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LNG Price Responsiveness in Asia

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1 Introduction

This note is a high-level comment on LNG price responsiveness. It provides some thoughts that are intended as input to a high-speed policy debate. It does not purport to be, or to substitute for, a fuller analysis of the global LNG market.[1]

The focus is on understanding the potential impacts of limiting wholesale gas prices to 50 €/MWh ($16/MMBtu).[2] While in the short-term this would unlikely impact production volumes, it might impact the market-based allocation of gas across countries through the LNG trade channel.

2 Conclusions

Our preliminary assessment based on the evidence laid out in this note is as follows. We begin with a discussion of the major LNG importing countries:

Japan

It is conventional wisdom in the industry that Japanese buyers will pay whatever it takes to secure needed LNG at a time of emergency such as the Fukushima nuclear accident. It is very unlikely, or would require ultra-extraordinary price levels (above the current levels of 100 €/MWh–150 €/MWh), to outbid Japanese buyers in the spot market, though it procures more than 80% of LNG through long-term contracts.

EU policy makers could seek a "political solution" in the form of a solidarity agreement whereby the Japanese government would agree to measures to reduce domestic LNG use to free up supply for Europe in case of "emergency in Europe" (and vice versa in a future scenario where Japan was in need of help). The political feasibility of such an agreement is of course a matter of debate, and will depend on specific circumstances at any given moment. It would require Japanese policy makers (and the Japanese public) to put considerable weight on their relationship with Europe, in light of the traditional heavy focus on security of supply in Japanese energy policy.

[1] In principle one would normally perform this assessment through some combination of bottom-up modelling (looking at the determinants of demand as a function of price, segment by segment) and top-down (econometric estimates of price elasticities), taking into account the differences between short and long run. One might also perform similar analyses of supply elasticities. Moreover, the analysis would take into account the effect of the prices of multiple commodities (gas, oil, coal, etc) in a systematic way. In this note we rely instead on a simpler and less rigorous approach, which we nonetheless consider useful (provided its limitations are understood).

[2] The proposed price cap of 50 €/MWh is converted (for demonstrative purposes) to $16/MMBtu using the $/€ exchange rate as of 30 March 2022 (1 € = $1.11). Note that the $/€ exchange rate has fluctuated in 2022, with a low of 1 € = $1.09 and a high of 1 € = $1.15.

In practical terms, it is important to understand the potential for Japan to free up LNG through 1. fuel switching (i.e., using alternative sources of energy other than LNG), and 2. fuel saving (i.e., using less energy).

1. With regards to fuel switching, it is important to distinguish between short term and long term. In the short term (e.g., for winter 2022/23) Japan has limited potential for fuel switching. In the power sector, Japan is in the process of phasing out production from other fuels (e.g. oil, nuclear). Switching back to oil-fired power generation will require considerable work to refurbish old facilities that are currently "mothballed" and would not be reliably online until after next winter. Practical and political obstacles would be a major barrier to any increase in the use of existing nuclear power stations. In the longer term there would be greater potential, e.g. through the addition of more renewable generation capacity.
2. With regards to energy saving, again it is important to distinguish short and long term. It is also important to distinguish between energy efficiency measures (getting the same level of services while using less energy) and "pure" reductions in consumption. With regards to energy efficiency, Japan has already made considerable efforts, particularly after Fukushima, so the potential for further short-term savings is limited (the "low hanging fruit" has already been picked). With regards to pure reductions in consumption (e.g., turning down air conditioning), experience post Fukushima shows that the Japanese public can make significant sacrifices if it is sufficiently engaged. Again, the likelihood that this would happen in response to European need is hard to judge in advance, and will depend very much on circumstances at the time. In our judgment it would be equally unrealistic to assume that it will happen or that it will not. One can also ask whether high prices will reduce consumption. However, Japanese consumers would face only limited exposure to high spot LNG prices, because regulated power prices reflect the average of all import prices (and the majority of imports are made via long-term import contracts that would likely have more moderate prices), and are smoothed out over time.

South Korea

Similar comments apply to South Korea as to Japan, albeit with smaller volumes. The power segment is not exposed to the increase in LNG spot prices however, and there is very limited potential for reducing gas consumption.

China

For China the situation is somewhat different, in that there is at least some potential evidence of demand response. In the first quarter of 2022, spot volumes are declining when spot prices are very high (though there may also be other demand factors causing the decline in spot volumes). It may be that Chinese buyers would have the ability and willingness to switch away from LNG to some extent in response to higher prices. However, 50 €/MWh is a very high price for gas,[3] and based on coal forward prices quoted in March 2022, power generators would have

[3] For comparison, the spot LNG price in Asia (as proxied by the EAX price index) has only exceeded 50 €/MWh on four occasions before August 2021. The first instance was for a single day in June 2012. The next two instances were 13 days in February 2013 and 9 days in February 2014, during the winters in Japan when it was still acutely experiencing the repercussions of the

already substituted away from gas towards coal at the proposed price cap of 50 €/MWh. China uses coal as a major heating and power generation resource rather than LNG or natural gas imported via pipeline from Russia or Central Asia. Especially after the Beijing Olympics when during periods of limited pressure for clean air, the government would increase reliance on coal for both heating and power generation, rather than LNG or natural gas at higher prices. On the other hand, as China does not join the West's sanctions against Russia, its NOCs may be flexible to procure LNG or natural gas at a lower-than-market price from Russia. As a result, opportunistic Chinese buyers may take advantage of a premium in the LNG spot market for arbitrage between Russia as a seller and the Western buyers. Note that this conclusion is purely based on our understanding of the technical ability to substitute gas with coal for power generation; more research is needed to take into account the impact of carbon pricing, emission regulations, taxes and availability of spare coal-fired generation capacity. Finally, the likelihood of a political solution between Europe and China is presumably negligible.

India

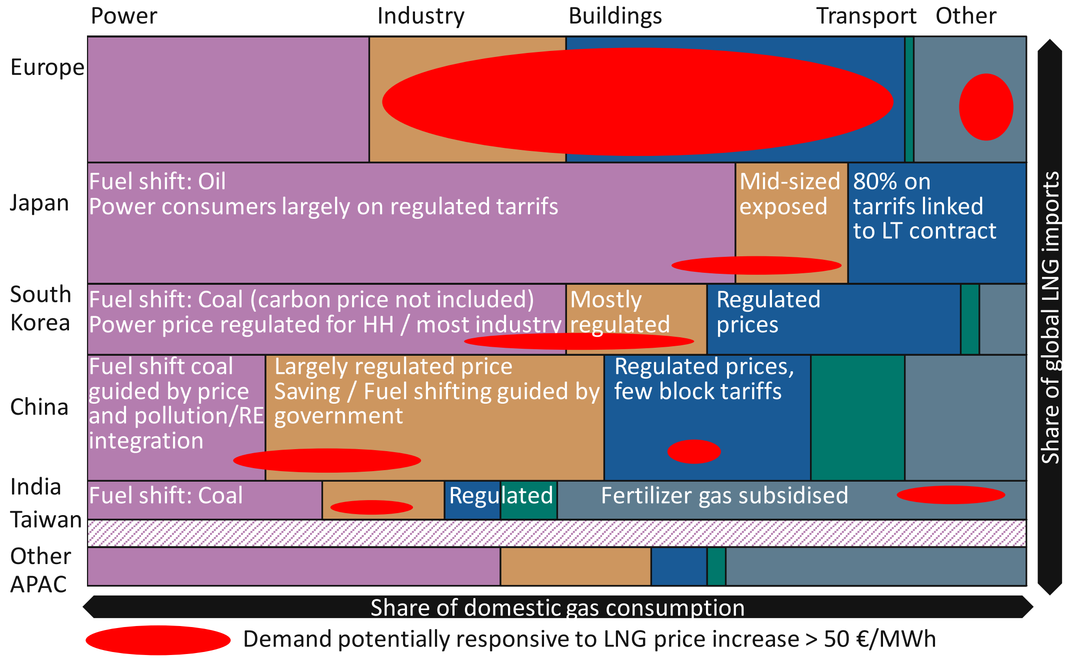
Similar comments apply to India as to China, albeit with smaller volumes.

