SPE-191532-MS

Evolution of Natural Gas Business Model With Deregulation, Financial Instruments, Technology Solutions, and Rising LNG Export. Comparative Study of Projects Inside the US and Abroad

Amina Talipova, Higher School of Economics; Sergei Parsegov, Texas A&M University; Roman Shulkin, Yamal LNG

This paper was prepared for presentation at the 2018 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, 24-26 September 2018.

Abstract

One of the primary energy sources, natural gas is widely used for power generation, industrial production, transportation, commercial buildings, and households. The industry is a capital intensive one for all stages from exploration to delivery. Two types of supplies: pipeline and Liquefied Natural Gas (LNG), recently have faced a direct intra-industrial competition. Physical nature of methane and associated transportation costs lead to domination of so-called "natural monopolies" or "national champions" and strict government regulation, which postponed the development of free trade and competition. After decades of technical innovations and cost curve improvement in LNG sector, shale boom in the USA, increasing global consumption, and demand for supply diversification reformulated the role of gas in the global energy balance. While the pipeline sector remains to be in the hands of large corporations and a subject of strategic interstate and international agreements, or LNG provides more diversity and flexibility of trade. However, even after a long history of LNG shipment since the late 1950s, LNG market is still regional with high spreads between countries and terms of delivery.

The paper presents the evolution of business models in the natural gas industry, focusing on the primary drivers as government regulation, production technologies, and regional markets trends on the way to liberalization and cointegration. Thus, our primary objective is to show relative influence power of these drivers. This analysis also defines the competitiveness of corporate business model under conditions of asymmetric information, regional gas markets, deregulation trends, fast-growing production technologies and downstream infrastructure (specifically in LNG sector). We also enclose the analysis of the most globally competitive gas projects. We analyze changes in value chain change and trading contracts. Our methodological approach poses model-based principles, including option and contract models, jointly with game theory elements.

Introduction

Natural gas has a potential to decrease CO_2 emissions of coal-based electricity generation and to fuel vehicles in liquefied or compressed forms (LNG or CNG). The major problem, however, is the transportation of gas itself. In contrast to the global oil market, gas markets are separated without assessing highly expensive infrastructure: pipelines and underground storages. Construction of gas pipelines is long-term capital intensive and highly regulated business, especially if the pipe is crossing borders. That is why only several companies form oligopolistic regional markets.

In mid-1970s USA[1], UK[2], and Canada[3] initiated deregulation of pipeline sector. Business models changed gradually from vertical integration and strict government price control to hub-based trade and competition between LNG and pipeline gas. Meanwhile, first LNG shipments were back to the mid-1950s, the economic impact of intercontinental LNG trade translated into the smaller spread and energy security only two decades ago.

In the first part of the paper, we define main value-chain components and drivers of the business model. We divide them into three conceptual groups: technological, regulatory, and market ones. In the second part, we discuss regional gas markets evolution in three historical periods. Finally, in the third part, we analyze possible ways to identify the weaknesses and improve business-models of gas producers in current lower-for-longer market conditions.

There is no other segment of petroleum industry which experienced such a dramatic transition due to shale revolution, new technologies of liquefaction, and regasification. Pipeline transmission has been the first technology to transport gas from fields to consumers. But without LNG option development of gas fields were uneconomical (stranded gas).

On the other hand, growing economies of Japan and South Korea secured by LNG supply from Qatar, Malaysia, and Indonesia. Another example - Algerian LNG complex initially constructed for securing Great Britain consumption before pipeline gas from the Netherlands partially took its place after significant North sea discoveries. And even though pipeline gas is generally cheaper for short distance case; the customer has to invest underground storages to balance peak demand. That's why full LNG tanks commonly used as a winter storage facilities. Such flexibility allowed the UK to cancel pipelines construction from Slochteren gas field (Dutch sector) and develop isolated natural gas grid (Correljé and Odell 2000; Williams 1981). Technical improvement of LNG floating storages and related cost curve may lead to even more flexible trading schemes and higher volumes on the spot market in the future.

Natural gas chain. What factors affect the business model?

The state of Technology

Extensive use of natural gas started in the middle of the 20th century after several milestone events which exhibited not only the feasibility of using gas as a fuel but also the technologies to transport it to longer distances. Pipelines were the first mean to deliver gas from producers to consumers and up to the present account the largest amount of gas transported and internationally traded. Later developed advanced technology to liquefy gas so that it could be transported by ship to the distances which are not economically efficient by the pipeline. Grid transportation grid was expanded from about 725,000 km globally in 1970 to more than 2,500,000 km by the end of 2015. The routes from the FSU and Africa to Central and Western Europe[4] today are where the largest amount of pipeline gas is interregional traded. Besides the transportation, which in most cases is treated as a central place in the project, other elements in the process chain are no less influential and could be more mission-critical for a business organization.

In case the customer has no direct access to the pipeline two ways of processing commonly taking place: compression into CNG or liquefaction into LNG. Fig. 1 represents the typical value chain. We pointed out the critical elements for competitiveness elements of each stage of production, transportation, and end-use. For instance, the distribution stage is the most vital is access to the final customer, whether it will be export or domestic consumption, the direct pipeline or the LNG, etc.

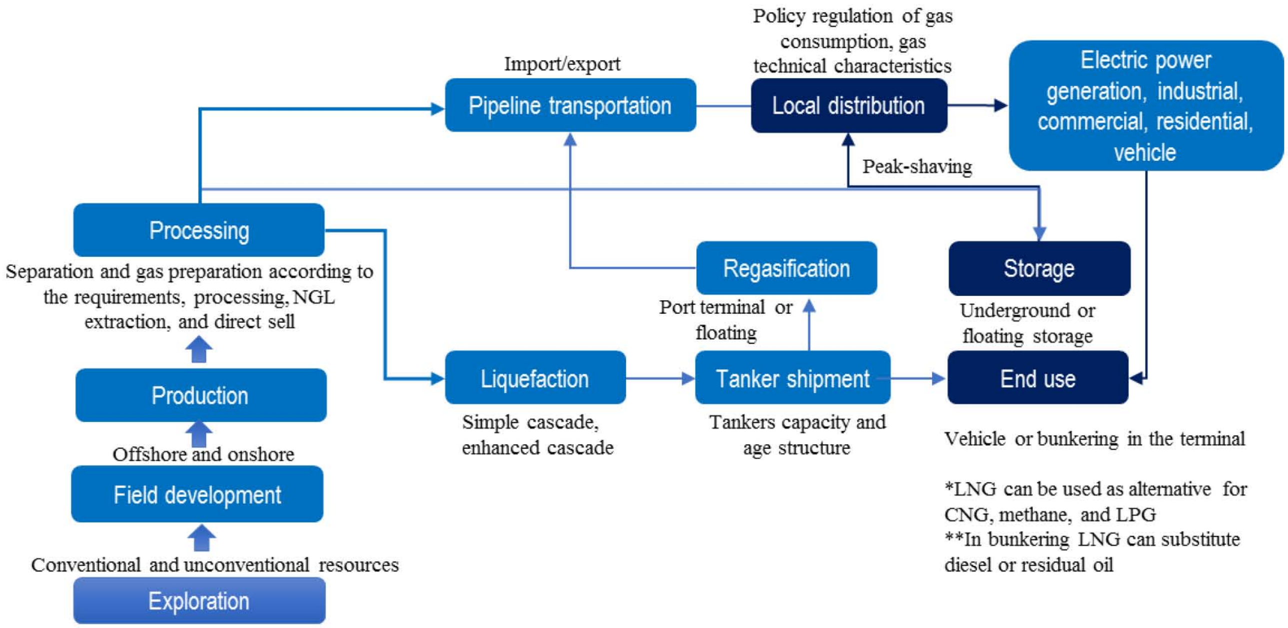

Figure 1—Natural gas processing scheme: upstream, midstream, and downstream.

Production and processing. Resources and reserves are the primary assets in oil and gas business. The structure[5] of fields in development, gas composition, the average level of depletion and finally, the offshore/onshore type of production are the key in determining the overall competition of natural gas to be sold on the upstream stage of the production chain. In other words, these components affect the wellhead price.

Unconventional technology production has become one of the market drivers in the oil and later in gas industry for the past decade. Natural gas production is making strides in the offshore, growing by almost 30% in the past decade to more than 1,000 Bcm/year (35,314 Bcf), according to (IEA 2017a). Many countries and regions, from Brazil to Australia to the Eastern Mediterranean, have plans to boost offshore production. But fastest growth we expect in the Middle East, with continued development of the world's largest gas field - South Pars for Iran, the North Field for Qatar, and in Africa, notably because of huge gas discoveries of Tanzania and Mozambique. Two facts come from there. Firstly, virtually all new gas volumes will be exported due to the enormous capital expenses to be recouped. Secondly, more than 90% of offshore gas reserves are trapped in deepwater fields (**Appendix 1**), whose economics suffered from shale revolution and related after oil price collapse. In the oil and gas, there the major producing or service companies own the technologies and learning curve, the question is about how the national companies and the government will agree on the joint projects. For example, Tanzania has been expected to become a new LNG player for a few years. However, because of the location of the offshore field, high production costs with simultaneously low oil prices and government regulation difficulties the project is in Tanzania is still under negotiations even though, the investment decision is carried.

A big problem for offshore gas fields development is a lack of technologies in developing countries. So, national oil and gas companies do capacity to construct LNG independently and will work through Production Sharing Agreements (PSA) with major petroleum operators.

The collapse of interests appear when in such countries there is the absence of elaborated legislative framework and if a decades ago when the first PSA agreements were agreed in current gas exporting countries like Indonesia or Malaysia[6] and event though perfectly affordable conditions were not settled a long ago. The demand for technologies was higher, unlike today when the governments wouldn't take such risks. Here two mentioned elements (technological and regulative) are intersected. Therefore, competition with such projects with onshore resource base is quite reasonable or makes sense to be included in the portfolio as many large companies use to (Fig. 2).

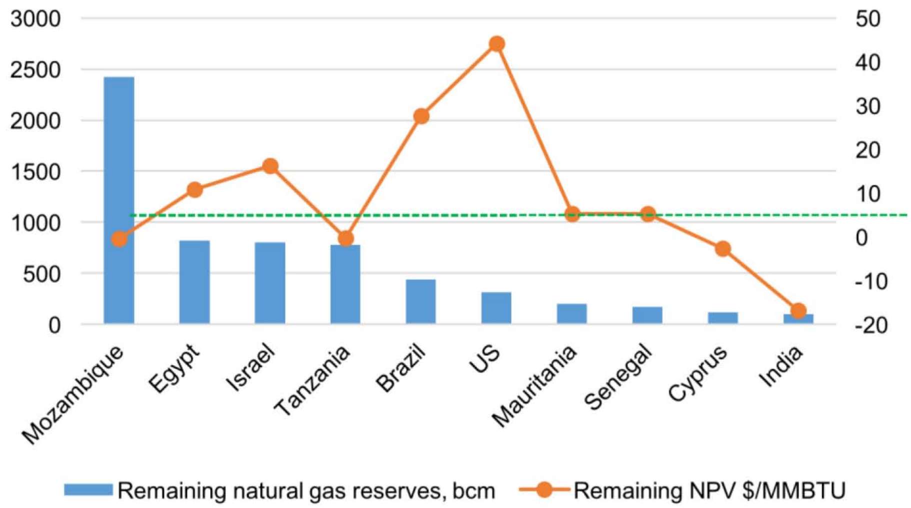

Figure 2—Remaining natural gas deepwater reserves and the expected NPV. Source: offshore technology[7], authors

Another flip side for these countries is existing well-developed offshore production in other countries that will constrain the market entry and objectively will be more competitive. The analysis shows that GCC countries will continue to dominate as offshore producing countries and also will dominate as gas exports themselves, particularly in LNG export (**Appendix 2**).

The largest share of offshore gas production accounts for Qatar, Norway, and Iran. Norway is estimated to produce just over 4 mln. boe per day, of which only over 50% is gas, most of it from Troll and Ormen Lange projects. The gas-dominant countries (Qatar and Iran) are following with 3.9 mln. boe per day and 3.3 mln boe per day, respectively (IEA 2017a).

Competition with such giants and stable market players as LNG exporters become a challenge unless the same players participate in new projects or high stable demand from South-Eastern Asia as expected. Deepwater Horizon accident in 2010 hit the offshore industry with higher safety regulations and associated cost. Shale revolution made the second hit in 2014 providing a flexible pool of onshore projects with shorter lifecycle trapped, however, inside the local US gas market. At the same time, expectations for higher oil prices are likely to show new decisions. More than 100 offshore projects expected to be sanctioned in 2018, compared with only 60 projects in 2017 and 40 in 2016 (Rystad Energy, 2017)[8].

The primary drivers of these projects are still the same: the projected growth of demand in Asia-Pacific and the falling costs is declining day rates by offshore drilling contractors, which is to date down 50-70%. Operators note that the time required to drill and complete a well has fallen by 30% in the North Sea, the GOM, and Brazil over the past four years. However, all these relate to the oil production, not to the gas. Hence, we see constraining factors from all of three aspects here for offshore prospects to change the significantly gas market configuration. The influence of this segment will be moderate and gradual.

Another important aspect that will define the future architecture of gas business is production technologies used to recover resource, depending on if it is conventional or traditional gas field development, tight or shale gas (Fig. 3). Natural gas is poised to take a more significant share of the global energy mix, but this would require that a higher proportion of the world's vast resources of unconventional gas are brought to market not only in a profitable manner but also in a way that addresses the legitimate public concerns about the associated environmental and social impacts.

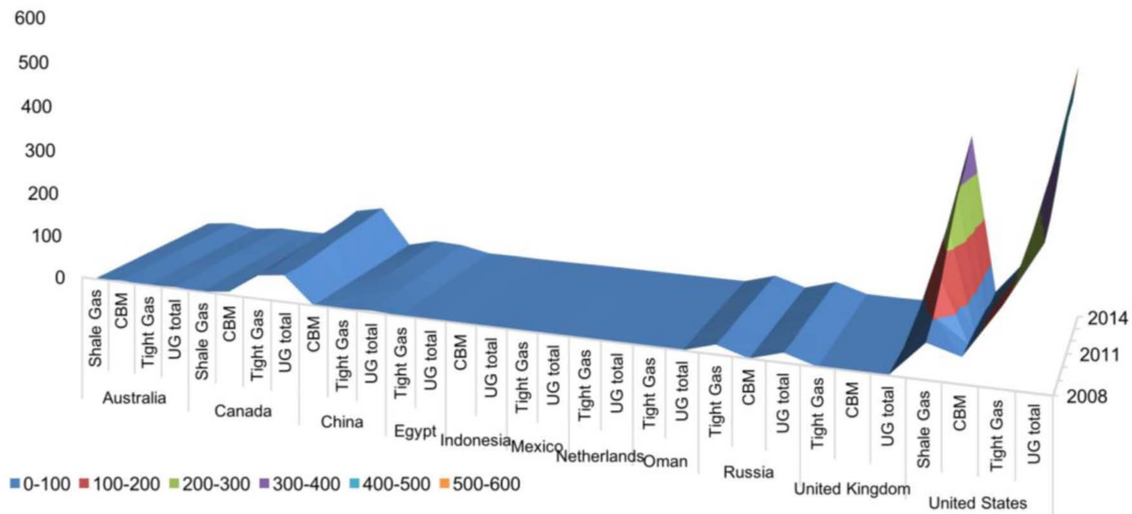

Figure 3—The structure of conventional, shale and tight gas of the top gas producing and exporting countries. Source: authors, IEA.

We do not anticipate difficulties with the technology in itself, and moreover, we expect the improvement curve will rise with time. The uncertainty lies in the regulative sphere and further cost-effectiveness of these technologies. However, if at this date amid slumping oil and gas prices they showed relative resiliency, the perspective of different gas technologies types equal competitiveness is somewhat positive. The most significant uncertainty, which will be discussed in the part of the blind-spots is China's expected shale production development. Similar to the US revolution it may break all expectations of the LNG exporters relying on enormous demand in China for LNG in the future.

The type of technology of gas extraction is more likely to affect global gas business which already proved its feasibility. The USA is still the only bright example but turned out to be enough to change regional pricing and marketing. Natural gas production from shale gas and tight oil plays now makes up about half of the U.S. total dry natural gas production.

Tight gas became a separate wellhead pricing category when the Natural Gas Policy Act of 1978 was passed and established an incentive to produce tight gas resources when natural gas resources were believed to be scarce. When wellhead natural gas prices were deregulated, tight gas lost its specific market-related definition and now refers to a natural gas produced from low-permeability sandstone and carbonate reservoirs. In (**Appendix 3**) we show an increase of production efficiency per drilling rig in the USA. Success of the shale revolution deemed to be replicable only in the case of all three conditions satisfied: technological, legal, and open market will be favorable for operators and service companies.

Summarizing the aspect of upstream gas production, in the mid-term the US will still dominate in the market with unconventional resources and new offshore projects may be put into operation in case of favorable market and price conditions or other circumstances producers will seek for further risk avoiding and risk-sharing schemes, etc.

Gas specifications. The most exciting points occurred in the last two decades is strengthening replacement possibility of LNG as compared to the processed pipeline gas so that LNG is now can be successfully transported to the countries where pipeline consumers already exist. Technically, it means, that LNG has the same requirements after processing, transportation, and regasification as the gas directly transported through the pipeline. If previously LNG projects were quite inflexible: with long-term contracts and fixed destination (no re-selling or re-export) and few buyers, there were no issues in product design and plant specifications.

The more LNG becomes tradable and target more consumers; the more project margin will depend on technical and timing flexibility to exploit shrinking market inefficiencies. Two of them will remain regardless of rising competition: LNG specifications and seasonal volatility. There is no surprise that LNG shipments and the contractual quality are not in the public domain as well as exact timing and destination in long-term contracts. The problem lies in the LNG technological curve and competitiveness between the old plants and new ones with improved processing and larger-scale effect.

Natural gas technical requirements meet several purposes such as corrosion prevention, liquid drop out relative to pipelines, burning, freezing relative to the LNG. For example, the requirements for corrosion prevention include regulation of CO_2, H_2S concentrations, mercaptans or sulfur. LNG facilities treat gas down to 50 ppm CO_2 to avoid freezing in the cryogenic processing unit and therefore meet receiving end pipeline specifications. LNG producers, at the same time, must remove C_4+ components to prevent freezing in the liquefaction process and further transportation. Other parameters refer to the quality of gas.

The first type parameter of the natural gas whatever form it takes is higher and lower calorific values. Two other characteristics come from there: higher heating value (HHV) and Wobbe Index (WI) (**see Appendix 4**).

Different conditions set can be observed in different regional markets. Asian countries, for example, import rich LNG with higher ethane (C_2+) content, while the US or the UK import LNG with a smaller C_2+ fraction. These requirements come from the pipeline gas specifications where the LNG goes after regasification. The stricter norms of California gas pipeline system (C_2+, CO_2, and N_2 content) virtually block the import of LNG.

Following that, new LNG projects may benefit (from monopolistic power) if technical flexibility would allow them to tune LNG composition for the desired market, take a quality premium, and block further reselling to third parties. Moreover, growing spot market with short-term contracts allows more technically flexible LNG projects to benefit from seasonal variations of LNG demand.

Transportation. It took almost 35 years from the commencement of commercial shipments for LNG fleet to reach 100 vessels, in 1998, but the 200 vessels mark was achieved in the next eight years – in 2006 (Fig. 7). However, LNG tankers fleet is still tiny in comparison to the oil counterpart with more than 12,000 oil tankers globally (**Appendix 5**).

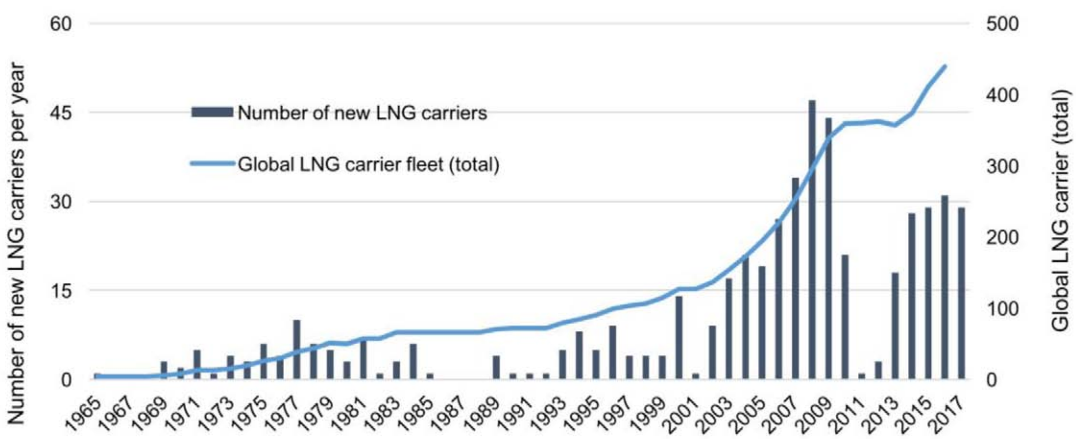

Figure 4—Statistics of global LNG fleet. Source: Gas in focus, 2017.

