

PARTNER COUNTRY SERIES

The Asian Quest for LNG in a Globalising Market



PARTNER COUNTRY SERIES

The Asian Quest for LNG in a Globalising Market

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.

- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
 - Improve transparency of international markets through collection and analysis of energy data.
 - Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
 - Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia

Austria

Belgium

Canada Czech Republic Denmark Estonia Finland France Germany Greece Hungary Ireland Italy Japan Korea (Republic of) Luxembourg Netherlands New Zealand Norway Poland Portugal Slovak Republic Spain Sweden Switzerland Turkey United Kingdom United States

International **Energy Agency** 1974-2014

Secure • Sustainable • Together

© OECD/IEA, 2014

International Energy Agency 9 rue de la Fédération 75739 Paris Cedex 15, France

www.iea.org

Please note that this publication is subject to specific restrictions that limit its use and distribution. The terms and conditions are available online at http://www.iea.org/termsandconditionsuseandcopyright/

The European Commission also participates in the work of the IEA.

Foreword

Four years ago, the IEA introduced the concept of the Golden Age of Gas, and nowhere does the future for natural gas look more golden than in Asia. By 2035, the IEA expects the continent's demand to grow by as much as the current total production in the United States, and so most of the more than USD 200 billion investment wave in liquefied natural gas (LNG) facilities worldwide Page 3 is focused on the region.

But much must change to achieve that golden future.

Less than two years ago, in our latest in-depth study of Asia's potential for gas, the IEA highlighted the need for a more transparent and efficient market, including gas trading hubs, to reduce the significant premium that Asians pay for LNG. The extensive and enthusiastic response to those findings shows that change is necessary. While the world has more than 200 years' supply of gas in the ground, which reserves are pumped and used soonest depends more on a policy environment conducive to production and trade than the underlying geology. Energy policies that fail to encourage investment but keep gas priced below its true market price are going to produce both scarcity of supply and runaway demand growth.

That is true for any region, of course, and that is why the issue of the changing gas market is more than just an Asian concern. Gas is not only abundant but also a key component of a medium-term energy mix that helps limit global temperature rise when replacing more carbonintensive fuels. Recent geopolitical tensions remind us of the importance of gas supply security, and for many regions, LNG is the most credible and feasible diversification source.

But with those tensions adding to the persistent tightness of the global gas trade, rigid and illiquid markets in Asia increase the challenge to make gas cost-competitive and easily accessible. Growing energy demand there means that gas not only must compete against other fuels but needs to be available in ever-growing quantities. Asia needs to prepare for that surge. For instance, much of the continent has little storage capacity and limited intraregional exchange, which raises the cost of maintaining supply security. Very high prices and supply bottlenecks have the potential to derail the Golden Age of Gas: Asia's gas consumption outside China actually declined in 2013, and the rush to lock in new coal capacities continued unabated. The challenges will not be resolved automatically when North American gas starts to cross the oceans. That new supply is coming: probably the single most important recent development in the regional gas market, North American LNG was just a pipedream a few years ago and has now become a certainty. But new supply alone cannot make up for inadequate policy preparation, so Asian countries should not work from the assumption that US LNG alone would solve their energy dilemmas.

That is where the broader Asian quest for LNG comes in. Done right, LNG offers a more secure and cleaner energy future for Asia, though that does not mean a cheap one. Unlike unconventional extraction that has cut prices in North America, the physics of LNG are not novel, and there are no prospects for radical new technologies leading to cost breakthroughs. Supercooling gas to a liquid state will always be capital and energy intensive, and so is shipping it in special tankers. Consequently, by relying on intercontinental LNG imports, Asia will pay more for gas than selfsufficient or exporting regions. But efficient and reliable markets will minimise costs and create incentives for exploration and development of new resources while expectations of robust Asian demand growth with sustained premium pricing drive investments and innovation into new business models. One example is new gas finds in East Africa that promise shorter delivery distances for much of Asia. At home, trading hubs can provide transparent regional prices and thus efficiently balance supply and demand, and optimise trade flows like they have done in many OECD regions. While geographical factors will continue to hinder pipeline connections, greater interconnection, too, can foster flexibility that reduces the risk of supply disruption.

The Golden Age of Gas is one of changing markets that make the best possible use of abundant resources to boost development in individual regions and, for the medium term, minimise climate change for everyone. Those economic and environmental necessities make LNG a global issue, rewriting long-held tenets about gas being regional by nature. As one example, Russian pipeline gas supply to Europe enabled post-earthquake Japan to import LNG that was previously destined for Europe, linking the supply security of diverse regions.

Page | 4

The experience of IEA member countries proves that there is only one direction forward for LNG, natural gas in general, and all fuels: efficient and transparent markets coupled with sustained investment to build reliable, varied and economical sources of energy for a secure future. This is a lesson Asia is adopting, and one for other regions of the world to implement as well.

This report is published under my authority as Executive Director of the IEA.

Maria van der Hoeven Executive Director International Energy Agency

Table of contents

Foreword	
Acknowledgements	
Executive summary	Page 5
Introduction	
Challenges to the status quo	
Medium-term perspectives for global LNG markets16	
How pricing works today17	
Cracks in the initial model	
Glitches over the past decade 20	
How LNG projects started to deviate from the traditional model	
On the market side: Open wounds 24	
Contracted gas supplies in Asian countries	
New co-operation models	
Developments in LNG trade 2013-14: A mixed picture	
The LNG supply picture	
Investments of Asian companies in the four regions	
LNG contracted by Asian countries	
, LNG pricing mechanisms	
Break-even cost analysis	
Liquefaction's capital costs	
LNG transport costs	
Total costs	
North America	
The supply picture	
Investments of Asian companies 59	
Russia65	
The supply picture	
Investments from Asian companies72	
Australia75	
The supply picture	
Investments from Asian companies	
East Africa	
The supply picture	
Investments from Asian companies85	
Outlook for East African LNG 87	
Enhancing market efficiency: Regulatory measures in importing countries	
Progress made in Asian countries since early 201391	
Japan	

