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Institute for Energy Economics and Financial Analysis

South Korea's LNG Overbuild

Import terminal projects are accelerating despite climate targets and declining gas demand outlook

Michelle Chaewon Kim, Energy Finance Specialist, South Korea

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Key Findings

South Korea has reacted to the war-driven energy crisis by accelerating its push to build new liquefied natural gas (LNG) import terminals and storage facilities despite having some of the lowest utilization rates for its existing LNG terminals.

The rapid growth of proposed LNG infrastructure presents a high risk of overinvestment and overcapacity amid the country's transition to net-zero carbon.

Many of the 11 planned terminal projects are located close to one another, suggesting an inefficient allocation of assets that may further hinder usage rates.

IEEFA suggests aligning the build-out with LNG demand based on Nationally Determined Contribution targets, boosting public-private efforts for efficient use of LNG receiving terminals, and avoiding the promotion of technologies and services that would prolong LNG use without aiding national climate goals.

Executive Summary

Following the start of Russia's invasion of Ukraine in February 2022, Asian countries found themselves in direct competition with European buyers for limited global supplies of liquefied natural gas (LNG). Prices of the fuel skyrocketed, and energy security became an urgent priority for countries around the region.

South Korea has responded to the crisis by accelerating its push to build new LNG import terminals and storage facilities, aiming to bolster its ability to manage supply and demand in a highly volatile, post-invasion LNG environment.

> **The rapid growth of proposed LNG import terminals by both state-owned firms and the private sector presents a high risk of overinvestment.**

However, the Institute for Energy Economics and Financial Analysis (IEEFA) finds that the rapid growth of proposed LNG import terminals by both state-owned firms and the private sector presents a high risk of overinvestment. Government climate targets envision a nearly 20% reduction in long-term natural gas demand, and LNG markets are expected to remain extremely volatile for the remainder of the decade. Already, the country has some of the lowest utilization rates for its existing LNG terminals compared with other major LNG importing economies.

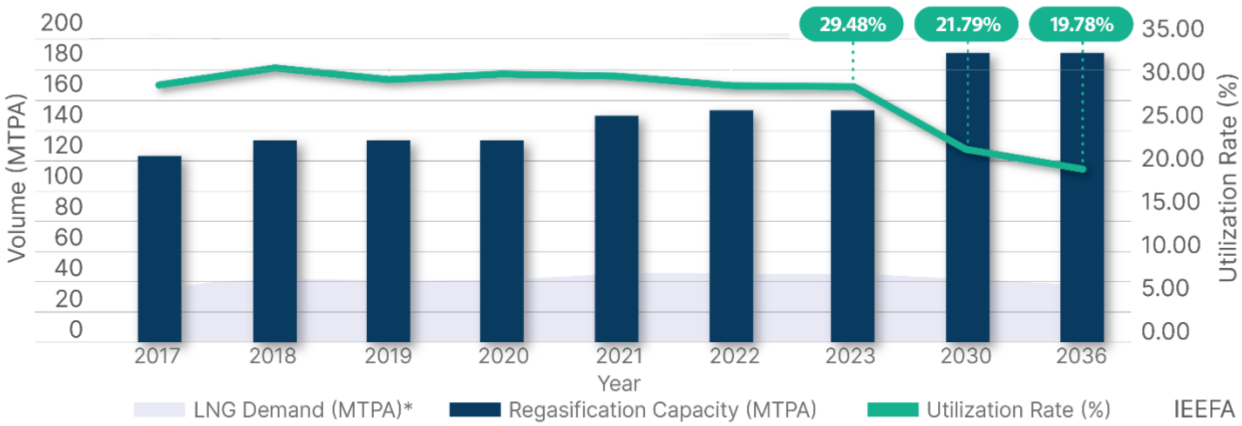
Moreover, many of the country's newly proposed LNG investments are located close to one another, suggesting an inefficient allocation of assets that could further hinder usage rates. Expanding the use of LNG in new applications, such as blue hydrogen production, bunkering and hydrogen-LNG blend power plants, offers limited potential for addressing climate targets effectively.

IEEFA estimates that South Korea's new LNG receiving terminals could cost about ₩11.3 trillion[1] (US$8.7 billion). Overall, incumbents and new entrants in the country's LNG market aim to complete 11 LNG terminal projects by 2031, many of which are either under construction or at earlier stages of development. These terminals account for roughly 37 million tonnes per annum (MTPA) of regasification capacity, which, if built, would increase national capacity to 190 MTPA, up from 153 MTPA currently.

South Korean companies have also proposed 3.4 million tonnes (MT) of new LNG storage capacity, which would represent a 53% increase in the country's current capacity of 6.3 MT to nearly 10 MT. However, existing storage facilities are already sufficient to meet the government's nine-day LNG storage target for the peak demand season in winter.[2]

[1] The figures are based on public disclosure documents from each company regarding the 11 projects, which are under construction, have signed business agreements or have obtained pre-feasibility approvals.
[2] Ministry of Trade, Industry and Energy (MOTIE). 15th Natural Gas Supply-Demand Plan. April 27, 2023, p. 12.

Figure 1: Growing Underutilized Regasification Capacity by 2036



Source: IEEFA, MOTIE

IEEFA's analysis shows a growing mismatch between LNG import infrastructure and demand targeted in the country's net-zero goal, given the South Korean government's climate targets have projected that the share of LNG-fired power generation will fall to 9.3% by 2036,[3] down from 26.8% in 2018.[4] Through 2036, the government expects natural gas demand to record 37.66 MTPA, a 17% decrease from 45.4 MTPA in 2022.[5]

The current report assesses the reasons behind the overinvestment in LNG import infrastructure. South Korean companies' race to build new LNG infrastructure largely stems from: a perceived need to boost energy security in the wake of the Russian invasion of Ukraine; growing competition in the domestic gas market; and the development of new LNG applications, including blue hydrogen, bunkering services, and hydrogen blending in power generation.

This report also outlines major issues exacerbating overinvestment risks in the country's LNG sector, including: declining natural gas demand amid the country's transition to net zero; inefficient asset allocation and stranded asset risks in key areas; volatile LNG market outlooks; and the limited role for new LNG applications in the country's climate-aligned pathways.

Further, IEEFA is presenting the following recommendations for the South Korean government and companies to mitigate the overinvestment risks in the country's LNG import sector:

- Align the build-out of LNG import and storage infrastructure with LNG demand based on Nationally Determined Contribution (NDC) targets.

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[3] MOTIE. 10th Power Market Supply-Demand Plan (PSDP). January 12, 2023, p. 7.
[4] MOTIE. 10th PSDP. January 12, 2023, p. 8.
[5] MOTIE. 15th Natural Gas Supply-Demand Plan. April 27, 2023, p. 7.

- Strengthen public-private collaboration at the national level to achieve efficient use of new and existing LNG receiving terminal capacity.
- Avoid promoting technologies and services that would prolong the use of LNG without contributing to national climate goals. These may include blue hydrogen, LNG bunkering and LNG-hydrogen co-fired power generation.
- Accelerate the transition to renewable energy with investment and policymaking to reduce high dependency on costly fossil fuels and enhance energy security in power generation.

Introduction

South Korea began importing LNG in 1986 and has historically been one of the world's largest LNG customers. In 2017, former President Moon Jae-in reaffirmed the role of LNG as a primary fuel for power generation in his "Coal and Nuclear-free Economy" policy, announced during the Group of 20 Summit in Germany. The government established a goal of elevating the use of natural gas in power generation from a 16.9% share in the power mix in 2017 to 18.8% by 2030, along with an aim to increase the share of renewable energy to 20% from 6.2%.[6,7]

The official shift to renewables and natural gas came as a surprise to many, given South Korea's heavy dependence on coal and nuclear power. The change was partly due to increasing optimism around the development of LNG markets, particularly after the United States began exporting LNG in 2016. With significant new supply from the U.S., alongside higher demand from Japan after its 2011 earthquake, global gas markets became considerably more integrated. South Korea viewed LNG as a means to achieve energy supply security, competitiveness and sustainability.

These narratives have contributed to South Korea's excessive investment in LNG infrastructure build-out in recent years. The trend is compounded by three other key factors: a perceived need to boost energy security amid the Russian invasion of Ukraine; growing competition in the domestic gas market; and the development of new LNG applications, including blue hydrogen, bunkering services, and hydrogen blending in power generation.

[6] MOTIE. 8th PSDP. December 29, 2017.
[7] The government also proposed reducing the share of nuclear energy generation in the power mix to 23.9% in 2030 from 30.3% in 2017, and coal from 45.4% to 36.1% over the same period.

Reasons for South Korea's LNG Build-out

A Response to the Russia-Ukraine Crisis

Following the start of the Russian invasion of Ukraine in February 2022, Europe began importing significantly more LNG to replace lost pipeline imports from Russia. Europe, once considered a "balancing buyer" that absorbed excess supplies from Asia, began competing directly with Asian purchasers, especially in Northeast Asia. In response, South Korean companies – both incumbent players and new entrants – have proposed new LNG terminals with the goal of managing the volatile global supply and demand dynamics amid the energy crisis.

