits, gas power more economical & commercially viable and ultimately revival of stranded assets.

- Enhanced commercial viability of gas-based power
- Improved competitiveness
- Revival of stranded gas assets
- Increased investor confidence in gas-based projects

Environmental cess on coal-based generation

Introduction of an environmental cess of ₹0.50 – ₹1.00 per unit on coal-based power generation will internalize the cost of emissions, air pollution, and environmental degradation.

It will also enhance the economic viability of gas-based power by narrowing the cost gap with coal, encouraging its use as a cleaner and more efficient alternative for balancing RE generation.

This will accelerate India's clean energy transition by reducing coal dependency, optimizing stranded gas-based assets, and aligning with long-term sustainability and carbon reduction commitments.

- Improve the economic viability of gas-based power
- Enhanced Supply of Clean Energy
- Alignment with sustainability goals

8.2.1.3 Supply side measures.

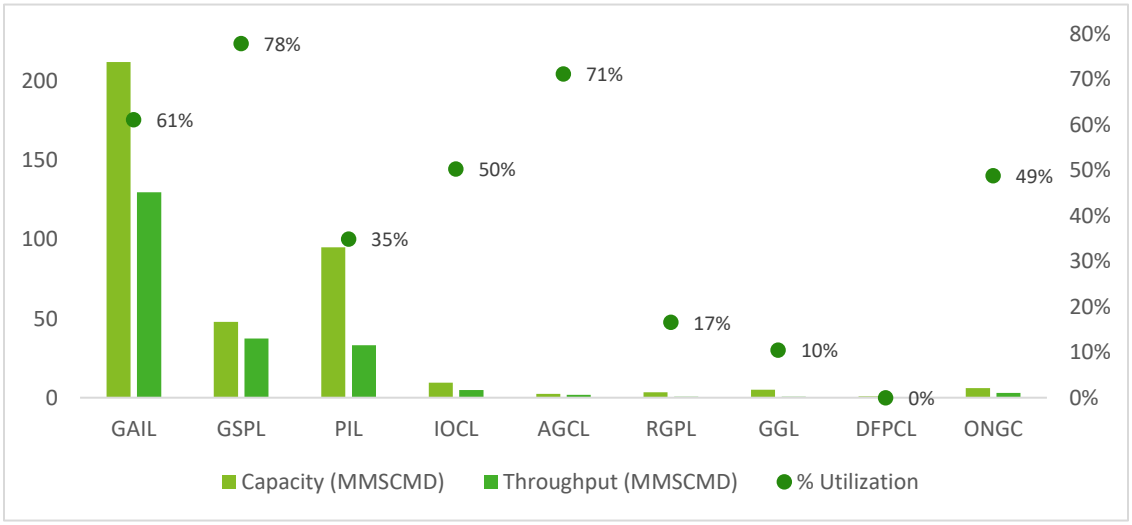
Pipeline infrastructure access.

Several Gas based plant operators have experienced obstacles with last-mile connectivity, such as expensive network expansion costs, complications in procuring financing, and a sluggish rate of pipeline development. Currently, the capacity booking for natural gas is still an opaque mechanism and there exists a need for more transparency.

Non-discriminatory third-party access to infrastructure

- Expanding **non-discriminatory third-party access** to a larger share of LNG import terminals, along with clear reporting on available capacity, tariffs, and charges, could enhance terminal utilization and secure adequate supply as India's LNG demand continues to grow.
- Enabling a more **transparent, regulated access to gas transmission pipeline infrastructure** for all market participants would boost competition and improve domestic pipeline utilization.
- Allowing CGD networks to open up for third-party access **after the marketing exclusivity period** would further enhance distribution efficiency and market competitiveness.

Figure 51: Pipeline Capacity and % Utilization-FY24



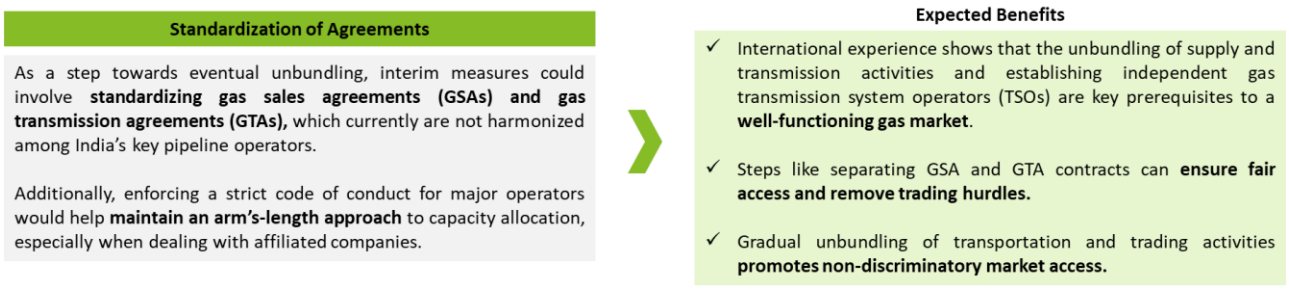
Source: PNGRB - Common Carrier NG Pipeline network

Unbundling transport and sales & marketing operations

The implementation of unbundling India's main transmission pipeline operators shall be gradually over an extended period citing India's distinct challenges and the different market conditions than matured markets in Europe and North America.

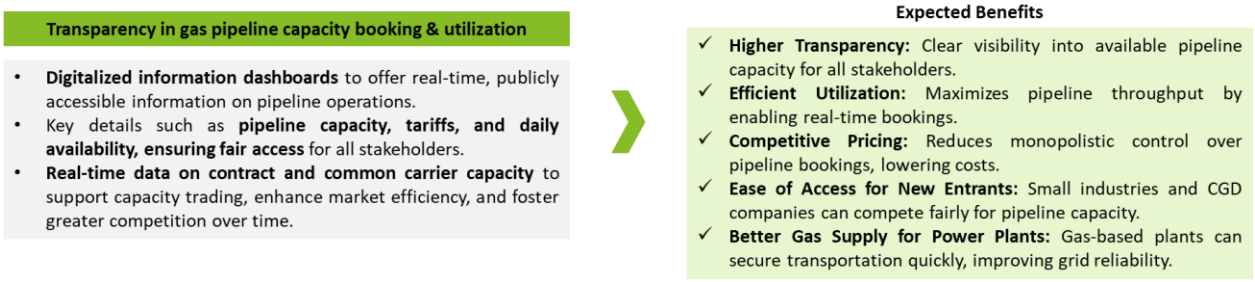
However, in the long run, legally separating transportation from marketing and sales operations could foster greater market competition, enhance flexibility, and optimize infrastructure utilization, ultimately strengthening the role of natural gas in India's energy mix.

Figure 52: Standardization of Agreements



Unbundling transport and sales operations enhances market competition, optimizes infrastructure, and promotes non-discriminatory access, strengthening India's gas market.

Figure 53: Transparency in gas pipeline network.

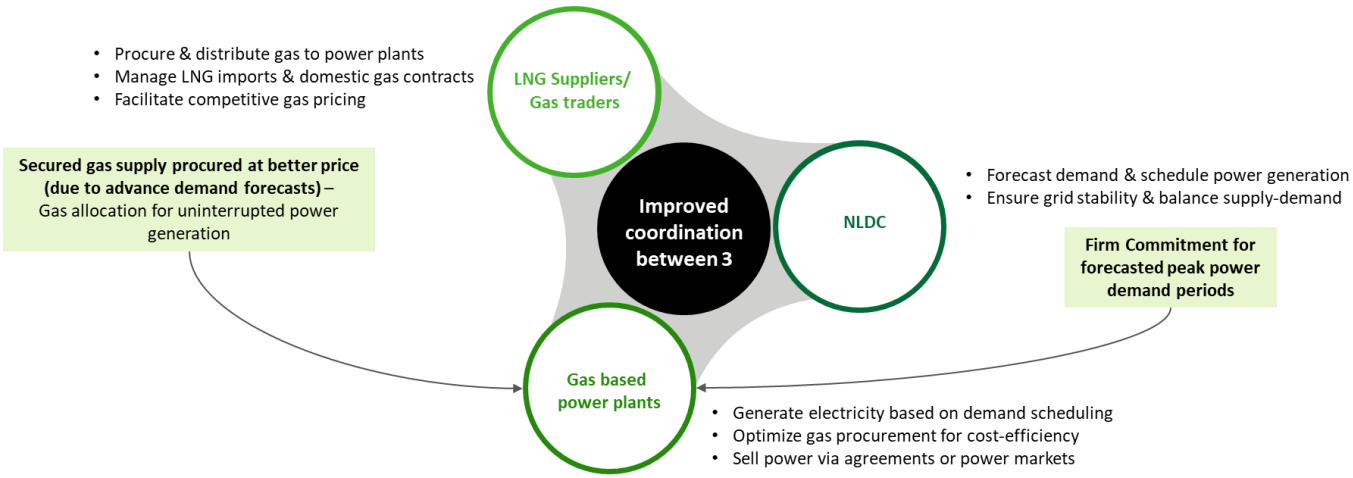


Intermediary charges resulting from the unbundling of GAIL's transportation and sales & marketing functions should be aligned with the actual value added by each activity. A proportionate and transparent cost allocation ensures economic efficiency, avoids cross-subsidization, and promotes fair competition. Such an approach is essential for fostering a balanced and sustainable natural gas market in India.

Coordination between power scheduling, gas trading agencies & gas plants

Power is scheduled in 15-minute blocks, while gas requires 3-day advance booking (GAIL has now reduced with introduction of 1-day advance day ahead booking), causing coordination issues and inefficiencies despite available supply and demand. Limited pipeline capacity utilization as well as lack of data transparency between power and gas suppliers worsen the situation.

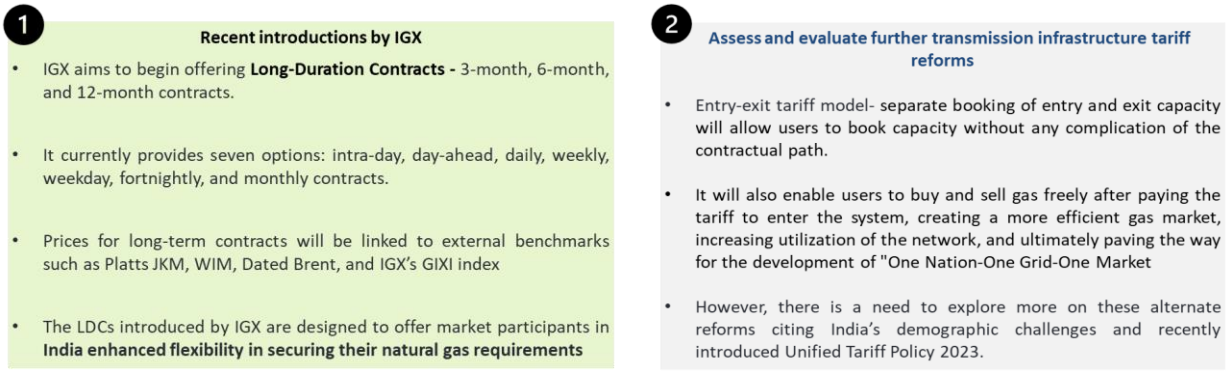
Figure 54: Coordination between different stakeholders



Enhanced coordination between power scheduling, gas trading, and plants can mitigate inefficiencies and ensure stable power supply through better planning.

Supply diversity in IGX trading.

Introducing some part of domestic gas in IGX trading, offering new Long Duration Contracts and implementing entry-exit tariff model can enhance gas market efficiency, procurement flexibility, ultimately aligning into a unified gas market amidst demographic and infrastructural challenges.



Re-invent PSDF 2015-17 like schemes.

The Power System Development Fund (PSDF) 2015-17 supported gas-based power plants by subsidizing imported RLNG costs, ensuring viability and grid stability. The scheme provided for per-unit tariff subsidy from the PSDF disbursed to the Discoms based on a reverse auction mechanism in 4 phases. Key benefits of the schemes were **Customs duty, VAT, CST, entry tax waiver on imported LNG**, **Waiver of Transmission Charges and Losses** (CTU & STU) for 2 years, **Waiver of Service Tax** on regasification and transportation of the e-bid RLNG, etc.

Stranded gas-based plants still face low utilization due to high fuel costs. A revamped scheme can help optimize gas assets and reduce reliance on coal.

- Higher PLF for gas plants
- Lower emissions vs. coal-based power
- Improved energy security and diversification
- Support for India's clean energy transition

Revival of RLNG e-Bid Reverse Auction

The Government launched the Scheme for Utilization of Gas-Based Power Generation Capacity in 2015 to revive stranded gas-based power plants and those receiving domestic gas but operating below the targeted Plant Load Factor (PLF).

The scheme aimed to supply imported spot RLNG – referred to as "e-bid RLNG" – at a reduced price and enhance the cost competitiveness of gas-based power generation.

Improved utilization of stranded gas-based plants by ensuring fuel availability at viable costs and strengthened energy security and grid reliability by promoting gas as a cleaner balancing power source.

- Increased utilization of stranded assets
- Enhanced grid stability and reliability
- Cost-competitive gas-based power
- Reduced dependence on coal

Evaluate strategic gas storage reserves.

- Small storage quantity available in the operational pipeline network (basically 2 modes of storage possible currently, both for short terms- either in terminal tanks for 15-30 days or in operational pipelines). A commercial storage facility in place which can be utilized based on "non-discriminatory rules/regulation" shall be considered.
- Presently, GAIL provides a "parking" facility to some of the major gas generators; PIL also provides a storage facility at some nominal charges/premium. (~INR 5 per MMBTU).
- A broader range of alternatives, including expanded LNG storage capacity, flexible commercial arrangements, and policy-based mechanisms, such as Japan's strategic buffer LNG framework, alongside strategic gas reserves can be considered.

