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ASIAN LNG TRADING HUBS: MYTH OR REALITY

BY MIKE FULWOOD
MAY 2018

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ACKNOWLEDGEMENTS

The author wishes to thank Tim Boersma, Akos Losz, Antoine Halff, and two anonymous reviewers for their helpful comments on previous versions of this paper and Matthew Robinson for editorial assistance. This paper represents the research and views of the author. It does not necessarily represent the views of the Center on Global Energy Policy. The paper may be subject to further revision.

This work was made possible by support from the Center on Global Energy Policy. More information is available at http://energypolicy.columbia.edu/about/mission.

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EXECUTIVE SUMMARY

The growing importance of liquefied natural gas (LNG) in Asia's energy mix has spawned efforts in the region to create a trading hub like the established hubs in the United States and Europe. Asian policy makers find the idea of a trading hub attractive, though at times there seems to be confusion over the fact that a hub is not a tool (to create competitive prices) but rather the outcome of the creation of an ecosystem in which market forces can thrive. History shows us that creating a competitive market environment is a lengthy process that can at times be painful, especially for the incumbents that benefit most from the status quo. The most advanced hub initiatives are in Singapore, Japan, and China. However, each of these locations faces its own set of challenges, and none has so far been successful in establishing market-based gas pricing or a trusted pricing benchmark for the global LNG market. Viewed against examples such as Henry Hub in the United States and the National Balance Point (NBP) and the Title Transfer Facility (TTF) in Europe, there are legitimate questions as to whether an Asian LNG trading hub is a myth or will become a reality.

The purpose of this paper is to see what might be required to develop an LNG trading hub. The important factors that supported pipeline hub development in other regions included significant domestic production and gas storage facilities, a competitive wholesale natural gas market, nondiscriminatory third-party pipeline access, standardized contracts for both transportation and the sale and purchase of gas, liquid physical markets that encourage the development of a futures market, and price reporting. The paper also considers what the alternatives might be if an LNG trading hub cannot easily be achieved. The key takeaways are as follows:

- Gas hubs first developed in the US market, operating as physical locations, where multiple pipelines intersect, with Henry Hub being the most famous in the US. In Europe, NBP and TTF are now the most liquid trading hubs, often described as "virtual" hubs, but in essence they are little different to Henry Hub. NBP and TTF are both products of the physical gas transmission systems in the UK and the Netherlands, respectively, just as Henry Hub is the product of the physical Sabine Pipeline.
- While China, Japan, and Singapore are the focus for a potential LNG hub, none of these countries has really developed a competitive wholesale natural gas market. China still has a long way to go in terms of separation of transport and commercial activities and introducing regulated third-party access (TPA) as well as reducing the level of government control. Japan needs to establish a clearer separation of transport and commercial activities, and the government needs to integrate the network and introduce TPA. Singapore is the most liberalized market, but the domestic market is simply not big enough and lacks sufficient market players to create the truly competitive wholesale market that is a prerequisite for a hub.
- There are also a number of obstacles that would prevent an Asian LNG hub from achieving sufficient churn. Among these issues are the sheer size of a single cargo of LNG and the

uneven nature of deliveries. In contrast, pipeline receipts and deliveries are continuous and almost instantaneous. There is also no clear geographic location in the region where traded LNG would automatically default to delivery if the parties to the trade wished to do so. This is a fundamental feature of pipeline hubs.

- If a true hub cannot be developed easily, that does not mean that a reliable price benchmark for LNG could not be developed. Numerous price benchmarks are available for LNG, especially in the Asian markets, from the main price reporting agencies. However, these benchmark assessments are largely based on participants' views on what the price would be if a trade were done and not on actual trades.
- There are other models that could also be considered for Asia. Instead of only looking to gas markets, other markets, such as oil, might be considered. The Brent oil market developed in the 1980s with a spot and physical forward market. Later, a futures market, directly linked through the settlement price and EFPs to the physical market, developed. Many of the characteristics that led to the development of a liquid trading market for Brent crude are applicable to the LNG market.
- Based on pipeline hubs and the Brent oil market, there are five key elements necessary to create a reliable price benchmark in LNG: pricing transparency, market diversity and size, access to infrastructure, standardization of contractual arrangements, and a physical delivery point at which all trades could be delivered.
- Out of all the markets in Asia, Japan appears the most likely market in which a reliable price benchmark could be developed. Japan's Ministry of Economy, Trade, and Industry (METI) is actively promoting pricing transparency, and the nation's market is sizeable, with a reasonable diversity of players. Integrating the pipeline infrastructure for at least Central Japan, where almost 80 percent of Japan's LNG is consumed, would create a large market. Nondiscriminatory open access to all the regasification terminals and the pipeline system would be required, preferably with all the infrastructure (regas terminals and pipelines) being combined in one system with an independent system operator. It may then be possible to trade LNG as it enters the storage facilities at each regas terminal, making it much simpler to introduce a short, standardized contract for "in-storage LNG." The ability to trade smaller volumes should promote trading and improve price reporting and transparency, promoting a reliable price benchmark.

INTRODUCTION

Almost every LNG conference has on its agenda nowadays the topic of Asian LNG trading hubs. Governments, regulatory authorities, academics, and market participants are all presenting on how a hub might be developed in Asia. There have also been a number of reports published in the last few years on the development of hubs in Asia.

The most advanced hub initiatives are in Singapore, Japan, and China. However, each of these locations faces its own set of challenges, and none has so far been successful in establishing market-based gas pricing in Asia or a trusted pricing benchmark for the global LNG market. Are the aspirations of these countries realistic? Is there a good understanding of what is required to create a hub? Adapting the concept of a gas hub—which developed in onshore locations with abundant pipeline interconnections in Europe and North America—and implementing it in the context of the global LNG market is challenging in its own right.

Much of the motivation for a hub seems to be premised on the fact that Henry Hub works in the United States and NBP and TTF work in Europe, so why not establish one or more in Asia? Then we will have a market with prices determined by supply and demand.[1] However, there doesn't seem to be have been much detailed work published on what the real function of a hub is and what it achieves, let alone whether there are alternatives that may be more realistic in the Asian LNG market.

The purpose of this paper is to assess whether an Asian LNG trading hub is a myth or reality. The author believes there is a need to go back to the basics of how pipeline hubs were formed in order to really understand if an LNG hub can be modeled on pipeline hubs. This is reviewed and discussed in section 1, which will consider existing hubs, where they are, how they work, what they do, and how they were formed. This section will also look at hub liquidity and price reporting, which are key elements in the hub development process.

Having reviewed the existing hubs, we can turn our attention to what is or is not happening in Asia, especially with respect to LNG. Section 2 will look at the progress on creating LNG hubs in Asia, focusing on China, Japan, and Singapore; the possible motives of governments in wanting a hub; and the progress on creating the necessary conditions for the development of a hub. In addition, the section will also consider how liquidity might be created in the LNG market.

If the development of a hub for LNG is not possible, then what might the alternatives be to promote trading and get reliable price signals? Section 3 will firstly review the many price references and benchmarks that have developed in recent years and consider how robust these are before exploring possible alternatives to an Asian LNG hub, including looking outside the gas market for examples, particularly in the oil market. The section will also look at the possible growth in spot and flexible cargoes and whether this might help promote trading.

Section 4 moves on to look at the prospects of creating a reliable price benchmark, which may or may not be linked to a hub, including the key elements required. It will also consider whether these key elements can be implemented in any Asian country, with a focus on Japan, which in the author's view has the greatest potential.

Section 5 will cover the conclusions.

It is not the intention of this paper to repeat at length the excellent work that has already been done in this area nor to reinvent the wheel on all of this. However, we will draw on and reference relevant papers and reports, notably from the International Energy Agency (IEA),[2] the Oxford Institute for Energy Studies (OIES),[3] and more recently, the US Energy Information Administration (EIA)[4] since they cover comprehensively many of the fundamental issues to be addressed. We hope to go further, however, in considering alternatives to an LNG hub that would lead to a trading market and reliable and transparent pricing.

EXISTING GAS HUBS

What Does a Hub Do, and How Does It work?

The concept of a hub is widely used in the airline industry, with many airlines operating a hub and spoke operation. In the gas industry, hubs first developed in the US market, operating as physical locations, usually where multiple pipelines intersect, often close to storage facilities, and looked very much like the airline model. Henry Hub was one of the first hubs and is the most famous. This section will consider Henry Hub and how it works and then look at the UK's National Balancing Point (NBP) and the Netherlands' Title Transfer Facility (TTF), which are the primary European gas hubs.

Henry Hub

Henry Hub is owned and operated by Sabine Pipe Line LLC and its affiliates. It is actually one end of the Sabine Pipeline, which is a bidirectional mainline pipeline that stretches from Port Arthur, Texas, to the Henry Hub. It is an interstate pipeline that is certified as an open-access gas transporter, and it is directly connected to four industrial consumers and one producer. Henry Hub is interconnected to eight interstate pipelines and three intrastate pipelines. Henry Hub also has a direct connection to storage facilities. These facilities are salt-dome caverns characterized by high deliverability and high cycling rate, which allow for several withdrawal and injection cycles each year.

Henry Hub is shown, in a simplified schematic in figure 1, with the pipeline interconnections.

Figure 1: Henry Hub schematic

Source: RBN Energy LLC, CGEP

In reality, however, the pipelines are located significant distances apart and connect across the spaghetti bowl of pipelines that crisscross Vermillion Parish in South Louisiana.

In addition, the Henry Hub is not all at Henry, Louisiana. In fact, the Henry gas processing plant shut down more than 10 years ago, and the hub interconnects to Sabine are scattered across the area around Henry. Thus, the name Henry Hub is more a remnant of its origins and a concept, not a place where a lot of pipelines all connect at a single point. Despite the slight misnomer, the concept does still apply. The Sabine system really does provide interconnects to 11 pipelines designated the Henry interconnects: Columbia Gulf (CGT), Gulf South, Bridgeline Intrastate, NGPL, Sea Robin, Southern Natural (SONAT), Texas Gas, Williams/Transco, Trunkline, Arcadian, Jefferson Island Storage, and of course Sabine. And Sabine continues westward, where it connects to another 13 facilities in Louisiana and nine more in Texas.[5] In addition, as the Sabine Pipeline is bidirectional, effectively gas delivered into Sabine from a connecting pipeline can be redelivered to any other interconnecting pipeline.

The transfer of gas from one pipeline to another via the Sabine Pipeline / Henry Hub is facilitated by Sabine Hub Services through its IHT (Intra-Hub Transfers) service.[6] IHT is a nonjurisdictional accounting service used to track multiple title transfers of natural gas packages at a market center.

Any party wanting to trade gas through Henry Hub needs to apply to Sabine Hub Services for an IHT number, which becomes that party's unique identifier. After a party trades (buy/sell) natural gas at the Hub, its scheduler will submit a nomination to Sabine Hub Services via e-mail or by using the "Online Nominations" screen on the Sabine Hub Services website. This nomination will detail all of the IHT purchases (upstream) transactions as well as the IHT sales (downstream) transactions. Each line item on the nomination will have an IHT counterparty number and a volume in dekatherms per day. The total of the upstream transactions will equal the total of the downstream transactions. All counterparties must balance their IHT (upstream equals downstream) each day.

Any physical gas entering the hub to a party's IHT account must enter the hub via a pipeline transportation agreement. On the IHT nomination, the upstream transaction capturing this transportation of physical gas will detail the pipeline transportation agreement number as well as the volume. Any physical gas exiting your IHT account is "IHT'd" to the downstream pipeline. On the IHT nomination, the downstream transaction capturing this transportation of physical gas will detail the name of the downstream pipeline point, the pipeline transportation agreement number that will pick up the gas, and the volume.

UK NBP

Unlike Henry Hub, which is a physical point on the Sabine Pipeline system and enables interconnections with multiple pipelines, the NBP or National Balancing Point is what is known as a "virtual" point. Figure 2 is a map of the UK's gas transmission system, owned and operated by National Grid. The red lines show the gas transmission system and the black triangles the terminals, where pipe gas enters the system; the red squares are the LNG terminals, both pipe and LNG, where gas enters the system.

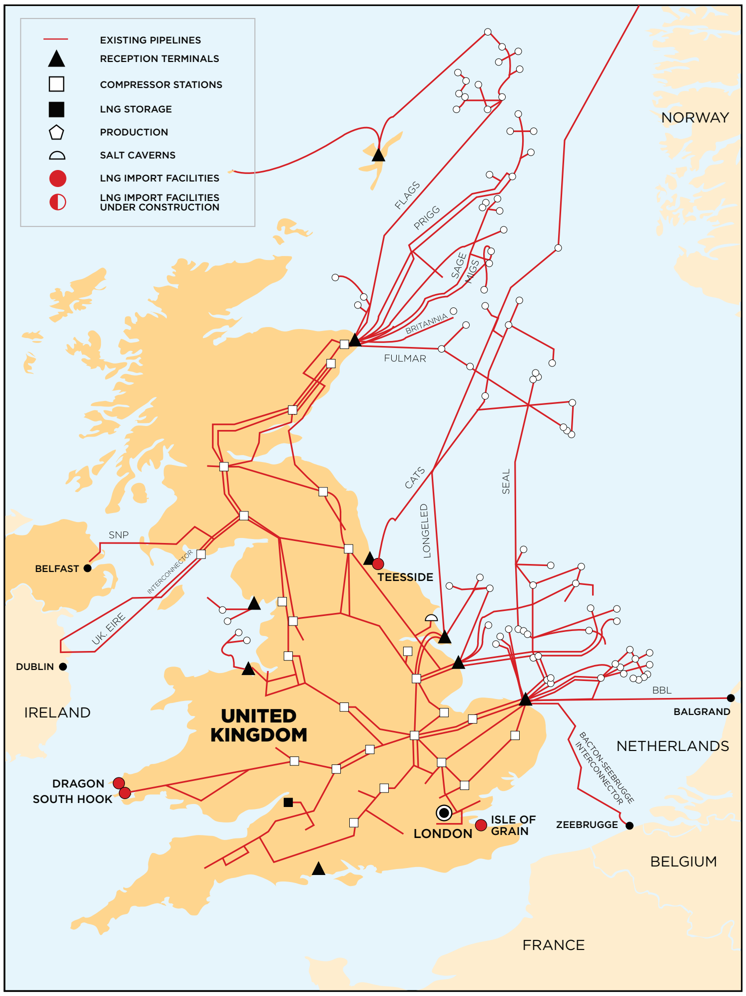
National Grid in the UK operates an entry-exit system for booking and paying for transmission capacity and for the nomination and scheduling of gas flows. The system entry points are largely the terminals shown on the map, while the exit points are offtakes from the national transmission system to local distribution zones or to major off-takers, such as power plants. The NBP is effectively the whole of the national transmission system since when gas enters the system, it is effectively at the NBP until it exits the transmission system.

While Henry Hub and the Sabine Pipeline allow for the transfer of gas between many different interconnecting pipelines, in the UK there is only one transmission pipeline system. Apart from that, there is great similarity between the way the Sabine Hub Services IHT works and the way the UK system works through the nominations process.