As of 2023, South Korea has seven LNG import terminals with a combined regasification capacity of around 153 MTPA (Table 1). The country also has about 6.3 MT of LNG storage capacity. Late last year, some of this storage capacity experienced "tank tops" due to milder winter temperatures and excess purchase of spot cargoes, prompting importers to redirect surplus LNG volumes to other markets and expand storage.[8]

Table 1: Current LNG Receiving Terminal Capacity

Company	Terminal	No. of Storage Tanks	Tank Storage (MT)	Regasification (MTPA)	Category
KOGAS	Incheon LNG Terminal	23	1.55	54.93	State-run
	Pyungtaek LNG Terminal	23	1.50	41.00	
	Tongyoung LNG Terminal	17	1.17	26.54	
	Samcheok LNG Terminal	12	1.16	11.56	
	Jeju LNG Terminal	2	0.04	1.05	
POSCO International	Gwangyang LNG Terminal	5	0.33	7.10	IPP
GS Energy/SK E&S	Boryeong LNG Terminal	6	0.54	10.77	IPP
Total		**88**	**6.29**	**152.95**	

Source: IEEFA, MOTIE, financial reports of each company
Note: KOGAS = Korea Gas Corporation; GS Energy = GS Energy Corporation; SK E&S = SK E&S Co Ltd; IPP = a privately owned independent power producer.

[8] S&P Global Commodity Insights. Asian LNG importers seek cargo deferrals as storage terminals report tank tops. November 11, 2022.

Table 2: Projected LNG Receiving Terminal Build-out in South Korea

Company	Terminal	No. of Storage Tanks	Tank Storage (MT)	Regasification (MTPA)	Target in Service	Investment (₩ bill)	Status	New/ Incumbent	Category
GS Energy/ SK E&S	Boryeong LNG Terminal	1	0.09	3.15	H2 2023/ Oct 2024	196.50	Complete/Under Construction	Incumbent	IPP
POSCO International	Gwangyang LNG Terminal 1	1	0.09	0.00	Jun 2024	143.70	Under Construction	Incumbent	IPP
NEH (POSCO International)	Gwangyang LNG Terminal 2	2	0.18	1.75	Dec 2025	866.80	Under Construction	Incumbent	IPP
POSCO International /LX International	Dangjin LNG Terminal	2	0.24	3.50	2027	760.00	Business Agreement	Incumbent/ New	IPP/ Private
Hyundai Development Company/ Hanwha Energy	Tongyoung LNG Terminal	1	0.09	0.00	Jun 2024	1300.00	Under Construction	New	IPP/ Private
KNOC/SK Gas/MOL Chemical Tankers	Ulsan Korea Energy Terminal	2	0.19	7.88	Jul 2024	1205.30	Under Construction	New	State-run/ IPP/ Private
		1	0.10		Apr 2026		Under Construction		
		1	0.10		May 2026		Under Construction		
KOGAS	Dangjin LNG Terminal	4	0.48	13.67	Dec 2025	1556.30	Under Construction	Incumbent	State-run
		3	0.36		2028	793.30	Under Construction		
		3	0.36		2030	NA	Under Construction		
Hanyang	Yeosu Northeast Asia LNG Hub Terminal	2	0.18	7.53	2024	1200.00	Under Construction	New	Private
		2	0.18		2025		Under Construction		
KOMIPO	Boryeong LNG Terminal	2	0.18	0.00	Dec 2027	732.10	Pre-feasibility study approved	New	Genco
KOSPO	Hadong LNG Terminal	2	0.18	0.00	Dec 2028	885.62	Pre-feasibility study approved	New	Genco
KOGAS/BPA	Busan New Port LNG Hub Terminal	3	0.36	0.00	2031	1700.00	Pre-feasibility study approved	New	State-run
KOEN	Samcheonpo LNG Terminal	2	0.18	0.00	TBD	TBD	Under Consideration	New	Genco
KOWEPO	Pyungtaek LNG Terminal	2	0.18	0.00	TBD	TBD	Under Consideration	New	Genco
KDHC	TBD	TBD	TBD	TBD	TBD	TBD	Under Consideration	New	Genco
EWP	Ulsan LNG Terminal	2	0.18	TBD	TBD	TBD	Scrapped	New	Genco
Total (IEEFA)		**32**	**3.35**	**37.49**		**11339.62**			

Source: IEEFA, MOTIE, financial reports of each company
Note: Genco = a publicly owned power generation company; private = broadly speaking, a company that may also have power assets; state-run = state-owned companies KOGAS, KNOC and the Busan Port Authority. The investment figure of Tongyoung LNG Terminal includes an LNG power plant construction project. The proposed projects are as of mid-2023. Boryeong LNG Terminal finished building its seventh storage tank in July.[9]

Against this backdrop, several LNG importers are seeking to expand their LNG receiving terminal infrastructure. Five out of 11 currently planned projects have been initiated or accelerated since the war began in February 2022.[10] Apart from the 11, four projects are under consideration or have been recently scrapped.

SK Gas Co Ltd, South Korea's largest LPG provider, released an investment prospectus in December last year,[11] indicating a plan to invest about ₩242.8 billion by December 2026 to construct the first LNG storage tank at the Korea Energy Terminal (KET) in Ulsan city. SK Gas holds a 47.6% share in the KET project, and the Korea National Oil Corporation (KNOC), 52.4%.[12]

Boryeong LNG Terminal, a joint venture of GS Energy and SK E&S, is constructing its seventh storage tank and 3.15 MTPA of regasification facilities with an investment of about ₩196.5 billion. The storage tank was reported to have been completed in July this year,[13] while the regasification facility is scheduled to come online next October.

Meanwhile, POSCO International signed a memorandum of understanding (MOU) with commodity trading firm LX International Corp in June to invest ₩760 billion in a new LNG terminal in Dangjin city, South Chungcheong province, aiming for completion in 2027.[14]

State-owned entities are also expediting their own LNG infrastructure plans. Korea Midland Power Co Ltd (KOMIPO), a genco subsidiary of Korea Electric Power Corporation (KEPCO), received pre-feasibility study approval from the government in March last year to construct its own LNG receiving terminal in Boryeong city with a target completion date in December 2027.[15] Korea Southern Power Co Ltd (KOSPO), another KEPCO subsidiary, obtained pre-feasibility study approval in June last year to build an LNG terminal in Hadong.[16]

Increasing Competition in the Domestic Gas Market

Escalating competition within the domestic market, coupled with direct LNG importers' rapid expansion of their market share, has further fueled the enthusiasm for expanding LNG terminal infrastructure.

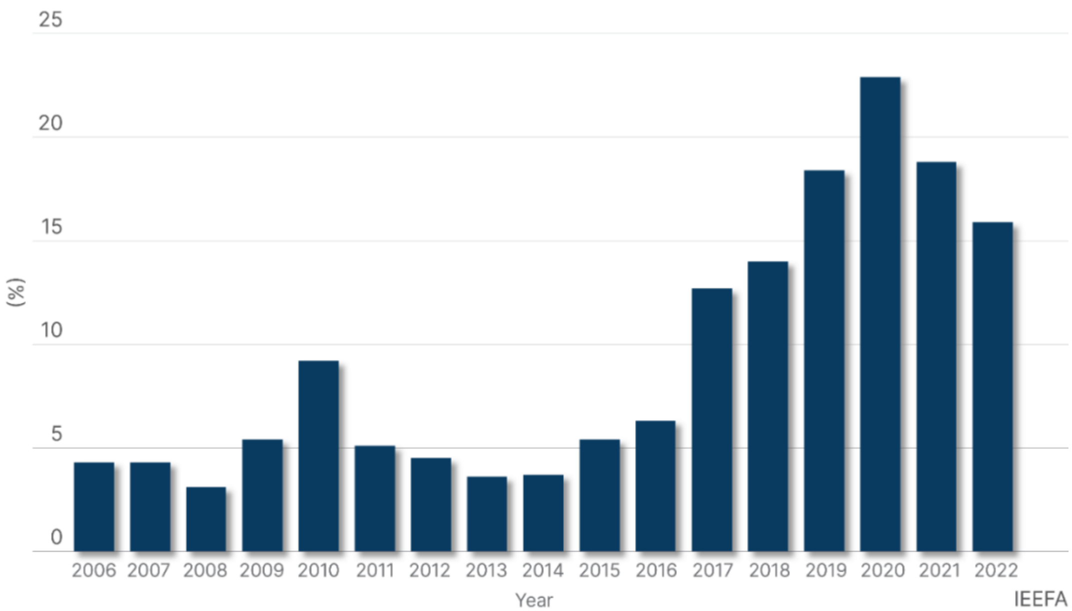
State utility KOGAS, which owns five of the seven LNG receiving terminals in South Korea, has historically controlled the country's LNG imports (Table 1). In 1997, however, the Petroleum

[9] Energy Platform News. First expansion phase of Boryeong LNG Terminal is complete, accelerating private-sector LNG terminal projects. November 6, 2023.
[10] Projects that have been initiated or accelerated since the Russia-Ukraine crisis include the KET, Gwangyang LNG Terminal, POSCO International's Dangjin LNG Terminal, KOMIPO's Boryeong LNG Terminal and KOSPO's Hadong LNG Terminal.
[11] SK Gas. Investment Prospectus. December 15, 2022.
[12] KET. Semi-annual Report. August 11, 2023.
[13] Energy Platform News. First expansion phase of Boryeong LNG Terminal is complete, accelerating private-sector LNG terminal projects. November 6, 2023.
[14] Energy Newspaper. Dangjin LNG terminal buildout, investing ₩760 billion. June 5, 2023.
[15] KOMIPO. Investment Prospectus. July 6, 2023.
[16] KOSPO. Semi-annual Report. September 16, 2023.