SHR based domestic gas allocation.

Gas plant generators suggested that the domestic gas allocation to power plants shall be based on the plant efficiency i.e. SHR based as described below:

- Newer plants – having better SHR > more priority given.
- Older plants – having higher SHR > lesser priority given for domestic gas allocation.

Following the efficiency-based methodology, older plants which can be retired, and the gas allotted to them can be diverted to the well-functioning newer plants.

Need modifications in HP-DAM mechanism.

No response on HP-DAM market- The HP-DAM market has been inactive (with the no HP-DAM transactions) with the average price hovering around 12-13 USD per MMBTU. There also exist an issue with HP-DAM that there are only sellers but no buyers at all in the marketplace.

Key Observations (October-November 2024):

- Trading in HP-DAM was limited, occurring only between October 10-20, 2024.
- Total traded volume: 15.8 million units (MUs).
- Average price: INR 16.95 per unit—lower than the INR 20 ceiling but still relatively high.

8.2.2 Single Planning Agency mechanism

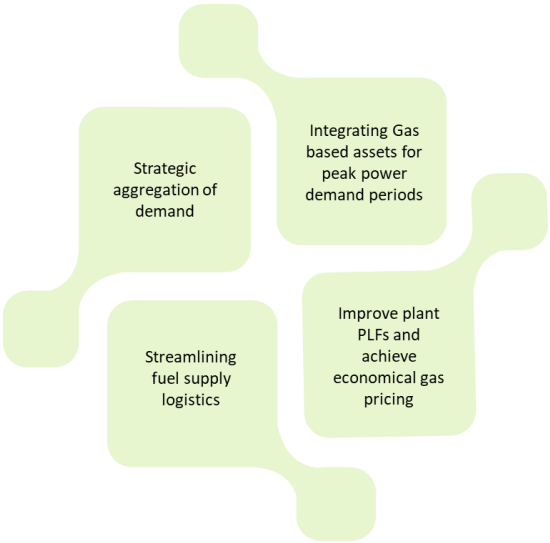
India has developed significant gas-based power generation capacity over the past decades, amounting to approx. 25 GW (recently installed capacity dropped to 20.13 GW[19]**)**. However, a large portion of this capacity remains underutilized due to constraints such as high cost of natural gas, limited availability of domestic gas, higher dependance on imported LNG leading to lack of long-term PPAs. With increasing penetration of RE in the power mix, gas-based plants offer a flexible and quick ramp-up power source that can play a crucial role in maintaining grid stability and supporting the energy transition.

Recognizing the strategic importance of gas-based capacity, there is a need for an institutional mechanism to coordinate planning, fuel supply, dispatch, and market access for these assets. A "Single Planning Agency" (or SPV), operating with representation from relevant ministries and stakeholders, can serve this role effectively.

A Special Purpose Vehicle (SPV) overlooking the gas-based assets along with the concerned stakeholders in the G2P sector which basically comprises LNG suppliers (govt entities as well as private suppliers), government agencies in Gas and Power sectors among others.

This kind of arrangement can provide:

1. Gas supply on long term basis at an economical price
2. Employment security for the gas generating station personnels.
3. Environmentally friendly energy generation as compared to coal-based generation.



This single planning agency (or SPV) having administrative mechanism in coordination with the government agencies shall:

[19] CEA April 25 data (access here)

- Have a Section-11 like mandate for meeting peak load demand periods over next 3–5-year timeframe.
- Enable to secure long term gas supplies which will subsequently reduce the SPOT price.
- Enable gas-based plants under “must run” status for improving plant utilization.
- Assist more utilization of LNG terminals which are currently not fully utilized (PLL can be considered for this arrangement as it is backed by government entities)
- Provide an option for bulk procurement of gas (maybe at a lower DES price) with the support of concerned empowered players for next 3-5 years.

Figure 55: Key players of the proposed single planning agency.

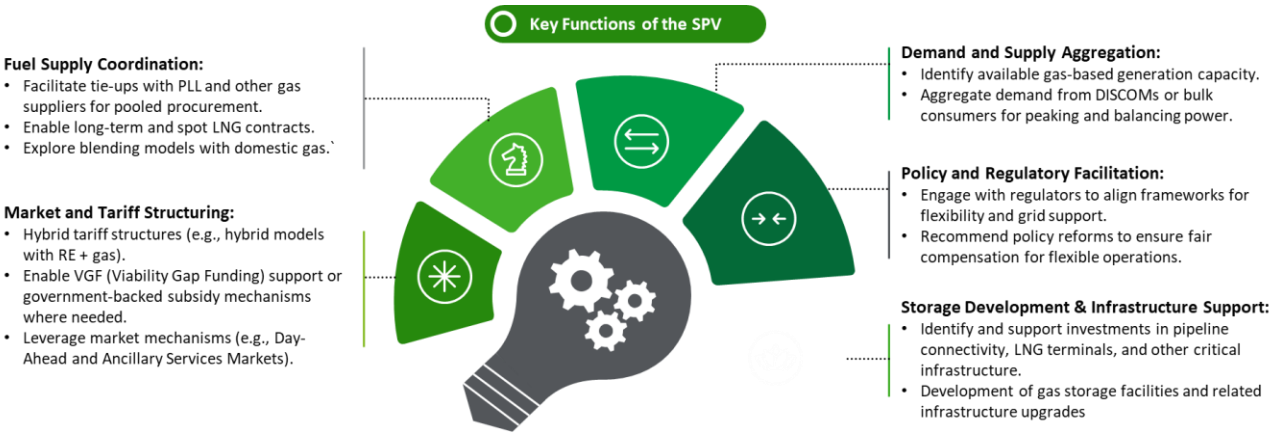
National Gas-Based Power Coordination Agency (NGPCA)

Type: Special Purpose Vehicle (SPV) / Statutory Body

Table 22: Collaborating Ministries' role.

Ministry	Responsibility
Ministry of Power (MoP)	• Creating demand for gas-based power. • Formulating schemes for DISCOMs to offtake power • Scheduling and Forecasting in Merit Order
Ministry of Petroleum and Natural Gas (MoPNG)	• Gas Demand Aggregation • Procurement of Natural Gas (through Long Term Contracts/SPOT) • Providing incentives for gas procurement

Figure 56: Key functions of SPV mechanism.



Source: Deloitte Analysis, Stakeholder interactions

A "Single Planning Agency" (or SPV), operating with representation from relevant ministries and stakeholders, can fulfill the desired integration effectively and can have expected outcomes as:

- Revival and increased utilization of stranded gas-based capacity (from ~14% PLF[20] to 50 – 60%). Thus, this arrangement will avoid the new investments and capital expenditure on new power generating sources.
- Utilization of gas-based assets will ensure lower carbon emissions and thus lower carbon footprint paving a way for sustainable development.
- Improved financial health of DISCOMs through efficient short-term procurement.
- Mandate Section-11 guidelines for GBS to generate power.
- Creation of a transparent, market-driven, and collaborative planning ecosystem.

[20] NPP April-25 Link

Table 23: Risks and Mitigation measures of SPV mechanism

Risk Category	Description	Likelihood	Mitigation Measures
Governance Risk	Conflicting interests among stakeholders leading to delays in decision-making	Medium	Establish clear governance structure, predefined decision protocols, and conflict resolution mechanisms.
Regulatory Risk	Misalignment between policies of energy, environment, and finance ministries	Medium	Regular inter-ministerial consultations; ensure regulatory harmonization and policy alignment
Operational Risk	Inefficient coordination between gas allocation, supply, and power dispatch	Medium	Implement centralized digital coordination platform with real-time monitoring and control capabilities.
Supply Risk	Inadequate or unreliable gas supply (domestic/imported LNG)	High	Diversify sources, ensure long-term contracts, maintain strategic gas reserves.
Financial Risk	Non-viability of gas-based power due to high fuel cost or lack of subsidies	Medium	Develop a transparent financial support mechanism (e.g., VGF), and explore pooled pricing models.
Legal/Compliance Risk	Delays due to legal clearances, environmental norms, or land acquisition issues	Low	Proactive regulatory compliance tracking and dedicated legal advisory support.
Technology Risk	Integration issues with grid or gas infrastructure; outdated systems	Low	Upgradation in gas infrastructure, smart grid tech, and interoperable systems.
Market Risk	Low demand for gas-based power due to cheaper alternatives (coal, renewables)	Medium	Ensure strategic dispatch planning; prioritize gas plants for peaking and balancing power
Institutional Risk	Weak institutional capacity to coordinate among multiple stakeholders	Medium	Build a dedicated, technically skilled project management unit (PMU) within the SPV

8.3 Policy Interventions

To overcome the challenges in power sector, the following table represents the key focus areas along with its impact on power sector.

Table 24: Key Focus Areas

Sr. No.	Focus Area	Description	Potential Impact on Power Sector
1.	**Replicating MoP's recent GBS Section-11 notification beyond summer months to cater high-demand periods**	The MoP notification to operationalize GBS to address increased demand May and June could also be extended to cover the other seasonal peak demand periods. Gas-based generation can bridge the gap in demand caused by increasing agricultural demand and declining hydro generation during winter months.	✓ Increase in power supply. ✓ Utilization of gas-based assets
2.	**Increasing gas demand at consumer end**	Various Government initiatives such as following shall promote the demand side of the gas to power market: • GBS as a cost-effective alternative to ESS • Replicating MoP's recent GBS optimization notification beyond summer to cater high demand periods. • Gas-based generation can bridge the gap in demand caused by increasing agricultural demand and declining hydro generation during winter months. • Gas based power can be incorporated as an alternative to coal thermal in the RE RTC tenders	✓ Increased uptake for Gas based power. ✓ Decline in gas price
3.	**Synchronization between Power trading and Gas trading market timeframes**	• With the existence of Day Ahead capacity scheduled by GAIL along with the Intra-day trading transactions, imbalances occur in the pipeline network. • Synchronization between Power trading and Gas trading market timeframes would be efficient way in which 4hours timeframe should be implemented across 6 blocks in a day for gas market transactions like the 15-minutes timeframe in a day implemented in power trading market (96-time blocks per day in IEX for trading). Also, the same may not be acceptable for pipeline operators.	✓ Optimization of gas procurement ✓ Increase in gas-based power
4.	**Storage Facility**	• Currently, there is a very small storage quantity available in the operational pipeline network (basically 2 modes of storage possible currently, both for short terms- either in terminal tanks for 15-30 days or in operational pipelines). They suggested to have a commercial storage facility in place which can be utilized based on "non-discriminatory rules/regulation". Also, GAIL provides a "parking" facility to some of the major gas generators, in addition	✓ Enhanced utilization of gas pipeline network ✓ Transportation of Gas more economical & commercially viable

Sr. No.	Focus Area	Description	Potential Impact on Power Sector
		to it PIL also provides a storage facility at some nominal charges/premium. (~Rs 5 per MMBTU). For long-term storage of gas, feasibility studies need to be done. • Access to LNG terminal should be more open and non-discriminatory with option of "Parking" accessible to every category of natural gas consumer.	
5.	**RE RTC bids to be specifically complemented with gas power generation from stranded assets**	To boost stranded thermal assets, MOP had earlier issued guidelines for RTC generation by RE assets complementing with coal based thermal generation only. However, later, MOP amended the RTC Power procurement guidelines and allowed RE power to be complemented with power from any source. Considering the advantages Gas has over other balancing power like coal, and the boost required to the stranded Gas assets, specific bids should be called for, for complementing RE power with power generation from stranded gas asset only.	✓ Another avenue for uptake of Gas based power. ✓ Improved utilization of stranded gas-based assets
6.	**ISTS Charges and losses on gas power to be exempted for C&I sale**	GoI has extended the ISTS charge exemptions to RE generators till 2025. To give special incentives to BESS, pump hydro projects, ISTS waive offs are provided to battery storage and pump hydro projects as well along with solar and wind. Similar waive off can be sought for gas projects for C&I sale as well. This will improve the opportunity to revive the stranded gas asset which already has capital invested.	✓ Waivers to provide fiscal benefits. ✓ Gas power more economical & commercially viable ✓ Revival of stranded assets
7.	**Open Access route for stranded gas assets**	MOP vide its Draft Electricity Rules, has given a priority to RE sector with following incentives: • RE Open Access to be given a priority over non-RE OA • No limit of power supply for the captive consumers taking power under RE open access. • Incentives on charges like- AS waiver, restrictions on increasing CSS over time. Similar incentives to be provided to gas power generators. OA to be prioritized for these assets, capacity restrictions to be eased out. OA charges to be waived off and increase in charges in future may also be restricted. Policy support may be sought both at the central and state level. Cues can also be taken from states like Karnataka, which had earlier introduced fixed incentives for RE projects (incentives in wheeling, transmission and OA charges) for a fixed term of as long as 10 years in its WBA. Such assurance	✓ Incentives on Open Access route will promote gas-based generators to sell power to C&I consumers

