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NATURAL GAS PRICING IN THE ASIA PACIFIC REGIONAL MARKET: PROBLEMS AND PROSPECTS*

The natural gas market in Asia is going through a transformation. Both the institutional environment and price mechanisms are changing radically. The Asia Pacific region, characterised by a traditional market structure with long-term contract and oil indexation, has consistently had the highest price levels among all regional markets. As a result, new potential price setting mechanisms are now being actively discussed in the region. Throughout these discussions, Asian gas importers have two main objectives: firstly, reaching adequate price levels, and secondly, increasing competition (ability to choose suppliers). The low oil prices in 2014–2015 brought natural gas prices in the Asia Pacific closer to the EU prices and a level of gas price in the United States plus LNG transport costs. Therefore, the appetite for new pricing and hubs is diminishing.

This paper sets out to evaluate the extent of potential changes in the regional market. The ultimate rationale is to determine the main factors, which Russia and its oil and gas companies should take into account when forming their strategy in the APR. Russia is one of the biggest players in global energy markets and has made serious steps to expand its presence in this region.

The paper provides an assessment of the APR gas market and analyses the main natural gas price setting mechanisms (oil indexation, indexation to the prices of competing fuels, competition-based pricing). It also reviews the implications of using these mechanisms. The prospects of forming a regional gas trading hub are given particular attention. Refs 54. Figs 4. Tables 2.

Keywords: Natural gas, LNG, the Asia Pacific region, regional market, price setting, long-term gas supply contract, indexation, competition, gas trading hub.

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ЦЕНООБРАЗОВАНИЕ НА РЕГИОНАЛЬНОМ РЫНКЕ ПРИРОДНОГО ГАЗА В АТР: ПРОБЛЕМЫ И ПЕРСПЕКТИВЫ

Рынок природного газа в Азиатско-Тихоокеанском регионе (АТР) находится на стадии трансформации. Исторически в АТР сложилась традиционная структура рынка с преобладанием долгосрочных контрактов и привязкой к цене на нефть. В результате цены на газ в регионе стабильно были выше цен в Европе и Северной Америке, что и породило значительные дискуссии о необходимости альтерации механизмов ценообразования в АТР. Путем их изменения азиатские импортеры пытались достичь снижения уровня цен и роста конкуренции (в данном случае возможности выбирать поставщика). Однако в 2014–2015 гг. в результате падения цен на нефть цены на газ в АТР также снизились, достигнув паритета с ценами на европейском рынке и ценой газа в Северной Америке плюс стоимость условной транспортировки в Азию. Это снизило остроту вопроса о поиске альтернативных способов ценообразования.

Цель настоящего исследования — оценить степень возможных изменений на региональном рынке и определить факторы, которые должны учитывать Россия и ее нефтегазовые компании в выстраивании своей стратегии в АТР. Россия — один из крупнейших игроков на мировых энергетических рынках — сделала серьезные шаги по наращиванию своего присутствия в этом регионе.

В статье дана характеристика газового рынка АТР, проанализированы основные механизмы ценообразования на природный газ (индексация по цене на нефть, индексация по конку-

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рирующим видам топлив, конкурентное ценообразование), а также рассмотрены проблемы, которые возникают в связи с использованием данных механизмов. Особое внимание уделено перспективам формирования регионального газового хаба. Библиогр. 54 назв. Ил. 4. Табл. 2.

Ключевые слова: природный газ, СПГ, Азиатско-Тихоокеанский регион, региональный рынок, ценообразование, долгосрочные контракты на поставку газа, индексация, газовый хаб, конкуренция.

Introduction

Russia is one of the biggest players in global energy markets and has made serious steps to expand its presence in the gas market of the Asia-Pacific Region (APR). In 2010, Russia started exporting liquefied natural gas (LNG) to Japan and the Republic of Korea. In 2013, Russia approved a law liberalising its export regulations for LNG: companies producing gas on the shelf and having agreed the terms of long-term supply contracts received the right to export LNG. Rosneft and Novatek met these criteria, with their LNG projects being mainly oriented towards the Asia Pacific region [Mitrova, 2013]. Finally, in 2014, Gazprom and CNPC signed two pipeline gas supply agreements. The first agreement was a contract for the delivery of 38 bcm of gas annually for the next 30 years on the "Eastern" route (from East Siberia to the North-East of China) [OGJ, 2014] and the second one set the main conditions for the "Western" route deliveries (the Altai route framework agreement) [Gazprom, 2014]. In the past few years, therefore, Russia has made a significant step towards resolving the issue of diversifying natural gas deliveries by partially "turning to the East". From an economic point of view, this means that Russia could grow its overall gas exports and therefore its revenues and hard currency earnings. From a political point of view, geographical diversification strengthens Russia's global influence. Finally, in the context of Western sanctions, which have been introduced throughout 2014 and have had a deliberate effect on Russia's energy sector [Kulagin, Grushevenko, Kozina, 2015], it is Russia's interest to search for new partners to solve the problems of access to technology and financing [Paik, 2015]. The Asia Pacific region has those potential partners.

The APR gas market is one of the three large regional natural gas markets alongside the European and the North American ones. As of 2015, these remain significantly differentiated in terms of the energy balance structure and the logic of price setting mechanisms. This fact dictates different price levels, and consequently the formation of a single global natural gas market, which until recently seemed realistic in the short term, now appears far from practical implementation. The possibility of price arbitration between the regions is seen as the basis for price correlation and consequent integration trends between the regional markets [Jong De, Linde Van der, Smeenk, 2010]. International Energy Agency in 2011 observed a higher degree of correlation between regional prices and integration trends between regional markets, although following the economic crisis of 2008–2009, the formation of the global market no longer seemed realistic [IEA, 2011].

Indeed, prior to 2008–2009, natural gas prices in various regions tended to move in the same direction, mainly as long-term contracts used in Europe and the APR used the oil-linked price setting mechanism. However, in 2009 a large gap appeared between price levels in the three regional markets, and the price in the APR became the highest [BP, 2014]. This was driven by the "shale revolution" in the US and a move to competitive price setting for a large proportion of gas deliveries in Europe.

A traditional market structure with long-term contract as the basic feature of such market and a link to oil prices in gas contracts continue to dominate in the Asia Pacific region.

This has consistently led to the highest price levels among all regional markets. As a result, new potential price setting mechanisms are now being actively discussed in the region, with the aim that these would allow to reach "fair" gas price levels. Asian gas importers have two main objectives: firstly, reaching adequate price levels, and secondly, increasing competition (in a simplified form, this means consumers are able to choose suppliers). These objectives will inevitably translate into changes in the institutional structure of this market — a similar process was observed in Europe, for example, in 2008–2014 and led to a major change in the way that gas was being traded. It is quite natural that similar changes in the Asian market would give a supplier as large as Russia serious cause for concern, as major projects had been started in order to enter this market. The fall of oil prices in 2014 led to the situation when average gas sales prices went down in 2015. Low oil prices brought natural gas prices in the Asia Pacific closer to (1) the EU prices and (2) a level of gas price in the United States plus LNG transport costs. Therefore, the appetite for new pricing and hubs is diminishing.