Due to the long history of LNG shipping, technical requirements are well-developed in both importing and exporting countries and regulated by the International Maritime Organization (IMO). LNG carriers have a high safety degree of design features: they are double-hulled and consist of two type of tanks, ballast, and cargo. The most frequent transporting hazards are flaming and spill. There have been recorded about 52 incidents that involved LNG tankers worldwide since 1964. As LNG is a liquid, it doesn't burn, because of lack of oxygen to sustain combustion. The risk of burning usually caused by vapors, but only in case the air they content is about 5-15%. If the concentration of the fuel is lower than the low bound (5%), it cannot burn as well. If the fuel concentration is higher than the high bound (15%), it cannot also burn because there is too much oxygen relative fuel (**Appendix 6**). Average LNG capacity per tanker is steadily rising since 2007 (Fig. 8).

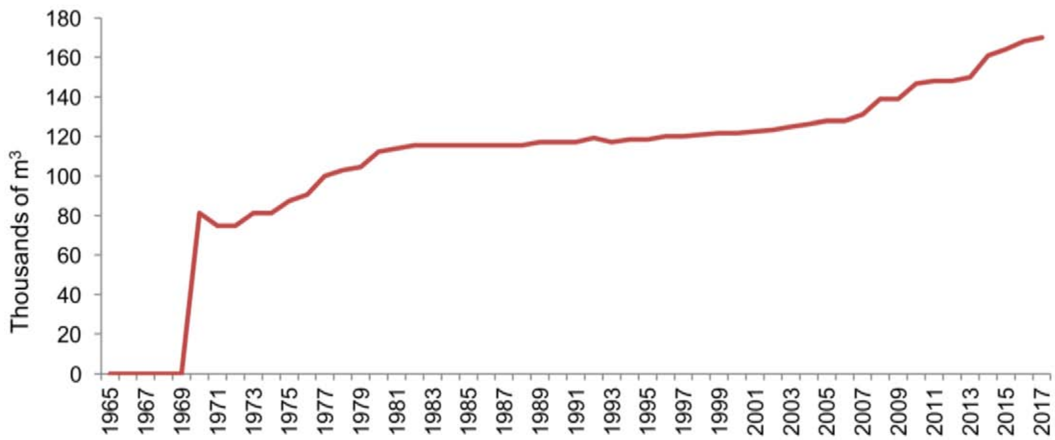

Figure 5—Statistics of global LNG fleet capacity. Source: Nexant, global LNG outlook, 2017.

Therefore, we assert that the lack of fleet together with the slightly increasing ship volume. Consequently, we affirm that the lack of fleet, along with the slightly rising ship capacity, will still constrain the markets from globalizing.

LNG flaming risk is a combination of the chances of vaporizing, mixing with the air in a certain proportion and an ignition source. The specialized systems on the carrier strictly regulate spill hazard. As ships are safe and reliable, the choice of LNG transportation is based primarily on route economics, daily rate, delivery schedule, and capacity rather than technical or performance criteria.

Two technical measures of efficiency characterize the tankers that may affect regular shipments. Technical efficiency (TE) is the efficiency of a ship in its as-designed condition (straight from the yard) and operational efficiency (OE) is an estimate of real-world efficiency as characterized by the relationship between the transport demand (e.g., tones of a commodity shipped) with actual capacity-distance (e.g., tonnes cargo x nm sailed). LNG carriers are usually designed so that the amount of BOG is equivalent to the amount of energy required at the design speed, in which the vessel will burn 100% BOG. Operationally other factors influence the actual BOG, such as ambient temperature and the temperature of the LNG when loaded. Immediately after loading there may not be enough gas as the cargo is cold, so the vessel will start slow and speed up as the BOG increases. The Qatar series of ships (Q-flex, Q-max) was designed at a time when the price of heavy fuel oil (HFO) was historically low. They are the only LNG ships that were not designed to burn LNG for propulsion, instead of using HFO for regasification the BOG. About 13% of LNG carriers are Qatar series. Because of the flexibility of LNG carriers in using different types of fuels, prior studies by the International Council of lean Transportation that quantify energy consumptions from shipping did not examine the energy mix in LNG carriers. Given the fact that LNG carriers need to consume BOG for most but not all of their trips. Average energy efficiency of the LNG tankers is given in **Appendix 7**.

Floating regasification is a flexible, cost-effective way to receive and process shipments of LNG. Floating regasification is increasingly being used to meet natural gas demand in smaller markets, or as a temporary solution before construction of onshore regasification facilities. Of four countries planning to begin importing LNG. In 2015, three of them, Pakistan, Jordan, and Egypt chose to do so using floating regasification rather than building full-scale onshore regasification facilities (IEA 2017b).

Floating regasification offers a flexible, cost-effective solution for smaller or seasonal markets, and can be developed in less time than an onshore facility of comparable size. It can also serve as a temporary solution while permanent onshore facilities are constructed, and an FSRU can be redeployed elsewhere once construction is completed. There are currently 16 FSRUs functioning as both transportation and regasification vessels and five permanently moored regasification units that have been converted into FSRUs from conventional LNG vessels (IEA 2017b). This type of technology may relatively affect the spot market in terms of fast operations and lower costs.

Markets and trade

The gas industry still remembers 2011 watershed year, when IEA raised the key question: "are we entering a golden age of gas?". Standing almost 10 years later that wide discussion about gas future gas, the answer doesn't still appear to be fully positive as it was expected, with the only exception of the USA where the scale and resilience of the "shale gas revolution" exceeded the wildest expectations.

However, the growth of demand is observed in Europe and expected in Asia-Pacific, so that natural gas is still an object for resting the hopes in. Natural gas has a good reputation of a clean and the least carbon-intensive fuel that may play an essential role in future energy transition (if applicable). As for LNG, the market has grown significantly because of new economically efficient projects and new importers emergence, technology development, over the last 10-15 years.

It has doubled in size and moved from a market dominated by long-term trade with strict destination clauses to one influenced by spot sales, traders, gas benchmark-link, increasing re-trades and destination swaps. The emergence of new LNG importers as Poland, Pakistan, Jordan, Thailand, etc. absorbed new production and held out a hope to increase the demand.

China is of big interest and expected to be not only one of the largest importers of LNG in the mid-term, namely the second after Japan, period because of its gas transition program establishment, but also a new driver of Asian market LNG trade organization transformation. Regional gas markets still show price difference, with a slow trend of converging, however. Spot contracts' share rose in for the last ten years, but still around 30-35% in total[10]. Market and particularly future hub trade development directions are more likely will be the highest uncertainty for analyzing gas business.

Gas markets regional nature. The cross-national gas trade has been growing for the past 50 years, since the first LNG exports began, from the USA and Algeria, and the cross-countries pipelines were built from the Netherlands to European neighbors after Groningen discover. Today only 30% of produced gas is traded across national boundaries, two-thirds of which by pipeline and the other third as LNG. Worldwide trade, especially in LNG, will continue to grow regarding both the volume and the number of importing countries.

We outline several reasons for that: the amount of gas reserves to be monetized by producers, affordable prices; substitution of coal consumption; domestic production decline in EU and Asia with simultaneous demand increase; increasing gas-on-gas type of competition due to flexibility in terms and costs; slight spot trade increase; and numbers of LNG plants under construction.

Historically, gas markets and trade, therefore, are regional by nature because of big infrastructure investments along the whole value chain as it was mentioned previously and high capital costs to build pipeline networks. High costs in their turn caused natural monopoly concentration and strict regulation. Along with an objective competition with other fuels, LNG gas for a long period wasn't competitive with the pipeline having another marketplace. Today top-3 regions accumulated more than 90% of all gas trade and formed three historically independent markets (**Appendix 8**). We made the following conclusions:

1. The USA covers the decline of import in North America (the sum of the USA and Canada). Whereas the USA demonstrates gas production boom, the fundamental question stays, will the companies producing unconventional gas be able to improve much better than now costs at lower rigs amount.
2. Predicted high demand for gas in Asia is expected, but the structure of import by country is more important in this sense (Fig. 6). The more interesting in Asia for market players whether China's demand will exceed Japan's in the mid-term because now the latter is still the largest world importer.

No less important is a government policy of recently appeared importers towards liberalization and open market organization.

3. EU will continue to experience domestic production decline mainly driven by the Netherlands. The highest uncertainty here is the EU's released national strategy on LNG and storages and how successful it will be implemented accordingly to the price volatility. The attraction of this regional market will be affected by national energy policies, political interests and further process of European integration as well.

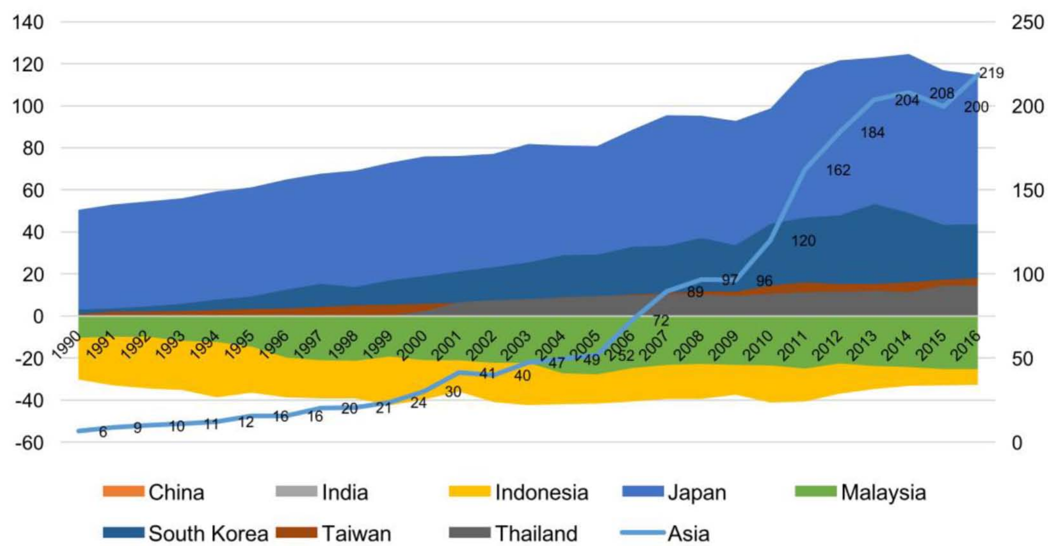

Figure 6—Net import by country in Asia (in Bcm). Source: Enerdata

With a high level of certainty, the same regional structure is expected to exist in a mid-term, but these three markets will work more mutually dependent. Looking at the market tightness for the past 20 years, the indices Asian markets tight as sharp demand rise (**Appendix 9**). European market tightened mostly from 2013 because of fast production decline. The EU market eases the increase of import supply which is being supported since the last year by a new Security of Gas Supply Regulation[11]. Finally, in the North America market tightens since the LNG export flows to rise. As the primary share of new LNG production capacities accounts for the Asia-Pacific, it eases the market. Stable regional structure preserve is of significant interest for exporters to plan their flows and returns.

Natural gas is traded with different histories, contracts, requirements and transportation types. The USA and Canada consume about 30% of world gas supply and have the most liberalized market that is based on pipeline and gas-on-gas competition, therefore. The EU gas market appeared after huge gas resources discovered in the North Sea. Historically it goes back to a coal-based system. Since the European Commission came to the idea of a Single Gas Market, there has been some increase in the number of suppliers, but negatively it created a battlefield for these market incumbents interested in saving their status quo and supported by their governments. Hence, significant discussion about "depoliticization" of gas trade, cost reduction and security increase through internal gas supply flexibility take place in EU. Asian-Pacific region's consumption is equal to the European but shows the fastest growth over the past two decades. Historical trace answers why this market in its current organization form. After the oil embargo of 1973, Japan adopted a strategy for energy security development. At that time the country generated 75% of electricity from oil combustion.

The government encouraged gas utilities to involve in a long-term take or pay based LNG contracts. Similar to the EU, trading was based on crude oil imported. Although Japan is still the largest consumer, other countries for the past 30 years started to import LNG (Bangladesh, Taiwan, Thailand, China, etc.)

and this may dramatically change Asian market in the next few years. The most arguably is the probability of new hubs appearance in China, Singapore or Malaysia, which already released readiness to form a new benchmark that will change the trade rules towards unification and more fair competition. When talking about connectivity among these markets as well as about future gas trading, at most the LNG is understood and how it can change traditional mid/long-term trade.

Undoubtedly, the objective reasons for gas trade constraints are apparent, transporting requires the pipeline construction, port facilities, larger fleet, while industries' refocusing on gas takes time and costs billions with economic benefits in most cases though.

The other side that sometimes may not be apparent, but no less high powered is barriers formed by non-competitive pricing, thin markets, risk aversion, restrictive contracts, government trade policies. That is why still more than 70% of all produced gas in consumed in the country of origin[12]. When it is pointed that the LNG traded rose from ~170 MT in 2007 to 290 MT, the fact that original structure and balance among three (four including ME) markets should be taken as well (Fig. 7).

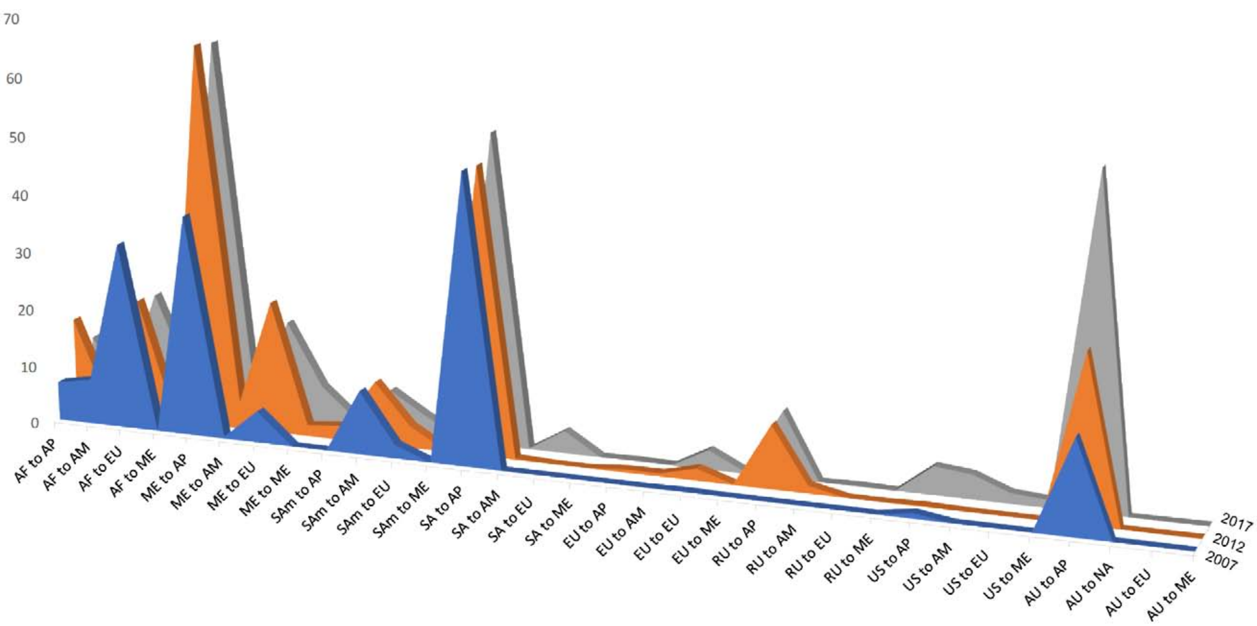

Figure 7—LNG trade flows (exporters & regional markets), 2007-2017.
Source: International Group of Liquefied natural gas importers, authors

The trade in the USA is an interesting example, because it is based on the pipeline trade mostly, and only recent LNG projects there allowed gas industry to make suppositions about Henry Hub (HH) as a future global gas benchmark, even though there is a separate LNG future in the NYMEX. In 1975 only four exporters were on the market, by 1995 this amount doubled to eight and, finally, as of 2017, forty countries are LNG importers, and 19 nations are exporters. Totally, in 2017, global LNG trade accounted for 289.8 MT with a 9.9% increase compared to 2016. Form this total LNG traded amount 77.6 MT (around 27%) was purchased on a spot or short-term basis, while other volumes are long-term contracted. The share of spot trade hasn't changed a lot over the past years also but rose more than 40-50% on average.

Thus, regional structure of gas markets developed due to objective reasons: 1- deregulation in the USA and domestic production, 2 – coal substitution in EU, a significant amount of pipeline import and recent deregulation, 3 – oil substitution and high oil prices in Asia along with economically ineffective pipeline supply. This regional structure will save in the mid-term period due to the relatively small share of cross-country gas trade and historically different types of markets based on different types of competition which is difficult to change rapidly.

This status quo, however, may be transformed only by the combination of the following factors:

1. The emergence of new hubs in Asia (China and Singapore as expected) that will cause a slight change of contracts structure and new benchmarks;
2. Economic growth and high demand for gas from power generation and industrial sectors (including transportation/bunkering);
3. Increasing environmental concerns and coal substitution (mainly in China);
4. Security supply and geopolitics related to the pipeline projects (mostly in Europe);
5. Developments and improvements in upstream technology (primary relates to the USA shale production and how they will develop their cost curves).

Global LNG trade flows show that the most significant amount of that will be still concentrated in the Asian market. Here we point only one region, namely the South China Sea that will continue to consolidate the main trade flows without limiting other forgoing regions. The South China Sea is the most intensive LNG trade route worldwide. According to EIA, 40% of global LNG trade passed through this region. It accumulates flows from Brunei, ME exporters, Malaysia which go to Taiwan, Japan, China, South Korea, and Thailand (**Appendix 10**).

Notably, it is an essential route for Qatar and Malaysia which account for 60% of their total LNG trade. About 50% of Qatar's shipments go via this route, and 100% Malaysia's export flows are concentrated there. Also, floating LNG ships are under construction in Malaysia. Other exporters also use South China Sea trade routes. In 2017, Oman, Brunei, and the UAE shipped about 85% of their total LNG exports through the South China Sea.

Other exporters in the region, such as Australia and Indonesia, use different trade ways. In 2017, about 25% of total Australian LNG exports and about 30% of Indonesian LNG exports were shipped via the South China Sea. Other exported volumes passed in the direction to Japan, South Korea, and northern China avoiding the South China Sea.

The more LNG producing companies will change, the more markets and trade organization will change. Whether it relates equally to technology or trading is one of the key objectives to study. For that very reason, the regional landscape markets in mid-term never been so challenging as it is now. At the same time, as liberalized (or liberalizing) markets are being studied, the supply-driven imbalance factors and demand-driven factors should also be studied.

The in-depth insight of interplay among the three markets, resulting from potential new developments and supply-demand factors, will allow market participants to make reasonable business decisions and for policymakers to act for public interests.

Costs. In this part, we will not concentrate on the whole production chain costs from gas development to the final consumer. We will point only transportation costs, which, however, take almost one-third of the total amount and on the liquefaction capacity. These two aspects, to our opinion, define the future trends in the gas market whether there still will be technological constraints and cost escalation or high competition will arise. A big attention paid on LNG is explained by the market demand, which asymmetrically high in the Asia-Pacific.

Doubtless, on very short distances the pipeline is the most appropriate. The main Asian-Pacific high margin market, however, is located too far from producers as well as a new emerging consumers Pakistan, Bangladesh, Jordan, etc. and the LNG becomes the most appropriate way to deliver natural gas. The 2000s were famous for new developing countries emergence as China and India, which showed enormous economic growth which, consequently, led to the high energy demand and higher commodity prices. Less visible evidence from that period was the increase of upstream OpEx and CapEx indexes along with the growth in the power sector (**Appendix 11**).

Liquefaction costs per unit tonne of LNG reflected this trend from the first side, but several times higher. At the same time, liquefaction capacity for each LNG train hasn't increased in the same degree or higher, even though, the total capacity of each plant increased. This metric plays a significant role in the project's competitiveness due to the scale-effect. The Fig. 8 represents the dynamic of new LNG capacities put in operation until the end 2017 of each train. It means that different points can be one of the several trains in particular LNG plant. The highest capacity throughout the history was implemented in Malaysia.