Business Act was amended to allow private power generation companies and other industries to directly import LNG for their own consumption.[17] The legal revision was primarily intended to offer consumers more fuel supply choices, foster competition within industrial sectors, and encourage greater private investment in LNG infrastructure.

Beginning with POSCO in 2005, the proportion of direct LNG imports[18] grew significantly. According to South Korea’s Private LNG Industry Association, the share of direct LNG imports increased from 4.3% in 2006 to 22.9% in 2020, then fell to 15.9% in 2022.[19] The data corresponded with a decline in KOGAS imports from nearly 100% prior to 2005 to around 80% in 2020.

Figure 2: Share of LNG Imports by Direct Importers (%)



Source: Private LNG Industry Association

In 2020, KOGAS introduced an individual pricing plan for power generation companies to maintain their share of the domestic gas market. The plan allows such companies – both gencos and IPPs – to sign gas purchase agreements with KOGAS for individual power plants.[20] Previously, most gas sales contracts between KOGAS and power generation companies were structured around an average pricing plan that determined sales prices according to the average price of the state gas utility’s long-term contracts and spot purchases.

[17] Hankook Ilbo. Increasing LNG direct imports but regulations lagging. March 21, 2023.
[18] GS Caltex Corporation, GS EPS, GS Power Co Ltd, KOMIPO, Narae Energy Service Co Ltd, Paju Energy Service Co Ltd, POSCO Energy, SK Energy Co Ltd, SK E&S and S-Oil Corporation are among companies allowed to import LNG directly without going through KOGAS. This group includes IPPs, gencos, refineries and petrochemical producers.
[19] The decline in the proportion of direct LNG imports last year was partly due to high LNG spot prices.
[20] KOGAS. Semi-annual Report. August 14, 2023, p. 20.

In the first half of this year, KOGAS secured around 440,000 tonnes of natural gas through individual pricing plans with local power generation companies, a 120% increase over last year.[21] However, the share of individual pricing plans in total gas sales volumes was still negligible at about 1.2%, albeit up from 0.5% a year ago.

Nevertheless, power generation companies have reacted with a mounting backlash against their gas purchase agreements with KOGAS via individual pricing plans. This opposition stems from concerns about issues such as the non-transparent pricing mechanism, unequal negotiating power and challenges in utilizing KOGAS LNG terminals and pipelines.

As a result, both new and existing power generation companies are thoroughly evaluating various options, including the construction of their own LNG terminals. A growing number of gencos and IPPs are building LNG receiving terminals to pave the way for direct imports. Moreover, the Urban Gas Business Act mandates that direct LNG importers must be "capable of storing an amount equivalent to 30 days' worth of natural gas self-consumption volume for the year in which the business is commenced."[22] This requirement has partially led to direct LNG importers investing in storage capacity.

In total, five private-sector companies and six state-owned entities are either constructing or proposing new LNG terminal projects (Table 2). Whereas KOGAS used to be a major driver of new terminal projects, smaller companies are now spurring regasification and storage tank investment as a means of securing a larger market share and reducing dependence on KOGAS.

Development of New LNG Applications

South Korean companies are expanding into new areas of the LNG value chain, developing integrated positions on infrastructure, technologies and services. Companies that have traditionally focused on upstream and downstream segments are constructing midstream assets, as well as establishing trading capabilities. Some are developing large LNG import infrastructure with the goal of utilizing them for other applications, such as bunkering, along with hydrogen production, storage, trading and blending in power generation.

For example, POSCO International merged with POSCO Energy in January, bringing the latter's midstream business into its broader LNG portfolio, which included exploration, liquefaction, storage and power generation assets.[23] The motivations were twofold. First, POSCO Energy's midstream business offered relatively stable profit margins, because leasing fees from long-term terminal use agreements (TUAs) covered fixed and operating costs.[24] Second, POSCO Energy was able to take

[21] KOGAS. Semi-annual Report. August 14, 2023, p. 31.
[22] Korean Law Information Center. Urban gas business act enforcement decree 10-6.
[23] POSCO International. Semi-annual Report. August 11, 2023, p. 50.
[24] About 20 years.

advantage of its ability to re-export LNG into the high-priced spot market environment of 2022[25] and would thus be expected to give POSCO International an edge in future.

In 2022, POSCO Energy reported revenues of ₩316 billion in the LNG midstream segment, which constituted 61% of its total operating profit.[26] POSCO International now aims to position the LNG midstream business as its primary segment.[27] It signed the aforesaid MOU with LX International in June to construct a new Dangjin tank terminal by 2027 at a cost of ₩760 billion.[28]

Other organizations are also developing large LNG import infrastructure projects with the goal of utilizing them for other potential LNG-related applications, including bunkering, blue hydrogen, and hydrogen blending in power generation.

For example, KOGAS has announced its intentions to establish a new receiving terminal as the LNG bunkering hub on the west coast of South Korea. The first phase of the KOGAS Dangjin LNG Terminal project is scheduled to come online in December 2025.[29]

Hanyang Corporation Co Ltd, a prominent South Korean construction company, is building an LNG receiving terminal in Myodo in southern Korea. The company's goal is to position its project as a Northeast Asian LNG hub terminal for South Korea, China and Japan.[30] Hanyang intends to build regasification capacity, storage, an LNG-fired power plant and a hydrogen ammonia terminal.[31] The company also aims to offer a comprehensive range of services, including gas trading, LNG bunkering, financial services and logistics. It is targeting completion of the storage and regasification facilities by October 2025.[32]

Another development in the south is the Busan New Port LNG hub terminal, encompassing three storage tanks scheduled to be operational by 2031. KOGAS and the Busan Port Authority are expected to spearhead the project, subject to government approval. In 2021, the Ministry of Oceans and Fisheries (MOF) announced that the project would also incorporate an LNG bunkering terminal and blue hydrogen production facilities.[33]

Within a 35km radius, yet another LNG hub terminal, the KET, is under construction in Ulsan. It was launched with government support in 2013 aiming to be northern Ulsan's Northeast Asian oil hub port. The scope was broadened to include an LNG tank terminal business after MOL Chemical

[25] Korea Investors Service Inc. POSCO Energy Rating Report. December 19, 2022, p. 4.
[26] POSCO Energy. 2022 Financial Reports. March 31, 2023.
[27] POSCO Energy. 2022 Financial Reports. March 31, 2023.
[28] Energy Newspaper. POSCO International-LX International to build Dangjin LNG terminal. June 5, 2023.
[29] KOGAS. Semi-annual Report. August 14, 2023.
[30] Hanyang. Company website.
[31] The company website also states its intention to build a carbon capture and storage facility.
[32] Hanyang. Company website.
[33] MOF. The challenge of ports for hydrogen economy expansion begins. November 26, 2021.

Tankers Pte Ltd joined prevailing shareholders KNOC and SK Gas in 2019 to take part in the project in 2019.[34,35]

Importantly, the success of the three proposed LNG terminal hubs in Myodo, Busan and Ulsan is predicated on the ability of many LNG businesses in South Korea to receive licenses to import and export LNG. However, other than KOGAS, only POSCO International currently has the license to do so, while other businesses are authorized to import LNG directly only for their own captive consumption.

Burgeoning Overinvestment Risks

Despite the various reasons for constructing LNG receiving terminals in South Korea, IEEFA has identified four key problems that are giving rise to concerns of overinvestment, including: declining natural gas demand amid the country's transition to net zero; inefficient asset allocation and stranded asset risks in key areas; volatile LNG market outlooks; and the limited role for new LNG applications in the country's climate-aligned pathways.

Declining Demand amid Transition to Net Zero

In recent years, South Korean demand for LNG has declined slightly. Over the longer term, the substantial discrepancy between the proposed infrastructure and projected demand under South Korea's climate targets is expected to amplify overinvestment risks.

South Korea's gas demand decreased by 1% year on year in 2022, primarily due to the high LNG prices and increased power generation from nuclear, renewable and coal-fired energy.[36] This decline is expected to persist in 2023, with natural gas demand nationwide likely to go down by 2%, as forecast by the International Energy Agency (IEA).[37] The slowdown can be attributed to the commissioning of new coal-fired power generators and an increase in nuclear power generation from new reactors, such as Shin Hanul #1 and #2.

According to the MOTIE's 10th PSDP, released in January, the country's LNG demand is expected to be 37.66 MTPA in 2036.[38] The plan projects the share of LNG in the power mix to fall to 9.3% by 2036,[39] down from 27.5% in 2022.[40]

[34] KET. Semi-annual Report. August 11, 2023, p. 9.
[35] Out of all three LNG hub terminal projects, the KET is the only one that has secured pre-TUAs with several entities, including SK Gas (tank #1), Ulsan GPS (tank #1), Korea Zink (tank #2) and SK Energy (tank #3). It is uncertain whether the Yeosu LNG hub terminal or Busan New Port LNG hub terminal has obtained any pre-TUAs.
[36] IEA. Gas Market Report Q2 2023. May 2023, p. 21.
[37] IEA. Gas Market Report Q2 2023. May 2023, p. 21.
[38] MOTIE. 15th Natural Gas Supply-Demand Plan. April 27, 2023.
[39] MOTIE. 15th Natural Gas Supply-Demand Plan. April 27, 2023.
[40] Korea Energy Statistical Information System (KESIS). Monthly Energy Statistics Update. October 2023.