The main purpose of this paper is to assess the degree of potential changes in the regional Asia Pacific gas market and determine the main factors, which Russia and its oil and gas companies should consider when setting their strategy. In order to do that, we analyse the main natural gas price setting mechanisms (oil indexation, indexation to the prices of competing fuels, competition-based pricing). We also investigate the implications of using these mechanisms in the regional context. The prospects of forming a regional gas trading hub are given particular attention.

1. Conceptual framework, methodology and literature review

This article makes a contribution to furthering research on the issue of developing price setting mechanisms in the Asian gas market. The paper attempts to analyse possible changes in these mechanisms by assessing the viability of their alternatives.

The topic of the perspectives of the Asia Pacific gas market has been studied by Russian and foreign researchers, research institutions and analytical agencies.

Regional research is the first group of literature on this subject — in particular, studies conducted by the International Energy Agency [Corbeau et al., 2014; Ten Kate, Varró, Corbeau, 2013], the Japanese Institute of Energy Economics [ERIA, IEEJ, 2015] , the China Energy Fund Committee [CEFC, 2013], the Oxford Institute for Energy Studies [Stern et al., 2008]. The following Russian researchers study the development of the Asian gas market: A. A. Konoplyanik [2010; 2013], K. N. Milovidov [2006], T. A. Mitrova [2011; 2013], V. V. Mikheev [2006].

Publications by the Energy Charter Secretariat [Dickel et al., 2007] and the International Gas Union [IGU, 2011; 2012; 2013; 2014a] were useful for studying the evolution of pricing mechanisms in other regional markets, since the Asia Pacific regional market could potentially follow these. The issue of oil indexation is a key one when we speak of price setting in the Asian gas market. Several publications of the Oxford Institute for Energy Studies dealt with this issue [Flower, 2008; Miyamoto, Ishiguro, 2009; Rogers, Stern, 2014].

Table 1. **Development of natural gas markets and trade — Conditions of development, Regional markets in 2009 and 2015**

<table>
<tr><th colspan="7">Conditions for market development</th></tr>
<tr><th colspan="2">North America and United Kingdom</th><th colspan="4">Continental Europe and Japan/Korea</th><th>China</th></tr>
<tr><td colspan="2">Development based on own resources, no initial dependence on imports</td><td colspan="4">High import dependence from the start</td><td>Initial development based on own resources</td></tr>
<tr><td colspan="2">Supply based on small and medium-sized fields</td><td colspan="4">Supply based on imports from giant / super giant fields</td><td>Supply based on own production but geologically challenging</td></tr>
<tr><td colspan="2">Standardized rent-taking; development decision by private players</td><td colspan="4">Rent maximisation of exporting countries
Development decision by exporting country</td><td>Centralised decision on development by government</td></tr>
<tr><td colspan="2">Demand elasticity from power generation</td><td colspan="4">Limited demand elasticity in the EU
In Japan, Korea pass-through of import prices onto final consumers</td><td>Limited demand elasticity</td></tr>
<tr><td colspan="2">Gas-to-gas competition; price development limited by oil prices; in the US market — clearing price vis-a-vis coal in power generation; UK market subject to supply and demand of LNG</td><td colspan="4">Traditionally: oil prices as reference in price formula;
Now: EU increasing reference to hub prices; Japan, Korea: starting reference to LNG spot prices</td><td>Regulated pricing for domestic supplies until 2011; in 2011 — test pricing reforms in Guandong and Guanxi with Shanghai as reference market; 2013 — country-wide gas pricing reform (indexation against fuel oil and LPG)</td></tr>
<tr><th colspan="7">Regional markets before 2009</th></tr>
<tr><th>North America</th><th>UK</th><th>→ model for reform</th><th>Continental EU</th><th>LNG Trade</th><th>Japan / Korea</th><th>China</th></tr>
<tr><td>Hubs created by industry, churn 100, many players
Before the shale revolution, potential absorption of LNG was expected to be high
High LNG imports were expected</td><td>NBP created by regulation, churn 15 to 10, many players, limited absorption of LNG
Import of LNG mainly by LTCs</td><td>↔</td><td>Several hubs, historical dominance LTCs, few strong players</td><td>↔
No LNG hub but LNG as price transmitter</td><td>No hub, historical dominance LTCs, few strong players</td><td>No hub yet
Until 2011: wellhead price regulated by the government, cost-plus principle + locally regulated tariffs along the supply chain
WEP I launched in 2004 [WEP II in 2010-11]. Pipeline imports from Central Asia started in 2009, bring gas to the East through WEP
LNG imports started in 2006. By 2009, operational terminals in Guandong, Fujian, Shanghai</td></tr>
<tr><th colspan="7">Regional markets in 2015</th></tr>
<tr><th>North American market</th><th colspan="3">European market</th><th>LNG Trade</th><th colspan="2">Asian market</th></tr>
<tr><td>Hubs created by industry, churn 100, many players. Potential LNG exports. Hub prices limited by oil prices and often a result of market clearing against coal in power
Affects European gas and coal markets through interfuel competition within North American power industry</td><td colspan="3">Third-party access to transmission infrastructure
Entry-exit system
Large regasification capacity to absorb surplus LNG
Virtual hubs across the EU, with price correlation between them. Most important: NBP (in GBP) and TTF (in €)
Review of the LTC with key traditional suppliers to include hub price linkage
At 50 USD per barrel, no large difference between prices within oil-indexed LTCs and at hubs</td><td>↔
Asia: LNG imports growth potential.
EU: most liquid to absorb short-term surplus</td><td colspan="2">No regional hub
More than 70% of LNG supplies under LTC with oil indexation
Imports (both spot, short-term and LTC) are sold to domestic customers on cost-plus basis
At 50 USD per barrel, no large difference between prices within oil-indexed LTCs and spot cargoes
Increasing role of supplies to China under traditional LTC with oil indexation.
Pricing reform in China (implemented in 2013)
Pipeline pricing for non-resident is based on netback
Pipeline pricing for resident is based on cost-plus ex-plant
LNG pricing depends on import price and regas cost
Unconventionals: pricing is liberalised</td></tr>
</table>

Note. This table includes the information from its earlier version available in [Dickel et al., 2007] as well as suggestions from R. Dickel of October 2015 [unpublished communication].

Sources: [Dickel et al., 2007; Chen, 2014].

Part of the discussion / literature on pricing principles in the Asia Pacific gas market has been driven by a wish to fulfil a prophecy of gas hubs without analysing the necessary conditions for it, nor if, how and when they might by met in Asia.

This article follows [The Pricing of Internationally Traded Gas, 2012; Mitrova, 2011; Dickel et al., 2007] in its representation of the regional gas market trends (Table 1).