LNG plant cost data were collected by the authors based on the previous research conducted by Oxford Institute of Energy Studies (Songhurst 2014) with extension up to the 2024 year for the world scale liquefaction plants built since 1965 from open sources published information and reports. The metric cost of $/tpa was calculated, and the results are shown in Fig. 9. We also classified the costs by scope according to the value –chain so that they would be comparable. The physical capacity of the plant, as stated above, shifts costs and improves economics. On the Fig. 9 the red points indicate the plants with the liquefaction facilities only. Mainly, the recent plants of such type are located in the US, while previously they also were built in Nigeria, Malaysia, and Australia (Songhurst 2014).

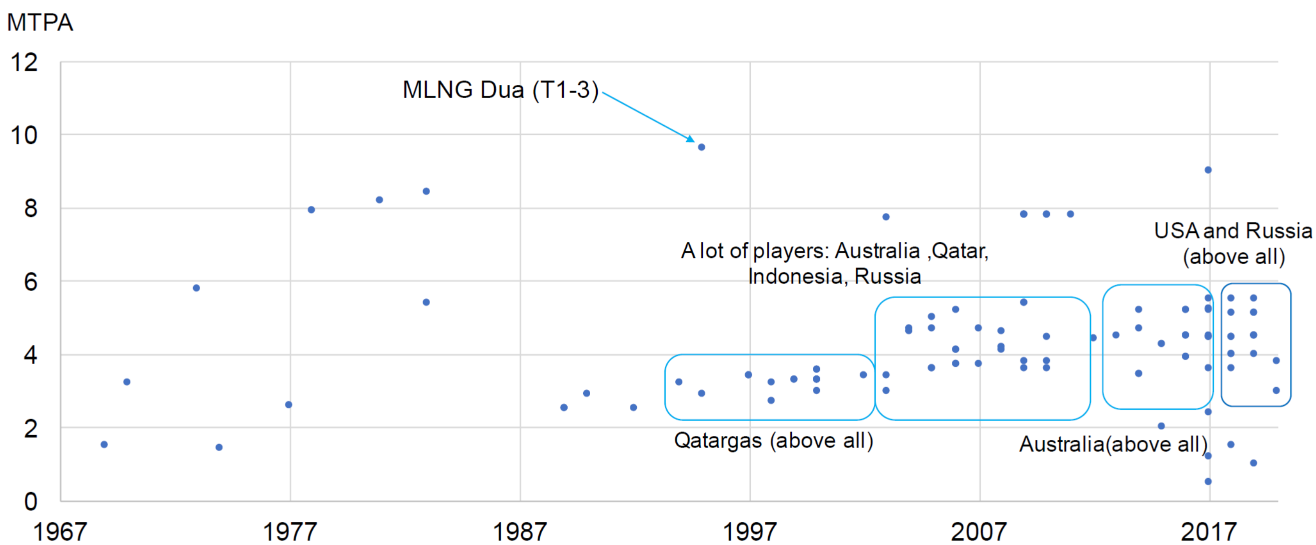

Figure 8—Liquefaction train size growth. Source: authors, IGU

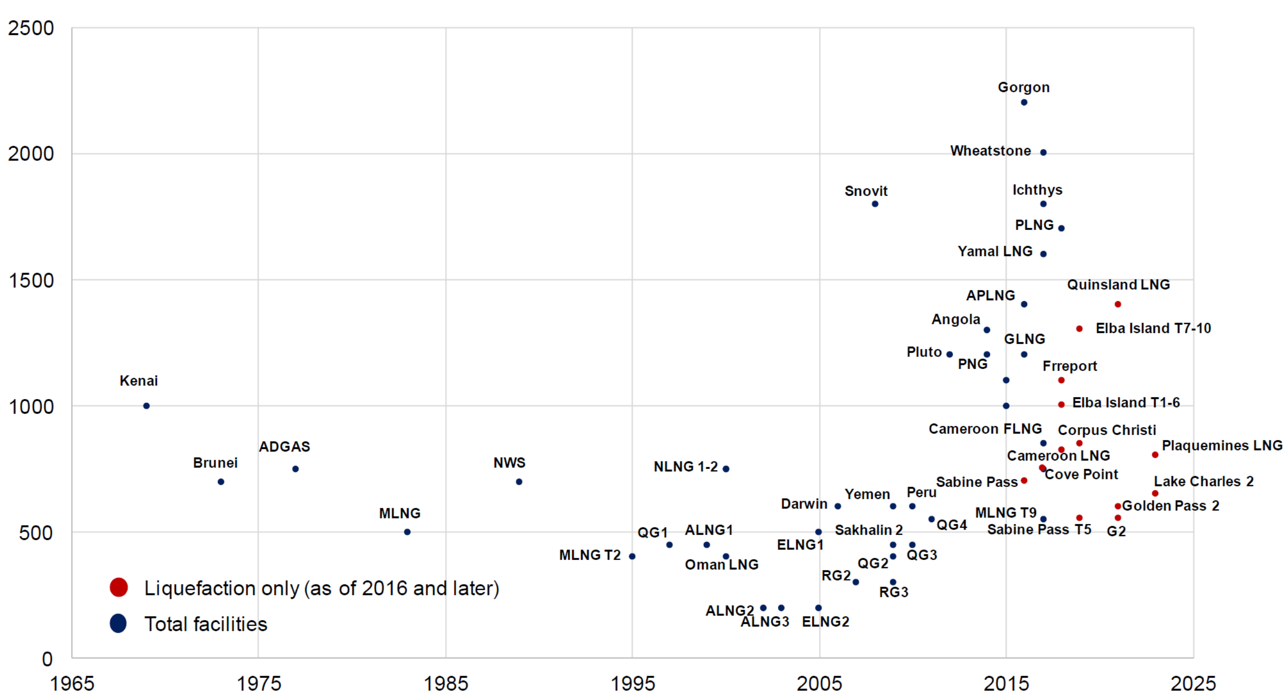

Figure 9—LNG CapEx $/tpa curve. Source: authors, IGU, Cheniere, DOE, APLNG, Offshore technology, Bloomberg, LNGnews, other open sources

The first expansion was undertaken at the Malaysian LNG plant in 1995, and the cost was lower than the original grassroots plant, as would be expected. The expansions since then, as shown by the red diamonds, are all at a lower cost due to their reduced scope. If we take a look at the facilities scope today, there will not be so obvious that the costs are low, because the production capacities of the new LNG plants that will come to the operation from 2019-2024 are big enough and fully optimized for export, LNG terminal capacities and expected growth.

Secondly, we point out the key role of the transportation in the future market transformation, and mainly, the whole transportation costs that define the export routes and companies margin. The key components that make up the cost of shipping LNG include:

1. Chartering fee. Made for securing access to shipping capacity by chartering a vessel. There are broadly three ways to secure access to shipping capacity: own vessel capacity; long-term time charter and spot (short-term) time charter (for a single voyage). Chartering fee declined for the last few years (see **Appendix 12**). Vessel charters are typically arranged through specialist brokers and attract a 1-2% fee, and this should also be taken.
2. Fuel consumption: The voyage fuel or 'bunker' consumption is directly proportional to the distance and speed of the vessel. This is typically the second largest cost component after the chartering cost. Most LNG vessels can burn fuel oil, boil-off gas or a blend of both in their boilers. As a result, the calculation of fuel cost is closely tied to that of boil-off gas.
3. Port costs: The components and level of the costs of loading and unloading at ports can vary widely depending on location. For example, ports in less stable regions can levy large security charges associated with ensuring the safety of the vessel. Here are the canal costs may also be included. Transit costs have to be paid for using the cross-continental Suez and Panama canals.

Suez canal transit costs are a complex function of vessel dimensions, and cargo (laden voyages being more expensive), and LNG vessels are entitled to a 35% discount after which the costs are in the region of USD 300-500k per transit. With the Panama Canal widening project, around 80% of LNG vessels can make the transit. This reduces the distance from 16,000 to 9,000 miles from the US Gulf coast to premium Asian markets (Timera Energy, 2017).

Finally, the Figure below (Fig. 10) provides the comparison of the LNG vs. pipeline competition depending on the transportation distance.

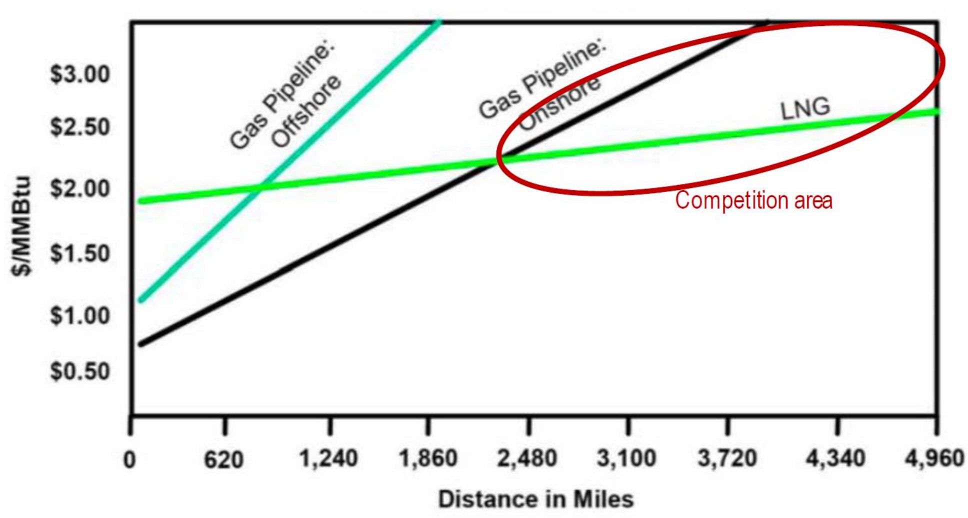

Figure 10—Economic comparison of Pipeline and LNG. Transportation costs. Source: Institute of gas technologies

Summarizing the main idea we advocate for the core importance of the two main aspects that will define future trade, namely, the competitiveness of the LNG plants due to the capacity and CapEx per unit ($/mtpa) and the transportation costs which will define the overall substitution of the pipeline gas by LNG.

Pricing and contracts. The record price convergence in regional gas markets has been observed for the last five years in point of fact. As mentioned, both demand and supply played an important role in forming the current spreads. It's worth pointing out several non-price key factors as:

1. The USA shale gas production boom
2. European financial crisis that brought on the demand decline
3. Japan nuclear crisis and refocusing on gas

Does this mean an upcoming arbitrage in gas markets? – Not actually. Sellers' and buyers' business interests are usually don't overlap each other. Buyers get a fair price and secure supply through a large diversified number of sellers, whereas sellers try to pay-off their investments through fixed long-term (preferably) contracts.

Even though the biggest pipeline companies with a monopoly position in some markets tend to disagree with insisting on the fact, that this type of gas supply is the most safety, we strictly disagree with this assumption. All historically natural gas monopolies (due to significant CapEx required) in developed countries soon or late were deregulated when possible so that the competition rose and real price was formed.

Choosing the monopoly of pipeline import whatever or no make any buyer a price-taker. Today's competitive environment in the gas industry makes buyers price-makers or at least formers of the market where no one seller may influence the price (equivalent to the hub-based pricing). Another contradiction introduced here is the sense of hub and spots which may cause a speculative part that increases prices. Partly, this evidence may take place in a long-term future when all regional gas markets are enough liquid, but only in case, the gas will indeed play the same role in the future as the oil.

Pricing mechanisms in gas markets can be broadly classified into competitive or non-competitive, depending on whether prices are set on the supply-demand basis or by fuel substitution, bilateral monopoly, monopolistic, or by the government. That any type of price formation different from what is defined by supply-demand, cause reverse-bias to the inefficiently high or low price. Both competitive and non-competitive pricing mechanisms are seen in different markets, depending on the previously mentioned reasons.

Despite the growing LNG trade and deregulation, non-competitive pricing still predominates in the high-margin markets. According to IGU, as of 2016 international trade of gas accounted for 28% of total consumption and this is one of the reasons the gas markets remain regional. Pipeline import of the total volume reached 57%, while 76% of LNG trade had OPE basis (**Appendix 14**).

Since 2005, the GOG share has increased from 31% to 45%, at the expense of OPE which has declined from just over 24% to 20% in total, with the main change in Europe where GOG increased from 15% to 66%. GOG also gained in Russia in 2009 in 2015 following the pricing reforms. Inspire the official data of IGU about trade he pricing structure in FSU (where Russia accounts for about 90% of all consumption); we don't agree with this due to some institutional reasons. Even though the traded gas in Exchange has been accounted as a GOG this share is reported as a raised, in fact, the trade in the exchange is still provided by the main monopoly company by more than 70%. However, the data are given in origin.

The main changes in pipeline import for the last decade have been observed in Europe where the GOG share of contracts raised from 23% in 2005 to 57% as of 2017, while the LNG supply was quite stable. It may seem a bit unusual, but even though the share of spot trade in LNG markets rose from 10-13% to 32-35% in the same period (2015-2017), the most significant percentage of this growth was observed only in the period 2005-2007/2008 when the UK and several other European countries started to trade NBP based LNG contracts. It means that if the trade rises in the Asian market, competition based (GOG) contracts and in most cases spot share decreases as it was, for example, in 2016 when the GOG share of LNG imports fell back to 24% (**Appendix 15**). Almost the half of pipeline import in the world has a GOG base.

This statistic, however, is going to change rapidly in the next few years and transform significantly gas markets. China's pipeline import will be doubled by the Siberia Power from Russia and South Stream. In Europe, TANAP was recently announced with total 6 bcm/y first pipeline capacity. A significant incident happened in EU dispute with Gazprom as well that will soon affect the trading in EU gas market.

The key issue here for producers and exporters is the price these mechanisms lead to. Will the exporter be anxious about whether the price on its gas competitive or not when the last gives the highest margin? The question is not it about economic fundamentals. However, it also takes place. The competition is usually considered between two similar commodities as we now call it - GOG.

As for Asian markets, historically the competition was caused by the absence of resources, and therefore different types of fuels competed. Current market prices show the highest margin on OPE type of gas contracts. Even when the oil price fell in 2014, they were still much higher unlike any other regional competitive prices (**Appendix 16**).

Logically, very high LNG capacities construction calls for contracts, which in their turn have OPE base. As a result, in the past ten years, high oil prices formed high LNG prices in the Asia-Pacific region. The conflict between Asian buyers and sellers is growing, therefore. While the first insist that oil-indexed LNG prices are no more untenable, LNG producers assert the fuel competition (which is not competitive fundamentally) that contracts based on the HH price will not create project economics (or support the development of unconventional gas resources). In theory, the higher competition (GOG is considered including the pipeline) in the market among sellers, the more market should be deregulated by the government so that to make markets liquid with a financial instruments trade (futures, options, spots). In this case, producers will face barriers to guarantee their capital returns as new hypothetic contracts will no more reflect the real fuel competition being under another price pressure. In other words, the current pricing mechanisms appropriate for any current producer (and upcoming projects under construction) requires at least netback (excluding shipping costs) to be enough for capital return unless other business-model optimizing opportunities are available.

Table 1—LNG Pricing Mechanism 1: Henry-Hub linked Sales Purchase Agreement

<table>
<tr><td colspan="3">Cheniere Example: 115% of Henry Hub + Liquefaction</td><td>S/MMBtu</td></tr>
<tr><td colspan="3">Henry Hub spot ($3.00, for example) * 115%</td><td>$3.45</td></tr>
<tr><td colspan="3">Liquefaction charge (Customer pays liquefaction charge regardless of lifting LNG cargo or not)</td><td>$2.25</td></tr>
<tr><td colspan="3">FOB cost</td><td>$5.70</td></tr>
<tr><td colspan="3">Shipping (Japan via Panama Canal)</td><td>$1.10</td></tr>
<tr><td colspan="3">DES cost</td><td>$6.80</td></tr>
<tr><td colspan="4">Supply Chain Responsibility: Terminal operators obligation in green. Offtaker’s commitments are in red</td></tr>
<tr><td>Source Gas</td><td>Deliver Gas to Liquefaction Terminal</td><td>Liquefy Gas</td><td>Offtake LNG to destination</td></tr>
<tr><td colspan="4">LNG buyer pays:
1. Liquefaction/usage fee: Paid regardless of whether the customer uses the facility. Covers the project company’s facilities and fixed costs.
2. Gas fee: Payable based on the amount of gas liquefied.</td></tr>
</table>

Source: Navigant Consulting, Platts

Table 2—LNG Pricing Mechanism 2: Tolling model. Cove Point Example – Cove Point produces LNG but does not take title or market LNG

Supply Chain Responsibility: Offtaker's obligation in red. Terminal operators obligation in green.			
Source Gas	Deliver Gas to Liquefaction Terminal	Liquefy Gas	Offtake LNG to destination
LNG buyer pays: 3. Reservation/capacity fee: Paid regardless of whether the customer uses the facility. Covers the project company's facilities and fixed costs. 4. Liquefaction/usage fee: Payable based on the amount of gas liquefied.			
Risks		Rewards	
Source, secure, nominate & scheduling gas into pipeline & LNG plant		Long-term control of gas supply needs (up to 45 years)	
Contact sufficient pipeline capacity at liquid market points to the LNG plant, ensuring competitive gas supply		Not competing with the plant owner in marketing LNG	
Manage a new business model with value-chain segments upstream of liquefaction to control		Vertical integration beyond DES and FOB, back to wellhead	
Gas supply interruptions (freeze-offs or hurricanes)		HH – supply gas arbitrage opportunities	
Source: Navigant Consulting: Susan L. Sakmar, Energy for the 21st Century: Opportunities and Challenges for LNG			

Source: Navigant Consulting, Platts

Table 3—LNG Pricing Mechanism 3: Spot Indexation and Futures. Platts announces the launch of Platts GCM (Gulf Coast Marker).

Parameter	Detail
Frequency	Published each business day, reflecting the close of Asian Markets (1:30 pm CST)
Basis & Location	Cargoes lifted Free-On-Board (FOB) from production/reload ports across the US Gulf Coast. Laycan is normalized to the geographical location of Sabine Pass, using an assessed deviation cost
Unit	All prices are quoted in US dollars per million British Thermal Units ($/MMBtu)
Quality	Price assessments reflect lean and rich gas
Volume	Standard loading cargoes of 135,000-175,000 cu m
Timing	GCM represents the average of the two half-month cycles which represent the first full month
Contact Roll	GCM rolls on 1st and 16th of each calendar month

Source: Navigant Consulting, Platts

Markets financialization. Depending on the way the natural gas is traded, there are two types of trading: physical and financial. The basic type of trading is physical. The commodity is delivered to consumers at the expiration of the contract. On the other hand, financial gas trading, as any other financial commodity trading, includes the options to buy derivatives or other instruments and the physical delivery does not exist. As in any other commodity markets, the financials are aimed at mitigating the risks of price volatility. The main concerns appear are the speculators that also may enter the market and affect the price, and therefore they set greater risk to profit off the price changes. Natural Gas is future contracts are traded by mainly two categories of people: hedgers and speculators.

Every last week of the month the so-called "bid week" undergoes. During the period producers often sell their volumes while buyers try to balance their additional needs. The average prices coincide n the physical prices in this week. The largest financial market is located in the NYMEX. Almost all gas derivatives are traded on the so-called over-the-counter (OTC) market, which is represented by the market players aimed at exchanging certain derivatives. During the bid week gas commodity is often priced at:

- First-of-month index
- NYMEX Final Settlement/Basis traders

- Fixed priced deals and hedging; gas daily prices

The financial instruments that usually support physical natural gas trade include index swaps, fixed for float swaps, swing swaps.

Generally, the standard scheme of financial trading includes (not necessarily all) three steps. First, the market players trade with the basis swap (or another instrument), then the gas daily swap accomplished and finally, the swing swap. The simplified scheme is shown in the Fig. 11.

