Global Gas Prices

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Abbreviations and acronyms

bcf	Billion cubic feet
bcm	Billion cubic metres
BIM	Bilateral monopoly
DES	Delivered ex-ship
CPI	Consumer Price index
EIA	US Energy Information Administration
FOB	Free on board
GCM	Gulf Coast Marker
GOG	Gas-on-gas
GSPA	Gas Sales and Purchase Agreement
HH	Henry Hub
IEA	International Energy Agency
IGU	International Gas Union
JCC	Japan Customs Clearing or Japan Crude Cocktail
JKM	Japan Korea Marker
LNG	Liquefied Natural Gas
mmBtu	Million British thermal unit
mt	Million tons
MWh	Megawatt hour
NBP	National Balancing Point
NET	Netback from final product
NWE	Northwest Europe
OIES	Oxford Institute of Energy Studies
OPE	Oil price escalation
OTC	Over-the-counter
PPA	Power Purchase Agreement
QP	Qatar Petroleum
RBC	Regulation below cost
RCS	Regulation cost of service
RSP	Regulation social and political
SPA	Sales and Purchase Agreement
SRMC	Short run marginal cost
tcf	Trillion cubic feet
TOP	Take-or-pay
TTF	Title Trading Facility
TWh	Terawatt hour

Executive Summary

- This report provides a detailed explanation of the elements that dictate gas prices around the world, including the mechanisms for setting a gas price formula, the role of trading hubs and the influence of major suppliers. It also examines recent trends in gas prices including changes in the nature of gas contracts and the impact of the coronavirus pandemic. The report concludes with a forecast of future developments.

- Gas prices are still largely set on a regional level and are most influenced by factors in regional markets such as North America, Europe or Asia. A well-developed global gas market has yet to emerge but a spot market for LNG cargoes does exist and is becoming more global in reach.

- Gas has traditionally been sold using long term contracts linked to the oil price. This remains the norm in Asia but is increasingly not the case in North America and Europe. Gas trading hubs have developed in North America and Europe. Also short term contracts and spot market transactions are becoming more common.

- Gas pricing mechanisms are varied but can be divided into two broad categories: market pricing and regulated pricing. The proportion of gas consumed globally that is subject to market pricing reached more than 70% in 2020 due to liberalisation programmes in a range of markets.

- Th first gas trading hub emerged in the US in the early 1990s, with the creation of the Henry Hub (HH) benchmark. The two main European gas trading hubs are the Netherlands' Title Trading Facility (TTF) and the United Kingdom's National Balancing Point. A trading hub has yet to emerge in Asia, but Singapore has developed as the centre for gas trading in the region.

- LNG pricing has undergone considerable evolution in recent years as more suppliers have started operations, there is more interconnectedness between markets and historic long term contracts have come to their end. There is a move away from long term contracts especially in North America and Europe towards short term contracts and the spot market. This trend is likely to continue especially in Asia.

- The largest gas exporters are Australia, Qatar, the US and Russia. In 2020, Australia overtook Qatar as the world's number one LNG exporter. However, Qatar is undertaking a major expansion of its LNG export capacity.

- In late 2018, the global gas market entered a period of oversupply as new LNG production came on stream. The collapse of demand in early 2020 as a result of the economic impact of the coronavirus pandemic exacerbated this situation and prices collapsed. However, a stronger and faster than expected recovery in Asia, especially China, from mid 2020, led to record price rises.

Prices have remained strong in 2021 but not at record levels as demand in China remains strong and several suppliers have suffered unexpected shutdowns.

- In 2022-24, global LNG supply is expected to remain tight as demand increases. In the longer term, the global response to climate change will be the main factor that shapes the dynamic of the global gas market. The use of natural gas is coming under pressure as governments attempt to transition to less carbon intensive energy systems. While natural gas is viewed as the cleanest of the fossil fuels, it emits carbon dioxide when burnt and is itself damaging to the atmosphere, if released. However, natural gas will continue to be an important source of energy for several decades and changes are unlikely to occur quickly.

Introduction

This report provides an explanation of the dynamics of global natural gas prices. It describes the elements that make up gas prices, the mechanisms for setting gas prices, the role of gas trading hubs and the impact of major suppliers. This report also analyses recent trends in global gas prices and forecasts the impact of those trends on future gas prices.

A truly global market in natural gas has yet to emerge in the same way as global markets in crude oil or coal exist. This is due largely to the physical nature of gas and its more recent emergence as a major fuel (compared to oil and coal). While there are many similarities between oil and gas in terms of exploration, production and end use, natural gas is a more difficult commodity to handle and transport. Unlike oil or coal it cannot simply be put in a ship or other container and transported to a market. Before a gas field is developed, the end customer needs to be known as infrastructure to connect the field to the end customer has to be built, especially in greenfield and brownfield markets This infrastructure could be a pipeline or an LNG liquefaction plant.

Elements of Gas Pricing

This section examines the elements that are considered as part of setting a price formula for natural gas. These elements include:

- The competing fuel (such as oil) and its price,
- Indexation mechanisms e.g. a link to inflation or some other factor,
- Time, including the start date for delivery, the time period for delivery and the end date,
- Transportation costs,
- Other factors such as placing a floor and/or ceiling on the price and the ability to disrupt supply.

Each of these elements is considered in more detail below.

Link to oil or other competing fuel

Until the last decade or so, the formula of linking gas prices to oil product prices, dominated international gas transactions. Some of the world's largest long-term gas contracts continue to use this link, e.g. Turkmenistan supply to China and Russian supply to China are both oil-linked.

The choice of oil prices as a reference for gas prices has two main drivers:

- For a company that sells gas to customers that heat their homes, run their factories, or operate their power generation stations on various oil products – light heating oil, or heavy fuel oil – then a price that stays competitive with the price of those products will ensure that the natural gas can continue to be sold in the market. Such a company (the buyer) is prepared to take the volume risk, as the price terms help it to protect its ability to market the gas and/or the secondary energy product it produces (such as electricity).

- For a company that is in the business of producing oil and gas, its shareholders are familiar with valuation based on oil prices and on the oil price risk. Such a company (seller) is prepared to take the price risk, as its customer (buyer) is assuring it of the volume offtake.

Thus, in general terms, the buyer is willing to take the volume risk because it knows the price it has achieved will enable it to sell the gas, or the output it produces from the gas, and the seller is willing to take the price risk, as the buyer is providing an assured volume offtake. The parties to the contract reach an agreement on the balance of risks that each party is prepared to take. This could include not passing through the full value of changes in oil prices. Thus, as the price of oil rises, the seller might get only some of this value, but as they fall, the buyer might not receive the full benefit of the decline. The parties also agree on the necessary conversion factors from dollar oil prices to local currency units.

The price of oil and oil products are outside the control of any one company, or indeed any one national regulator/government, and this is of fundamental importance to natural gas producers, selling their product to different countries. Where there is no market that sets gas prices by the interplay of supply and demand for gas itself, then a seller's only protection against imposition of a price by a regulating government is to find an outside reference. Transparent, internationally traded oil prices are such a reference.

Thus, although in the past this was much more prominent, today oil indexation is typically used where there is no local market for traded gas. This is normally the case in young greenfield gas markets, in markets where the main sources of supply are long distance LNG projects, and markets where there is no extensive meshed pipeline network which can provide a variety of choice to customers both in terms of where they bring gas into the system, and if necessary, where they can take it off. Oil indexation continues to be the prominent indexation used in Asian LNG and pipeline contracts, although going forward this may no longer be the case (see below, LNG Pricing).

When European gas demand crashed in the recession following the 2008 global financial crisis, many European utilities struggled to meet their take-or-pay (TOP) commitments in their long-term contracts at oil linked prices, when crude prices were rising above $100/barrel. The resulting surplus of gas was a key factor in creating a hub-priced gas market (see below, Gas Trading Hubs). Since then, European contracts have gradually shifted to include more hub indexation, although the amount depends critically on the end market and supplier. Markets in northwest Europe have moved more towards hub indexation or spot sales, whilst further east or south in Europe they still retain substantial oil linkage (see, IGU World Gas Pricing Survey), especially because they still lack pipeline integration and diversity of suppliers.

Nevertheless, it is safe to say, that although there are still purely oil-indexed contracts, pricing is becoming more complex. The traditional purely oil-indexed contract model has gradually diminished across much of Europe in favour of more hub indexation or a mix of the two. The dominant form of pricing in Europe is currently a hybrid system, with some form of oil indexation, but put into a pricing corridor. Pricing corridors are designed so that contract prices track European hub prices up and down, stopping them from spilling beyond the hub price if the oil price rises or falls too far.

The classical form of indexation to oil products usually also includes a weighting of each different kind of oil product to reflect the weight of each of the buyer's consumption sectors (e.g. home/office heating or heavy industrial use). Parties also need to agree which oil reference price to use. The most common one in Asian trade has been the Japanese Customs Clearing price (also known as the Japan Crude Cocktail, see below for more details) which is the average price recorded by Japan for its slate of oil imports. In oil linked contracts, a time lag is built into the indexation formula, which can range between 3 to 9 months, to allow for the gathering of the relevant data. When a gas price is said to be based on oil parity, the price of gas is 17.24% of the price of Brent, on an equivalent energy basis.

Japanese Customs Clearing (Japan Crude Cocktail, JCC)

The Japan Crude Cocktail price, or the average price for customs-cleared crude oil imports, is used as the benchmark for LNG prices for Japanese buyers. The Japan Crude Cocktail is an average of crude oils imported into Japan and can be the average of a dozen different crude oils imported, all with different contracts, formulae and linkages, including crude oil prices and spot cargo deliveries. So, although the JCC price linkage mechanism is not a pure Brent linkage, one can notice that there is a direct, lagged relationship to Brent. The data provided also includes a dollar/yen exchange rate.

The original rationale for the contract structure in Japan was that LNG was seeking to substitute for oil in both heating and in power generation. Japan was actually burning crude oil in power generation, so the use of a crude reference price made sense as a proxy for the value of LNG. It should be noted, however, that the formula does not have the sophistication of European pipeline contracts, where the reference price is broken down between fuel oil and heating oil and given respective weightings in order to mimic as closely as possible the final value of natural gas in each market segment.

Challenges of oil indexation

In the early days of the gas industry, linking the price of natural gas to that of oil was an effective way to incentivize investments in major gas projects, while helping consumers to manage the price risk of switching away from oil. The price was determined based on the replacement value of the gas, which in practice meant the price of oil, as the main competing fuel. In Europe, much of this was introduced in the early 1960s, to underpin the development of the super-giant Groningen gas field in the Netherlands.

Gas markets look different today: the primary competitor for gas is often now coal on one end of the spectrum and renewables on the other. Thus, oil and gas markets have diverged in recent years, and therefore linking the price of the one to the other calls into question the most important function of prices, namely, signalling scarcity and triggering timely investment where and when it is needed. Although it cannot be taken for granted that gas-to-gas competition – or hub-pricing - generally delivers lower prices than oil-indexation, it certainly delivers “correct” prices in the sense that they reflect the value of gas, not that of another product.