In summary, and recognising high level of uncertainty, a 50 €/MWh price cap would likely have minimal impact on diversion of volumes from Japan and South Korea under a government-to-government swap agreement at a time of "emergency". The price cap could have a somewhat greater impact on diversion of volumes from China and India, but that impact is unlikely to be very material unless China has significant ability and willingness to switch from gas- to coal-fired generation in the short-term - which again would be economical at lower price levels but subject to broader considerations including for example air quality.

Figure 1 below provides and stylized view on the LNG demand responsiveness to changes in spot prices.

2011 Fukushima incident. The fourth instance was 7 days in January 2021, the first winter after the start of the Covid pandemic. Starting on 26 August 2021, EAX has increased above 50 €/MWh and remain above as of 30 March 2022.

Figure 1: Summary of price responsiveness by country and by segment



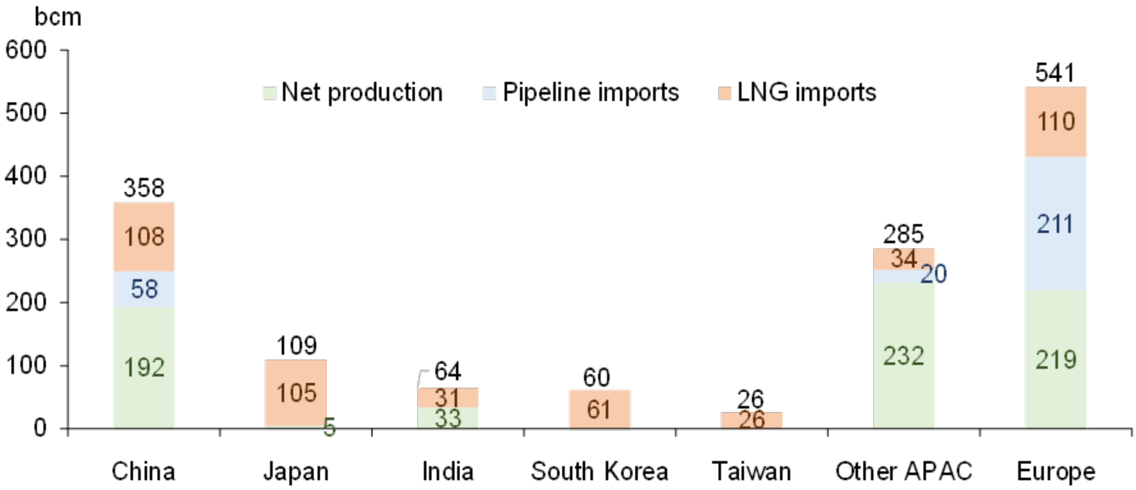
Source: Own analysis based on Figure 2 and Tables 4-1 to 4-7

3 Overview of the global LNG market

Liquefied natural gas ("LNG") is a form of fossil fuel used in many countries. Compared to natural gas in gaseous form (also referred to as "pipeline gas"), LNG can be transported by sea via LNG cargo ships. The transportability and storability of LNG mean that demand for LNG comes mainly from countries where pipeline gas is not an option (Japan, South Korea, Taiwan, sometimes referred to collectively as "JKT") or when gas demand significantly exceeds existing pipeline capacity (China and India in Asia, Spain and Portugal in Europe).

Figure 1 shows the global gas consumption in 2021 by country and source of gas (pipeline import, LNG import, own production).

Figure 2: Gas consumption by country (2021) and aggregates (2020) (including both LNG and pipeline gas)



Source: Own analysis based on data for 2021 from JODI (2022) for individual countries, and BP (2021) for 2020 for the aggregates Other APAC and Europe.

The transportability of LNG also means that it is part of a global market. The global LNG market has the following characteristics:

1. In 2020, 60% of the LNG trade was done on a long-term basis.[4] The terms of these LNG sales are specified in long-term contracts ("LTC") lasting five to 30 years. These LTCs generally require the seller to make available a certain volume and for the buyer to purchase a certain volume. LTCs also define the price formula of these long-term sales, which for historic reasons is often linked to oil prices. Below is an example of price formula under an LNG LTC for delivery in Asia, where 14% is also called the "slope", and Brent (6,0,3) is a way to calculate the trailing average oil price:[5]

$$LTC\ LNG\ Price = 14\% * Brent(6{,}0{,}3)$$

2. LNG not traded under an LTC is traded on the spot market. Historically (notably after the Fukushima accident in 2011) Japan has been the "marginal" buyer of spot LNG.

[4] In 2020, 60% of the total LNG trade is on a long-term basis. This is a decrease from 2019, when 64% of the total LNG trade is on a long-term basis. GIIGNL 2021: p.5 and GIIGNL 2020: p.5.

[5] For example, to calculate the indicative price of an LNG cargo delivered under a LTC in January 2021, one would first have to calculate the "Brent (6,0,3)" price as of January 2021. This in turn is the average Brent price in the previous six months, i.e., July 2020–December 2020, or $44/bbl. Using the Brent (6,0,3) price as of January 2021, we then apply the 14% slope by multiplying the two figures together, to get $6.11/MMBtu. This can be seen in Figure 2, where it sits below the spot EAX price of $14.72/MMBtu in the same month. We used a 14% slope as an indicative measure. It does not necessarily represent the average slope in the market, and we have seen slopes lower and higher than 14% in long-term LNG contracts.