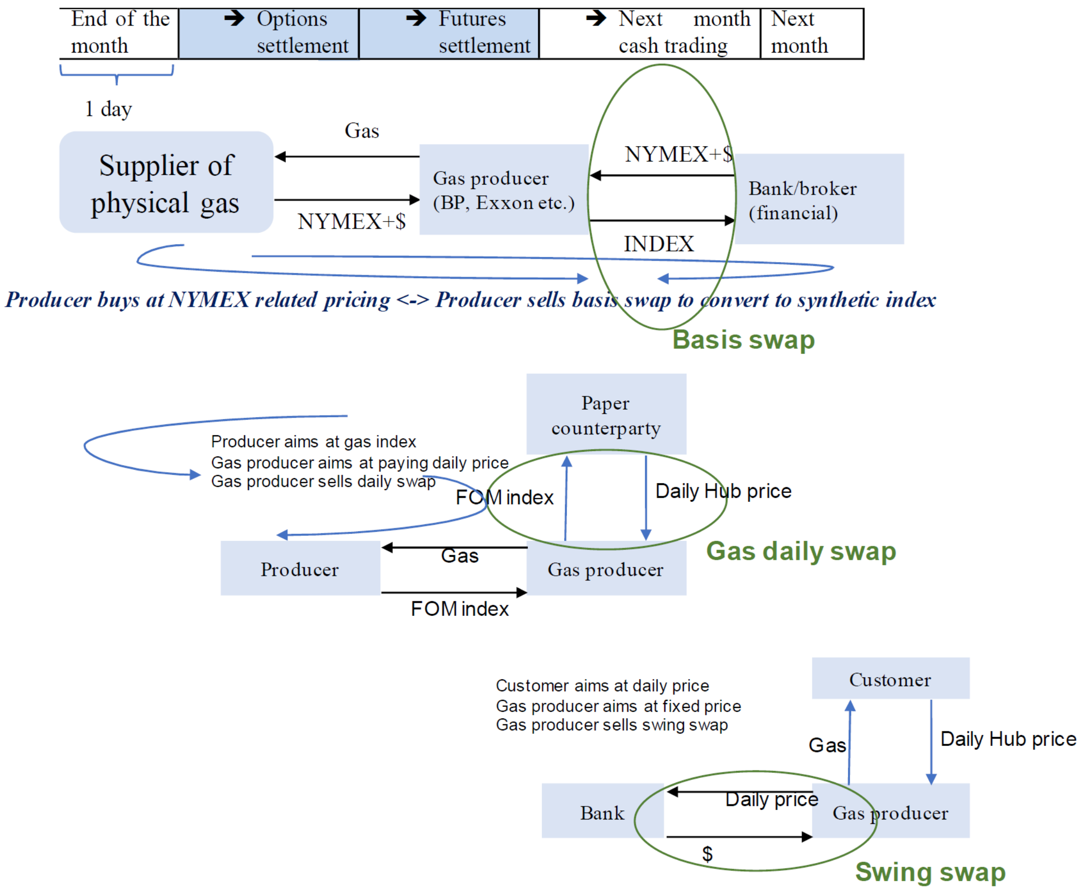

Figure 11—Sample scheme of financial trading in gas market. Source: authors, NYMEX, BP

Financial market is a vital part of open, flexible and liquid commodity market. The two well developed today are the USA and UK with a range of instruments and clearing access. Future business-models in gas industry and their change include the financials which allow:

- Market responsibility and successful trading
- Financial instruments offer flexibility and risk management
- Volatile and liquid market
- Innovative product offerings for growing customer needs

Regulatory policy

Gas industry regulation has an extensive trail in literature. This issue is widely studied, mainly in countries leading the policy of liberalization, reforming commodity markets in the direction of increasing competition between producers.

In Europe, this problem has been studied for several decades in many countries, but mostly in the UK. Later work of (Juris 1998) covers the only liquid virtual hub - the National Balancing Point (NBP). Also, a significant number of gas regulation related papers are carried out by (European Commission 2009). Finally, the Oxford Institute for Energy Study, which for recent years has been studying the existing gas markets in the EU, is engaged in studying the regulation of gas markets today (Heather 2015). In the North America two shining examples of how Canada and the USA deregulated gas industry appear widely in the literature as well. (Pierce 1988) discussed regulated prices and long-term contracts for the period preceding the gas market reform in the US. A lot of authors use policy and price/tariff regulation interchangeably. The reason for that is the nature of monopolistic power coming from access to pipelines or a barrier of construction costs. However, in respect to the gas markets, the concentration with subsequent industrial monopolization led to the understanding that the economy of scale in the transportation segment gives the monopolist an instrument to receive an extra-rent and finally led to the deregulation (Fig. 12).

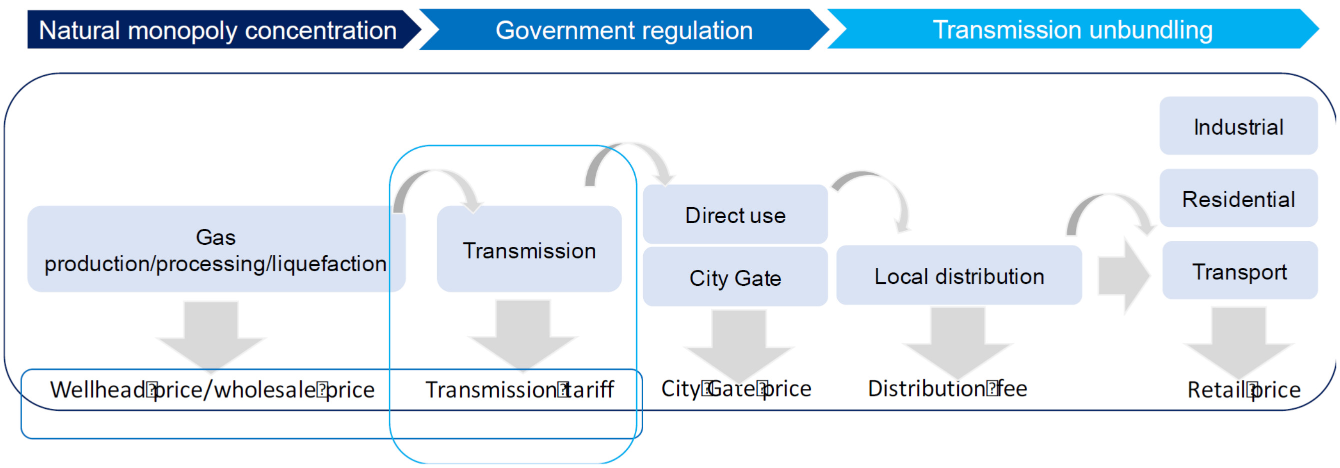

Figure 12—A lifecycle of natural gas markets from arising of natural monopoly to deregulation across the value chain. Source: authors

A broad analysis of the natural gas industry in different countries which were one of the first to use gas fuel in their energy balance shows that they all passed the similar way to found the open and liquid gas market at long last. In the early stage, the concentration and natural monopoly formation were in evidence.

Then the authorities started to regulate and strength the conditions of the monopolist to avoid adverse effects of price manipulation etc. A broad set of instruments were applied in the past such as price fixing, bid rigging, market division schemes and other forms of "non-price" collusion, etc. All of them, somehow, do not reflect the competitive price even though they seem to be low and affordable for the consumers creating in this way the illusion of a consumers' welfare which is not true. Deregulation, however, leads the market asymmetry elimination in the long-run.

In **Appendix 17**, we show a direct demonstration that deregulation may not necessarily reduce but instead increase prices. And this is very counterintuitive but powerful conclusion.

Then, the government finally came to develop a liberal regime, and in most cases left under control, the transmission tariffs preliminary unbundling the value chain (Fig. 9). Within this context, the development and change of business organization in the industry changed consequently from very stiff with strong connectivity between buyers and consumers to more flexible operating in the open markets.

Natural monopolies hence may abuse their power being vertically integrated, or the transmission segment of the chain is not adequately regulated or doesn't allow other players to enter the market due to the no third party access operations. In this case, the monopolist is free to use of safe and reliable gas supply as bargaining, and the typical arguments pro the save the natural monopoly structure are low margin costs and low price that could be offered. The best example of this behavior is a constant tension between European customers and Russian state-owned monopolist Gazprom.

A lot of historical precedents were before governments adopted the regulatory practices in the gas industry, including cases of US Steel, Standard Oil, and American Tobacco. The general result in the natural gas industry mainly is the regulation of transmission tariff and a non-discriminatory right of access to pipeline network that set the turning point towards deregulation.

In the paper, we assert that the policy regulation in gas markets always was a breakpoint after which trade flows and market liquidity significantly increased. Moreover, in almost all cases studied the government decisions were preceded by different historical precedents, political in common that forced the understanding of the need to proceed for deregulation (oil embargo, gas transition disputes, etc.). However, these evidences are out of the objective in this paper and only briefly mentioned.

The arguments cons in the countries where the regulation of gas industry still exist insists on the disadvantages of deregulation policy in the sense of high prices after splitting the monopoly and, hence, no consumer surplus as mentioned. In fact, high scale effect and high transaction costs that constrains the entrance of other players in case of low demand elasticity show that the monopoly is effective. But if the target of the deregulation is rising competition and equal rights for all players, then the competitive price will increase. In this paper, we focus on the most significant cases of policy regulation precedents, to our point of view, which eventually led to the transformation of gas markets' players' business organization and demonstrated the supreme importance of this aspect over the two other aspects studied.

In other words, particularly due to the decisions to deregulate gas markets in these countries, today's open and liquid regional gas market can be observed. Namely, we point out the gas industry deregulation in the USA, UK, and EU; and, finally, consider the perspectives of deregulation in China.

We argue that China is the headlining country and the key player in the future transformation of Asian market not only because of increasing demand but also for several other reasons such as diversified gas import, pipeline, and LNG, the and transition to gas consumption.

The USA. The big wave of the antitrust regulation gained its momentum in the USA, where the common history observed the cases since the mid of the 19th century, where among the most famous are the Massachusetts Railroad Commission of 1869, proposed by Charles Francis Adams Jr., railroads Interstate Commerce Act of 1887, Sherman Act of 1890 on contracts prohibition, etc. (Whinston 2006). Following that, it is not surprising that the first country where the gas industry proceeded the process of deregulation was the USA, although that was preceded by the decades of strict regulation and monopoly concentration.

Reinforcement in point of the regulation the sale from producers to pipelines was adopted in 1954 as a result of the Supreme Court's Phillips decision and required the federal government to regulate natural gas prices at the wellhead. As a result, the prices were restricted in the same way, that natural gas sold by interstate pipelines to local distribution companies. Regulatory control continued until the mid-1970s when probably the most significant in the present history incident of oil embargo happened and all the countries at that time experienced huge oil shortages, and the role of natural gas as a fuel fell in place. Deregulation procedures started with the gradual removal of wellhead price control in 1978. Almost ten years later in 1989 the final Natural Gas Wellhead Decontrol Act (NGWDA) ended all remaining wellhead price controls and concluded with the competition through the unbundling of services declared in the FERC Order 636 in 1992.

The most important conclusion from the deregulation of the gas industry in the USA is the one case we are going to study during the period of the wellhead prices strict regulation when the gas trade asymmetry was in the US market, and the government tried to overcome with it for two decades.

Chronological tracing shows the following. In 1973 the El Paso project was approved and started the operation. In March 1978, the El Paso I LNG Project (sanctioned in 1973) finally commenced operation. Three companies participated in the project and collectively agreed on the long-term contract base Basically, business-model was organized as follows: the LNG, delivered to the importing terminals in four locations

(Cove Point, Maryland, Elba Island, and Georgia) were supposed to be the first US LNG import and to use for the base load supply. The project has been delayed several times due to the regulation conflicts.

The problem was that one year before, in 1977, President Carter replaced the LNG import policy adopted in 1976 with one which set no U.S. or per country limits, and which provided for a case-by-case review of individual LNG projects and simultaneously the authority to approve natural gas imports and exports was transferred from the FPC to DOE. In addition to the wellhead price regulation, it stopped almost all the trade flows for the next years. The first case of the Doe in this respect was Pac Indonesia LNG Company request to import 200 Bcf per day under a long-term (20 years) import contract via Oxnard, CA LNG terminal. Two main fixed customers were as it was common at that time two large utilities, namely, Southern California Gas Company and Pacific Gas and Electric Company.

Unfortunately, due to the new regulation rules and price control, the project was officially canceled in 1985. One year later, in December 1978, the DOE declined two Algerian import projects. The same business model was supposed to be organized in this frame: the amount of import was 365 Bcf p.a. (20-year long-term contract) via the Texas Gulf Coast LNG terminal and via New Brunswick (Canada). Officially declared reasons for were as follows: projects failed to satisfy DOE's presumption in favor of direct LNG sales by importing companies to gas distribution utilities. Sponsors did not demonstrate a national or regional need for the gas; the enactment of the NGPA and FUA would make more natural gas available, both regarding overall quantities produced nationally and quantities available to the interstate market.

The prices started to rise very fast (Fig. 13) and in addition to the consequences of the oil embargo, the authorities finally recognized the urgent need for industry transformation.

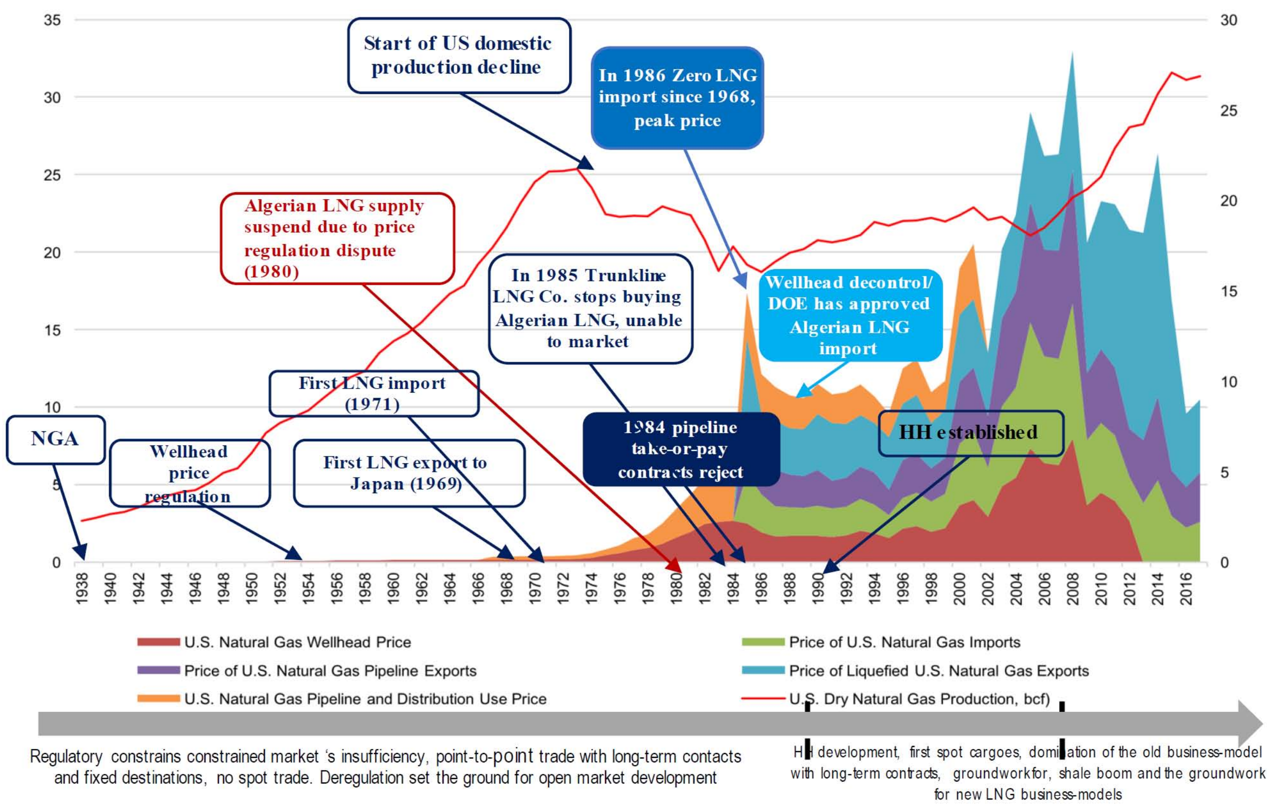

Figure 13—The historical tracing of the USA policy regulation effect on the gas market organization. Source: authors, US EIA, North American Gas Trade.

In 1978 Congress passed the NGPA and the Fuel Use Act (FUA). Even though the bill wasn't aimed at the decontrol and assumed intrastate and low-priority users wellhead price control, it set the foundation to that. The main idea of the law was the deregulation of gas fields discovered after 1977. The immediate effect, as expected, of this law was to stimulate the production of gas and move it from the intrastate market to the interstate market so that to reduce the share of low-priority users for producing companies.

Moreover, in 1979 the Secretary of Energy informally outlined the policy on future domestic consumption of the gas, but, unfortunately, the LNG was at the lowest priority there due to the continuing price regulation. All that resulted in the disappearance of the LNG import from the US market and caused dramatically rising prices. Later on, in 1982, Trunkline company tried to import one LNG cargo, the protracted disputes in the Congress started again.

Only in 1984-1985, the DOE made the first attempt towards the market deregulation. In short, two types of business models appeared because of new import policy guidelines:

1. Operation under new and renegotiated long-term contracts containing provisions which fluctuate to changes in the marketplace;
2. Short-term contract-based business-model with spot market type transactions under two-year "blanket" import authorizations.

After a long-lasting dispute finally, the critical moment that in Asia the demand for gas increased and more exporters requested DOE the approve of their LNG export projects, the DOE finally passed the law of the wellhead price decontrol. In one year the HH was established as the result of the gas industry deregulation that in several years (see the part about business models evolution) the first spot cargoes came from Australia and Spain. However, that still had no impact on other regional market due to the low LNG producing in the absolute terms, rapid decline of domestic production and the US supposed to become a net LNG importer in the 21th century with the traditional large share of long-term contracts business organization with fixed destination, until the shale boom occurred.

EU Entire Gas Market. The first idea of Single Gas Market was adopted in the EU in the late 1980s within a general strategy of markets liberalization and followed adopted in 1988 «The Internal Energy Market». The primary argument was to dismantle the impediments to intra-communitarian trade in goods and services, but also the neo-liberal outlook on competition and efficiency and business interests played a significant role.

In theory, the appearance of spot and liquid markets in conditions of fair access, minimum regulation, and supply-demand basis pricing is unavoidable. A precondition for this was that the competing traders would be given access to the essential facilities in transport, distribution, and storage, to reach their customers. To this end, three basic regulatory principles were embraced in Europe.

Firstly, the essential facilities would have to be 'unbundled' from the production and trading activities, in the sense that the operators of such facilities would not have any commercial interest in manipulating the gas flows. Most of the networks were separated from the former wholesale companies and local gas utilities and now controlled by the system operator.

For LNG, storage, and conversion, depending on their position as a (local) monopoly, different regimes were allowed. The second principle involved the provision of "non-discriminatory access" for trading parties to these essential facilities. This, obviously, not only involved access to the transport systems but also to storage, LNG and quality conversion facilities. Access to the transmission pipelines, generally, came to be organized as a so-called entry-exit model in which "shippers" of gas book their entry and exit rights, for specific volumes of gas to be fed in or taken out of the transport system at particular locations (Glachant et al. 2014).

A third principle involved the notion that the gas infrastructure should improve tariff policies, transport costs. With three consecutive Gas Directives, the European Commission provided increasingly explicit and stringent rules. The last Directive is the most important one, which enhanced EU cooperation. It is worth mentioning that as long ago in 1973 the oil embargo forced energy supply diversification after the price shocks, the similar situation in EU during the disputes between Russia and Ukraine on the gas transition and followed gas supply shortages to EU, when EC forced the third Gas Directive in which the security supply was the one of priority (Fig. 14). However, the first broad result appeared only recently and allowed us now to talk about the real transformation of EU market towards competitive.

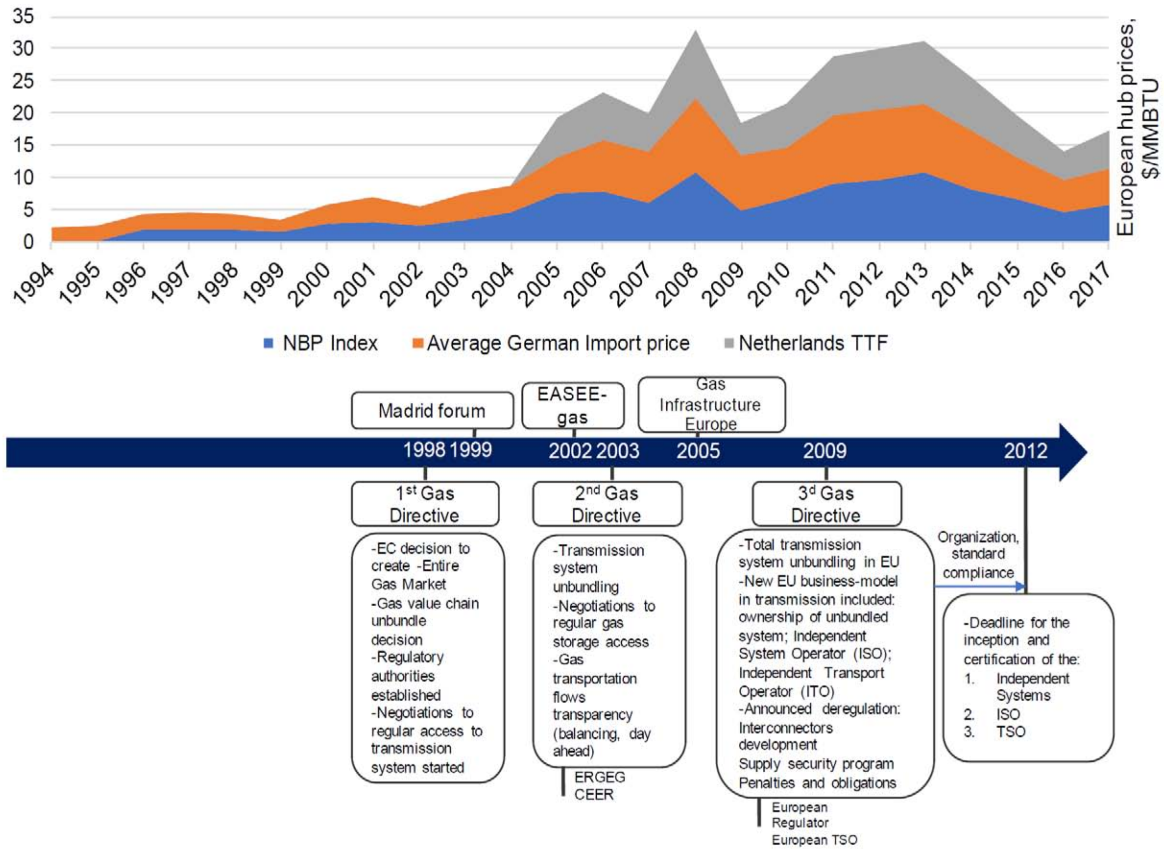

Figure 14—The historical tracing of the European policy regulation effect on the gas market organization. Source: authors, Eurostat, IEA, GasInFocus.