If oil prices rise faster than gas prices, this would put a strain on the system, as those buyers locked into oil-indexed gas contracts face economic hardship and seek ways to benefit from cheaper spot gas. If on the other hand, oil prices were to be low for longer, then oil-indexed gas prices would suggest ample availability of gas at a time when new investments in gas might in fact be needed. Well-functioning gas markets, therefore, require a price that reacts to changes in the supply-demand balance for gas (which is not the case if prices follow fluctuations in the oil market). However, a competitive and/or cheaper priced gas market does not follow automatically from a switch in pricing mechanism.

Other indexation mechanisms

There is a wide range of indexation mechanisms, other than oil indexation. These include hub indexation, indexed to some other published index of prices (such as the consumer price index), or indices of labour costs in manufacturing, or referenced to wholesale electricity prices. Such indexation mechanisms play an important role in ensuring the independence of the gas price from influence by one of the parties to the contract, and from the host government of either of the parties.

Such alternatives can be more appropriate in some cases, notably when the customer's final market is not connected in any way with the oil business: fertilizer manufacturers sometimes negotiate price indexation that include an element of the price of ammonia in global commodity markets; electricity companies negotiate tolling arrangements sometimes where the gas price is wholly or partly linked to the price of electricity, so that their gas price moves back-to-back with their power purchase agreement (PPA). This is usually only possible, however, where electricity itself is sold on a traded market, or where there is a long term PPA with a buyer that is not itself subject to price controls by a government or regulator. Failing this, as was the case in Israel, where the antitrust authority and the electricity authority intervened, it led to a distortion of the prices and an unstable gas market.

Inflation linkage

Older models of gas prices in Europe included indexation to general price indices – linking the price of natural gas to a measure of power generation inflation or to the consumer price index (CPI). Some contracts with pure inflation indices survived in Britain until the 1980s, whilst those linked to power generation inflation were mostly phased out by the 1990s.

While both sides of a gas contract may see attractions in an inflation based indexation, CPI indexations are in fact now relatively rare in gas contracts. This is because CPI is of questionable relevance and will be a poor proxy for the inflation either of upstream oil and gas costs, or for the downstream power generation costs. In the past, oil and gas costs, as measured by the IHS upstream capital cost index, increased far more than regular inflation in most developed economies. CPI might be more appealing from the market perspective where gas is sold directly to a large number of residential and potentially even commercial consumers, whose budget is determined by their disposable income.

A partial CPI indexation could be acceptable if only a fraction of the gas price is linked to it, such as to reflect the inflation element of operational expenses. This is more acceptable than the full linkage, since with gas, the development is done upfront and thus the costs and consequentially the gas price is protected from any inflationary increase.

Time periods

Long term contracts

Long term GSPAs have been the framework of the international trade in natural gas. Long term contracts (typically 15-25 years) have supported the growth of both pipeline and LNG transactions from the earliest days of the natural gas trade. Long term contracts were necessary to underpin the costs of developing the gas resources and constructing the infrastructure to transport the gas to market, such as a pipeline or LNG facility. Long term contract reduce risks for both the gas seller and the buyer. For sellers, a long term contract secures a price that allows the developer to proceed with planned investments and/or to secure finance. For buyers long term contracts secure their needs with long-term contracts at an assured price. These contracts are done via bilateral negotiations and remain confidential. The buyers can then use any volume flexibility they have in their long-term contracts to nominate down their purchases (down to their take or pay levels or lower sometimes) to try to optimize their purchases on the short-term market when hub/spot prices are lower.

Long-term international trading contracts are priced based on three different pricing mechanisms: linked to oil prices, achieved via bilateral negotiations, and gas-on-gas competition, which is a synonym for being linked to hub prices. Contract gas prices are often quoted as a percentage of the hub price and often include a premium or discount thereto. It is estimated that on average LNG contracts around the world in 2019, when Brent averaged around $64 per barrel, led to delivered price for legacy long term contracts of $9.5/mmBtu. Long-term prices since the beginning of this year have been about $5.3/mmBtu in Europe and around $10.00 in North East Asia.

The spot market

The origins of the international spot market in natural gas can be traced back to the 1990s but only really became established in the last 5-10 years. The origins of the spot market lie in the liberalisation of gas markets in the US and UK and the move away from long term, oil-linked contracts. The creation of the Henry Hub futures market in 1990 and the UK's National Balancing Point (NBP) in 1996 marked the start of international price benchmarks. Liberalisation of gas markets in Europe and the growth in LNG trade between different regions in this century have allowed natural gas to become a globally traded commodity and allowed the creation of the spot market. However it is only in the last five to ten years that a dynamic and liquid spot market has emerged. The spot market today is based on trading hubs in North America and Western Europe, which are discussed in more detail below.

Spot prices, such as spot LNG cargoes sold into markets where there are no trading hubs, is defined by IGU as the "price of the cargoes reflecting the current supply-demand situation".

Short term contracts

Short term LNG contracts are a more recent innovation in the sector. Such contracts are typically 5-7 years in duration. These have become more popular in recent years as LNG buyers have demanded more flexibility and reluctant to commit to long term contracts. The growth of the spot market has given buyers more confidence that supply can be sourced at short notice in the event of shortfalls.

Gas pricing mechanisms

The International Gas Union (IGU), a global non-profit organization which has conducted wholesale gas price surveys for the last decade, differentiates between 9 types of price formation mechanisms (see below, Table 1). These nine types can be divided into two broad categories: market pricing and regulated pricing.

Table 1: Summary of price formation mechanisms

Oil Price Escalation (OPE)	**The price is linked usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices or electricity prices are used.**
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). Not all gas is bought and sold on a short-term fixed price basis and there will be longer term contracts, but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category are spot LNG cargoes, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place but often the arrangement is at the government or state-owned company level. Usually there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers trading bilaterally.
Netback from final product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer producers. This may occur where the gas is used as feedstock in chemical plants, such as ammonia or methanol and is the major variable cost in producing the product.
Regulation: cost of service (RCS)	The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.

Regulation: social and political (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.
Regulation: Below cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas, often as a form of state subsidy to the population.
No price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
No known (NK)	No data or evidence

Source: IGU

Gas subject to market pricing rose from 62% in 2005 of all gas consumed globally to 71.5% of total gas consumption in 2020. These changes can occur because of actual changes in price formation mechanism or because of more rapid growth in consumption in markets with a specific type of price formation mechanism. The 2020 increase in market pricing is due to two main factors:

- The move away from regulated pricing in Russia, Argentine and Nigeria, and

- A rise of LNG imports which are based on Oil Price Escalation (OPE) or Gas-on-Gas Competition (GOG) and which replaced indigenous consumption of gas in markets which were regulated.

In the regulated price category, the IGU identifies three categories: regulation cost of service, regulation social and political and regulation below cost[1].

For the international gas trade volumes (gas traded internationally by pipeline or LNG), which in 2020 represented 29% of total global gas consumption[2], all transactions are based on one of three pricing mechanisms:

- Oil price escalation (OPE, 38%),

[1] Wholesale gas price survey, 2021 edition. A global review of price formation mechanisms 2005 to 2020, June 2021. https://www.igu.org/resources/global-wholesale-gas-price-survey-2021/

[2] Global gas consumption in 2020 was 3,940 bcm, out of which 655 bcm was traded globally via pipeline and 458 bcm as LNG

- Gas-on-gas competition (GOG, 56%), and
- Bilateral monopoly negotiations (6%).[3]

Table 2 below shows the percentage of gas subject to each IGU pricing formation mechanism across four categories: gas consumption, gas production, pipeline imports and LNG imports for 2020. In 2020, the share of GOG in all gas consumption rose to 49.3%.

Until 2016, the rise was largely due to the rising share in pipeline imports, almost wholly in Europe, but post 2016, the rise in GOG globally was largely driven by a significant shift in LNG imports to a GOG price mechanism and away from OPE. Indeed, GOG share in LNG imports rose sharply again in 2020 to 44% of total LNG imports reflecting rising spot LNG imports in all markets.

OPE is now largely concentrated in the importing Asian Pacific countries and a handful of European countries, with the OPE share globally being supported through more rapid demand growth in Asian markets.

Table 2: Percentage of gas subject to IGU pricing formation mechanisms

	GOG	OPE	BIM	NET	RCS	RSP	RBC	NP
Consumption	49%	19%	3%	-	9%	14%	6%	-
Production	47%	11%	2%	1%	12%	19%	8%	-
Pipeline imports	65%	25%	10%	-	-	-	-	-
LNG imports	44%	56%	-	-	-	-	-	-

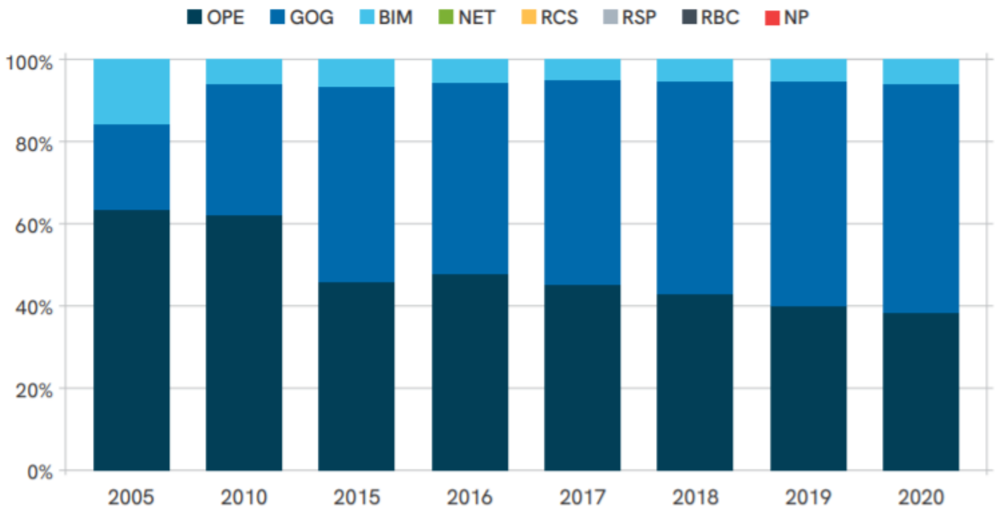
Source: IGU

World Price Formation - Total Imports

Figure 1 below shows the changes in pricing mechanisms used for global gas imports between 2005 and 2020. Total imports are the sum of pipeline and LNG imports and are subject to three pricing mechanisms in that period: OPE, GOG and BIM. In the period 2005-20, GOG pricing has risen from around 20% of imports in 2005 to 56% in 2020.

[3] Ditto IGU report.

Figure 1: Gas import pricing mechanisms 2005-20



Source: Natural Gas World

Table 3 below provides a breakdown by region of the gas pricing mechanisms used for gas imports in 2020. Total imports in 2020 amounted to 28% of total world consumption, approximately 1,113 bcm.

