CHAPTER 20

The Trading and Price Discovery for Natural Gas

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Pricing mechanisms are crucial elements in gas trade. In the last decade, they have been increasingly under the spotlight as disagreements between suppliers and buyers increased. This happened first in Europe, particularly in the first half of the 2010s, and subsequently in Asia, towards the end of the decade. A wave of renegotiations and arbitrations of long-term supply contracts shook the pillars of the gas industry, with pricing being the core issue. This chapter aims to briefly discuss general notions of pricing, reflect on the importance of pricing mechanisms, analyse different pricing mechanisms across time and space, and account for the most important recent transformations, some of which are still unfolding.

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1 Pricing and Prices—General Remarks on Their Functions

One could argue that what ultimately matters for both suppliers and buyers are price levels. In this sense, pricing mechanisms are important insofar as they are one of the key factors that influence price levels. As a matter of fact, pricing mechanisms are instruments that determine how changes in the supply and demand balance (market fundamentals) for a commodity are translated into price levels. In other cases, pricing mechanisms do not take into account market fundamentals. In any case, while price levels are probably the most important outcome of pricing mechanisms, suppliers and buyers might nurture other long-term and/or strategic interests with regard to pricing mechanisms that go beyond the prices that such mechanisms deliver in a specific moment in time. These interests might relate for instance to stability (lack of volatility) and transparency. There are cases in which short-term interests might clash with long-term interests. For instance, a supplier might support a pricing mechanism over another even if this delivered a relatively low price initially, because it might hold expectations of delivering higher prices over the long term.

The importance of the function played by prices (and pricing) in the gas business cannot be overestimated. First of all, price levels (and pricing mechanisms) are key ingredients to adjust demand and supply. Moreover, they are a fundamental component of any risk management strategy, for both buyers and producers. They also play an important role in signalling investment opportunities and investment needs. For example, if a region pays a substantial price premium relative to a bordering region, there will be a signal to invest in cross-border trade capacity. Also, pricing and prices are decisive factors determining the competitiveness of gas with respect to alternative energy carriers. They also influence the competitiveness of certain gas sources with other gas sources. Pricing and prices will influence sales levels and thus revenues—provided that buyers are not captive and are able to switch to an alternative supplier. Finally, gas pricing and prices are an important factor to look at when analysing the competitiveness of products for which gas is an important input and a key cost component (e.g. fertilisers).

2 Variety of Pricing Mechanisms Along the Gas Value Chain

It is intuitive that gas prices change over time and it is quite well known that they also change across geographies. What is less known is that they also change along the gas value chain. Upstream, a wellhead price will be charged. This is essentially the wholesale price of gas at its point of production. As gas is transported, stored and distributed, new price components will be added to reflect additional costs incurred (keeping in mind that it is paramount to analytically distinguish prices and costs). For instance, prices will tend to reflect entry fees, storage fees and exit fees. First of all, supply transportation costs will have to be covered (international pipeline fees or shipping in case of LNG). Market import prices (border or beach prices) are not yet the final prices that end-users in a country will end up paying. In fact, prices will also need to reflect costs of transmission in the destination market area and merchant selling costs (including taxes and excises, as well as a margin for the merchant). Some large users are directly connected to the transmission network. But customers further downstream will pay a price that is also reflective of storage and distribution costs, once again including taxes and excises as well as a margin for the distributors. Another important concept is that of 'citygate price': this is usually the price charged at the entry of the distribution network, where gas is transferred to a local utility. Retail prices differ significantly from wholesale prices and import prices.

Gas is also traded differently at various levels of the value chain. For pricing purposes, it is particularly relevant to make a distinction between trade that takes place between a producer and an importing company, for example, Gazprom and Eni, and domestic sales by an importing company, that is, Eni's deliveries to its Italian customers, including industrial users, power plants and retail users. Traditionally, the more one moves towards the downstream segment, the more gas tends to be traded under short-term arrangements. International trade, on the other hand, used to be dominated by long-term contracts. While these are still the dominant arrangement governing internationally traded gas (for both piped gas and LNG), short-term trade has made substantial inroads in recent years. Short-term trade refers to both contracts with a duration of 3–4 years or lower and spot transactions[1]—which can in turn take many different forms (Over-the-Counter, Exchange, etc.).

3 A Taxonomy of Pricing Mechanisms

Generalising considerations about pricing mechanisms beyond this point is very difficult, because gas prices and pricing are very much subject to geographical variables. Unlike oil, gas markets still retain marked regional characteristics. This has to do with the fact that transporting gas is relatively more expensive than oil. This is in turn explained by the different nature of gas molecules (gaseous) and oil molecules (liquid)—which makes the energy density of gas lower than that of oil. Given the larger impact of transportation on final gas delivery/procurement costs, gas trade has traditionally tended to be (at best) regional rather than intercontinental. Actually, the vast majority of gas produced in the world is consumed in the same country where it is produced.

LNG trade is changing this. Price convergence across regions is increasing. However, differences between the gas market and the oil market remain, and a full gas price convergence at the global level is unlikely. While Asian and European prices might very well become more structurally and closely

[1] According to the classification by GIIGNL (International Group of Liquefied Natural Gas Importers).

correlated as LNG trade progresses towards full commoditization, the gap between prices in producing/net exporting regions and consuming/net importing regions is going to remain. It is going to be very difficult for Europe to achieve Henry Hub parity, simply because domestic production in Europe is declining and European prices depend on international trade and availability of flexible volumes. Conversely, in the US, local hub prices are set by domestic supply and demand dynamics. Albeit to a lesser extent than today, regional pricing and price spreads are thus expected to persist.