The article uses the definitions and conceptualisations of the pricing mechanisms as in [ERI RAS, ACRF, 2013; Dickel et al., 2007]; uses the concept and methodology of gas net market value calculations based on competing fuels as developed in [Miyamoto, Ishiguro, 2009] with relevant current data. This paper uses statistical data by the International Energy Agency [IEA, 2014a], the International Gas Union [IGU, 2011; 2012; 2013; 2014a], BP [BP, 2015] and GIIGNL, the International Group of Liquefied Natural Gas Importers [GIIGNL, 2014]. Forecast data was obtained using a modelling (simulation) complex at ERIRAS [Eliseeva et al., 2011; ERI RAS, ACRF, 2014], which uses data inputs from Nexant [Nexant, 2014] and the IEA [IEA, 2014a].

2. Review of the regional market

In 2014, natural gas consumption in the Asia Pacific region[1] was around 678 bcm, which was nearly 20% of global consumption [BP, 2015]. As can be seen from the figure below (Figure 1), the key net-importing countries having the largest impact on international gas trade dynamics are Japan, South Korea, China and India — with significant levels of demand plus significant volumes of needed imports.

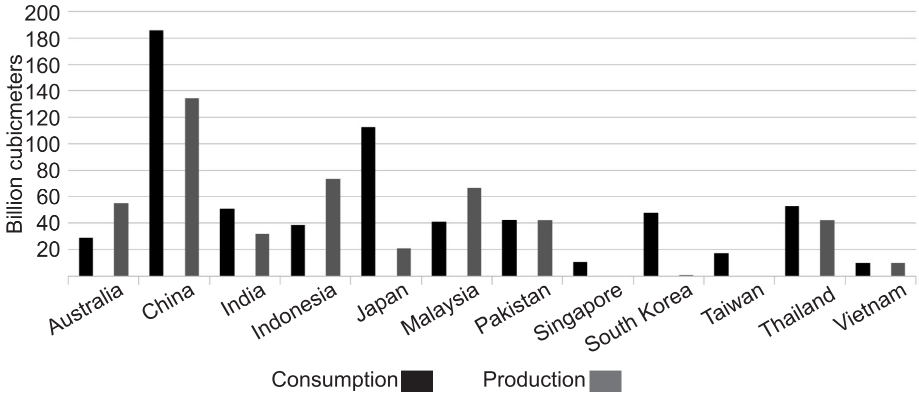

Figure 1. Key natural gas producers and consumers in the APR (bcm).
Source: [BP, 2015].

The Asia-Pacific region is the largest LNG market: in 2013, 61% of world's LNG deliveries were made to this market. Japan, the Republic of Korea and Taiwan are the key LNG importers [IGU, 2014b]. In the medium– and long-term, further consumption growth is

[1] In this article the geographical APR region includes the following regions, based on a classification by IEA: OECD — Asia and Oceania (Japan, Republic of Korea, Australia, New Zealand) and non-OECD Asia (Bangladesh, Brunei, Vietnam, Cambodia, China, India, Indonesia, Korean National Democratic Republic, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Singapore, Thailand, Taiwan, the Philippines, Sri Lanka and other territories).

expected in the region [IEA, 2014b; 2014c]. Thailand is another significant player with consumption level at 52,7 bcm in 2014, a large part of which is covered through domestic production. Natural gas is the main fuel for country's power generation sector. Sharp declines in indigenous production are expected to lead Thailand to become a prominent player in the regional market in the medium term[2].

The main LNG importers — Japan, Korea and Taiwan — have a high proportion of demand covered by "contracted" supplies; in the period to 2025, these countries are not expected to generate additional LNG spot demand. China and India, on the contrary, are characterised by a fairly low proportion of "contracted" supplies to cover demand. Therefore, development of the regional market outside the current price mechanisms to a large degree depends on this group of importers.

The majority of natural gas in the Asia Pacific region is sold under long-term contracts. Despite a tendency towards shorter terms within new contracts, long-term contracts will remain the basis of the gas market in the Asia Pacific region, at least in the medium term [Corbeau et al., 2014, p. 17].

Indexation to oil price and regulated pricing are the main price setting mechanisms used in the Asia Pacific gas market[3] (Figure 2). The second mechanism (regulated pricing) is applied only to domestic gas deliveries and to some consumer groups, while oil indexation applies both to domestic and cross-border deliveries.

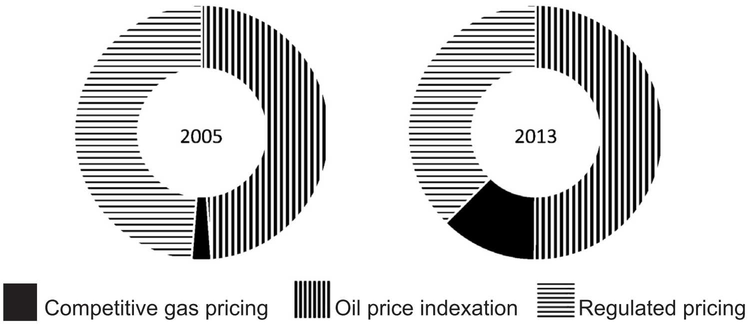

Figure 2. Price-setting mechanisms for gas in the Asia-Pacific region in 2005 and 2013 (All consumed gas,%).
Source: [IGU, 2011; 2012; 2013; 2014a].

The majority of LNG deliveries to the Asia Pacific region are made under long-term contracts (71,3% according to GIIGNL [GIIGNL, 2015]). Although pipeline trade gains importance in the region with China importing from Central Asia and concluding supply

[2] The IEA in its Medium Term Gas Market Report notes that over the next six years, imports will need to increase steeply for consumption to remain the same. Options for covering up for decrease in own production could potential come from two directions: pipeline imports from Myanmar, and LNG imports through the Map Ta Phut LNG terminal, which currently has significant spare capacity. Myanmar already supplies aroud 10 bcm of gas to Thailand, but might find it difficult to increase this as it needs to meet own demand as well as export obligations to China. Thus, it seems likely that Thailand will become increasingly involved in international LNG trade [IEA, 2015, p. 42–43]

[3] Gas price regulation can have various reasons and explanations. IGU distinguishes the following forms of price regulation: 1) regulation based on production costs (prices below production or at production level); 2) social-politically based regulation 3) setting the price based on agreements (bilateral monopoly) [IGU, 2014a, p. 7].

contracts with Russia, the issues of LNG contract deliveries is central within the institutional framework for gas trade in this regional market.

The first contracts for LNG imports were signed by Japan in the 1960s. Prior to the price shocks in the oil markets in the 1970s, Japanese contracts set a fixed price for the period of 15 to 20 years. However, in the 1970s, major large contracts were re-negotiated. The price of LNG began to be tied to the oil price (the price of JCC[4] — the average price of the oil imported to Japan — was used as a benchmark). At the end of the 1980s, South Korea and Taiwan followed Japan, introducing oil indexation (JCC-indexed price) as they were increasing LNG imports.