Table 3: Pricing mechanisms for global total gas imports in 2020

Region	Total Imports			
	OPE	GOG	BIM	TOT
North America	0.0	133.4	0.0	133.4
Europe	104.7	343.7	0.0	450.4
Asia	138.3	65.2	0.0	193.5
Asia Pacific	152.9	54.9	0.0	207.8
Latin America	16.4	9.9	0.0	26.3
FSU	6.8	9.5	32.4	48.7
Africa	4.1	0.0	3.9	8.5
Middle East	9.7	4.6	29.7	44.1
Total	423.0	623.2	66.0	1,112.7

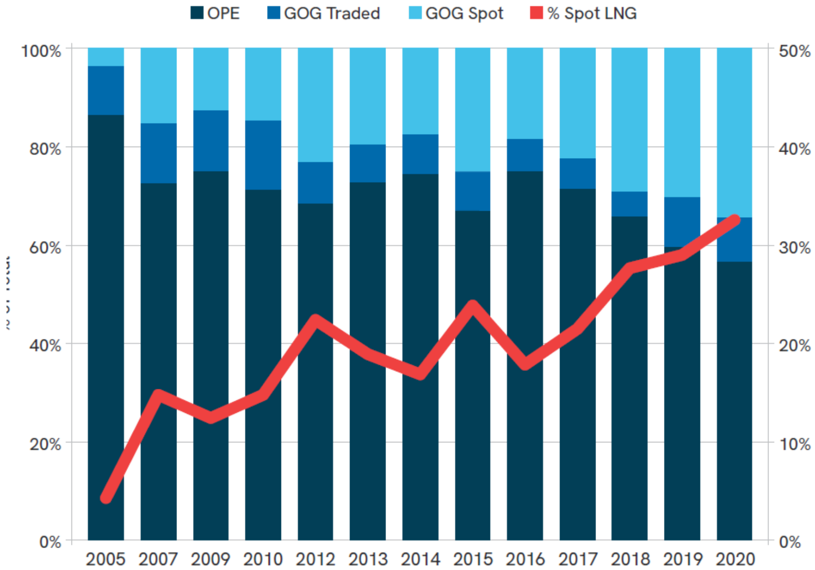
Source: Natural Gas World

World price formation 2005-2020 - LNG imports

Figure 2 below shows the growth of GOG pricing for LNG imports along with the growth in spot LNG trades. In 2020, LNG imports were split 56% OPE and 44% GOG. OPE was used for approximately 258 bcm of gas volumes, mostly in Asia Pacific (Japan, Korea, Taipei), followed by Asia (China, India, Pakistan) and some European countries, such as Spain, Turkey, France, Portugal and Italy.

GOG totals some 200 bcm and can be divided into imports into North America, as well as the UK, Belgium, France and Netherlands, where the domestic market mechanism is GOG, and all other markets which are mainly importing spot and short-term priced LNG cargoes. Since 2005, spot cargoes have risen from less than 5% of total cargoes to more than 30%.

Figure 2: LNG import pricing mechanisms 2005-20

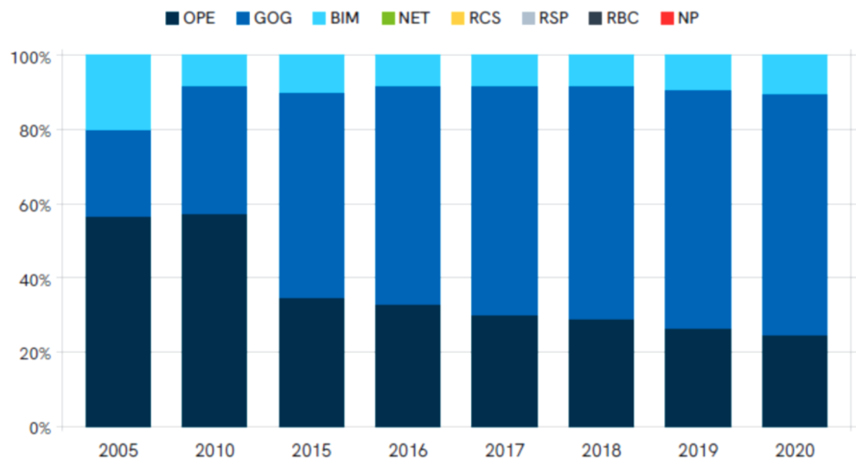


Source: Natural Gas World

World price formation: pipeline imports

Figure 3 below shows the changes in pricing mechanisms used for pipeline imports and especially the growth in the use of GOG pricing. Pipeline imports in 2020 accounted for some 17% of total world consumption (655 bcm). These imports were split between 3 categories: OPE (25%), GOG (65%) and BIM (10%); the last confined to the Former Soviet Union and Middle East.

Figure 3: Pipeline import pricing mechanisms, 2005-20



Source: Natural Gas World

Gas trading hubs

European Hubs

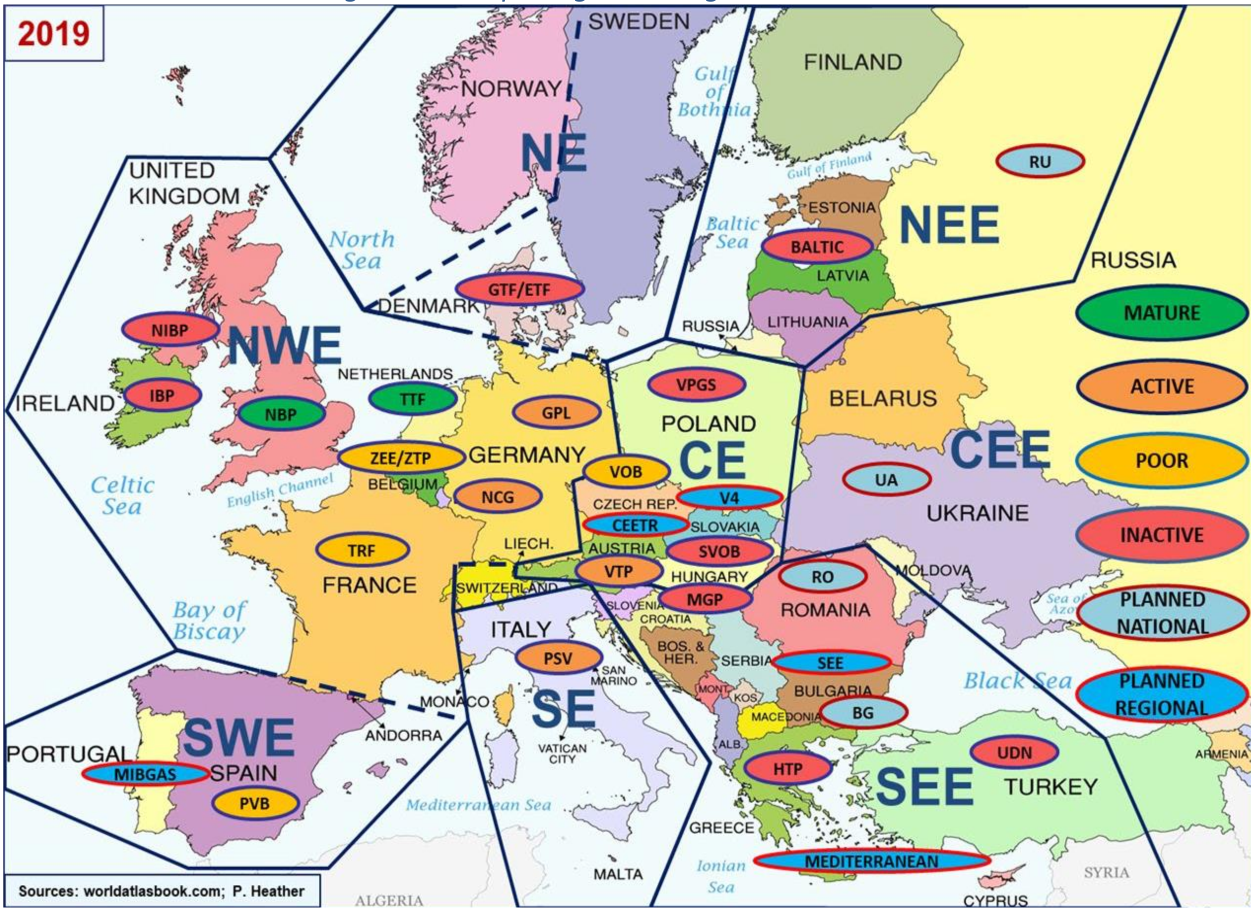
There are two main trading hubs in Europe, the Title Trading Facility (TTF) of the Netherlands and the National Balancing Point (NBP) in the United Kingdom. Both are virtual trading systems, that is, they are not physical places or exchanges. There are also active trading hubs in Germany, Austria and Italy as well as a large number of other trading hubs, (see below, Figure 4). The NBP denotes prices in Sterling pence per therm. European hubs usually express the amount of gas traded in a measure of electricity such as megawatt hours (MWh) as most gas is used to generate electricity i.e. the TTF uses Euros per MWh e.g. €45.60/MWh.

Transactions take place (and prices derived) in two ways on these trading hubs:

1. Over the counter (OTC) which accounts for approximately 70% of transactions. Dealers transact directly and the focus tends to be on gas for immediate delivery (rather than futures or forward delivery). The main price reporting entities such as Platts, ICIS and Argus gather, assess and report prices by speaking to the traders.

2. Via a clearing exchange (such as ICE, Pegas, Petronext, CME) where multiple participants trade in the gas under strict rules and regulations and prices are computerized and reported every 15 minutes. Some of the pricing reporting entities also include transactions carried out on the various exchanges in their daily pricing reports. Exchanges account for around 30% of transactions and a wide variety of contract types are available, including future contracts (also known as future curve), which can be for up to 6 years ahead, day ahead, weekend, working week+1, balance month, winter/summer(year) or gas year(year).

Figure 4: European gas trading hubs



Source: OIES

Insofar as the reporting of forward prices is concerned (day ahead, month ahead, year 2023, summer 2024), the price reporting agencies include a keyword in their assessment to differentiate between assessed prices vs. actual bids. Thus T is for trades meaning the price was assessed based on trading data, namely that it was confirmed that a transaction took place. B is for bid-offer spreads etc. Very often trades are done for speculative purposes. An x volume of gas can change hands 20-25 times if not more before it's delivered to end consumers at a set date.

Total natural gas volumes traded on all European hubs in 2020 reached a new record of 70,512 terawatt hours (TWh) (240,597 mmBtu), surpassing a previous record high set in 2019 by 11%. No full-year 2021 volume estimate is yet available as there is just too much uncertainty and no clear pattern. The TTF continued expanding, with trading volumes growing in 2020 by 24% year on year to 49,072 TWh. The hub, which was launched in 2003, has tripled in size since 2015. The TTF surpassed the NBP as Europe's most liquid trading hub in 2016 and consolidated itself as the main destination for exchange-based forward trading to hedge global LNG volumes.

Trading expanded despite European gas consumption being hit hard following lockdown measures to contain the coronavirus in 2020. The proportion of gas traded versus physically consumed in a market, otherwise known as the churn ratio, was 14 in 2020, compared to 12 in 2019.The total indicative notional monetary value of European gas fell 27% to around €680 billion ($800 billion), its lowest level since 2010.

The hub saw 120.8 times more gas traded compared to what was consumed in the Dutch market last year, outshining its European peers. However, gas traded at the TTF is also delivered to markets outside the Netherlands, making this measurement less accurate. The TTF has provided a floor for the LNG market, with prices in mid-June 2021 rising to their highest level since 2013. Asian LNG imports were 11% higher in the first 5 months of 2021 compared to 2020, while European volumes were down 19%.