	Korea	95
	China	97
	India	100
	Singapore	101
Page 6	Indonesia	102
rage U	Malaysia	103
	Thailand	103
	Others	104
	The way forward	105
	What could lead to an accelerated price convergence case?	105
	Are we entering a renewal phase for Asian market players?	109
	Renegotiation: Why Asia is not quite Europe	111
	HH price indexation in new contracts: Caveat emptor	115
	The practical aspects of establishing a trading hub in Asia	117
	Key differences between Asian gas markets and European and North American one	s 117
	Dealing with LNG cargoes	117
	National versus regional hubs	118
	An ASEAN way?	119
	Dealing with fossil-fuel subsidies	119
	Combining LNG and the TAGP	120
	Technical supply issues	122
	Differences in market structures and domestic policies	123
	Existing cross-border pipelines are bilateral	123
	Harmonising regulation	124
	The role of small-scale LNG and break-bulk LNG	124
	Enabling measures to establish a natural gas trading hub in ASEAN countries	127
	Is the idea of a natural gas trading hub well received by ASEAN countries?	128
	Acronyms and abbreviations	130
	References	132

List of figures

Figure 1 • Evolution of regional gas prices, 2003-14	10
Figure 2 • Incremental gas demand growth, 2013-19	11
Figure 3 • Evolution of LNG imports and the share of China/non-OECD Asia versus total LNG	
imports, 2013-19	16
Figure 4 • Wholesale price formation, 2013	18
Figure 5 • Price formation for domestic gas production, 2013	18
Figure 6 • Pricing mechanisms for pipeline imports, 2013	20
Figure 7 • Pricing mechanisms for LNG imports, 2013	20
Figure 8 • Spot and short-term LNG trade and share of total LNG trade, 2000-13	22
Figure 9 • Expectations of US LNG trade, EIA statistics 2005 versus 2014	22
Figure 10 • Evolution of selected Asian LNG import prices, 2010-14	25

Figure 11 • Profits and losses of Japanese power companies, 2007-13	25	
Figure 12 • Meeting Chinese gas demand under different gas production scenarios	28	
Figure 13 • Types of contracts for major Asian countries, 2008 versus 2020	29	
Figure 14 • Contracted gas supplies by Japan, 2013-30	30	
Figure 15 • Contracted gas supplies by Korea, 2013-30	30	
Figure 16 • Contracted gas supplies by China, 2013-30	32	Page 7
Figure 17 • Contracted volumes by India, 2013-30		rage /
Figure 18 • Contracted volumes by Chinese Taipei, 2013-30	33	
Figure 19 • Contracted volumes by Singapore, 2013-30	33	
Figure 20 • LNG contracted by region (firm contracts)	40	
Figure 21 • LNG contracted by region (firm and preliminary contracts)		
Figure 22 • LNG contracted by country in Australian LNG projects under construction	41	
Figure 23 • Capital costs of different LNG projects		
Figure 24 • Evolution of daily shipping rate for LNG spot cargoes	47	
Figure 25 • Comparison of transport costs	49	
Figure 26 • Comparison of total costs		
Figure 27 • Comparison of total costs	52	
Figure 28 • Comparison of total costs to different LNG importers	54	
Figure 29 • US LNG liquefaction plants as of October 2014		
Figure 30 • Contracts of selected US LNG export plants, October 2014	64	
Figure 31 • Contracts of selected Canadian LNG export plants, October 2014	64	
Figure 32 • Russian LNG projects	67	
Figure 33 • Russian gas projects in East Siberia and the Far East	68	
Figure 34 • World LNG trade and the share of Australian LNG, 2001-13	75	
Figure 35 • Australian LNG production capacity increase to 2018		
Figure 36 • Australian LNG projects	78	
Figure 37 • Gas reserves in Mozambique and Tanzania as of October 2014	84	
Figure 38 • LNG receiving terminals and main gas pipelines in Japan	94	
Figure 39 • LNG receiving terminals and main gas pipelines in Korea	97	
Figure 40 • LNG receiving terminals and main gas pipelines in China	100	
Figure 41 • Gas prices in the New Policies Scenario and the Gas Price Convergence Case	106	
Figure 42 • Potential evolution of pricing mechanisms in Asia	109	
Figure 43 • Volume developments in contract termination in Japan, 2014-30	111	
Figure 44 • Volume developments in contract termination in Korea, 2014-30	111	
Figure 45 • Evolution of HH-delivered gas prices (transport cost at USD 3/MBtu)	116	
Figure 46 • US LNG exports according to different forecasts (EIA 2010 to 2014)	116	
Figure 47 • Gross calorific values from different LNG sources	118	
Figure 48 • Existing and proposed pipelines of the TAGP	121	
Figure 49 • LNG terminals in the ASEAN	. 128	

List of tables

Table 1 • Gas pricing mechanisms	17
Table 2 • Key long-term uncertainties faced by Asian countries	26
Table 3 • Investments of Asian companies in selected regions	38
Table 4 • Pricing mechanisms prevailing among LNG suppliers, October 2014	44
Table 5 • Shipping rates (USD/MBtu)	50
Table 6 • Investments of Asian companies in the United States and Canada	55
Table 7 • US LNG projects with DOE's approval for non-FTA countries as of October 2014	57
Table 8 • Canadian LNG projects with NEB's approval as of October 2014	58

Table 9 • Gas sources of Gazprom's projects	
Table 10 • LNG projects in operation in Australia	
Table 11 • LNG projects under construction as of October 2014	
Table 12 • Competitive market requirements of Asia's largest LNG importers	
Table 13 • Competitive market requirements in the ASEAN	104

Page | 8

List of boxes

Box 1 • Why are gas prices indexed to oil prices?	19
Box 2 • Shale gas production in China is a major uncertainty for future LNG needs	27
Box 3 • Asian LNG buyers' upstream Investment trend	42
Box 4 • Factors affecting US LNG project costs	46
Box 5 • The Panama Canal	47
Box 6 • Comparing shipping costs to regions other than Asia	53
Box 7 • Pipeline gas supply from Russia to China	66
Box 8 • The Gydan Peninsula LNG project	
Box 9 • The "Power of Siberia" gas pipeline	70
Box 10 • Other Russian LNG project: Baltic LNG	70
Box 11 • Pipe dreams? Gas pipelines from Russia to Korea, Japan, Mongolia and India	75
Box 12 • The LNG futures market initiative	95
Box 13 • Sellers can also renegotiate their long-term contracts	113
Box 14 • Experiences with small-scale LNG	125

Acknowledgements

This report was prepared by the Gas, Coal and Power Division (GCP) of the International Energy Agency (IEA). The analysis was led and co-ordinated by Anne-Sophie Corbeau, former senior gas expert, with significant contributions from the GCP gas team: Anne Braaksma, Farid Hussin, Rodrigo Pinto Scholtbach and Takuro Yamamoto, as well as Yayoi Yagoto of the Office of Global Page | 9 Energy Policy.