The 10th PSDP aligns with South Korea's revised Nationally Determined Contribution (NDC) for the Paris Agreement, submitted in October 2021.[41,42] Under the NDC, South Korea has set an official target to reach net-zero emissions by 2050. This includes a shorter-term target to achieve a 40% emission reduction by 2030 compared with 2018.[43]

Table 3: MOTIE's Projected Power Generation by Energy Resources in 2030 vs 2036 and Current Level (%)

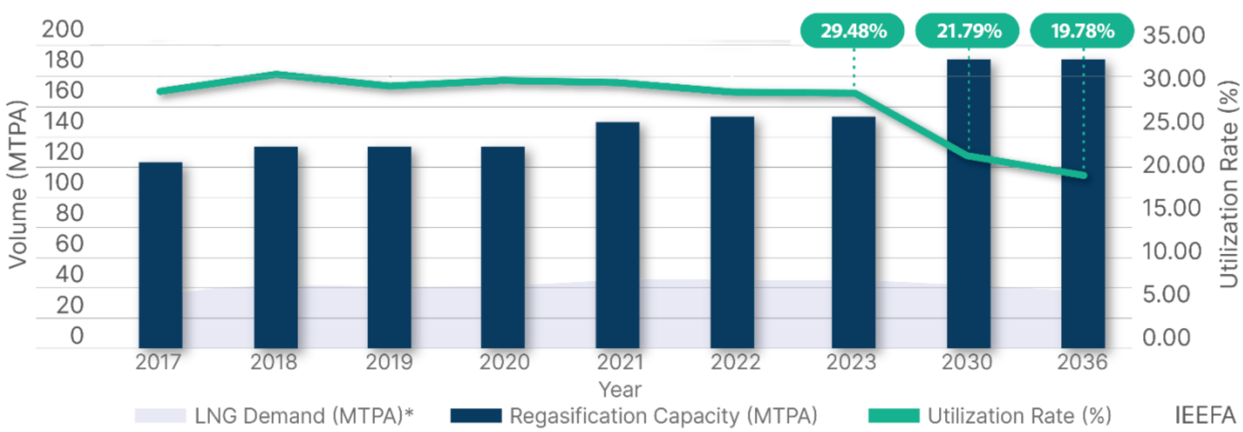
Year	Nuclear	Coal	LNG	Renewables	Hydrogen/ Ammonia	Others
2030	32.4	19.7	22.9	21.6	2.1	1.3
2036	34.6	14.4	9.3	30.6	7.1	4
2022 (Current)	29.62	32.51	27.52	8.95	NA	1.4

IEEFA

Source: MOTIE, KESIS
Note: "Others" in 2022 includes oil (0.33%) and pumped storage hydroelectricity (0.63%).

Based on IEEFA's calculations, the utilization[44] of regasification facilities under this demand scenario would fall to 19.78% in 2036, considering an annual LNG regasification capacity of about 190 MTPA in 2036. This assumes that all 11 proposed projects listed in Table 2 are completed.[45]

Figure 3: Growing Underutilized Regasification Capacity by 2036



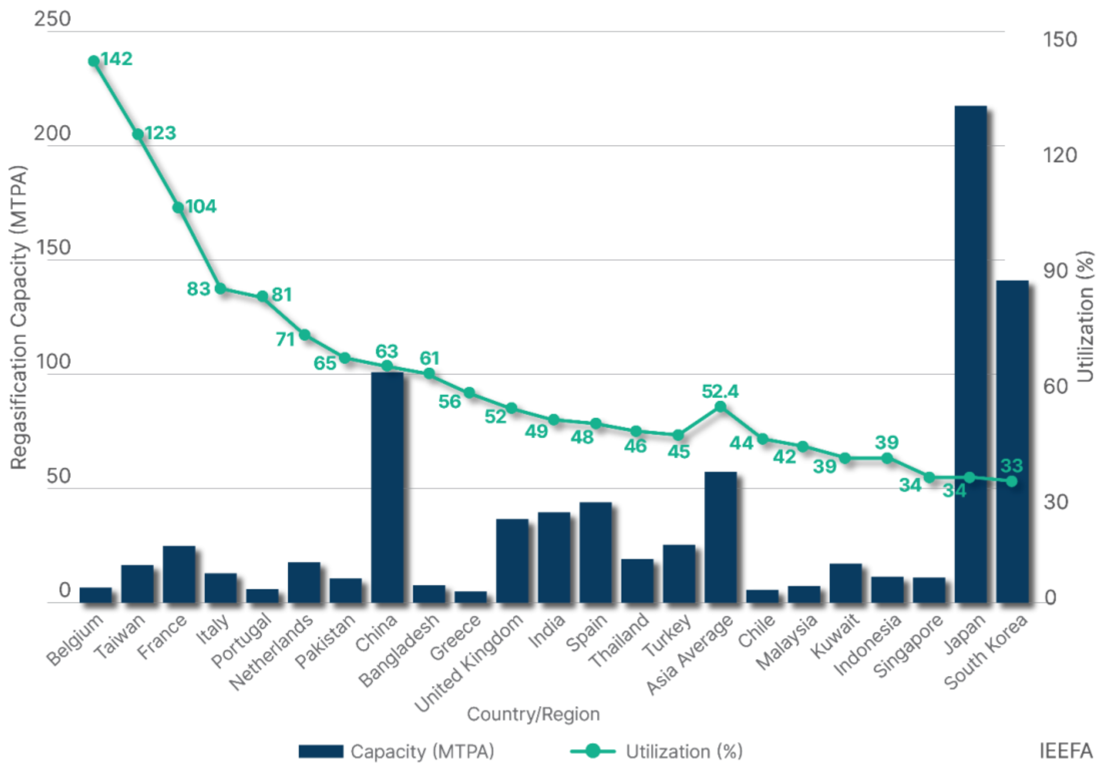
Source: IEEFA, MOTIE
Note: LNG demand from 2023 onwards comes from MOTIE projections.

[41] MOTIE. 10th PSDP. January 12, 2023, p. 7.
[42] Under the Paris Agreement in 2015, member countries agreed to cooperate in collectively limiting global warming to well below 2 degrees Celsius, and to 1.5 degrees Celsius above pre-industrial levels.
[43] Ministry of Environment. Net-zero green growth strategies. April 2023, p. 7.
[44] The utilization rate was calculated by comparing current and projected LNG demand versus nameplate regasification capacity.
[45] This excludes the four projects that are either under consideration or have been scrapped.

The projected regasification utilization rate for 2036 is considerably lower than the 2023 level of 29.48%.[46] According to IEEFA's analysis, unused LNG regasification capacity could rise from 107.9 MTPA this year to 152.8 MTPA in 2036.

The findings underscore the substantial overcapacity risks, as South Korea's annual average regasification utilization is already one of the lowest in Asia (Figure 4). According to 2022 data from the International Gas Union (IGU), South Korea's annual average regasification utilization was recorded at 33%, while the global average utilization was 41% and Asia's, 52.4%.[47]

Figure 4: LNG Receiving Terminal Regasification Capacity and Utilization

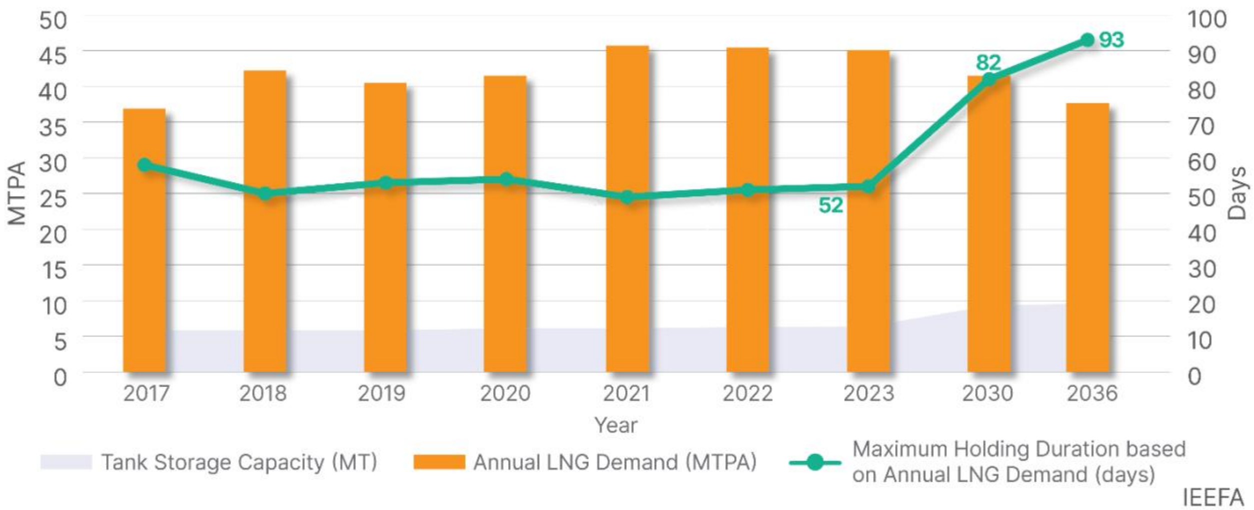


Source: IGU 2023 World Report

Regarding storage capacity, the proposed projects, if completed, would meet 25.6% of annual LNG demand in 2036, which is forecasted to reach 37.66 MTPA, according to IEEFA calculations. This is nearly double the 2023 level of 14.1%. In practical terms, it means that the planned storage capacity could store around 93 days' worth of annual LNG demand in 2036, up from the current 52 days. This figure well surpasses the government's mandated target of nine days of peak winter demand.[48]

[46] Calculated based on the MOTIE's projection of 2023 LNG demand.
[47] IGU. 2023 World LNG Report. July 12, 2023, p. 45.
[48] MOTIE. 15th Natural Gas Supply-Demand Plan. April 27, 2023, p. 12.