In May 2018, the EU has settled a seven-year dispute with Gazprom after the Russian state-controlled energy giant agreed to change its operations in central and eastern Europe. An investigation by the European Commission launched in autumn 2012 found that Gazprom broke the EU's competition regulations in many central and Eastern Europe countries. Commission findings on the matter were delivered to Gazprom in April 2015.

Finally, the Commission issued its final ruling in the case. The decision mandates that Gazprom, under threat of a fine, modify its contract practices within the EU. Among other things, Gazprom must allow the sale of gas to third parties, commit to upholding market pricing and ease gas deliveries to the four EU member countries dependent on Gazprom pipeline supplies. Observers note that Gazprom has already modified most of its operational practices to conform with EU standards and that the company has promised to abide by the Commission's decision.

The UK. Before the Second World War the UK the gas industry was dominated by gas manufactured from coal. With the 1948 Gas Act, the industry moved towards nationalization; a policy proposed and executed by the political decision by the Labour Party. The Act introduced a new Gas Council and the 12 Boards. Because the local or regional pipelines were not interconnected, risk management and security were in the hands of each Area Board. The Gas Council took the relevant initiatives for importing LNG, negotiating with Algeria, Shell, Conch International Methane, to implement LNG import commercial project. It not only expressed the will to introduce LNG for the improvement of manufactured gas production but also the vision for the establishment of a national grid along the lines of the long-standing electricity network. Subsequently, it served as the vision for an integrated system that would transmit North Sea natural gas. Eventually, natural gas was introduced quickly in the UK energy mix, facilitated by the existence of the pipeline built to deliver the regasified LNG to the local areas. The Gas Council acquired exclusive, monopoly rights to the sale of gas (Davis 1984). The Gas Council and the Area Boards exercised extensive power and rights in the management of the flows, distribution, and sale of natural gas. The 1965 Gas Act gave the Gas Council the power (not exclusive) to produce and buy gas in the UK and beyond. The 1972 new Gas Act boosted the centralization and concentration of power: Gas Council was renamed the British Gas (Arapostathis et al. 2014; Simmonds 2000). Demonstratively the process is shown in the (Fig. 15).

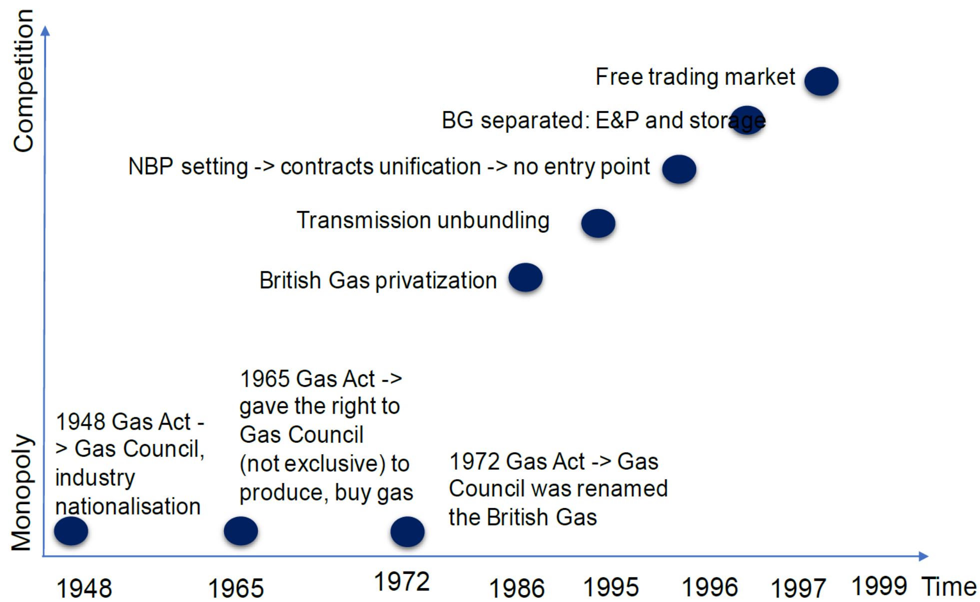

Figure 15—Timeline of UK gas market deregulation. Source: authors, IGU, Oxford Institute for Energy Studies

The British Gas Corporation's privileged position ended with Oil and Gas Enterprise Act of 1982; further changes were introduced by the Conservative ("Tory") party towards the privatization of the industry (Davis 1984; Williams 1981). The power granted to Gas Council and then BG between 1948 and 1982 created a high level of vertical integration. However, it is worth mentioning that the system remained flexible enough even during the period of monopoly pursuing technological changes, imported LNG, horizontal integration through the natural gas grid. These transformations in production and transmission led to radical social engineering strategies to change end-use technologies and to promote natural gas as an efficient, inexpensive, "modern" and "clean" energy source.

China. China already is one of the largest consumers in the Asian market (excluding Japan), the second largest world economy and at the same time the highest uncertainty for the gas market. One of the biggest uncertainties is the government plans on resource markets regulation and the ambitions. A few years ago the only concern was the struggling from serious environmental problems caused by the long-time coal-based electricity generation. To reduce the air pollution, the national strategy assumed the drop-in coal percentage in energy balance up to 62% by 2020 and prioritizing the natural gas consumption rise to at least 10%. The national strategy of developing countries later sooner come on the perspective to deregulate markets for more substantial benefits to own producers.

Moving to a newly established national strategy, China is going to imply the three key components in liberalizing natural gas market. The first is the breaking up of monopolies, encouraging diversification and competition among participants. The second area is the acceleration of the creation of a natural gas trading market, involving training market intermediary organizations and ensuring improvement in service.

The construction of the Shanghai Oil and Natural Gas Trading Centre should be accelerated. Also, at an appropriate time, research should be carried out regarding the creation of natural gas trading platforms for Beijing, Tianjin, Guangzhou, Chengdu and other trading centers. The third area is deepening the extent of reform of state-owned enterprises, encouraging the growth of modern energy companies. We analyzed natural gas pricing, financial, and tax reform as follows:

1. ensure that there is a mechanism by which competition in the natural gas industry results in market adjustments and that "natural" monopolistic power is subject to legal regulation;
2. internalize the costs of externalities such as environmental protection that required in the course of exploitation of energy resources and reduction of greenhouse gas emissions, which will go towards establishing energy pricing parity;
3. bring about gradual integration with international natural gas markets;
4. adopt natural gas as a clean and highly efficient energy type, with major encouragement being given to increased production capacity and importing;
5. eradicate cross-subsidization, which will ensure that "hidden subsidies" become "known subsidies."

In this sense, if in the next few years China will achieve success in at least creating LNG trading centers in the regions mentioned above, it would be a reliable driver for other importers to review their national laws and regulation.

Summarizing the importance of government regulation in the business organization transition the following findings should be mentioned:

1. In all to date developed gas markets the reforms on the way to deregulate natural monopolies passed the similar way and took at least a decade;
2. The price during the deregulation process often increase in the short-term period and then come up to a competitive value;
3. China is expected to play the key role in changing the Asia-Pacific gas market through the initiated gas market deregulation.

Table 4—The gas industry ongoing regulation reforms in China

	Price deregulation	Pipeline reform
2013	Regulation from wellhead to city gate: from 0,4 RMB/cm price cap for existing gas, incremental gas prices with the link to fuels	
2014	-Existing gas city gate prices increased by 0,4 RMB/cm -Incremental gas city-gate decreased by 0,44 RMB/cm	-Measures for supervision of the oil and gas pipeline TPA -TPA to infrastructure is surplus capacity is available -Regulation for the Natural Gas Infrastructure Construction and Operation -Encourages investment of gas infrastructure by all capital types. Requires independent accounting of gas infrastructure operations
2015	Two prices converged	
2016	Negotiable city gate price with mineral amendment producers; city-gate prices liberalization trial in one province	-Regulation for the Nature Gas Pipeline Tariff (trial) -Measures for Supervision of the Nature Gas Pipeline Tariff and Cost (trial) -Policies for gas pipeline pricing mechanism and supervision. The pricing mechanism is adjusted to “permitted costs plus reasonable profits.” -Strengthening Regulation of Local Natural Gas -Transmission and Distribution Tariff and Reducing Gas Costs of Consumers -Policies to regulate provincial and local gas pipeline pricing aimed to lower end-user’s energy costs
2017	A government report on non-residential city gate price decrease	-Strengthening Regulation on Distribution Tariff -The permissive rate of return does not exceed 7%
2018	Market orientation to hub-based price trading	

Source: CNPC Economics & Technology Research Institute, authors

Business models in gas industry: evolution and perspective

Business models and value chain analysis in gas industry is not of such a high interest as, for instance, the development of gas and namely LNG market or pricing mechanisms and price convergence in regional gas markets. We also involved this in the first part of the paper as any business models inevitably consist of pricing and the final efficiency is determined by the competitiveness of each of them accordingly to the market they aimed at. The importance of analyzing the evolution of business organization and underline the future perspectives is no less because today it predefines the market tone and helps all the parties involved and interested in the gas trade to prepare for changes and in some cases even manage the risks. Previously, the problem of the value chain in the sense of business organization was studied by several authors. For example, the financial and regulatory aspects of the US natural gas value chain analyzed by (Weijermars 2010) and shows the possible long-term and operational decisions to be made for enhancing the competitiveness of national transmission system in both regulatory and financial terms. Among others, corporate strategy for LNG value chain relative to the vertical integration (Rüster et al. 2006), prospective for producers and buyers to maximize the value from LNG agreed upon specification, US oil and gas business models in the frame of unconventional resource development (Medlock 2010) and the portfolio business-model as a critical driver for the future short-term gas trade enhancing (Rogers 2017) are studied. In this paper we focus on identifying key drivers of business model's transformation by tracing the technological, policy or market change through the time so that to make a prospective presumption on the future business organization and, finally, to implicate it in the proposed modeling of competitive contract structure for gas exporters, namely in the US.

In the first part, the key elements, of the general business model in gas industry were explored. Analysis of technology, market and regulatory aspects shows that each of them at a specific time contributed to gas industry business development and transformation. In this part, the historical tracing of how these aspects affected the business organization in the industry are studied and the perspective for each of them to contribute the perspective transformation in gas markets provided.

The history shows that all-natural resource markets developed after some «shocks» that stated in a sudden regulatory shift, technological leap or objective processes of market financialization and integration. That was a key point for analysis to understand perspective. The development of the natural gas industry as a cross-boarding trade started not long ago.

Before the mid-1950s all the trade (90%) was concentrated in the USA. Rapid economic growth and, hence, very high energy demand in other industrial countries in Europe and Asia (Japan, South Korea) showed a huge potential to shift their economies to gas as well. Among other trade strengthening factors, the policy regulation was, probably, the key one. Thus, in the USA the first rise in gas trade can be observed after the deregulation act of 1978 that led to a boom in new fields drilling.

One important fact here is that in the USA potential import of LNG in the 1970s failed as the government prohibited domestic buyers from accepting high price of Algerian LNG that was the main LNG supplier at that time. As a result, two of four LNG regasification facilities stood idle for over a decade. Later the final well-head price decontrol opened new opportunities for future competitive pricing mechanism based on the hub trading. The same scenario repeated a decade later in the UK when the 1982 Oil and Gas Enterprise Act destroyed the British Gas monopoly. Thus, laying the foundation for the same fair trade based on the supply-demand basis when in the 1990s gas trade was shifted to NBP hub.

In Europe, industrial development was also significant. Italy was the first country with gas fields discoveries (Po Valley). But the history relocated the revolution to the north and only after the Groningen field was discovered in 1959 and a few years later large gas fields in the UK part of the North Sea, we can talk about the start of the pipeline gas business in Europe. Similar to Asia, the principle of business organization was based on substitution of other fuels and inter-industrial competition between state companies and large utilities as the largest at that time economies of Japan and Europe were dependent of oil. Eastern Europe meanwhile being dependent on the Soviet Union, experienced the process of the pipeline network expansion which was a part of the general plan of the Soviet Union called "the gas-rich rule" (Victor et al. 2006). In parallel, the LNG evolved technology allowed this type of gas to find its niche and first contracts were agreed upon in Japan. Several suppliers and buyers operated on the same conditions as the pipeline gas business models in continental parts of the US or Europe.

The critical moment for both pipeline and LNG gas businesses happened in 1973, thanks to Arab oil embargo. All market players understood the risk of one fuel dependency, the need of diversification and the new role of natural gas a commodity that is capable of coping with this role in a changing energy balance (**Appendix 18**).

Rapid shortages raised the prices and demonstrated the effect of fuel dependency. Together with high prices, it forced countries to diversify from the oil. Before the crisis, Japan planned to substitute for oil, and the embargo made this process fast and aggressive as the government forced generation companies to gas transition. So two aspects played the essential role in business change were government policy followed by some political happenings and available technologies. That was start point as well of LNG big investment decisions, but not for the fast gas trade growth, however, because the technological constraints still took place.

While the pipeline was economically inefficient and caused the remain regional structure of gas industry forming two major markets in the USA and Europe, the rising demand in Asia-Pacific region found to be covered by the LNG technology. There were other small pipeline markets in the Latin America, Middle East, and Southeast Asia, but without any significant effect on the global gas trade so that they may not be included in the analysis. With the time high-pressure interconnectors in between Europe and Russia and long pipelines expanded the cover of regional markets, but the real international gas business appeared only after significant development and economic feasibility due to the shipping volume of the ocean gas transportation technology. That was a hold promising technological shift that made gas trade available over to transoceanic distances. Moreover, in a logical way LNG shipping technology could make business more flexible because suppliers and consumers are no longer dependent on each other by the pipeline which in its turn automatically leads (in theory) to the arbitrage regional gas markets. However, as the practice shows, there was not enough and yet the pure arbitrage can't be still observed. As mentioned, the oil embargo brought on a lot of investment decisions in LNG business as the shipping technologies already appeared at that moment. The total annual growth in capacity from 1964 to 1978 was about 380% (Fig. 16).

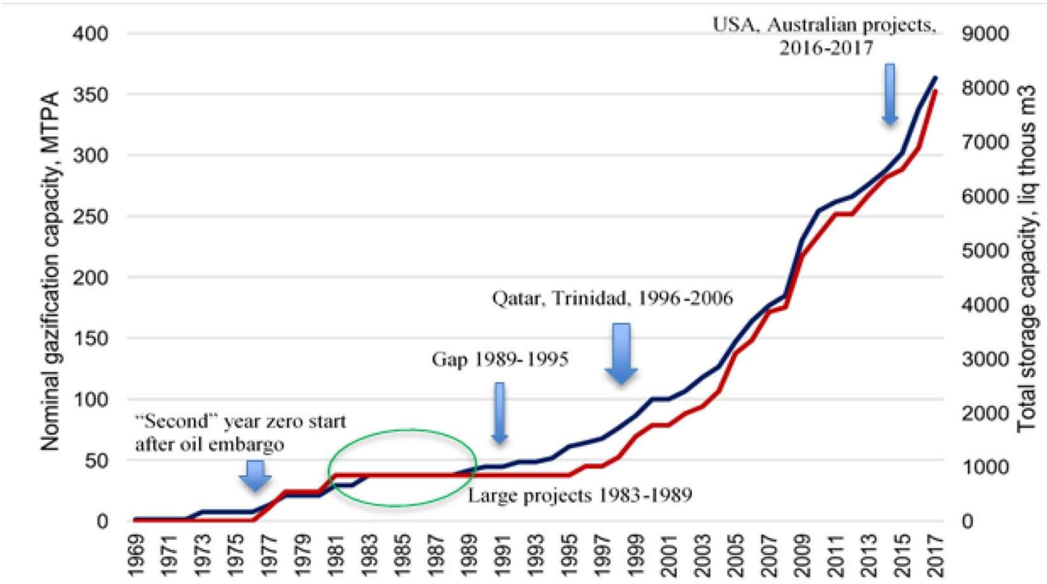

Figure 16—Milestones of LNG trade development. Source: authors, US EIA, IEA, GINGL

Commercial LNG export started from a large LNG plant in Algeria to cover the demand in France and UK, and by 1972 there also was mid-capacity plants in Alaska, Brunei, and Libya. Government decisions about secure gas supply and fuel competition initiated several new LNG capacities in Indonesia (in 1977) and UAE (in 1977). And again, there were the same business organization models with long-term contracts and the final destination to Japan. The next two decades Malaysia (in 1983) and Australia (in 1989) appeared on the marketplace with larger capacities and hence, better scale effect that allowed them to take the market share. Another wave of gas business appeared in the mid-1990s when Qatar (in 1996), Nigeria (in 1999), Trinidad (in 1999), and Oman (in 2000) entered the market with affordable ship economies, large liquefaction capacities, better technologies and competitive upstream production costs (Victor et al. 2006).

Summarizing what drove the transformation of the gas business organization, two simultaneous processes are observed in the first three decades of the LNG era. For the first two decades from the early 1960s and till the mid-1980s LNG business was similar to the pipeline and quite conservative. The participating players included gas producers, large utilities, governments. Pipeline tight constraints formed two isolated markets in Europe and the USA, however, in the first one insignificant volume of LNG was traded from Algeria.

If the USA never experienced the fuel competition and directly started from naturally monopolistic and strictly regulated market with deregulation process followed later on, in Europe the business model was initially organized on the oil-gas competition. It is worth mentioning also the split of pipeline market in the UK and Continental Europe when the first started the process of separation vertically integrated BG into production and transmission.

Continental Europe built extensive pipeline network from the Netherlands and Norway, the two main gas exporters and formed the same market as it was in the UK, but which remained unchanged until the EU was established and the European Entire Gas Model was adopted. However, the EU market is still far to be called fair, influenced by the dependence from the Russian pipeline gas and long-term contracts as well as by the LNG inflows that are still mostly linked to the oil.

While the two pipeline gas markets were moving towards the fair trade, Asia was a target market for LNG where the oil was substituted, and the price was without any flexibility. LNG was shipped from the supplier to consumer by the strictly fixed marine route unless some demand range occurred. Japan was the largest and in the first years the only consumer (still plays this role) and demanded reliability in gas delivery. The financing process of those huge LNG projects was mainly based on credits with the high credit ranking and guaranteed long-term sales contracts agreements. Except for Japan, in other countries, LNG hasn't met enough demand and remained as a unique niche commodity in remote regions where it was delivered as a stranded gas.

Fundamental changes in business model and LNG trade transformation which made this commodity of a significant interest raised in the late 1990s. The changes came from both energy demand, new high competitive suppliers (Qatar and Trinidad), new consumers as China, Taiwan, and other Asia-Pacific countries, the appearance of large gas hubs (for example, NBP) and development of currently operated (HH). These new realities signaled that in the future LNG would not work with a business model that depended only on strict point-to-point shipping and when long-term contracts define the exact destination of each LNG cargo. All that maintained by the deregulation processes in the USA and UK toward gas-on-gas pricing and privatization of natural gas business around the world. LNG business started to transform into a more flexible, competitive and entrepreneurial. The process value chain of LNG delivering infrastructure needed less of the vertical structure of the operator. Also, the emergence of new consumers in other economic sectors declined the influence of previously dominating generation utilities in Japan.

Finally, in 1993 the first spot cargo on a regular base was shipped from Australia to Spain without any long-term component in the contracts. Later, the spot cargoes reached the USA from UAE (in 1996) and Australia (in 1997). In 1998, a new LNG project in Trinidad not only related to country's location but also due to the unusual in that period technology od improved cascade applied had a big potential to profit from emerging arbitrage between the US and recently developed Spain market. Thus, a new period of flexible liquid international trade of natural gas started. We mark several reasons for that:

1. Competitive market development in the USA and HH trade beginning forcing the spot contracts based on gas-on-gas mechanism and thereby giving a lot of opportunities for both sellers and buyers;
2. Competitive market development in the UK and NBP trade beginning, which model was similar to the USA generally;
3. Flexible flow of spot volumes and retrade from Spain to the USA due to the new fair market in the USA, Asian market with TPA.