Valuable comments and feedback were received from Keisuke Sadamori, Laszlo Varro, Ian Cronshaw, Misako Takahashi, David Benazeraf, Marc-Antoine Eyl Mazzega, Stephen Gallogly, Dagmar Graczyk, Jon Hansen, Florian Kitt and Kevin Tu.

A special thank you goes to Janet Pape and Kristine Douaud for editing the report.

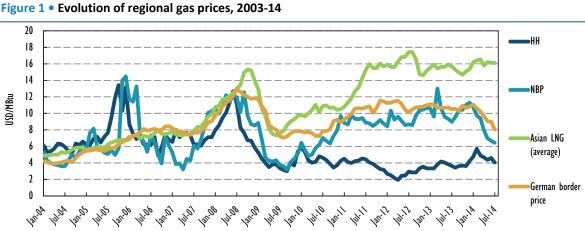
The IEA Communication and Information Office (CIO), particularly Astrid Dumond, Muriel Custodio, Greg Frost, Angela Gosmann, Therese Walsh, Robert Youngblood and Bertrand Sadin, provided essential support towards the report's production and launch.

The report was made possible by assistance from GasTerra BV, Ministry of Economic Affairs of the Netherlands, Ministry of Economy, Trade and Industry of Japan, Petronas and Tokyo Gas.

Executive summary

As 2015 approaches, the growth in liquefied natural gas (LNG) supply is unprecedented: 150 billion cubic metres (bcm) of LNG capacity, equivalent to 40% of the current global total, is either under construction or planned to start over the next four years. But prospects for further natural gas demand, and particularly LNG growth in key regions, has never been so uncertain. Over the past two and a half years, there has been a significant gap between United States (US) and Asian gas prices of USD 12 per million British thermal units (USD/MBtu). This price difference is responsible not only for the flurry of planned LNG projects targeting mostly Asia, but also for Asian countries' attempt to find ways to diminish their gas bills by taking innovative actions in the field of LNG.

This report analyses the LNG market and how recent and future changes could lead to significant modifications of the global LNG and pricing situation. Below, Figure 1 shows the contrast in four regional gas markets: the United States (Henry Hub [HH]), the United Kingdom (National Balancing Point), Germany (German border price) and Asia (Asian LNG).



Gas producers are looking to Asia as the fastest-growing market, given Europe's uncertain demand prospects and the near disappearance of North America as an LNG importer. However, Asia's demand for gas is subject to what supplies are available, the competitiveness (or lack thereof) of natural gas against coal and other sources of energy in the power sector, and the price at which natural gas reaches markets. While gas is certainly cleaner than coal, the current backbone of energy supply in Asia, at current prices it is debatable whether gas is a cost-efficient channel to achieve environmental and climate advantages. Asian gas markets are diverse, encompassing the

mature gas markets of Japan and Korea, energy giants like the People's Republic of China and India, and the rapidly developing countries of the Association of Southeast Asian Nations (ASEAN). Those countries will have different supply and demand growth patterns, and different reactions to global pricing evolutions.

Regardless of their maturity and size, most Asian countries will need to import more gas to meet demand growth, as production (when relevant) fails to grow at the same pace as consumption. Over the medium term, half of the anticipated increase in gas consumption will require additional imports. Due to the geographical specificities of the region, LNG is expected to continue to play a leading role. Hence, Asia is forecast to absorb 80% of the incremental LNG imports over the medium term. Only pipeline gas from the Former Soviet Union (FSU) and, potentially, Iran could compete with LNG to meet this growing demand, and the country the most likely to be targeted is China, as illustrated by the recent Russia-China gas pipeline deal. Figure 2 shows the composition

of global medium-term incremental gas demand growth by region, with more than 50% of incremental gas demand growth in Asia.

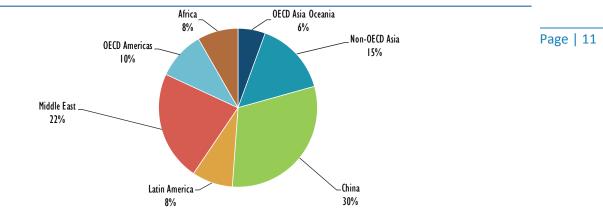


Figure 2 • Incremental gas demand growth, 2013-19

Natural gas prices play a very important role in the supply/demand balance and import picture. Even though natural gas may be the cleanest combustible fuel, it is facing competition from less expensive alternatives regardless of its environmental benefits. In Asia, the main competitor is coal, which is cheap and abundant in key countries such as Indonesia. Natural gas prices also have an effect on gas supply, as prices are often subsidised in non-Organisation for Economic Coordination and Development (OECD) Asian countries. Low domestic gas prices disincentivise domestic production, make new imports expensive compared with the prevailing domestic gas prices, trigger budget issues for governments or gas companies, and deter investors.

There are several reasons why Asia has been paying a premium for gas supplies:

- oil-linked pricing in long-term contracts
- the emphasis on security of supply
- a low level of demand flexibility
- the lack of appropriate regional spot prices reflecting Asian supply and demand balance.

The issue of LNG pricing in Asia is crucial because it will determine future supply/demand prospects as well as the pace at which flexibility and liquidity will be introduced into the gas market in several Asian countries. Pricing also influences the willingness of LNG producers to invest in the next generation of projects. Asia's LNG situation is therefore not a simple matter of demand and supply. Midway through the decade, many planned LNG projects face growing pressures because of the pricing system based on oil indexation that still predominates in Asia.

There are two primary LNG issues:

- the pricing mechanism with oil indexation which currently makes oil-indexed gas prices much higher than hub-indexed gas prices
- the relative inflexibility of the LNG supply chain with final destination clauses (FDCs) and takeor-pay clauses.