Figure 5: Growing Excess Storage Capacity by 2036



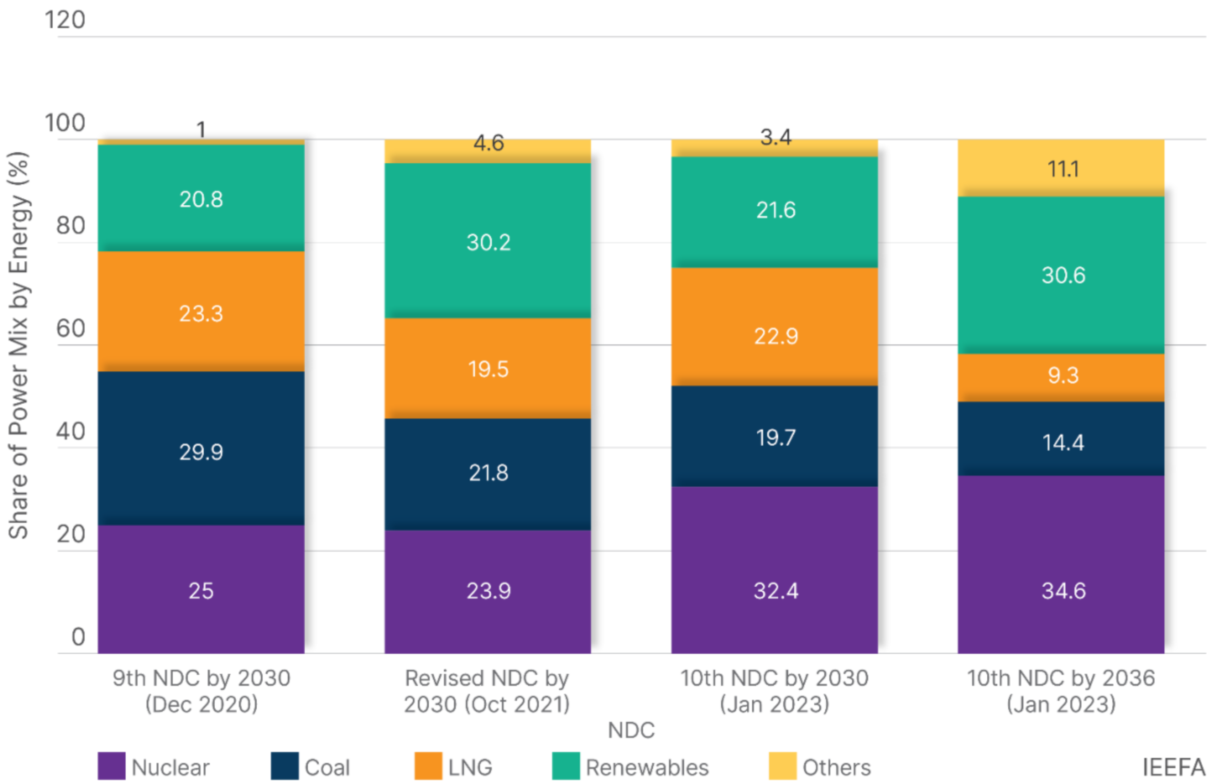
Source: IEEFA, MOTIE, Korea Energy Economics Institute (KEEI)
Note: LNG demand from 2023 onwards comes from MOTIE projections.

The significant gap between the infrastructure build-out and the projected demand based on the latest NDC target demonstrates that new LNG infrastructure projects have not been planned in alignment with national net-zero goals. Moreover, countries are to enhance their NDCs every five years, as required by the Paris Agreement.[49]

IEEFA believes that the underutilization of LNG receiving terminals will likely worsen if South Korea further revises its NDC target to reduce the share of LNG-fired power generation in the energy mix in the coming years, amid the accelerated global call for energy transition.

[49] Countries are expected to announce the first Global Stocktake during the United Nations Climate Change Conference from November 30 to December 12 in Dubai.

Figure 6: Acceleration of LNG Reduction in NDC Target



Source: MOTIE

Inefficient Asset Allocation and Stranded Asset Risks

As discussed earlier in this report, domestic market competition is a driving factor behind the race to build out LNG terminals in South Korea. Fierce competition is causing developers to propose large LNG infrastructure projects in close proximity to one another, raising risks related to inefficient asset allocation and stranded assets. In Dangjin, for example, state-run gas utility KOGAS is competing with IPPs and private companies, while in Boryeong, gencos are competing with IPPs, to build huge LNG terminal infrastructure.

Dangjin

In Dangjin, South Chungcheong province, competition to construct LNG receiving terminals has escalated despite the overinvestment risks. Two large-scale projects are underway within a 19km radius, one led by KOGAS and the other by the joint venture of POSCO International and LX International. These projects, if completed on schedule, would increase Dangjin’s LNG storage capacity to 1.45 MT and regasification capacity to 17.17 MTPA by 2030.

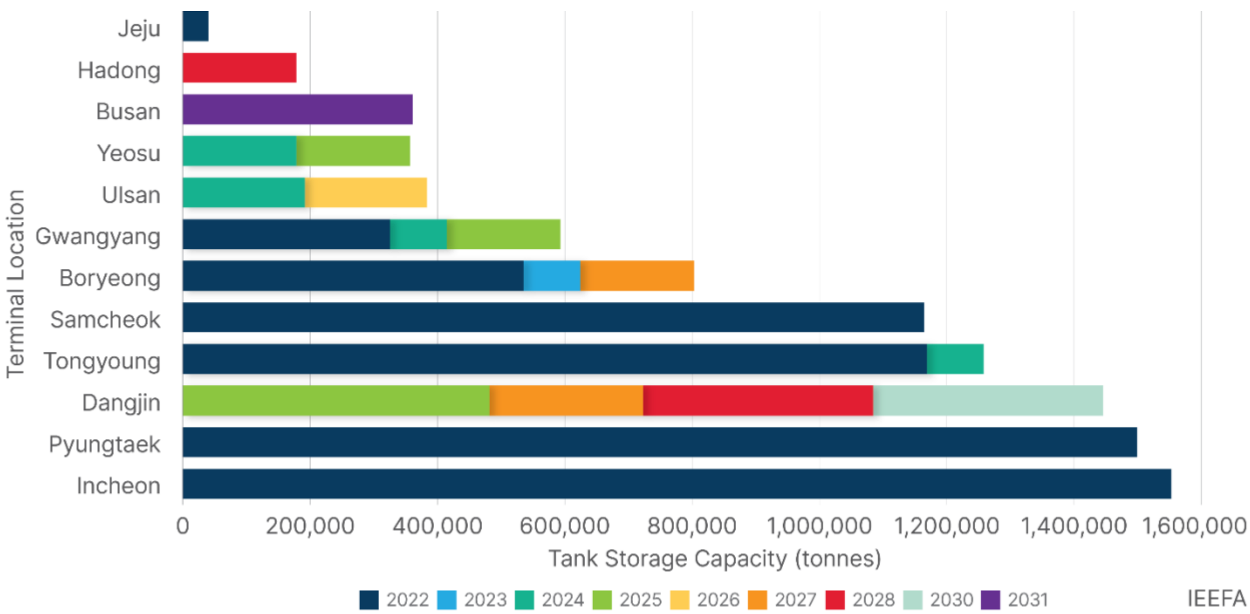
Table 4: Proposed LNG Import Infrastructure Projects in Dangjin by 2030

Company	Regasification Capacity (MTPA)	Tank Storage Capacity (MT)	No. of Storage Tanks	Target in Service	Investment (₩ bil)
KOGAS	13.67	1.2	10	by 2030	2,349.60
POSCO International/ LX International	3.5	0.24	2	by 2027	760
Total	**17.17**	**1.45**	**12**	**NA**	**3,109.60**