The most widely followed taxonomy for pricing mechanisms is provided by the International Gas Union (IGU) (IGU 2019). This taxonomy makes a first distinction between oil price escalation and gas-to-gas competition, a dichotomy at the heart of the renegotiations and arbitrations that shook the gas business in the 2000s (and are likely to continue shaking the gas business in Asia). The main difference between oil price escalation (oil indexation) and gas-to-gas competition (hub indexation) is that under the former scheme, the price of gas is indexed to that of another commodity (oil), while under the latter, the price of gas is determined by gas supply and demand. The debate on whether oil indexation is still acceptable is very fierce. Oil indexation has been called a 'barbarity' and an anachronism by some (Pirrong 2018). Others are almost emotionally attached to long-term oil-indexed contracts, defending their merit and historical role in providing stability and consensus and in mobilising essential capital-intensive investment (Komlev 2016).

In oil indexation, the gas price is indexed, typically through a base price and an escalation clause, to the price of crude oil (notably in Asia) or a basket of oil products such as fuel oil, gasoil and gasoline (more frequent in Europe). Theoretically, gas prices could very well be indexed to prices of other energy carriers. Instead of oil, the price of electricity could be used as benchmark, or the price of coal. This has been done only in isolated cases. Actually, it might make more sense to index gas prices to coal prices because gas and coal still compete directly in the power sector, while gas and oil do not compete much at the moment.

In gas-to-gas competition, the price is determined by supply and demand. The trading activity that sets prices can take place over different periods: every day, every month, ever year and so on. Day-ahead, month-ahead, year-ahead prices reflect these different trading horizons. Trading can happen at physical or virtual hubs. It is important to highlight that gas can be exchanged in term contracts with an *indexation* to hub prices or directly through spot transactions that take place on hubs. Long-term contracts and hub prices are therefore perfectly compatible: clearly, hub prices need some spot and short-term trading activity to take place in order to exist (and in order to be reliable: the more trading activity and the more traders, the more the hub price will be set transparently and the more it will be a trusted, representative benchmark). But nothing prevents parties from adopting hub pricing mechanisms in long-term supply contracts.

Besides oil and hub indexation, a third pricing mechanism included in the IGU taxonomy is bilateral monopoly. This refers to a price that is set in bilateral negotiations between seller and buyer. The price can be set using a variety of criteria. It cannot be excluded that some of these criteria might be market related, but often there will be a mix of cost-related considerations, considerations on what a 'fair price' might be, and political considerations. After an agreement is struck, it will remain in force for a fixed period, typically one year. The agreement is often high level, involving governments or state-owned incumbents. With respect to internationally traded gas, it is a mechanism that has been mostly used in the Former Soviet Union and in the Middle East, but seldom in the Western world.

Oil indexation, hub indexation and bilateral monopoly are the three broad categories of pricing mechanisms used in internationally traded gas. For domestic sales, there are some additional possibilities. The first one identified by the IGU taxonomy is called 'netback from final product'. This essentially means that the gas supplier will receive a price that is a function of the price received by the buyer of gas for the product (e.g. a fertiliser) that the buyer of gas produces. This typically happens when gas is a major variable cost in a production and there is the intention to maintain the buyer of gas (and producer of the final product) afloat financially.

Besides, gas prices are often regulated. This however usually applies to domestic gas rather than internationally traded gas (Fig. 20.1).

Fossil fuels are still heavily subsidised in a number of jurisdictions. This is often grounded on sound social and political motivations, even if it is under increasing attack from the climate agenda perspective, and the International Energy Agency (IEA) consistently calls for an end of fossil fuel subsidies.[2] In fact, a significant share of population in a number of low-income countries would not be able to pay international market prices for energy. Low-income countries also need to promote manufacturing for economic diversification purposes, and it is often by offering low energy prices to national industries that governments ensure their international competitiveness. In very cold countries, gas heating also performs key humanitarian functions. However, regulated prices have a number of distortive effects. One of them is that consumers will not perceive gas as a scarce resource. This encourages wasteful use of the commodity, decreasing energy efficiency. Over time, this can put processes in motion that result in booming domestic demand, which can get out of control if combined with massive demographic and economic growth. Some countries in North Africa, for example, have been struggling and are still struggling to honour their gas export contracts because their domestic demand is growing in an uncontrolled way, also due to regulated prices at home. This example is also useful to illustrate that while regulated prices refer to national gas consumption, there are links with international gas trade as well. The large gap often found between the price of gas in developing countries and global

[2] https://www.iea.org/topics/energy-subsidies.