The issue is not the long-term contracts themselves, which are still in many cases an important element in the completion of an LNG project with high capital costs. Most recent LNG liquefaction plants in Australia, the United States and Russia have made final investment decisions (FIDs), as they were backed by long-term contracts. The issue is rather the terms of these contracts. In renegotiating existing long-term LNG contracts and negotiating new LNG contracts for projects that are still at the planning stage, there are several options for buyers and sellers, keeping in mind that what buyers really want are lower gas prices:

- continue with oil indexation, but with lower slopes and S-curves
- use HH indexation
- include in the contract the possibility of using a still-to-be-determined Asian spot price once its liquidity is deemed sufficient.
- Page | 12 Each option has its benefits and drawbacks. While oil indexation seems to be synonymous with expensive gas prices, not so long ago, the oil-indexed gas price in Europe was lower than the spot price. Besides, the same mechanism can lead to widely different outcomes: oil-indexed prices with a 14.85% slope trigger prices at around USD 15/MBtu whereas a 12% slope oil-indexed gas price at USD 100 per barrel (USD/bbl) would give a delivered gas price similar to US gas delivered to Asia with HH at USD 5/MBtu. Importantly, oil-indexed gas prices fail to reflect developments in gas markets; there is less and less competition between oil and gas at the end-user level, notably in power generation (OIES, 2011). Indexation to coal would simply move the issue from one fuel to another, and finding a reliable and transparent Asian coal price could prove challenging. Finally, many producers are more comfortable with oil-indexed prices, arguing that many development costs are linked to oil prices; they are less comfortable with hub prices, citing in Europe the lack of liquidity, the limited curve, fears of manipulation and concerns about volatility (OIES, 2011).

Over the medium term, using HH indexation is the only credible alternative to change the pricing indexation, confirming that North American shale gas production has had a profound impact on global gas markets. Asian buyers are already contracting US LNG with such an indexation. Based on HH prices of about USD 4.5/MBtu and the Cheniere export price formula¹ for the Sabine Pass project, LNG can be delivered to Asian markets at about USD 12MBtu to USD 13/MBtu (depending on the importing country), significantly below the current contract gas prices but slightly higher than Asian spot prices (as of July 2014). This is of course an appealing prospect for Asian buyers. But the dynamics of HH are quite different from those of the Asian market – which means that producers are reluctant to take this as an alternative, not to mention the currently low levels and volatility of HH prices – and the latest generation of contracts signed for Australian LNG is based on oil indexation and unlikely to be changed given these projects' expense (IEA, 2014a). But having the HH alternative as another pricing option also improves the bargaining power of Asian buyers.

Over the longer term, Asia could have its own trading hubs; given the size of the market, there is room for several of them capturing the differences between the different markets. There is no spot price in Asia, unlike in Europe and North America. In the report Developing a Natural Gas Trading Hub in Asia (IEA, 2013c), the International Energy Agency (IEA) focused on the obstacles and opportunities for the Asia-Pacific economies to establish natural gas trading hubs that allow gas prices to reflect local/regional demand and supply (IEA, 2013c). Such a change would be based on the processes of gas market liberalisation already under way in several countries. This liberalisation is having a substantial influence on institutional changes (including wholesale price deregulation, the separation of transport and marketing activities, and large customers if not smaller ones being able to choose their suppliers) and structural conditions, including the existence of sufficient network capacity and transparent access to it, sufficient participants to engender competition, and the involvement of financial institutions. IEA analysis shows that a natural gas trading hub is likely to take a decade to develop, so while it could be used as a future indexation in long-term contracts, it will not have any meaningful medium-term impact on prices. The progressive development of a trading hub could also reinforce the bargaining power of Asian buyers, as it would provide another price signal which would be active during the duration of future long-term contracts.

¹ The formula is based on free-on-board (FOB) prices of 115% HH gas prices plus a tolling agreement of up to USD 3/MBtu. The buyer needs to add the transport cost, which depends on the shipping arrangements taken by the buyer.

The development of an Asian natural gas trading hub must not, however, lead to deteriorating investor confidence and a suspension of LNG projects. It seems possible that only a few LNG projects in the United States will take FIDs over 2014-15. As Asian LNG demand is likely to keep increasing, new liquefaction projects will be needed to meet not only incremental needs but also to replace existing facilities where reserves are being depleted. Additionally, some countries face increasing domestic demand, resulting in a reallocation of LNG production to domestic markets.

The second aspect of the LNG market under consideration is its flexibility, notably in Asia. Flexibility is crucial for eliminating the Asian price premium. If nuclear generation begins again in Japan, demand for gas will decline, given the country's slow power demand growth and robust solar investments. Many projects have been conceived with one exporting plant, some dedicated ships and a few receiving plants, with no flexibility for the buyer to redirect unneeded LNG. US LNG projects would provide the needed flexibility, but there have been many examples of projects planning to take advantage of price arbitrage such as LNG volumes sold from global portfolios to the most attractive market. Meanwhile, seasonal gas demand fluctuations require supply flexibility. FDCs were originally required to guarantee security of supply, but it is necessary to abolish these clauses in order to create and then improve the liquidity of trading in Asia. The co-operation of importers could improve this situation.

Note that the Asian gas market differs from its European counterpart. The latter relies on a mix of pipeline, LNG and domestic supplies. But, crucially, it has developed trading hubs that provide a credible alternative to oil indexation by enabling reliable price formation based on gas-to-gas competition. This has helped considerably in renegotiation of long-term contracts (European and Asian contracts have different renegotiation clauses). Development of trading hubs in Asian countries will require a fundamental departure from their traditional model of government intervention, regulated gas prices, limited access to networks and a few (state-owned) champions controlling the energy market. Singapore incontestably leads in fulfilling the above market criteria, and other countries such as Japan and China are making progress. But for many others, the journey is only beginning. The European Commission also played a role in developing the framework in Europe, but no equivalent exists in Asia. In addition, the specificities of LNG, including storage, different gas qualities, size of cargoes and absence of continuous flows, may complicate devising a trading hub based on LNG.

New LNG being sold on different terms does not mean the end of oil indexation over the medium term, and a mix of oil, HH and Asian hub indexation could be expected to govern contracts over the longer term. Their exact proportions will depend very much on how fast and where LNG supplies will develop, the contractual behaviour of Asian companies, how successful they are in negotiating terms with LNG projects they may also be part of, the respective evolution of global energy prices, and any unexpected global demand or supply shock. As most existing and new long-term contracts are based on oil indexation, notably from Australian projects under construction, such a pricing format will continue to represent a significant share in the LNG market. Yet, even oil indexation can be changed, through various factors such as slopes and S-curves at a higher oil price, resulting in what Asian buyers are looking for: lower gas prices. Asian pricing is therefore likely to evolve from oil indexation to include HH indexation when new US LNG arrives over the period 2016-20. Then, in the longer term, regional Asian hub prices could start playing a role. The Asian market is wide enough to support several hub prices reflecting the sub-regional supply/ demand balances. However, this does not mean a convergence of global gas prices because, unlike oil, capital costs to liquefy and transport LNG are significant, acting to maintain a certain gap between importing and exporting regions.