IEEFA

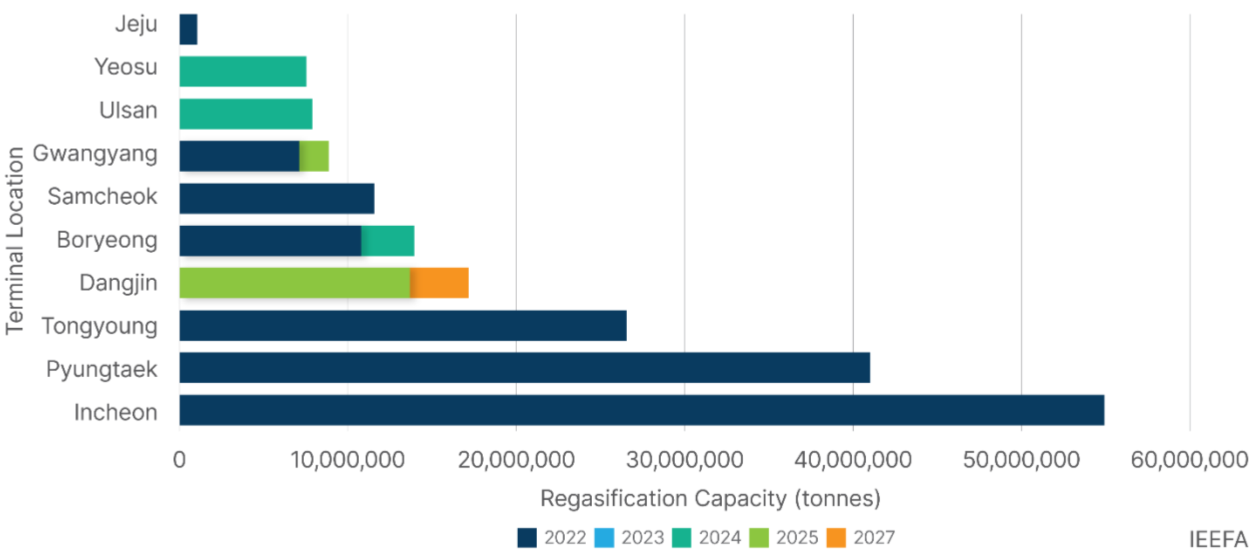
Source: IEEFA, KOGAS, POSCO International, LX International

Figure 7: Tank Storage Capacity by Location and Targeted Completion Date (Tonnes)



Source: IEEFA, MOTIE

Figure 8: Regasification Capacity by Location and Targeted Completion Date (Tonnes)



Source: IEEFA, MOTIE

The infrastructural expansion comes despite the limited number of potential users of the terminals and the need for a thorough evaluation of the facilities' necessity in Dangjin. GS EPS is now the only IPP in the city, operating four LNG combined cycle power plants with a total capacity of 2,406 MW. These consumed roughly 0.6 MTPA of LNG last year.[50,51]

One of the gencos, Korea East-West Power (EWP), aims to bring online an additional 2,000 MW of LNG-fired capacity in Dangjin by converting four coal plants to run on natural gas. If these coal-to-gas switching projects are completed by 2030, this would bring the total LNG-fired power capacity in Dangjin to 4,406 MW, including capacity from GS EPS. Assuming these plants operate at baseload levels, IEEFA estimates that EWP could require 0.9 MTPA of LNG in 2030 to run them.[52]

Therefore, IEEFA estimates that the total fuel requirements of LNG power plants in Dangjin will be 1.5 MTPA by 2030. This accounts for just 8.8%[53] of the total LNG regasification capacity of 17.17 MTPA proposed by KOGAS and POSCO International/LX International.

Regarding storage, the proposed new capacity of 1.45 MT would store about 350 days of the expected annual LNG procurement volume by EWP and GS EPS. This significantly exceeds the government's mandated stock level of nine days during winter.

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[50] GS EPS. Semi-annual Report. August 11, 2023, p. 14.
[51] GS EPS. Semi-annual Report. August 11, 2023, p. 11.
[52] The estimated LNG purchasing volume was calculated based on the consumption level in line with other LNG-fired power plants located elsewhere in the country. The figures were from the EWP Semi-annual Report. August 11, 2023.
[53] IEEFA assumes that all procured LNG will be regasified and fed to LNG-fired power generators.

Securing end-users for the terminals will also pose a challenge to both Dangjin terminals. Given the large proposals for new infrastructure and limited demand base, developers will face significant competition to secure new customers and maintain existing terminal users.

For example, GS EPS now buys 0.2 MTPA of LNG from KOGAS through an individual pricing plan for its #1 LNG-fired power plant (538 MW) in Dangjin. This plan ends in December 2025.[54] The company also buys 0.185 MTPA from KOGAS via an average pricing plan for its #2 (550 MW) and #3 (415 MW) LNG-fired power plants in the same location. This plan ends in December 2032.[55]

Therefore, KOGAS faces the risk that GS EPS, one of its anchor customers, will opt for new pricing arrangements and suppliers by the time KOGAS brings its new LNG infrastructure online by 2030. GS EPS has entered into separate agreements to buy 0.23 MTPA from Mitsui and Co and other suppliers, imported through Boryeong LNG Terminal on a 20-year TUA.[56] More gencos and IPPs are procuring LNG from non-KOGAS suppliers, posing a financial risk to the state gas utility's mega-infrastructure build-out.

Table 5: Analysis of Potential LNG Terminal Users in Dangjin by 2030

Company	EWP				GS EPS			
LNG Power Plant	#1	#2	#3	#4	#1	#2	#3	#4
Capacity	1,000 MW*		1,000 MW*		538 MW	550 MW	415 MW	903 MW
Long-term LNG Contract	TBD				KOGAS IPP	KOGAS APP		Mitsui etc.
Volume	TBD				200,000 mt/year	185,000 mt/year		226,994 mt/year
Duration	TBD				Jan 2022-Dec 2025	Mar 2000-Dec 2032		2019-2039
Terminal	TBD				KOGAS pipeline	KOGAS pipeline		Boryeong LNG Terminal (2019-2039)

IEEFA

Source: IEEFA, EWP, GS EPS, KOGAS, Boryeong LNG Terminal
Note: Coal-to-gas switching by 2029 for #1 and #2, and by 2030 for #3 and #4.

Boryeong

LNG proposals in Boryeong, another city in South Chungcheong province, face similar challenges of overinvestment, underutilization, and competition between IPPs and gencos for the limited demand. A joint venture of GS Energy and SK E&S, two large direct importers and IPPs, operates the existing

[54] KOGAS. Semi-annual Report. August 14, 2023, p. 323.
[55] KOGAS. Semi-annual Report. August 14, 2023, p. 323.
[56] GS EPS. Semi-annual Report. August 11, 2023, p. 12.

Boryeong LNG Terminal but plans to expand regasification and storage capacity. Separately, KEPCO subsidiary KOMIPO obtained government approval last year for a pre-feasibility study to construct an LNG receiving terminal by December 2027. If the two mega-LNG import terminal projects are completed, regasification capacity in Boryeong will reach 13.93 MTPA and storage capacity, 0.80 MT, by 2027.

Table 6: Proposed LNG Import Infrastructure Projects in Boryeong by 2027

Company	Regasification Capacity (MTPA)	Tank Storage Capacity (MT)	No. of Storage Tanks	Target in Service	Investment (₩ bil)
KOMIPO	NA	0.18	2	by 2027	732.1
Boryeong LNG Terminal	13.93	0.62	7	by 2024	196.5
Total	**13.93**	**0.80**	**9**	**NA**	**928.6**

IEEFA

Source: IEEFA, MOTIE, KOMIPO, Boryeong LNG Terminal
Note: The targeted start of service and investment for Boryeong LNG Terminal cover only ongoing tank storage and regasification expansion projects. Regasification and tank storage capacity data for Boryeong LNG Terminal includes existing capacity.

The expansion projects are being planned despite the limited number of potential terminal users – only KOMIPO by 2027 – and intensifying competition between incumbent and new terminal operators. Currently, Boryeong has only one genco, KOMIPO, operating three LNG combined cycle power plants with a combined capacity of 1,350 MW (Table 7).[57] These consumed roughly 0.68 MTPA of LNG last year.[58,59]

KOMIPO is constructing a new 500 MW combined cycle LNG-fired power plant in Boryeong, scheduled to come online in June 2026.[60] This is part of KOMIPO's coal-to-gas switching power generation projects, which will convert the #5 and #6 coal-fired power plants (total 1,000 MW) to LNG.[61] It would bring the total combined cycle LNG-fired power generation capacity to 2,350 MW in Boryeong. Assuming these plants operate at baseload levels, IEEFA estimates that KOMIPO could require 1.18 MT of LNG in 2027 to run its proposed LNG-fired power plants.[62] This accounts for just 8.5% of the total proposed new LNG regasification capacity in Boryeong.

[57] KOMIPO. Website.
[58] KOMIPO. Annual Financial Report. March 28, 2023, p. 11-12.
[59] Korea Power Exchange (KPX). Power Plant Capacity Update. July 2023, p. 10.
[60] KOMIPO is converting the facility from a coal-fired power plant to run on LNG.
[61] MOTIE. 9th PSDP. December 28, 2020, p. 42.
[62] The estimated LNG purchasing volume was calculated based on the consumption level in line with other LNG-fired power plants located elsewhere in the country. The figures were from KOMIPO's annual financial report. March 28, 2023, p. 11-12.

Regarding storage, the proposed new capacity of 0.8 MT would store about 248 days of KOMIPO's expected annual LNG procurement volume in 2027. This significantly exceeds the government's mandated stock level of nine days during the winter peak.