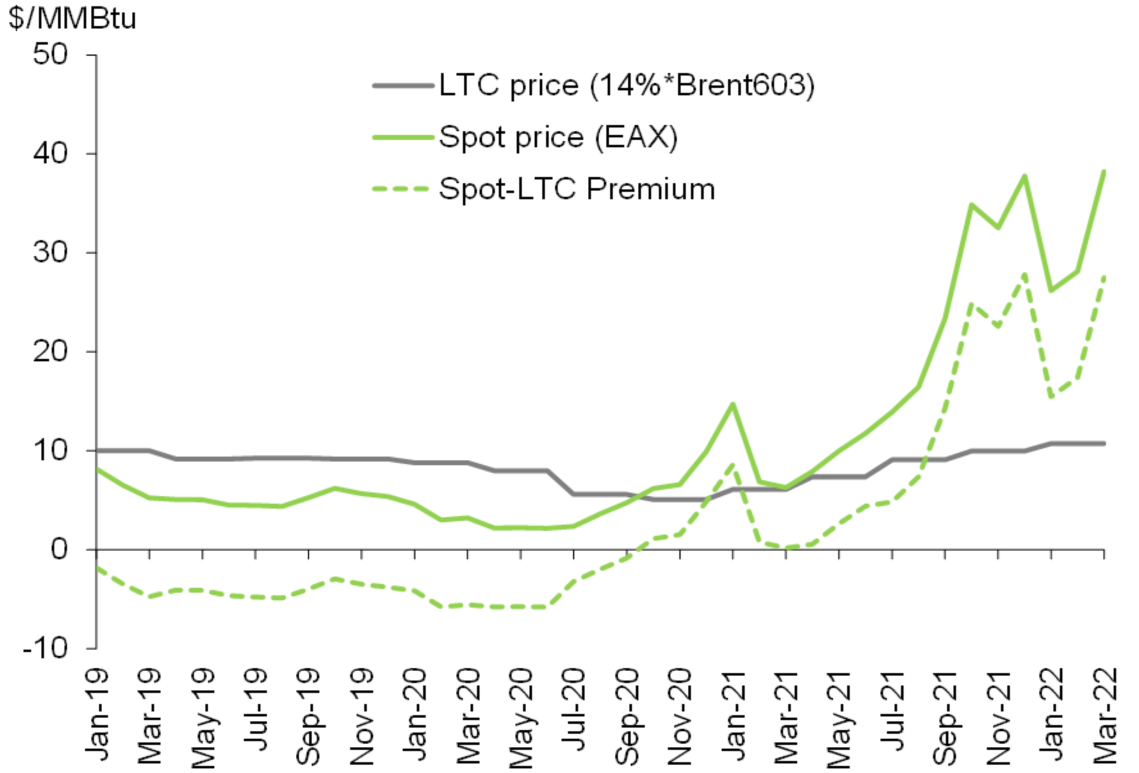
Although Japan procures more than 80% of LNG under LTCs, China which now exceeds Japan as a top LNG buyer, depends on the spot market for more than 70% of its imported LNG. This means that the price of spot LNG at a given point in time would increase until there are no additional buyers from China willing to pay more. The LNG spot price is often referred to JKM (Japan Korea Marker) published by Platts, which used to reflect marginal LNG price the Japanese had to pay, now rather reflects Dutch TTF as Asian LNG spot cargo transaction seems a subset of the European spot natural gas and LNG market.

3. Various data providers publish an assessment of the spot LNG price. The two most well-known indices are the East Asia Index ("EAX") by ICIS and the Japan Korea Marker ("JKM") by Platts.[6]

$$Spot\ LNG\ Price = EAX\ or\ JKM$$

Figure 3 below compares these proxies for spot and LTC LNG prices:

Figure 3: Comparison of spot and LTC LNG prices



Source: Own analysis based on data from Independent Commodity Intelligence Services (ICIS) and U.S. Energy Information Administration (EIA)

[6] Both indices have now been updated to reflect spot market value of cargoes delivered ex-ship into Japan, South Korea, China and Taiwan.

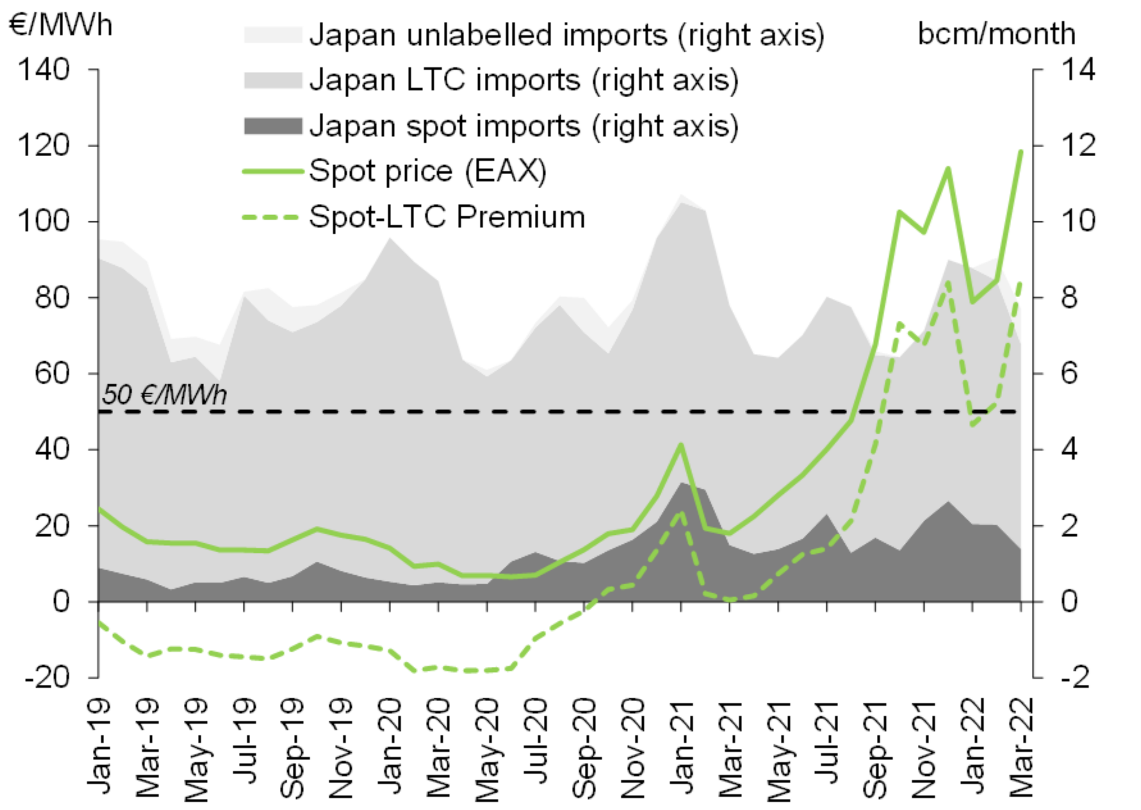
4 Analysis of LNG trade by country

In this section, we analyse the volume of spot LNG imports on a per-country level. We also describe the potential responsiveness to changes in gas prices for each segment of consumption (power generation, industrial, residential/commerce, transport and other) in each country. Sources and abbreviations are explained in detail in Section 5.

4.1 Japan

Comparing Japan's spot LNG imports (dark grey area) against the spot LNG price (solid green line), we observe a high correlation from January 2019 until the beginning of 2021, i.e., prices and volumes moved in tandem. This is especially noticeable in January 2021, when spot import volumes spiked at the same time spot prices spiked, suggesting that the seasonal demand in Japan was driving the spot price. Japan has experienced in the past generation capacity shortage across the country and as a result, the procurement of fuel supplies to electricity generators, LNG for the most part as been a top priority.

Figure 4: Comparison of LNG price in the spot market and LNG price under LTC



Source: Own analysis based on data from ICIS, EIA.
Note: See Section 5 for the full definitions of "spot", "LTC" and "unlabelled" for the purposes of this graph.