Introduction

Global gas markets may be at the threshold of a new age. An unprecedented gap between regional gas prices – Asian prices on the one side and US gas prices on the other – has triggered fundamental changes for future global gas market dynamics. While expanding shale gas production in North America has had a lasting effect on this region's gas prices, and European gas buyers have managed to reap some benefits from this evolution by renegotiating their long-term contracts and introducing more hub-price elements, this has so far translated to neither a decline in Asian contract gas prices nor renegotiations of the terms of these contracts.

This price gap comes at a time when the gas industry is expanding liquefied natural gas (LNG) export capacity by one-third, with most of this capacity targeting the Asian market. Even more LNG capacity is at the planning stage in four key regions: North America, Russian Federation, East Africa and Australia, all four of which anticipate a greater share of growing LNG sales and are also targeting Asian markets to a large extent. For good reason: the region will represent almost half of the world's incremental gas consumption over the medium term (2013-19) (IEA, 2013a). Over the longer term, the *World Energy Outlook 2013 (WEO 2013)* forecasts show that an additional 750 billion cubic metres (bcm) will be needed by 2035, which is equivalent to slightly more than today's US gas production (IEA, 2013a).

Japan, Korea and Chinese Taipei have been importing LNG for decades, but other countries are still relatively new to the LNG business. China and India started importing in 2005-06, while Southeast Asian countries became LNG importers only in 2011. Besides, some countries are even becoming LNG importers/exporters. So, while importing LNG has become more common, countries have taken widely different approaches. The region does not enjoy the similar degree of policy co-ordination and integration due to the lack of a central body to undertake such a task, as in the case of European Union.

The scenario is markedly different on the producer side. With the exception of brownfield projects in the United States, the capital costs of most recent LNG projects have increased sharply. In some cases, such as that of Australia, costs have escalated out of control; consequently, producers are concerned about recovering their investments. This issue is very much present in the minds of those planning to invest in the next generation of LNG projects, which would come to the markets mostly after 2020. The large majority of these projects target Asia, but it is unlikely that all of them will move forward.

However, while gas demand is growing quickly in Asia, notably in China and Southeast Asia, and high prices make this region the preferred destination for LNG sellers, it would be a mistake to expect such a situation to continue unchanged. Three assumptions could be at stake:

- robust growth of Asian gas demand
- lagging domestic gas supply
- the dominance of LNG.

Gas has to be competitive against other fuels for its demand to expand, and growth will depend on whether countries can afford more expensive gas. Some Asian countries, China and Indonesia, in particular, have huge unconventional gas potential, which could still be a game changer. Pipeline supplies from the FSU have developed and will continue to expand in Asia, notably in China, with possible expansions from Iran to India, while the planned Trans-ASEAN Gas Pipeline (TAGP) could augment LNG supplies in Southeast Asia.

Above all, the two real issues are cost and flexibility: the cost of developing new gas supplies, whether for domestic consumption or exportation; the costs of liquefaction projects and transporting

the LNG; and the development cost of alternative energies (notably coal) compared to the cost of gas in the end-user market and what buyers can afford to pay. With capital costs of LNG projects recently rising, and as the cost needs to be reflected in its price, affordable gas supplies seem to be moving out of reach. Meanwhile, flexibility provides the means to face unexpected, rapid changes in either supply or demand, by redirecting unwanted LNG or taking advantage of price arbitrage, an important tool against demand and import uncertainties.

Asian governments and companies have become critical of unsustainably high gas prices and inflexible gas contracts. The pricing issue is even more acute in non-OECD Asian countries where subsidised gas prices are often lower than market prices. Of the USD 51 billion of subsidies in ASEAN countries in 2012, around 6% involved natural gas. But even Japanese and Chinese companies are experiencing financial difficulties. The difficulties faced by Asian gas companies and utilities could be the trigger for changes, forcing suppliers to renegotiate contract terms. Heavy reliance on LNG makes renegotiations challenging, but not impossible, as it is currently a buyer's market.

Very few experts believed back in 2008 that oil indexation could lose its supremacy in European gas markets, yet in a few years' time it did. The change was triggered by a demand shock coupled with an LNG supply boom, but it was also made possible by market conditions which enabled a pricing change. These conditions, however, are not yet present in Asia.

For changes in pricing and flexibility to occur in Asian markets, global LNG markets need to change. Asia's quest for LNG is leading it to a new, potentially game-changing LNG supplier: the United States. New US LNG could dismantle the traditional model of oil indexation and inflexible gas contracts, although these elements had already undergone some changes over the past decade. By providing a hub indexation based on the US HH spot price and selling the gas with no FDCs (allowing the gas to be marketed wherever the buyer wishes), US companies are forging a business model for planned LNG export plants. At currently low US gas prices, US LNG is arriving at a significantly lower price than oil-indexed gas in Asia, making it quite appealing for buyers. While US LNG could take a large share of LNG sales, other suppliers are not exactly standing by idle: some are already moving towards some sort of hybrid pricing, mixing oil and HH indexation, while others still offer oil indexation. At the same time, there is much hesitation to move to an indexation other than that of oil, which many sellers see as a protection against the escalating capital costs of LNG liquefaction projects. In the past, some LNG had been sold at HH prices, but the price collapse in 2009 significantly impacted LNG sales revenues so that sellers are now hesitant to use this indexation.

For the buyer, the security of US LNG exports is dependent upon the evolution of HH gas prices as well as the North American gas supply over the next 20 to 30 years, two elements which have proven to be uncertain. Either one or two indexations (oil and HH) must also be relied upon, neither of which reflects the supply and demand fundamentals of the Asian region. In addition, significant quantities of US LNG have been contracted by aggregators able to resell LNG according to their own terms, perhaps using HH indexation, but also using hybrid pricing. Alternatively, aggregate sellers could arbitrage between the different regions during times of scarcity.