The UK gas system is governed by the Uniform Network Code[7]—essentially a gas transportation agreement. The NBP was established in the original network code as the balancing point—hence the name—at which all shippers on the system had to balance their gas flows, with gas entering the system being balanced with gas exiting the system. The NBP was never intended as a "trading" point or hub at which gas could be traded, but the way the network code was drafted allowed trading to develop. Shippers on the system are required to make input nominations for gas entering the system at entry points and output nominations for gas exiting the system at exit points. The code allows that the sum of input nominations on any one day need not be equal to the sum of output nominations on that day.[8] In addition to input and output nominations, shippers can also make trade nominations under the code. The trade nominations can either be a "disposing trade nomination"—a sale—or an "acquiring trade nomination"—a purchase. Under the code, the sum of disposing trade nominations on any one day must equal the sum of acquiring trade nominations on that day.

It was this provision in the code allowing trade nominations that promoted the use of NBP as the trading hub in the UK and, for a long time, the primary trading hub in Europe. All any party had to do to trade gas was to apply to become a shipper to the pipeline and to the regulator Ofgem (Office for Gas and Electricity Markets), which was not a particularly difficult process. Once a Shipper license was granted, the party could then easily trade gas at the NBP using the trade nominations process. The shipper didn't even have to bring gas into the system through the entry points or take gas off the system at the exit points to trade gas since he or she could just use the trade nomination process, which many early participants did. In many respects, the virtual hub structure in the UK allows for the trading of physical gas in a simpler manner than in the United States at, say, Henry Hub, where the hub is set up to actually move physical gas from one interconnecting pipeline to another. This requires participants to enter into multiple transportation agreements and physically actually move the gas on these pipelines and so be involved in the gas industry. Under the UK system, a party can trade physical gas with no supply and no customers but just with other counterparties.

Figure 2: Map of UK gas transmission system

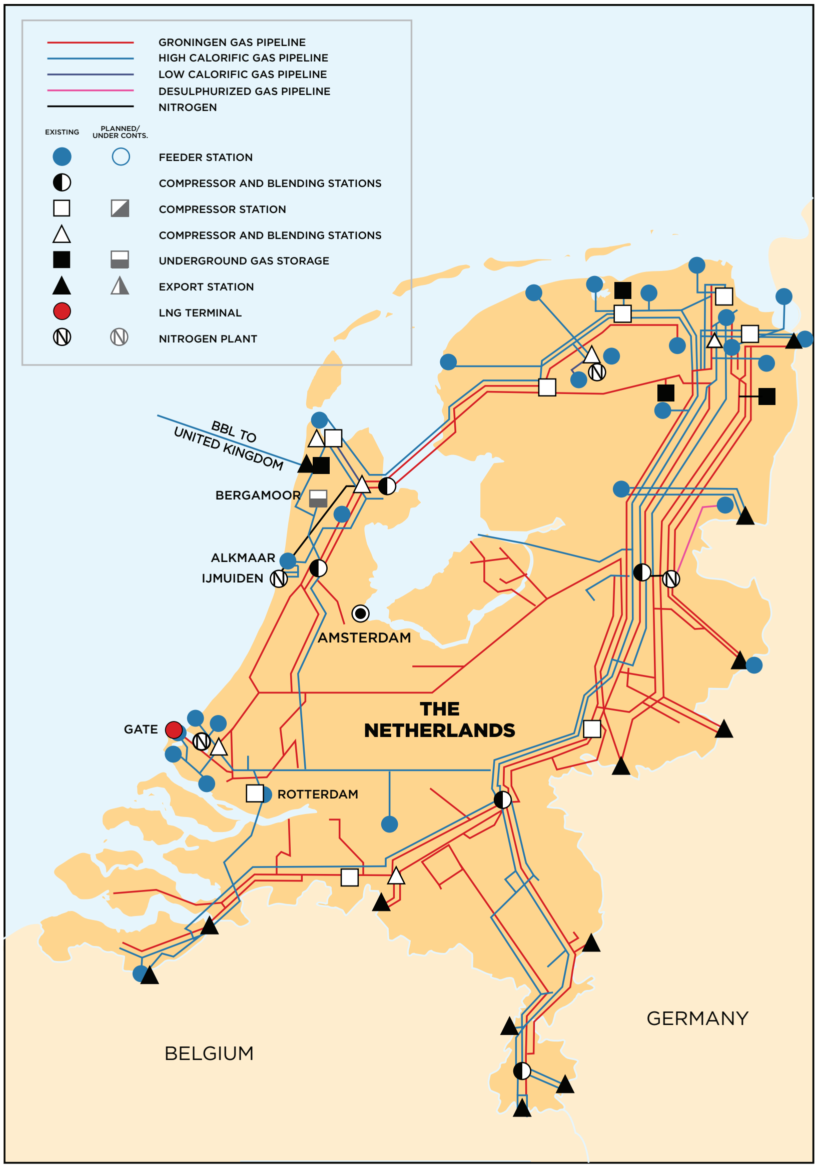


Source: International Energy Agency and Department of Business, Energy, and Industrial Strategy

Netherlands TTF

In many respects, the Netherlands TTF is much the same as the UK NBP in that it is a virtual balancing point on the Gasunie Transport Services system, shown in figure 3 below. It is important to distinguish between Gasunie Transport Services (GTS), which is the transmission system operator, and Gasunie. The former balances the grid and manages TTF, whereas the latter also has interests in the GATE LNG terminal in Rotterdam, storage capacity in Zuidwending, the BBL pipeline to the United Kingdom, a part of the German transmission grid, and Nord Stream 1. There is a Chinese wall between GTS and Gasunie.

Figure 3: Netherlands transmission system



Source: International Energy Agency

The system is very similar to the UK system, with entry points at the borders and exit points to the Dutch distribution system and power plants, but the Gasunie system also has multiple exit points at borders to other countries.

Gasunie set up TTF in 2003, and it was modeled on the NBP, but it was set up as a hub immediately, and it was no "accident" like NBP. TTF is a virtual market place, where gas is being traded that has already been introduced into the transport system, which makes it easily tradeable. The gas is registered by means of a "nomination" from certified shippers. Nominations are electronic notifications stating the volume of gas transferred, the period, the quality of the gas, and the buying and selling parties. Even though this trade in gas is a mutual process between Gasunie customers, they need to notify Gasunie of these transactions. This way, Gasunie always knows who owns the gas and can balance the system. TTF, however, only deals with gas that is already in the system, or "entry-paid" gas, and as such mirrors the trade nomination process in the UK Uniform Network Code.

The creation of TTF was part of an effort to liberalize natural gas markets that was dictated by the European Commission in Brussels. It is worth noting that the European Commission published various legislative proposals that indicated that physical and legal unbundling of public and commercial activities was the best means to create competitive markets. The minister of economic affairs at the time (Brinkhorst) was a fervent supporter of this doctrine, and consequently the Netherlands went further in implementing this then most member states (with notably the United Kingdom leading the way). In essence, the Dutch state purchased the transportation assets, deemed key to preserve public interests, from its owners (collectively organized in the so-called Gasgebouw) and created a new legal entity to operate them. Somewhat confusingly, the name "Gasunie" migrated with this new entity, and the remaining commercial activities had to be carried out by a company that required a new name (GasTerra), which remained part of the Gasgebouw.

Initially, support for TTF was, understandably, not overwhelming. At that time, Zeebrugge was the emerging trading hub in Continental Europe, but it was physical and quite closely linked to NBP. By requiring trade to go through the new exchange rather than on the border, incumbents lost a significant revenue stream and initially fought it. The independent regulatory authority Nederlandse Mededingsautoriteit demanded that GTS use an entry-exit model as in operation in the United Kingdom. There were concerns at the time—for instance, that the Dutch network had been designed to market the specific low calorific Groningen gas rather than facilitate competition—but in the end, and with expansion of the domestic network and nitrogen capacity,[9] the market accepted the new direction. It is worth noting that there were tensions between existing players, legal requirements in the form of European directives, and the interpretation thereof by the independent regulatory authority (which in this case arguably was strictly legal, even though the Dutch state lost a revenue stream over this).

Once TTF was created in 2003, it took time to get used to this new model. The newly named GasTerra was assumed to offer commodity on the newly created exchange, but on the other hand, there was concern that, given its dominance on the local market, the regulatory authority would intervene. Major shareholders in GasTerra likely also had strong views on the path forward. One could argue that without liquidity, and limited price transparency, it was difficult for market actors to purchase additional natural gas or sell excess commodity. In other words, the relevant legislation might have been in place, but the market needed maturing. A specific initial complication in the case of the Netherlands was that trade initially was essentially split up in low calorific and high calorific natural gas, with quality conversion as an added service. In the end, a compromise agreement was reached (or forced by the regulatory authority), and GasTerra started trading various products on TTF, notably by 2005. In January 2009, the costs of quality conversion were socialized, and from then onward, trade on TTF could take place in MWh. In 2011, GasTerra started offering within day and day ahead products on TTF to further incentivize wholesale trade.

Hubs Comparison

Even though Henry Hub is a physical hub and NBP and TTF "virtual" hubs, they essentially serve the same purpose in that they are all "meeting points" or market centers at which parties can buy and sell gas with the title transferring between them under agreements put in place by the hub or pipeline operators using the nominations processes. While NBP and TTF are described as virtual hubs, they are in essence little different to Henry Hub.[10] NBP and TTF are virtual in the sense that there is no exact physical location on a map where they can be identified. However, they are both products of the physical gas transmission systems in the UK and the Netherlands, respectively, just as Henry Hub is the product of the physical Sabine Pipeline. NBP and TTF physically represent the entirety of the UK and Netherlands gas transmission systems in that as soon as gas enters each of those systems, it is "at" NBP or TTF until the gas exits those systems.

In some respects, the trade nominations process with NBP and TTF makes trading somewhat easier than at Henry Hub, promoting multiple trades of the same molecules of gas. However, this can also be achieved at Henry Hub if the parties nominating under the IHT can net off-flows. For example, if a party is delivering 100 units of gas to interconnection pipeline A but also receiving 60 units of gas from interconnection pipeline A, then the party only needs to deliver 40 units of gas on a net basis to balance its flows under the IHT.

All three hubs were also in countries with significant domestic production and gas storage facilities.

Hub Development and Market Liberalization

Creating a Wholesale Natural Gas Market

The IEA paper concluded that there were a number of institutional and structural requirements needed to create a competitive wholesale natural gas market.[11] The institutional requirements were as follows:

- **A hands-off government approach to natural gas markets.** This implies a shift from direct policy making and market involvement to market monitoring through an independent antitrust agency.
- **Separation of transport and commercial activities.** Vertically integrated supply systems need to be broken up, either through full ownership unbundling or through financial separation, as long as commercial and transport activities are run as separate entities.
- **Wholesale price deregulation.** Letting the market set the wholesale price level for natural gas, breaking the former bundled, regulated, natural gas price into a transmission price and a wholesale price that includes commodity, services, and a profit margin.

The structural requirements were as follows:

- **Sufficient network capacity and nondiscriminatory access to networks.** Nondiscriminatory access will increase the number of market participants, while sufficient network capacity will ensure that there are no bottlenecks and fragmented markets that behave according to their own supply/demand dynamics. An independent transmission system operator (TSO), either divested or functionally separated, is preferable, together with a well-developed network code (set of rules).
- **Competitive number of market participants.** A genuinely competitive gas market requires a number of gas suppliers and traders with competitive market shares along with multiple producers and buyers of gas.
- **Involvement of financial institutions.** A competitive natural gas market will also need financial parties that are willing to cover financial/operational risks for parties involved in the natural gas trade and also participate as traders.

In addition to the six requirements put forward by the IEA, we would add a seventh one, which is market size, which we would say is necessary to have a competitive number of market participants, so it would also be a structural requirement.

The IEA was concerned, largely, with assessing the requirements for creating a wholesale natural gas market. In the process of market liberalization, many countries have also gone as far as opening up the retail markets to competition, especially in Europe. However, this does not appear to be a requirement to develop a competitive wholesale market since in the United States, many states have not developed a competitive retail market, whereas there is clearly a very competitive wholesale market and liquid trading hubs. A caveat to this may be for relatively smaller markets, where retail competition may help to promote wholesale competition by breaking up the national and local distribution monopolies.

The IEA noted that the structural requirements were essential to kick-start a natural gas market and should be guaranteed by an independent regulator. However, the IEA also noted that a transparent natural gas price that reflects the current and future state of the market will not be realized unless a platform for the ownership exchange of natural gas is developed. This is where hubs such as Henry Hub, NBP, and TTF come in. As described above, they provide a platform for changing the ownership of natural gas in an efficient manner.

In terms of the three hubs described earlier, all can be said to meet the six IEA requirements plus the additional seventh one of market size. It is not the intention here to describe the history of the liberalization process in each country, which has been well documented in many publications. The US market was largely fully liberalized by 1992 with the issuance of order 636 by the Federal Energy Regulatory Commission (FERC); the UK market, at the wholesale level, was largely liberalized by 1996 with the issuance of the Network Code; and in the Netherlands the establishment of TTF in 2003 reflected the beginning of wholesale market liberalization, although it was not fully complete for a number of years.[12]

From Wholesale Market to a Hub

The requirements to develop a wholesale natural gas market, outlined above, include regulated third-party access to the pipeline infrastructure and the unbundling of gas supply from the transportation of gas. As described above, the contractual arrangements at Henry Hub, NBP, and TTF naturally and easily promoted the development of the hub and allowed the shippers (in effect the gas suppliers) to exchange ownership or title to their gas.

Heather described the process leading to mature and successful hubs as being a "path to maturity,"[13] which is summarized here, in the order of development:

1. Third party access to pipelines and regas terminals
2. Bi-lateral trades
3. Price discovery and disclosure
4. Balancing rules and standardized trading contracts
5. OTC brokered trading
6. Non-physical players enter
7. Futures exchange
8. Liquid forward curve develops
9. Indices derived for long-term contracts

Heather noted that the process usually starts with a move to third-party access (TPA) to the network infrastructure, with a requirement for the adoption of rules and regulations governing the physical side of the business, while the emergence of standardized contracts will favor the commercial aspects. This will then be followed by bilateral trading, helping to create trading opportunities between counterparties. These trades start to be reported by the price reporting agencies (PRAs) in their regular publications, thus creating the beginnings of a transparent market. With price disclosure comes price discovery, which in turn attracts more players to the market. The creation of exchange products (futures), based on the underlying physical contracts, offers greater access to the market, especially by nonphysical players (who will always close out their trading positions before maturity).

Gradually, as increasing numbers of varied participants come to trade in a particular market, a forward curve will develop, and this will be used for risk management purposes. The final stage of maturity is when the hub develops sufficient liquidity for traders to use specific traded products (such as the day-ahead or the month-ahead) as indexes on which to price their physical transactions.

The development of futures markets will be covered below, but the physical market at the hub consists not only of what might be termed as spot gas but also of the forward physical market. Spot gas is usually assumed to cover the current day or tomorrow—within-day (WD) or day-ahead (DA). The balance of the period to the end of the week or month is often called the prompt, with the near curve being around a year and anything beyond that the mid (up to two years) and the far (up to five years or sometimes beyond).

At the physical trading level, trading started out as over the counter (OTC) trading, often through brokers. Exchanges then developed for physical trades, although there are also futures exchanges as described below. For OTC trading, these are bilateral contracts so the counterparty and credit risk remain with the parties to the OTC trade. In contrast, exchanges are "regulated markets where traders are secure in the knowledge that they are governed by the relevant financial regulator in each country and that the clearing house also financially guarantees all of the trades executed."[14] The counterparty and credit risk, therefore, is taken by the exchange.

The same exchange can often cover both physical and futures trading. For physical trades, at the time of delivery, the nomination and scheduling of that trade has to be made to the relevant pipeline. Typically, the exchange, as part of its service offering, will handle the nomination and scheduling details on behalf of the relevant parties.