Starting in September 2021, although spot LNG prices first rose above 50 €/MWh, spot imports into Japan remained relatively high. This reflected several unplanned outages at coal generation plants as a result of their intermittent operation due to increase in PV generation during day-time. Then generation companies rushed to run alternative generators such as oil and LNG of which their inventory went extremely low to stop for weeks. Very tight power market lasted for weeks with limited supply of fuels (oil and LNG).

On the demand side, Japan's gas consumption can be analysed as follows:

Table 4-1: Japan's gas demand by segment

Segment	Consumption (bcm in 2021)	Characteristics
Power generation	76	• LNG-based power generation is the highest-cost generation method at any LNG prices above a $16/MMBtu (50 €/MWh) price cap. • At these price levels, only impact through power prices can reduce electricity and thus LNG demand. • No ability to switch to coal, nuclear or even fuel-oil capacity in the short term. In the medium long-term generators would need Gov. economic support to re-open capacity. • Only 20% of households are currently exposed to electricity tariffs responding with short delay to spot prices. They might respond. The remaining 80% of household consumers opt for regulated tariffs instead of a market price[7] and are hence not responsive to spot price. • 80% of supplies to power utilities is sold under long-term Power Purchase Agreements indexed to Japanese average LNG import prices ("JLC"). Only 20% of the market would be exposed to spot electricity prices (JEPX) mainly driven by spot LNG prices.
Industrial	13	• The retail gas market is on paper liberalised, though 19% of volumes continue to be sold under regulated tariffs. • Japanese customers pay one of the highest prices in the world (even before taxes).
Residential/ Commercial	21	
Transport	0	
Other	0	
Overall	109	• Importers have been negotiating lower slopes over the past decade. Potential for cross-subsidy between gas purchased under LTC and spot purchases for companies selling to regional utilities under long-term PPAs indexed to import prices. However, any increase in LTC volumes will absorb capacity for the spot market and will be limited given the limited volume upward flexibility in LTCs.

Source: Own analysis on consumption by segment is based on the following: JODI (2022) and IEA (2021a). Additional sources reviewed include EIA, 2020; IEA, 2021b; Lexology, 2021

While the analysis shows that Japanese LNG demand overall exhibits limited short-term responsiveness to LNG spot prices exceeding 50 €/MWh due to the majority of long-term contracts

[7] High-voltage customers in this context includes large factories (2,000kW+), mid-sized factories (500kW–2,000kW) and small factories and buildings (50kw–500kW). Low-voltage customers are small shops and households (below 50kW). METI 2018, p.7.

being linked with crude oil price, Japan has potential exposure in high crude oil and spot LNG price in the long-term, impacting cost of industrial production and competitiveness.

On the other hand, Japan always is exposed to an "emergency" shortfall of fuel imports due to sellers' contingency situation, and more notably, risk of disruption by large earthquakes, impacting facilities of fuel imports. For energy security purposes, the Japanese government would be better-off if it had an Emergency LNG Swap Agreement with the EU to provide LNG to each other in case of sellers' contingency and buyers' contingency without substantial price spikes by pre-determined price cap agreement.

After the 2011 Fukushima accident a combination of mainly voluntary energy-savings measures reduce power demand by 15%. With LNG being the marginal fuel in power generation, such a program would in today's circumstances directly translate into a reduction of LNG demand for power generation of 30% and hence of overall LNG demand by 21%.[8]

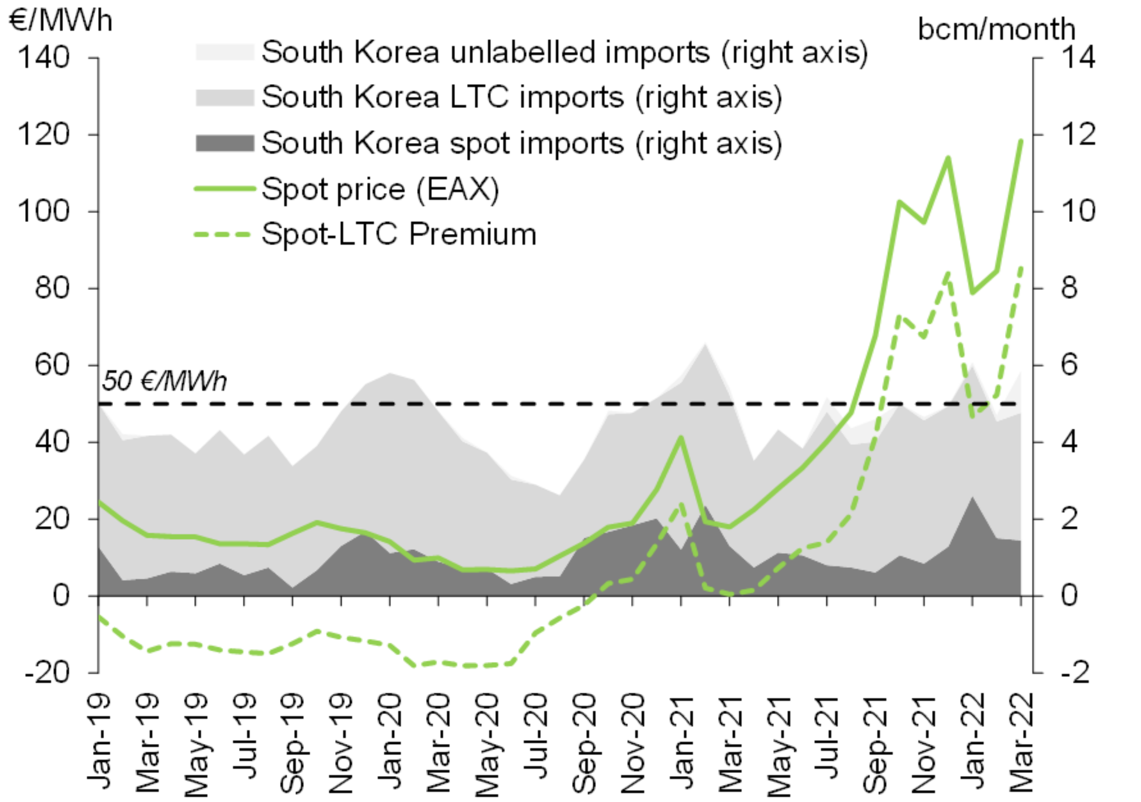
However, and although the Japanese Government might be willing to collaborate with EU in the development of some solidarity mechanism, the reality is that Japan´s priority is for a stable energy supply. Diversions of LNG to Europe would not have the public opinion support. In addition, considering that Japan has already made a big effort in managing and reducing energy demand since Fukushima, and in particular electricity demand, the scope for further demand destruction, or replacing gas consumption in the power segment, would be very limited.

4.2 South Korea

Comparing South Korea's spot LNG imports (dark grey area) against the spot LNG price (solid green line), we observe a moderate correlation from January 2019 until the beginning of 2021, i.e., prices and volumes moved in tandem.

[8] Percentage reduction in LNG demand for power generation * Share of power generation in total LNG demand / Total LNG demand = Percentage reduction in total LNG demand, hence 3% * 76 bcm / 109 bcm = 21%.

Figure 5: Comparison of LNG price in the spot market and LNG price under LTC



Source: Own analysis based on data from ICIS, EIA.
Note: See Section 5 for the full definitions of "spot", "LTC" and "unlabelled" for the purposes of this graph.