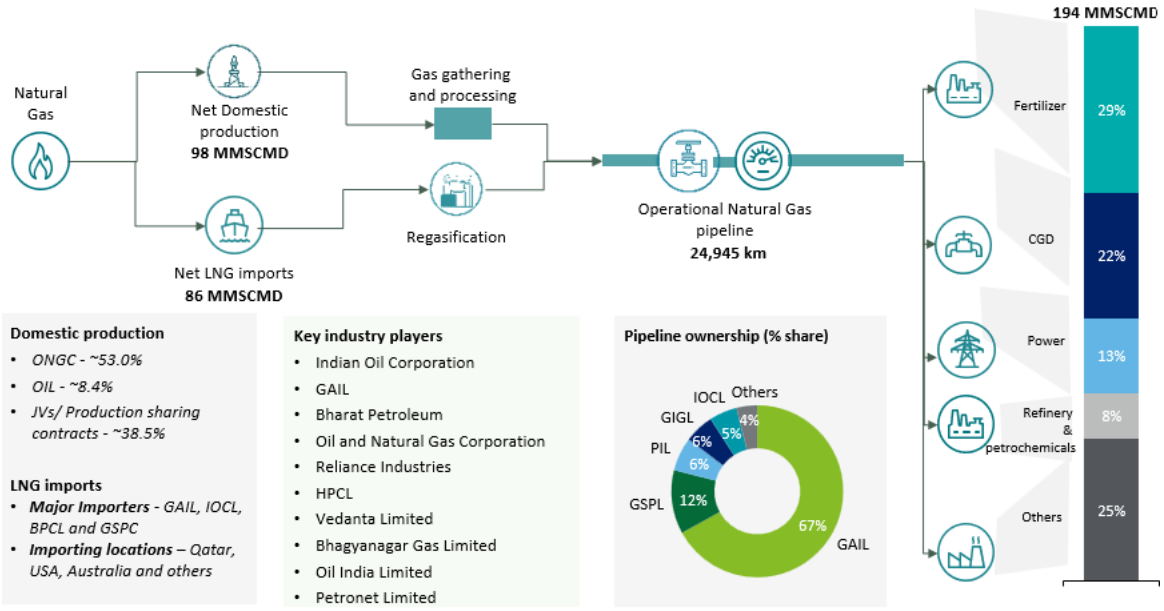
Sr. No.	Focus Area	Description	Potential Impact on Power Sector
		of incentives for a longer span of time, will give a boost to the sector.	
8.	**Inclusion of gas-based power in Green Energy policies**	State like Gujarat has come up with state specific RE hybrid policy to incentivize RE Hybrid projects with several incentives & waiver offs on ED, Wheeling charges OA charges etc. However, the current regulation is applicable for only wind solar hybrid projects. May be extended to gas-based power projects as well where RE can be the majority.	✓ Increased uptake for Gas based power from Supply point of view
9.	**Natural Gas under GST regime**	Inclusion of Natural gas under GST regime and 5% GST to be levied in line with coal for sale as well as transportation. At present, natural gas attracts central excise duty, state VAT (which varies from state to state) and central sales tax. The Kitin Parikh committee 2022 also recommended that gas should be brought under the GST regime. Having a common taxation such as GST for gas in lieu of state level VATs, which vary from 3 per cent to as high as 24 per cent, will help develop the market.	✓ Improved Market development for Gas based power
10.	**Gas Purchase Obligation**	Gas Purchase Obligation similar to RPO considering gas being the clean source of energy. In 2022, MoPNG has suggested an obligatory purchase mechanism, along the lines of the Renewable Purchase Obligation, for reviving gas-based power plants.	✓ Increased uptake for Gas based power from supply side
11.	**Tax exemptions/ Waivers on Pipeline charges**	PNGRB issued tariffs for 116 tariff paths under the Unified Tariff Policy segregated into three zones. Additional cost components in the unified tariff such as additional GST implication on the zonal tariffs (Rs 0.02/MMBTU valid till 31-May-2024) may be exempted/subsidized to reduce the overall costs for pipeline gas. IGX has also recommended to PNGRB to implement entry-exit tariff model, The EU, for instance, has moved to this mode to provide seamless gas flows. Under this model, tariff is delinked from several physical points of delivery to create a single national market comprising one virtual hub	✓ Transportation of Gas more economical & commercially viable
12.	**Replacement of thermal generation with RE under existing PPA.**	As part of its larger efforts to have 500 GW of clean energy generation capacity by 2030, MOP has enabled replacement of fossil fuel/ coal-based energy generation with energy from RE sources under existing PPA. Moreover, many states allow waiver of OA charges to RE projects. Similar options and incentives could be extended	✓ Increased uptake for Gas based power. ✓ Another avenue for uptake of Gas based power.

Sr. No.	Focus Area	Description	Potential Impact on Power Sector
		to other complementing technologies like Gas as it is also a clean source of energy	
13.	**Revival of RLNG e-Bid Reverse Auction**	Government introduced the "Scheme for Utilization of Gas Based Power Generation Capacity" in 2015 to revive the Stranded gas-based power plants and plants receiving domestic gas but operating at a PLF lower than the targeted PLF. The Main Objective of this scheme was to supply imported spot RLNG "e-bid RLNG" at a reduced price and make gas -based power more competitive. Government can reintroduce such schemes with proper assessment of gas required to complement variable RE. Bid process can be carried by a central agency with similar incentives and using innovative structures like blending of gas power with RE. etc.	✓ Government push for utilization of stranded assets
14.	**Explore Alternate Technologies for Other Gas-Dependent Sectors**	Efforts should be expedited to utilize green hydrogen for fertilizer production instead of grey hydrogen produced from natural gas and allocate the required amount of domestic gas to the power sector under a "no cut" category.	✓ Increase of gas share in power sector
15.	**Inclusion of Natural Gas as a clean energy source for green energy transition**	• As part of its larger efforts to have 500 GW of clean energy generation capacity by 2030, MOP has enabled replacement of fossil fuel/ coal-based energy generation with energy from RE sources under existing PPA. • Moreover, many states allow waiver of OA charges to RE projects. Similar options and incentives could be extended to other complementing technologies like Gas as it is also a clean source of energy.	✓ Increase of gas share in power sector

9 Annexures

9.1 Overview of Indian Natural Gas Market

Figure 57: Supply and Consumption of Natural Gas in FY25 (in MMSCMD)

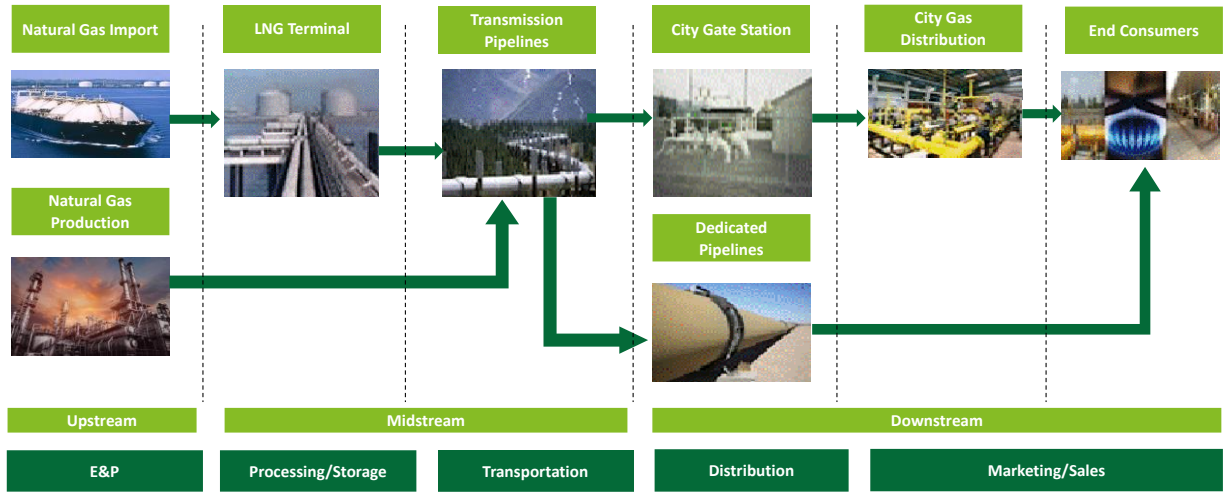


Source: PPAC

Amidst these promising developments, challenges persist within the natural gas value chain. Gas share has been stagnant owing to combination of affordability issues and infrastructure creation. Each part of the value chain is dominated by 1-2 key players leading to unfavorable dynamics in the natural gas market. While existing provisions aim to bolster market development and infrastructure, a concerted effort is imperative for India to move towards a more open and matured gas market.

A snapshot of present policy and regulatory environment across the natural gas value chain has been depicted:

Figure 58: Value chain of the Natural gas market in India.



Source: PPAC

The detailed value chain of Natural Gas market in India has been described below:

9.1.1 Upstream

LNG imports

The developing Indian gas market presents an opportunity for strategic development, particularly through a greater emphasis on long-term contracts. By prioritizing a substantial portion of gas procurement through these contracts instead of relying solely on spot supplies, which are prone to significant price fluctuations and fail to ensure energy security, India can effectively address the demands of its expanding market. Long-term contracts offer a stable and reliable solution to meet the evolving needs of a growing economy like India's. Major importers are GAIL, IOCL, BPCL and GSPC. Major exporting countries are Qatar, USA, and Australia among others.

Exploration and Production

India boasts 26 sedimentary basins, covering a vast expanse of 3.4 million square kilometers. Spanning across land areas, shallow waters up to 400 meters, and extending into the deep waters within the Exclusive Economic Zone (EEZ), these basins offer significant potential for exploration and production (E&P) activities.

To expedite E&P endeavors, the Ministry of Petroleum and Natural Gas (MoPNG) initiated the OALP Bid Round-IX for International Competitive Bidding on January 3rd, 2024. This bid round presents 28 blocks, collectively spanning approximately 136,596 square kilometers, available for bidding. Among these blocks, 9 are situated on land, 8 in shallow waters, and 11 in ultra-deep waters, distributed across 8 sedimentary basins.

This initiative aims to bolster the nation's exploration acreage, with projections indicating an increase of 0.5 million square kilometers by 2025 and an additional 0.1 million square kilometers by 2030, reflecting India's commitment to expanding its hydrocarbon exploration and production endeavors.

Natural gas-producing companies allocate a portion of their gas production for internal consumption and flaring, which is essential for technical purposes. Following these internal processes, along with accounting for flare losses, the net production available for sale to various consuming sectors such as power, fertilizer, city gas distribution (CGD), refineries, and petrochemicals, amounted to approximately 82.38% of the gross production in April 2024.

ONGC and OIL collectively dominate the production segment of the value chain, accounting for approximately 53% and 8.4% respectively. Meanwhile, joint ventures (JVs) and production sharing contracts contribute significantly, making up around 38.5% of the total production share.

9.1.2 Midstream

LNG terminals

Over the past five years, India has significantly expanded its LNG terminal infrastructure, increasing total capacity by nearly two-thirds to approximately 45 MTPA. An additional 20 MTPA of capacity is currently under development, reflecting the country's continued focus on strengthening its gas import infrastructure. Despite this substantial growth, average capacity utilization remains suboptimal, primarily due to subdued domestic gas demand and inadequate evacuation infrastructure. As of FY2024–25, India operates seven LNG terminals, with average utilization improving modestly to around 56%, up from 50% in the previous year. This improvement is largely attributed to a 21% year-on-year increase in LNG imports. However, terminal-wise utilization exhibits considerable disparity. Petronet LNG's Dahej terminal operates at a high efficiency level of 95%, whereas its Kochi terminal remains significantly underutilized at approximately 20%, largely due to the absence of a fully operational pipeline network connecting it to major demand centers. Looking ahead, two new terminals—HPCL Shapoorji Energy Private Limited's Chhara facility and Swan Energy Ltd.'s Jafrabad terminal—are expected to commence operations within the current fiscal year, which may further influence utilization trends and regional supply dynamics.

List of operational LNG terminals:

- Dahej (Petronet) – 17.5 MMTPA
- Hazira (Shell) – 5.2 MMTPA
- Dabhol (GAIL) - 5 MMTPA
- Kochi (Petronet) – 5 MMTPA
- Ennore (IOCL) – 5 MMTPA
- Mundra (GSPC) – 5 MMTPA
- Dhamra (Adani) – 5 MMTPA

Companies intending to establish new LNG terminals or expand existing ones must obtain downstream regulation approval from PNGRB. The draft regulation targets both operational and future terminals, necessitating registration with the regulator. Additionally, any entity planning to construct an LNG terminal must notify PNGRB before finalizing investment decisions.

Natural gas Storage

India is considering the construction of gas storage facilities to mitigate supply disruptions. Following rationing of gas to sectors like fertilizers due to import interruptions from Russia during the Ukraine conflict, India recognizes the need for gas storage to ensure steady supply and mitigate global price volatility. While India possesses strategic oil reserves, gas storage infrastructure remains lacking. Potential storage solutions include repurposing abandoned gas wells and implementing underground storage facilities.

Natural gas pipelines

GAIL holds ownership of 67% of the pipeline, with GSPL, PIL, GIGL, and IOCL accounting for 12%, 6%, 6%, and 5% respectively.

Gas pipelines are crucial for safe and cost-effective transportation of natural gas from sources to markets. By 2024-25, the goal was to increase pipeline coverage by 54% to 34,500 km (currently operational network is 33,475km), ultimately connecting all states by 2027 for enhanced economic and social progress.

9.1.3 Downstream

Domestic natural gas allocation to end-users is managed by GAIL on a biannual basis. PPAC provides GAIL with average consumption data for each City Gas Distribution (CGD) sector, encompassing CNG (transport) and PNG (domestic) segments, along with other sectors such as fertilizer, power, LPG, etc.