Once KOMIPO's own tank storage comes online, the competition between new and incumbent terminal operators in Boryeong will intensify. In addition, the existing LNG terminals that KOMIPO is using could lose their core terminal users, which would increase underutilization rates.

KOMIPO uses POSCO International's Gwangyang LNG Terminal to regasify volumes for its long-term LNG sales and purchase agreement with Vitol (Table 7). However, its TUA for Gwangyang LNG Terminal is set to expire in December next year.[63] It is unclear whether KOMIPO will extend the TUA or use other terminals.

The company also buys around 0.26 MTPA of LNG from KOGAS for its existing combined cycle LNG-fired power plants in Boryeong via an average pricing plan which will expire in December 2039.[64]

Table 7: Analysis of Potential LNG Terminal Users in Boryeong by 2027

Company	KOMIPO			
Combined Cycle LNG-fired Power Plant	#1-#3 ST*, #1-#6 GT**			#5-#6**
Capacity	1,350 MW			1,000 MW
Long-term LNG Contract	KOGAS APP	Vitol	Petronas	TBD
Capacity	260,000 mt/year	350,000 mt/year	250,000 mt/year	TBD
Duration	Jan 2007-Dec 2039	Jan 2015-Dec 2024	Jan 2020-Dec 2024	TBD
Terminal	KOGAS pipeline	Gwangyang LNG Terminal (~Dec 2024)	-	TBD

Source: IEEFA, KOMIPO, KPX, KOGAS, MOTIE.
Note: The partial volume from Vitol and Petronas may be supplied to other LNG-fired power plants run by KOMIPO in the country. The KOGAS average pricing plan supplies #1-#3 combined cycle LNG-fired power plants. #1-#3 ST refers to steam turbines. #1-#6 GT refers to gas turbines. #5-#6 are coal-to-gas switching plants.

Rather than construct its own LNG terminal facilities in Boryeong, KOMIPO has three other options. It could use the existing Boryeong LNG terminal, extend its current TUA with Gwangyang LNG Terminal, or sign additional LNG purchase agreements with KOGAS. All of these arrangements

[63] Korea Investors Service. How long can direct LNG importers' differentiation persist? March 2019, p. 13.
[64] KOGAS. Semi-annual Report. August 14, 2023.

would cover KOMIPO's current and expected LNG volume requirements. This might also help KOGAS secure customers for its proposed terminal in neighboring Dangjin.

The upsides are particularly viable when considering the shareholder relationships between KOGAS and KOMIPO. KOMIPO, a major genco in South Korea, is wholly owned by state-run power utility KEPCO.[65] KEPCO, in turn, is a significant shareholder in KOGAS with a 20.5% ownership stake, second only to the South Korean government's 26.2%.[66]

Meanwhile, GS Energy and SK E&S, which own the existing Boryeong LNG Terminal, may also be struggling to secure new terminal users for their expanded regasification and storage plans. As of 2023, the users of Boryeong LNG Terminal are the SK Group, Shin Pyeongtaek Power Co Ltd, GS EPS and GS Caltex.[67] There has been no announcement of new terminal users signing TUAs to utilize the expanded capacity as construction continues.[68]

The failure of new terminals to secure consistent end-users makes it challenging to ensure a healthy return on investment. Nevertheless, many gencos, including KOMIPO, KOSPO, Korea South-East Power Co Ltd (KOEN), Korea Western Power Corporation (KOWEPO) and the Korea District Heating Corp (KDHC), are still contemplating the construction of their own LNG receiving terminals (Table 2). IEEFA believes that this represents an inefficient allocation of assets, which could lead to the risk of stranded assets, in turn increasing the financial burden on investors and taxpayers.

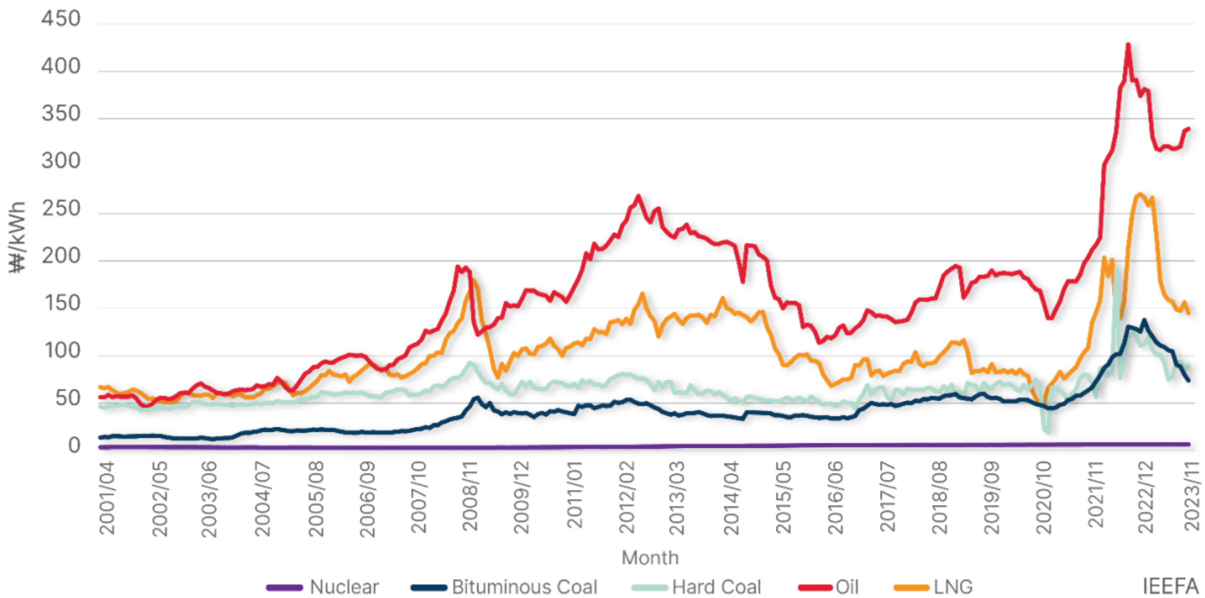
Volatile LNG Market Outlook

LNG markets have experienced extreme volatility over the past three years, which has undermined the fuel's affordability and reliability. Higher, more volatile LNG prices, combined with South Korea's declining natural gas demand, erode the economic case for new LNG infrastructure. An overbuild of new gas import infrastructure threatens to further bind the health of the South Korean economy to unpredictable global commodity markets, hindering the country's energy transition to cheaper, domestically sourced renewable energy.

Following the start of the Russian invasion of Ukraine, LNG prices reached unprecedented levels. In March last year, the S&P Global Japan-Korea Marker, a common spot market pricing benchmark in Northeast Asia, hit a record US$84.76 per million British thermal units.[69] High prices throughout the year had a knock-on effect on power prices in South Korea. That November, the cost of LNG-fired power generation reached a historic ₩270.38 per kilowatt-hour (kWh) (US$0.21/kWh), up 100.21% year on year, according to KPX data[70] (Figure 9).

[65] KOMIPO. Investment Prospectus. July 6, 2023, p. 312.
[66] KOGAS. Semi-annual Report. August 14, 2023, p. 59.
[67] Boryeong LNG Terminal. Semi-annual Report. August 14, 2023.
[68] Boryeong LNG Terminal. Semi-annual Report. August 14, 2023, p. 11.
[69] S&P Global. Asian LNG demand for industry continues falling, despite prices moderating, as output shrinks. November 18, 2022.
[70] KESIS. Website.

Figure 9: Monthly Fuel Unit Cost for Power Generation by Energy Source (₩/kWh)



Source: KPX
Note: Nuclear fuel costs are significantly lower than fossil fuel costs, in the range of ₩3-₩7. Capital expenditures for nuclear energy, however, are among the highest of any asset class.

Although prices have retreated since the start of the Russian invasion, they are widely expected to remain high until significant new export capacity from other parts of the world can come online later this decade. Moreover, disruptions in global energy markets, such as the Israeli-Palestinian conflict, could maintain upward pressure on South Korean gas prices.

In turn, higher fuel prices may cause IPPs to generate less LNG-fired power as they would face thinner operating margins and are not obligated to provide electricity in the first place. This could then lead to a decrease in LNG imports by the LNG receiving terminals operated or leased by the IPPs, adding to issues of underutilization and stranded asset risks. During 2022, the utilization of LNG terminals throughout Asia declined substantially.

In addition, the South Korean government rolled out a system marginal price (SMP) cap in the country's wholesale electricity market on December 1 last year, which worsened the underutilization of the IPPs. The SMP determines the price at which power generation companies sell electricity to the state-run KEPCO. Due to the new cap, IPPs may be unable to fully recover their variable costs, which include expenses associated with LNG procurement.

Conversely, gencos owned by KEPCO might increase operating rates due to their obligation to maintain a steady power supply to the national grid. This could require KOGAS to buy additional LNG volumes from highly volatile spot markets, increasing retail gas and power prices.

The extreme volatility of LNG prices can also result in delays or even cancellations of new LNG projects. In October 2022, for example, KOMIPO announced that it would delay the groundbreaking of its new regasification terminal from April 2023 to June 2024. Project costs had increased from ₩662.9 billion to ₩732.1 billion, KOMIPO financial reports show.