Formula (1) represents the standard formula for the Japanese contracts [Flower, 2008, p. 406]:

$$P_{LNG} = 0{,}1485 \times JCC + B, \tag{1}$$

where P_{LNG} — LNG price (US Dollars/mboe); JCC — JCC oil price (US Dollars / barrel); B — constant coefficient in the range of 0.6 to 0.9.

JCC indexation and an S-curve[5] is the basis of long-term LNG supplies to the Asia Pacific Region. Nevertheless, the viability of tying LNG prices to JCC prices raises doubts even in Japan itself. Power plants in Japan have stopped using oil and petroleum products, switching to other energy sources. An even bigger debate is prompted by the reason for which Korea and Taiwan and later China and India (who have substantially increased LNG imports) should tie the prices of gas that they import, to average price of Japan's oil imports.

This frames the so-called «JCC problem» — the economic viability of indexing the price of gas against oil prices is questioned. In the 1970s, when the linkage was introduced within the Japanese contracts, it made practical sense: electric power sector was the main gas consumption sector in Japan, and oil was the main competing fuel in that sector. Now, following major changes in the electric power sector, oil and gas are in most cases used in different sectors of final consumption, and therefore this linkage no longer has a practical meaning. The same problem could arise if the gas price were indexed against other fuels, since the energy balance of the countries tends to change in the process of economic and technological development.

In the situation of high oil prices, characteristic for the period of 2009-2014, JCC indexation led to high price of gas delivered under the long-term contracts. As Japan needed to increase its LNG imports after the Fukushima disaster of 2011 (gas-fired generation was the key to maintaining electricity supplies as nuclear power generation in the country came down to zero due to safety checks), it became increasingly active in spot and short-term LNG trade.

[4] JCC — Japan Customs Cleared (more often referred to as Japan Crude Cocktail) — average price of oil imported by Japan, published monthly by the Japanese Finance Ministry.

[5] S-curve is an instrument used for smoothing LNG prices when the prices of oil and petroleum products are volatile, as LNG prices are tied to those. This instrument means applying differentiated coefficients within an indexation formula for various ranges of the JCC price. For the central part of the range — i. e. average prices — a standard coefficient of 0.1485 is used. For high and low JCC prices, smoothing coefficients are used with the aim to protect LNG buyers and suppliers respectively from extreme volatility of oil product prices. As a result, the graph of LNG price dependence on JCC has the shape of letter S, which is where this mechanism takes its name from. More detail is given in [Flower, 2008].

3. Price indexation under long-term contracts: alternative fuels

In view of low oil prices as of 2015, the heat is out of discussions on JCC indexation. However, since oil and gas are still not competing in the core sectors of gas consumption, and since the larger part of natural gas is supplied under the long-term contract, it is necessary to look at alternative pricing options within the contracts.

Suppliers and consumers — the parties of the contracts — approach the issue of the "value" of gas differently. From supplier's perspective, the price should cover the expenditure plus a normal level of profit in the gas industry. This price accounts for capacity reproduction costs. It can be considered as the real price of gas supply. One of the proposed formulae for calculating this price is based on the NPV method [Milovidov, 2006, p. 22].

From buyer's perspective, the reasonable price level is level at which gas is competitive in the domestic market of the given country, taking into account its environmental benefits and advantages for the consumer (the speed of construction of gas power plants, the absence of requirements for a rail infrastructure, ease of placement, etc.). The netback methodology[6] can be used here, with the only difference being that it will not be the formula for the contract that would be determined but an indicative price level at which the use of gas in the importing countries would make economic sense.

To determine the range of competing fuels one can refer to the energy balance of the relevant countries and compile a data table, which would define the share of alternative sources in consumption by sectors, minus gas. The share of the sector in the demand for gas $S_{nat\ gas}$ is defined as the ratio of the gas volumes consumed $Q_{nat\ gas}$ to total energy consumption in this sector Q_{Sect1} (to display the percentage this would have to be multiplied by 100)[7].

$$S_{nat\ gas} = \frac{Q_{nat\ gas}}{Q_{Sect1}}, \tag{2}$$

where $S_{nat\ gas}$ — share of the sector in the demand for natural gas; $Q_{nat\ gas}$ — total gas volume consumed; Q_{Sect1} — total energy consumption in this sector.

The share of the competing source in the sector i (S_{Fi}) excluding gas (sources which clearly do not compete with gas are also excluded) is defined in a similar way, as the ratio of consumed volumes of this source Q_{Fi} to consumed volumes of all fuels competing with gas[8]:

$$S_{Fi} = \frac{Q_{Fi}}{Q_{Sect1} - Q_{nat\ gas}^{Sect1}}, \tag{3}$$

where S_{Fi} — the share of the competing source in the sector i; Q_{Fi} — consumed volumes of the alternative source; Q_{Sect1} — total energy consumption in this sector; $Q_{nat\ gas}^{Sect1}$ — natural gas consumption in this sector.

[6] The netback methodology suggests subtracting the costs of bringing natural gas to the market from its replacement value [Dickel et al., 2007]. The principle can be represented in the form of the formula: $P = (Q) - [intermediary\ costs]$, where $P(Q)$ is the maximum price at which additional unit of energy can be sold at 'Q' volume of demand [Milovidov, 2003; 2006].

[7] «The share of the sector in gas demand $S_{nat\ gas}$» matches NGS category (segment's share in total natural gas consumption) in [Miyamoto, Ishiguro, 2009, p. 9].

[8] «The share of competing fuel in sector S_{Fi}» matches CES category (market shares of competing energies in a consumption segment) [Miyamoto, Ishiguro, 2009, p. 10].

Table 2 provides the outcomes of reviewing the energy balances of China, India, Japan and the Republic of Korea. The numbers show that coal is the main competing fuel (it presents maximum competition in the sectors, which provide maximum demand for gas). In Japan and South Korea, electricity competes with gas in the industrial, commercial and household and utilities sectors, in addition to this. Petroleum products are also present as alternative fuels and in particular in the household and utilities sector in China.