The development of both OTC and exchange trading was significantly enhanced by the use of standardized contracts. The industry, both in North America and Europe, took the lead in developing these standard contracts. In the United States, in September 1994, the Gas Industry Standards Board (GISB) was established as an independent and voluntary North American organization. Its purpose was to develop and promote the use of business practices and related electronic communications standards designed to promote a more competitive, efficient, and reliable gas service. In 1996, the GISB Base Contract for Short-Term Sale and Purchase of Natural Gas was introduced.[15]

In the UK, market participants produced a standard NBP contract called NBP97. As noted by Heather,[16] the key features of the NBP97 contract were that deliveries are for "flat"[17] gas, that participants are "kept whole,"[18] that in practice there is no force majeure (FM),[19] and that there are standardized billing and payment terms. Some but not always all of these features are also included in some of the European hubs. The only FM permissible would be an event beyond the control of the affected party resulting in the inability to get a trade nomination into or accepted by Gemini, the pipeline operators' nominations system. These features were key to the success of the NBP as a traded gas hub. The European Federation of Energy Traders (EFET) has prepared a similar standardized contract[20] for other European hubs and markets.

Development of Futures Markets

Once a hub has been established and physical trading is taking place, then the possibility of developing a futures market arises. Futures markets are essentially paper markets, with importantly *no expectation that there will be any physical delivery of the volume of gas*, although any trade can go to physical delivery depending on how the futures market works.

The first natural gas futures market was introduced by NYMEX in April 1990, with Henry Hub being the underlying physical location for the market. A participant in the NYMEX gas futures market will automatically go to physical delivery unless the open position is closed before expiration. The delivery process resulting from the futures contract represents the linkage between the physical market and the financial market. The Henry Hub contract is traded in monthly periods for the current year and the following 12 years. The volume for a single monthly contract is 10,000 MMBTU. The ICE (Intercontinental Exchange) also has a Henry Hub futures contract similar to NYMEX, which trades for monthly periods but with a single contract of 2,500 MMBTU, mostly for monthly trades but sometimes for daily. The trading time horizon is for 13 years, similar to NYMEX. However, the ICE contract is cash settled[21] and doesn't go to physical delivery, with any open contracts being automatically cashed out at the NYMEX settlement price.

The UK NBP futures contract was started by the International Petroleum Exchange (now owned by the ICE) in February 1997. The NBP futures not only has monthly contracts—running for 78 to 83 months—but also 11 to 13 quarters, 13 to 14 seasons (winter/summer), and 6 years. The trading unit is 1,000 therms per day—a lot—and the minimum trading amount is five lots or 5,000 therms per day. For a 30-day month, the total minimum volume would be 150,000 therms, which is equivalent to 15,000 MMBTU—larger than the NYMEX monthly minimum trade. The NBP futures contract is deliverable if the contract is not closed out before reaching the settlement day.[22] In practice, however, virtually all contracts are closed (and cashed) out before the settlement day is reached.

Assess Hub Liquidity and Churn

As the physical and futures markets develop, liquidity in the market can be expected to increase. Heather identified five requirements for successful trading: liquidity, volatility, anonymity, transparency, and traded volumes.[23]

- Liquidity is a measure of how easy it is to trade volume at a given price without "moving" the market. Standardization of traded contract terms and conditions helps liquidity.
- Volatility is a measure of price movement in relation to market activity.
- Anonymity is key to futures trading. The Clearinghouse is the counterparty to all trades, and this allows any size participants to trade alongside each other.
- Market transparency is very important in the development of a successful traded market. It means that traded volumes and prices are quickly disseminated in the public arena.
- Traded volumes simply relate to the total actual volume traded in any given market; this could be the OTC volume or the exchange volume.

Heather also identified five key elements that can be used to assess the depth, liquidity, and transparency of traded gas hubs:[24]

- Who trades in each of the hubs
- What products are traded there
- How much volume is traded, and over which periods

- The Tradability Index
- The churn rates

They are all important, but Heather stated that the churn is possibly the preeminent factor in assessing market liquidity, which is fundamental to a traded hub. We will focus, therefore, on the churn rate, as that simply encapsulates depth, and liquidity especially. For a detailed review of the other factors, please refer to Heather. The churn rate is the multiple of traded volume to actual physical throughput: a measure of the number of times a "parcel" of gas is traded and retraded between its initial sale by the producer and the final purchase by the consumer. In this one metric, all others are, necessarily, reflected: if there are many participants trading many different products in large quantities, then the churn rate is likely to be high. The churn rate is used by traders as a "snapshot" of a market's liquidity; some traders will not participate in markets with a churn of less than 10, and many financial players will only participate when the churn is above 12 times. The churn is probably the most important single factor in determining the success of a traded market.

The churn rates are a recognized as the most appropriate measure of a hub's real liquidity and success and are a parameter used in most commodity and also financial markets. Churn rates have been published in many reports and presentations, but it is not always clear exactly how they are calculated, and different numbers are widely quoted for the same markets for the same time periods. The numerator is traded volumes, but are these just physical trades, or do they include futures and options? The denominator is often the level of consumption in a country, but this may not cover all the throughput at the hub—this is especially relevant for the Netherlands.

We will look at churn rates for the United States, the UK, and the Netherlands for both physical and futures trades and all trades in total. The denominator will attempt to cover the total throughput of the relevant system by taking the average of consumption plus exports and production plus imports as published by the IEA.[25] The period covered in each case will be 2011 to 2016.

United States

The data for the United States on traded volumes has been taken from the annual report published by Cornerstone Research.[26] Cornerstone used data from FERC's form 552 to calculate the volume of physical trades. FERC form 552 collects transactional information from natural gas market participants. Physical natural gas buyers and sellers must complete and file the form annually if their "reportable" natural gas purchases or sales are equal to or greater than 2.2 trillion British thermal units (TBtu) or 2.2 million (2,200,000) MMBtu in the reporting year. Smaller players are therefore excluded. Submissions have to separate the volume of fixed price transactions in the year separately from indexed transactions linked to both daily and monthly price indexes. In 2016 the total of reported physical transactions was some 130,000 TBtu. This double counts the actual volume of trades since both parties to the trade report the transaction. The actual volume of trades, therefore, is calculated by dividing the reported transactions by two.

The information on the futures trades is collected from the two main futures exchanges:

CME Group (CME)—who runs NYMEX—and Intercontinental Exchange (ICE). Cornerstone aggregated the number of contracts for each exchange, which was 140 million for CME and 230 million for ICE. However, the CME contract is for 10,000 MMBtu, and the ICE contract is for 2,500 MMBtu. The number of contracts in each case is multiplied by these respective volumes to get the total volumes traded on the futures markets.

The table below shows the calculation of the churn rates using these volumes and IEA data for the denominator volumes as described above.

Table 1: US traded volumes and churn

	BSCM									RATIO		
	Futures	Physical	Consumption	Exports	Production	Pipe Imports	LNG Imports	C+X	P+I	Future Churn	Physical Churn	Total Churn
2016	53,968.04	1,776.16	778.64	63.02	749.24	82.46	2.50	841.65	834.20	64.41	2.12	66.53
2015	50,210.78	1,680.52	767.07	48.90	766.52	74.37	2.38	815.97	843.27	60.52	2.03	62.55
2014	49,186.07	1,625.87	750.47	41.91	733.43	74.64	1.52	792.38	809.59	61.41	2.03	63.44
2013	56,017.46	1,639.54	739.35	45.17	685.68	78.91	2.74	784.52	767.33	72.19	2.11	74.31
2012	65,581.42	1,666.86	728.31	48.19	680.80	83.91	4.88	776.50	769.58	84.84	2.16	86.99
2011	60,116.30	1,748.84	692.97	41.98	648.76	88.34	8.71	745.81	745.81	81.20	2.36	83.56

Source: Cornerstone Research, IEA

It is noticeable that the futures churn far exceeds the physical churn, which as we shall see is quite low for a traded market. This may be largely explained by the fact that it is relatively easy to trade on the futures market, whereas with the multiple pipeline structure in the United States, there is a need to be a significant entity in the physical market. The physical churn has been relatively stable over time, while the futures churn has apparently declined. This in part reflects some definitional changes in ICE futures data from 2013 on.[27] The number of CME contracts over time has not varied that much and has been rising since 2014.

UK

Data for the UK traded volumes has been taken from Ofgem.[28] This is slightly different data to that used by Heather but does not materially affect the results. The traded volumes consist of OTC for the physical trades plus a small amount of trades on the ICE Endex, while the futures trades are taken from ICE. The OTC data is taken from the London Energy Brokers Association (LEBA), the same source used by Heather.

The table below shows the calculation of the churn rates using these volumes and IEA data for the denominator volumes as described above.

Table 2: UK traded volumes and churn

	BSCM									RATIO		
	Futures	Physical	Consumption	Exports	Production	Pipe Imports	LNG Imports	C+X	P+I	Future Churn	Physical Churn	Total Churn
2016	924.99	901.02	81.60	10.66	41.55	37.48	10.89	92.26	89.92	10.15	9.89	20.05
2015	976.20	932.25	72.03	13.44	41.34	30.85	13.65	85.47	85.85	11.40	10.88	22.28
2014	878.03	1,002.52	70.48	9.64	38.78	31.44	11.31	80.12	81.54	10.86	12.65	23.51
2013	499.35	1,002.76	77.21	9.60	38.53	39.71	9.41	86.81	87.66	5.72	11.50	17.22
2012	589.72	1,169.86	78.19	11.37	41.12	36.59	13.87	89.56	91.59	6.51	12.92	19.43
2011	494.22	1,229.32	82.72	14.30	47.67	28.61	25.06	97.03	101.33	4.98	12.39	17.38

Source: Ofgem, IEA

The physical churn had been relatively stable until 2014, with the traded volumes declining broadly in line with throughput. The futures churn has been rising, however, taking some of the trading away from the OTC market. In 2016 the churn rates declined. In fact, looking at the monthly data from Ofgem, the decline in the churn rate began in July 2016, shortly after the vote in the UK to leave the European Union—possibly an early sign of Brexit leading to trading moving to continental Europe!

The balance between futures and physical churn is much more balanced in the UK than in the United States, with a much higher physical churn. This may reflect the ease of the trade nominations process in the Uniform Network Code with just a single transmission network.

Netherlands

Data for the Netherlands for traded volumes was taken from Heather (2015),[29] with additional data from an updated note in March 2017.[30] Heather's source of data for traded volumes was LEBA for OTC data and ICE and EEX—part of the Powernext group—for physical exchange and futures exchange data.

The table below shows the calculation of the churn rates using these volumes and IEA data for the denominator volumes as described above.

Table 3: Netherlands traded volumes and churn

	BSCM									RATIO		
	Futures	Physical	Consumption	Exports	Production	Pipe Imports	LNG Imports	C+X	P+I	Future Churn	Physical Churn	Total Churn
2016	679.87	1,720.57	42.12	48.11	50.37	40.65	1.52	90.23	92.54	7.44	18.83	26.27
2015	462.45	1,381.66	39.89	58.19	54.42	35.43	2.35	98.08	92.20	4.86	14.52	19.38
2014	207.40	1,256.32	40.26	58.51	69.97	27.87	1.12	98.77	98.96	2.10	12.71	14.81
2013	61.92	834.34	46.07	60.32	86.19	26.00	0.94	106.39	113.13	0.56	7.60	8.17
2012	67.39	758.56	45.56	51.38	80.14	25.07	1.01	96.94	106.23	0.66	7.47	8.13
2011	53.99	625.74	47.96	49.91	80.57	23.01	-	97.87	103.58	0.54	6.21	6.75

Source: Ofgem, IEA

The Netherlands has shown a continued growth in the churn rates since 2013 both for physical and futures, with the combined churn rate rising above the UK's for the first time in 2016. The Netherlands market is significantly different from the US and UK markets as it both imports and exports a lot of gas by pipeline. Other churn rates quoted for the Netherlands may often be much higher than these here since only consumption will be used as the denominator, and consumption is now less than half the system throughput. As for the UK, the ease with which the TTF trade nominations process works facilitates OTC physical trading.

What Churn Rate Signifies a Liquid Hub

Henry Hub, NBP, and TTF all have high churn rates, well above the level deemed necessary for a liquid trading market. For the US market, the vast bulk of the trading is focused around the futures markets, with a relatively low physical churn. In contrast, in the Netherlands, most of the churn is physical OTC, while the UK is more evenly split between physical OTC and futures. The bias towards physical trades and churn in the UK and the Netherlands would seem to reflect the market structure with a single transmission system and within the network codes, the ability to undertake trade nominations, relieving the shipper of any requirement to actually physically receive or deliver gas. In that respect, the OTC markets in the UK and the Netherlands are similar to a futures market, minus the need to take part in the clearing process and be subject to margin calls.

Heather also calculated churn rates for other European hubs, but none of them have churn rates much above five.[31] There is no right answer as to what level of churn rate signifies that the market and/or hub is liquid and that the pricing at the hub can be relied on. Heather states that "commodity markets are deemed to have reached maturity when the churn is in excess of 10 times."[32] Even if this level is understated, it is clear that Henry Hub, NBP, and TTF can be deemed as liquid hubs, while no other hub in Europe can. As a consequence, the prices at these hubs are most often used as reference prices in long-term contracts.

Price Reporting—How It Works

Price reporting by the industry to price reporting agencies (PRAs) began as market liberalization started and even before hubs were properly established and well before futures markets linked to the physical hubs were set up. Industry participants voluntarily submit trade data to the PRAs so market prices and price indexes can be calculated.[33]

As the traded volumes increased, then the confidence in the accuracy and transparency of the reported prices increased. With the advent of the futures exchange, where transaction prices are reported on a real-time basis, price discovery and transparency further increased. A similar process occurred in the UK with the development of the Heren Index.[34]

Similar to the US market, as the physical market developed and price reporting established a reliable pricing benchmark, the IPE futures exchange began shortly after in 1997, adding to the price transparency. By the time TTF trading began, there were well-established PRAs and publications.

The key point of the establishment of price reporting in the United States, the UK, and eventually in Europe is that all the price reporting was actual trades, thereby increasing confidence in the accuracy and transparency of the reported prices.[35] The accuracy of the reported prices enhanced market confidence and encouraged trading, creating a virtuous circle of more reporting and more trading and so on.

LNG HUBS IN ASIA—CHINA, JAPAN, SINGAPORE

Market Liberalization Progress in China, Japan, and Singapore

Market liberalization is a fundamental prerequisite to the development of trading hubs, as was discussed in the previous section. Much of the discussion concerning hubs in Asia has focused around China, Japan, and Singapore. The progress of gas market liberalization in these countries is considered in turn.