US hubs

Henry hub (HH), established in 1990, is the most widely quoted gas price in the US and perhaps globally. There are other gas trading hubs in the US, but these only serve regional or very local markets. While there is not yet a global price benchmark for gas (in the way that Brent is for crude oil), HH probably comes closest to playing that role. Unlike the European hubs, HH is a physical location in Louisiana. HH prices are usually denoted as US dollars per mmBtu. Like European hubs, transactions can take place either over the counter or on exchanges such as NYMEX.

Over the past decade, the price of benchmark Henry Hub gas has averaged $3.01/mmBtu. Consistently low prices have long been the hallmark of shale drilling and will remain a major selling point for gas as a residential-commercial and industrial fuel.

The US Energy Information Administration expects 2021 HH prices will average $3.07/mmBtu. Through 2030, the real, inflation-adjusted, price of benchmark Henry Hub gas will average just $2.85/mmBtu (Platts). Through the decade that follows, prices will likely rise by less than 45 cents.

Strong summer gas demand, combined with tighter production stemming from 2020 supply cuts, have driven higher Henry Hub pricing. Increased pipeline flows to Mexico have also created upward pressure on HH pricing.

> “First week of July saw August US gas futures cruised to 2½-year highs, closing at $3.70 per million Btu, as a short-covering rally caught fire amid hot and humid conditions enveloping major markets in the eastern US. Meanwhile, historic heat along the US West Coast from Los Angeles to Seattle and across the border in Canada came at the worst time, as hydroelectric supply is not up to par due to severe drought. The last time prices were this high was in December 2018, when the January 2019 Henry Hub contract expired at $3.642/MMBtu. Then, as now, storage inventories were of concern.
>
> Natural Gas Intelligence (Lisa Lawson, Tom Haywood) - Sizzling Weather Sends US Gas Rallying to 2½-Year Highs, 7.7.2021

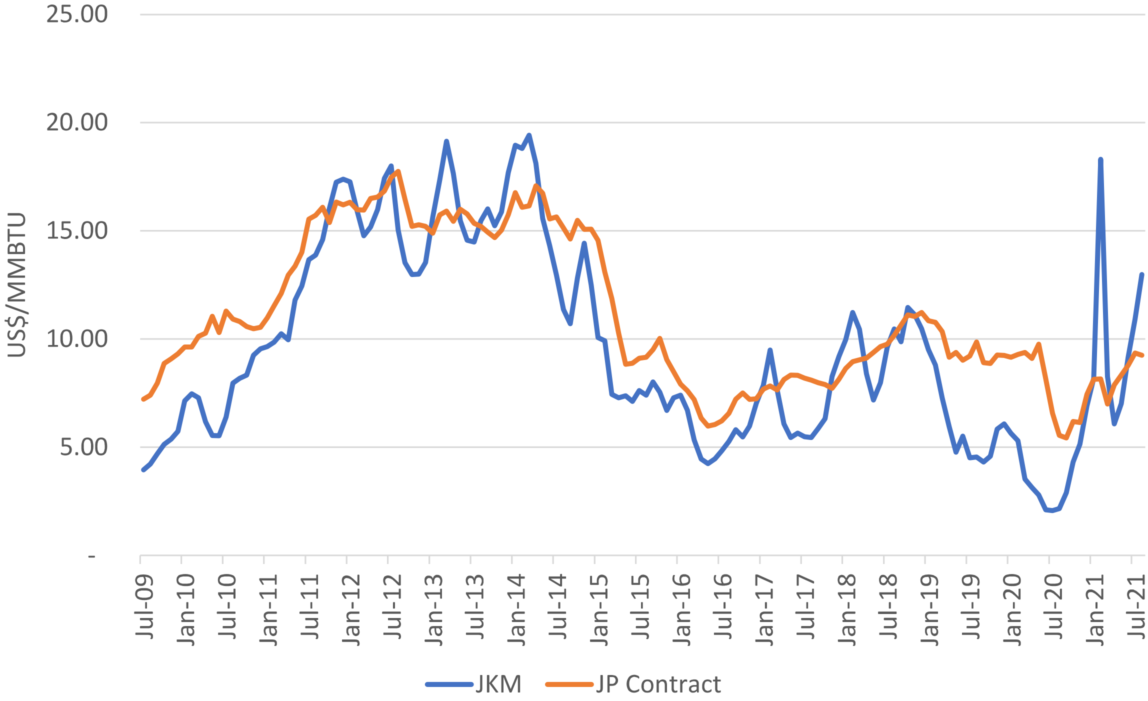
"Strong export demand, as well as temporary production declines, may be propping up prices in the extreme short term"

Natural Gas Intelligence (Myers)

Asian hubs

Natural gas trading hubs have not yet become an established part of the gas trading system in Asia. This is due to the continued preference for long term LNG or pipeline supply contracts in the region. There is not the same interconnectedness of Asian markets in the same way that now exists in Europe or North America.

Figure 5: JKM spot price vs Japan LNG contract price



Source: OIES

The nearest to a trading hub in Asia currently is the Japan/Korea Marker (JKM) produced by Platt's or another albeit less developed market the EAX produced by ICIS. JKM is a daily assessment of LNG spot cargo prices delivered ex-ship in Asian markets. Platt's staff survey traders and other participants in the market for LNG prices related to a wider range of contract types. The assessment is published at the close of each trading day in Singapore. JKM was first published in 2009. Singapore has become the established location for gas traders in Asia with most major players operating trading desks in the city state.

Even in China, the index used is often the JCC, the JKM or HH. Indeed, China cannot establish a domestic LNG pricing index or a gas trading hub without solid market reforms, despite overtaking Japan to become the world's biggest LNG buyer this year, industry insiders say. The country thus now uses foreign pricing indexes such as the Japan Crude Cocktail (JCC), S&P Platts' Japan Korea Marker (JKM) or US Henry Hub benchmark to price the its LNG fuel. he ChTinese market is still too small and overregulated to have its own index.

The relationship between contract and spot prices in Asia is of significant interest. Buyers tend to seek changes in the formation of prices when their impact causes them to suffer very substantial financial losses. This certainly occurred in Europe when spot and contract prices diverged and customers began to demand a move away from oil-linked pricing to hub-based prices, catalysed by new EU rules and market liberalization.

Thus, in Asia, in the early 2019, there was a decisive break between the oil-linked contract price and the JKM spot price. Contract prices came down in early 2020 as oil prices had fallen a few months before. The prices began to converge towards the end 2020 before JKM spot prices rallied in February this year. The summer 2021 rise in spot prices has seen JKM jump above the contract prices. At current oil prices, the level of oil-indexed contract prices is likely to be in the range of $9-10/MMBtu over the next year. This is broadly similar to the forward JKM prices through the whole of 2022.

The JKM price marker is being used as a benchmark for new projects outside of the region. For example, the Houston-based company Tellurian has based its publicly announced financial forecasts for its Driftwood LNG project in Louisiana on JKM. In August 2021, Tellurian estimate that $5 billion in annual cash flows from operations of the first phase could be enough for a payback period of less than three years for the development cost, based on a margin of $9/mmBtu. The estimate, which factor in Tellurian's upstream production plans, include an LNG sales price of $12/mmBtu after transportation costs, using JKM benchmark. The company estimated liquefaction and transport costs of about $1/mmBtu and gas sourcing cost of $2/mmBtu.

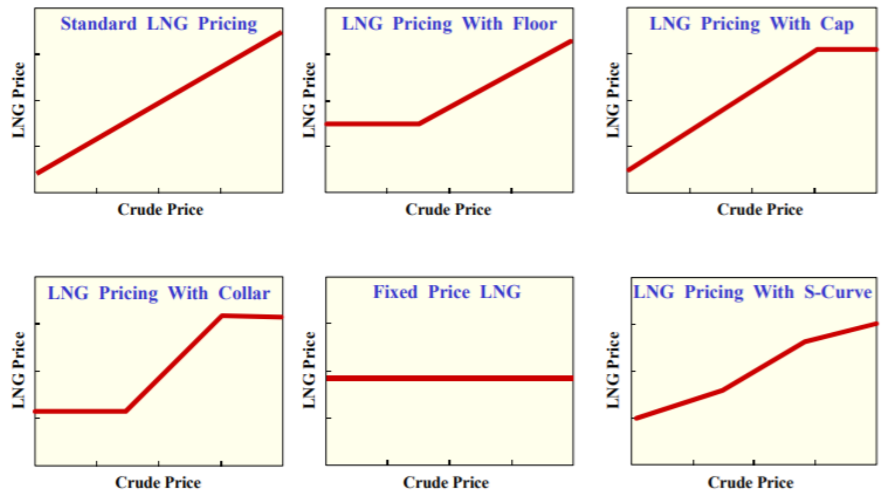
When spot prices were well below contract prices, there was discussion as to whether there would be a real challenged to oil-indexed contracts, if the trend persisted. However, with the prices converging again, the pressure has lessened, at least temporarily (OIES).

LNG pricing

LNG pricing is evolving from the long term, oil-linked formula that has historically dominated the industry. More recently, LNG GSPAs or SPAs have used prices incorporating elements such as gas hub prices or using a formula with a mixture of hub prices and alternative fuels. The contract price may also be linked to other economic indicators such as inflation or tax rates.

Most, but not all, LNG prices include a constant/fixed element (usually ranging between \$0.5-\$1/mmBtu), to take account for the relatively fixed infrastructure element of LNG. Figure 6 below shows typical LNG pricing scenarios.

Figure 6: Typical LNG price scenarios



Source: Norwegian University of Science and Technology

According to S&P Global Platts, "LNG's pricing and non-pricing evolution is underpinned by a combination of important global supply and demand drivers", as follows[4]:

- **Increasing non-oil competition for Asian LNG**: Legacy Asian LNG procurement has been dominated by oil-price linked contracts, partly because oil represented the substitute fuel to LNG in some buyers' energy mixes. However, for important fast-growing LNG importers, e.g. China, India and across Southeast Asia, non-oil fuels, including coal and renewables, are often the primary alternative to LNG. For these growing LNG importers, oil-price linked LNG contracts are therefore becoming fundamentally less important.

- **Increasing flexible procurement, reducing LNG contracts' length and size**: Unlike when contracts were initially negotiated, 'foundation' sellers and buyers no longer require offtake and supply certainty to secure project funding. They are therefore

[4] S&P Global Platts, the rapidly evolving global LNG pricing matrix, 24.9.2018

free to contract for shorter periods and size. North Asian LNG buyers, particularly Japan, face ongoing uncertainty regarding the future of nuclear plants, demographics and their impact on LNG demand. This, combined with the ongoing start-up of smaller LNG importers including Jamaica, Malta, Bangladesh and Bahrain, has facilitated shorter, smaller contracting.

- **Growth of destination-flexible US LNG supply**: The strong ongoing ramp-up of US LNG has already resulted in US cargoes deep penetration into the East of Suez markets. US LNG is typically sold on an FOB basis, allowing the cargoes to flexibly respond to country-specific demand fluctuations, unlike legacy point-to-point LNG contracts.

- **Legacy LNG contract expiry**: While the number of US and Australian contracts are increasing, total contracted LNG legacy volumes will decline dramatically post-2020. Many of these legacy LNG exporters possess insufficient gas reserves to renew their contracts at existing volumes/durations, while buyers are increasingly confident relying on the LNG spot market for security of energy supply.