9.2 Natural Gas Production

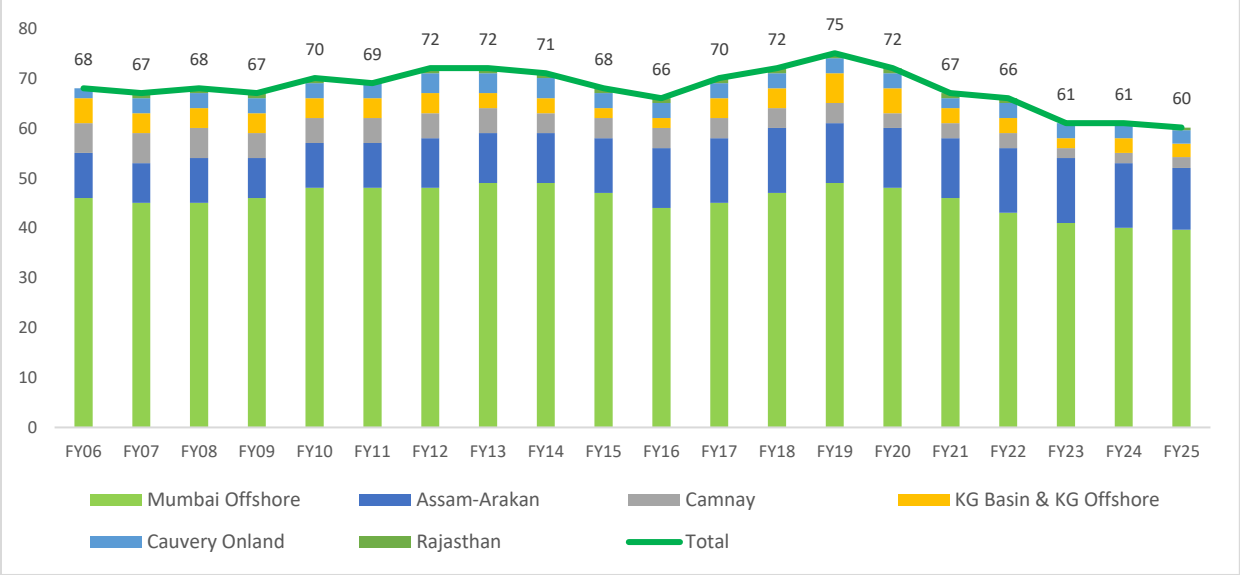
Natural gas can be obtained in 2 ways – Domestic production and LNG import which are discussed further.

9.2.1 Domestic Production

Domestic production in India can be further divided into 2 categories – Production from National Oil Companies (NOCs) and Production from Pvt./JV Companies (under Production Sharing Contracts-PSCs).

As of FY25, out of total domestic production of 98 MMSCMD, 60 MMSCMD came from NOCs while the rest 38 MMSCMD came from Pvt./JV companies.

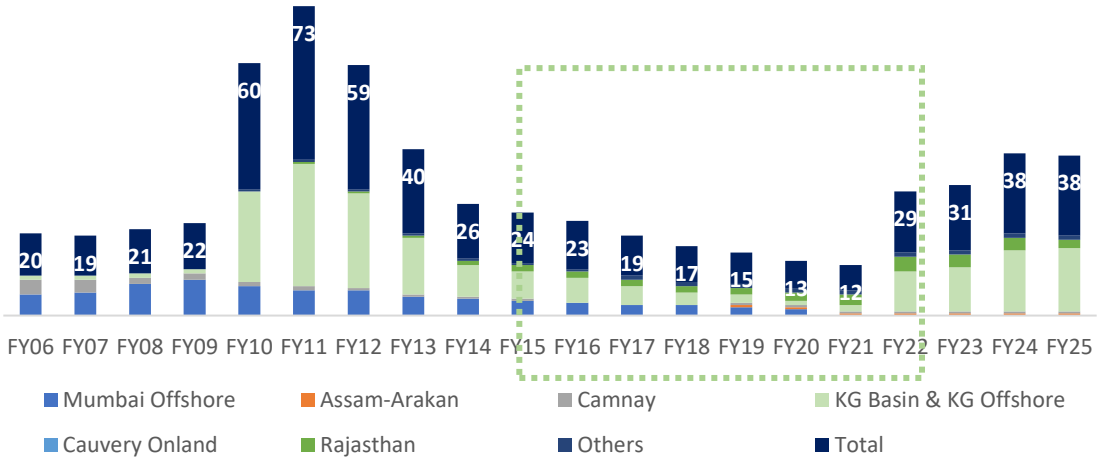
Figure 59: National Oil Companies (NOCs) basin-wise domestic production (in MMSCMD)



Source: ICED NITI Aayog Dashboard

Around 65 – 70% of the domestic production by NOCs comes from Mumbai offshore basin followed by Assam-Arakan, KG Basin & Offshore as of FY25 production by NOCs.

Figure 60: Pvt./JV Companies (PSCs) basin-wise domestic production (in MMSCMD)



Source: NITI Aayog Dashboard

Around 40 – 50% of the domestic production by Pvt./JV companies under PSCs comes from KG Basin & KG Offshore. Domestic production of Pvt./JV companies reached the maximum level of 73 MMSCMD in FY11 and has seen a declining trend and reached to a level of 12 MMSCMD in FY21 and onwards. To resolve this issue, government launched the national seismic programme in 2016 to carry out assessment of unpraised areas across the country for potential oil and natural gas reserves.

Also, domestic production from Pvt./JV Companies under PSCs has risen due to recent discoveries in KG – D6 basin.

Recent developments in KG – D6 basin

- In May 2023, the MJ oil and gas well in the KG-D6 block began production, which is the most recent discovery in the basin.
- Reliance Industries Ltd (RIL) and its partner BP Plc have received government approval to invest more in developing gas reserves in the KG-D6 block, which could increase production by 4–5 million standard cubic meters per day.
- The R Cluster, Satellite Cluster, and MJ fields are expected to produce 30 million metric standard cubic meters per day (MMSCMD) of gas by FY2024, which could contribute about 30% of India's gas production.
- So far, Reliance has discovered 19 gas fields in the KG-D6 block. D-1 and D-3, the largest of the lot, were brought into production in April 2009, while MA, the block's solitary oilfield, and was placed into production in September 2008.
- KG-D6 has increased the domestic output of natural gas, which is used to generate electricity, make fertilizer, or be converted into CNG for use in autos or piped to kitchens for cooking, to a multi-year high of 99 mmscmd.

Additionally, with decline in production from legacy fields, vast operationalization timeline of new discoveries till production in challenging geological complexities, and lack of any major new discoveries in recent years, production from NOCs like ONGC and OIL has decreased in most basins.

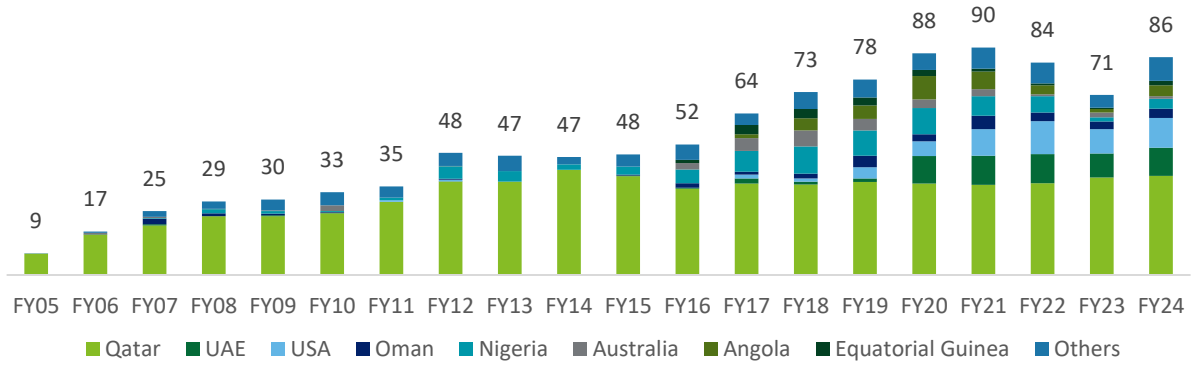
The government had introduced various policy reforms (since 2015 till date) such as HELP, OALP, and DSF to enhance domestic Exploration and Production (E&P) activities which is described later in this report.

9.2.2 LNG Import

Till 2015, India used to import nearly 70 – 80% from Qatar, post which the quantum of LNG import from Qatar stayed constant but the total import increased as India increased its import and started diversifying. In 2021, total import peaked at 90 MMSCMD, nearly twice the import in 2015.

As per FY24 statistics, total imported LNG was 86 MMSCMD in which Qatar (45%), USA (14%) and UAE (13%) are the major countries from which LNG is imported. Countries such as Oman (5%) and African countries such as Nigeria and Angola contributed approx. 5% each of total LNG Imports followed by a minuscule share of Australia (1%).

Figure 61: LNG Import trend by country (in MMSCMD)



Source: ICED NITI Aayog Dashboard

In recent 5 years, import from UAE and USA has seen a step rise with each having a share of ~12 % in overall LNG import in FY24.

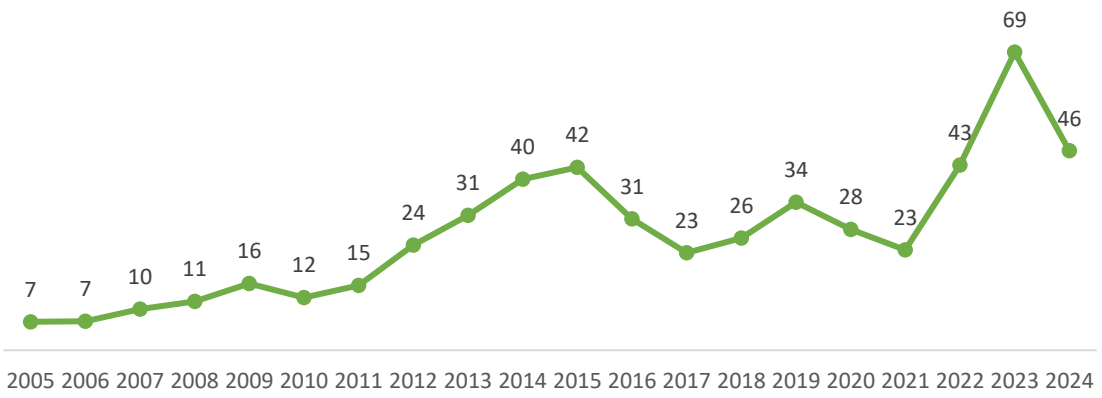
Table 25: Major countries for LNG import (in MMSCMD)

Year	Qatar	UAE	USA	Oman	Nigeria	Australia	Angola	Equatorial Guinea	Others
FY19	37	1	4	5	10	4	5	3	7
FY20	36	11	6	3	10	3	9	2	7
FY21	36	12	10	5	8	3	7	1	8
FY22	36	12	13	3	6	1	4	1	8
FY23	39	10	10	3	2	2	1	1	5
FY24	39	11	12	4	4	1	4	2	9

Source: ICED NITI Aayog Dashboard
(All numbers are rounded off)

Due to surge in LNG import prices from INR 23.3 per Kg in 2021 to INR 46 per Kg in 2024, LNG import has declined from 90 MMSCMD in 2021 to 71 MMSCMD in 2023 which increased to 86 MMSCMD in 2024, although the monetary value of LNG import has also increased from INR 58.3 thousand crore in 2021 to INR 111 thousand crore in 2024.

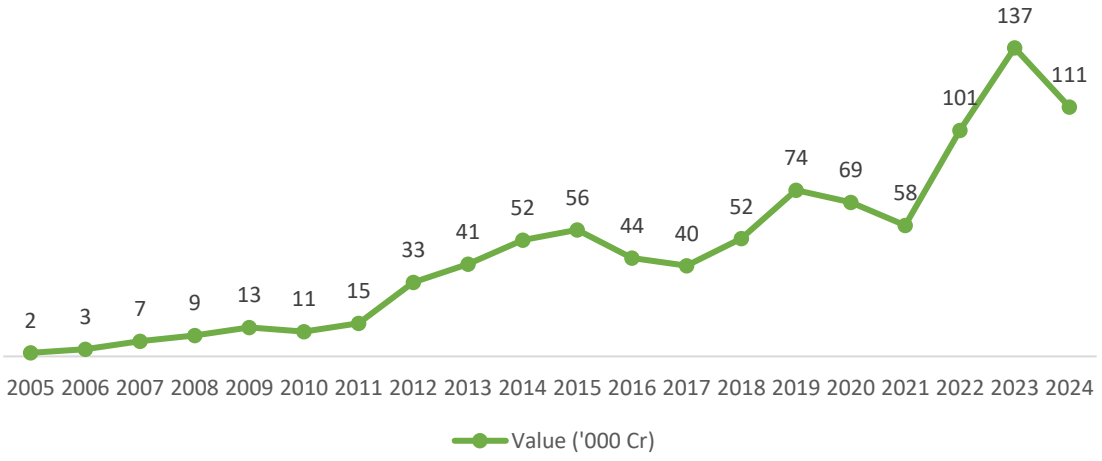
Figure 62: RLNG Average Import Price (in INR/Kg)



Source: NITI Aayog Dashboard

The RLNG import prices in India has seen an upward trend over the years, with a few fluctuations, indicating a significant growth in the RLNG import market. The RLNG import prices in India have been influenced by various factors such as changes in global LNG supply and demand, infrastructure development, and government policies and increasing demand particularly in the fertilizer and city gas distribution sectors along with the growth of regasification capacity in India.

Figure 63: Monetary value of import (in '000 Cr)



Source: Source: NITI Aayog Dashboard

9.3 RLNG Terminals

LNG (liquefied natural gas) is delivered to LNG terminals in a highly condensed liquid state after being super-cooled. At the terminal, the LNG is warmed up in special regasification units, converting it back into natural gas in its original gaseous form. This RLNG is then transported via pipeline networks to end users across the country.