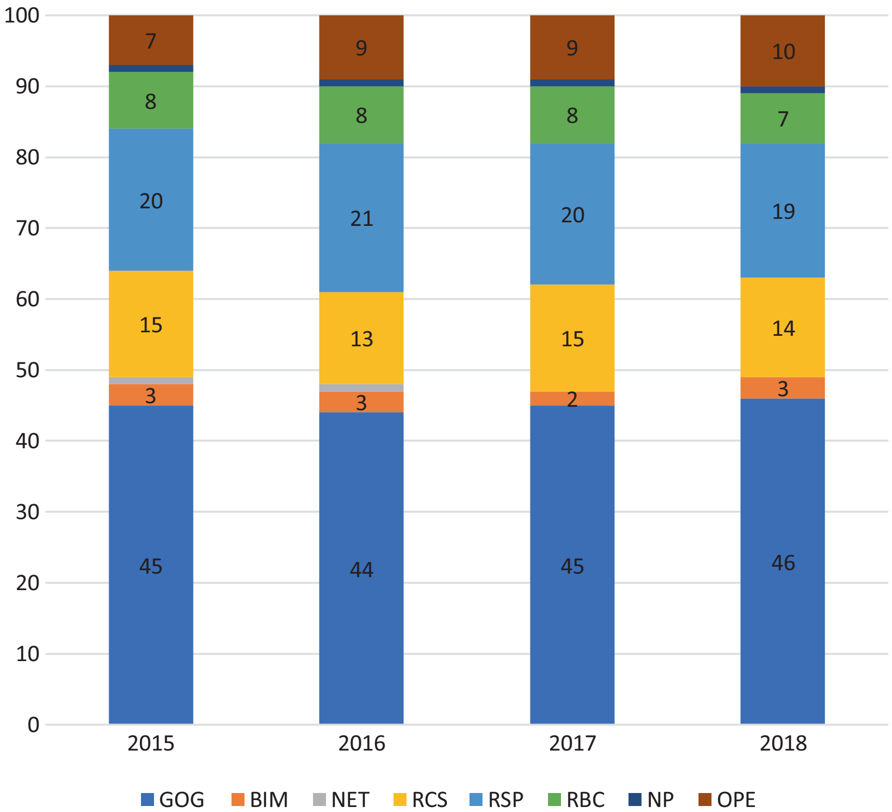

Fig. 20.1 Evolution in pricing mechanisms of domestically consumed gas (IGU 2019). *GOG* gas to gas competition, *BIM* bilateral monopoly, *NET* netback, *RCS* regulated cost of service, *RSP* regulated social and political, *RBC* regulated below cost, *NP* no price, *OPE* oil price escalation. Source: IGU 2019

gas markets is also at the basis of international oil and gas companies' reluctance to commit to substantial sales to local markets. They tend to prefer selling to global markets. However, host countries will often want some local gas development programmes to industrialise and reduce poverty. IOC-host country negotiations on pricing, prices and share of domestic sales are often complex and drawn-out.

In regulated prices, a first broad, important distinction can be made between prices set above cost and prices set below cost. In fact, prices are sometimes lower than market prices but nevertheless allow for the recovery of costs of production (and sometimes also of transmission and other activities throughout the gas value chain). In other, more extreme cases of subsidisation, prices are so low that production (or other activities in the value chain) is performed at a loss. The government will have to step in, with the result that the costs are socialised. Sometimes there is also cross-subsidisation, that is, some users are charged more than others and allow to cover the gap left by non-paying customers or protected customers. The IGU further distinguishes between 'regulated cost of service' (RCS), when the price is determined by a government agency or regulatory authority and the price is designed deliberately to cover costs and a minimum rate of return, and 'regulated social and political' (RSP), when a price is set at irregular time intervals on a markedly political or social basis, in response to specific needs or to raise revenue. The last category identified by the IGU is 'No Price' (NP). Gas is provided for free in a number of cases, either to military users or to domestic industries, particularly in settings where there is a lot of associated gas production and no other clear or evident uses for the gas, which would otherwise be flared.

4 The Rationale of Oil Indexation

As mentioned, in international gas trade transactions, oil indexation and hub indexation are the prevailing price mechanisms, and a transition is underway from long-term oil-indexed contracts to shorter term trade and hub pricing.

One might wonder why gas has been (and still is) indexed to another commodity. The short explanation is that gas markets have been limited in size and participation, while the oil market has been a truly global, liquid market for decades. The physical characteristics of the two commodities—as described above—largely accounted for these differences. Because gas markets were immature, they were not considered able to express reliable benchmarks. The potential for price manipulation is high in a market that is primarily local and dominated by a monopoly (or a cartel). Another overarching reason why oil indexation survived for so long is that, in general, there is inertia to changing pricing mechanisms. Once trust in a system is established, it is not easy to deviate from it without shocks.

When long-term oil-indexed contracts were conceived, the rationale was strong. Gas suppliers had to allocate substantial investment in production and transportation, and gas buyers often had to invest a lot in distribution networks. Appliances geared towards gas had to be adopted downstream by industrial residential and commercial users, often with the help of the State. The gasification of entire countries carried hefty costs. Strong guarantees were thus needed by both suppliers and buyers, and oil—by virtue of its liquid, global, traded nature—offered stronger guarantees than a nascent commodity.

The discipline of Transaction Cost Economics—and particularly the work by its founder Oliver Williamson (1979)—helps explaining why long-term contracts, rather than spot transactions, are adopted to govern certain types of exchanges. Under perfect market conditions, as described by neoclassical economics, there are no transaction costs. With zero transaction costs, Williamson argues, there would be no need for economic organisation. However, in real-world economic exchanges, information is never perfect and transaction costs exist. Special governance structures will have to replace standard market exchanges when transaction-specific value is high. According to Williamson, transaction-specific governance structures have to be created to govern transactions that are recurrent, entail 'idiosyncratic' investment and are conducted in a context of uncertainty. Let us review these concepts below.