Starting in September 2021, although spot LNG prices first rose above 50 €/MWh, spot imports into South Korea remained relatively high.

On the demand side, South Korea's gas consumption can be analysed as follows:

Table 4-2: South Korea's gas demand by segment

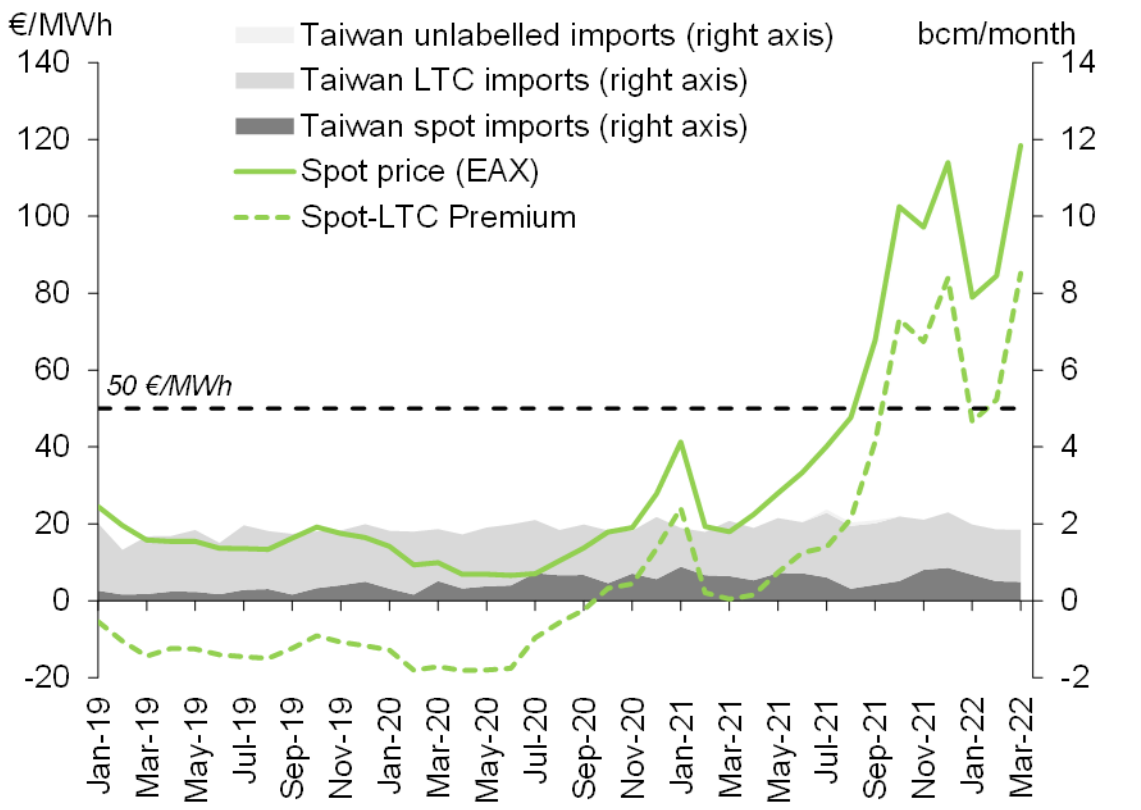
Segment	Consumption (bcm in 2021)	Characteristics
Power generation	30	• Very limited response of demand since in the near term there is no alternative to gas. • Coal power is already at maximum since coal is cheaper than gas. • Electricity tariffs for households and industry reflect average not marginal generation costs, hence increased LNG prices will have very limited impact on electricity prices for households, commerce and industry and thus also on demand response.
Industrial	9	• Gas use important for petrochemical/metal industries • The gas price, and demand, for industrial sector is more responsive to international price, than power and residential/commercial sectors.
Residential/ Commercial	16	• Retail price is strictly controlled by the government and the price does not reflect recent hike so we do not expect any significant response in near term, up to 1~2 years.
Transport	1	
Other	3	
Overall	60	• KOGAS imports ~80% of the country's LNGs.

Source: Own analysis on consumption by segment is based on the following: JODI (2022) and IEA (2021a). Additional sources reviewed include IEA, 2020.

4.3 Taiwan

Comparing Taiwan's spot LNG imports (dark grey area) against the spot LNG price (solid green line), we observe a relatively stable and increasing consumption from January 2019 until present.

Figure 6: Comparison of LNG price in the spot market and LNG price under LTC



Source: Own analysis based on data from ICIS, EIA.
Note: See Section 5 for the full definitions of "spot", "LTC" and "unlabelled" for the purposes of this graph.

Starting in September 2021, although spot LNG prices first rose above 50 €/MWh, spot imports into Taiwan remained relatively high.

On the demand side, Taiwan's gas consumption can be analysed as follows:

Table 4-3: Taiwan's gas demand by segment

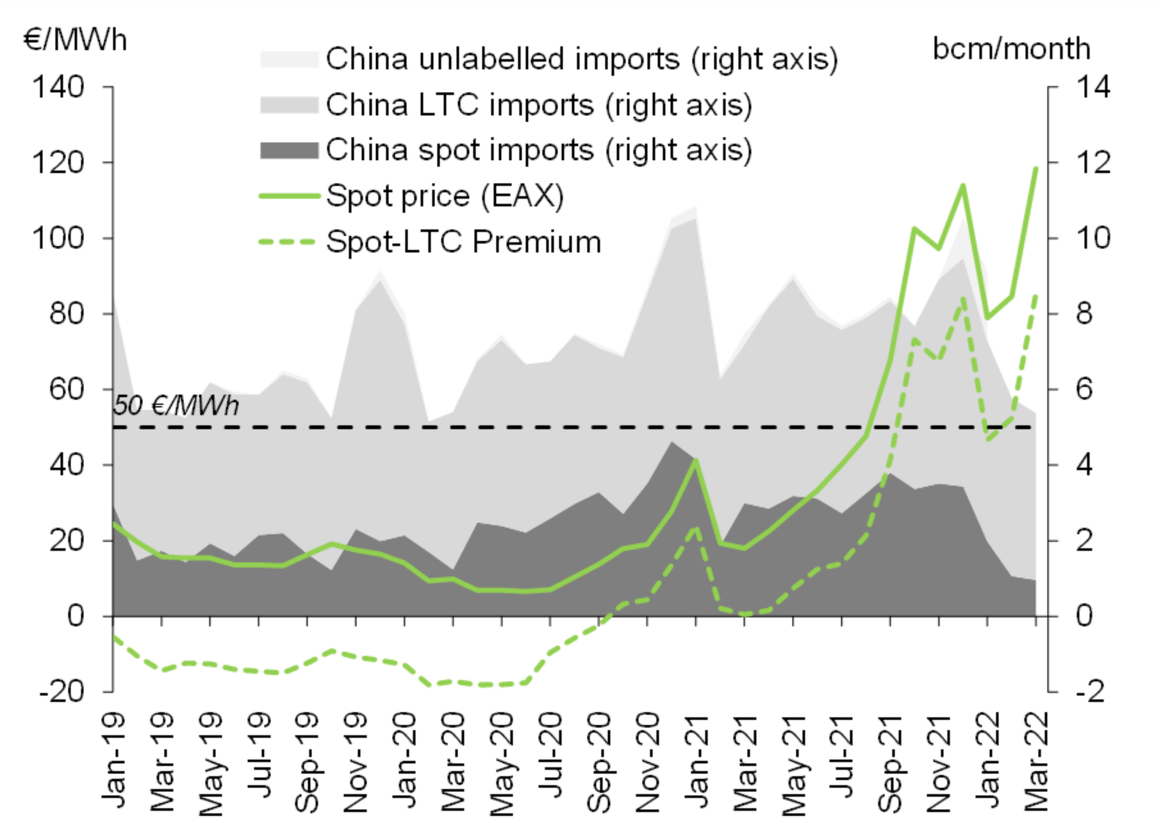
Segment	Consumption (bcm in 2021)	Characteristics
Power generation	N/A	• Coal is 45%, natural gas is 31%, nuclear is 14% • Nuclear: Gradually phasing out nuclear. 2/3 nuclear plants are decommissioning, while construction of a fourth one is stalled • Electricity prices heavily subsidized, one of lowest in the world
Industrial	N/A	
Residential/ Commercial	N/A	
Transport	N/A	
Other	N/A	
Overall	26	• CPC near monopoly, gas prices not fully price-reflective