Given the high inflationary pressures in the country, the potential for additional interest rate hikes has notably intensified concerns regarding the increasing capital expenditure in planned LNG terminal projects. In July 2023, KOMIPO issued a corporate bond, securing ₩70 billion with an annual interest rate of 4.017%.[71] As of November, South Korea's benchmark interest rate was 3.5% per annum.[72] This represents an unprecedented gap of 2 percentage points compared with the U.S. interest rate of 5.5%, indicating the potential for further interest rate hikes.

While LNG fuel costs for power generation has nearly doubled from a year ago amid the energy crisis, the estimated unit cost[73] of solar power generation last year edged up 4%-8% over the same period to ₩128-₩155/kWh,[74] according to KEEI data. The unit cost of wind power generation[75] was also estimated to be much lower than LNG, at ₩164-₩166/kWh in 2022, up 1%-4% year on year.[76]

These figures emphasize that LNG-fired power generation remains highly volatile compared with renewable power generation, particularly in the face of the ongoing price fluctuations in the LNG market due to geopolitical tensions. IEEFA believes that a faster transition to renewable energy will mitigate the highly volatile fuel cost of power generation caused by unforeseen supply shocks and bolster the energy security of South Korea.

Limited Role for New LNG Applications in Climate Goals

IEEFA has identified that one of the motivations driving South Korea's rush to construct LNG terminals is prompted by the prospect of new business opportunities. However, new technologies and services designed to prolong South Korea's dependence on LNG are incompatible with the country's net-zero targets. Building new LNG assets with the intent to retrofit them in the future could exacerbate overinvestment and stranded asset risks.

Given the accelerated pursuit of net-zero goals globally, there are doubts about the financial and environmental sustainability of the LNG trading business, bunkering operations, blue hydrogen, and LNG blending in power generation. The success of LNG trading will depend on more companies in South Korea receiving licenses to import and export LNG.

The World Bank has issued a warning in its recent report, stating that "LNG is likely to have a limited role as a bunker fuel, with any demand for LNG rapidly declining after 2030. Therefore, to minimize

[71] KOMIPO. Investment Prospectus. July 5, 2023.
[72] Bank of Korea. Website.
[73] Levelized cost of electricity (LCOE).
[74] KEEI. Establishment and Operation of Long-term LCOE Forecast System for Expansion of Renewable Energy (3/5). December 31, 2022, p. 77.
[75] This refers to inland wind power generation.
[76] KEEI. Establishment and Operation of Long-term LCOE Forecast System for Expansion of Renewable Energy (3/5). December 31, 2022, p. 78.

the potential loss of returns, industry stakeholders should consider LNG's questionable long-term competitiveness as a bunker fuel when developing their future business strategies."[77]

The report indicates that LNG bunkering has limited potential to contribute to achieving the net-zero target by 2050. This is attributed to the relatively high methane emissions and substantial life-cycle carbon dioxide emissions associated with LNG. Natural gas is responsible for around 12% of global anthropogenic methane emissions.[78]

Another rationale for undertaking these multibillion-dollar LNG receiving terminal projects is the production of blue hydrogen from natural gas and the capture of GHGs through carbon capture, utilization and storage (CCUS). The idea is that repurposing and retrofitting the existing LNG import infrastructure can help mitigate risks associated with stranded assets.

Nevertheless, controversies are ongoing regarding whether blue hydrogen and CCUS installations are genuinely effective in reducing[79] GHGs and achieving carbon-neutral targets.

IEEFA wrote last month: "Blue hydrogen's environmental benefits rest largely on assumptions in a Department of Energy (DOE) model named GREET, a congressionally mandated tool for evaluating U.S. hydrogen projects. Due to its unrealistic and extremely favorable assumptions, the model significantly understates the likely greenhouse gas intensity associated with blue hydrogen production."[80]

Separately, IEA also wrote: "Today, hydrogen production is more of a climate problem than a climate solution. Demand for hydrogen is rising, reaching 96 MT in 2022, but most of it is met by emissions-intensive supply,[81] resulting in more than 0.9 GT of direct CO_2 emissions in 2022. Production of low-emissions hydrogen[82] from water electrolysis or from fossil fuels with high levels of CO_2 capture and storage amounted to less than 1 MT in 2022."[83]

Furthermore, there are persistent challenges that must be overcome for blue hydrogen and CCUS projects to attain commercial viability. These challenges involve the rate at which demonstration-stage technologies can progress to achieve financial profitability and the role of regulatory frameworks in facilitating public awareness and acceptance of these technologies.[84]

[77] World Bank, The role of LNG in the transition toward low- and zero-carbon shipping. Englert, Losos, Raucci and Tristan. April 15, 2021, p. 79.
[78] EFI Foundation. The future of natural gas in a deeply decarbonized world. June 1, 2021.
[79] IEEFA. Blue hydrogen: Not clean, not low carbon, not a solution. Schlissel and Juhn. September 12, 2023.
[80] IEEFA. Fact sheet: Blue hydrogen - Don't believe the hype. October 3, 2023.
[81] Including blue hydrogen and grey hydrogen.
[82] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 208
[83] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 136.
[84] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 147.

In light of these considerations, the IEA has revised down the anticipated contribution of CCUS to GHG reductions in its recent report, released in September 2023. This revision contrasts with forecasts presented in the 2021 edition of the report.

IEA specified that "after years of underperformance, CCUS must now show it can deliver. So far, the history of CCUS has largely been one of unmet expectations. Progress has been slow and deployment relatively flat for years."[85]

Lastly, the new demand opportunities stemming from hydrogen-LNG mixed power generation in South Korea may be overestimated as well. According to the MOTIE, projected total capacity for hydrogen-LNG blend power generation in 2030 is about 6.1 terawatt-hours (TWh).[86] This would consume only 0.3 MT of hydrogen, and the power generation capacity would represent just 1% of the total forecasted generation of 621.8 TWh in 2030.[87]

The IEA has highlighted a reduced contribution of hydrogen-LNG co-fired generation in its updated net-zero road map for 2023. It said: "Hydrogen also plays a smaller role [in power generation] than in the 2021 version as a result of continuing high costs and competition for potential end-users."[88] According to the IEA, hydrogen and ammonia are projected to account for only 1% of global power generation in 2030.[89]

Conclusion

The recent natural gas supply shocks caused by Russia's invasion of Ukraine, the frequent unexpected outages at LNG production facilities, and the more recent conflict between Hamas and Israel have all reaffirmed the inherent unreliability, uncertainty and unaffordability of LNG as an energy resource.

This report highlights that South Korea's recent push to build out LNG receiving infrastructure has put the spotlight on significant issues, including declining natural gas demand amid the country's transition to net zero; inefficient asset allocation and stranded asset risks in key areas; volatile LNG market outlooks; and the limited role for new LNG applications in the country's climate-aligned pathways.

The excessive investment in LNG receiving terminals by state-run companies is expected to place a heavier financial burden on taxpayers. Similarly, private-sector companies engaging in such overinvestment may exacerbate financial stability concerns by increasing their debt load, potentially reducing cost resilience and leading to decreased operations of LNG power plants.

[85] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 132.
[86] MOTIE. 10th PSDP. January 12, 2023, p. 9.
[87] MOTIE. 10th PSDP. January 12, 2023, p. 8.
[88] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 84.
[89] IEA. Net Zero Roadmap: A global pathway to keep the 1.5 °C goal in reach. September 2023, p. 197.

This, in turn, is likely to result in higher utility bills due to state-run gas utilities making additional spot LNG purchases at elevated costs to compensate for IPPs’ reduced power generation under the SMP cap and squeezed profit margins.

IEEFA offers the following key takeaways in light of the issues discussed.

Key Takeaways

- Align the build-out of LNG import and storage infrastructure with LNG demand based on Nationally Determined Contribution (NDC) targets.
- Strengthen public-private collaboration at the national level to achieve efficient use of new and existing LNG receiving terminal capacity.
- Avoid promoting technologies and services that would prolong the use of LNG without contributing to national climate goals. These may include blue hydrogen, LNG bunkering, and LNG-hydrogen co-fired power generation.
- Accelerate the transition to renewable energy with investment and policymaking to reduce high dependency on costly fossil fuels and enhance energy security in power generation.

Ultimately, it is crucial to recognize that LNG is not a long-term solution but rather an interim “bridge energy” on the path toward achieving a net-zero economy. LNG is a fossil fuel that needs to be phased out eventually.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the Authors

Michelle Chaewon Kim

Michelle Chaewon Kim is an Energy Finance Specialist, South Korea, at IEEFA. Over the past 15 years, she has worked across various energy and commodity sectors in Singapore and South Korea. Before her tenure at IEEFA, Michelle spent more than 11 years at S&P Global Commodity Insights and IHS Markit in Singapore, where she served as a senior market analyst focusing on oil, LNG and petrochemicals. She also held positions at Ernst & Young's Energy M&A Advisory team in South Korea as an assistant director, and at Korea Economic Daily as a business reporter. She holds a bachelor's degree in Sociology from Yonsei University in Seoul, South Korea, and a Master of Science in International Business from the University of Birmingham in the United Kingdom. mkim@ieefa.org

Institute for Energy Economics and Financial Analysis