Table 2. **Fuels competing with gas by sector: China, Japan, South Korea, India, results of calculations with the use of formulas (2), (3)**

CHINA						
Sector	$S_{nat\ gas}$	S_{Fi}				
		Coal	**Oil**	**Oil products**	**Electricity**	**Renewables**
Industrial	0,21	0,59	0,00	0,08	0,33	0,00
Transport	0,09	0,01	0,00	0,97	0,02	0,00
Electricity generation	0,18	0,99	0,00	0,00	n/a	0,01
Other sectors	0,51	0,32	0,00	0,22	0,42	0,05
JAPAN						
Sector	$S_{nat\ gas}$	S_{Fi}				
		Coal	**Oil**	**Oil products**	**Electricity**	**Renewables**
Industrial	0,07	0,35	0,00	0,28	0,32	0,00
Transport	0,00	0,00	0,00	0,98	0,02	0,00
Electricity generation	0,64	0,61	0,11	0,24	n/a	0,01
Other sectors	0,28	0,01	0,00	0,37	0,62	0,00
SOUTH KOREA						
Sector	$S_{nat\ gas}$	S_{Fi}				
		Coal	**Oil**	**Oil products**	**Electricity**	**Renewables**
Industrial	0,21	0,23	0,00	0,11	0,60	0,00
Transport	0,02	0,00	0,00	0,99	0,01	0,00
Electricity generation	0,50	0,90	0,00	0,10	n/a	0,00
Other sectors	0,27	0,03	0,00	0,30	0,67	0,00
INDIA						
Sector	$S_{nat\ gas}$	S_{Fi}				
		Coal	**Oil**	**Oil products**	**Electricity**	**Renewables**
Industrial	0,19	0,49	0,00	0,12	0,21	0,00
Transport	0,03	0,00	0,00	0,98	0,02	0,00
Electricity generation	0,36	0,96	0,00	0,03	n/a	0,01
Other sectors	0,42	0,13	0,00	0,41	0,46	0,00

Source: [IEA, 2014a].

At the same time, gas is more expensive than coal, its main competitor, and therefore without targeted measures by the governments to reduce coal consumption within the initiative to cut CO2 emissions, gas will lose out to coal in inter-fuel competition in the electric power sector. This explains the efforts of importing countries to reduce gas prices.

Getting back to the contracts issue: one alternative to oil indexation is a tie to the prices of alternative fuels, following the logic of the above presented calculations. Indexation, which accounts for the share of competing fuels in the energy balance of importing countries, is quite an adequate mechanism in a bilateral (*but not regional*) format. The difficulty of indexation in a regional format is due to the fact that specifics of the energy mix should be taken into account during indexation. The structure of the energy balances and the systems of taxation, subsidies, market regulation and therefore prices are significantly different among the countries of the region. As a result, average regional values could significantly differ from optimum determined by the percentage of indexation in each of the national markets [Miyamoto, Ishiguro, 2009, p. 14].

For this formula to work most effectively in the interests of both parties signing the contract, it should reflect the price of fuels which actually compete with gas in the end-use sector of the given region or country. Therefore, when one uses indexation at the prices of alternative fuels, there should be a viable possibility for the consumer to switch to these alternative fuel sources. If there is no real opportunity to do so, then there is no adequate justification for their use in the indexation formula.

The first version of alternative indexation, which logically follows from the outcomes of the calculations, is coal prices as an indication of price level for gas if it were to be competitive with coal. However, the option of actual coal indexation within gas supply contracts has proved to be unacceptable, for example, during negotiations on gas deliveries from Russia to China. The primary reason is a longer period of return on investment for the gas supplier (in this case — for Gazprom). This is due to the fact that at the time of negotiations, the gas price tied to coal prices was expected to be much lower than the oil-indexed gas price. Moreover, indexing gas prices against coal prices raises the issue that in the case of deliveries to China, China as a major coal supplier could influence coal prices. [Ten Kate, Varró, Corbeau, 2013, p. 30, 39, 74–75].

In addition, indexation against alternative fuel prices does not solve the fundamental issue, which arises under long-term contracts: when the situation in the energy sector of the respective countries change, pricing principles need to be adjusted, often much earlier than the expiration of the contract term. There are no guarantees that when a long-term contract is being signed using indexation against alternative fuels at a price relevant at the time, this indexation would remain relevant in the future — the "JCC problem" could arise again in the medium term [Galkina, Kulagin, Mironova, 2014].

4. Indexation against the Henry Hub?

Indexation against alternative fuel types is not the only option possible under long-term contracts — the other option is to use hub-indexed prices. It is thought that the best solution to this problem would be to switch to a mechanism of competitive price setting by increasing the proportion of spot LNG trade[9].

A gas trading hub is a point at which there is a transfer of ownership of gas between the seller and the buyer. At the primary stage of market development, this point had an exclusively administrative significance (the function of recording natural gas sales deals). A

[9] IGU, for example, observes the following: «Further changes in regional price formation mechanisms will most likely move in the direction of increasing the proportion of LNG spot deliveries in all markets, including APR» [IGU, 2014a, p. 17].

hub can be physical (a site where several pipelines cross over, in conjunction with nearby gas storage facilities and/or LNG terminals) or virtual. As natural gas markets in various regions develop, gas trading hubs gain importance, since given competitive deliveries and gas demand, prices formed at the hubs can serve as indicators of equilibrium prices in a given market.

Practical implementation of this option becomes possible in Asia with the start of LNG exports from North America. The principle which would make it possible to implement hub-indexed pricing is linked to the specifics of long-term contracts in the North American market: the parties investing in liquefaction terminals want to sign long-term contracts for using liquefaction capacity, the so-called *tolling agreements*. In this case, gas is purchased in the wholesale market (and not at the wellhead). There are also no limits in relation to the end point of LNG sales: buyers can route tankers according to their priorities in relation to the region and the final sales price [IEA, 2014d, p. 166]. Therefore, the price at the largest American Henry Hub can be translated to the Asia Pacific region by adding liquefaction, transportation and regasification costs.

The first tolling agreements for gas delivered from the US were signed by Korean, Japanese and Indian companies. These were 20-year long contracts signed by Freeport LNG Development with Japan's Toshiba Corp. and South Korean SK E&S LNG to process 4.4 million tons of natural gas annually at its third planned liquefaction unit in Texas. Freeport also signed deals with Chubu Electric and Osaka Gas, as well as BP for the delivery of 8.8 million tonnes a year from the first two units [White].

According to these agreements, the price is determined under the following formula:

$$P = 1{,}15 \times P_{HH} + A, \tag{4}$$

where 1.15 — constant coefficient, which will be applied in the US to LNG export contracts; P_{HH} — current price at the Henry Hub; A — fixed allowance that is assigned to each customer (from 80 to 107 US Dollars / thousand cubic metres) [Stern, 2014, p. 47].

The main motivations for Asian importers who sign contracts in the North American market is as follows: a) the possibility to reduce the end prices since the given formula provides a price level lower than average gas prices in the Asia Pacific region in 2011–2014; or b) the possibility of arbitrage profits from the supplies to the premium Asia Pacific market. To see whether this logic will work in the conditions of price volatility both at the Henry Hub, a liquid trading point, and oil price volatility, we determined at which oil price levels parity can be reached with the prices of gas imported by Japan. Figure 3 below gives the results of our calculations.

To use the formula (1) with JCC prices, the following assumptions were made:

- A — constant component, the average value of 2.625 US Dollars / Mmbtu (depending on the contract, from 2.25 to 3 US Dollars / Mmbtu)/
- Transportation and port charges at 2.35 US Dollars / Mmbtu/
- The average cost of regasification at Japanese ports at 0.7 US Dollars / Mmbtu.