China

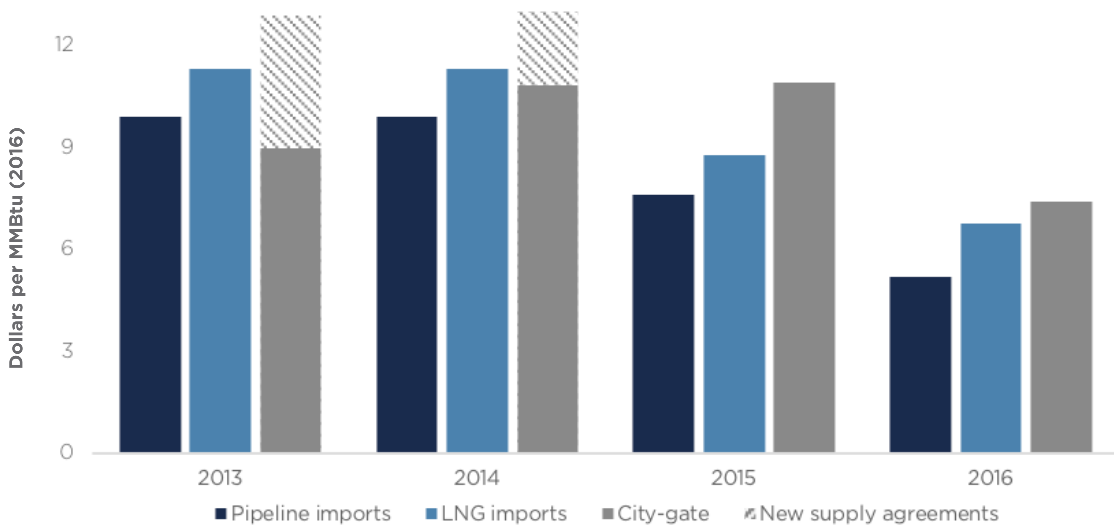
According to the IEA's World Energy Outlook 2017 special report on China,[36] the Chinese natural gas market remains heavily regulated along the entire supply chain. The upstream and midstream is very concentrated, and the three NOCs (CNPC, Sinopec, and CNOOC) dominate the production and transmission of gas. With hundreds of different companies distributing gas to consumers, the distribution sector appears more diverse; in reality, the distribution companies have local monopolies and hardly compete with each other for customers. This structure has allowed the gas market in China to grow very quickly over the last decade, but it is widely seen as inadequate for the next stage in its development.

The sources of gas supply to the Chinese market are, however, becoming increasingly diversified since in addition to domestic production, there are increasing quantities of pipeline imports from Central Asia, Myanmar, and, in the future, Russia, together with a rapid growth of LNG imports from a widening diversity of suppliers.

China's government is pursuing the goal of fully liberalizing producer and consumer prices while regulating network tariffs. A uniform city-gate price[37]—generally speaking, a wholesale price—was introduced in 2015, although pilot programs were started in Guangdong and Guanxi in 2011. Prior to this, there were two city-gate prices in place: one for "stock gas" and one for "incremental gas" (i.e., the price mechanism discriminated between existing and new supply agreements). The latest pricing reform, passed in late 2016, has introduced important elements of market-based price formation and tighter regulation of pipeline tariffs, but there is still a long way to go before the system is fully liberalized.

At present, around half of the gas consumed in China is marketed without any price regulation. Prices paid by residential gas consumers, accounting for a little less than a fifth of China's gas use, remain fully regulated by the National Development and Reform Commission (NDRC) at preferential rates. Prices for nonresidential gas consumers that are not large enough to directly buy gas and that rely on conventional output or imported pipeline gas are partially regulated; this consumer group accounts for some 30 percent of China's gas consumption. Partial regulation means that the NDRC sets a benchmark city-gate price but allows buyers and sellers to negotiate prices that are lower either than the benchmark or up to 20 percent higher. City-gate benchmark prices include the pipeline tariffs and are thus typically higher than the import prices for LNG or pipeline gas (see figure 4).

Figure 4: Average natural gas import prices and average city-gate benchmark price in China



Soure: IEA WEO 2017, Figure 14.15

It should be noted that the prices for pipeline imports in this figure understate the delivered gas price to the east coast of China since they reflect the border prices for gas from Turkmenistan (predominantly) and Myanmar, and once transportation costs to the east coast are added, pipeline import prices will be more than $3 per MMBTU higher. This would largely make them the most expensive source of gas on the east coast.

The EIA report describes the steps being taken to establish a trading hub in Shanghai, which is a significant gas market, receiving both pipeline gas and LNG.[38] The government of China has taken steps to set up institutions to promote more market-driven oil and gas trading. The Shanghai Petroleum Exchange (SPEX) began offering spot LNG contracting in 2010. In 2013, the Shanghai Free Trade Zone and Shanghai International Energy Trading Center were established to facilitate the international trading of oil and gas. In July 2015, the Shanghai Petroleum and Natural Gas Exchange (SHPGX) was launched to provide a market-based trading platform for oil and gas. The SHPGX reports daily trades in pipeline natural gas and LNG. For the first six months of 2016, there were 458 LNG trades, averaging 20,000 MMBtu per trade from the Ningbo LNG import terminal near Shanghai.

In late 2017, it was also reported that China planned to launch a natural gas exchange in Chongqing.[39] The Chongqing Oil and Gas Exchange—supported by state energy majors and private and local government-backed gas distributors—would provide a trading platform for domestic output, pipeline imports from Central Asia and Myanmar, and imports of liquefied natural gas (LNG). Chongqing is close to Sichuan Province's large gas basin, and there is already a relatively well-developed gas grid, with gas distributors keen to participate.

The IEA also discusses the direction of reform in China and notes that gas market reform is not a stand-alone policy item: it forms one part of a wider set of linked energy market reform in China, including electricity and coal markets. The IEA also notes that price reform is an essential component of a functioning gas market, but its success is contingent on effective implementation of upstream and midstream reform, which removes the dominance of the big three NOCs.

Japan

Unlike China, Japan is almost totally dependent on LNG imports for its gas supply, with only a very small amount of domestic gas production. There are over 30 operating LNG import terminals on the Japanese islands, but the pipeline infrastructure largely connects the terminals to the local markets. There is very little interconnectivity among regions and hence no real integrated national market. There are however, many electric utilities and large industrial customers that buy gas as well as many gas utilities.

Japan began the deregulation of the electricity and gas markets in the mid-1990s as the electricity market allowed independent power generators to enter the market and sell to utilities, while in the gas market, sales to customers consuming more than 2 million cubic meters a year were liberalized. Reductions in volume thresholds in the retail market were made in 1999 and 2004/5, although effective competition was slow to develop. Full liberalization of the electricity market occurred in April 2016, with the gas market following a year later.

The Ministry of Economy, Trade, and Industry (METI) has taken the lead in promoting further market restructuring and in May 2016 published its Strategy for LNG Market Development.[40] This strategy included a number of initiatives to secure "greater supply flexibility and resiliency and market utilization."[41] The aim appears to be to attract more potential players to the gas market seeking access to LNG terminals as well as buying and selling gas system-wide. Eventually, METI sees this evolving into gas trading on a larger scale than is now the case.

The Japanese government believes that a market hub located in Japan would provide valuable price information for both the domestic and the global LNG market. The JCC LNG pricing formula has long set gas prices across the Asia Pacific. Recently, a number of price indexes have been developed, which purport to represent LNG trades in Japan, South Korea, China, and Taiwan, and these have provided indication of spot market prices for the region. A major step toward the development of a liquid trading hub would be the establishment of reliable price indexes based on competitive market forces.

METI's stated goal is that Japan obtain internationally recognized LNG hub status by the early 2020s. METI has identified three policy initiatives to further this goal:[42]

1. Enhance the tradability of LNG and natural gas: METI will promote the elimination of destination clauses in LNG contracts that it views as a barrier to easier trading. METI will also work to resolve other barriers to trade, promote wider use of natural gas and LNG, improve pipeline connectivity, work with other countries and industries to develop standard practices and uniformity, and improve tanker access to LNG terminals.

2. Create a proper price discovery mechanism: METI will encourage further spot trading and the development of price indexes that reflect gas supply and demand fundamentals.
3. Enhance the physical infrastructure and improve access: METI will promote TPA to LNG terminals and to the gas network and support efforts to improve the LNG, pipeline, and storage infrastructure.

However, Japan will still remain a long way from developing a domestic hub given the structural changes that are required to the physical gas infrastructure and the development of pipeline interconnectivity and TPA. With multiple private local distribution companies controlling the gas network, such a restructuring may take some time.

Singapore

Singapore is a relatively small market compared to both China and Japan—in 2016 gas consumption was 12 bscm compared to over 200 bscm in China and just under 130 bscm in Japan. Natural gas is largely consumed in the power sector, with some in industry. The residential and commercial sectors burn small amounts of manufactured gas, which is made from oil products.

Singapore has two separate gas pipeline networks. One supplies gas used primarily for cooking and heating by residential and commercial customers, while the other supplies gas for electricity generation and industrial feedstock.[43]

The pipelines are owned by PowerGas, a member of Singapore Power Group, which is responsible for shipping the gas to customers that purchased it from gas shippers and retailers. City Gas Pte. Ltd. supplies the town gas, and natural gas is imported from other countries through licensed gas importers.[44] There are 11 licensed gas shippers, 9 licensed gas retailers (all but two are also shippers), and 7 gas importers (two of which are Shell companies, but all are shippers). The shippers largely consist of either gas importers or power generators.

Do They Have the Necessary Conditions?

In the previous section, the requirements for achieving a competitive wholesale natural gas market—a prerequisite for developing a hub—were described. How do our three countries measure up against these requirements at the moment?

Table 4: Competitive market requirements in China, Japan, and Singapore

Institutional/Structural Requirement	China	Japan	Singapore
Hands-off government approach	–	–	+/–
Separation of transport and commercial activities	–	+/–	+
Wholesale price deregulation	+/–	+	+
Sufficient network capacity and TPA	–	–	+
Competitive number of market players	+/–	+	–
Involvement of financial institutions	–	+/–	+
Market size	+	+	–

Note: "+" means currently contributing towards a competitive natural gas market, "–" means currently not contributing toward a competitive natural gas market, "+–"means that it is currently unclear

The assessments in each case can be subjective and are the opinion of the author and also represent the current situation.

China is a large market and has a diversity of supply from its own production, pipeline, and LNG imports, but while it has begun to deregulate many aspects of the gas market, it still has a long way to go in terms of separation of transport and commercial activities and introducing regulated TPA as well as reducing the level of government control.

Japan is also a large market but almost totally reliant on LNG imports. However, this may not necessarily be an insuperable obstacle since the liberalization process is well under way and there are multiple market players. To complete the process, what is required is a clearer separation of transport and commercial activities and solving the issue of integrating the network and introducing TPA.

While Singapore ticks most of the boxes in terms of liberalization and a competitive market, it falls down on the number of market players—only 11 shippers, and these are mixture of buyers and sellers—and the size of the market—too small to develop enough market players with sufficient volumes to trade.

While none of the countries is yet at the stage where it could be said to be truly competitive wholesale markets from which a hub could be developed, that is not to say that one or more could not get to that situation. However, it may take many years for China, especially, and Japan to get there, even assuming that there is the political will to do so in both countries. This is not to say, however, that reliable price benchmarks could not be created in these countries, and this is addressed later.

Government Motives for Hubs

In the early days of hub development in North America and the UK, there was no real government or regulatory drive to create a trading hub, since there were no good examples in the gas industry. The regulatory driving forces in these markets were to achieve competitive markets in as much of the industry as possible since competition was seen as a "good thing" and would produce lower prices than in a noncompetitive market.[45] The development of a trading hub was the *outcome* of the liberalization process.

In the discussion on the development of LNG trading hubs in Asia, it could almost appear, to the casual observer, that this process has been reversed. The process sometimes appears to be "if we develop a trading hub, then we will have a market price, and our market will be competitive," and this view forgets the conditions necessary to develop a competitive market with the hubs as a consequence rather than a cause. This would certainly seem to be the case in China, where the government has been promoting the Shanghai Petroleum and Natural Gas Exchange (SHPGX), but with very little progress on market liberalization.

Singapore seems to have picked up on the LNG trading hub as an "add-on" to its role as a financial hub, together with the large community of traders of other commodities. Indeed, almost every player in the LNG industry has set up significant operations in Singapore to trade LNG. However, that doesn't make Singapore a location for a LNG trading hub as the trading of LNG could be for cargoes anywhere in Asia, or even globally, with the traders simply "meeting" in Singapore. Singapore's advantage is mainly the skill set of the people already working there.

In Japan the progress has been somewhat more circumspect in that the program of market liberalization in the gas sector has been laid out for a number of years, so the ambition to create a hub at the end of the process would seem somewhat more realistic. METI has stated that it wishes to promote more spot trading and remove any barriers to trade, including enhancing the physical infrastructure. However, beyond these statements of intent, there is as yet not much in the way of concrete proposals.

How Can Churn Be Created in an LNG Hub?

In the previous section, it was noted that the churn rate—the volume of gas traded divided by the volume of gas actually flowing on the system—is a key measure of trading liquidity. Churn rates in the UK and Netherlands are above 20 times for physical and futures trade together and more than 60 times in the United States. The trading in these countries takes place within the pipeline systems, where there is a continuous flow of gas, and trades can, and do, take place in relatively small quantities. The EIA paper estimates that in Asia Pacific for LNG the churn rate is just over one.[46]

Even assuming that in the Asia Pacific LNG market the necessary prerequisites for developing a competitive market were in place—which, as Table 4 shows, they are not—the creation of a hub also requires the standardization of the contractual arrangements for both pipeline transportation and for the sale and purchase of gas. It was noted in the previous section that the contractual arrangements at the hub, specifically the IHT services at Henry Hub and the process of trade nominations at NBP and TTF, make it very easy to trade physical gas *without actually needing to deliver it*. This creates liquidity and results in multiple trading of the same molecule of gas.

LNG suffers from significant drawbacks in respect to multiple trading of the same molecules of gas. As the EIA report notes, the size of LNG cargoes and the uneven nature of LNG cargo delivery schedules is one confounding factor—pipeline receipts and deliveries are by contrast continuous and almost instantaneous. In addition, pricing uncertainties result from the sheer size of the Asia Pacific LNG market and the distances that separate the ports. Variations in the quality of the gas among cargoes is also an issue, which can affect the comparability of prices reported at different locations and times. Pipelines maintain calorific standards through limitations on the specification of the gas that can enter the pipeline system to address this problem.[47] Additionally, the pipeline hubs effectively have a geographic location within the pipeline system(s), which allows for delivery if the parties to a trade wish to do so. It is not clear that LNG in Asia Pacific has such a geographic location where traded LNG would automatically default to delivery if the parties to the trade wished to do so.

Theoretically, an LNG cargo could be bought, and sold, while en route, which would create a churn of two if this was done once. However, to do this trade 20 times, as is the norm in the UK and Netherlands, and then for all the LNG traded, would seem not to be credible. It is also conceivable that the LNG cargo could be split into a number of standard units, and these could be held by different buyers and sellers and then traded while in transit. However, establishing such a system may logically require the LNG tanker to be treated as a "transport only" under regulated TPA, just like a pipeline, and also running regular routes to a timetable, somewhat like a ferry.

The creation of churn in the LNG market is something that we will return to later.

ALTERNATIVES TO AN ASIAN LNG TRADING HUB

A key conclusion following the first two sections is that the industry is a long way from realizing its ambition to develop an LNG trading hub in Asia comparable to Henry Hub in the United States or NBP and TTF in the UK and Netherlands. Indeed, it may never be possible to achieve an LNG hub where the molecules can be traded multiple times in either the physical or futures market without actually needing to deliver it, as is the case with the pipeline hubs.

One of the key benefits of a liquid trading hub is that it provides a reliable price benchmark and reference point that the market can use in longer term contracts. If it is not possible to create a hub for LNG, can a reliable price benchmark be created without a hub like HH, NBP, or TTF?

Review the LNG Price References—How Do They Work?