In that period a significant potential for arbitrage appearances in the Atlantic basin. The prices in Europe were linked to oil and due to the relatively low transportation cost through the Atlantic basin, the first destination where the cargoes from Spain to the open USA market. Gas demand in Spain at that time was big enough to lead the spot trade and arbitrage even though the pricing mechanisms differed from that in the US, where they were linked to the oil due to the large LNG share in total gas consumption.

The key driver for such an existing arbitrage was as mentioned the fair open and liquid market in the US. When the Atlantic LNG in Trinidad started production in 1999, there was a right condition for arbitrage and, indeed, other sellers later tried to replicate the same model definitely in the Atlantic LNG market. One instrument that made the trade relatively more flexible and diversified in the Pacific market and today appears quite promising was the swap cargo. LNG swaps, as described in section 1, help sellers to save their surplus from unexpected shocks in demand and hence market volatility. Cargo swaps in the Pacific are also growing in number in response to market volatility created by unforeseen changes in demand, such as during the 1998 Asian financial crisis, the shutdown of Indonesia's Arun LNG plant in 2001 due to civil unrest in province Aceh and during Japan's nuclear disaster in 2011.

Second, over the 1990s especially, LNG has been subject to technological and commercial innovation that has sharply lowered the cost of moving gas from distant fields to its final users. The improvements are evident in every link of the LNG train and the total reduction in cost is perhaps as much as one-third in just one decade with trends suggesting continued gains. Some of the improved economic performance has come through removal of "gold plating" that was required by Japanese buyers who imposed specific rules in an effort to raise security, but most of the improvement is the reflection of true innovation improved existing processes; some of it allowed the realization of substantial economies of scale (Jensen 2004). As discussed, the cost reduction was critical to developing LNG projects to serve the robust US gas market.

Finally, the disintegration of ownership in the LNG value chain has created potential opportunities for intermediaries to emerge to take on the risks of buying LNG at the point of export and creating flexible, market-related opportunities to delivery based on immediate market conditions. But heady visions common in the late 1990s of a wholly atomized LNG value chain and purely spot market trading have largely disappeared. In part, this vision collapsed with the dwindling of the merchant energy business that intended to be its principal market-maker. The promise and much of the capitalization of these merchant companies mostly disintegrated in the wake of the Enron accounting and other trading scandals. Some merchant groups such as Tractabel (Suez LNG) remain, but in no small measure, the global gas business is back squarely in the hands of international energy majors who stayed the only players with the robust financial capabilities, global operations, long-term vision, and established relationships with national oil companies in natural gas producing countries.

New LNG projects are risky and costly – requiring typically capital investments of $5-8 bln. The scale of such ventures explains, in part, why the shift to a truly oil-like liquid commodity market will be longer in coming. Nonetheless, integrated major LNG companies have opted to keep some sales volumes from new projects available for spot trading, which is a sign of the rising of the importance of this activity.

To date, spot trades of LNG cargoes occur relatively infrequently. Historically, LNG was priced off the oil or the oil products that is displaced in the offtake market. Japan as a dominant player in LNG markets, prices its import via an explicit linkage to a basket of imported petroleum, an index dubbed the JCC. While the specific indexes and contract terms vary, this model continues to be the general rule for the most LNG trade. LNG buyers purchase gas inclusive of all transit costs, on CIF terms. Japanese contracts typically dub this pricing arrangement as destination-ex-ship (DES). A few small Indonesian sales contracts of Japanese buyers do include explicit charges for shipping, thus pricing the LNG pre-shipping.

The development of a robust market in spot LNG trading will require more standardized pricing mechanism for LNG cargoes – essential to allowing financial intermediaries to participate more freely in the market. Such a structure will need a movement to contract structure with explicitly separate the price of LNG at the loading port (or FOB). Currently, most spot trading that occurs is priced off the NYMEX.

Four periods were identified in the gas industry when the business models underwent significant changes and state that they directly correlate with LNG industrial development even though the share of this commodity trade has not exceeded one third till the beginning of the 2010s (**Appendix 20**).

We assume that the percentage of LNG imports in internationally traded gas flows is less critical influencing the market transformation. Absolute values of the trade that defines market's flexibility and forces its financialization.

We split the periods of business transformation accordingly to the analysis provided. This stage is mandatory before moving to the particular case study and results in implications. The first period covers the time from 1957 and 1964 when the first pipeline export from Canada to the US through LNG cargo was shipped internationally and till 1979-1986 when the USA and UK deregulated their gas market. In the middle of 1973 oil crisis, Japan signed new SPA agreement of four generating and one metal companies

(Chubu Electric, Kansai Electric, Osaka Gas, Kyushu Electric, and Nippon Steel) with Pertamina for 8.18 mln tons p.a. delivery on a long-term base.

The first two train of Indonesian Bontang LNG plant with a total capacity of 3.3 mln tons p.a. (1.65 mln tons p.a. each) placed in operation in 1977. The second largest Arun plant with three trains and full capacity of 5.1 mln tons p.a. put in place a year later in 1978, making Indonesia the largest LNG exporter to Japan for the next couple of decades consequently. That was a period of gas business development when the market players replicated the models. Main characteristics ae mentioned above.

As the markets at that time were not sufficient along with the significant capital resources required for both pipeline and LNG project, forced producers to look for the guaranteed consumer from which the fixed cash flow for an extended period will come. Due to these consequences, only major companies were the market players (Fig. 17) in collaboration with state companies in some countries.

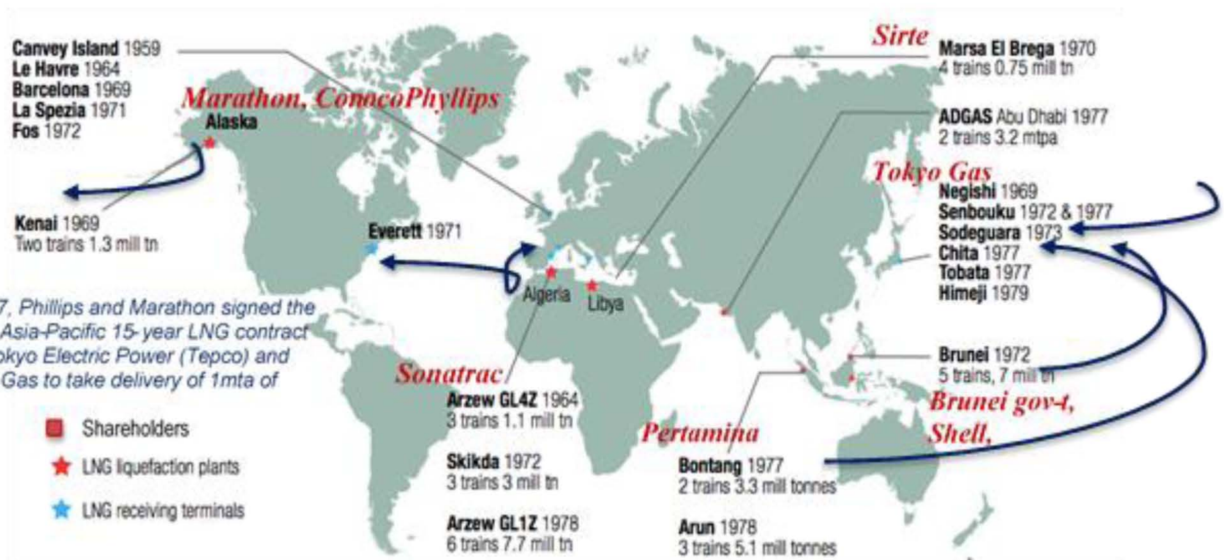

Figure 17—The first period of international LNG gas model development. Source: authors, BG, GINGL, Tokyo Gas, Shell

One more feature specific for that period was the preliminary agreements with customers when the long-term contracts were signed in the first turn. For example, the first LNG plant in the Middle East was built at Das Island in Abu Dhabi. The Gas Liquefaction Project Agreement was signed in 1971; a 20-year Sale Agreement with Tokyo Electric was signed in 1972 and construction of the ADGAS plant started in 1973. Trains #1 and #2 were commissioned in 1977, each with an operating capacity of 1.6 mln tons p.a. The third train with 4 mln tons p.a. of full capacity (that time the largest and most advanced in the world) was erected in 1994. (British Chamber of Commerce 2014).

Fifteen years after the startup of the first commercial LNG plant in Algeria eight liquefaction plants were operating globally with a total capacity of almost 33 mtpa and the first plant at Arzew had been expanded to reach a total capacity of 8.9 mln tons p.a. In 1979 Algeria exported 8.5 million tons of LNG, and global sales reached 24.7 million tons. 14 million tons went to Japan and the second largest buyer was the USA, taking 5.3 million tons. The total count of the world fleet was then 52 ships with the only dominant consumer, namely Japan (Fig. 18).

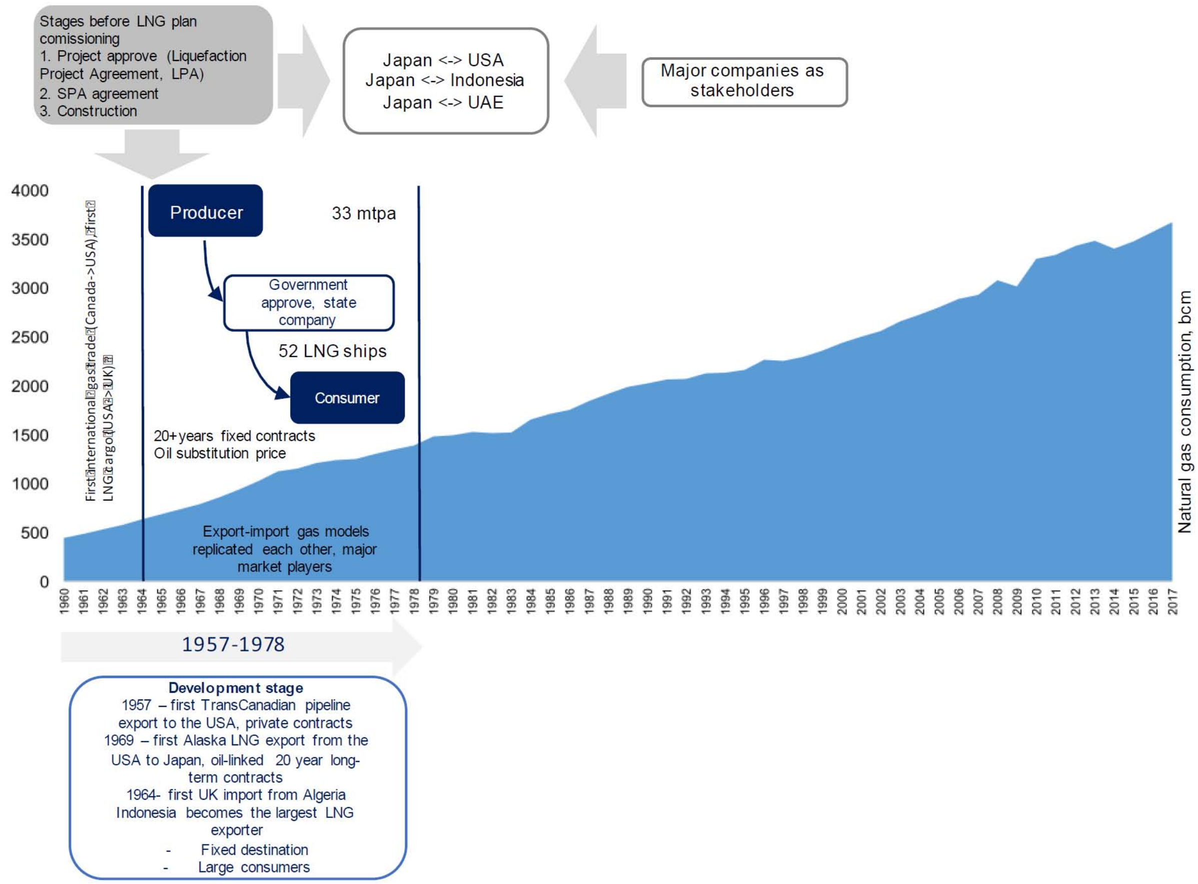

Figure 18—Business-model depending on the contractual forms. Source: authors

Simultaneously, while in the USA and Asia-Pacific LNG was the subject to long-lasting disputes which finally ended with the market pricing deregulation, in Europe 1958 was a break year when Groningen field was discovered.

The business model adopted by the Dutch government is still partially-reusable in the long-term contracts and for the decades have been defining the gas market organization in Europe. The competition was followed afterward by plans for LNG export from Algeria, Russia to Eastern Europe, and in the following decade by supplies from Norway to northwestern Europe.

The uniqueness of the Dutch model included several essential points that were in one or another combination replicated by other market players. They consisted of the following: "market-value" or netback value principle as opposed to the regular cost-plus town gas (Konoplyanik 2010). As the export prices were based on the market value of the individual customer country netted back to the Dutch border (by subtracting the costs to bring the gas to the customer), the Dutch border price would differ depending on the destination country. "Destination clauses" were therefore imperative to ensure that gas with a low price at the Dutch border destined for more distant markets could not be used to undercut. higher-priced gas in markets closer to the source. Price review (or re-opener) clauses into the export contracts; "capacity charge," which was payable regardless of the gas consumed.

Using Dutch terms, but without the capacity charge payments, new GSAs were signed with more distant producers, including the following benchmark contracts. The producers took the view that their shareholders both understood and accepted oil price risk without resistance. End-users, on the other hand, sometimes felt that electricity, coal, or even used vehicle tires were viable alternatives. The description of the model is given in Fig. 19.

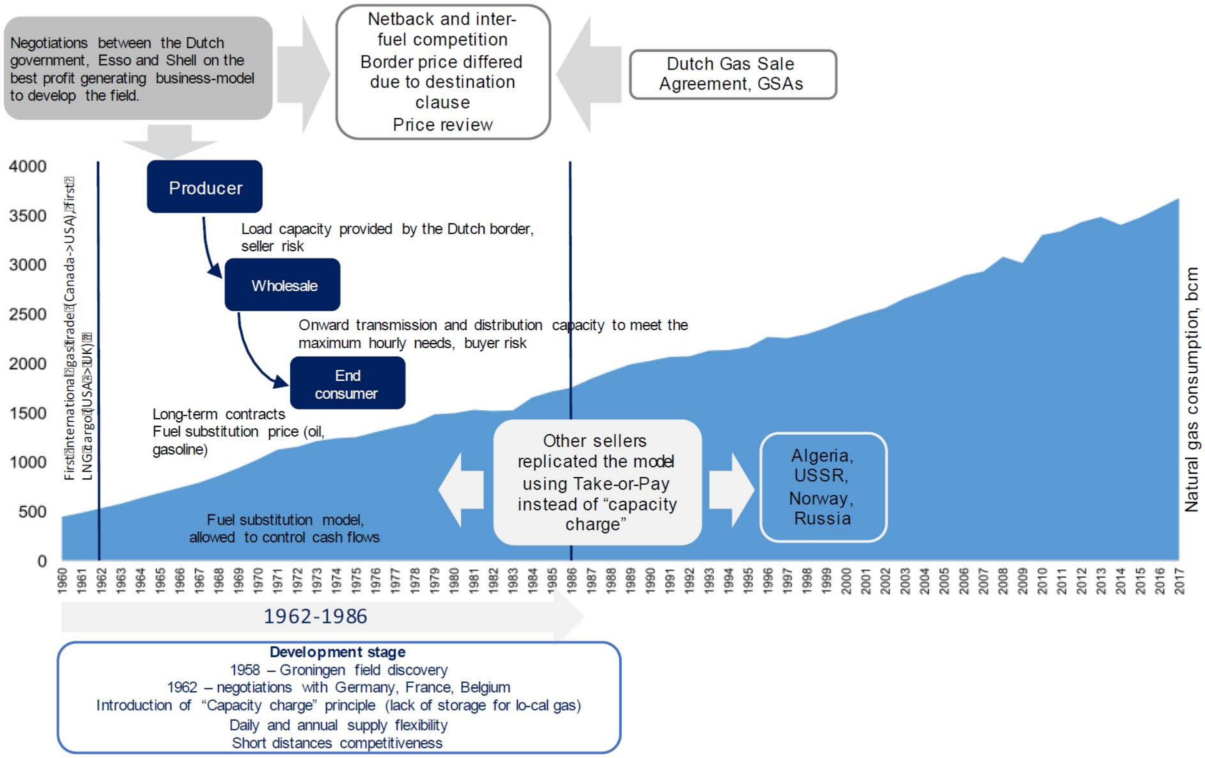

Figure 19—Description of the GSA model with terms similar to the Dutch gas supply agreement. Source: authors

Until the development of spot markets, LNG contract pricing terms in continental Europe were also based on oil-indexed formulae, with some key differences: 1- contracts often included "transportation" element reflecting shipping costs; 2- volume flexibility range (95 to 100 %) was lower than for pipeline gas deliveries. LNG contract terms were similar to pipeline supplies: typically, around twenty years. The growth of world LNG trade coincided with the growth of European spot markets, and in recent years an increasing proportion of Europe's LNG supplies have been on short to medium-term bases (Melling 2010).

A new era of the business organization came with the first spot cargo and technological improvements, which signed the irreversible change of the markets and how the players will operate. The landscape began to change in Europe in the 1990s. The United Kingdom was the first which announced the way on liberalization after a long history of deregulation. Natural gas traded was similar to the USA. In 1998, the UK gas pipeline system physically was linked to Belgium Zeebrugge interconnector, and the trade accomplished.

In 2003 the National Petroleum Council forecast that domestic gas production would only be able to meet 75% of US demand, with the balance having to be imported as LNG. By the end of 2003, 31 LNG receiving terminal projects had been announced in the US, Canada, and Mexico and over the next few years 11 new liquefaction projects were announced in Norway, Equatorial Guinea, Yemen, Angola, Peru, Indonesia, Qatar, Egypt and Trinidad with the assumption that the bulk of their production would be supplied to North America.

Also, the well-developed market gave the participants equal market entrance conditions. The US reopened its three mothballed LNG import terminals and built eleven more but, for many, the LNG never arrived. LNG imports peaked at 16 mtpa in 2007 and declined after that due to the development of domestic shale gas (British Chamber of Commerce 2014). In three main regional markets, today operate not only with physical deliveries but with financial instruments as well. In general, the principle is the same: buyers, brokers, and traders hedge the risks through financial instruments available (Fig. 20).

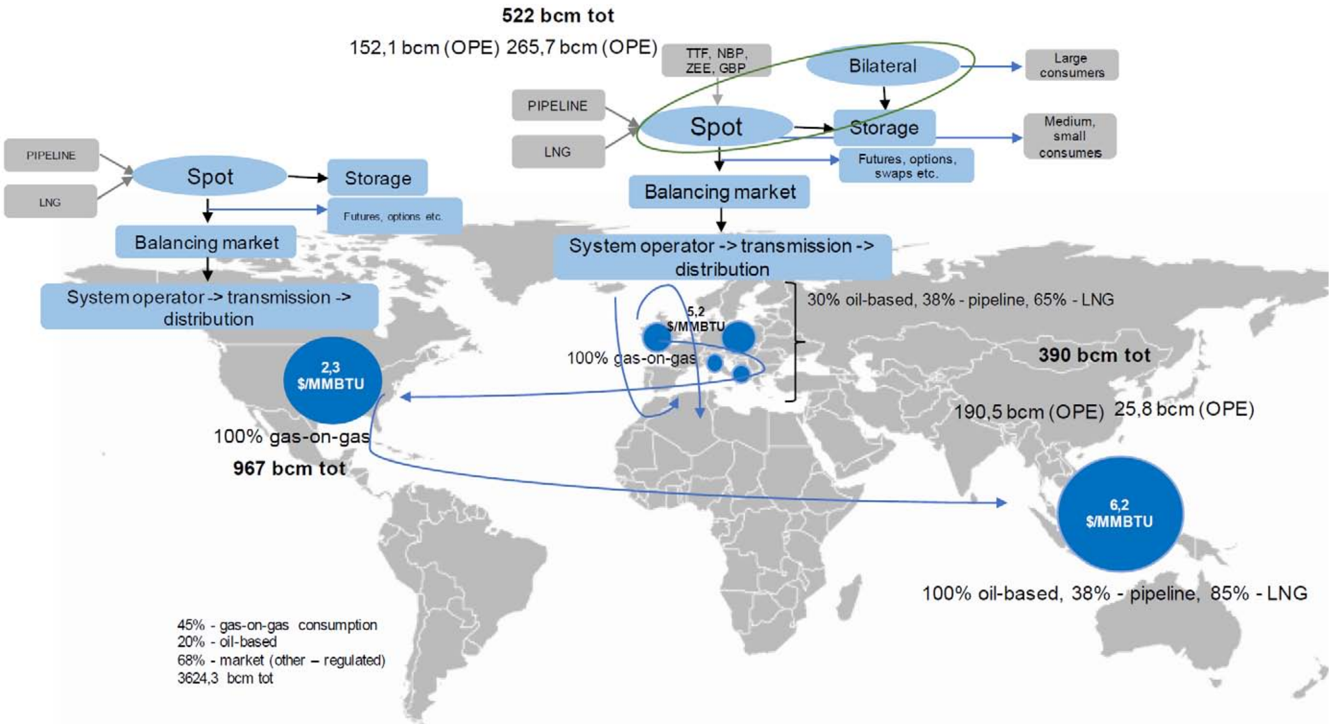

Figure 20—Business-model depending on the contractual forms. Source: authors, IGU, BP

The last indicative examples of the transition to more financialized market are the recent trends in European hubs. Additionally, to the overall rise of traded volumes and, hence, increased competitively traded gas and renegotiated contracts with the largest pipeline importers, namely Gazprom, the last 4 years dramatically changed European market architecture. If previously the NBP was almost the only pure benchmark with all financial instruments available, today a rapid growth on Continental gas hubs and particularly on the Dutch TTF is in the evidence (Fig. 21).