As of July 2021, the majority of LNG contracts globally remain linked to Brent crude oil prices, with long-term LNG contracts at average slopes of 13% for older contracts and 11% for newer ones.

However, in a sign of the changing nature of LNG contracts, in July 2021, Petronas signed a 10-year agreement with CNOOC Gas and Power to supply LNG sourced from the 14 million ton per year LNG Canada, to provide CNOOC with 2.2 million tons/year of LNG over 10 years in a deal valued at $7 billion. Petronas said LNG Canada would start operations by the middle of the decade. What is new about the deal is that the LNG supply would be priced against a hybrid pricing formula comprising oil benchmark Brent and Canada's natural gas benchmark Aeco. This marks the first time an Asian LNG term contract would include a North American gas index. Petronas has been pitching Aeco as an alternative price index to Asian buyers as it is a transparent and liquid index that trades substantially below US Henry Hub. Earlier this year, it sold an Aeco-indexed spot cargo to an Asian buyer. Figure 7 below summarises the evolution of Asian LNG pricing.

Figure 7: Asian LNG pricing evolution

Pre-2011	2011-2014	2015-Present	Future?
Oil-linked LNG pricing dominates: Relatively inflexible long-term LNG contracts transacted	**The rise of Henry Hub-linked LNG pricing:** LNG players, starting with the former BG's 2011 SPA with Cheniere, increasingly sign US gas Henry Hub price-	**Fast-growing LNG spot pricing and derivatives trade:** Platts JKM, the LNG benchmark price, increasingly used in physical LNG transactions globally and Platts JKM derivatives	**Potential future LNG pricing evolutions:** Rising US LNG production increases adoption of Platts Gulf Coast Marker (GCM) and derivatives. Growing

between a limited group of LNG buyers and sellers. LNG pricing linked to oil, particularly.	linked contracts for US LNG supplies. This was facilitated by oil prices above $100/b, lower Henry Hub prices, soaring Japanese LNG demand following the Fukushima disaster and limited flexible LNG suppliers.	trade soars. This has been underpinned by increasing LNG legacy contract pricing disputes, rising Chinese, Indian and Southeast Asian demand – where LNG primarily competes with non-oil fuels – growing LNG trader activity and flexible LNG suppliers increasing.	LNG pricing sophistication facilitates trading Platts JKM options. Rising commoditization and transparency increases price assessment and transactional activity on screen-based LNG platforms.

Source: S&P Global Platts, the rapidly evolving global LNG pricing matrix, 24.9.2018

US LNG exports pricing formula

When US LNG exports started in February 2016, new pricing formulae were established for these volumes of gas. These include primarily – but not exclusively – prices based on the Henry Hub price and on a tolling model for the liquefaction, as follows:

- Henry-Hub linked GSPAs:
    - Cheniere Model - this is based on 115% of Henry Hub price plus a liquefaction charge. The liquefaction charge varies between about $2.25-$3.50/mmBtu, depending on what has been negotiated. The buyer commits and pays the liquefaction charge, regardless of whether it lifts the LNG cargo or not. This fee covers the project company's facilities and fixed cost. The gas fee, on the other hand, is only payable based on the volume of gas liquefied. The gas is sold on an FOB basis. With Cheniere's two export projects, Sabine Pass and Corpus Christi, Cheniere supplies the feed gas for its long-term customers.

    - Cove Point Model - under this model, Cove Point liquefies the gas, although it does not take title of or market the LNG. Rather again it is the off-taker/buyer that sources the gas, is responsible for delivering it to the liquefaction terminal and offtake the LNG from the terminal to its destination[5]. For Cove Point and the subsequent Cameron and Freeport LNG projects, each of the tolling customers are responsible for their own feed gas.

- Platts spot indexation - This is based on the Platts spot indexation. On 16 June 2018, Platts launched its Gulf Coast Marker (GCM), a price assessment reflecting the daily export value of LNG traded FOB from the US Gulf Coast. According to Platts, "The Platts GCM reflects bids, offers and transactions on an FOB US basis,

[5] S&P Global Platts, LNG Prices & Pricing Mechanisms, Chris Pederson, North American LNG Pricing Analyst, 6th February 2017.

normalized to the US Gulf Coast, and expressed in US$ per million British thermal units (MMBtu)[6]. The GCM is published each business day, reflecting the close of Asian Markets. It reflects both lean and rich gas and is based on standard loading cargoes of 135,000-175,000m^3, and represents the average of the two half-month cycles which represents the first full month[7].

- TTF linked gas price - Cheniere also has a marketing agreement with EDF to supply DES cargoes linked to the TTF hub price.

- JKM linked gas price - Tellurian signed an MOU with trading giant Vitol for a 15-year contract, for the Driftwood project, with prices linked to Platts' Japan Korea Marker (JKM). In addition, Tellurian's Driftwood project stands out for being a unique model in the US where it not only wants to build and own a terminal, but to produce its own gas, build pipelines and sell cargoes to the global LNG market. In this case, however, many believe that general lack of confidence in the JKM as a benchmark for long-term contracts restricts it to spot and short-term deals, despite exponential growth in JKM derivatives trading.

- Brent linked indexation – NextDecade announced in April 2019 the signature of the first US LNG contract linked to Brent, signed with Royal Dutch Shell[8].

- Risk sharing - Another alternative is the risk-sharing model, where buyers of export volumes would look to get exposure to low US wellhead prices in exchange for giving US producers a greater ability to benefit from higher international prices.[9]

Nearly 80% of US LNG export volumes for projects in operation and currently under construction have been contracted on pricing terms directly linked to the Henry Hub price, or under a hybrid pricing mechanism with links to Henry Hub. Oil linkage remains popular with some LNG buyers from the US with end users where oil is the competing fuel and for the sake of familiarity. Going forward, US LNG export contracts may be "an amalgam, a formulaic price mixing gas and oil"[10].

Higher oil prices could support renewed Asian end-user interest in US LNG projects as indeed rising oil and gas prices could see US LNG and Henry Hub-linked deals back in the money. And it is possible that portfolio players and traders who are short in the mid-2020s, may see an opportunity to access new North American supply now. (Wood McKenzie 2.7.2021)

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[6] https://www.spglobal.com/platts/en/our-methodology/price-assessments/natural-gas/platts-gulf-coast-marker-gcm-lng-price-assessment

[7] S&P Global Platts, LNG Prices & Pricing Mechanisms, Chris Pederson, North American LNG Pricing Analyst, 6th February 2017.

[8] Platts, 4.4.2019

[9] World Gas Intelligence, 30 January 2019

[10] World Gas Intelligence, Oil Indexation Still Exerts Strong Grip on Asian LNG, 27 February 2019

In the meantime, the cost of supplying US LNG to Asia has also risen this year, primarily because of a jump in transportation costs for LNG, driven by higher charter rates and fuel prices. Despite these hikes, US LNG production is expected to reach a new record high of 72 million tons in 2021.
Spot gas prices in Europe and Asia are expected in the future to settle in a range between short-run marginal cost of importing US LNG ($4-7/MMBtu) and the global long-run marginal costs of developing new LNG.

The short-run marginal cost (SRMC) of US LNG exports to the Asian market rose to $5.60/mmBtu in June 2021. This is a 65% increase from $3.4 in mid-2020 and a 30% increase on last year's average of $4.30. In addition, US LNG cost were boosted by a recovery in domestic gas prices. The EIA projects that the HH spot price will rise to an average of $3.19 for 2021 from $2.11 in 2020.

In 2020, the US was the most expensive supplier of LNG, but is not expected to be the most expensive to Asia in 2021. This is because Egypt has restarted LNG exports, becoming a marginal supplier with an SMRC of about $6.30/mmBtu. Asian spot prices have been between $12 - $17/mmBtu the last several months, and even crossing $18/mmBtu at the end of August, allowing even for the cost of Egyptian supplies to be absorbed. By mid-year however, even Egyptian exports of LNG fell considerably due to heightened domestic demand during the hot Egyptian summer months.

The SRMC is not the only factor to influence the LNG market. In addition, there is also pre-tax liquids revenue which is the pre-tax revenue from oil sales for the upstream projects that feed LNG plants, divided by LNG production. Thanks to higher oil prices in recent months, and taking into account pre-tax liquids revenue, many integrated LNG projects have seen improved competitiveness so far this year. Thus the variable cost of LNG can be offset by oil production revenues and thus some LNG projects can even be profitable even if LNG prices fall to zero. For example, Qatar's Qatargas 1 LNG train 1 is a good example. Consultants don't expect LNG prices to fall to zero or even to a level in line with the SRMC of Egyptian LNG. Both European and Asian LNG demand are projected to remain robust, bolstered by restocking, high carbon dioxide prices and (lower than expected) Russian pipeline gas exports to Europe, as well as the ongoing post pandemic recovery.

European LNG pricing

Delivered European prices spent the better part of 2020 at discounts to TTF despite potential premiums in regional hubs such as the UK's NBP, which usually price at a premium to TTF in the winter owing to shortfalls in storage capacity. However, owing to sharp declines in global demand on the back of the global pandemic, the DES Northwest Europe fell to its lowest ever level of $1.343/mmBtu on May 28, 2020.

Currently, European LNG volumes have risen to a premium of 20 cents/mmBtu to the TTF month-ahead natural gas contract amid strong competition from a tight market in Northeast Asia and persistent demand from South America. For example, the Platts DES Northwest Europe was assessed at $11.343/mmBtu on June 25, the highest level since October 2014, with the cargo price premium to the TTF hub growing alongside this price rally. Prior to June 9, the delivered price of an LNG cargo into Europe had spent 84 days trading at a discount to hub levels.

The last time there was a sustained period of cargoes into Europe being priced above TTF was at the start of Q1 this year, when Japanese utilities found themselves without ample supply to face a cold snap, with the effects of Norwegian production issues meaning European buyers had to compete for less volume against a surging JKM. As well as this, the sharp drop in temperatures during this period in parts of the US, including Texas, meant the Henry Hub price gained support, leading some Atlantic traders to sell back into the hub, thus limiting European buyers' ability to secure volume from the US.

Going forward, with the freight market showing signs of gains, there could be more pressure from Atlantic sellers with surging underlying Euro gas values giving yet more justification to elevated offers. According to Platts data on June 25, the Atlantic shipping rate was valued at $80,500/day, whereas the Asia Pacific rate came to $68,500/day as tightening availability for spot voyages supports the Atlantic freight market.

Suppliers

Australia

Australia delivered its first LNG cargo in 1989 from the North West Shelf project (Western Australia). A series of further large offshore gas discoveries in Western Australia and the development of unconventional gas resources in Queensland have allowed the country to develop a number of LNG export projects that have catapulted it to the top of the LNG exporter league. Indeed, in 2020, Australia became the largest LNG exporter, overtaking Qatar (see below, Table 4). The bulk of this LNG is sold on long term, oil-linked contracts to Asian customers, particularly in Japan, China and South Korea.

However, Australia's newly gained title as the world's largest LNG exporter is already under threat. Qatar has embarked on a major expansion of its LNG export capacity (see below). Also Australia's export ability is under threat from both the end of some of those long term contracts and technical difficulties with some new projects. The North West Shelf project may need to shutdown at least one of its trains as long term contracts with Japanese customers end and the sellers face more competition from other producers. Also, Australia's two newest LNG projects, the Gorgon and Wheatstone LNG projects in Western Australia have experienced temporary shutdowns due to technical issues. Australia also has new projects under development. The Australian company is developing the Woodside 8 million ton/year Scarborough-to-Pluto LNG project at a cost of $12 billion. The company claims that it will be able to supply Northeast Asia for $6.80/mmBtu.