To use the formula (4) with HH prices A — a constant increase, which is assigned to every buyer, expressed in US Dollars / Mmbtu — the average value of US Dollars 0.75 / Mmbtu was adopted.

HH price linkage would only be attractive in Asia given high regional oil prices and a relatively low price at the Henry Hub itself. As of October 2015, Henry Hub price for

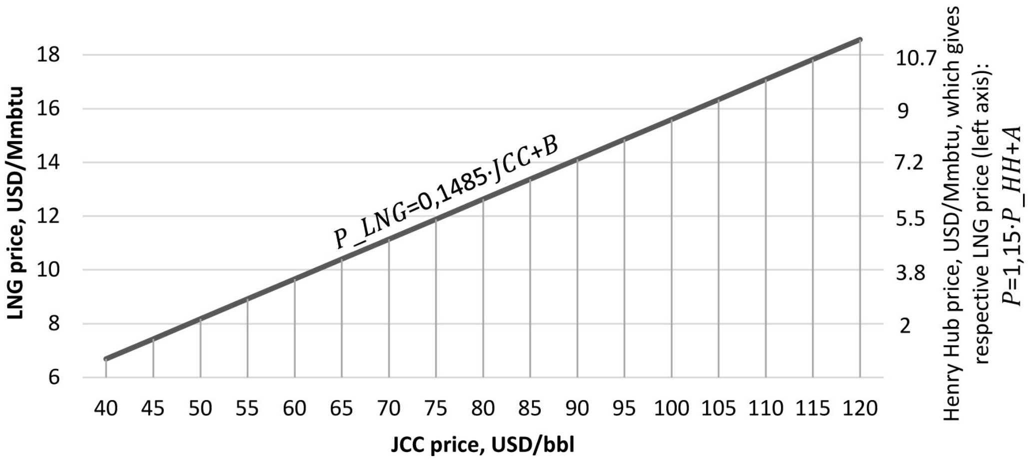

Figure 3. Price of LNG imported by Japan as a function of JCC price, and comparison of Japan's LNG import price with needed HH price in case of HH-indexation.

November delivery is at 2.5 US Dollars / Mmbtu [Platts, 2015], which translates into 8.55 US Dollars / Mmbtu if delivered to the Asia Pacific region. This is lower than LNG import price indexed to JCC (at 59 US Dollars per barrel in August 2015 [Petroleum Association of Japan, 2015], translates into 9.5 US Dollars / Mmbtu of LNG), but above the price of spot deliveries of 7.7 US Dollars / Mmbtu in August 2015 [METI, 2015]. The spot price for deliveries in December 2015 are estimated at even lower level of 6.8 US Dollars / Mmbtu [Platts, 2015].

HH-linkage pricing was quite beneficial for Asian companies at the time of signing the contracts (2012–2013); however, its viability is questionable in the long term. As it is clear from the figures above, there is no guarantee that the price generated in this way will be lower than the price linked to JCC. Consequently, in the long term such agreements may not lead to lower LNG import prices or to high earnings hoped for by the Asian parties signing these contracts. Moreover, the price does not reflect basic characteristics of the gas market (in fact, HH-linkage would denote a price in the Asian market that would be oriented towards the balance of supply and demand in the US).

Before moving to the perspectives of hub formation in the Asia-Pacific region itself, let us draw preliminary conclusions for sections 3 and 4. Under certain market conditions, various pricing methods can be used to respond to the following challenges: a) economic justification of the existing JCC-linkage under long-term Asian contracts and alternative indexation options and b) the desire to lower the price levels. These pricing methods include indexation against competing fuel types and cost-plus principle from a hub price in another region (above we have discussed HH as the example which would materialise in case of North American LNG exports). However, these methods do not resolve the fundamental problem of the discrepancy between the resulting price and equilibrium prices *in the Asia Pacific market itself*. Neither do these pricing methods guarantee lower price levels as compared to JCC-linkage.

5. Spot trade in Asia as the basis for increasing competition in the regional natural gas market

A tie to prices formed during spot trading could be one of the solutions for long-term contracts. For example, in Europe in recent years an increasing number of contracts being renewed are based on a partial link to spot prices [Franza, 2014, p. 18]. In principle, Asia could follow this practice.

Argus and Platts agencies calculate JKM (Japan Korea Marker) price index [Platts…] based on open information on spot deals with deliveries to these two countries, calibrated by the Japanese import statistics for spot imports [METI, 2015]. The use of JKM within long-term contracts is very limited. This is due to the fact that the JKM price largely correlates to JCC-linked LNG prices and as such does not represent a fundamentally different price setting model. In addition, there is often a gas deficit in the Asian market, which leads to an increase in spot prices. As a result, there is not a particular interest on the part of the consumers to switch to JKM indexation in long-term contracts. The issue of reducing price levels would not be solved.

Changes, which would nevertheless lead to the JKM prices being more actively used as a benchmark, would include increasing spot trading even in the absence of a hub (between 1994 and 2011 spot trading volume in the region was up from 3 to 48 bcm [GIIGNL, 2014, p. 9]). Another issue is that much of the demand is covered by "contracted" supplies and therefore potential spot trading volume in the period to 2020 is not substantial: it would not provide enough depth to increase liquidity.

In addition, in the last months of 2014 — beginning of 2015 there was an overall decrease in the average prices of spot deals. This could prompt key importers to review their preferences in relation to JKM indexation. As of the beginning of 2014, Chubu Electric and GDF Suez have been using new contracts with a tie to JKM, for the period to March 2016 [Platts…, 2014; 2015].

The proportion of competing deliveries to the Asia Pacific region is growing and LNG buyers are interested in changing the pricing mechanism for gas. There is also growing price volatility of spot prices and market participants have to use derivative mechanisms (futures and options). All of these factors make a case for developing an Asian LNG trading hub.

From the point of view of establishing a trading hub, the issue is that there is limited integrated regional trade in the APR. Prospects of setting up a regional gas hub has been on agenda for several years: examples of research which envision the movement of the Asian market along *the European way of development* include publications from the OIES, the IEA etc [Corbeau et al., 2014; Ten Kate, Varró, Corbeau, 2013; Rogers, Stern, 2014]. A hub would in fact perform an administrative function, simplifying the transfer of ownership rights for gas.

Much of the discussion, however, has been driven by a paradigm that hub prices *must* be established. Unfortunately, this discussion is largely omitting the set up and relations of players (private companies, state companies, governments) nor the way gas is priced at the final customer. In Asia, most often a cost plus of import prices is passed onto the final customer, and most often without any competitive alternative or benchmark. Therefore, the natural gas hub discussion in Asia is significantly different from that in Europe. What we will speak about below is *largest areas of LNG trade*.

It is not our intention to say that these trading areas are competing for the role of the *central hub* (this seemed to be one of the objectives of the IEA study on gas hubs in Asia [Ten Kate, Varró, Corbeau, 2013]). If Asian trade develops more into the direction of hub-based trade, it is not the competition between potential hubs, but rather common approaches of the importing countries which will predetermine such movement.