Source: Own analysis on consumption is based on data from JODI (2022). Additional sources reviewed include EIA (2016), Feigenbaum and Hou (2020), Yang and Wang (2021).

4.4 China

Comparing China's spot LNG imports (dark grey area) against the spot LNG price (solid green line), we observe a correlation from January 2019 until the beginning of 2021, i.e., prices and volumes moved in tandem. This is especially noticeable in January 2021, when spot import volumes spiked at the same time when spot prices spiked, suggesting that the seasonal demand in China was driving the spot price.

Figure 7: Comparison of LNG price in the spot market and LNG price under LTC



Source: Own analysis based on data from ICIS, EIA.
Note: See Section 5 for the full definitions of "spot", "LTC" and "unlabelled" for the purposes of this graph.

Starting in September 2021, although spot LNG prices first rose above 50 €/MWh, spot imports into China remained relatively high and only declined towards the end of the heating season in February as already in 2021.

On the demand side, China's gas consumption can be analysed as follows:

Table 4-4: China's gas demand by segment

Segment	Consumption (bcm in 2021)	Characteristics
Power generation	67	• Natural gas-based power generation may be operated to reduce emissions and enhance flexibility even where gas prices exceed coal prices. However, the larger the price gap, the more likely it is that existing coal power generation will be operated at higher capacity or wind power generation at lower capacity to reduce flexibility need from gas power stations. • These prioritisations are ultimately political, hence difficult to assess at what LNG-coal price spread the shift will be implemented, but unless exceptional circumstances (like winter Olympics) result in high emphasis on

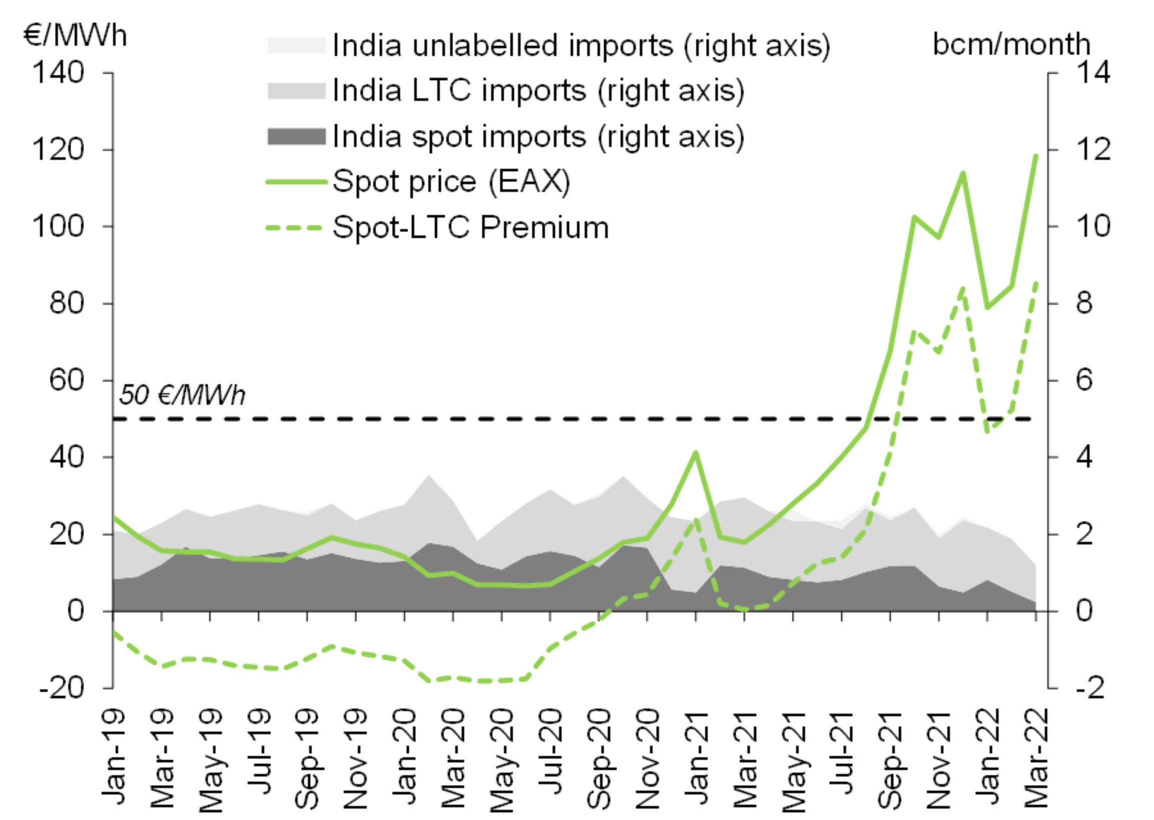
		clean air, we assume at moderate mark-ups, e.g. with typical coal prices already below 50 Euro/MWh.
Industrial	131	• Fuel shifting between gas and coal is possible in a variety of enterprises. Also, capacity utilisation may shift for example between coal and gas-based fertilizer production. Hence LNG demand responds to LNG prices exceeding coal prices. • To enhance resilience to LNG supply interruptions, natural gas-intensive basic material production (chemicals, fertilizer, hydrogen) store intermediate products at a scale that allows for reduced production volumes for extended periods in the range of 6-9 months, and intermediate products can also be imported from countries not dependent on LNG supply. These flexibilities are already used during winter periods, hence it is unlikely that price increases exceeding 50 Euro/MWh will unlock significant additional flexibility.
Residential/ Commercial	78	• Most residential demand is on regulated tariffs decoupled from LNG spot prices. In few major cities, the highest price band of multi-band tariffs reflect full gas prices. This small fraction of overall consumption typically among higher income households is therefore exposed for a fraction of heating demand to global LNG spot prices. Overall very limited price responsiveness to be expected unless governments implement dedicated programs for natural gas savings. For example, amid shortages in 2017, households that had bought more than 1500 cubic meters of gas were limited to 15 cubic meters per day from Dec. 15th onwards (Reuters, 2017). • Heating demand is clearly linked to heating season which lasted last winter from November 1st to March 15th and covers the period of high volumes of spot gas price purchases.
Transport	36	• As of 2017, China had 6 million natural gas vehicles in use, and had policies in place to further expand the fleet for both light- and heavy-duty applications (Pan et al., 2020). Promotional policies have focused on reducing air quality and limiting GHG emissions, especially in heavy-duty vehicles where electrification potential is limited. Overall, rather limited demand response is expected.
Other	45	• At a sufficiently high natural gas/coal price spread, coal gasification may occur.
Overall	358	

Source: Own analysis on consumption by segment is based on data from JODI (2022) and IEA (2021a).