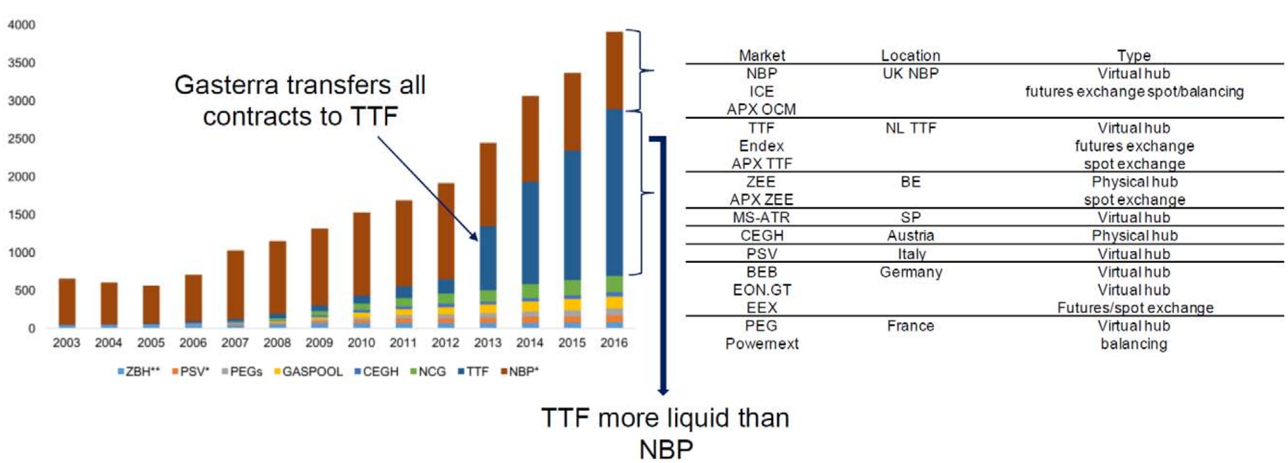

Figure 21—Change of the liquidity of major European gas hubs. Source: authors, IHS Markit, Eurostat

The main reason was the shifting all contracts by GasTerra to the TTF so that TTF today and in future is expected to become the same benchmark. The highest uncertainty is the declining domestic production and new trade flows. The Netherlands by 2030 will suffer from import needs, and a new window opens here for importers only confidence is that the trade will go through the hub. A significant dispute is going on now about which gas will substitute gas from Groningen.

Some argue that only Russia seems to have enough deliverable gas and transportation capacity (not just enough reserves) to increase its exports to Europe/the Netherlands substantially (Henderson 2017). However, we do not expect so much clarity in this situation, as discussed in Section 4, the flexible market and affordable conditions may substitute substantially pipeline with LNG as well.

Prospects of business-models evolution. Implications for US exporters

In the previous two parts, we detailed analyzed the evolution of the gas industry, how it affected business organization and what mainly drove it through the prism of three main characteristics, namely, technologies, regulatory and market development. The below-given Fig. 22 briefly reflects the main findings which consist of the following and could be accounted as the propositions:

1. Historical features of gas industry assume to be concentrated, and natural monopolies often appear as the evidence. Hence, the regional structure followed by the pipeline network systems in EU, UK and the USA with the particular features in each region have objectively reasonable causes to remain the same at least in the mid-term. Moreover, even the similar hub trading will not lead to the equivalent arbitrage;
2. Even though in the mid-term the price may seem to converge in different markets, it is caused by the different forces;
3. The previous sets the different market premiums, therefore;
4. China is the largest uncertainty in all three aspects: how the country will deregulate its gas industry and develop Shanghai exchange, what will be with the shale production and own substitution, what price indices China will use for the import (Asian spot or newly established hub etc.), will the country renegotiate prices in pipeline projects in Russia;
5. Technological improvement will be significant in the downstream, including LNG terminals construction and the rise of tankers' efficiency;
6. We expect a moderate shock in the market if the Singapore online LNG exchange that recently started trading will continue to operate, but not so big due to the existing technical constraints;
7. Long-term contracts will dominate the market players' portfolio and only will change the duration and pricing mechanism;
8. Hub-based trading is expected to grow, and long-term contracts will be adjusted to it, changing pricing mechanism and duration;
9. In case the hub pricing plays a more important role, financial instruments in the different market may come and allow more opportunities for both sellers and buyers;
10. Volatility, one of the main characteristics, therefore, will arise distinctively in different markets. However, in a short period one may be interconnected with another and reflect some surges of supply or demand;
11. The more financial markets will be accessible; the more instruments will be allowed. Relatively to the physical market, the more important role the storage and terminal accessibility will play;
12. LNG will have several "windows" in the mid-term, including a big one China due to the new policy and in Europe (after the own production will start to decline).

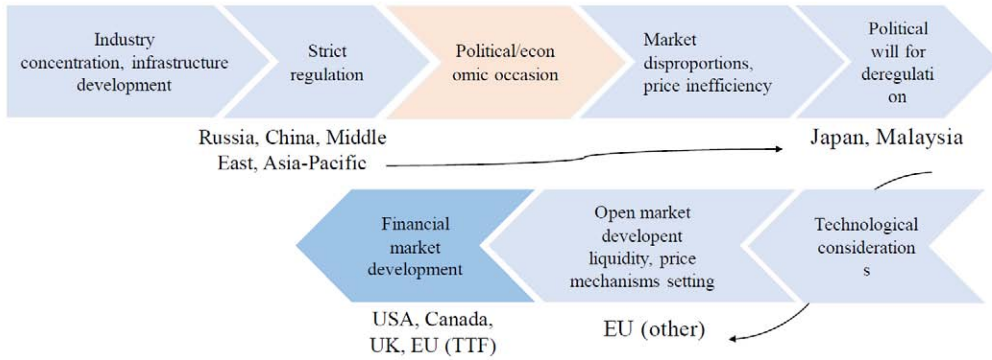

Figure 22—The demonstrative process of markets financialization.

In the above mentioned assumptions, high demand growth for natural gas purposely passed off. leIndeed, in the past, faster growth of gas consumption (~2,7% worldwide, more than the average energy consumption growth) was achieved due to the demand for electricity and in industrial sectors. The same forecast is proposed for the next two decades as well, and the gas is supposed to be preferable in generation (IEA 2017b) and the LNG is accepted in its turn as the most perspective choice to overcome with the problems of remoteness in the countries (mostly in Asia) where the highest demand is expected.

It doesn't, however, mean, that the pipeline construction will stop. The will be built, but with addressing the most significant gaps in supply. From the regions reach in gas, as the USA, Arctic, Africa etc., taking into account huge expenses on some projects as well as technological challenges (for example, offshore location of the main fields in Africa), gas export to the premium markets as LNG becomes the only mean of investment returns unless the other opportunities are accessible for the producers. Also, we partially agree with the statement about energy security and diversity not just because of supply security, but due to the long-term price benefits appear in the long-term period (the instrument to manipulate the prices disappears and consumers in the period of growing demand is a price maker).

We haven't carefully studied and only briefly mentioned the political side and tension. Fundamentally, natural gas always addressed geopolitical disputes as long as its role in energy security rose, even though still far from the same with oil. It already became a current practice to account political risks (including transition) to the supply end of the gas production chain while on another end there is a regulatory risk. A lot of concerns globally still take place, as Panama Canal widening, the impendence of Iran probable blocking of the Strait of Ormuz, transition disputes in EU, etc. First, the problem is to access the probability of the appearance such cases. Secondly, theoretical assessments of possible lose may pass into the entirely different situation and make such predictions pointless. The only one important conclusion from the history made is that the political issues always were the highest accelerators of the market transformations in the gas industry.

Here we suggest to avoid an overestimated expectations and account a gas as a commodity under the influence of different factors, passing the conventional way to become a global commodity (or not to become ever). Hence, for players recently entered the market, following the assumptions mentioned above, the first core conclusion is that the main strategy and business cycle should be closed in a mid-term period. As soon as the market realities change, the more flexible to uncertainties the model should be. It implies both regarding contracts and returns. Second, even though competitive trade in current conditions seems to be far in the Asian market, some not fundamental changes may arise as the pricing formula changes and absolute terms of spot market rise with more projects coming into operations. In this case, the overall strategy should be separated accordingly to the market and trading strategy, whether it is physical or financial.

Theoretically, the problem scope lies in the so-called the value of information or, the more applied and broadly discussed approach, namely the experienced-based markets' equilibriums. It means that the more markets are imperfect and asymmetric what we observe in the gas market (no arbitrage, several dominant players, relatively monopsony consumption), the more any kind of equilibrium among players becomes impossible, and market volatility is suggested as one of the reliable instruments to optimize own returns.

More formally, in more flexible, liquid and developing markets the information and your competitor's actions start to play an important role in business organization and strategy implication as if a set of games between suppliers represents the market regarding best price offer and the buyer regarding highest market power. In this case, the time when the market is in equilibrium (e.c. all players are getting the maximum gain) goes to zero. The original works go back to (Maskin and Tirole 1988) and the framework for the analysis of dynamic oligopolies (Ericson, Pakes, 1995). It played the groundwork for the applied analysis of dynamic oligopolies with symmetric information. This generated large empirical and numerical literature in different areas of applied problems (see (Benkard 2004; Weintraub et al. 2008), for empirical examples (Besanko et al. 2010)). Unfortunately, none of these models have allowed for asymmetric information and imperfect markets until recently applied approaches. The information then is divided into public and private. For example, the historical market prices are public information, or the supply/demand and the capacity volumes of the market players. The private information may include any features of the business organization that may not be observed by others and bring to the no-win actions in the market in the short-term period. The payoff relevant characteristics of market player i, which is denoted by $\omega i \in \Omega i$, take values on a finite set of points for all i. There are two types of actions; actions that will be observed by the player's competitors m°_{i}, and those that are unobserved m^{u}_{i}. For the simplicity, the cases are usually limited when a player's actions are either known only to itself ("private" information), or to all others ("public" information). Thus, simple profits for firm i in period t are given by (Fershtman and Pakes 2012):

$$\pi\ (\omega_i,t,\ \omega_{-i},t,\ m_i,t,\ m_{-i},t,\ d_t) \tag{1}$$

where $\pi(\cdot)\ :\ \times^{n}{}_{i=1}=\ \Omega i\ \times^{n}{}_{i=1}=1\ M_i\ \times\ D \longrightarrow R,\ \ \omega_{i,t}$ - evolves and its conditional distribution may depend on the actions of all competitors, that is

$$P\omega\ =\ \{\ P\omega(.|\ m_i,\ m_{-i},\ \omega);\ (m_i,\ m_{-i})\ \in \times n_i{=}M_i,\ \omega\ \in \Omega\} \tag{2}$$

A common special case occurs when the probability distribution of $\omega_{i,t+1}$, or $P\omega(.|\ m_i, m_{-i,\omega})$, does not depend on the actions of a firm's competitors, or m_{-i}. Then we have a "capital accumulation" game (Ericson, Pakes, 1995).

Then, the public information is denoted by $\xi_t \in \Omega(\xi)$, while the private information component is $z_{i,t} \in \Omega(z)$. Since the player's information at the time actions are taken consists of $J_{i,t} = (\xi t,\ z_{i,t}) \in J_i$, the strategies are assumed as the functions of $J_{i,t}$ (Fershtman and Pakes 2012):

$$m(J_{i,t}):\ J_i \longrightarrow M \tag{3}$$

In the next stage, the s combines the information sets of all players active in a particular period (the period of gas future completion or the period od short-term contracts), that is $s\ =\ (J_i,\ \ldots,\ J_n)$ when each J_i has the same public component ξ. Again $J_i\ =\ (z_i,\xi)$ is a component of s if it contains the information set of one of the firms whose information is combined in s:

$$s\ =\ (z_1,\ldots,\ z_n,\xi) \tag{4}$$

$$S = \{s{:}z\ \in\ \Omega(z)n,\xi\ \in\ \Omega(\xi),\ \text{for}\ 0 \le n \le n\}\ \ \text{- lists the possible states} \tag{5}$$

Firms' strategies in any period are a function of their information sets, therefore, so they are a function of a component of that period's s.

Hence, the theoretical equilibria in the market consist of three main elements:

1. A subset $R \subset S$;
2. Strategies $m^*(J_i)$ for every J_i which is a component of any $s \in S$;

3. Expected discounted value of current and future net cash flow conditional on the decision mi, say $W(m_i|J_i)$, for each mi $\in M_i$ and every Ji which is a component of any $s \in S$

And for every J_i which is a component of an $s \in R$, strategies are optimal given $W(\cdot)$, that is $m^*(J_i)$ solves:

$$max_{mi \in Mi W}(mi|Ji) \quad (6)$$

where:

$$\text{where: } W(m*(J_i)|J_i)=\pi^E(m*(J_i),J_i)+\beta\Sigma W(m*(J_i')|J_i')p^e(J_i'|J_i') \quad (7)$$

where in turn:

$$\pi^E(m*(J_i),J_i) \equiv \Sigma_{J\text{-}1}\pi i(\omega i,m*(Ji),\omega-i,m*(J-i),dt)\ p^e(J-i|Ji) \quad (8)$$

Following the theoretical framework, we suggest the implication to the natural gas market so that the π^E is represented by the contracts (long and short-term, and spot traded volumes outcomes). In addition, we adjust this approach so that the observed component (public) is represented by the physical trade, and the hidden component (private) which is not observed by any market player at the certain going period (as mentioned above, the player chooses the period duration itself. However, we suggest it to be equal to spot deals or long-term contracts on the contrary). The below figure (Fig. 23) shows an illustration of the proposed approach.

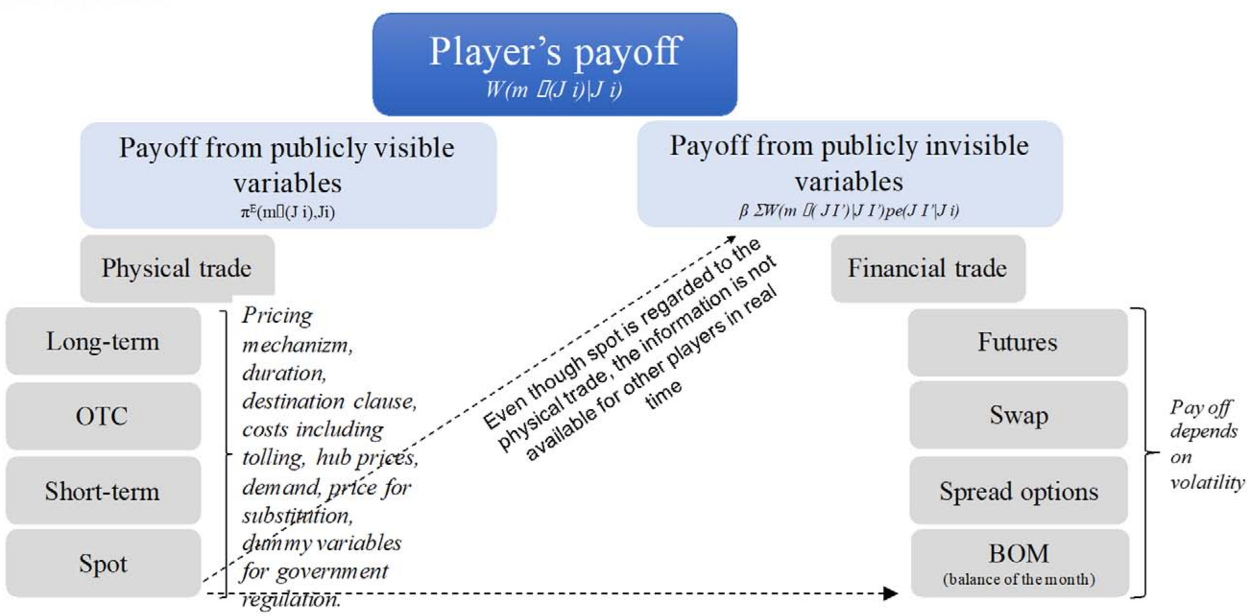

Figure 23—Proposed pay off structure for LNG exporter in current gas industry organization. Source: authors

In the frame of theoretical approach, we propose to express the revenue (payoff, outcome) of each player regarding the contract so that the total revenue is equal to the sum of short-term, long-term, spot contracts and the proposed so-called hidden variable defined by the operations in the financial market. More detailed information about formulas and definitions are, given in **Appendix 20**. The components in the formula (7) hence are replaced relatively to the LNG exporter as follows:

$$W(m*(J_i)|J_i) = \Sigma_{J\text{-}1}L_i\,(pc, lq, t, p_{oil}, p_{hh}, t_f) + \Sigma_{J\text{-}1}S_i\,(pc, lq, t, d, p_{subst}) + \Sigma_{J\text{-}1}Sp_i\,(pc, lq, t, d, t_r, s, b_{cap}) + \Sigma\eta_i\,(f, sw, so, bom) \text{ -> } max \quad (9)$$

where L_i – long-term contracts, S_i- short-term contracts, Sp_i- spot cargoes, η_i- the sum of revenue from the financial market, pc- production costs, lq – liquefaction costs, t – full transportation costs, p_{oil} - oil price,

p_{hh} – benchmark hub price (Henry Hub), t_f – tolling fee (if applicable), d – demand in the destination point, p_{subst} – price for substitution fuel, t_r – reloading tariff, s – seasonal fluctuations, b_{cap} – balancing and storage, f -futures, sw- swap, so – spread options, bom – balance of the month.

The last variable η_i comes from the idea that the player may not know the variables of the competitors as well as so-called unobservable (or private) information but knows the history and current trends in the financial and spot markets, consequently. While seasonality predefines the spot market, different supply/ demand shifts, etc., the financial markets are defined by the volatility.