Table 4: Top 10 largest LNG exporters

Country	bcm	% share
Australia	106.2	21.8
Qatar	106.1	21.7
US	61.4	12.6
Russia	40.4	8.3
Malaysia	32.8	6.7
Nigeria	28.4	5.8
Indonesia	16.8	3.4
Algeria	15.0	3.1
Trinidad & Tobago	14.3	2.9
Oman	13.2	2.7

Source: BP Statistical Review of World Energy 2021

Qatar

Qatari LNG capacity is expected to grow from 78 million tons/year to 126 million tons/year by end-2027. Interest in Qatar's expansion has been driven by its industry-beating low costs of production. But new Qatari output is less competitive than state-owned Qatar Petroleum's (QP) existing production. Expansion gas should come in at a long-term price of just over $4/mmBtu compared to Wood Mackenzie estimates of $2.46/mmBtu for existing Qatari LNG, according to a recent QP bond prospectus.

Qatar has traditionally charged a premium for reliable supply. But recent deals point to a shift in strategy, with QP lowering prices as it goes all out for market share. A look at the prospectus explains why: QP will have over 75 million tons/year of uncontracted volumes to sell by 2027, accounting for around 70% of its portfolio. The company has time to conclude more contracts and will probably feel comfortable selling more output on the spot market than it does now. Nevertheless, it has a lot of gas to find a home for so will undoubtedly look for synergies between its marketing efforts and partner selection.

US

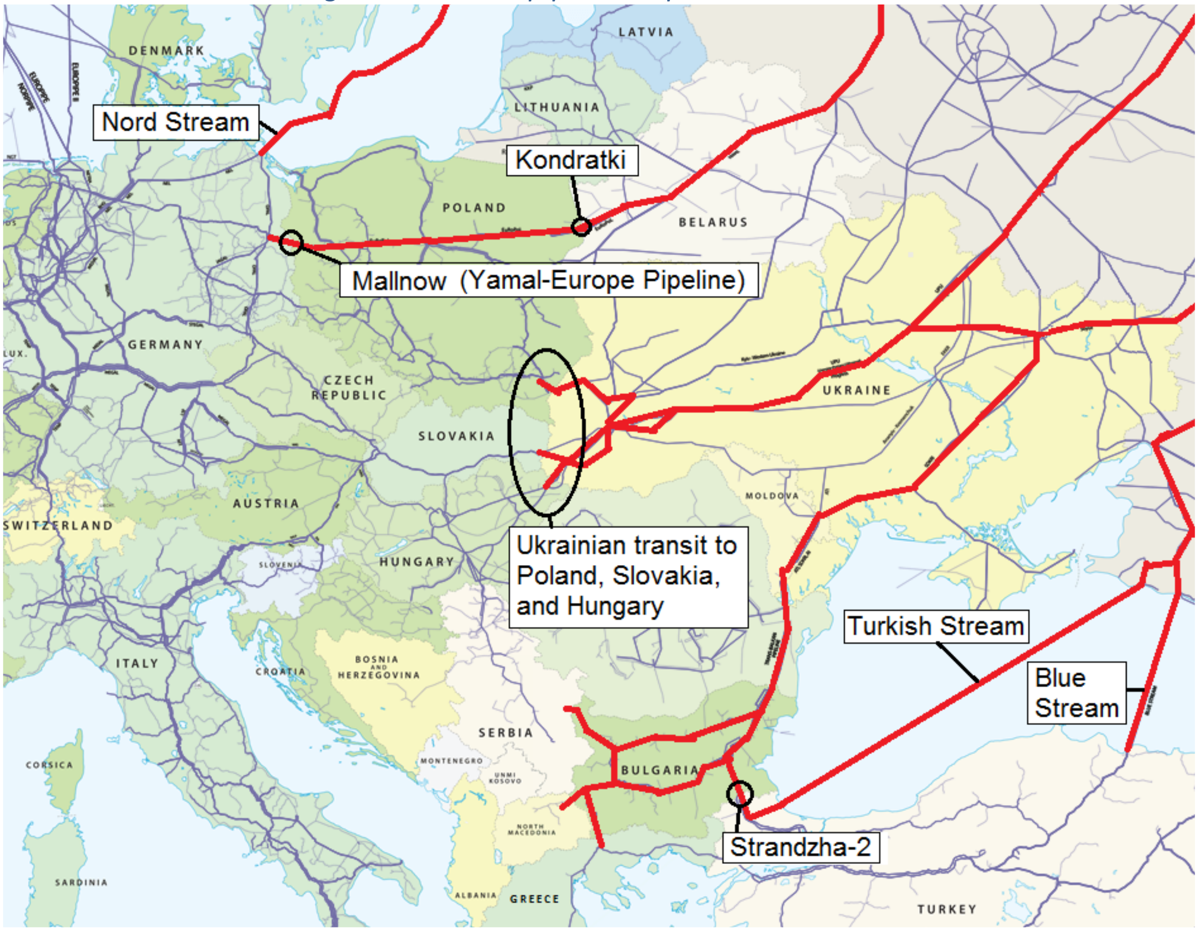
In the last five to ten years, the US has gone from a gas importer to one of the world's top LNG exporters. This has occurred as the result of the rapid expansion of the production of unconventional gas resources onshore in the US. A series of LNG plants have been constructed, especially on the eastern coast, to provide export routes for this gas. In addition, former LNG import plants such as the Lake Charles facility have been re-engineered as export terminals. The momentum in the growth of the LNG export sector has slowed more recently with projects now facing delays in reaching project sanction as their economic viability is re-assessed. This re-assessment comes in the light of the apparent oversupply in the market as noted elsewhere in this report.

Russia

Gazprom's cost to produce and transmit gas to Europe is now less than $4/mmBtu, which means its current margins are around $6 at $10/mmBtu hub prices. Gazprom's margins have small variations depending on whether it exports via Ukraine, Nord Stream 1 or the Yamal line across Belarus and Poland.

Pipeline exports of gas from Gazprom to continental Europe have dropped roughly one-fifth in 2021 on pre-pandemic levels despite a sharp rebound in demand and low stockpiles. The imbalance has helped send prices in Europe to the highest levels since 2008. Analysts said that while Gazprom was meeting its long-term contractual obligations, its reluctance to boost supplies to Europe through more immediate measures such as spot market sales was putting pressure on the market. Gazprom is understood to be trying to maximise its profits at a time when spot prices are high, gas storage is empty and LNG demand in Asia is strong. Indeed, Gazprom's export tactics have been widely blamed for keeping European natural gas prices high through the first half of 2021. The blame is not unwarranted. The Russian company has enough upstream capacity to further increase gas production and exports to Europe if it wanted, but Gazprom remains reluctant to book incremental transit capacity through Ukraine. Indeed Gazprom opted not to book additional interruptible capacity via Ukraine for July despite maintenance works on alternative Russian routes.

Figure 8: Russian pipeline export routes



Source: OIES

Gazprom's stance is not the only reason for rising prices. A cold winter has drained natural gas in storage in Europe to the lowest levels in nine years, while demand from utilities for gas instead of coal has been boosted by soaring costs of EU carbon allowances. Globally, gas supplies are tight as more cargoes of LNG sail to Asia rather than Europe. Inventories in Europe have been low due to a difficult winter that saw significant LNG volumes head to Asia and further kept down by Europe's own elevated weather-related demand.

Currently (end-August 2021), EU storage facilities are filled to only 60% capacity (76% of the years 2016-2020 average), or just under 70 bcm of gas. That needs to get up to at least 80 bcm by October 1 to ensure a proper buffer against market fluctuations through winter. "Going into the current winter with less in storage, Europe is walking a tightrope — and it wouldn't take a huge gust of wind to knock us off," Jack Sharples, a research fellow at the Oxford Institute for Energy Studies said in August. "All it would take is for some LNG projects currently offline to not come back on, or some unplanned maintenance on a pipeline bringing gas into Europe, or just another cold winter."

In addition, the meteoric rise in Europe's carbon price reaching a record of over €50 per ton in May and reaching €60 end of August (and set to reach $118 by mid-this decade according to Bloomberg) played a key role in TTF price formation.

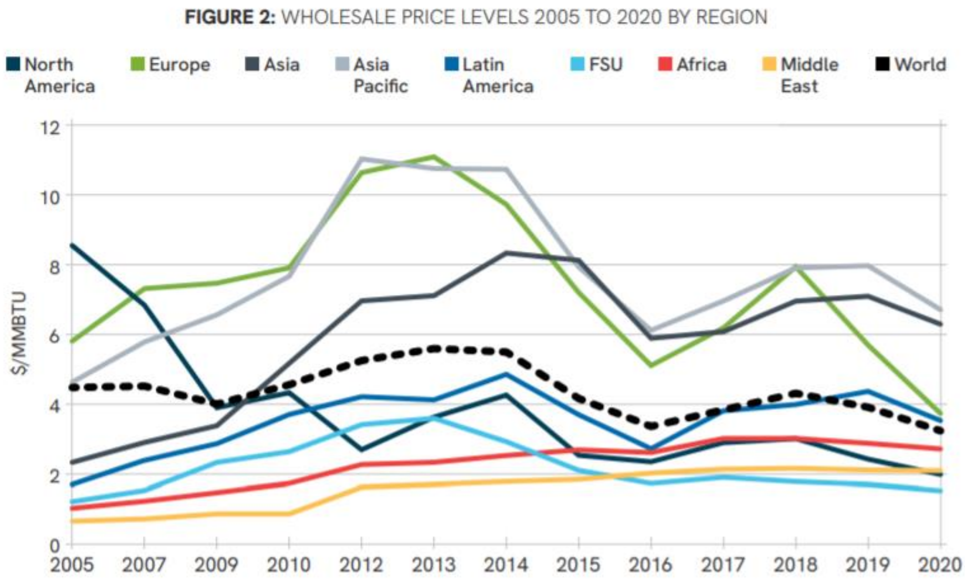
Even as July started, Gazprom held off upping its supply to Europe despite low storage levels, with stocks at its own sites such as Rehden in Germany and Haidach in Austria at very low levels. It has so far opted not to increase volumes being sent via Ukraine, which could be in part due to its desire to show the need for the Nord Stream 2 pipeline to Germany, whose first string could begin commercial flows in October. Matters will not be made easier by the August 25 decision from the Dusseldorf Higher Regional Court in Germany to reject an appeal by Nord Stream 2 to allow the pipeline to be exempt from the European Union's Gas Directive rules. In Q3, the tight supply situation will also not be helped by the annual maintenance on the Nord Stream 1 pipeline from July 13-23 and on the Yamal-Europe line on July 6-10.

Recent trends

The context

First, some context: globally, prices in regional gas markets converged from 2005-2015, but since then, this trend has stalled. From 2015, prices in Asia, Asia Pacific and Europe broadly tracked each other, but this link was broken in 2019 as spot prices collapsed which impacted the European market much more than Asia/Asia Pacific.