The largest LNG trading centres are almost all located in Northeast Asia (Figure 4). They include areas in Japan (Tokyo bay), China (Shanghai / Hangzhou bay, Northeast / Bohai bay), Singapore, as well as smaller ones in Korea and Taiwan. The largest number of gas trade flows intersections are located in China. Added to the fact that China is developing various pipeline import projects, it is becoming the one single most important player in the regional gas market.

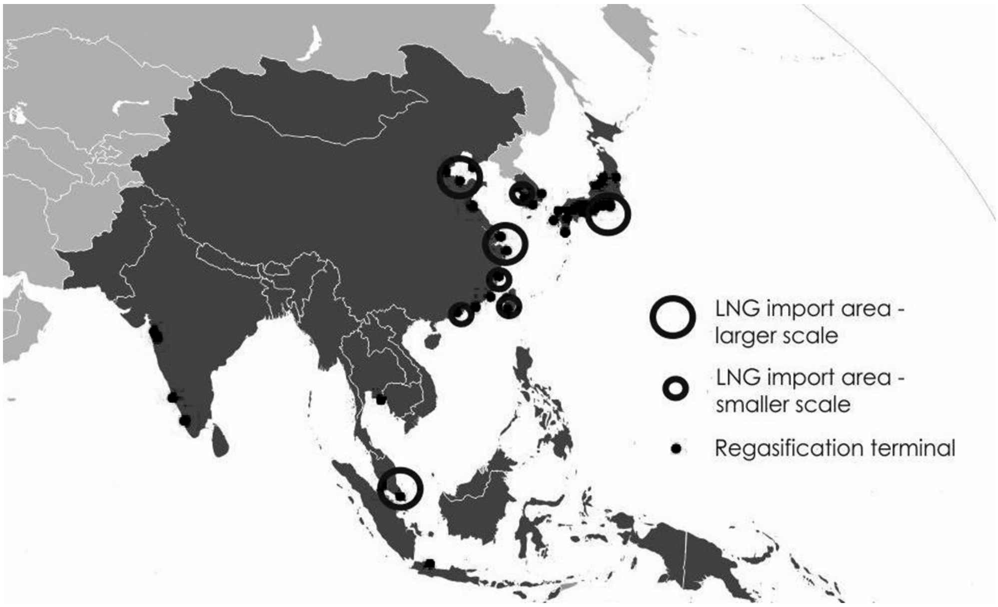

Figure 4. Largest gas trade centres across the Asia Pacific region.
Source: Regasification terminals shown in accordance with [GIIGNL, 2015, p. 19, 26].

5.1. Asean

Singapore has a very beneficial geographical position, when its role in regional gas trade is concerned. Firstly, Singapore is located on the route of a large number of LNG tankers travelling to the APR. Secondly, several pipelines which are of strategic importance to ASEAN run through Singapore. In addition, Singapore has made big steps in the liberalisation of the gas market. Domestic prices are not state-regulated and are formed competitively. As of 2014, this was the only ASEAN country, which provided free and non-discriminatory access to the infrastructure. The most significant restrictions, which would hamper the establishment of a gas hub in Singapore, would be the insufficient capacity of the market, total import dependence on energy sources and the lack of necessary gas storage facilities, which could smooth out peaks in demand for gas. However, this issue can be successfully addressed with the implementation of the TAGP (Trans-ASEAN

Gas Pipeline) project, which is designed to integrate well-developed but fragmented pipeline infrastructure in the region into a single system. The development of low-tonnage LNG tankers could help achieve this purpose. These tankers would enable to shift small volumes of LNG at reasonable prices to regions with low gas demand.

5.2. China

From the perspective of domestic market development, there are two key developments in China: the pricing reform and the development of infrastructure. The domestic gas pricing reform in China has led to a substantial increase in prices in 2013–2014. The infrastructure is being actively developed, which points to the development of the domestic market and China simplifying domestic trade operations.

New import channels are also actively being developed and, as a result, in the medium term the Chinese market will be more closely connected with several sub-regional markets. These include a much more diverse set of options, than options that Japan and the Republic of Korea have in the form of LNG. China has started to import natural gas from Central Asia; from and through Myanmar (this route allows for LNG imports to avoid passing through the Malacca straight); and concluded contracts with Russia, which overall fits into China's 'compass' strategy of supply sources [Henderson, Mitrova, 2015; Paik, 2015].

The issue of price is central for economies such as China (but even more so in case of India, for example): they gradually increase their dependence on imports, but the domestic users have to be able to afford natural gas (thus the price needs to be sufficiently low, to e. g. replace coal in power generation). From the other hand, the domestic price has to reflect the international price to allow the gas importing companies actually make profits when implementing the imports. However, so far price levels in China are still below average regional levels.

The pricing reform aimed not so much at integrating into regional trade, but rather at increasing profitability of domestic production. There are signs of price levels being regulated within the pricing system, despite a move to the netback principle. In 2014, gas sales fell in a number of provinces as a result of de-facto increasing prices. This included the North-eastern provinces Heilongjiang and Jinlin. On the one hand, the pricing reform did not make it possible to fully move away from regulated prices. On the other hand, as prices rose, the reform created conditions for setting up platforms to sell surplus gas.

The experience of the Henry Hub shows that to set up a physical hub, it would be sufficient for a trading platform to *set* the point of delivery on spot deals, as was the case at NYMEX for the pipeline in Louisiana in 1990 [Dickel et al., 2007, p. 119]. Examples which go into this direction in China include:

- Shanghai International Energy Exchange (a division of the Shanghai Stock Exchange), which plans to launch a futures market of LNG that could be quite attractive for participants with the regulation of the Shanghai Free Trade Zone. In 2012, a platform for spot LNG trade was launched at this stock exchange. The platform started testing the mechanism of spot transactions for LNG and LPG in December 2010 in an auction format[10].

- Ningbo[11] Commodity Exchange, which launched China's first forward LNG contract using ICIS Asian LNG spot price assessment as a benchmark [DNV-GL, 2014].
- Dongbei[12] Commodity Exchange with possible pilot platform for spot trading of pipeline gas operated by CNPC [Zhang].

We can see a certain similarity of the Chinese gas market to the US market at an earlier stage of development. This is especially the case considering the initiatives, which are present not only in terms of LNG, but also in respect to pipeline gas transactions in the Northeast of the country. In view of the reforms, as well as initiatives for setting up trading in natural gas, it is a matter of time before a hub is established in China. It would primarily act as a physical point of delivery and / or record wholesale gas flows.

5.3. Japan

Tokyo Bay is the world's largest LNG receiving area comprising five regasification terminals with total capacity of over 100 bcm of natural gas per year, as well as storage capacity of 6 bcm of LNG per year as of 2012 [IEA, 2012; Nexant, 2014].