Challenges to the status quo

Medium-term perspectives for global LNG markets

Page | 16 Global LNG trade is expected to expand by one-third, to 450 bcm, by 2019 and is likely to increase even further, based on projects currently at the planning stage. Which projects will move forward and in what time frame are considerable uncertainties, given the competition among the projects (see the sections dedicated to the four main regions later in this report). These projects will be critical not only to meet additional gas demand, but also to replace declining LNG supply. The existing liquefaction capacity of 406 bcm per year (bcm/yr) produced 322 bcm in 2013, implying a utilisation rate of 79%. This is substantially below a normal utilisation rate and reflects the fact that gas is increasingly diverted to the domestic market in some countries at the expense of LNG exports or due to the fields' maturity. Egypt is the most striking and recent example of this evolution. In other cases, this could reflect a depletion of or drop in domestic gas production.

Even among major Asian LNG exporters such as Indonesia and Brunei, LNG exports could decline over the coming years. These countries have been providing a large share of the LNG supplies to Asian countries, a share which has been declining over time as exports have dwindled, while the Asian thirst for LNG increases.

Over the medium term, non-OECD Asian gas markets will play a key role in attracting additional LNG supplies. By 2019, they will import close to 150 bcm, more than Japan, which is currently the largest LNG importer. China will rank as second LNG importer, having taken this position away from Korea. LNG will play a key role in China, as the country will become the second largest net importer behind Europe by the end of the decade. The diversity of supplies helps China to maintain a diversified supply mix and feed the gas-hungry coastal region, which remains distant from pipeline or most domestic gas supplies. In India, LNG is the only likely source of imports over the medium term, as pipeline projects remain a far-away dream.

Southeast Asian countries are also turning to LNG, the geographical specificities of the region playing a crucial role. While pipeline import projects have been promoted, they have progressed slowly. Meanwhile, LNG offers flexibility and better matches the island specificity of some countries in addition to offering the possibility for exporting countries to divert LNG from exports to internal imports.

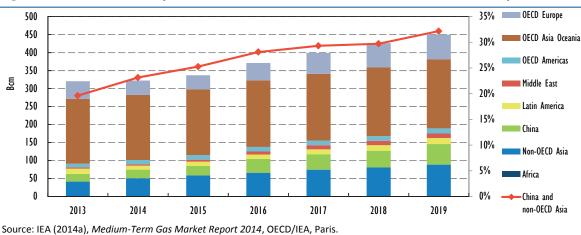


Figure 3 • Evolution of LNG imports and the share of China/non-OECD Asia versus total LNG imports, 2013-19

Even though their role in global LNG markets is limited, both Latin America and the Middle East have recently emerged as new LNG importing regions. In both cases, the issue is not the amount

of gas resources, as both regions are endowed with significant gas reserves. Rather, wholesale gas prices, often kept at persistently low levels, failed to deliver the necessary signals to increase gas production at the same pace as the rapidly increasing gas demand. While some countries in the region could have supplied piped natural gas to these countries, difficult political relationships have prevented this from happening, thus leaving LNG imports as the only solution.

Importantly, the use of floating storage and regasification units (FSRUs) is favoured in many Page | 17 developing countries in Latin America, the Middle East and Asia, as they enable new importing countries to start LNG imports quickly. Meanwhile, on the supply side, floating liquefied natural gas (FLNG) may enable development of stranded gas reserves. FLNG is currently being developed in Australia, Malaysia and Colombia.

This expansion of global LNG trade will allow buyers to source gas from a wider range of suppliers and to develop more flexible contracts, even though the oil-indexed formula is likely to remain dominant. Indeed, bilateral long-term contracts with restrictive take-or-pay and destination clauses still play an important role and tend to "lock in" Asian customers. Meanwhile, many active contracts expiring by the end of the decade will need to be replaced; while this represents an opportunity for buyers (supply diversification; possibility to negotiate different formulas with different contractual options such as the abolition of FDCs), there is also the potential risk of a low number of FIDs transforming the market into a seller's market.

How pricing works today

The main reference points concerning gas prices are the HH price in the United States, the NBP in the United Kingdom, and the average Japanese LNG import price. While these are important benchmarks, they fail to reflect the diversity of gas prices, notably in terms of levels and geographical coverage. These prices are relevant for developed countries, but not always for developing ones.

Gas prices are determined according to different gas pricing mechanisms. Since 2005, the International Gas Union (IGU) has been reviewing the evolution of gas price levels and has pricing mechanisms across the world in its wholesale gas pricing survey. The eight different gas pricing mechanisms are outlined in Table 1.

The IGU study highlights two very important facts. Looking at the pricing mechanism at the wholesale level, it is striking that gas-to-gas competition represents around 43% of the gas sold globally, twice as much as oil-indexed gas which represents only less than 20%. Also of note is the important share of the different types of regulated gas prices, which together represent 33%. This difference in shares can be explained by looking at the pricing mechanisms for production and imports separately.

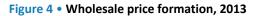
Mechanism	Description
Oil escalation	The gas price is linked to oil or oil products
Gas-to-gas competition	The gas price is determined based on supply/demand fundamentals
Bilateral mechanisms	The price of natural gas is agreed upon between two governments for a certain duration
Netback price	The natural gas price is linked to the end product; this happens sometimes in the case of methanol
Regulation cost of service	The level of the gas price covers the costs of production and transport plus a certain margin
Regulation social and political	The gas price is decided on an ad-hoc basis by the relevant ministry
Regulation below cost	In other terms, the gas price is subsidised
No price	The gas is given for free; this tends to disappear

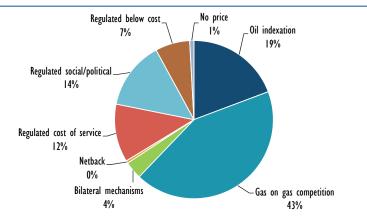
Table 1 •	Gas	pricing	mechanisms
-----------	-----	---------	------------

Source: IGU (2014), Wholesale Gas Price Survey – 2014 Edition, IGU, Oslo.

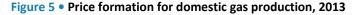
Pricing mechanisms are relatively diversified when it comes to production: half of the domestic gas production sold on the same market is determined by some sort of regulation, and roughly 44% is based on gas-to-gas competition. In this context, oil indexation has a relatively limited role. In global trade, however, both LNG and pipeline gas exchanges are largely based on either oil indexation or gas-to-gas competition, with some pipeline gas trade based on a bilateral mechanism. In particular, 71% of the global LNG trade is now based on oil indexation with some of the LNG going to North America, Europe or even Asia based on spot indexation. Figures 4 and 5 contrast the breakdowns of wholesale and domestic pricing mechanisms.