Figure 9: Wholesale gas prices by region 2005-2020



Source: Platts

For regional gas prices:

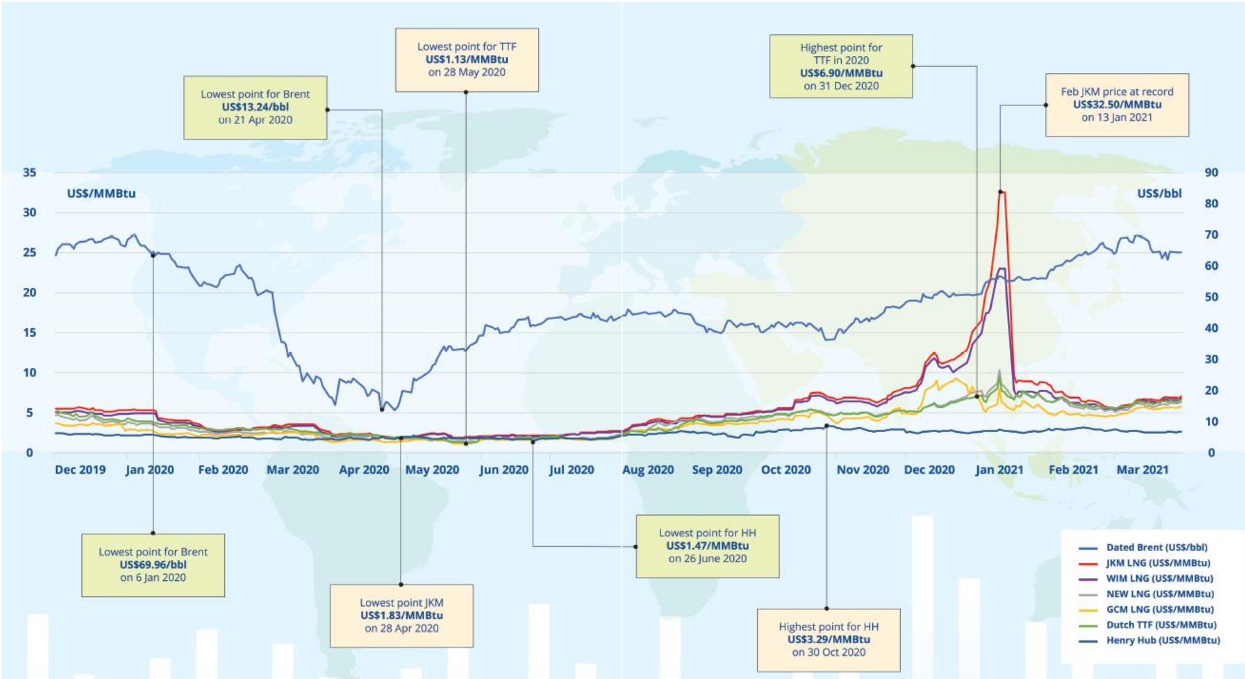
- February 2017 to early October 2018 - relatively tight global LNG market, with elevated spot prices in Asia (winter 2017/18 spike to $10/mmBtu) due to high demand in China and Europe. Thereafter, in summer 2018, Asian and European spot prices increased in counter-seasonal way, to above $10/MMBtu and $7.5/mmBtu respectively, on the back of tight LNG markets; they were also supported by higher oil, coal, and carbon prices.

- From early Oct 2018 – mid-2019 - start of the much-anticipated LNG oversupply, with Asian (JKM) and European (NBP) gas prices tumbling to the level of US LNG exporters' operating costs. Reversal of trend - more LNG supply than incremental demand in Asia, with new plants started operating or ramped up in Australia, Russia, US whilst LNG demand growth in Asia weakened under the combined pressure of warmer weather and nuclear power plant restarts in Japan. Weakness in Asian demand was compounded by a much lower Middle East and North African LNG demand. JKM and NBP prices continuously dropped and reached $4.4/mmBtu and $3.4/mmBtu, respectively, less than half their level a year before. This double whammy thus led to sharp price drop, well below the oil-linked gas prices of long term contracts and down to around the level of estimates of US LNG exporters' operating costs.

2020

Wholesale prices declined for most of 2020, with the year starting as an already oversupplied market flowing over from the end of 2019 and demand being further hit by the Covid-19 pandemic. These two factors led to very sharp falls in spot prices around the world, to an annual average of $3.24/mmBtu, the lowest global average since 2005, with European prices well below Asia and Asia Pacific prices.

Figure 10: Global gas prices



Source: Wood Mackenzie

However, prices recovered in the fourth quarter of 2020 with spot LNG prices in Asia-Pacific reaching record levels. This recovery was due to a combination of factors: a recovery in Asian LNG demand as economies emerged from the first wave of the pandemic, unexpected production outages, delays at the Panama Canal and reduced LNG carrier availability.

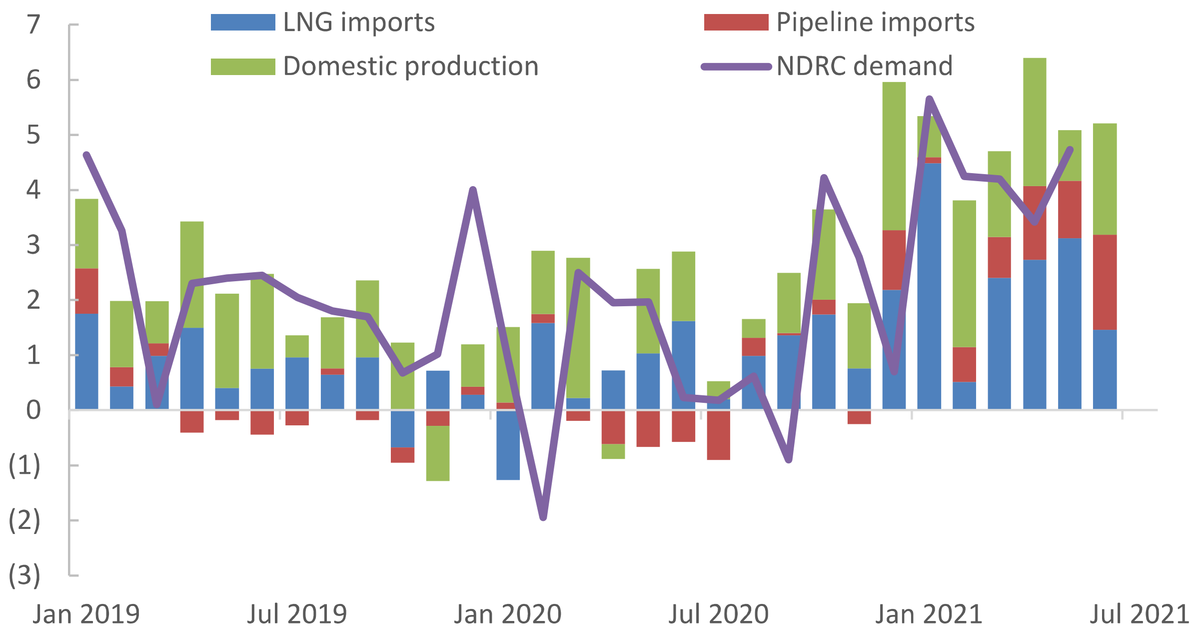
In addition, in 2020 global LNG production levels were affected due to a number of unexpected shutdowns in the first half of the year. These included Norway's Hammerfest LNG plant (expected to remain offline until March 2022), LNG trains down in Australia and at Russia's Far East Sakhalin plant. In addition, drilling off Trinidad and Tobago did not result in the volumes of gas expected and this left Atlantic LNG short of feed gas. In late 2020, there were further production shortfalls in Qatar, Malaysia and Nigeria.

The expectation then was that the sharp spike in prices would dissipate, owing to a surplus of production capacity, primarily the result of the rise of US LNG and dampened demand growth, the result of the Covid-19 pandemic.

However, in Q4 2020, shipping constraints in the Panama Canal restricted supply from the Atlantic region. The conditions forced many US LNG exporters to chart a longer more expensive route to Asia. As a result, the spot shipping market tightened with the Atlantic basin charter rate reaching a record high of $300,000/d on 11 January 2021, which implies that the shipping cost to get a cargo from the US to Asia using the longer Cape of Good Hope route rose to $6/MMBtu.

2021

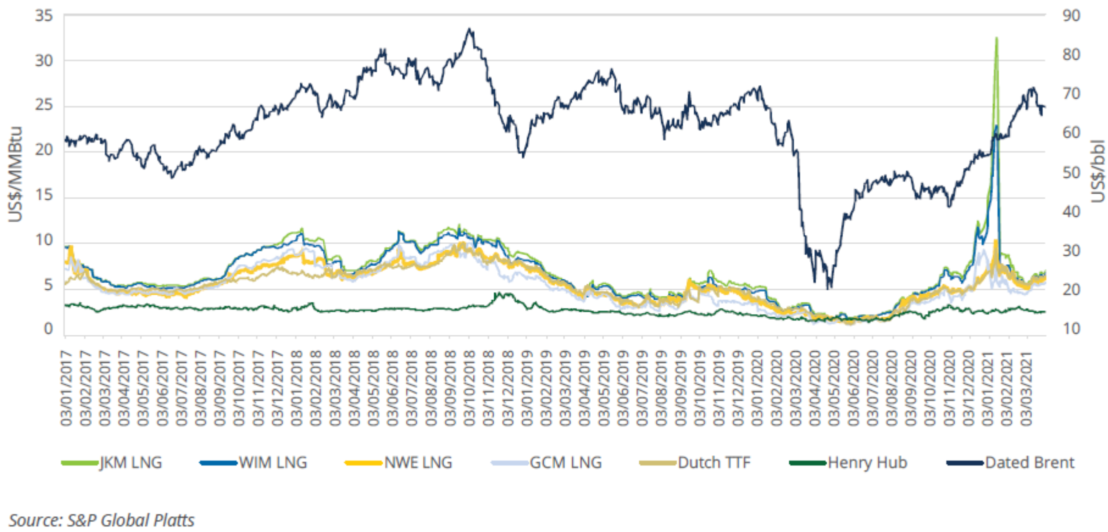
Figure 11: Chinese gas supply and demand



Source: OIES

To date in 2021, prices have fallen slightly from the highs reached in 2020, but have sustained high prices in comparison with the early part of 2020. In Asia, demand remained strong, especially in China. Even in India, which remained hard hit by the pandemic, cargoes which could have faced cancellation have been flipped back into the wider Asian market at a profit, signalling that far from a resurfacing of the LNG glut, demand is for the moment outstripping supply. Prices in Asia surged as major cities such as Tokyo, Seoul and Beijing were gripped by the worst cold spell in decades for a week in January 2021. The 24-hr average electricity price in Japan on Jan 13 was equivalent to $432/mmBtu. This led to users seeking prompt LNG cargo deliveries in January and February 2021 leading to the JKM price rising to a record $32/50/mmBtu for February.