There is no governmental intervention in pricing issues. There is free access of third parties to the infrastructure, mainly to the regasification terminals. There is a sufficient number of players in the market, which increases potential for setting up a hub.

On the other hand, the pipeline network in the country mainly connects each specific LNG terminal with a specific end-user and does not allow to diversify energy flows. The region's high dependence on LNG imports is an important restriction and a negative factor for Japan's energy security. It also complicates the task of establishing a highly liquid hub in the country. In addition, it is expected that in the period up to 2040 capacity of the Japanese market will contract [ERI RAS, ACRF, 2014].

To establish a physical gas hub at the site of the Tokyo Bay terminals, it has to be logistically possible to store LNG in volumes. This is necessary to conduct spot trading and relevant shipment operations. There is also a need for an exchange, which would administer contracts with deliveries to the hub. The Japanese themselves are not doing this, and it is not convenient for trading platforms in other countries to tie contracts to deliveries to Japan.

In Japan, demand is largely covered by "contracted" supplies (and a relatively active entry into spot markets happened as a result of the Fukushima accident and a subsequent increase in gas demand). The only mechanism for switching to an indexation method different from JCC-based pricing is to hold talks with the aim of changing the existing long-term contracts. Significant state control over the operation of energy markets and

[10] Ningbo and Shanghai are on opposite sides of the Hangzhou Bay and each has existing regasification terminals.

[11] Ningbo is a large port region in the province of Zhejiang, lies south of the Hangzhou Bay. On the other side of the Bay is the Shanghai port.

[12] Dongbei is the name of a region in Northeastern China, including the provinces of Heilongjiang, Liaoning and Jinlin (sometimes includes portions of inner Mongolia). The region is located to the north of Beijing and borders with Russia. There are plans to import gas from Russia to China via this region under the contract of May 2014.

insufficient integration of the domestic transport infrastructure are two significant restrictions.

5.4. A net of hubs

Overall, in the short term, it appears problematic to create a hub-based price benchmark in the Asia-Pacific region, especially within the logic of competition between various locations for the role of the 'central hub'. No such central hub is possible at any of the locations discussed above. It is most logical that the national markets will develop so as to take advantage of the level of prices at the regional market, and the regional trade in the Asia Pacific will develop with the 'net of hubs' each serving the purposes of the respective domestic markets. The notion of hubs will also be different from 'gas trading hubs' in 'western' understanding, for one simple reason: long-term contract is chosen as the instrument of securing supplies, as opposed to hedging mechanisms through gas derivatives, as in North American and increasingly the European market.

Conclusion

The main problem faced by importers of natural gas in the Asia-Pacific region used to be high price levels. As prices in the European and North Asian markets declined throughout 2010–2014, the Asian players were looking at pricing mechanisms used in those markets as means to bring Asian gas prices down as well. The pricing mechanism is most often named as the reason for disparity in price levels. For the APR, this reason is the dominant use of oil price linkage under long-term contracts. This paper discussed alternative pricing mechanisms in the APR natural gas market. However, as of 2015, following the drop in oil prices, Asian gas prices went down as well. This removed the sense of urgency in finding new formats of pricing natural gas in the Asia Pacific.

Various pricing methods can be applied in certain market conditions to resolve the issues of a) economic justification of the existing reference to JCC price in Asian long-term contracts and the use of alternative indexation methods and b) the desire to reduce price levels.

Establishing competitive pricing mechanisms is not a priority for Asian players. Rather, their main objective is to create an institutional structure of the market, which would ensure lower prices. This level can be reached within completely different pricing calculations, not all of which are examples of competitive pricing in its traditional sense. For example, under certain external conditions it may be advantageous for Asian LNG importers to tie the price of LNG to the JCC basket, and not to Henry Hub. Neither of these mechanisms reflects the balance of supply and demand for gas in the APR itself.

The option of indexation against alternative energy sources is being actively considered as an alternative to oil linkage, based on the share of these sources in the energy balance. The use of this mechanism carries a significant problem. The energy balance changes over time, sometimes very significantly in a relatively short time period. Therefore, it is highly likely that there would be a situation when the mechanism of indexation to alternative fuels would no longer reflect market conditions, and this could happen long before the expiry of the existing long-term contracts. There is no guarantee that such linkage would reflect the market reality better than tying gas prices to JCC. Moreover, Asian countries are often forced to take a softer stance with their suppliers because of the need to ensure energy security. Yet, there are no objective conditions, which would enable most of the Asian countries to dictate their terms to suppliers and offer an alternative to the pricing mechanism with linkage to energy sources, based on their share in the energy balance.

Linkage to Henry Hub prices cannot be preferred over other pricing mechanisms on a regional scale. The price formed within this system would not reflect the basic characteristics of the Asian gas market. In fact, HH-linkage would denote a price guided by the balance of supply and demand in the US. Neither is there any assurance that the price would offer savings to consumers in the Asian market. This indexation option is attractive in Asia only in conditions of high oil prices and low HH prices. The events of the second half of 2014 — beginning of 2015 were a clear demonstration that this system can hardly be used as a universal pricing mechanism in the Asian market in the medium and long term due to lower oil prices. HH prices could also increase significantly in the future.

Another option for organising natural gas trading in the region is the creation of a regional hub. However, in the short term, the creation of Asia's benchmark price based on gas hub prices is problematic, especially within the logic of competition between various locations for the role of the 'central hub'. No such central hub is possible at any of the locations discussed above (Singapore, Japan, several locations in China). It is most logical that the national markets will develop so as to take advantage of the level of prices at the regional market, and the regional trade in the Asia Pacific will develop in the form of the 'net of hubs', each serving the purposes of the respective domestic markets.

Taking into account the interests of the Russian companies with prospects of increasing their presence in the Asia-Pacific gas market, we can make the following conclusions. It is clear that an "ideal" model of gas pricing in the Asia-Pacific region does not exist, as there is no consensus among key importers on the preferred mechanisms. The existing portfolio of long-term contracts determines the dominance of oil indexation for the next 10–15 years. Natural gas trading at exchanges will still be developing. The main value of having commodity exchanges to carry out transactions with natural gas and the value of having liquid hubs is that both the buyer and the seller can make a gas transaction at a known and adequate price. This is not solely negative news for a supplier, interested in return on investment (it is the guaranteed return on investment that becomes an issue when hub trade is introduced widely, as is the case in the European context). Often we refer to competitive pricing when a consumer has a choice of a supplier. Thus, the very concept of "gas-to-gas competition" is focused on the side of the consumer. For a market to function properly, a supplier should be able to choose a supply destination in exactly the same way (let us call it "buyer-to-buyer competition"). From this point of view, Russian companies would benefit from the formation of a competitive market in Asia, with the possibility of delivery to different hubs. A key task for the Russian natural gas export strategy is to develop the principles to respond to potential implementation of various development scenarios for the regional market. This would include the principles of long-term operation in a market with a high degree of competition between suppliers.

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