Frequency is important because problems related to imperfect information (and the parties' ability to project future costs and benefits) begin to matter when an interaction is repeated or continuing, while they are not relevant in one-time transactions.

Secondly, Williamson argues that goods that are not specialised do not pose significant hazards because buyers can easily fall back on alternative suppliers and vice versa. However, in cases when the individuality of the parties affects costs significantly, conditions of 'non-marketability' can arise. Transactions involving this type of goods are called 'idiosyncratic'. In this respect, it is important to emphasise the higher specificity of investments in pipelines than in LNG (when the LNG market starts being global and mature): while LNG flows can be rerouted in case a customer is lost (or LNG can be sourced from another location if a supplier is lost), a pipeline cannot be moved, thus creating situations where buyers and suppliers are captive.

Contracts covering idiosyncratic activities have to solve problems arising from bounded rationality and opportunism. Once an investment is made on assets that have no alternative use to the one for which they were earmarked, such investment will be 'sunk'. In default of special governance structures offering guarantees and reassurances, marked asset specificity leads to what Klein et al. (1978) described as a 'hold-up' situation: perceiving a high risk of not being able to recoup the benefits of its investment, the investing party will be reluctant to invest, which can lead to endemic underinvestment. When there are idiosyncratic activities, spot exchanges will fail to provide the right investment incentives, and the assurance of a long-lasting relation is necessary as a ground for investing.

Uncertainty also plays an important role. Long-term contracts implemented in uncertain conditions make comprehensive contracting ('presentation') pricey if not impossible. Not all future eventualities for which revisions are needed can be anticipated at the beginning. Flexibility is thus key. In contracts whose future payoffs depend on future states of the world ('state-contingent claims'), disputes are likely to arise and, given that parties are assumed as opportunistic, it is difficult to establish whose claims should be believed. Mechanisms for dispute settlement are thus also needed.

Long-term gas supply contracts reflect all of these features. While it was said earlier that, conceptually, oil indexation and long-term contracting are different, the two were part of an 'inseparable package' at the beginning of gas trade between, for instance, Europe and the Soviet Union, on the one hand, and Japan and South-east Asian LNG exporters, on the other.

They can be regarded as 'inseparable packages' in the sense that they were complex risk allocation schemes, that is, arrangements where volume, duration and price clauses were all essential components for making it acceptable for both buyers and sellers to embark on a gas trade adventure that would last for decades. For this reason, even if this chapter focusses on pricing, a number of key non-pricing contract clauses must be discussed.

The schemes that were adopted, namely, in Euro-Soviet contracts, conferred greater price risk to exporters and greater volume risk to importers. Exporters were exposed to (higher) price risk in the sense that they were committed to providing contracted volumes regardless of the contract price. Fluctuations of oil prices trickled down to contract prices, and there was no guarantee that these would not be low for protracted periods of time. To limit price volatility, contract prices were calculated on the basis of the average price of a basket of oil products over several months (typically the 12 previous months) and applied for a shorter period (typically the 6 following months). It would however be incorrect to state that price risk was entirely taken by exporters. Importers were in fact also exposed to price fluctuations but with a limited risk—as they could pass through (higher) sourcing costs to their end-users, which were captive (in a pre-liberalisation environment). Instead, the main risk for importers was to be unable to sell the contracted gas volumes in case of lower-than-expected demand (volume risk).

Oil indexation was chosen because, as a liquid gas market did not exist, contracting parties found it necessary to peg contract prices to a more deeply traded commodity. Oil indexation was also chosen because companies in importing countries already had experience with it, and international oil market dynamics were well known to operators in the energy sector. Furthermore, oil indexation made sense because gas and oil were deeply interwoven at the time, not only in the upstream (with sizeable associated gas production) but also in the downstream—since gas was competing with oil products in heating and industry and to a lesser extent in power generation (Stern 2012). As mentioned, unlike Asian contracts, indexed to crude oil, contracts between Russia and Europe were indexed to oil products, especially heavy fuel oil—competing with gas in industry—and gasoil—competing with gas in the residential sector. A typical oil-indexed formula used in European import contracts could be simplified as follows:

$$\mathbf{P_t = P_o + \alpha \times a_1 \times b_1 \left(Go_t - Go_o\right) + \left(1 - \alpha\right) \times a_2 \times b_2 \left(HFO_t - HFO_o\right)}$$

with P_t representing the contract price, P_o the base price, α and $1-\alpha$ the weight of different market segments (in this example, the residential and industrial sectors); a_1 and a_2 the factors to convert oil product units to natural gas units; b_1 and b_2 the pass-through factors to transform oil product price changes into gas price changes (usually applying an 80–90 percent discount rate vis-à-vis oil products); and Go_o and HFO_o the values of gasoil and heavy fuel oil at a time t_o, calculated on an average of several months.[3]

[3] Cf. also L. Franza, *Long-Term Gas Import Contracts in Europe: The Evolution in Pricing Mechanisms*, Clingendael International Energy Programme, 2014.