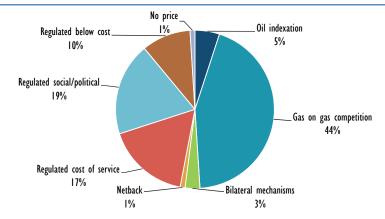
Page | 18





Source: IGU (2014), Wholesale Gas Price Survey - 2014 Edition, IGU, Oslo.





Source: IGU (2014), Wholesale Gas Price Survey - 2014 Edition, IGU, Oslo.

In the global gas market, the share of gas-to-gas competition has been increasing progressively, mainly due to the growth of demand in North America and changes in indexation in European long-term contracts. For example, the share of oil indexation in pipeline imports went down from 53% in 2012 to 48% in 2013. But oil indexation remains a key part of the indexation in Asia, due to its large share in LNG imports.

New LNG imports to Asian countries will be based on either one of two pricing mechanisms: oil indexation or gas-to-gas competition. The oil indexation pricing mechanism prevails in the LNG business and is unlikely to lose much strength in Asia over the short to medium term, as most Australian LNG projects arriving to the markets are based on oil indexation. These projects represent roughly half of the capacity currently under construction (83 bcm/yr), even though not all of this LNG has been contracted and some may be sold as spot LNG or under short-term contracts.

Box 1 • Why are gas prices indexed to oil prices?

Oil indexation has existed for several decades and long been the unchallenged pricing mechanism governing imports and sometimes gas production. The mechanism was first adopted in the 1960s when the Netherlands was looking at exporting part of its natural gas production from the Groningen field, which was discovered in 1959 and started producing in 1964. The European gas market was in its infancy, with gas demand at around 15 bcm, and most gas was consumed in its country of production. To sell the Dutch gas, a price had to be found that would allow gas demand to grow; at the same time, however, the Dutch government did not want to sell this gas at too low a price. Since Groningen's production costs were low, the cost-plus approach was not taken.

The "market value principle" or "netback value principle" was developed, whereby gas needed to gain market shares against its main alternative in each consuming sector. In 1960s, this alternative was often fuel oil or gas oil. To encourage the development of gas consumption against oil, some rebates were provided to compensate for the investments needed to switch to natural gas. This method calculates the market value for each sector (residential, commercial, industrial and power), then calculates the weighted average. Network costs (transmission, distribution and storage) are subtracted to obtain the so-called "border price".

Typically, an oil-index pricing formula looks as follows (IFRI, 2011):

 $P_m = P_o + 0.60 \times 0.80 \times 0.0078 \times (LFO_m - LFO_o) + 0.40 \times 0.90 \times 0.0076 \times (HFO_m - HFO_o) + K$

In this formula, P_m represents the gas price in month m. P_o is the reference gas price, while LFO_o and HFO_o are the reference prices of light fuel oil and heavy fuel oil. LFO_m and HFO_m represent the prices for the month m, but actually are usually the averages of the previous six to nine months with a time lag of one to six months. The coefficients 0.60 and 0.40 represent the shares of the market segments competing respectively with light fuel oil and heavy fuel oil. The coefficients 0.80 and 0.90 are pass-through factors. K is a fixed factor.

Oil indexation spread progressively to Asia, although the current mechanism of Japan Customs-cleared Crude (JCC) indexation was not established immediately. When Japan started importing LNG at the end of the 1960s the price of LNG was fixed, which was not an issue until oil prices substantially increased in 1973, putting LNG at a discount to oil. The long-term contract prices were progressively increased over time until they were codified with the creation of the Government Selling Price (GSP). However, some countries started to sell oil at market prices different from the GSP. After the 1986 oil price collapse, suppliers selling LNG at oil parity prices encountered difficulties securing the recovery of capital costs of their LNG projects, so the LNG pricing formula was modified again. Today, most Japanese LNG contracts use the JCC (nicknamed the "Japanese Crude Cocktail"), which is the weighted average price of Japanese oil imports.

Although oil indexation is the most commonly used, other indices such as coal and electricity prices have been used in long-term contracts, notably in Europe. Inflation is used as a proxy for the evolution of electricity prices, when there is a high share of electric heating in residential heating. More sophisticated approaches exist, such as the S-curve, protecting both the buyer at very high oil prices and the seller at very low oil prices. There are also options in the formulas to move from one fuel to the other as a variable, should the first one exceed a certain price. There are also options to turn to spot indexation if a certain index which is just being developed at the time of the contract becomes significant in terms of volumes traded, churn ratio and types of forward prices traded.

But oil indexation is losing its relevance because oil is now less an alternative to natural gas than it was in the 1970s. Various technological alternatives such as nuclear, coal and recently renewables have been deployed to reduce oil use in power generation. Such technological substitution does not yet exist in the transport sector. Oil represents 3.3% of the total generation in the OECD region (2012 data), with Japan consuming half of this to replace nuclear. Moreover, oil now also represents a smaller share in the non-OECD region (6.1%). This share is particularly high in the Middle East, which currently uses mostly oil and natural gas in the power sector. The Middle East is the last region where oil indexation still has a fundamental basis.

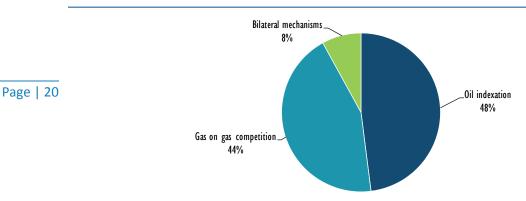
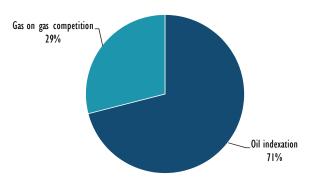


Figure 6 • Pricing mechanisms for pipeline imports, 2013

Source: IGU (2014), Wholesale Gas Price Survey - 2014 Edition, IGU, Oslo.

Figure 7 • Pricing mechanisms for LNG imports, 2013



Source: IGU (2014), Wholesale Gas Price Survey – 2014 Edition, IGU, Oslo.

Moreover, the same pricing mechanism can lead to widely divergent pricing levels. For example, both the HH and the NBP are hub prices, but on average NBP prices are more than twice as high as those on the HH. Similarly, oil-indexed prices can result in widely divergent gas prices depending on the slope, the constant and the existence of an S-curve.²

Cracks in the initial model

Glitches over the past decade

The initial LNG model was relatively simple: one liquefaction plant, one regasification plant, cargoes linking them and a long-term LNG contract based on oil indexation and an FDC underpinning the LNG investment, providing long-term security of supply to the buyer and cash flow certainty to the seller. Unlike oil, the natural gas – and especially the LNG – business is very capital-intensive, with investments of several billion US dollars for the liquefaction plant alone. For many years, this model delivered security of gas supply and competitive gas prices.