Hereafter we will on the case-study base show the effect of each parameter on the sample exporter of LNG. The first part denotes open information the players may use (and they do it, indeed) so that to compete with each other. In the case considered these parameters include: volume produced, costs, distances to the consumer, re-export volume, pricing mechanisms in the long-term contracts (if available), etc. Commonly, the information about OTC clearing is not open and rarely declared than other contracts. The problem arises is dedicated to the widely discussed open question about US LNG competitiveness, particularly, will it compete with other importers in EU and will the price offered to be competitive and how it will affect renegotiations with the dominant importers (e.c. pipeline gas from Russia or new emerged LNG). In that case, one the last (but not least, the theme was also discussed by the Oxford Institute for energy Study (Bross 2017) is provided by the SP Platts and shows the comparative assessment of the US LNG positions in EU and the pipeline from Russia. The main findings of the assessment were that the EU markets hold low prices and the US LNG is not competitive in such conditions. Also, much more gas from Algeria, Norway, and Russia came to Europe in previous years. The record volumes from Russia has often declared opposition to the expensive LNG to Europe. Moreover, one of the largest pipeline gas importers announced that the competition would never happen as "the US LNG would struggle to ever be competitive with Russian gas because of how low Russia's gas production costs can go" and US LNG exports would be a loss-making enterprise in the next 20 years "with 100% probability". We do not argue with the record volumes, but the key question, to hour opinion, is not how many volumes the US may export to Europe or will the economics of US LNG be higher or lower than that from Russia, but how fast the US may redirect its free destination volume to Europe if needed at a price included in the business model. The above-proposed model almost totally implemented by the US already including the first three components (L_i, S_i, Sp_i) except the η_i (according to the open sources). The Figure below (Fig. 24) demonstrates how diversified the final destination becomes in the US exporters portfolio (the data showed cumulative for two years). Free destination cargoes go accordingly to the best-proposed transportation fee and immediately appeared demand. Another part of the portfolio includes long-term based destinations that provide the stable flows and accounts the largest share in total shipping. The longer export will be guaranteed by both L_i and S_i; the more exporter will afford to:

1. Expand the share of Sp_i
2. Be informed on the volatility fundamentals in the financial market and benefit from the η_i

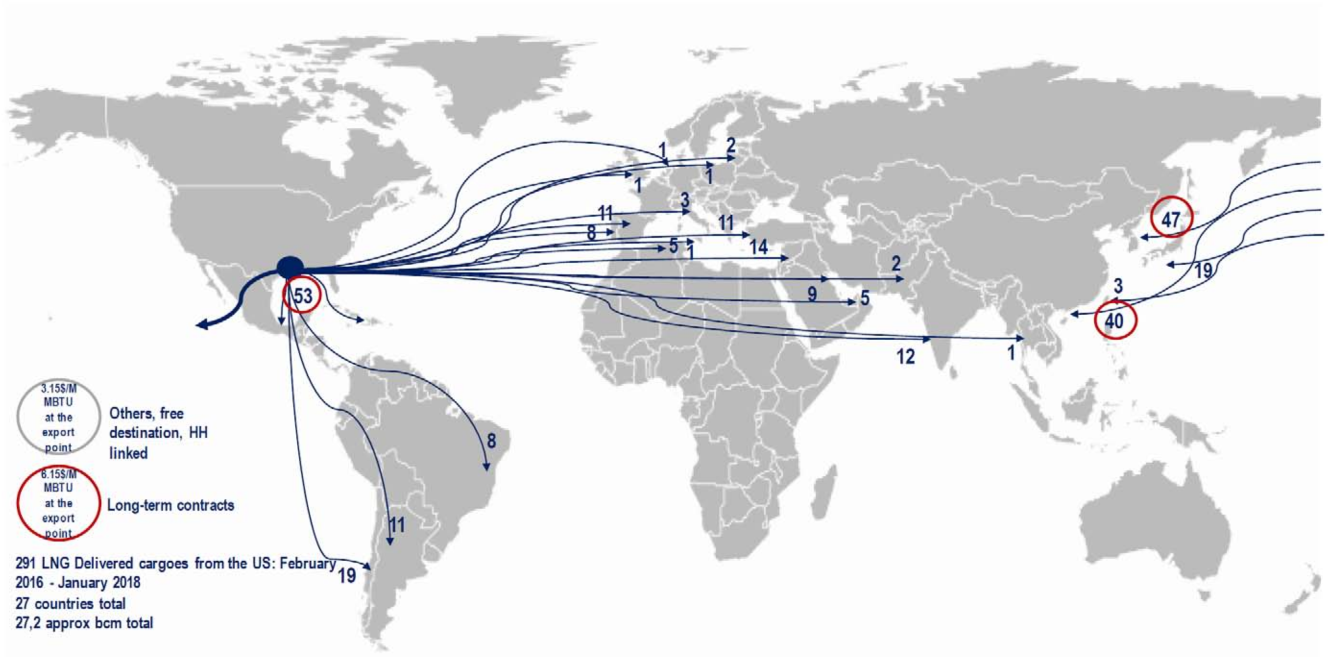

Figure 24—Shipments of Domestically-Produced LNG Delivered (Cumulative starting from February 2016 through January 2018) Source: authors, US DOE

On the contrary, if to take a look at the current positions of the state-owned monopolist in the European market, and particularly, on the price convergence after long-lasting disputes and price renegotiating, along with the huge investments in the other pipeline projects and the lack of access to the capital markets as the result of sanctions makes the position disputable. The next Figure (Fig. 25) shows the loss of bargaining power in the European market after the EU gas hubs raised their traded volumes and the EU set the security supply strategy relying on the potential diversification through the new LNG volumes from the USA as well.

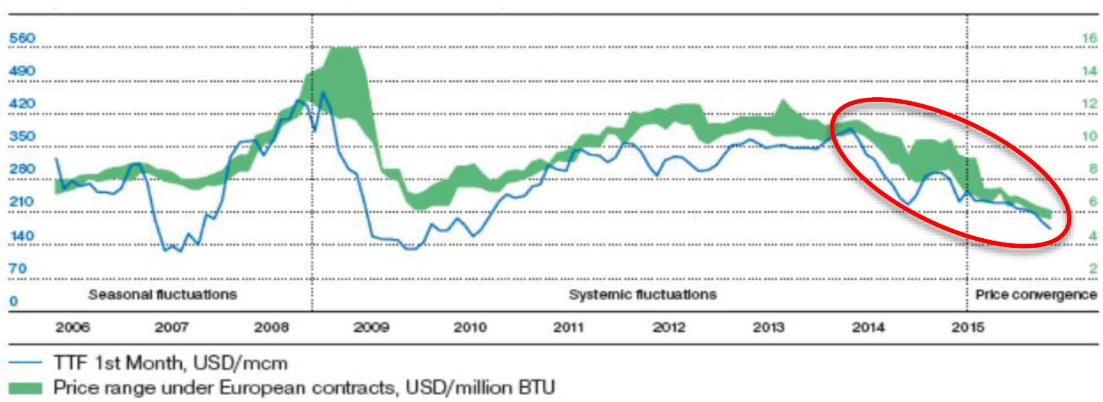

Figure 25—Hub prices vs. RJSC Gazprom's long-term contract prices, 2006-2015. Source: BAFA, Bloomberg, WB, IEA

This position may also be found in the company's results for the past few years (Fig. 26). We will not move on another critical issue such as the loss of more than 100 bcm/year in the domestic market in the most high-margin regions etc., however, that also should be taken into consideration turning back to the Experienced Based Equilibria theory and the value of information (total loss in the domestic market is given in **Appendix 21** in absolute terms).

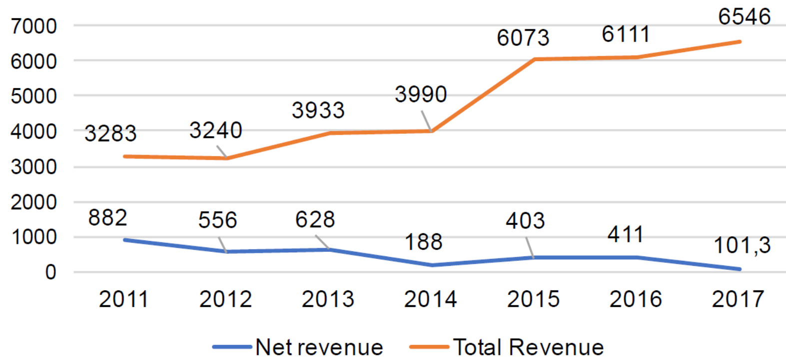

Figure 26—Gazprom results, mln.rub Source: Gazprom, authors

Hence, we assert, that the position of different product players in the European market is not correctly considered in most cases.

Another recently emerged LNG exporter Yamal LNG counted about $27 bln and became the first Arctic Circle project with new technologies and ambitions to build the second plant by 2020, namely Arctic LNG. The plant received vital government support. However that has underpinned the commerciality of the Yamal LNG development, including a 12-year tax holiday from Mineral Extraction Tax, added to the fact that Russia LNG exports pay no export tax, has improved project economics, and the Russian government has also subsidised the construction of the port facilities as part of its plan to develop the Far North of Russia (Henderson, 2017). All of that affected the economics of the project providing favorable positions.

We are not discussing the social welfare from the projects even though the LNG projects in Russia becomes quite arguably in this sense, but yet the level of competitiveness has been risen at the expense of the government budget and support, consequently. The Figure provided below (Fig. 27) shows the average comparison of different routes and costs depending on the market. Transportation costs to European consumers are almost equal and differ only on the Asian route. Unlike Yamal, US exporters have more opportunities in South America, and the current portfolio already shows that.

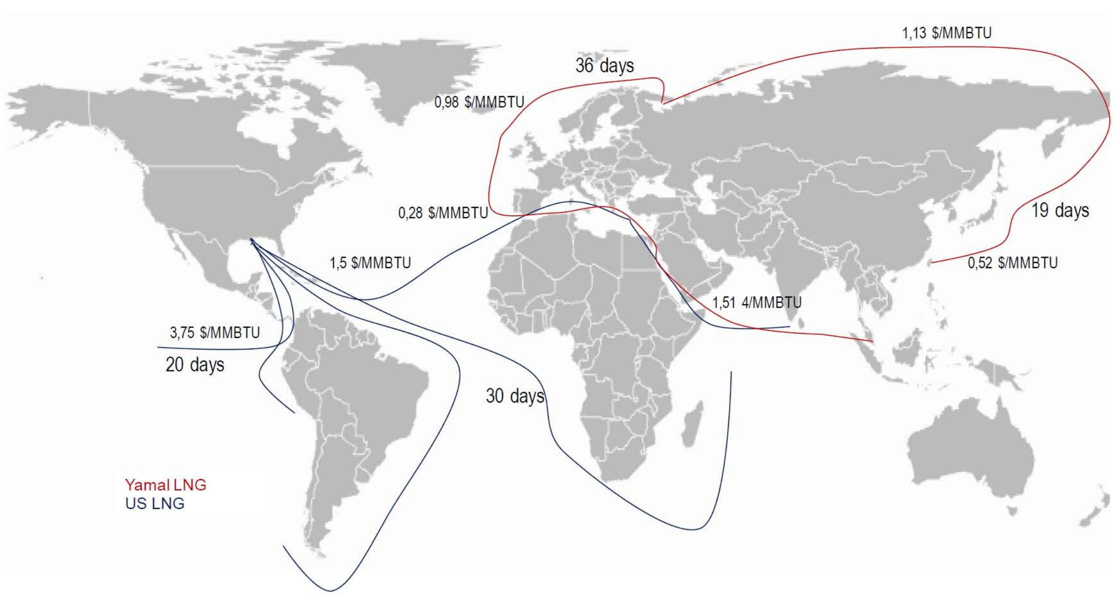

Figure 27—Comparison of basic value chain economics of LNG producers. Source: Columbia Center on global energy policy, NOVATEK, authors

Finally, the opportunity to derive additional profit from the present-day business models proceeds from the premises that more flexible and diversified trade in the seller's portfolio develops experience and more private (inside) information that may generate profit in the financial market. In other words, obtaining and analyzing this information producer can easily identify the set of strategies that maximize total potential revenue from all contracts' types or, in case of declining of one or more components. As a reminder, the potential revenue is a sum of four components which we express in the contract terms (long-term, short-term, spot, financials). The US pricing and contracting type, therefore, in theory, has more advantages and opportunities in a long-run. In practice, however, the realization of the revenue maximization process is under the pressure of different external factors. By the 2019 52 MTPA of new LNG capacities will come into operation in the US (Fig. 28). All of them will compete amid each other and with other players in the premium markets. In such conditions, the value of information and experience becomes more critical.

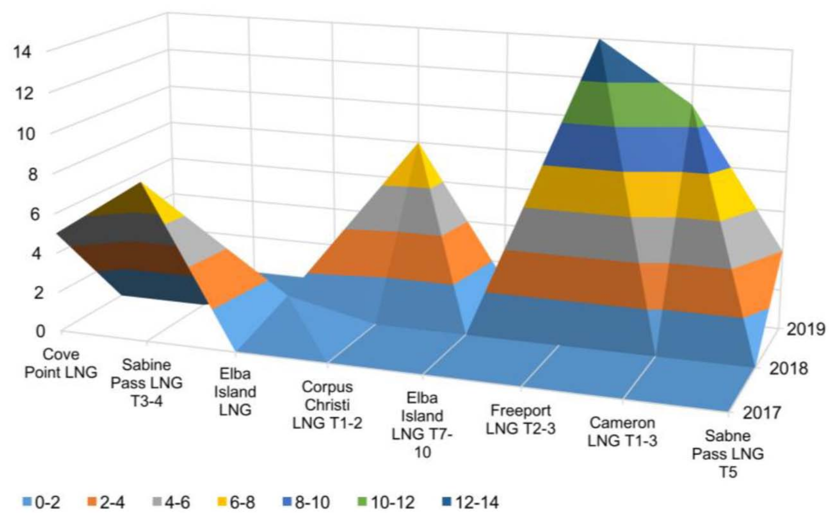

Figure 28—New LNG volume expected to be added by the US from 2017 to 2022. Source: McKinsey Energy Insights

US export's contracts initially have completely another structure which suggests only one fixed option denoted to the liquefaction (2,5$/MMBtu for Sabine Pass) so that all other related costs variable and depends on the market and supplier and determines the decision making. Then, unlike common SPA contracts, they have more options and being linked to the HH, will benefit from the spread between this benchmark and regional spot and swaps LNG prices in the market they are being shipped to. The inherent flexibility consists of the following (Timera Energy, 2017):

1. Send export volumes to the highest priced market (on a spot price netback basis)
2. Ramp down contract volume take to zero if market prices do not cover variable costs

In support of our argument, the upcoming structure of the contracts should be considered (Fig. 29). Thus, by 2022, LNG volumes from the US are expected to offer the highest flexibility regarding destination to their consumers, Particularly, 96% of the total volume will include the free destination clause. For the present consumers, it also will bring benefit as they will be able to re-export the volumes to other regions in case of oversupply and benefit from the arbitrage that in that case may appear inside the particular basin.

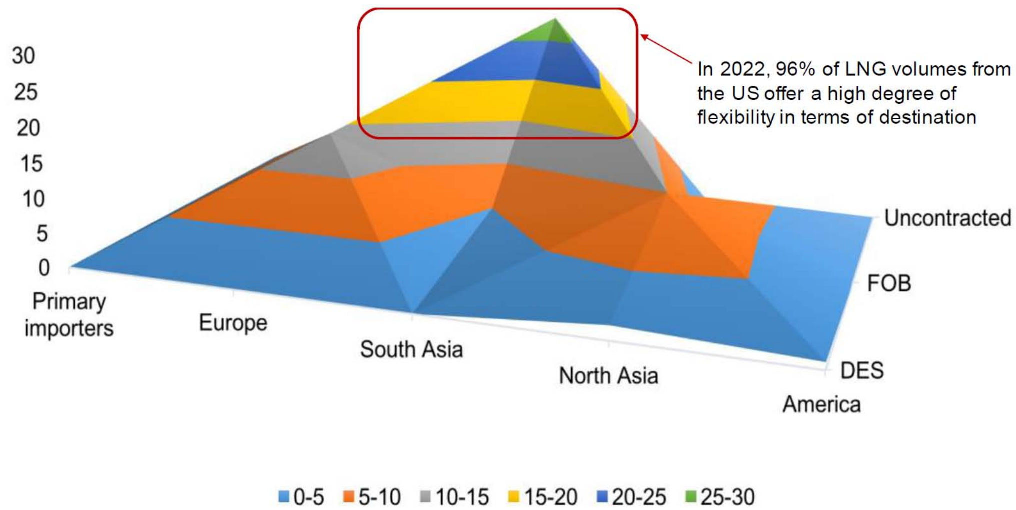

Figure 29—US LNG volume contract breakdown in 2022. Source: Cedigaz, McKinsey Energy Insights, authors

Simply, as the above-described model of each component maximization, the component η_I is composed of the sum of swaps, futures and other options dealt. The opportunity arises in the short period and depends on the different volatility comparison in different markets. For extension, we used the proposed spread option payoff maximization by Tymera and added other options. Thus, for exporter η_I component maximization appears as follows:

$$\max\left(\left\{\begin{array}{c} 0 \\ P_{EU(TTF)} - P_{HH} - \left(P_{HH} * 0{,}15 - t - t_{regasification}\right) > 0 - EU\ delivery - (1) \\ P_{Asia\ FOB} - P_{HH} - \left(P_{HH} * 0{,}15 - t\right) > 0 - Asia\ delivery - 2 \\ P_{HH} - \left(P_{HH} * 0{,}15 - t - t_{regasification}\right) => 0{,}0525 * JCC + 1{,}55 \\ -Australia\ compete - Asia\ FOB\ (China) - (3) \\ P_{HH} - \left(P_{HH} * 0{,}15 - t - t_{regasification}\right) => 0{,}127JCC - ME\ compete - India\ FOB\ (4) \\ P_{HH} - \left(P_{HH} * 0{,}15 - t - t_{regasification}\right) => 0{,}0525 * JCC + 1{,}55 + 0{,}5(t) - \\ Indonesia\ compete - Asia\ FOB\ (China) \end{array}\right\}\right) \qquad (10)$$

The proposed model will allow US exporters to operate efficiently on both physical and financial markets and become more competitive in the regional gas markets. Despite the high expectations about future of natural gas, we assert to avoid possible overestimations. The strategy that exporting companies choose in the US depends on the different factors which for the overall business organization in the industry. The mechanism is based on the idea of value of information any market player receives over the years. The US exporters are in a fortunate position in that sense, having a mature competitive gas market. The maximization in the last formula is directly based on the opportunity to imply the experience and own (private) information while exporting in different markets. The lack of the model is related to the incompatibility amid the development of different financial gas markets, the commodities traded and the maturity of these benchmark in Asia. However, we anticipate the upcoming changes in the Asia-Pacific. However, the uncertainties coming from China have already been mentioned. We intentionally excluded renewables and other substitutes (e.g. coal) from the analysis as it requires more complicated propositions and inconsistencies may arise. Turning to the US exporters, it is worth mentioning that companies still miss the opportunity to benefit from the financial market even though the business-model they applied allows for the conclusion that it provides all the means for that. Recently announced LNG futures with physical delivery by the pioneer in LNG industry in the US, probably, the first call that the players are coming to the understanding of the importance of information and its role to generate additional value.

Conclusion and future works

Today's gas industry organizations and business-models evolved have been developing for several decades under the influence of different factors, economic and political processes. Several mature gas markets already developed in the USA and UK allow market players to build new business-models based on physical and financial portfolios. However, the uncertainties along with market and regulatory constraints in the most premium markets in Asia that consumes the largest volume of flexible internationally traded commodity, namely LNG, still remain to talk about the global gas market. The main findings from the paper are as follows:

1. Comprehensive analysis of different aspects (technological, market, regulatory) provided shows that they all will continue to play an essential role in gas markets and the US exporters will have to consider all of them so that to build efficient business-model;
2. The main constraining factor in Asia-Pacific region related to the policy regulation. Big players such as China will proceed quite a long process of deregulate gas industry with the purpose to form a competitive market and create consumer benefit;
3. Regional structure and long-term contract will dominate in the mid-term with possible decline of the contracts' duration, however;
4. Pricing mechanisms is one of the key factors to determine the business organization, will move towards the hub based formula more and Asian buyers' ambitions to organize regional LNG benchmark will promote these processes;
5. The US exporters are in more favorable conditions to create flexible business-models and rapidly adopt in the markets. At the same time, they are still behind on business organization that allow to use information and benefit more from different types of gas markets;
6. Following that, we propose the model using the experienced based equilibria and the value of information to identify the maximum profit the US exporters may derive from the both types of the markets and the future works expects to validate it on the real data available.

Nomenclature

EIA - US Energy Information Administration
WB - World Bank
FSU - Former Soviet Union
LNG - liquefied natural gas
NGL - natural gas liquids
LPG - liquefied petroleum gas
UK - United Kingdom
US - United States
NGPA - National Gas Policy Act
Thous. km - thousand kilometers
MT - million tones
IMO - International Marine Organization
GOM - Gulf of Mexico
PSA - Project Share Agreement
°C - Celsius
°F - Fahrenheit
Mdwt - Metric Dead-Weight tons
Mcbm - Million Cubic Meters
thous.m.cub. - thousand cubic meters

km - kilometers
bcm - billion cubic meters
$\omega_{i,t}$ - evolves with time and over its conditional distribution
$m^{\circ}{}_{i}$ - actions that will be observed by the player's competitors
$m^{u}{}_{i}$ - actions that will not be observed by the player's competitors
ξ_t - public information
$z_{i,t}$ - private information
$J_{i,t}$ - player's information at the time actions
S - information set
W - optimal strategies
π^E - payoff
L_i - long-term contracts
S_i - short-term contracts
S_{pi} - spot cargoes
η_i - the sum of revenue from the financial market
p_c - production costs
l_q - liquefaction costs
t - full transportation costs
p_{oil} - oil price
p_{hh} - benchmark hub price (Henry Hub)
t_f - tolling fee
d - demand in the destination point
p_{subst} - price for substitution fuel
t_r - reloading tariff
s - seasonal fluctuations
f -futures
sw - swap
so - spread options
bom - the balance of the month
b_{cap} - balancing and storage,

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