Asian price formulae were designed differently. Apart from indexation to crude oil rather than products, one of the most distinctive features in Asian long-term contracts has been the presence of an oil slope with a gradient equal to 14.85 percent (derived from the historical 'benchmark' contract between Indonesia's Pertamina and Japan's Western Buyers consortium) (Flower and Liao 2012). The slope was changed over time and across contracts, but it typically remained in the range of 10–17 percent. The slope essentially determined the indexation ratio (taking into account the calorific difference between the two commodities). In the early days of LNG trade, there was a linear relationship between LNG and crude oil prices (in addition, the formula included a proxy for inflation). Typically, the original Asian formula of the type described above delivered a price of gas that was higher than crude oil in a low-price environment and potentially lower in a high-oil-price environment. S-curves (softening the relationship between gas and oil prices when the latter ones were either very low or very high) were intermittently applied when pricing became unsustainable for one of the parties (Flower and Liao 2012).

A fundamental property conferred to long-term contracts and pricing mechanisms was indeed flexibility. As the payback time of transmission pipelines was projected to extend over decades, contracting parties anticipated that market conditions would change along the lifespan of contracts, requiring dynamic adaptations. As has just been mentioned relative to Asian contracts, and as was certainly the case with European-Russian contracts (*below*), pricing mechanisms could be adjusted by one of the parties if the situation became unsustainable.

With hindsight, long-term import contracts proved extremely flexible: in spite of deep geopolitical transformations and fundamental changes in energy use, they sure have been bent—yet never broken—in decades of trade.[4]

First of all, volumetric flexibility was provided, entailing that when demand was falling, buyers could purchase volumes below the Annual Contracted Quantity (ACQ—with the possibility of compensating in the following years). Clearly, there were downward thresholds that the buyer had to respect. The buyer could still buy lower physical volumes, but, under a certain threshold, it would have still had to pay the equivalent price of gas not purchased (whereby the expression 'take or pay', which could be reformulated more clearly as 'whether you take it or not, you still have to pay for it'). This lower threshold is referred to as Minimum Contracted Quantity (MCQ) of take-or-pay (TOP) threshold, and it is usually somewhere between 75 and 85 percent of the ACQ. In addition to this downward flexibility, there is also upward flexibility, allowing sellers to ship volumes above the ACQ. Russia in particular

[4] Cf. Gustafson, "recent gas negotiations have shown flexibility and adaptation between Russian sellers and European buyers, and commercial logic has driven significant compromises—particularly on the Russian side, as Gazprom has responded to commercial and regulatory pressures", T. Gustafson, *The Bridge: Natural Gas in a Redivided Europe* (Cambridge, MA, 2020): Harvard University Press.

committed to make available larger volumes if requested, thanks to its spare production capacity.

The second element of flexibility related to pricing. Review clauses allowed the parties to ask for amendments to pricing mechanisms in certain time intervals (originally every three years) if justified by changes in the market. This was done to avoid that pricing formulae would deliver price levels that were entirely unprofitable for either the buyer or the seller (including opportunity cost considerations). In Eurasian gas trade, for instance, given the asset specificity of the investments and the need for market access, Gazprom was interested in extracting profits from gas sales as much as it was in keeping its European buyers satisfied (to avoid switching to other energy sources or gas suppliers) or at least financially solvent.

In sum, long-term contracts were sophisticated governance structures designed to allocate commercial risk between contracting parties involved in schemes that also had geopolitical objectives. Given the prominent ambition of *détente* as a catalyst for the Euro-Soviet contracts, and the characteristics of the underlying transactions, long-term contracts were given a relational character. Their provisions were designed to minimise disputes or at least to manage them. Contracts between Japan and South-east Asian countries were also strengthened by high-level political coordination. Japan chose to pursue robust LNG imports and internal gasification for security of supply reasons, namely, to reduce its dependency on oil (and the Middle East) after the 1973 price shock. A *rapprochement* with Indonesia and Malaysia—two countries that Japan had occupied during WWII—was favoured by the necessity to sign gas deals.

This political digression is important to highlight that, historically, pricing mechanisms have been part of a broader 'inseparable package' that served long-term strategic purposes both commercial and geopolitical. To be sure, the schemes also had to make commercial sense. This, together with their flexibility, made them resilient for decades. To use Williamsonian jargon, the mechanisms described in this section were intended to limit ex-post opportunism by the parties in presence of highly asset-specific investment, recurrent transactions and remarkable uncertainty.

5 Oil Indexation Comes Under Pressure: Gas-to-Gas Competition

For quite some time, the US has been an exception in the global landscape when it came to gas pricing. In fact, the US, a major producer of gas, did important pioneering work in establishing hub pricing as an industry norm. The important price-setting role of Henry Hub is not a simple given, but rather the result of painstaking regulatory work.

In the US, removal of wellhead price controls was one of the first key steps in the liberalisation of gas markets, followed by the introduction of competition in the wholesale market through unbundling of transmission infrastructure and third-party access. The first steps in deregulating the US gas market were made in the 1978 Natural Gas Policy Act, which contained rules for the gradual removal of price ceilings at the wellhead. Complete deregulation of wellhead prices was carried out later, by the 1989 Natural Gas Wellhead Decontrol Act. The New York Mercantile Exchange (NYMEX) opted for Henry Hub as a location for contracts in 1989, as full deregulation of wellhead prices took place. Henry Hub was chosen because of the great concentration of supply and infrastructure in that part of Louisiana. Indeed, one of the advantages of the US, greatly helping liquidity, is the fact that the country is itself a major producer.