4.5 India

Comparing India's spot LNG imports (dark grey area) against the spot LNG price (solid green line), we observe a relatively constant level of imports. In January 2021, when the spot LNG price spiked, there is a dip in spot import volume. Unlike the previous four countries (Japan, South Korea, Taiwan, China), India imported less LNG in 2021 compared to in 2020.

Figure 8: Comparison of LNG price in the spot market and LNG price under LTC



Source: Own analysis based on data from ICIS, EIA.
Note: See Section 5 for the full definitions of "spot", "LTC" and "unlabelled" for the purposes of this graph.

On the demand side, India's gas consumption can be analysed as follows:

Table 4-5: India's gas demand by segment

Segment	Consumption (bcm in 2021)	Characteristics
Power generation	16	• Gas based power stations are allocated a limited quantity of 'domestically' produced low price gas. • All further gas demand needs to be met by addition procure RLNG (Re-gasified LNG).

		• Demand for this additional RLNG is highly price elastic at low to moderate LNG prices. Once RLNG is the most expensive generation option, which is the case at 50 €/MWh, additional price increases will not further impact merit order. • Prices exceeding 50 €/MWh can only impact R-LNG demand in power, if they result in demand reduction or load shedding. • Electricity prices are regulated based on average generation costs. Would not be impacted on short-term and with small share of LNG based power generation also very limited in longer-term. Hence no demand response to be expected. • LNG Prices exceeding 50 €/MWh could trigger additional load shedding, if R-LNG based power generation would be required to meet load but would not be dispatched because generation costs exceed the price cap of 20 Rp/kwh (24 c/kwh). This would require prices to power stations exceeding 10 Rp/kwh. (100 €/MWh). This price level was reached and demand was shed multiple hours over the last 6-8 months. Apparently, the price levels were seen to be too high, and the price ceiling has been reduced from 20 to 12 Rp/kwh. R-LNG prices exceeding 60 Euro/MWh can now trigger demand reductions through load shedding in India.
Industrial	8	• Some fuel shifting to Propane / Fuel oil and of refineries to naphtha occurred at prices below 50 €/MWh. In the longer-term, refractory industry which uses gas can and may keep shifting to alternate fuels.
Residential/ Commercial	4	• Gas supply to domestic (household) and transport is served by CDG with domestically produced gas. Domestic gas production is based on cheap domestic on-shore gas at$2.4/MMBtu and somewhat higher levels for deep-water production. This demand and production is therefore not responding to LNG prices. • Commercial users are like industry exposed to RLNG import prices and expensive domestic (e.g. deep-water) gas production. They may thus have incentives to reduce demand also at higher gas prices – but often in the short-term limited flexibility.
Transport	4	
Other	32	• A large share corresponds to gas used in the production of fertilizer (urea). • Fertiliser sector gets pooled price (i.e. mix of domestically produced and R-LNG) and is thus cushioned from LNG prices (MOP&NG, 2015). Given its need for food production, unlikely that this will be reduced.
Overall	64	

Source: Own analysis on consumption by segment is based on data from JODI (2022) and IEA (2021a).

4.6 Other APAC and Europe

The following tables summarise the gas consumption by segment in Other APAC and Europe:

Table 4-6: Gas demand in Other APAC by segment

Segment	Consumption (bcm in 2021)	Characteristics
Power generation	124	
Industrial	46	
Residential/ Commercial	18	
Transport	5	
Other	92	
Overall	285	

Source: Own analysis based on data from JODI (2022) and (IEA, 2021a).

Table 4-7: Europe's gas demand by segment

Segment	Consumption (bcm in 2021)	Characteristics
Power generation	164	
Industrial	112	
Residential/ Commercial	196	
Transport	6	
Other	64	
Overall	541	

Source: Own analysis based on data from JODI (2022) and IEA, 2021a.

5 Additional information

5.1 The threshold price of natural gas at which using coal to generate electricity may be profitable

We have attempted to estimate the threshold price of natural gas at which using coal to generate electricity may be profitable. For this analysis we assume that such switch would be driven only by short-term profit margins, and we do not analyse any practical constraints, or long-term considerations that may prevent this.

To estimate the above-described threshold price of natural gas we take the following steps:

1. Estimate the cost of producing a MWh of electricity for a coal plant based on:

   a. the forward prices of coal as of 15 March 2022,[9]
   b. an average heat rate of a coal plant of 8,000 Btu/kwh which corresponds to an efficiency rate of 40% of the plant,[10]
   c. an estimate of the heat content of coal of 6000 kcal/kg MMbtu/tonne (Aden et al., 2009).
2. Estimate the price of natural gas at which an electricity producer would be indifferent between using gas or coal (the blue line in Figure 8 below).
   a. To calculate this, we use the heat rate of 7,000 Btu/kWh which is the heat rate of a fairly new and efficient natural gas combined-cycle generator (EIA, 2013).

In addition, we considered two sensitivities. A first sensitivity considering the cost of carbon emissions, taking as a reference a price of USD 30/ton and standard emission factors for coal and gas.[11] Figure 8 below shows the coal forward curve between March 2022 and December 2023 (red line) and the estimated natural gas price threshold (blue line) above which a switch to coal in power generation may be more profitable. Considering carbon costs increases gas competitiveness by approximately EUR 5.00/ MWh.

[9] We use the forwards of coal delivered at the port of Rotterdam in the Netherlands in USD/tonne. We disregard any coal transport costs.

[10] Dark spreads measure returns over fuel costs of coal-fired generation (EIA, 2013).

[11] 0.0957 tons/MMBtu for coal and 0.0529 tons/MMbtu for gas. See EIA (2021).