Another method of LNG delivery is using specialized LNG trucks. These trucks can transport LNG directly to end users or to smaller satellite terminals where it can be re-gasified and fed into local pipeline systems.

India has 7 operational LNG terminals at Dahej, Hazira and Mundra in Gujarat, Dhabol in Maharashtra, Kochi in Kerala and Ennore in Tamil Nadu details of which is mentioned in the table below.

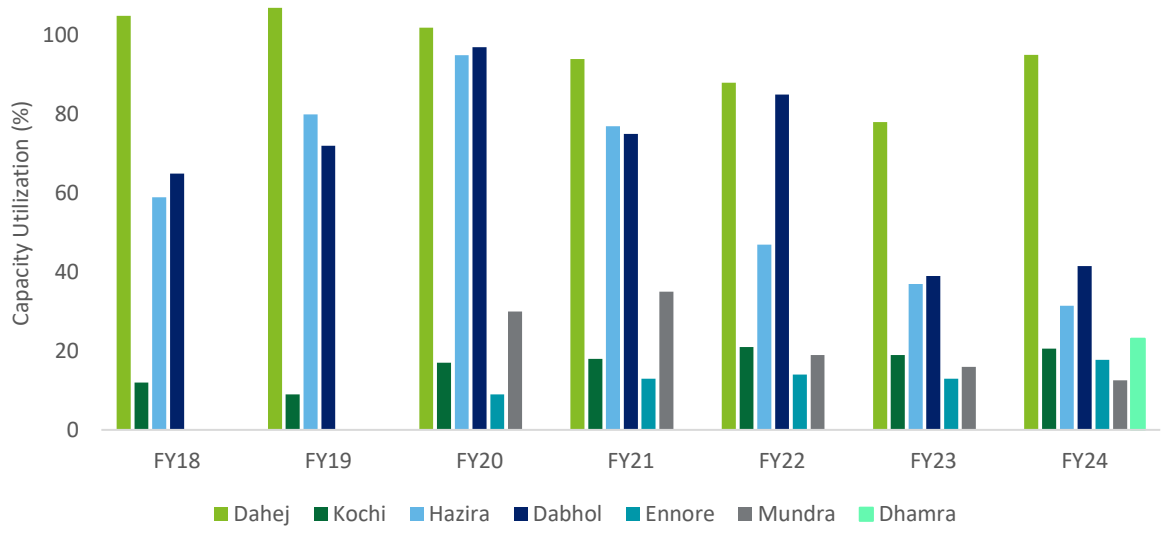
Table 26: LNG Terminals in India

Terminal	Promoters	Capacity (MMTPA)
Operational LNG Terminal		
Dahej (Gujarat)	Petronet LNG Ltd. (PLL)	17.5
Kochi (Kerala)		5.0
Hazira (Gujarat)	Hazira LNG Pvt. Ltd. (HLPL)	5.2
Dhabol (Maharashtra)	Ratnagiri Gas and Power Pvt. Ltd. (RGPPL- JV of GAIL & NTPC)	5.0
Ennore (Tamil Nadu)	Indian Oil LNG Pvt. Ltd. (IOLPL)	5.0
Mundra (Gujarat)	GSPC LNG Limited (GLL)	5.0
Dhamra (Odisha)	Adani LNG Pvt Ltd	5
Planned/Under-Construction LNG Terminals		
Dhabol Expansion	GAIL(KLPL)	3
Jaigarh (Maharashtra)	H-Energy	4
Jafrabad (Gujarat)	Swan Energy	5
Chhara (Gujarat)	HSEPL	5

Source: IPNG Statistics 2023

Out of these seven LNG terminals, four are operating below 25% capacity and another two are operating below 40%. Only the Dahej terminal, India's oldest and largest, operates above 95% capacity.

Figure 64: RLNG Terminals Capacity Utilization (in %)



Source: IPNG Statistics 2023

9.4 Pipelines

The Pipeline Network in India for transporting petroleum products is vast and spreads across different regions. Gas Pipeline infrastructure is an economical and safe mode of transporting the natural gas by connecting gas sources to gas consuming markets. Gas pipeline grid determines the structure of the gas market and its development.

Table 27: Common Carrier Natural Gas pipeline network as on 31.12.2024

Nature of pipeline		GAIL	GSPL	PIL	IOCL	AGCL	RGPL	GGL	DFPCL	ONGC	GIGL	GITL	Others*	Total
Operational	Length	11,007	2,761	1,483	143	107	304	73	42	24				**15,944**
	Capacity	233.2	43	85	20	2.4	3.5	5.1	0.7	6.0				-
Partially commissioned#	Length	5,062			1,080						1,302	364		**7,808**
	Capacity													-
Total operational length		**16,069**	**2,761**	**1,483**	**1,223**	**107**	**304**	**73**	**42**	**24**	**1,302**	**364**	**0**	**23,752**
Under construction	Length	3,607	100		416						899	1,737	2,640	**9,399**
	Capacity	26.3	3.0		1.0						0.0	36	42.0	-
Total length		**19,676**	**2,861**	**1,483**	**1,639**	**107**	**304**	**73**	**42**	**24**	**2,201**	**2,101**	**2,640**	**27,516**

Source: PPAC Existing NG Pipeline Structure
*Length in KMs; Authorized Capacity in MMSCMD (Arithmetic sum taken for each entity -capacity may vary from pipeline to pipeline); *Others-APGDC, IGGL, IMC, GTIL, HPPL Consortium of H-Energy. Total authorized Natural Gas pipelines including Tie-in connectivity, dedicated & STPL is 33,475 Kms (P), however total operational and Under Construction Pipeline length is 35,750 Kms (P)*

Currently, 23,752 km of common carrier natural gas pipeline network is operational (including partially commissioned) out of which GAIL owns 16,069 km (~67%).

Table 28: Natural Gas Pipelines Network in India (as of September 2024)

Details		Length (km)	Total (km)
Authorized Natural Gas Pipelines	Common Carrier	31,903	33,475
	Tie-in connectivity	792	
	Dedicated	780	
Operational Natural Gas Pipelines	Common Carrier	23,573	24,945
	Tie-in connectivity	202	
	Dedicated	653	
	STPL	517	
Under Construction Natural Gas Pipelines	Common Carrier	9,528	10,805*
	Tie-in connectivity	593	
	Dedicated	122	
	STPL	562	

Source: PNGRB data

Out of total 33,347 km of authorized natural gas pipeline around 70% are in operational phase whereas the rest 30% are under construction.

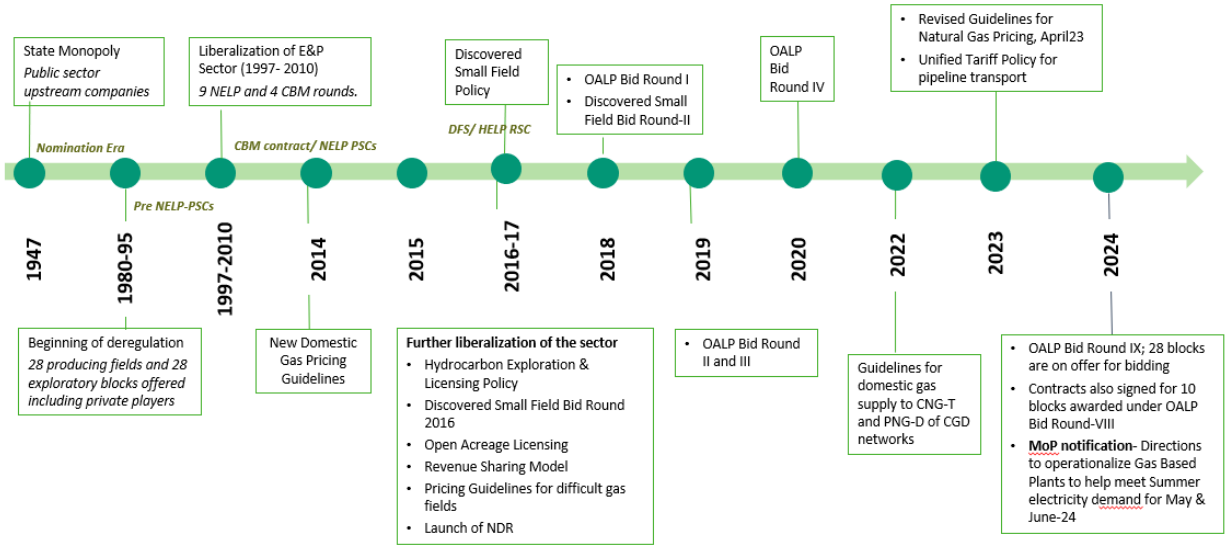
* The variation in the sum of the lengths of Operational and Under Construction Natural Gas Pipelines vis-à-vis the length of the Authorized pipelines are on account of one or more of the following factors:

i. Variation in As-Built length due to site conditions,
ii. Additional pipelines laid by the authorized entities for providing connectivity within the tariff corridor in line with the provisions of the NGPL Authorization Regulations,
iii. Length of the operational and Under Construction pipelines as above includes the available length of Sub-Transmission Pipelines (STPL) owned by CGD entities, etc.

9.5 Government schemes and policies for Natural Gas market

The government implemented various policies such as HELP, DSF, Gas pricing guidelines etc. in the last decade to boost domestic production of natural gas. Below are the notable government interventions and schemes issued in recent past years.

Figure 65: Timeline of government interventions.

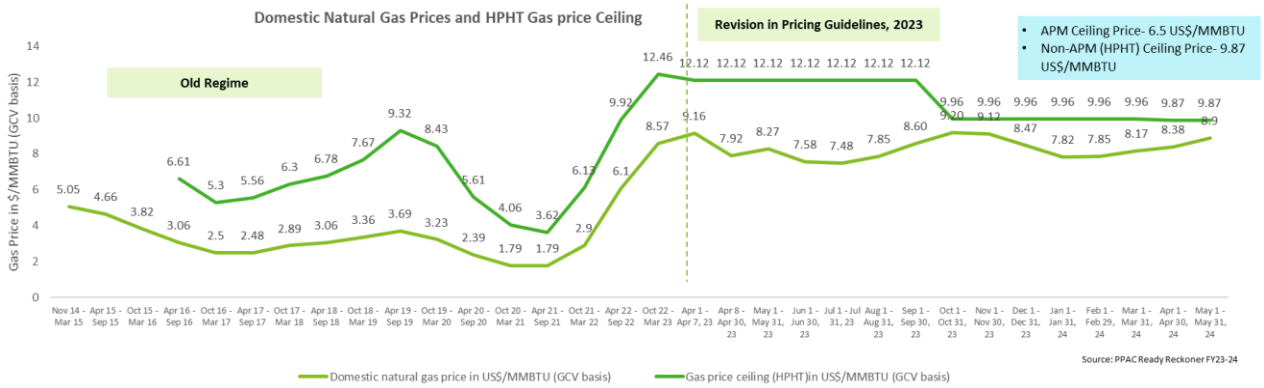


9.5.1 Revised Guidelines for Natural Gas Pricing 2023

The Government has approved the revised domestic natural gas pricing guidelines in April 2023 for gas produced from nomination fields of ONGC/OIL, New Exploration Licensing Policy (NELP) blocks and pre-NELP blocks, where Production Sharing Contract (PSC) provides for Government's approval of prices. The price of such natural gas shall be **10% of the monthly average of Indian Crude Basket** and shall be notified monthly. For the gas produced by ONGC & OIL from their nomination blocks, the Administered Price Mechanism (APM) price shall be subject to a floor and a ceiling. The initial floor and ceiling prices shall be $4/MMBTU and $6.5/MMBTU respectively. The ceiling would be maintained for the next two years (FY 2023-24 and 2024-25) and then increased by $0.25/MMBTU each year. Gas produced from new well or well intervention in the nomination fields of ONGC&OIL, where APM prices are subject to floor and ceiling, would be allowed a premium of 20% on these APM prices.

The reforms have led to significant decrease in prices of Piped Natural Gas (PNG) for households and Compressed Natural Gas (CNG) for transport.

Figure 66: Domestic Natural Gas Prices and HPHT Gas price Ceiling.



The new guidelines are intended to ensure stable pricing regime for domestic gas consumers while at the same time providing adequate protection to producers from adverse market fluctuation with incentives for enhancing production.

These reforms are a continuation of the various initiatives taken by Government of India to protect the interests of consumers by reducing the impact of increase in international gas prices on gas prices in India by significantly increasing the domestic gas allocation to City Gas Distribution sector.

9.5.1.1 Domestic Gas Pricing Guidelines 2014

Earlier the domestic gas prices are determined as per the new Domestic Gas Pricing Guidelines, 2014 which were approved by Government in 2014. The 2014 pricing guidelines provided for declaration for domestic gas prices for a 6-month period based on the volume weighted prices prevailing at four gas trading hubs - Henry Hub, Albena, National Balancing Point (UK), and Russia for a period of 12 months and a time lag of a quarter.

Marketing and Pricing freedom for gas producer from

1. High Pressure High Temperature (HPHT) reservoirs
2. Deepwater, ultra deepwater and difficult areas
3. Coal Bed Methane

As the earlier 2014 guidelines were based on 4 gas hubs and had a significant time lag & very high volatility, the revised guidelines in 2023 were introduced which made prices linked to the crude, more relevant to the consumption basket and has deeper liquidity in global trading markets, on a real time basis.