Since then, Henry Hub has provided the basis for price formation in the US. Regional hubs also exist, but they are usually following Henry Hub except for cases where bottlenecks exist. Henry Hub prices have seen important variations throughout the decades, but for the last 10 years and until 2021, they have been at very low levels (often below 3$/MMBtu) as a result of the shale revolution.

In the 1990s and 2000s, the gas business changed radically also outside of the US, and traditional pricing mechanisms started to also come under increased pressure elsewhere.

The asset specificity of the gas investment stock diminished, particularly in mature markets. Transmission and distribution infrastructure started to become amortised, and LNG became subject to significant reductions in capital intensity thanks to technological progress and upscaling (Cornot-Gandolphe 2003; Jensen 2003). Lower capital intensiveness leads to lower risks and limits the 'hold-up' problem (Chyong 2015), thus softening the requirement of backing investments with long-term contracts.

The growth in LNG trade relative to pipeline trade also contributed to these dynamics. Since LNG trade is less asset-specific than pipeline trade—owing to its liquid nature—it brought more flexibility to both sides of the market (Chyong 2015). Access to flexible LNG and an increasing number of players contributed to changing the underlying structural conditions under which long-term oil-indexed contracts had thrived.

Gas trade became more 'impersonal' and less relational, and the pressure for market-based pricing mechanisms increased accordingly. Long-term strategic considerations gradually started to give way to shorter term, profit-oriented motivations. As gas markets (and hubs) matured—thus increasing trust that gas-to-gas competition itself could offer reliable price discovery—and direct competition between gas and oil weakened, oil indexation lost a lot of its attractiveness and original rationale.

Exogenous factors also played a fundamental role in changing the approach to pricing. The most important factor is gas market liberalisation, which started in the US and then extended to the UK and Continental Europe. More recently, countries outside of the West also started to liberalise their gas markets. Japan has enforced third-party access to infrastructure, and even China is now unbundling its gas pipelines. Liberalisation is important for pricing because one of its main effects is that of breaking the strong ties between incumbents and end-users. In a liberalised market, end-users stop being captive. They are able to switch to an alternative supplier and procure gas directly on the hub. This has the key implication that incumbents (mid-streamers, i.e. the importing companies) lose the ability to pass through additional procurement costs. Liberalisation also sets a virtuous circle in motion whereby the larger volumes are made available on hubs, the more hubs become benchmarks, attracting more trade and so on. Provided of course that physical volumes are available.

In a liberalised market, prices are set on hubs, which are marketplaces where gas is exchanged, either virtually or physically. Henry Hub in the US, the National Balancing Point (NBP) in the UK and the Title Transfer Facility (TTF) in The Netherlands are the most liquid hubs in the world at the moment. In Asia, where the process of hub creation is not as advanced as in the West, a key market marker is the Japan Korea Marker (JKM), a proxy calculated by Platts on the basis of trading activity. Producing countries, after opposing hub-based pricing and defending oil indexation as much as they could, are starting to experiment with hub trade. Since they have seemingly acknowledged that oil indexation belongs to the past and that the most modern pricing mechanism is hub pricing, they are now trying to at least establish their own hubs, so that their revenues are not completely determined by a hub in the export market, over which they have no control whatsoever. Notably, Russia has recently established an exchange, the Saint Petersburg Mercantile Exchange (SPIMEX), and in 2018, it has started selling gas volumes to Europe through an Electronic Sales Platform (ESP).

The possibility for end-users to procure gas directly on hubs was revolutionary and brought old business models under pressure. Pressure reached a breaking point when the gap between oil-indexed supplies and hub prices widened so much that it became unsustainable for mid-streamers. In 2008–2009, a situation of global gas oversupply emerged. Qatari LNG volumes originally destined for the North American market could not be sold there because in the meantime the US had gained the ability to produce domestically all the gas that it needed. Qatari LNG was thus looking for new outlets and was directed towards Europe. The economic and financial crisis of 2008–2009 depressed gas demand, aggravating the mismatch between supply and demand. Hub prices in Europe collapsed. At the same time, mid-streamers (importing companies) had long-term commitments to purchase oil-indexed gas from Russia, Algeria and other suppliers. Because, unlike in the past, they could not fully pass through the increased procurement cost to their end-users, they found themselves in an unsustainable situation. On the one hand, they had to buy expensive oil-indexed gas; on the other, they had to sell at a major discount in order to be able to market it.

For this reason, in the first half of the 2000s, European mid-streamers started to ask for renegotiations of their long-term contracts. Their key demand was to bring contract prices in line with market prices. Gazprom, Sonatrach and Qatar initially refused to overhaul pricing mechanisms, but with time they all gave in, due to the threat of adverse arbitration rulings, Gazprom in particular initially tried to tweak the components of traditional formulae, such as the P_0 or the conversion factors, so that these formulae would deliver prices more in line with market prices—thereby offering relief to European midstreamers, without structurally changing the formula. However, over time, and starting in Northwest Europe, Gazprom and other suppliers were forced to more structurally adopt hub indexation. Hub indexation is now prevalent in European import contracts. In Asia, a similar pressure to renegotiate emerged in 2018–2019, with the key difference that Asia lacks fully liberalised market with gas-to-gas competition and national hubs (except for a somewhat artificial, albeit widely followed benchmark such as the JKM).