Despite the lack of an LNG hub in Asia, there are any number of price benchmarks that have arisen and are being promoted as the most appropriate benchmarks of LNG prices. The EIA report included an excellent summary of the main price benchmarks, covered in the table below taken from the report.[48] Other benchmarks, such as JOE, are also available but were not included in this table.[49]

Table 5: Characteristics of Asia Pacific LNG Price Indexes

Index	Japan/METI	JKM	RIM Japan	ANAE	EAX	SLInG
Publisher	METI	Platts	RIM Intelligence	Argus Media	ICIS	SGX & EMC
Start of Stats	Mar. 2014	Feb. 2009	Feb. 2016	2012	Jan. 2014	Sept. 2014
Ship (Cargo) Size	Any	2.9–3.7 Bcf	2.9 Bcf tankers & partial cargoes	2.9–3.3 Bcf & partial cargoes normalized	0.6–5.6 Bcf & partial volumes	2.9–3.7 Bcf
Index Coverage Area	LNG delivered to Japan	Spot physical cargoes delivered into Japan and South Korea	Japan, South Korea, Taiwan and China	Japan, South Korea, Taiwan, China	Physical cargoes to Japan, South Korea, Taiwan & China	Vessels on the water with potential to deliver to Singapore
Assessment Type	Census sent from METI to market players	Daily phone or electronic survey of market players	Trading info from OTC market; Price assessment from JOE LNG market deals & bids/offers	Daily phone or electronic survey of market participants	Daily phone or electronic survey of bids, offers (first-hand or observed)	Survey of select market participants
Assessment Frequency	Monthly price assessments	Daily, with market close prices	Assessed & published daily	Assessed & published daily	Assessed & published daily	Half-monthly assessments, published twice weekly
Sale or delivery	DES contracted and arrival	DES	DES	DES	DES	FOB
Assessment Forward Range	Any forward period for LNG delivery (contract-based); within-month (arrival-based)	Prompt delivery; 3rd & 4th or 4th & 5th half-month forward	Half-monthly assessments for the 3rd–5th half-months forward	Prompt delivery; 2nd–5th half-months forward	3rd–6th half-months out	3rd–6th half-months out
Index Calculated	Contract-based (for deals made in-month) and arrival- based (for cargoes arriving that month)	Prompt or deferred spot prices averaged for assessed half-months	Monthly average price for half-months calculated daily	Physical and forward swap are assessed daily for forward half-months	Daily front and second month ahead prices for all countries averaged	Half-monthly prices are averaged for the first full month
Types of Trades Included	Spot LNG to be delivered	Spot LNG to be delivered	Deals done and bids/offers on LNG cargoes	Spot LNG to be delivered in 6–12 weeks	Global prompt & mid-term charter LNG	Spot LNG able to be shipped to Singapore
Number of Contributors	~ 15	Not specified in Methodology	Not specified in Methodology	Not specified in Methodology	Varies daily; no minimum data threshold	50
Contributor Requirements	Companies/ consumers of spot LNG	Any market participant; buy/ sell prices must pass the "repeatability" test	None; market prices assessed from OTC market trading information	All credible market sources, market participants and brokers/trading platforms	Active or past LNG industry participants, not only the physical market	Active in the physical LNG market
Data Cleaning	N/A	Data aligned with standard assessment specifications	Higher bids & lower offers are prioritized as closer to market values	Market condition adjustments if assessment hierarchy would skew results	Data verified with trading counterparty; technical-purpose cargoes excluded	Top 15% and bottom 15% removed as outliers

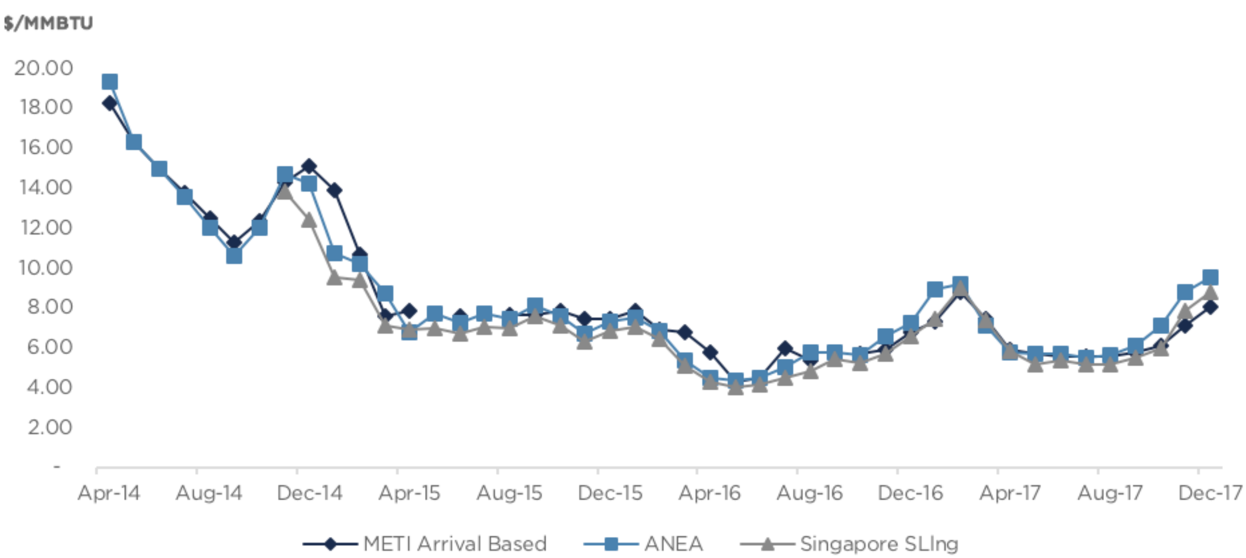
Source: US EIA. Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region, page 45.

Apart from the Japan/METI index, all the other indexes adopt broadly similar methodologies. The general concept is that a price for LNG is assessed—in some cases on a daily basis—for deliveries to that location or region for the prompt month or half-month, with the prompt period continuously rolling forward. The prices are usually assessed through surveys of market participants. Although the assessments will include actual transactions between parties, for the most part they are based on bids/offers and/or market participants' views on what the price would be if a trade were done—this is often referred to as "market chatter" or "heards," as in "heard on the street."

The Japan/METI index is different in that it is based on actual spot trades as reported to METI by the Japanese buyers, so it does represent prices of actual deals as opposed to "market chatter." In this respect, the METI index is somewhat closer to the price reporting for pipeline gas at Henry Hub, NBP, and TTF. However, the volume of trades reported in the METI index is very small, and in some months, if there are not two trades, then the index is not published, which could be a significant drawback to anyone wanting to use this index. This has happened five times for the contract-based index and three times for the arrival-based index, up to the end of 2017, since the index was first published in March 2014. Clearly there is no comparison between the number of METI index actual trades and the trades assessed in the United States and European price indexes, which run into the thousands if not hundreds of thousands or millions.

Of the other indexes, based largely on market assessments rather than actual trades, they are all considering cargoes delivered to specific locations, apart from the Singapore SLIng, which is assessed for cargoes as they pass by Singapore to be delivered elsewhere, usually in Asia Pacific. Recently SLIng has also developed a North Asia index and a Dubai-Kuwait-India index on similar principles.

Figure 5: Comparison of price indexes for spot LNG



Source: METI, Argus, SGX

While the different indexes of spot prices can vary—as illustrated in figure 5—they general track each other, with Singapore Sling—a FOB[50] assessment—being generally slightly below METI and ANEA,[51] which are DES[52] prices but also not the same location, so differentials might be expected.

More recently, benchmark prices have been created for US Gulf Coast LNG. Platts launched its Platts Gulf Coast Marker (GCM) in June 2016.[53] This is a price assessment meant to represent the daily export value of LNG traded free on board (FOB) from the US Gulf Coast. The methodology is broadly similar to the price assessments undertaken for Platts JKM but with one difference. In the absence of transactional data, Platts price reporters determine the most valuable netback for an exporter of US LNG based on prevailing market values in global demand centers such as Northeast Asia and Europe. Essentially, therefore, the price will reflect the spot prices in Europe and Northeast Asia less the Platts' estimate of shipping costs. Based on the current contractual arrangements from Cheniere's Sabine Pass terminal, it is probable, in the author's opinion, that there are virtually no trades and even very few bids and offers in the Gulf Coast area for LNG cargoes. All the off-takers purchase the LNG FOB straight out of the Sabine Pass plant and load it on to their own ships or ones they have chartered. It would seem improbable that they would actually then trade that cargo immediately rather than scheduling a delivery to a market, although it could be traded closer to the market.[54] In practical terms, therefore, the GCM would, more often than not, simply be the calculated highest value netback from Europe or Northeast Asia.[55]

Argus also publish a US Gulf Coast FOB price, but its methodology is different as it is based on its Henry Hub price times a premium plus a fixed charge—similar to the Cheniere contract structure from Sabine Pass.[56] ICIS also have a US Gulf price assessment and its methodology is similar to Platts'.[57]

The US Gulf Coast benchmarks are FOB or supply area benchmarks in contrast to the main Asian benchmarks, which are in the market area on a DES basis. In respect to establishing a price benchmark for LNG then, in the author's opinion, it is more appropriate to have a benchmark in the market area (i.e., Asia) rather than the supply area, where, in effect, the value of an LNG cargo is simply the netback from the market area anyway.

At the moment, the price benchmarks do not appear to include a sufficient number of actual trades to enable them to be considered a reliable price reference. Price benchmarks can only be seen as reliable once they reflect many trades between parties and the prices of these trades are reported and transparent, either through exchanges or via price reporting agencies. This is not to be critical of the price reporting agencies, which are all doing excellent and conscientious work in ensuring that the resulting published price assessments do reasonably reflect the market price, and they follow the correct procedures in a transparent and nondiscriminatory way. However, to be used widely as price references in longer term contracts, many more actual trades and liquidity are required.

JKM Futures Market

On the back of the Platts JKM price assessment, the ICE has introduced a JKM LNG (Platts) Future. This is a monthly cash settled future based on the Platts daily assessment price for the

LNG Japan/Korea Marker (JKM). It is traded on 10,000 MMBTU lots, and the settlement price is the declared JKM index for the month. Unlike the Henry Hub and NBP futures, therefore, there is no underlying physical market the futures market is linked to and that can be used to go to delivery as the default.

Trading in JKM futures has been modest in volume and has grown from 201 trades in 2012 to 270 trades in 2013, 1,654 trades in 2014, 2,793 trades in 2015, 12,717 trades in 2016, and 50,266 trades in 2017.[58] This represents 500 trillion Btu of futures trading in 2017, about 9 percent of recent annual LNG consumption in Japan and South Korea. 2018 has started at even higher monthly volumes.

How Does the Brent Market Work?

If the pipeline trading hubs in North America and Europe are not appropriate examples for LNG trading, are there other commodity markets which might be? The oil market is a possible example, especially as the bulk of oil is transported by tanker, as is LNG. The spot trading of oil has a long history, and descriptions of its early development were mostly written over 20 years ago. This section draws heavily on a World Bank publication[59] and a book by Horsnell and Mabro.[60]

Razavi[61] noted that the early spot market in oil trading began in the 1950s and 1960s as a residual market function with oil companies balancing their refinery requirements. The volume of spot trading was limited to around 5 percent of total trade, with the remaining 95 percent being based on contracts specifying prices and quantities over relatively long periods of time.

After the 1973–74 crisis, the spot market began to play a marginal role in petroleum trading, which was small but reasonably significant compared to the levels seen earlier in the residual market. In this world, the spot market becomes a leading indicator of market conditions as opposed to following contract prices. The real shift began in the 1975 to 1978 period, with low spot prices reflecting soft market conditions.

The move to a major trading point began in the 1980s, and by 1985, spot and spot-related transactions were thought to account for 80 to 90 percent of internationally traded oil. This arose firstly as excess capacity in the refining industry forced refiners to fight for their survival and look for the most economical way of securing crude oil, which was in the spot market where prices were lower than in the rigid contract market. Secondly, as OPEC countries began to lose market share, they began to engage in so-called spot-related sales to recapture the lost market share.

It was in the 1980s that the Brent market became key in the spot oil trading market. This is the subject of the Horsnell and Mabro book published in 1993.[62] Brent was actually a blend of crude oil from 19 separate fields in the Brent and Ninian systems.[63] Until the mid-1980s, the Brent market only referred to spot and physical forward transactions. In this period, there were two types of transactions in the physical market: one known as a "dated Brent cargo" and the other as "15-day Brent."[64] The former is essentially a spot transaction and the latter a forward deal. Dated Brent refers to the sale of a specific cargo that is either available in a specific loading slot from the Brent/Ninian complex or that is already loaded and in transit to a destination. The 15-day cargo is a standard parcel that will be made available by the seller to the buyer on an unspecified day of the relevant month.

Participants initially dealt with each other on a purely bilateral basis, but by 1990 they were using a standard contract prepared by Shell.[65] There was no exchange to match buyers and sellers in the 15-day market, and there were usually many more forward contracts for a given month than physical cargoes—churn as described for the pipeline gas markets. There was no obligation on any party to a deal to reveal its existence or details to any other party. However, the clearing of the 15-day market involves all participants, and it consisted of two different operations: book-outs and the seller's nominations, which can take place on any day in the period starting 15 days before the beginning of the relevant month and closing 18 days before its end. The month is said to have become "wet" on the first day on which sellers can begin to serve 15-day notices.

A book-out is an agreement between a set of participants to cancel their contracts with a cash settlement for the difference between an agreed reference price and the contract price. A book-out can take place whenever a set of claims on forward cargoes held by different participants can be arranged in a chain starting and ending with the same participant (the "circle").[66] In essence the book-out converts a contract for physical delivery into an agreement for financial settlement. In determining the terms of the financial settlement, the parties assume that there will be a deemed delivery of 500,000 barrels taking place on the 15th day of the relevant month or on the middle day of any notified (by the seller) window.

If contracts are not cleared through the book-out process because a "circle" is not formed, then they are cleared through the nomination process. This is initiated by the sellers with entitlements to Brent Blend at Sullom Voe, who have sold it through the forward market, serving 15-day notices to participants in the chain who had bought cargoes for the relevant month. The last company left with the buying nomination at 5:00 pm on the last day the notice can be validly served is deemed to be receiving the cargo, which has now become "wet" and is now a dated Brent cargo. However, this buyer or holder of the cargo can still trade it in the dated (spot) market.

On the back of the dated and 15-day markets, the International Petroleum Exchange of London (IPE)[67] launched the third version of its Brent futures contract. This was traded in 1,000-barrel lots but based on a physical market of 500,000 barrels. The first two contracts were based on going to physical delivery, but this created problems since participants had to put together 500 lots to do that. In the third contract, it was changed to cash settlement with no obligation to go to physical delivery. In this early period, the final day of trading the monthly futures contract is the day prior to the month of the contract becoming wet in the 15-day market. The settlement price under the Brent futures contract is the Brent Index, which was calculated as the average price from six price reporting agencies on all 15-day Brent deals believed to have been concluded during the day, starting with Tokyo opening to Houston closing. More detail on this is in Horsnell and Mabro.[68] The futures contract can be exchanged for physical delivery (EFP) if the participant has the 500 lots (500,000 barrels) to make the exchange.

Why did Brent become the most traded and liquid crude marker price? Horsnell and Mabro suggest four reasons:[69]

1. For the crude to be eligible, it is highly desirable that its ownership be diversified. Concentration of supply tilts the balance in favor of the producers and makes potential buyers reluctant to enter the market. This criterion immediately excludes OPEC and some non-OPEC crudes (Mexico and Russia).

2. The output stream needs to be sufficiently large to ensure physical liquidity, pretty much eliminating all crudes outside the North Sea and the United States.