9.5.2 Unified Tariff Policy 2023

The Petroleum and Natural Gas Regulatory Board (PNGRB) introduced the Unified Tariff (UFT) policy in April 2023 to create a single, consistent and fair tariff structure for natural gas transport across the country. The UFT policy apply to a network of 21 pipelines, representing around 90 % of pipelines in operation or under construction. The price of transporting gas consists of two components - a fixed unified tariff based on the levelized cost of service of the entire pipeline network, and a variable zonal factor depending on distance.

PNGRB has announced unified pipeline tariff w.e.f. 01.04.2024 till 31.05.2024 to be Rs.81.13/MMBTU (including additional GST implication of Rs.0.02/MMBTU) on GCV basis having unified zonal tariffs as follows:

Table 29: Pipeline tariff across different zones

Tariff Zone	Distance from gas source	Tariff (in Rs/MMBTU on GCV basis)
Zone-1	Up to 300kms	40.00
Zone-2	300 to 1200kms	79.00
Zone-3	Beyond 1200kms	114.52

Source: Unified Tariff Policy 2023

The main objective of the Unified Tariff Policy is to provide access of natural gas in the far-flung areas at competitive and affordable rates.

With commissioning of newer interconnected pipelines, the national gas grid will keep expanding for Unified tariff. These entities will get the tariff as per their entitlement while customers would pay Unified tariff. It specially benefits the consumers located in the far-flung areas where the additive tariff was applicable and facilitate development of gas markets and vision of government to increase the gas utilization in the country.

9.5.3 Guidelines for domestic gas supply to CNG (Transport) and PNG (Domestic) segments of CGD Networks, 2022

These Guidelines were amendment to the existing 2014 guidelines for the allocation & supply of pooled domestic Natural Gas to CGD entities for CNG(T) and PNG(D) segment. Key points under these guidelines are:

i. Revision of allocation for supply of pooled natural gas to CGD entities for CNG(T) and PNG(D) segments will be done on quarterly basis for better representation of consumption.
ii. GAIL will supply pooled natural gas 2.5% over and above the 100% requirement of CNG(T) and PNG(D) segments of each GA in the quarterly allocation period, the 100% requirement being calculated based on consumption in the previous quarter.
iii. To meet the shortfall in availability of domestic gas for supplies of pooled natural gas allocated at as per the above revised guidelines, GAIL will source domestic HPHT gas at ceiling price/ actual price whichever is lower, as per prevailing guidelines for mixing with available APM/ NAPM gas.
iv. For any further requirement, GAIL will also source Long Term RLNG failing which Spot RLNG may be sourced for mixing with available APM/ NAPM gas. The sourcing will be done by GAIL within their procurement procedure which will be vetted by PPAC.

9.5.4 Indian Gas Exchange 2020

IGX was the first nationwide online delivery-based natural gas trading platform launched in June 2020. It completes the entire value chain from gas production from multiple sources and imports of LNG from different global sources to having a transparent price mechanism.

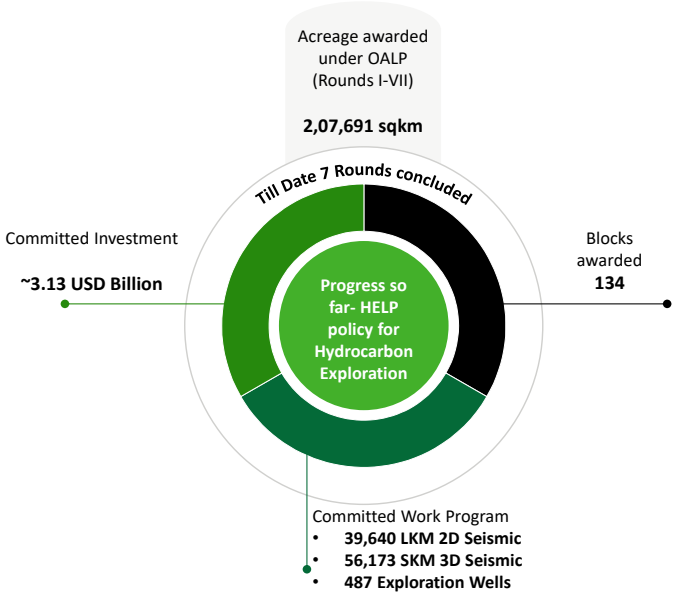
9.5.5 Hydrocarbon Exploration Licensing Policy (HELP) 2016 under E&P

Hydrocarbon Exploration and Licensing Policy (HELP), 2016 was launched with the clear objective of boosting the production of oil & gas in the Indian sedimentary basin. Under HELP Open Acreage Licensing (OAL) mechanism has been launched which allows the investors to carve out blocks of their choice by assessing E&P data available at NDR & by submitting an Expression of Interest (EoI). These blocks would be subsequently offered through biannual formal bidding process. OAL would be manifested through National Data Repository which will provide rapid jumpstart to E&P activities by providing seamless access to the entire G&G data for interpretation and analysis.

This scheme was based on the principle of "Ease of doing business". HELP aims to enhance domestic oil & gas production, bring in investment and enhance transparency:

- It brought about a **uniform licensing system** for all hydrocarbons with the benefit of **open acreage policy**.
- Contracts under HELP were made **revenue sharing models**.
- **Marketing and pricing freedom** was granted to Gas E&P contractors (offshore oil as well)
- **Exploration phase was increased** & a **Concessional Royalty Regime** was implemented for offshore E&P projects.
- **Customs Duty exemption** on import of equipment

Figure 67: HELP policy for Hydrocarbon Exploration



Source: MoPNG 9-years achievement 2014-2023

Till date seven OALP Bid Rounds have been conducted under the HELP regime, with total of 134 blocks being awarded covering an area of 39,460 LKm 2D seismic and 56,173 Sqkm 3D seismic with leading E&P companies.

9.5.6 Discovered Small Fields (DSF) 2015 under E&P

Marginal Field Policy 2015 was introduced to lessen the reliance on hydrocarbon imports and to efficiently use the unexplored established reserves. Later, the policy was renamed the Discovered Small Field Policy (DSF) and included into the new Hydrocarbon Exploration and Licensing Policy (HELP), which is a broad policy framework. The DSF policy provides low-risk investors with discovered acres along with several liberal features, including the following:

1. Revenue Sharing Contracts –
- Operational autonomy to developers and reduced micromanagement by the Government.
- Government needs to audit only production and revenue of the contractor and faster approval process.
- With revenue being shared with Government from the first day of production, the operator would focus on reducing its cost.

2. Single license for Conventional & Nonconventional hydrocarbon-
   Single license to explore and extract all hydrocarbon resources, including CBM, Shale gas/oil, tight gas, gas hydrates and other resources to be identified in future.

9.5.6.1 Current scenario

Under DSF Bid Round-I, 67 fields were put on offer. However, 21 fields could not be awarded due to insufficient response from the investor. Subsequently 60 DSF were approved for offer under DSF Round II with an estimated 194.65 mmtoe. Till date 3 rounds of DSF bidding are concluded and 85 contracts signed (54 contracts are active). 5 fields on production, 10 fields to come up on production by March 2025. DSF Rounds have brought 15 new players.[21]

The HELP & DSF Policies did not produce the results that were envisaged due to low response to their bids. This was because of the US Shale Revolution which came around the same time and LNG imports in India began to rise.

[21] MoPNG Ready Reckoner 2023

9.6 Summary of DAM and RTM data based on price band segregation.

RTM Summary

Final Scheduled Volume (MWh) (month wise)												
Price range	**Total**	**>=5 to <5.5**	**>=5.5 to <6**	**>=6 to <6.5**	**>=6.5 to <7**	**>=7 to <7.5**	**>=7.5 to <8**	**>=8 to <8.5**	**>=8.5 to <9**	**>=9 to <9.5**	**>=9.5 to <10**	**>=10**
Apr-22	1704277	55149	27130	48607	74863	43868	28303	84085	18850	64717	9679	916922
May-22	2318749	120518	84437	152191	165066	71406	51030	66076	41107	68644	27531	417770
Jun-22	2214240	94939	68928	101928	91838	69409	69073	85860	54981	62775	23296	554934
Jul-22	2130983	186161	101307	58506	33199	19106	24243	23990	21802	6290	4979	216403
Aug-22	2265456	153352	151376	111484	50553	34073	27305	52608	15366	24745	17390	210023
Sep-22	2192700	113615	104409	120809	23850	52486	21075	35515	17719	9923	19742	181650
Oct-22	2264594	117336	57024	28251	18088	10274	7735	8827	8464	6842	530	55621
Nov-22	1406877	230575	149813	82257	16753	16295	16964	11013	4823	5449	2257	48483
Dec-22	1763066	181770	155852	111961	59948	82033	43723	67573	26749	33239	11495	154783
Jan-23	2101891	125700	99753	95924	67182	22435	33617	82332	36798	38138	15806	452092
Feb-23	1714098	104659	160120	111013	97125	26902	63051	85681	95188	22163	16618	442481
Mar-23	2097802	112926	160009	113470	37349	79270	56619	45392	22083	12764	10236	89275
Apr-23	2152455	137067	114632	50475	41470	41373	11033	17173	9995	6444	8577	286613
May-23	2424255	141407	118591	79841	46821	67724	12787	28068	21216	11878	48116	361286
Jun-23	2675253	117084	175949	89169	41125	70357	14971	37697	22262	8508	23469	352824
Jul-23	2540448	115597	115570	94138	33054	31496	19890	4338	6657	6019	7576	266179
Aug-23	2738171	137222	203891	87489	147351	29474	37216	36707	19561	22461	18503	724621
Sep-23	2922960	147208	172384	128485	89184	90337	59419	30714	56604	8487	19026	453433
Oct-23	2402259	159601	119496	55582	50152	61888	41257	17248	14821	14425	11732	618782
Nov-23	2359067	124408	44214	18802	25695	10302	9707	3969	3053	5900	11059	93269
Dec-23	2404594	133609	78021	31850	31141	17826	18711	15349	8940	1592	12439	318829
Jan-24	2379903	146256	93722	49165	22539	23475	41868	18289	7150	4882	21823	749115
Feb-24	2256172	120816	88611	47883	14284	5824	10903	10097	11090	2625	6403	259011
Mar-24	2785618	121785	74033	39730	21511	6000	17500	13882	649	2660	4792	101828
Apr-24	2628557	149061	84615	56796	15646	25071	11639	15788	6872	6882	18224	385913

Final Scheduled Volume (MWh) (month wise)												
Price range	**Total**	**>=5 to <5.5**	**>=5.5 to <6**	**>=6 to <6.5**	**>=6.5 to <7**	**>=7 to <7.5**	**>=7.5 to <8**	**>=8 to <8.5**	**>=8.5 to <9**	**>=9 to <9.5**	**>=9.5 to <10**	**>=10**
May-24	3351657	176325	189998	41385	26347	15219	6079	22334	2381	5015	22289	440852
Jun-24	3212503	152101	62464	43200	21717	3698	16224	5332	3107	9876	14969	642680
Jul-24	3330836	93005	35589	11716	18618	2838	10506	7620	3301	2569	5496	621471
Aug-24	3484859	70193	53906	11732	2939	3020	1121	4473	4820	3313	963	245930
Sep-24	3912779	122390	94782	10937	12479	11373	6530	10913	0	3016	4061	254923
Oct-24	3451035	77438	45398	24424	12647	1980	7692	6549	4244	826	1312	577228
Nov-24	3019151	76084	27893	24498	6358	1995	6038	8298	1876	1492	2500	111486
Dec-24	3486627	134180	49872	21144	6360	9099	9300	9183	8112	10549	8140	607704
Jan-25	3291374	75921	37700	30260	21585	9918	10356	7870	5855	7272	14063	697596
Feb-25	2887473	100693	73417	25021	24331	4581	12367	12472	4577	4277	7032	243870
Mar-25	4096308	144542	92069	30019	30681	8822	17060	12735	3414	6559	19106	704686
Total	**94369049**	**4570698**	**3566976**	**2240144**	**1499849**	**1081249**	**852910**	**1006050**	**594488**	**513214**	**471229**	**13860566**

DAM Summary

Final Scheduled Volume (MWh) (month wise)												
Price range	**Total**	**>=5 to <5.5**	**>=5.5 to <6**	**>=6 to <6.5**	**>=6.5 to <7**	**>=7 to <7.5**	**>=7.5 to <8**	**>=8 to <8.5**	**>=8.5 to <9**	**>=9 to <9.5**	**>=9.5 to <10**	**>=10**
Apr-22	4113645	103312	143115	92072	169595	174227	42683	172660	104707	67182	49477	2405684
May-22	3172501	179923	189909	162058	216532	155886	68102	103817	53301	67421	25932	770380
Jun-22	4084993	278715	176362	223903	131570	186842	138028	164493	111608	125646	42029	1008861
Jul-22	3516651	265205	292892	83233	114543	72129	37498	73495	24237	44194	25051	485061
Aug-22	3528702	381478	261456	170662	121546	111591	34693	40845	40196	55546	34737	399961
Sep-22	4049644	344856	143816	127724	210454	147427	104489	132033	169431	41873	25888	610832
Oct-22	4325014	166023	92357	53269	25629	42376	29322	21424	28371	12360	13114	158190
Nov-22	5083847	506682	400683	150372	79430	84178	72817	22965	81650	29729	36201	89578
Dec-22	4977435	404221	345366	358944	140363	209631	156614	162561	115492	108763	25470	471608
Jan-23	4947961	159117	193903	331120	165834	106641	159503	183653	125288	56522	39110	1084876