6 Gas Pricing in the 2020s

Gas pricing undertook significant transformations as a result of the trends described above. According to the 2019 IGU Wholesale Pricing Survey (IGU 2019), hub indexation expanded by 16 percent between 2005 and 2018, while oil indexation declined by 5 percent. The reason for this mismatch is that while in some regions (notably Europe) hub indexation replaced oil indexation, in others, namely in emerging markets, oil indexation substituted more obsolete pricing practices, at least introducing a market component (albeit an exogenous one). Bilateral monopoly, which was already a marginal price-setting mechanism, further shrunk by 2.5 percent. Regulated pricing at cost of service increased by 9 percent, and social and political regulation increased by 3 percent. Finally, regulated pricing below cost declined by almost 20 percentage points, reflecting a phaseout of the most extreme, loss-making subsidy schemes (Fig. 20.2).

In Europe, as a result of developments described in the previous section, three quarters of gas are now hub-indexed. Oil indexation is confined to one-quarter of consumption and regions such as the Iberian Peninsula, North-eastern and South-eastern Europe. Hub indexation is not only prevalent in North-western Europe but also in Italy and Central-Eastern Europe. It is important to highlight that these are only approximate estimates, as many import contracts actually feature hybrid formulae combining oil indexation and hub indexation. Whether one or the other is applied also depends on the price level, as pricing corridors have been introduced in which contract prices follow hub or oil indexation depending on price levels. As a result of the European Commission DG Competition's decisions concerning Gazprom's activities in Europe, Gazprom committed to adapt pricing in Eastern Europe to market markers. Customers in those regions can now request that contract prices are calculated using an average of Western European hub prices. Pressure to move further away from oil indexation has decreased together with the fall in oil prices in 2014 and 2020.

In Asia, as mentioned, oil indexation has increased substantially because it substituted non-market pricing mechanisms. In terms of domestically produced gas, the expansion of oil indexation is explained by wider adoption in

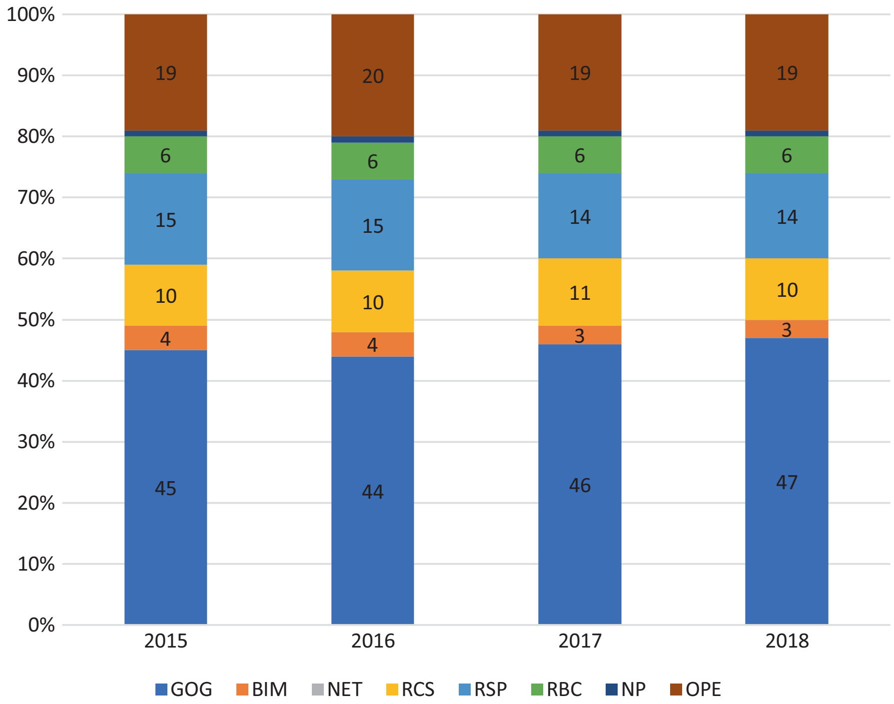

Fig. 20.2 Evolution in pricing mechanisms—global consumption (IGU 2019), %. *GOG* gas to gas competition, *BIM* bilateral monopoly, *NET* netback, *RCS* regulated cost of service, *RSP* regulated social and political, *RBC* regulated below cost, *NP* no price, *OPE* oil price escalation. Source: IGU 2019

China, Indonesia and Malaysia, where it has replaced regulated prices. Moreover, oil indexation increased because it was chosen as a pricing mechanism in new Turkmenistan-China gas contracts, which are very large from a volumetric perspective.

North America has not witnessed any transformation because it had already achieved full hub indexation (see above).

Africa has also seen limited changes in pricing mechanisms. Regulated pricing remains dominant although there has been a transition from regulation below cost to regulation at cost of service.

The Middle East remains dominated by regulated prices, particularly social and political regulation (76 percent). Subsidies are however being reduced, and there has been a particularly strong decrease in regulation below cost. The figure for regulated pricing is so high because this is the pricing mechanism adopted for domestic sales in gas heavyweights like Iran, Saudi Arabia and United Arab Emirates. Bilateral monopoly has been increasing between 2005 and 2018, reflecting a larger relative share of piped gas exports from Qatar to the United Arab Emirates and Oman.

Africa has seen limited changes in pricing mechanisms. Regulated pricing remains dominant although there has been a transition from regulated below cost to regulated cost of service.