3. The existence of an infrastructure capable of delivering in both a reliable and flexible manner the parcels specified in the trading contract, which was fulfilled by the Brent and Ninian complexes at Sullom Voe.

4. Almost unrestricted tradability, which Sullom Voe gave. The US pipeline system also gave this, although there were bottlenecks, and there were legal restrictions on exports.

The North Sea satisfied all these criteria at the time, but why was it a UK crude and not a Norwegian crude that was chosen? The UK, through Brent and Ninian, had higher volumes than the largest Norwegian crudes from Statfjord; the UK institutional framework was more market oriented than the Norwegian framework; the British National Oil Corporation (BNOC) received royalty crude and was a big potential supplier in the open market; and the fiscal regime in the UK valued the transactions for tax purposes at the market price, compared to an administered price in Norway, providing an additional impetus to the trading of crudes on the open market.

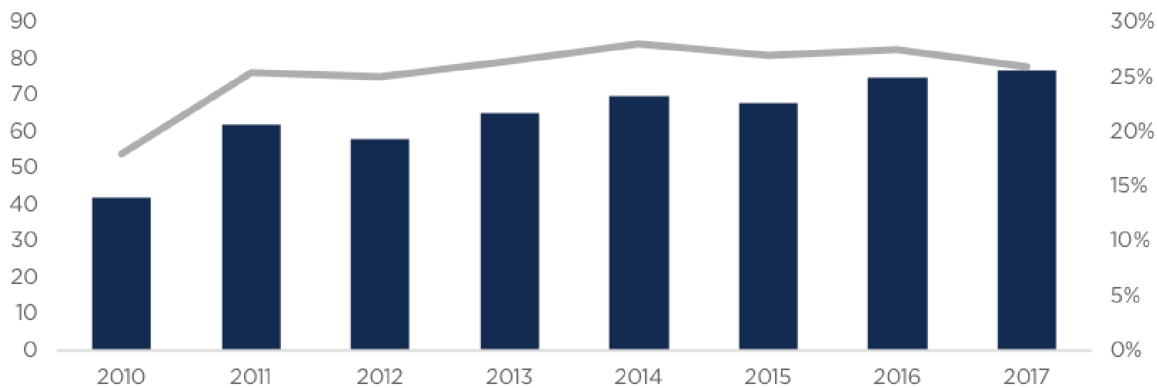
The development of Brent as the marker crude was not related to a hub but to a large liquid delivery point, and it has some interesting lessons and examples for the LNG market, which we shall return to in the next main section.

It should be noted, however, that the oil trading market is not just the trading of crude—such as Brent—but also oil products, and the key markets for trading oil products outside the United States are Rotterdam and Singapore. In these centers, oil products are often traded in the storage tanks as well as in tankers and pipelines. As regards LNG trading, LNG can be likened to crude trading, while oil products trading is more analogous to regasified LNG or pipeline gas.

Analysis of Spot Cargoes

There is a general consensus that there has been a move over time to more spot and short-term cargoes in the LNG industry, and the chart below from GIIGNL is often quoted.

Figure 6: Spot and Short-Term Cargoes

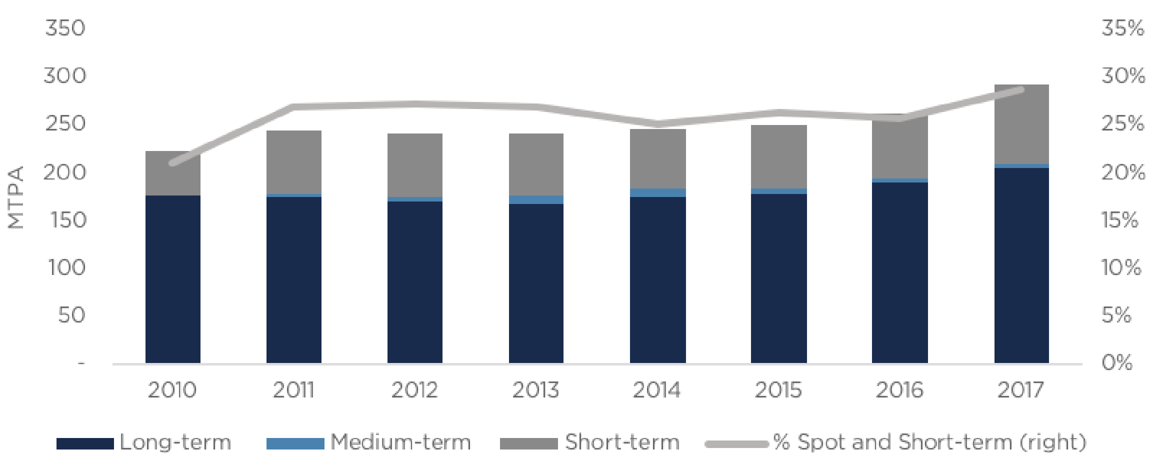


Source: GIIGNL

Short-term trades are defined as contracts of less than four years. The rising percentage of total LNG trade is often used to justify a more traded market with more spot cargoes. However, it is not necessarily clear that pure spot cargoes are increasing; it could simply be that more contracts are of shorter duration.

The IGU also publishes an LNG report very similar to GIIGNL. The IGU definition of short-term contracts, however, is less than two years, and then medium-term contracts are between two and five years. Figure 7 shows short-, medium-, and long-term trade from 2010 to 2017.

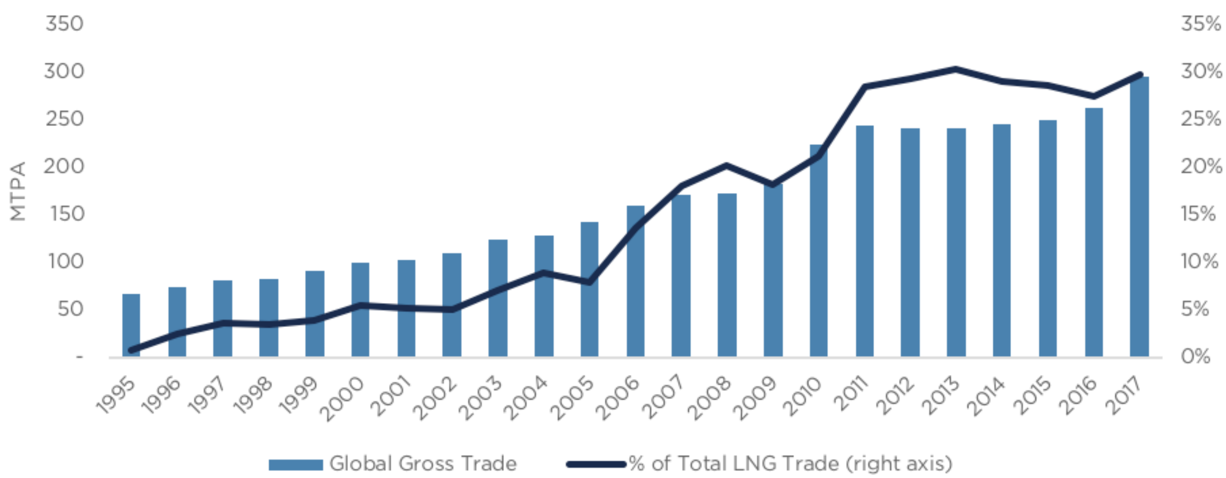
Figure 7: Short-, medium-, and long-term trade, 2010–17



Source: IGU, IHS Markit

The trend in the share of spot and short-term is similar to the trend in the GIIGNL report, but there doesn't appear to have been much change between 2011 and 2016, although some increase in 2017. Figure 8, also taken from the IGU report, shows the longer-term trend since 1995, with the share of spot, short and medium term (non-long term) increasing sharply from around 2005 to 2011.

Figure 8: Non-long-term volumes, 1995–2017

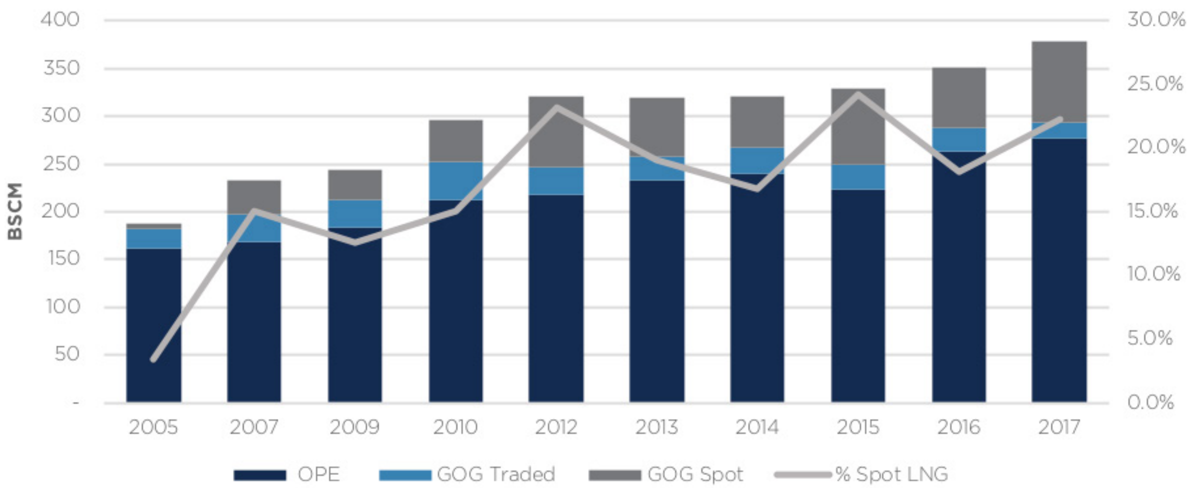


Source: IGU, IHS Markit

None of these figures, however, strictly focuses on pure spot cargoes as they all include contracted LNG.

The IGU also publishes the annual Wholesale Gas Price Survey, and this includes information on the pricing of LNG trade and whether it is indexed to oil prices (OPE)—under long-term contracts—or on gas-on-gas competition (GOG). Using the price survey data, it is possible to identify all LNG indexed to oil prices, LNG sold into traded gas markets such as the United States and the UK and then spot LNG—in the survey, this is defined as any contracts less than one year and pure spot cargoes, so it will include tenders put out by buyers and sellers. This latter definition, therefore, is much closer to a spot cargo.

Figure 9: Spot LNG trades, 2005–17



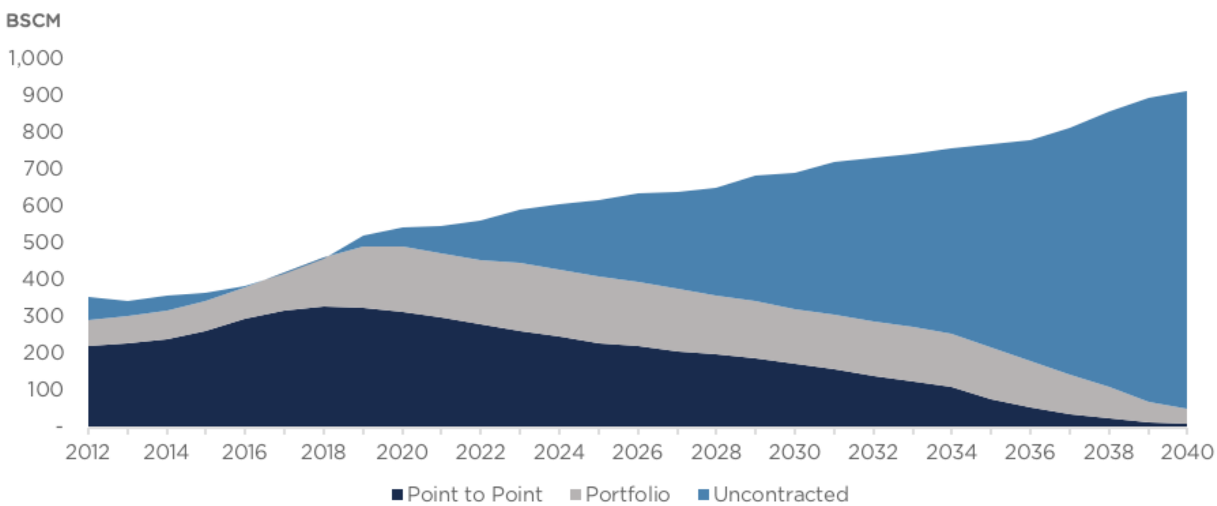
Source: IGU Wholesale Gas Price Survey

The trend is broadly similar to that shown in the other figures, but by limiting it to anything under one year and priced at market or hub prices, the level is somewhat lower, around a 20 percent share of total trade against the 30 percent usually quoted in the GIIGNL annual publication. However, the share of spot LNG appears to have stalled since around 2012.

The focus on spot and short-term contracts as some sort of proxy for more trade in LNG may now be becoming less relevant. With the push against destination clauses in LNG contracts, especially from the Japanese government, the EU, and buyers such as Korea, and the advent of US LNG exports, which are all effectively destination free, the focus should perhaps be on "flexible" LNG. The typical US contract of over 20 years has an obligation to be lifted by the off-taker, but it can then go anywhere, so it is capable of being traded and sold en route to traders or end user buyers in different countries.

Figure 10, taken from the contract database in Nexant's World Gas Model, shows the breakdown of the take-or-pay levels in contracts into "point to point" (i.e., those with destination clauses) and "portfolio" (those with flexible destinations), with the balance being uncontracted.

Figure 10: Flexible LNG contracts—TOP levels



Source: Nexant World Gas Model

The total LNG trade is broadly consistent with the IEA's New Policies Scenario in WEO 2017. Contracts are assumed to end and not be renewed in accordance with their original terms. However, clearly, even if contracts are renewed, it seems highly likely that there will be many fewer with destination clauses, leading to more flexible LNG available for "trading." By 2022, on the assumptions above, over half of LNG trade is either portfolio or uncontracted, with the uncontracted portion being steadily contracted but on a flexible destination basis. Trading is likely to rise in line with the increase in flexible LNG.

Mandatory Reporting—How Does It Work at FERC?

In the discussion earlier on the churn rates in the United States, the data collected by FERC on its form 552 was used. FERC form 552 is an annual report of natural gas transactions and is mandatory under the Natural Gas Act, section 23(a)(2), and 18 CFR, parts 260.401. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law.

Only physical transactions data is collected and only from larger participants. Physical natural gas buyers and sellers must complete and file the form annually if their "reportable" natural gas purchases or sales are equal to or greater than 2.2 trillion British thermal units (TBtu) or 2.2 million MMBtu in the reporting year. This does, however, cover almost all transactions.

The data is only published by FERC after the end of the year, and it does not include actual prices but does require those submitting to identify whether the transaction is fixed price or indexed and, if so, what index is used (e.g., daily, monthly, etc.). It is not, therefore, published in a timely manner.

The price reporting, as discussed earlier, by market participants to the price reporting agencies in the United States is on a voluntary basis, although it is considered that many participants do submit information on a regular basis. In 2017, FERC held a technical conference on the transparency and liquidity of natural gas price indexes.[70] FERC held the technical conference to discuss the factors that have contributed to declines in fixed-price deals observed since 2008. Those declines have stabilized in the past few years, especially in the day-ahead market. However, overall trends in FERC form 552 data show higher numbers of transactions tied to price indexes and smaller percentages of traded volumes reported, prompting the commission to look at how it can incentivize more companies to report.