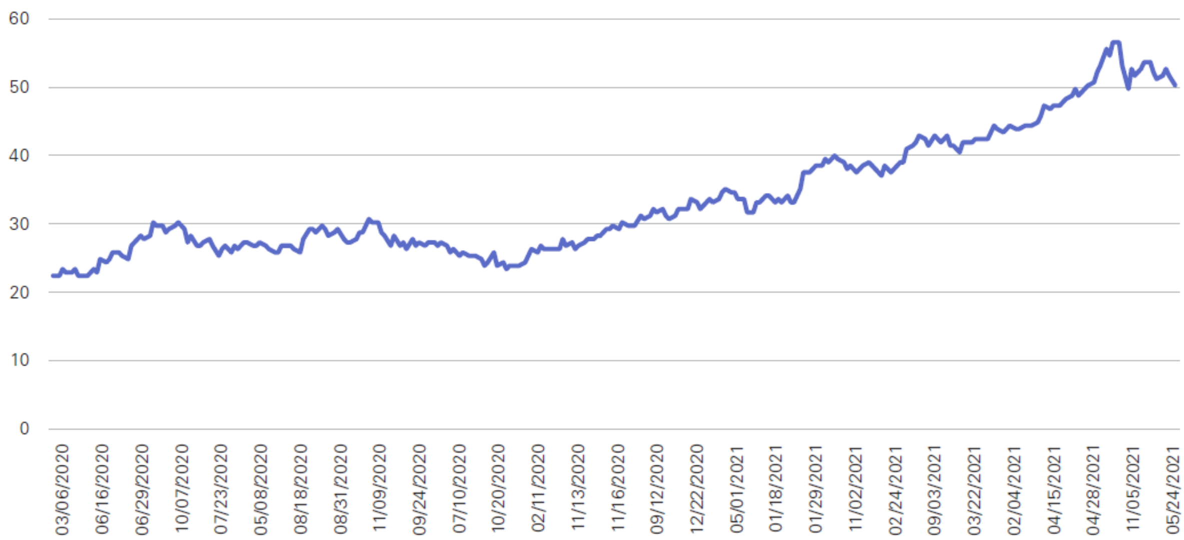
Figure 12: Asian market trends



Source: S&P Global Platts

However, it is the European market that has seen the most significant changes. New market dynamics are playing out in Europe, the most salient difference from 2020 being the price of carbon. Carbon prices have been on the rise since 2018 when it became clear that reforms to the system would do much to remove the huge surplus of allowances that had built up. Since the end of 2020, they have been on an even sharper upward trajectory, reaching over €50/ton in May and €60 end of August, increasing the incentive for using gas at the expense of coal.

Figure 13: European trading system carbon price



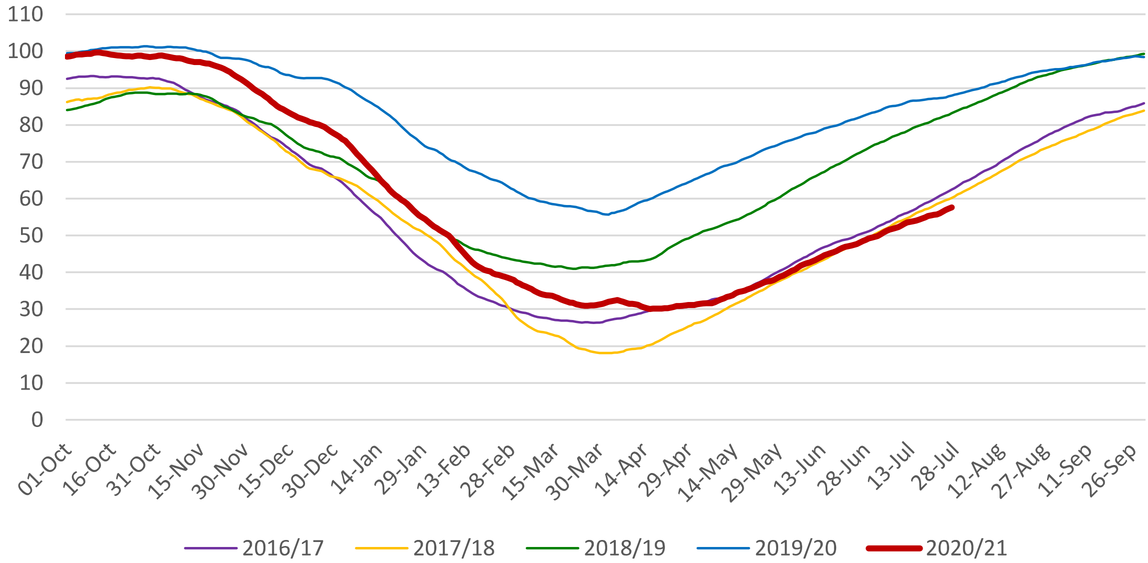
Source: amber-climate.org

One of the key factors behind this in the short term has been a combination of higher electricity and heat demand in Europe, coupled with low renewable energy output, which drove up demand for gas, thereby increasing demand for carbon allowances.

Nevertheless, by the summer of this year, gas prices reached record heights even making coal-fired power generation profitable, despite skyrocketing EU carbon prices. The fuel will likely remain in the money for the rest of the year, leading to the first increases in European coal usage in years. Coal has been in structural decline across the EU, accounting for 14% of the bloc's electricity production in the first six months of 2021, almost half its level in 2015, according to think tank Ember. But without coal as a backup, Europe could have been in trouble.

As gas demand has increased in Europe, supply has not matched this rising demand. Neither Norway nor Russia stepped up pipeline supplies, meaning European buyers faced a shortage of gas in a market in which LNG cargoes were being pulled into Asian markets. European gas storage levels are low as a result. April was cold in northern Europe, but wind generation was weak and both hydro and nuclear availability limited, again pushing up gas usage, supported by the effervescent carbon price. This combination of factors meant that April and May 2021 saw very low gas injections, leaving storage levels well below the norm.

Figure 14: European gas storage stocks



Source: OIES

Forecast

In the short term, factors such as the weather and supply issues will be the key factors driving LNG demand; in the longer term, the impact of climate change will shape LNG markets and the dynamics of demand and supply for natural gas.

2022-24

Global LNG fundamentals looks set to remain tight well into 2022 due to strong demand from northeast Asia, and particularly from China. The coal-to-gas switch policy in China’s Guangdong province will structurally keep the country’s LNG import demand strong. LNG spot pricing could weaken in 2022. The critical factor is likely to be the weather. First the heat of summer could drive forward an already strong outlook for LNG demand in China. Second will be the severity or otherwise of the northern hemisphere winter over 2021/22. But while the weather remains as unpredictable as ever – maybe more so – 2021 looks likely to be at least a supportive interlude for an LNG market technically in surplus and one which brings the rebalancing of supply and demand closer.

The weather always has a huge impact on the LNG market, not just at the time of unusual warmth or cold but in the lagged effect on storage volumes. Europe’s low tank level is of importance, but more generally, a rise in economic activity as many countries emerge from the Covid-19 pandemic should also be a key driver of gas demand. While European demand for gas is likely to remain strong, this may not translate into demand for LNG. The Nord Stream 2 pipeline, expected to start operations, will allow an increase in pipeline gas imports from Russia.

There are growing concerns the market will be tight from 2022-24 because of project delays and lack of project sanctions in 2015-18 and again in 2020. Delayed projects include BP’s Tangguh Train 3 (delayed from 2020 to mid-2022); TotalEnergies’ Mozambique LNG (delayed by at least a year from the 2024 target); BP’s Greater Tortue Ahmeyim (from 2022 to third-quarter 2023); and Shell’s LNG Canada (from 2024 to mid-decade). Nigeria LNG’s (NLNG) Train 7 looks likely to miss its 2024 start date as construction only began last month. Two planned projects in the US - an Annova development in South Texas and NextDecade's Galveston Bay LNG - have been canceled this year. In Russia, Novatek has decided to produce ammonia and methanol at its Obsky project, not LNG. There have been further delays at other schemes, including US-based Sempra's Port Arthur, Exxon Mobil's Rovuma in Mozambique and Inpex's Abadi in Indonesia. Rovuma shareholder Kogas said last week that a final investment decision (FID) has been pushed back to 2024.

There have been a few exceptions. Sempra sanctioned its 3 million ton per year Costa Azul project in Mexico in 2020. This year, Qatar Petroleum (QP) has given the go-ahead to its mega-expansion and Santos to its Barossa project in Australia, designed to backfill the 3.7 million ton/yr Darwin LNG. More are possible in 2021. BHP's move to quit oil and gas by selling its petroleum business to Australia’s Woodside should pave the way for approval of Woodside's Scarborough/Pluto Train 2 project, adding 8 million tons/yr. US-based Venture Global is close to sanctioning its 10 million ton/yr Plaquemines.

In total, Energy Intelligence's Research and Advisory unit sees around 43 million tons/yr of capacity reaching FID through 2022 under the base-case scenario in its latest long-term supply and demand outlook. In the US, that includes the first phase of Tellurian's Driftwood and NextDecade's Rio Grande LNG. It reckons buyers' demand uncertainty and growing need for flexibility, along with project promoters' eroding appetite for megaprojects, suggest smaller, easy-to-execute capacity increments may find a longer-term advantage. But mostly as the Qatari LNG construction juggernaut rolls on, all but a handful of developers elsewhere have delayed projects or called it quits. Amid coronavirus-related disruptions and concerns about decarbonization, most leading LNG suppliers are in no rush to commit to building expensive new liquefaction plants that could still be around midcentury, by when much of the world has pledged to go carbon neutral.

However, persistently high prices undermine the case for greater LNG penetration as a baseload generation fuel. The high cost of LNG combined with concerns about supply security and increasingly the attention to reducing fossil fuel use due to climate change concerns, could all serve in the long term to reduce demand for LNG and gas more widely.

The long term outlook

In the longer term, it will be government policies to address climate change and the market approach to meeting the challenges of climate change that will shape the dynamics of the natural gas market. While natural gas is seen as the cleanest of the fossil fuels (causing less emissions than the use of oil or coal), it is not immune from the pressures to reduce fossil fuel. Methane itself is potentially more damaging to the environment than carbon dioxide when it escapes in the atmosphere. There have been calls recently, e.g., from the International Energy Agency (IEA), for a complete halt to the exploration and exploitation of gas resources (along with oil and coal) in the very near future in order to meet international climate change commitments. At the same time, financial institutions are becoming increasingly reluctant to finance the development of oil and gas projects to meet their own climate change policies and under pressure from the growing influence of environmentally and socially responsible investors. Curbs on development of natural gas resources and construction of export facilities could depress supply growth and lead to gas prices remaining strong, further dampening long term demand growth.

Pressure on fossil fuel use is matched by encouragement of renewable energy sources such as solar and wind. Governments around the world are actively encouraging renewable energy projects e.g. the British government's ambition to become, "the Saudi Arabia of wind energy". As the economics of renewable become more attractive due both to scale and improved technology, they will challenge the use of natural gas as fuel for power generation. While natural gas is seen, for the time being, as a partner to renewables in order to overcome intermittency challenges, this role is also likely to decline over time. The expansion of battery storage will reduce the need for gas-fired generation to act as a back-up to renewable energy.

However, the need for gas will not disappear quickly or completely. Demand for gas for power generation is likely to persist for at least two to three decades. At the same time, increased use of natural gas for non-power generation applications and improvements in preventing emissions and capturing carbon could create new demand centres. The use of natural as a transport fuel, especially for maritime transport is rising. In addition, natural gas could play an important role in developing hydrogen as a cleaner fuel source.