In Russia, there was a move from regulation below cost in domestic production to gas-to-gas competition, as independent gas producers started to compete with each other and with Gazprom. Furthermore, Gazprom switched from regulation below cost to regulated cost of service, reflecting the Russian government's ambition to increase domestic prices and gradually bring them more in line with European netback parity. This process has been slowed down by the economic crisis that hit Russia but might resume in the future. Another transformation has been the switch from bilateral monopoly to oil indexation in Russia-Ukraine contracts, followed by the adoption of hub indexation in Ukraine import contracts as Ukraine started to import from Europe.

In Latin America, hub indexation has increased from 4 percent to 17 percent between 2005 and 2018 thanks to reforms in Argentina and Colombia and rising LNG imports, while social and political regulation declined from 52 percent to 16 percent and, against the global trend, regulation below cost increased from zero to 13 percent because of its adoption in Venezuela.

Globally, hub indexation is prevalent in piped gas trade while oil indexation is still prevalent in LNG (Fig. 20.3).

This might sound counterintuitive, because oil indexation is seen as 'old' (relative to hub indexation) while LNG is seen as 'new' (relative to pipeline

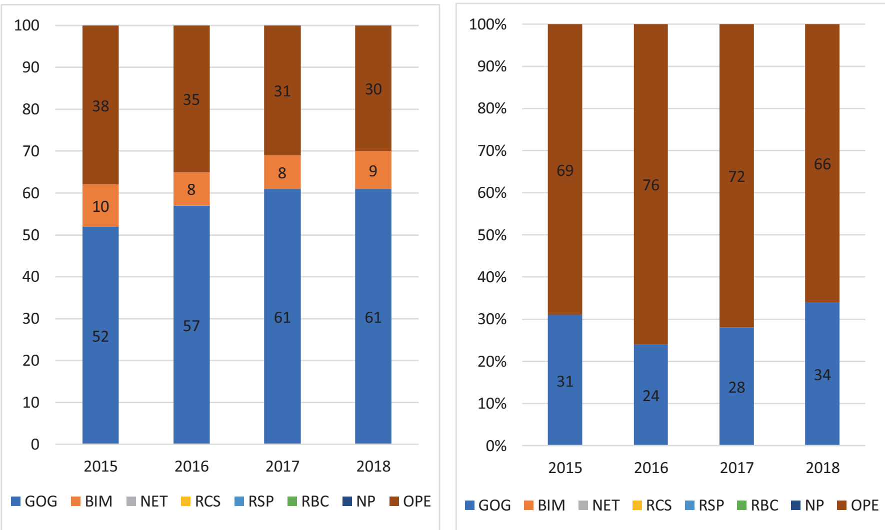

Fig. 20.3 Evolution in pricing mechanisms in pipeline and LNG trade (IGU 2019). *GOG* gas to gas competition, *BIM* bilateral monopoly, *NET* netback, *RCS* regulated cost of service, *RSP* regulated social and political, *RBC* regulated below cost, *NP* no price, *OPE* oil price escalation. Source: IGU 2019

trade). Also, we discussed how LNG has revolutionised gas trade and reduced asset specificity, paving the way for a transition away from point-to-point trade towards commoditization. The contradiction is however only apparent: the fact that LNG is predominantly oil indexed reflects the fact that three-quarters of global LNG flows target Asia, a region where oil indexation is still prevalent. Conversely, Europe represents a high share of piped gas imports. Oil indexation has not prevented LNG from revolutionising gas trade thanks to its destination flexibility.

7 Conclusion

Pricing mechanisms are a key element of gas trade as they are a decisive factor that concurs to determine price levels, namely, how prices respond to variations in supply and demand. The choice of a pricing mechanism also influences the strategic room for manoeuvre that suppliers and buyers have in opting for volume or value maximisation. Traditionally, gas suppliers defended long-term oil-indexed contracts. However, the old consensus on oil indexation, which had been a pillar of international gas trade for a decade, has been eroded in the last decade—particularly in Europe. More impersonal market exchange now prevails, whereas relational contracting had been essential to build the gas industry.

Gas markets are maturing and trading activity is increasing, creating an incentive to adopt hub indexation in a larger number of countries. North America has been a pioneer in deregulating wellhead prices and embracing gas-to-gas competition. Hubs offer better price discovery than in the past also in Europe because they are supported by more efficient financial services and more players are active on hubs, reducing volatility and opportunities for manipulation. Regulation played and continues to play a key role in facilitating the emergence of well-functioning, liquid trade hubs. The vast majority of gas sold to Europe is now hub-indexed. Asia is also gradually moving towards a larger share of hub indexation, although it is still lagging far behind in the process of establishing its own hubs. It now mostly relies on a proxy, the Japan Korea Marker by Platts, which has started to decorrelate from oil in 2018–2019. Elsewhere, regulated prices remain the norm. The weight of regulated pricing in total gas consumption is also explained by the large share of gas that is produced and consumed domestically.

Overall, gas prices remain regional. Additional convergence is materialising thanks to the globalising effect of flexible LNG, a commodity traded by parties that look for arbitrage opportunities. However, infrastructural bottlenecks, responsiveness to location-specific regulation and market fundamentals and lately the growing risk of politicisation (for instance, the introduction of tariffs on LNG as a result of US-China trade wars) limit the scope for further convergence.

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