At the technical conference, participants generally reiterated their support for the current system of voluntary price reporting and their confidence in the reliability of indexes. However, as it brainstorms ways to encourage more companies to report fixed-price and physical basis trades amid growing numbers of indexed deals, the industry still is debating the pros and cons of a system of partial mandatory reporting focused specifically on large natural gas marketers. While most in the industry suggested only minor adjustments in the current voluntary price reporting system, two major price reporting natural gas marketers, BP Energy Co. and Tenaska Marketing Ventures, said that FERC should potentially consider requiring other marketers, at least the larger ones, to report as well. The concern of these participants is that if fewer in the market report, then those who do can be in danger of being identified, leading them to stop reporting, making the situation worse, and undermining the reliability of the price indexes.

The industry remains split, however, with both the Natural Gas Supply Association (NGSA) and the American Gas Association (AGA) opposing any mandatory reporting, believing the voluntary system provides transparent and accurate price indexes. Indeed, the NGSA went as far as to state that "mandating that companies price report their fixed price transactions may drive some entities to avoid those types of transactions. This would have the perverse effect of negatively impacting the normal functioning of the market by limiting liquidity."[71] We would presume the argument here is that if entities are forced to report trades and prices of a certain nature, then they will be less likely to undertake such trades, especially if some entities have overzealous compliance departments.

In respect to LNG exports from the United States, the Department of Energy (DOE) publishes information on the volume and price of LNG exports as they leave the US terminals.[72] The data is published for each cargo and also the declared destination of that cargo. The prices published, however, can vary in definition. Some prices include the liquefaction fee, while many of those under long-term sales and purchase agreements only declare the purchase price of the gas at Henry Hub plus the 15 percent uplift under the Sabine Pass contractual arrangements but no liquefaction fee. These prices are often referred to as the FOB (free on board) price, but they do not necessarily reflect the price when delivered to the final destination, which is increasingly flexible anyway.

Mandatory Reporting in the LNG Market

A lot of the price data reported for LNG comes from customs data information and is collected and reported in various trade publications by Platts, Argus, ICIS, and others. The average price each month is calculated by dividing the value of imports by the volume.

As discussed above, there are also numerous LNG spot price indexes, but these are not necessarily based on actual trades.

As outlined in table 5, the METI index does not take customs data and does include only actual trades. The objective of the index is to report the price of spot LNG. According to METI,[73] spot LNG refers to LNG traded on a cargo to cargo basis, which do not include term contracts of LNG (so-called long-, medium-, short-term contracts). In addition, spot LNG—the price of which is linked to a particular price index (for example, the Henry Hub link and the JKM link)—is excluded from these statistics. The aim of these statistics are spot LNG the prices of which are determined at the time of contract (so-called fixed price). METI only publish the price in any month where there are two or more reporting entities that imported spot LNG.

The METI index does appear to be gaining a good reputation in the industry and is widely quoted. However, it does lack the liquidity and reliability at the moment to gain usage as an index on which LNG contracts can be based. There are some examples of the use of JKM as an index and clearly US LNG is largely priced on Henry Hub. In addition, NBP and TTF are also used as price references in LNG trades outside Europe.

So far, the Japanese authorities are the only ones to mandate price reporting of spot LNG, and while Japan is the largest market, there are many spot cargoes delivered to other markets, where a similar reporting mechanism could be put in place.

PROSPECTS FOR A RELIABLE PRICE BENCHMARK

If an LNG hub, as opposed to a pipeline hub in the Asia region, remains a somewhat remote possibility, that is not to say that a reliable price benchmark cannot be created, as happened with Brent crude oil in the 1980s.

As was noted in the earlier section, there are a number of price benchmarks in the Asian LNG market, provided by the PRAs (Platts, Argus, ICIS, etc.), ministries (METI in Japan), and exchanges (Singapore). However, all of these suffer from drawbacks of lack of physical trades and real liquidity. While some of the benchmarks, such as JKM, have reportedly been used to price deals, and there is also an ICE JKM futures contract, they are not yet thought to be reliable enough to underpin long-term contracts as Henry Hub has for US LNG and for NBP and TTF in European markets and even outside Europe in some cases.

It should be pointed out, though, that while the price benchmarks lack liquidity and sufficient physical trades, this is not to say that the resulting prices do not reflect the true market conditions.[74] It is simply that the market participants do not consider the benchmarks necessarily robust enough for them to use in long-term contracts.

Poten, in its January 2018 edition of LNG in World Markets, noted that there had been a strong move toward the use of Brent in new LNG contracts and away from some spot or hub indexes such as Henry Hub, NBP, and LNG swaps (such as JKM). Poten suggested that this indicates that market participants have yet to gain confidence in alternative benchmarks. While there has been a significant increase in liquidity in the Asian spot LNG swaps market, it is far less liquid than Brent paper markets. Other spot benchmarks remain illiquid and do not support any risk management tools.[75]

What Is Needed to Create a Reliable Price Benchmark?

In the absence of a hub, therefore, what is needed to create a reliable price benchmark? In developing pipeline hubs in North America and Europe, a prerequisite was the liberalization of, at least, the wholesale gas market. In oil, however, liberalization of the wholesale market as such was not the driver as there was not a great degree of regulation in the first place, but one of the reasons Brent rose to prominence as the price benchmark was that the UK institutional framework was market oriented.

The development of gas pipeline hubs and Brent oil trading, however, shared a number of common requirements, which will, in the author's view, be required to create a reliable price benchmark for LNG trades:

1. **Pricing transparency.** In the gas pipeline markets and in Brent crude, the market participants actively reported physical trades in a timely manner, mostly on a daily basis, to the PRAs, enabling them to establish price indexes against which longer-term deals could be priced. This also allowed the futures markets to develop on the back of, and linked to, the physical markets.

2. **Market diversity and size.** There were multiple participants in the Brent and Ninian system oil fields as well as in gas pipeline markets, and large volumes flowed continuously each day.

3. **Access to infrastructure.** In gas, the move to nondiscriminatory third-party access allowed all participants to move gas easily, and the Sullom Voe arrangements for Brent also allowed producers to trade their oil between themselves and with third parties.

4. **Standardization of contractual arrangements.** Standard contracts to access the infrastructure were developed in both markets, but just as importantly, they were also developed for the sale and purchase of the commodity, and such agreements were short and reasonably simple.

5. **Physical delivery point.** Even though NBP and TTF are called "virtual" trading points, they are, in effect, physical geographic locations, like Henry Hub, and Sullom Voe was the Brent physical point. A key element here is that the NYMEX, ICE Gas, and ICE Brent futures markets all allow physical delivery of the gas or oil, either as the futures contract naturally expires (settled as deliverable) or, if cash settled, is allowed an EFP.

The LNG market currently barely meets any of these criteria. Pricing transparency in spot cargoes is limited—only METI mandates the collection of spot price data—as much of the Asian market is still contracted and linked to oil,[76] and the industry remains somewhat secretive about pricing. Only Japan out of the Asian markets considered has the market size and the potential diversity, but access to infrastructure, standardization of contracts, and a physical delivery point seem some way from being developed. China, while having a much larger market and possibly more diversity with domestic production and pipeline imports, is some way behind in terms of market liberalization.

There has been some discussion within the industry in respect to contract standardization. The Energy Charter Secretariat recently published a report on the standardization of LNG contracts.[77] The report arose from a workshop held at the Energy Charter Secretariat on September 29, 2017, and a couple of LNG conferences during 2017. The general conclusion was that the development of a fully standardized LNG SPA for universal application is not currently feasible, although certain key "trends and issues" could be addressed by standard provisions, rather than developing an entire model LNG SPA at this stage.[78] It should be noted that several generic full LNG SPAs are currently in existence (for example, the GIIGNL Master Agreements) or potentially under development (for example, the proposed ASCOPE model LNG SPA).[79]

In respect to pricing transparency, in the pipeline hubs and for Brent crude trading, the industry came together to report prices because it was in the industry's interest to ensure there was a reliable price benchmark. So far, the LNG industry—both buyers and sellers—have not shown much inclination to be transparent in respect of pricing, with the notable exception, until recently, of Cheniere and their Sabine Pass and Corpus Christi projects, plus the METI initiative to collect and publish the prices of spot cargoes.

The increase in flexible LNG, however, particularly from the United States, may change the industry's perspective. As noted in the previous section, rather than focusing on spot cargoes, it may be better to focus on flexible LNG, since as soon as the tanker has left the export terminal, it effectively becomes much the same as a spot cargo. However, under the Cheniere style contract, we know the "cost" of the cargo—115 percent of Henry Hub plus the tolling fee plus shipping—but this is different from the "value" of the cargo in the market. The value in the European market, especially in Northwest Europe, is clear as it is probably, at the moment, either NBP or TTF, which could be above or below the "cost" of the cargo. However, without a price benchmark in Asia that is reliable, how is the value of the cargo determined when it reaches and is offloaded in, say, Japan? This could be established if the cargo is sold en route, but if it is a Japanese off-taker from the United States, which doesn't resell the cargo, then what gets declared as the price at customs? Even if it is sold en route then, to establish a transparent price would require that that price be reported to the PRAs.

Can a Reliable Price Benchmark Be Created in Japan?

Japan was identified, in the previous section, as being somewhat closer to becoming a liberalized market than China, although still some way away, and much larger than Singapore, which is more liberalized. In addition, with METI already publishing monthly the spot cargoes index, then this is helping develop more price transparency, albeit on limited volumes. However, the METI data is published well in arrears, so it is not necessarily timely enough for the market.

In 2016, Japan imported some 116 bscm of LNG, and the 2017 figure was thought to be little changed. A 160,000 cubic meter LNG tanker might be expected to deliver some 90 million cubic meters of regasified LNG. With total imports of 116 bscm, that is almost 1,300 cargoes a year or around 3.5 cargoes a day. In comparison, the Brent blend in the late 1980s and early 1990s was producing between 500,000 to 850,000 barrels a day, which, as the standard cargo was 500,000 barrels a day, is a little over 1 to 1.5 cargoes a day.[80] This allowed the development of a very liquid oil trading market.

On that basis, Japan has the total market size, but, as noted earlier, the Japan domestic gas transmission system remains fragmented, so it is not one market but several regional markets. Around two-thirds of Japanese gas demand is in power generation, and 80 percent of this is in the central area—Tokyo Electric Power, Chubu Electric, and Kansai Electric, which stretches from Tokyo down to the Himeji regasification terminal—and based on 2016, demand is around 60 bscm or just over half Japan's total demand. Of the city, gas demand of some 85 percent is in this same central area, which amounts to some 30 bscm. The total 2016 gas demand in the central area—which in the map below—is some 90 bscm or 2.75 cargoes per day.[81] Connecting these markets together may be easier than the whole of the Japanese market. It may even be possible to connect the entire island of Honshu for an even larger share of the total market.

Figure 11: Japan Gas infrastructure

Source: IEA Natural Gas Information 2017, GCEP.

This central area is dominated by the major buyers of LNG, such as Tokyo Gas, JERA (Tokyo Electric Power and Chubu Electric), Kansai Electric, Osaka Gas, and Toho Gas, but there are also a number of smaller players.

Integrating the central area to create one market would only be one step in the process. Nondiscriminatory open access to all the regasification terminals and the pipeline system would be required, preferably with all the infrastructure (regas terminals and pipelines) being combined in one system, with an independent system operator charging tariffs regulated by an independent regulator. Ideally, if all the regas terminals charged the same tariff, then, effectively, LNG delivered at any regas terminal would have equal value in the market to all consumers of the gas, whether power plants, industry, residential, or commercial.[82]

Effectively, this would create along the coast from Himeji to Tokyo a single physical delivery point for LNG, albeit involving multiple regas terminals. It may then be possible to trade LNG as it enters the storage facilities at each regas terminal since all LNG would be of equal value in the market.[83]

This structure is almost the inverse of the Brent structure at Sullom Voe, where all the crude came in on the Brent and Ninian systems and arrived at Sullom Voe before being loaded on tankers. For “Central Japan,” LNG can come from all over the world to be delivered at the physical delivery point. Depending on the timings of the LNG tankers coming into Japan, it may be possible to trade “dated Japan LNG” and “15-day Japan LNG” or some similar time period before actual delivery.

Finally, if it were made possible to trade LNG in the storage facilities—with all the LNG being of equal value—then it would be much simpler to introduce a short, standardized contract for “in-storage LNG” than a much more complicated contract that includes all the shipping arrangements. Oil products are traded “in-storage” in Rotterdam, so there is little reason why LNG can’t be.

To the extent that such a structure promoted active trading, especially of smaller volumes than an average size cargo of 90 million cubic meters, then price reporting and transparency could increase, promoting a reliable price benchmark. With multiple physical deals and a physical delivery point, the linking of a futures market to this physical location would be much easier.

CONCLUSIONS

The natural gas pipeline hubs in North America and Europe—principally Henry Hub, NBP, and TTF—developed in the wake of market liberalization in these regions to create a competitive wholesale natural gas market. The requirements to develop this competitive market were identified as follows: a hands-off government approach to natural gas markets; separation of transport and commercial activities, wholesale price deregulation, sufficient network capacity and nondiscriminatory access to networks, a competitive number of market participants, involvement of financial institutions, and sufficient market size.

In respect to the creation of pipeline hubs, the key elements in the liberalization process relate to nondiscrimination through regulated third-party access to the pipeline capacity and the standardization of the contractual arrangements for both pipeline transportation (in the United States via gas transportation agreements and in Europe through network codes) and for the sale and purchase of gas. Combining these elements with an appropriate geographical location promotes the development of gas trading. The contractual arrangements at the hub, specifically the IHT services at Henry Hub and the process of trade nominations at NBP and TTF, make it very easy to trade physical gas without actually needing to deliver it. This creates liquidity and results in multiple trading of the same molecule of gas, which in aggregate can be described as the churn rate.

Henry Hub has been traditionally called a physical hub and NBP and TTF "virtual" hubs, but they essentially serve the same purpose in that they are all "meeting points" or market centers at which parties can buy and sell gas with the title transferring between them under agreements put in place by the hub or pipeline operators, using the nominations processes. NBP and TTF are described as virtual hubs; they are in essence little different to Henry Hub. NBP and TTF are virtual in the sense that there is no exact physical location on a map where they can be identified. However, they are both products of the physical gas transmission systems in the UK and the Netherlands, respectively, just as Henry Hub is the product of the physical Sabine Pipeline. NBP and TTF physically represent the entirety of the UK and Netherlands gas transmission systems. As soon as gas enters each of those systems, it is "at" NBP or TTF until the gas exits those systems—in effect these are also physical geographic hubs.

On the back of these physical trading hubs, futures markets were developed in 1990 on NYMEX for Henry Hub and in the UK in 1997 on the IPE (now ICE). The futures market can bring in financial players, increasing liquidity, but the key to a successful futures market is to have an underlying liquid physical market to which it is inextricably linked.

Churn rates are recognized as the most appropriate measure of a hub's real liquidity and success.[84] Henry Hub, NBP, and TTF all have high churn rates, well above levels generally deemed necessary for a liquid trading market.

Price reporting of actual trades by the industry to PRAs began before functional hubs were established. The reliability and accuracy of the reported prices of actual trades helped promote further trading, which was enhanced when the futures markets were established with real time pricing. This creates a virtuous self-reinforcing process.

China, Japan, and Singapore are often put forward as locations for LNG trading hubs in Asia, but none of them yet meets the criteria for the development of a competitive wholesale natural gas market, let alone a functioning hub. China still has a long way to go in terms of separation of transport and commercial activities and introducing regulated third-party access as well as reducing the level of government control. In Japan, the liberalization process is well under way. But to complete the process, what is required is a clearer separation of transport and commercial activities and solving the issue of integrating the network and introducing third party access. Singapore is the most liberalized market among the three. But it is simply too small as a market, which lacks a sufficient number of market players to create a truly competitive wholesale market—and consequently a hub.