Final Scheduled Volume (MWh) (month wise)												
Price range	**Total**	**>=5 to <5.5**	**>=5.5 to <6**	**>=6 to <6.5**	**>=6.5 to <7**	**>=7 to <7.5**	**>=7.5 to <8**	**>=8 to <8.5**	**>=8.5 to <9**	**>=9 to <9.5**	**>=9.5 to <10**	**>=10**
Feb-23	4658762	335257	238369	267356	144645	139379	148887	226441	159850	90619	64631	913741
Mar-23	4718382	445827	308572	240535	174872	298549	191540	62650	103790	27624	39201	251182
Apr-23	4408928	194885	128872	137679	93947	93298	42518	40359	25779	26255	23044	680918
May-23	3999758	169068	139619	88513	89210	58105	21964	14997	26507	8662	70450	484567
Jun-23	4123338	127020	247514	152533	116294	60032	14225	39701	34704	15945	22215	705536
Jul-23	3966202	100685	76842	40694	60271	42790	13969	26779	28786	6283	48582	514189
Aug-23	3881407	201650	177618	208007	147912	75631	61002	51075	26681	38957	49533	1238287
Sep-23	3405416	270458	175320	129909	95254	98434	41636	28473	19839	11506	18517	809273
Oct-23	4688350	376652	187915	73473	47332	77725	34812	23754	29093	26069	21509	1576209
Nov-23	5196155	225157	99314	20436	26503	8905	11127	7188	22127	5097	11614	314691
Dec-23	4666429	161498	96086	68356	47165	32500	28202	48093	26074	42116	18823	629888
Jan-24	5561845	286694	73300	94031	52126	70653	26280	63219	39374	46847	27384	1826312
Feb-24	4741748	204938	100975	120539	51289	25864	36694	32903	36231	25507	13474	716233
Mar-24	4658586	227246	96100	49185	32969	19486	7138	11333	12493	1772	10146	75546
Apr-24	4131420	221458	138647	106782	53302	24749	27170	13456	11152	16142	14205	433679
May-24	4315583	272194	140030	62166	15085	22897	13897	11319	11985	4091	30560	672689
Jun-24	4836233	172582	113927	55680	32997	39748	10407	25282	26242	17146	41927	840423
Jul-24	5070637	151832	88065	54532	30812	39148	34303	6984	15308	8330	8306	919253
Aug-24	4711976	89599	80373	8698	20982	23985	16456	17739	4564	10840	29810	603273
Sep-24	4562103	181683	165680	55275	40498	28081	54567	14722	16961	20225	28183	477403
Oct-24	4810453	85773	39673	37477	18623	24347	16427	4494	5809	20960	26932	902671
Nov-24	5616936	123371	36138	35617	24449	27958	10746	10239	5033	13699	7939	280677
Dec-24	7272264	212084	61588	84986	67210	58948	34085	30876	16564	7440	18129	1348782
Jan-25	6634116	150932	86988	39588	17853	37979	21001	14570	16484	22501	42371	1681008
Feb-25	5408598	216320	110050	73563	53153	55386	13802	16687	26826	21352	25630	508534
Mar-25	6055466	247292	139268	66018	70779	30632	16657	18660	22872	18719	21130	1099252
Total	**167901484**	**8241688**	**5586702**	**4124990**	**3001027**	**2806136**	**1793258**	**1939942**	**1625410**	**1163939**	**1051255**	**27989247**

9.7 Shortlisted assets

9.7.1 Utility scale Gas based power plants | Priority 1

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
NTPC, KAWAS CCPP	656	Central Sector	11%	5%	4%	18%	4 X 106 MW GT 2 X 110.5 MW ST Combined cycle gas turbine	187	GUVNL	NTPC	✓	✓	✓	Own RLNG facility and improved PLF in last two years. Given it's a NTPC plant, demand can be aggregated with Gujarat's plants.
NTPC, GANDHAR(JHANORE) CCPP	657	Central Sector	12%	5%	7%	14%	3 X 131 MW GT 1 X 255 MW ST Combined cycle gas turbine	237	GUVNL	NTPC	✓	✓	✓	Improved PLF in two years, asset lies in Zone-1, 469MW spare capacity available since contracted PPA only for 187MW with GUVNL. Given it's a NTPC plant, demand can be aggregated with Gujarat's plants.
RATNAGIRI (RGPPL-DHABHOL)	1967	Central Sector	7%	2%	18%	15%	1 X 640 MW 2 X 663.5 MW 3 X 663.5 MW	1967	MSEDCL	NTPC & GAIL India (RGPPL, subsidiary of NTPC)	✓	✓	✓	Improved PLF in two years, asset lies in Zone-1, 420MW spare capacity available since contracted PPA only for 237MW with GUVNL. Given it's a NTPC plant, demand can be aggregated with Gujarat's plants.

9.7.2 Utility scale Gas based power plants | Priority 2

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
HAZIRA CCPP(GSEG)	156	State Sector	0%	0%	2%	29%	GT: 2 X 52 MW ST: 52.1 MW ABB GT-1,2-GT8C2 ABB ST-1 DKZ1-N33	156	Gujarat Urja Vikas Nigam	Gujarat State Energy Generation Ltd. (GSEG)	✓		✓	Near vicinity to LNG terminal. No improvement in PLF over the last 3 years. STU connected. Possible solution for asset utilization could be demand aggregation with other Gujarat state plants
GODAVARI (JEGURUPADU)	235.40	State Sector	0%	12%	25%	32%	Phase 1 - 217MW Phase 2 - 228MW combined cycle, GVK industries	235.4	Phase 2 - APDISCOMs & TSDISCOMs	GVK	✓		✓	PLF dropped to 0% in last two years, operational before that. Domestic Gas allotment also reduced from 2021 levels. Currently, PPA under execution with APDISCOMs. No spare capacity available. Can be clubbed for aggregating demand and negotiate for long term agreement.
DGEN Mega CCPP	1200	PVT/IPP Sector	9%	0%	0%	10%	3 Single Shaft Units of 400 MW each Single Shaft Configuration; Siemens F-class (4000F) Gas Turbines coupled with Siemens Steam Turbine and Doosan HRSG	770 (till 30th June 2024)	NVVN (NTPC) and TPL, 770 MW capacity has been contracted with a minimum of 388 MUs of guaranteed power to be supplied from March 16, 2024, to June 30, 2024.	Torrent Power	✓		✓	In summer 2024, 430 MW capacity was available (770 MW under PPA). Also, Torrent was able to run the plant at 53% PLF in FY25 till 9th Nov 2024.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
GAUTAMI CCPP	464.00	PVT/IPP Sector	0%	0%	0%	0%	two gas turbine generators and one steam turbine generator 152.42 (GT11) +152.42 (GT12) + 166.6 (Steam Turbine) = 471.44 MW Alstom GT13E2	464	APDISCOM in 2004 PPA valid up to 05.06.2024	GVK Energy Ltd (Gautami Power Ltd)	✓		✓	464 MW PPA with AP discom, currently under insolvency. Can be clubbed for aggregating demand and negotiate for long term agreement.
GMR - KAKINADA (Tanirvavi)	220.00	PVT/IPP Sector	0%	0%	0%	0%		220		GMR	✓		✓	Asset lies in Zone-1. Can be clubbed for aggregating demand and negotiate for long term agreement.
GMR-Rajamundry Energy Ltd.	768.00	PVT/IPP Sector	0%	0%	0%	0%	2 x 383.779 MW GT GE Frame 9 FA	384	With the beginning of e-bid RLNG Scheme 2015, the 768MW power plant can now operate at 50% PLF, thereby generating 384 MW and supplying power to AP Discoms continuously.	GMR	✓		✓	under insolvency. Can be clubbed for aggregating demand and negotiate for long term agreement.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
JEGURUPADU CCPP (GVK) PHASE- II	220.00	PVT/IPP Sector	0%	0%	0%	0%	185 MW Alstom GT13E2	220		GVK Energy Pvt Ltd	✓		✓	No spare capacity available. Asset lies in Zone-1.
KONDAPALLI EXTN CCPP. Ph-II	366.00	PVT/IPP Sector	0%	0%	0%	0%	Ph-I GE Power 9E.03 gas turbines; 2 X 119.5 MW & 1 ST Ph-II GE Power 9F gas turbine; 1 GT & 1 ST	366	Entered into PPA with Telangana Transco for 325 MW for supply of power from June to September 2015.	Lanco Kondapalli Power Pvt Ltd	✓		✓	under insolvency, matter resolved. No spare capacity available. Sold in auction to Reliance Syngas, India Ispat Udyog and MCM Pacific after multiple rounds with purchase price of INR 246 Cr
KONDAPALLI ST-3 CCPP (LANCO)	742.00	PVT/IPP Sector	0%	0%	0%	0%	Ph-III GE Power 9F gas turbine; 2 X 241 MW GT & 2 x 130 MW ST GE GT-1 9FA	742.5		Lanco Kondapalli Power Pvt Ltd	✓		✓	under insolvency, matter resolved. No spare capacity available. Sold in auction to Reliance Syngas, India Ispat Udyog and MCM Pacific after multiple rounds with purchase price of INR 246 Cr
VEMAGIRI CCPP	370.00	PVT/IPP Sector	0%	0%	0%	0%	233 MW GE GT-1 9FA	370		GMR Vemagiri Power Gen Ltd	✓		✓	Asset lies in Zone-1. Can be clubbed for aggregating demand and negotiate for long term agreement.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
HAZIRA CCPP EXT	351.00	State Sector	1%	0%	2%	43%	1 GT: 351MW GE Frame 109 FA, Manufactured by BHEL under license from GE Energy. GE/BHEL CCGT-2 9FA	351	Gujarat Urja Vikas Nigam	Gujarat State Energy Generation Ltd (SPV by GSPCL)	✓		✓	Near vicinity to LNG terminal. Improvement in PLF in FY25. STU connected. Long term 25-yr PPA signed in 2008 with GUVNL for 351MW which got expired in 2023. Possible solution for asset utilization could be demand aggregation with other Gujarat state plants

9.7.3 Utility scale Gas based power plants | Priority 3

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
BARODA CCPP (GIPCL)	310	PVT/IPP Sector	0%	0%	0%	1%	106 MW GE 6B.03 (6001BTG)	310	Gujarat Industries Power Corp. Ltd.	GIPCL	✓			PLF dropped to 0% in last two years, operational before that. Domestic Gas allotment also reduced from 2021 levels. Currently, PPA under execution with APDISCOMs. No spare capacity available.
PAGUTHAN CCPP (CLP)	655	PVT/IPP Sector	0%	0%	0%	0%	135 MW SGT5-2000E gas turbines	655	Gujarat Urja Vikas Nigam	CLP India	✓			Not operational since at least past 4 years. The plant's power purchase agreement with its previous customer ended in December 2018. Can be a viable option for asset utilization as asset lies in zone 1

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
MANGAON CCPP	388.00	PVT/IPP Sector	0%	0%	0%	0%	388 MW	388	PGPL supplied power under e-BID RLNG scheme to Telangana Discoms. PGPL has signed PPAs with The Southern Power Distribution Company of Telangana and The Northern Power Distribution Company of Telangana	Pioneer Gas Power Ltd Korea Western Power Company (KOWEPO) has a 40% equity stake in PGPL				No generation since FY18 due to no gas supply. KOWEPo has initiated international arbitration against GoI for not honoring FSA for plant (2018). It was envisaged that GAIL would supply gas from its Dhabhol-Dahej pipeline (8 Kms from the plant) and spur line connecting the plant. Could be a potential asset revival given gas is allotted.
GODAVARI (SPECTRUM)	208.00	PVT/IPP Sector	0%	0%	12%	23%	47 MW Siemens SGT 800 (SCC-800)	208		Spectrum Power Gen Ltd				Since the plant was operation in FY21 and FY22, it can be considered for LTA contracts as asset lies in Zone-1.
KONASEE CCPP	445.00	PVT/IPP Sector	0%	0%	0%	0%	Two (2) Siemens make V 94.2 Gas Turbines Generators (GTGs) 2 x 139 MW One (1) LMZ make Steam Turbine Generator (STG) 1 x 155 MW	445		Konaseema Gas Power Ltd				under insolvency. Last reserve price was INR 252.90 Cr on Feb 29, 2024.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
							Siemens gas turbine SGT5-2000E (V94.2)							
PEDDAPURAM (BSES)	220.00	PVT/IPP Sector	0%	0%	0%	0%	142MW Siemens gas turbine SGT5-2000E (V94.2)	220	- PPA with APDISCOM ended in 2017	Reliance Infrastructure Ltd				Captive consumption by Reliance itself. Asset lies in Zone-1
UNOSUGEN CCPP	383	PVT/IPP Sector	40%	2%	41%	58%	1 GT: SGT5-4000F gas turbine 1 ST: SST5-5000 steam turbine. Siemens F-class (4000F) gas turbine Siemens F-class (4000F), SGT5-4000F Gas Turbine coupled with Siemens Steam Turbine and Doosan HRSG.	278	Major part of power produced is supplied under long term PPA to Ahmedabad & Surat Discoms of TPL; spare capacity is sold as Merchant power based on demand	Torrent Power				Plant already operational with PLF reaching 70% in FY25
NTPC, FARIDABAD CCPP	431.59	Central Sector	4%	0%	3%	24%	Unit I: 137.758 MW Unit II: 137.758 MW Unit III: 156.07MW	432 MW	Dakshin Haryana Bijli Vitran Nigam and Uttar Haryana Bijli Vitran Nigam	NTPC				Plant already under PPA with HVPNL till Dec2025, no spare capacity available.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
							Combined cycle gas turbine							
UTRAN CCPP (GSECL)	374	State Sector	8%	0%	9%	54%	1 GT: 228MW 1 ST: 147 MW GE Power GT26 gas turbine and a GE Power STF15C steam turbine	374	Gujarat State Electricity Corporation Limited (GSECL)	Gujarat State Electricity Corp Ltd (Parent Co-GUVNL)	✓			Improvement in PLF over last year. STU connected, vicinity to RLNG terminal. Viable option for utilization through demand aggregation with other GSECL plant.
NTPC, ANTA CCPP	419.33	Central Sector	10%	4%	3%	10%	Unit I: 88.71 MW Unit II: 88.71 MW Unit III: 153.2 MW Combined cycle gas turbine GE Power GT13D2 gas turbine	419 MW	Rajasthan Rajya Vidyut Utpadan Nigam Ltd (RVUNL)	NTPC		✓		Plant already under PPA with Rajasthan Rajya Vidyut Utpadan Nigam Ltd (RVUNL), no spare capacity available.
NTPC, DADRI CCPP	829.78	Central Sector	10%	9%	11%	25%	130.19 MW Combined cycle gas turbine	829.78 MW	Dakshin Haryana Bijli Vitran Nigam and Uttar Haryana Bijli Vitran Nigam	NTPC				Plant already under PPA with HVPNL, no spare capacity available.