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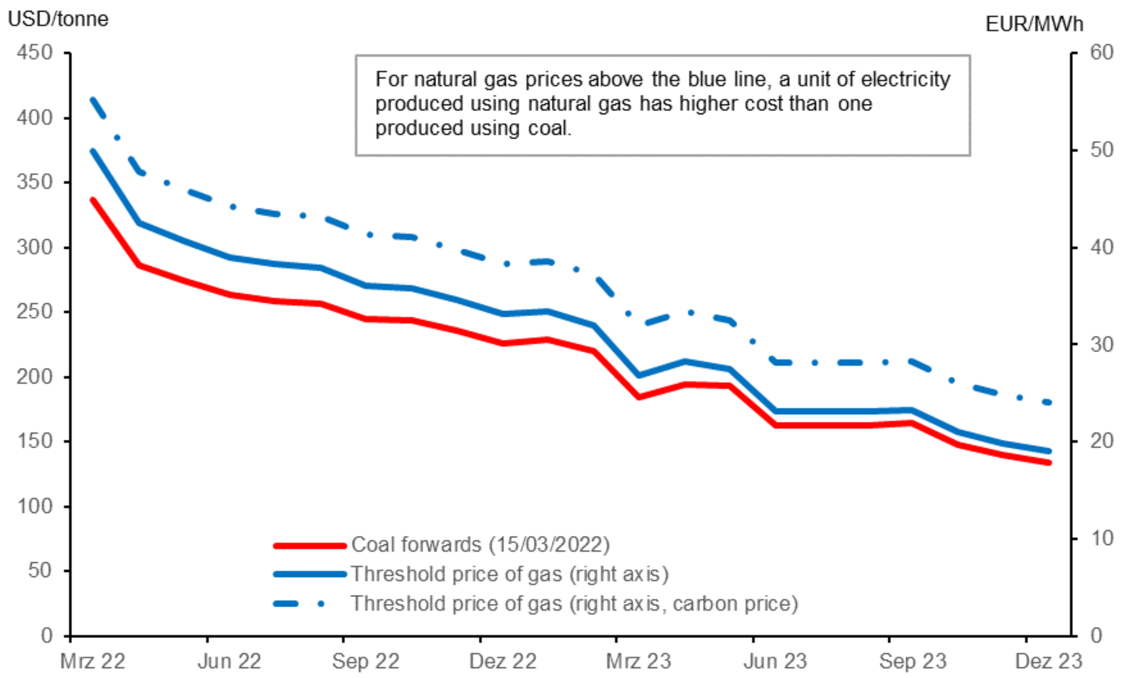
Figure 9: Coal forwards and the threshold price of natural gas including and excluding carbon prices of USD 30/ton, March 2022 - December 2023

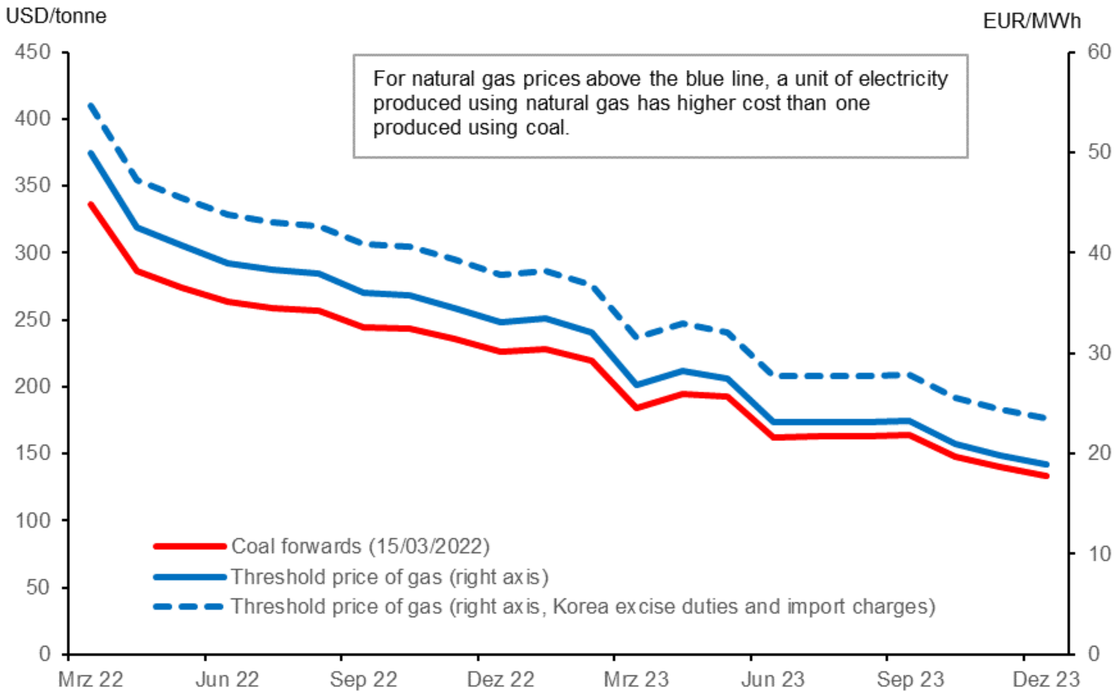


Source: Own analysis based on data from Bloomberg Professional and EIA, 2013 and 2021.

A second sensitivity considers the potential impact of excise duties and import charges on gas and coal, in this case taking Korea as an example.[12] Excise taxes in Korea have a similar impact to considering the cost of Co2 emissions. the higher excise taxes on coal increase gas competitiveness by approximately the same amount, EUR 5.00 MWh.

[12] 15,800 KWR/tonne for gas and 46,000 KWR/tonne for coal.

Figure 10: Coal forwards and the threshold price of natural gas including and excluding excise taxes and import charges in Korea, March 2022 - December 2023



Source: Own analysis based on data from Bloomberg Professional and EIA, 2013 and 2021.

5.2 Notes related to the data used in the analysis

Notes regarding the data used to calculate the spot and LTC volumes by country:

- Data reflects LNG delivered in the period from January 2021 to March 2022, as reported by ICIS. The data used was updated on 30 March 2022, hence LNG delivered on 30–31 March 2022 have not been fully reflected.
- Spot volumes are cargoes labelled with a "Sales basis" containing only the following terms: spot, ST, STC.
- Cargoes without any information are classified as "unlabelled".
- All other cargoes (whose sales basis could be MTC, LTC, or an ambiguous label such as "Spot|LTC") are categorised as an LTC cargo.

Notes regarding the data used for calculating the overall gas consumption by country:

- Data for individual countries reflects gas consumption in 2021. Data for aggregates (i.e., Other APAC and Europe) reflects gas consumption in 2020.

- Information for individual countries (China, Japan, South Korea, …) comes from the Joint Organisations Data Initiative ("JODI").
- Information on regions (Other APAC and Europe) comes from British Petroleum's Statistical Review (BP, 2021). Other APAC volume is calculated using Asia Pacific less the five named countries (Japan, South Korea, Taiwan, China, India). Europe volume includes Turkey but excludes Russia. The latter is in a separate category (along with Azerbaijan, Belarus, etc.) called Commonwealth of Independent States ("CIS").

Notes regarding the data used for calculating the gas consumption by segment and by country:

- Data comes from IEA's global energy balance for 2019.
- Information on Other APAC is calculated using the sum of "Non-OECD Asia", Australia and New Zealand less China and India.
- Information on Europe is calculated using OECD Europe. An alternative would be to also include "Non-OECD Europe and Eurasia", which would include some of the missing European countries such as non-OECD countries in Eastern Europe, but would further include countries that are not considered to be in Europe by the BP data, such as Azerbaijan. Calculating the segment split based on this alternative definition would increase the share of power generation from 30% to 40% while reducing the share of all other segments.
- Information on Taiwan is unavailable.

IEA provides additional descriptions for some of the segments:[13]

- Power generation: Electricity, CHP and heat plants as defined by IEA.
- Industrial: Industrial as defined by IEA.
- Residential/Commercial: Residential and Commercial and public services as defined by IEA.
- Transport: Transport as defined by IEA.
- Other: This segment includes agriculture/forestry, fishing, non-specified (other) and non-energy use. It also includes gas used for the Oil refineries, transformation segment

[13] World Energy Balances Spreadsheet, IEA (2021): Definitions tab.

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