Governments and regulatory authorities sometimes appear to believe that creating a trading hub will, of itself, lead to a competitive market and a reliable market price, overlooking the fact that the development of a trading hub is the outcome of the liberalization process rather than one of the requirements.

The ability to create meaningful churn at a prospective LNG hub in Asia is fraught with difficulties, not least because of the nature of the LNG market and the sheer size of a single cargo of LNG, which cannot easily be dissected and traded multiple times. In contrast, in pipelines, there is a continuous flow of gas, enabling trades to be done in relatively small quantities. There is also no clear geographic location in the region where traded LNG would automatically default to delivery if the parties to the trade wished to do so—this is a fundamental feature of pipeline hubs.

Despite the lack of LNG trading hubs in Asia, the main price reporting agencies have established numerous price benchmarks in the region, which are modeled on the price assessments that the same agencies developed for the pipeline markets in North America and Europe. However, in the absence of any actual physical trades in LNG, the assessments largely reflect bids and offers or mere "market chatter" by the various market participants. One exception is the Japan/METI index, which is based on actual spot cargoes delivered to Japan, although these can be limited in number. A small futures market around JKM has been developed by ICE, but this is a cash settled market and cannot go to physical delivery. Trades remain at very low levels at the moment, although there has been rapid growth recently.

Rather than looking at land-based gas pipeline hubs for inspiration, the LNG market could learn important lessons from the development of other commodity markets, especially oil. The Brent oil complex developed in the 1980s with a spot and physical forward market and then the futures market, directly linked through the settlement price and Exchange of Futures for Physicals (EFPs) to the physical market. Many of the characteristics that led to the development of a liquid trading market for Brent crude are applicable to the LNG market as well. Although Brent is not a hub in the sense of natural gas pipeline hubs, it nonetheless had physical offtake infrastructure at the Brent and Ninian facilities at Sullom Voe.

The consensus view has been that trading in LNG will develop if there are more spot cargoes around, but while the share of spot and short-term contracts in total LNG trade has been rising over time, it appears that the trend stalled between 2012 and 2016, with some increase in 2017.[85] The number of spot and short-term contracts is not likely to be the main driver of LNG trading in the future, with the advent of "destination-free" contracts from the United States and, increasingly, from existing facilities as contracts expire and are renewed on different terms and conditions. This flexible LNG, in turn, seems likely to promote more trading and greater liquidity, and it could eventually facilitate the development of a reliable LNG price benchmark over time.

Price reporting of trades is voluntary, and not mandatory, in all pipeline markets. In the United States, FERC requires mandatory reporting of all physical transactions in terms of volumes and whether they are fixed or indexed prices, but not the actual prices themselves. There has been discussion recently, organized by FERC, on whether there should be mandatory price reporting to the price reporting agencies. The industry in the United States remains split on this issue. For LNG, METI in Japan publishes a monthly price index of actual spot LNG trades, requiring end use consumers to supply the information. There is no other "mandatory" reporting of LNG transactions in Asia, although as it is done in Japan, then it should be possible in other countries, although the authorities and incumbents may not agree.

Even if an LNG hub (as opposed to a pipeline hub) remains a somewhat remote possibility in Asia, that is not to say that a reliable price benchmark—similar to Brent in the oil market—cannot be created. There are a number of price benchmarks in the Asian LNG market provided by the PRAs. However, all of these suffer from the same drawback: a lack of physical trade and real liquidity. There are five key requirements to create a reliable price benchmark in LNG – price transparency, market diversity and size, access to infrastructure, standardization of contractual arrangements, and a physical delivery point at which all trades could be delivered. The LNG industry barely meets any of these requirements at the moment. However, the increase of flexible LNG volumes, particularly from the United States, could fundamentally change the industry landscape in this respect.

Japan appears to be the most likely market in which a reliable price benchmark could be developed. METI is actively promoting price transparency, and the market is large with reasonable diversity of players, at least in the physical gas market, if not the financial market. Integrating the pipeline infrastructure for the whole of Japan may be a problem, but possibly much easier for Central Japan,[86] where almost 80 percent of Japan's LNG is consumed, with the delivery of between 2.5 and 3 LNG cargoes a day, more than twice the number of tankers loaded per day at Sullom Voe when the Brent market developed in the late 1980s and early 1990s.

Integrating central Japan to create one market would only be one step in the process. Nondiscriminatory open access to all regasification terminals and the pipeline system would be required, preferably with all infrastructure (regas terminals and pipelines) combined in one system with an independent system operator. This would, in effect, create a single physical delivery point for LNG along the coast from Himeji to Tokyo, albeit involving multiple regas terminals. It may then be possible to trade LNG as it enters the storage facilities at each regas terminal, making it much simpler to introduce a short, standardized contract for "in-storage LNG" rather than a more complex contract including all shipping arrangements. The ability to trade smaller volumes should promote trading, improve price reporting and transparency, and, ultimately, promote a reliable price benchmark for LNG.

NOTES

1. Another motive may be that buyers see oil indexed LNG as expensive and spot LNG as cheap, but this is not, or will not necessarily be, true.
2. International Energy Agency, *Developing a Natural Gas Trading Hub in Asia*. (Paris: OECD/IEA, 2013), https://www.iea.org/publications/freepublications/publication/AsianGasHub_FINAL_WEB.pdf.
3. Patrick Heather, *The Evolution of European Traded Gas Hubs* (OIES Paper NG 104, Oxford Institute for Energy Studies, December 2015), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/02/NG-104.pdf.
4. "Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region," US Energy Information Administration, March 2, 2017, https://www.eia.gov/analysis/studies/lng/asia/.
5. Sheetal Nasta, *The Henry Hub in Louisiana*, RBN Energy LLC.
6. Sabine Hub Services, https://www.sabinehubservices.com/Default.aspx
7. "Transportation Principal Document," Joint Office of Gas Transporters, https://www.gasgovernance.co.uk/TPD.
8. However, as part of the allocation process after the "day," any imbalances are cashed out by the transporter to bring every user back into balance.
9. Nitrogen is blended with high calorific gas to reduce the calorific value.
10. Henry Hub was a supply area hub, while NBP and TTF are more market area hubs, although with the change in supply patterns in the United States, Henry Hub is becoming more like a market area, with its price being a high US hub price rather than a low one.
11. IEA, *Developing a Natural Gas Trading Hub in Asia*, 34–35.
12. Retail competition came later in the UK and the Netherlands and developed only partially in the United States.
13. Heather, *The Evolution of European Traded Gas Hubs*, 6–7.
14. Heather, *The Evolution of European Traded Gas Hubs*, 8.
15. The North American Energy Standards Board (NAESB) eventually superseded GISB.
16. Heather, *The Evolution of European Traded Gas Hubs*, 6.
17. Flat gas: "flat" meaning that the volumes traded are delivered at a constant "flow rate" during the whole of the delivery period, without any renomination rights.

18. Kept whole: meaning that the volumes delivered are guaranteed to equal the volumes traded; there is no interruption or volume tolerance permitted.

19. Limited force majeure: there is no relief of the obligation to deliver/take gas at the NTS; even an upstream field failure or a downstream exit point shutdown does not constitute FM.

20. "Gas Master Agreement and Annexes," European Federation of Energy Traders, http://www.efet.org/standardisation/standard-contracts--gas--power/gas-master-agreement--annexes/.

21. If a buy or sell trade is not matched by an opposite sell or buy trade, then rather than going to physical delivery, the open position is cashed out at the settlement price for the period.

22. Matching acquiring and disposing trade nominations (buyer from ICEU, seller to ICEU) are input by buyer and seller to national grid via Gemini before 6:30 p.m. on the business day prior to the commencement of the delivery period.

23. Heather, *The Evolution of European Traded Gas Hubs*, 7–8.

24. Ibid., 67.

25. International Energy Agency, *Natural Gas Information 2017* (Paris: OECD/IEA, 2017).

26. Cornerstone Research, The Characteristics of U.S. Natural Gas Transactions (Cornerstone Research, May 2017), https://www.cornerstone.com/Publications/Reports/Characteristics-of-US-Natural-Gas-Transactions-2017.

27. Cornerstone Research, The Characteristics of U.S. Natural Gas Transactions, 6.

28. "Gas Trading Volumes and Monthly Churn Ratio by Platform," Ofgem, January 2018, https://www.ofgem.gov.uk/data-portal/gas-trading-volumes-and-monthly-churn-ratio-platform-gb.

29. Heather, *The Evolution of European Traded Gas Hubs*, 81.

30. Patrick Heather and Beatrice Petrovich, *European Traded Gas Hubs: An Updated Analysis on Liquidity, Maturity and Barriers to Market Integration* (Energy Insight 13, Oxford Institute for Energy Studies, University of Oxford, May 2017), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/European-traded-gas-hubs-an-updated-analysis-on-liquidity-maturity-and-barriers-to-market-integration-OIES-Energy-Insight.pdf.

31. Heather and Petrovich, *European Traded Gas Hubs: An Updated Analysis on Liquidity, Maturity and Barriers to Market Integration*, 11.

32. Heather, *The Evolution of European Traded Gas Hubs*, 80.

33. "Argus Natural Gas Americas," Argus, March 2018, http://www.argusmedia.com/~/media/files/pdfs/meth/argus_naturalgas_americas.pdf?la=en.

34. Patrick Heren, "Guest Article: The Birth of the ESGM and the Heren Index," ICIS, March 20, 2015, https://www.icis.com/resources/news/2015/03/20/9869776/guest-article-the-birth-of-the-esgm-and-the-heren-index/.

35. The author was actively involved in managing a gas trading company in the UK in 1997 and 1998, and at the end of each day, we faxed an anonymised copy of the trades we had done that day to all the PRAs. It was in the interests of the traders that the reported prices were accurate.

36. International Energy Agency, *World Energy Outlook 2017*, OECD/IEA 2017, 584–9.

37. The price of gas when delivered at the city gate, usually the connecting point between the transmission system and distribution system.

38. US EIA, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region*, 39–40.

39. C. Aizhu and H. Gloystein, "China's Chongqing Gas Exchange Aims to Be Asia Price Benchmark," Reuters, December 29, 2017, https://www.reuters.com/article/us-china-gas-exchange/chinas-chongqing-gas-exchange-aims-to-be-asia-price-benchmark-idUSKBN1EN0HN.

40. METI, *Strategy for LNG Market Development* (METI, Government of Japan, May 2, 2016), http://www.meti.go.jp/english/press/2016/pdf/0502_01b.pdf.

41. METI, *Strategy for LNG Market Development*, 2.

42. METI, *Strategy for LNG Market Development*, 7.

43. Energy Market Authority, https://www.ema.gov.sg/Gas_Market_Overview.aspx.

44. Ibid.

45. This is obviously not necessarily correct since a true market price reflecting supply and demand could be higher, although in practice, as markets liberalized in the United States and UK, prices did decline compared to previous periods.

46. US EIA, Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region, March 2, 2017, 50, https://www.eia.gov/analysis/studies/lng/asia/.

47. US EIA, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region*, 50–51.

48. US EIA, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region*, 41–45.

49. "TOCOM Announces Launch of New LNG Contract on JOE," Tokyo Commodity Exchange, http://www.tocom.or.jp/news/2017/20170403-2.html.

50. Free on board—effectively without shipping costs.

51. Argus North East Asia price assessment.

52. Delivered ex ship—including the cost of shipping to the buyer.

53. "Platts Gulf Coast Marker (GCM) LNG Price Assessment: Natural Gas Price Assessments," Platts, https://www.platts.com/price-assessments/natural-gas/gcm-gulf-coast-marker.

54. Although given the reported churn for LNG of around one, this does not seem to happen that often.

55. This would not necessarily make the GCM an unreliable indicator of value of US LNG, but that does not qualify it as a liquid trading point.

56. Argus LNG Daily, http://www.argusmedia.com/~/media/files/pdfs/meth/argus_lngdaily.pdf?la=en.

57. ICIS, "LNG Markets Daily Methodology," March 22, 2017, https://s3-eu-west-1.amazonaws.com/cjp-rbi-icis-compliance/wp-content/uploads/2017/03/LMD-Methodology-22-March-2017.pdf.

58. Data provided by Platts.

59. Hossein Razavi, *The New Era of Petroleum Trading*, The World Bank, April 1989.

60. Paul Horsnell and Robert Mabro, Oil Markets and Prices, Oxford University Press for the Oxford Institute for Energy Studies, 1993.

61. Razavi, *The New Era of Petroleum Trading*, 3–4

62. Horsnell and Mabro, *Oil Markets and Prices*, 1993.

63. Horsnell and Mabro, *Oil Markets and Prices*, chapter 2.

64. Horsnell and Mabro, *Oil Markets and Prices*, 40–42.

65. Shell, *Agreement for the Sale of Brend Blend Crude Oil on 15-Day Terms*, July 1990, http://www.shell.com/business-customers/trading-and-supply/shell-shipping-and-maritime/about-shell-shipping/_jcr_content/par/textimage_1579012192.stream/1448968496791/093b727a895456a02499579ce5b9f861d33b43937a56d73728b106b9f15e0876/suko90-fob-brent15day1990gtcs.pdf.

66. A sold to B, B to C, C to D, and D to A.

67. IPE is now the ICE.

68. Horsnell and Mabro, *Oil Markets and Prices*, 48–50.

69. Horsnell and Mabro, *Oil Markets and Prices*, 75–77.

70. J. Shelor, "Industry Continues to Debate Mandatory Price Reporting for NatGas Marketers," Natural Gas Intelligence, August 4, 2017, http://www.naturalgasintel.com/articles/111310-

industry-continues-to-debate-mandatory-price-reporting-for-natgas-marketers.

71. Ibid.

72. US Department of Energy, "LNG Annual Report—2017," https://energy.gov/fe/downloads/lng-monthly-2017.

73. "Trend of the Price of Spot-LNG," Japan's Ministry of Economy, Trade, and Industry, January 18, 2018, http://www.meti.go.jp/english/statistics/sho/slng/result/pdf/201712-e.pdf.

74. It is the author's opinion that the prices probably are a reasonably true reflection of the market price for LNG, but the prices are not underpinned by enough physical deals, and there is a distinct lack of any churn. Market participants may not have enough confidence that the pricing could be manipulated or driven by one or more larger players.

75. Poten and Partners, *LNG in World Markets*, January 2018.

76. With more flexible, destination-free LNG, this will change.

77. Energy Charter Secretariat, *Review on Potential Standardisation of LNG Sale and Purchase Agreements*, 2017, https://energycharter.org/what-we-do/publications/review-on-potential-standardisation-of-lng-sale-and-purchase-agreements/.

78. Ibid., paras. 48 and 49.

79. Ibid., para. 33.

80. Horsnell and Mabro, *Oil Markets and Prices*, 16, table 2.2.

81. Calculations based on information supplied by IEEJ—Hiroshi Hashimoto.

82. Strictly speaking, in the transmission system or at a Japanese balancing point since there would be additional charges once the gas enters the distribution systems.

83. Assuming no real quality differences between the different regions, or if that could be solved.

84. A parameter used in most commodity and also financial markets.

85. Although volumes have risen as the total market has grown.

86. The island of Honshu, or the city gas markets stretching between Tokyo in the north and Osake in the South.

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