Name of Power Station	Installed Capacity (MW)	Sector	PLF FY24	PLF FY23	PLF FY22	PLF FY21	Gas Turbine specs	Contracted PPA Capacity (MW)	Off-taker	Asset Owner	Frame work-1	Frame work-2	Frame work-3	Inference
												✓		
SUGEN CCPP (TORRENT)	1148	PVT/IPP Sector	37%	15%	44%	60%	3 units of GT with 382.5MW each Siemens F-class (4000F), SGT5-4000F Gas Turbine coupled with Siemens Steam Turbine and Doosan HRSG.	835	Major part of power produced is supplied under long term PPA to Ahmedabad and Surat Discoms of TPL; spare capacity is sold as Merchant power based on demand.	Torrent Power	✓			Plant already running at good PLF. Major part of power produced is supplied under long term PPA to Ahmedabad and Surat Discoms of TPL; spare capacity is sold as Merchant power based on demand.
DHUVARAN CCPP(GSECL)	595	State Sector	6%	0%	5%	32%	GT: 1 X 245 MW ST: 1 x 130 MW Siemens SGT5-4000F Gas Turbine Siemens SST5-3000 Steam Turbine, one 67.850 MW GE	595	GSECL	Gujarat State Electricity Corp Ltd (Parent Co-GUVNL)	✓			Improvement in PLF over last year. STU connected, vicinity to RLNG terminal. Viable option for utilization through demand aggregation with other GSECL plant.
PRAGATI CCPP	330.40	State Sector	29%	30%	53%	53%	2X 104MW, 1X122MW	330	Dakshin Haryana Bijli Vitran Nigam and Uttar Haryana Bijli Vitran Nigam	Pragati Power Corporation Limited (PPCL)	✓			Plant already under PPA with Rajasthan Rajya Vidyut Utpadan Nigam Ltd (RVUNL), no spare capacity available.

9.8 Peak power analysis

Scenario 1: 26.9 GW of coal being added till 2030[22] from 2024 onwards.

Particulars	2024	2027 (P)	2030 (P)
Coal	218	235	245
Nuclear	8	12	15
Hydro	47	50	54
Small Hydro	5	5	5
Solar	89	191	293
Wind	47	74	100
Bio-Power	11	13	15
PSP	5	12	19
BESS	0	0	42
Gas	25	25	25

Scenario 2: 80 GW of coal being added till 2030[23] from 2024 onwards.

Particulars	2024	2027 (P)	2030 (P)
Coal	218	268	298
Nuclear	8	12	15
Hydro	47	50	54
Small Hydro	5	5	5
Solar	89	191	293
Wind	47	74	100
Bio-Power	11	13	15
PSP	5	12	19
BESS	0	0	42
Gas	25	25	25

[22] CEA National Electricity Plan (NEP)
[23] PIB notification

Capacity factor for non-solar hours

	Capacity factor - 2024	Capacity factor - 2027	Capacity factor - 2030
Coal	80%	75%	78%
Nuclear	82%	80%	80%
Hydro	45%	50%	50%
Small Hydro	22%	25%	25%
Solar	0%	0%	0%
Wind	30%	25%	28%
Biomass	12%	10%	12%
PSP	100%	100%	100%
BESS	100%	100%	100%
Gas	34%	50%	50%

9.9 Gas asset operating assumptions

The following critical assumptions have been taken to maximize the utilization in the model.

Parameter	UOM	Value	Remarks
Discount on gas price	% DES price	8.5%	Owing to combination of Fixed Contract (RE blending) and sale on exchange during high demand periods, fuel consumption may be projected with higher certainty and regularity, which may create opportunity for discount in gas prices. Gas prices post discount are presented below (~ 8.4$/MMBtu in Jan'25)
Regasification and terminal charges	$/MMBtu	0.75	Discount of ~ 0.25$/MMBtu has been considered. This may be negotiated owing to high volume of gas consumption (~ 0.54 Mn MTPA)
Long term escalation in crude	%/month	0.15%	Crude has been considered to decline till June'27 (Fitch); post which, an escalation of ~2% per annum has been considered
Escalation in average IEX price	%/year	3.5%	Historical CAGR between 2013-14 and 2018-19 (pre-COVID) was ~4%; the same has been moderated to 3.5%

9.10 Stakeholder Interactions

9.10.1 Shell Energy India Limited

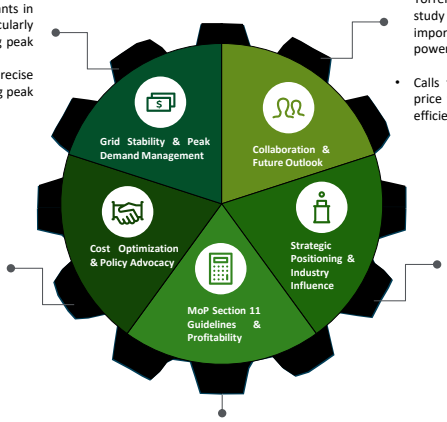
Gas Pricing Frameworks	Shell uses different pricing models, either linked to Henry Hub or Brent crude, depending on which is more favorable. Examples include Brent-linked pricing (12.67% slope based on the last 6 months' prices) and Henry Hub pricing (1.2x of the Henry Hub index plus $6 fixed for liquefaction and transportation). Shell suggests that Henry Hub pricing works best when gas prices are in the $10-12 range.
USA's LNG Export Expansion	The U.S. is expanding its shale gas export capacity by 80 million tonnes, aiming to become a global export hub. Shell mentions the unpredictability of future gas prices, especially those linked to the U.S. Henry Hub. India's gas pricing is currently dollar-based, with GAIL providing prices in INR.
No Storage Capacity	Shell points out that GAIL's NG pipeline network is usually at full capacity, both in terms of transportation and storage, leaving no room for additional storage. This implies a lack of storage facilities within the pipeline network.
Borrowing and Lending of LNG	Shell describes a global practice where LNG cargo can be reallocated to different customers based on immediate need, but this isn't practiced in India due to issues like double taxation. Shell is engaging with the government to incorporate this "Barter system" practice in India.
Monthly Offtake Commitment & Demand Forecasting for Pricing	Shell emphasizes the need for a "monthly offtake commitment" to avoid defaults in contracts. They suggest including an offtake guarantee (possibly within the next 30 days) to ensure smooth operations. Shell proposes that with a clear demand forecast for the next 3-5 years, including seasonal variations and monthly offtake quantities, they could offer better pricing.
Economical LNG Supply	Shell expresses willingness to provide LNG at economical rates if they are given the desired landed cost of power and a 3-5 year offtake schedule, even if this means foregoing market-linked pricing.

9.10.2 Natural Gas Society

1	Supply Sources	GAIL supplies natural gas by bundling long-term agreements send to it across the various consumer segments (CGD, Fertilizer, Power etc.). Key import countries, includes Qatar, USA, Russia, Australia, and UAE.
2	Price Linkage	Most contracts are linked to Brent Oil, making gas prices dependent on crude oil prices
3	Pricing constraint	• Operating gas-based power plants is not feasible due to high natural gas prices (~$8.24/MMBTU as per PPAC). • It is not that much economical importing Natural Gas from USA as compared to Qatar since Qatar sells LNG and Natural Gas imported from USA bears an extra liquification and transportation costs (~liquification cost 4$ + transport cost 2$ making it in range of 9-10 $/MMBTU)
4	Storage Feasibility	High CAPEX and volume loss make storage unfeasible. India's underutilized pipeline network can act as temporary storage.
5	Natural Gas demand improvement	Some of the best practices that can adopted for improving the Natural Gas demand were discussed as follows: • Aggregation of gas- example cited that by introduction of gas Gensets in Delhi in replacement of Diesel Generator sets improved the demand of gas in small scale MSEs, which can be replicated at an all-India level to ultimately increase the gas demand pan-India. Diesel replacement by Natural Gas can also provide environmental benefits. • Role of IGX in improving gas supply across sectors. NGS also highlighted that there are no issues in the LNG imports while there is underutilization of the operational 7 LNG terminals with 4 more upcoming LNG terminals. • Subsidies across the gas value chain.
6	Proposed measures	✓ Introduction of Gas Purchase Obligation (GPO) similar to RPO. ✓ Tariff restructuring and potential Clean Environment Cess on Natural Gas. ✓ Aggregation of demand through Long Term Contracts linked to Brent Crude Oil with sovereign guarantees. ✓ Inclusion of Natural Gas under GST to standardize taxation.

9.10.3 Torrent India

- Torrent emphasizes the critical role of its gas-based power plants in balancing the grid and supporting peak power demand, particularly during periods of renewable energy intermittency and evening peak hours.
- Torrent highlights the necessity of advanced planning and precise timing in procuring LNG cargoes to ensure reliable power during peak periods.

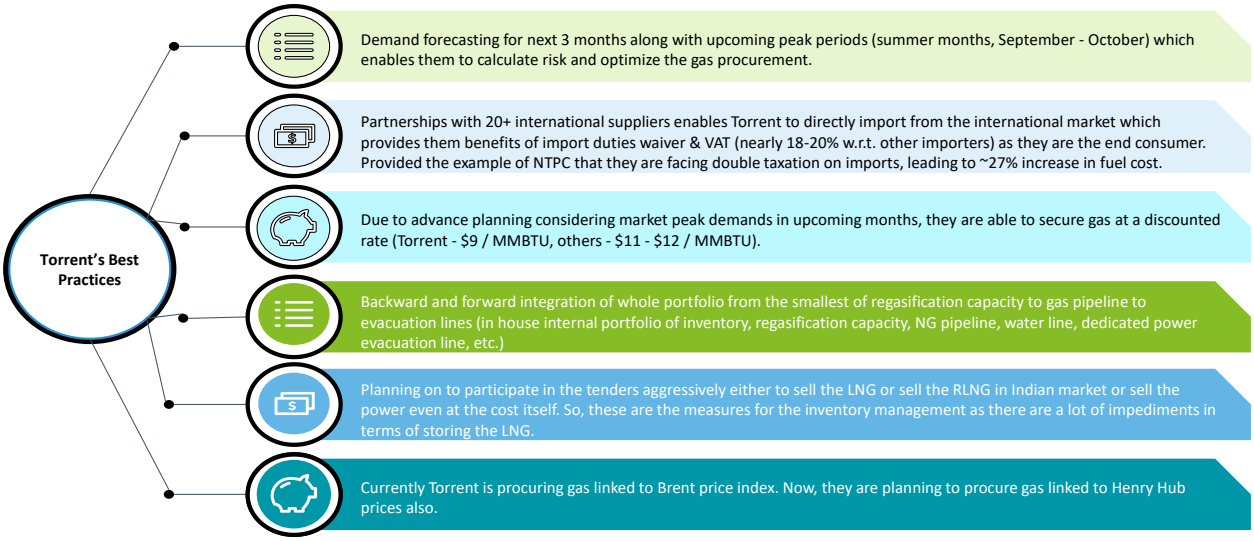


- Torrent stated that they provided valuable inputs for an ongoing PNGRB study on increasing the share of gas in the energy mix and stresses the importance of collaboration among stakeholders to advance the gas-based power generation sector.
- Calls for government intervention in demand aggregation, long-term gas price fixation, and improving LNG storage infrastructure to enhance sector efficiency.

- Torrent advocates for the replication of transmission charge exemptions, currently available for hybrid power plants, to be extended to gas-based power plants.
- Emphasizes the importance of removing intermediaries and reducing charges levied by authorities (e.g., SLDC) to lower operational costs.
- Despite domestic gas being priced at INR 5.5 per unit, Torrent acknowledges that renewable energy is available at a cheaper rate, highlighting the need for policy adjustments to provide more benefits to gas-based power plants.

- Torrent controls ~2.7 GW of gas-based power capacity out of India's total ~24.7 GW, emphasizing its significant role in the industry.
- Torrent argues for investment in overcoming gas supply constraints, positioning its ready-made, low fixed cost, and high variable cost assets as strategically advantageous compared to emerging technologies like BESS and PSP, which have higher fixed costs and longer operationalization times (5-6 years).

- The differences in PLF between Torrent's gas-based assets are attributed to PPA arrangements and LNG terminal connectivity.
- Torrent discusses the role of NVVN in purchasing power from DGEN, with pricing determined by a committee based on the plant's heat rate, including a 20% markup. This markup is passed to DISCOMs for plants with PPAs, while it is retained by Torrent for merchant sales.



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