Long-term contracts are usually used to make a project move forward, but they are not an absolute necessity; some portfolio players may take their equity gas and market it themselves. This happens

² An S-curve is an indexation technique in which the gas price does not follow the oil price linearly; rather, the indexation coefficient is lower at very low and very high oil prices, providing a smooth risk hedge for the seller and the buyer.

with large international oil companies (IOCs) present in different regions. But long-term contracts are otherwise widely used as a guarantee that the costs of the projects are going to be recovered somehow. The main importers, such as Japan and Korea, had never experienced a physical supply shortage, so the main argument that the long-term contractual structure guarantees supply security was historically proven right. This is not a negligible factor, as these buyers have isolated energy systems and no good domestic alternatives to imported LNG.

Page | 21

The line between the two sides of buyer and seller is no longer clear, as some countries both import and export natural gas, and particularly LNG. Since the 1970s, LNG has been successfully imported based on long-term contracts with durations of 20 years and based on oil indexation. While this model still largely prevails in Asia, some glitches occurred in other parts of the world in the first decade of this century. In the United States, which was then set to become a large LNG importer and benefits from a liquid gas market, LNG was going to be imported based on HH gas pricing. Given that US gas prices were on an ascending path over 2005-08, closely following the trend in Asia, this was not considered an issue.

But several elements over the past decade disturbed that model:

- the emergence of LNG spot cargoes and short-term LNG trade
- the rise of US shale gas exploitation, which transformed a would-be importer into a would-be exporter
- a large gap between gas prices in Asia and the United States.

These elements are interlinked. While the development of spot cargoes started well before the shale gas revolution, the withdrawal of North America as an LNG importer meant that LNG previously destined for this market was not contracted and available for sale. As reported by the International Group of LNG Importers (GIIGNL), short-term and spot LNG trades represented just over one-quarter of global LNG trade as of 2013, compared to 5% in 2000 (GIIGNL, 2014) (Figure 8). One of the decisive changes has been the rise of Qatari trade to Asia over 2009-11, because it had to find alternatives to the US gas market. While Qatar was aiming to send roughly one-third of its new LNG volumes (~20 bcm) to the United States, it became clear in 2009 that such a quantity of LNG was no longer needed. Consequently, a large part of Qatar's LNG was exported to Asia, while some continues to go to Europe.

US shale gas exploitation also meant that US gas prices remained low while Asia's increased following the trend of oil prices. This divergence, which reached over USD 14/MBtu in mid-2012, caused gas companies to consider exporting LNG to exploit the large gas pricing gap. The shale gas revolution, which has profoundly changed global gas markets, has proven that nothing is certain in the gas world. As recently as the summer of 2014, the gap between US and Asian prices had diminished as a result of milder weather in Europe and Asia, and a cold winter in the United States. As of June 2014, the gap between US and Asian spot prices had halved to around USD 6.5/MBtu, which would make US LNG barely competitive in Asia at current HH gas prices. The gap between US and United Kingdom (UK) spot prices collapsed to around USD 2/MBtu, which would not even cover the liquefaction costs. However, this seems to be a temporary effect due to oversupply; the underlying factors supporting a premium of Asian gas prices over those of the rest of the world still seem present, as these prices are still heavily linked to oil prices.

At current levels of around USD 4/MBtu to USD 5/MBtu, US gas prices are in the right zone to enable US domestic demand to grow further while allowing US LNG to be exported and to be competitive in both Europe and Asia. While the United States was previously expected to *import* well in excess of 100 bcm as early as 2015 and 180 bcm by 2025 (EIA, 2005), it now looks more likely to *export* about 70 bcm by 2025 (Figure 9). This difference of roughly 250 bcm represents 2.5 times the annual LNG exports from Qatar, or almost three-quarters of the current LNG trade. The changes in expectations are therefore tremendous.

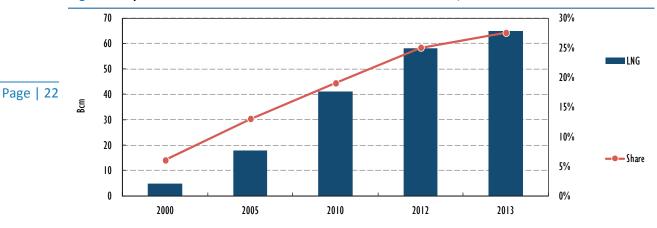


Figure 8 • Spot and short-term LNG trade and share of total LNG trade, 2000-13

Note: Short-term trade denotes trades under contracts lasting four years or less. Source: GIIGNL (International Group of LNG Importers) (2014), *The LNG Industry in 2013*, GIIGNL, Paris, www.giignl.org/system/files/giignl_the_lng_industry_2013_0.pdf.

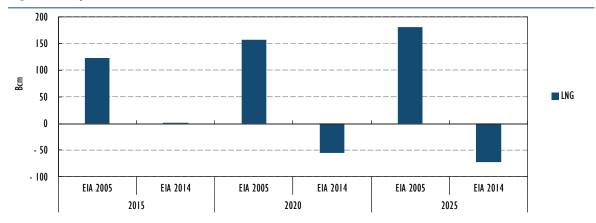


Figure 9 • Expectations of US LNG trade, EIA statistics 2005 versus 2014

Sources: EIA (2005), Annual Energy Outlook 2005, EIA, Washington, D.C., www.eia.gov/forecasts/aeo/archive.cfm; EIA (2014), Annual Energy Outlook 2014, EIA, Washington, D.C., www.eia.gov/forecasts/aeo.

How LNG projects started to deviate from the traditional model

Initially, LNG seemed to be a product relatively similar to pipeline gas, trade relationships were point-to-point and bilateral. A pipeline is inherently a more rigid infrastructure link that locks the exporter to a particular region. As a result, pipeline exports are more vulnerable to structural changes in end-use markets, and to the geological risks of upstream or transit developments. In contrast, LNG is also vulnerable to upstream issues, but its ability to react more swiftly to changes on the end-user market is increasingly appreciated. Transit issues have not affected LNG so far, despite the existence of some choke points.

Another important advantage of the LNG business model is the flexibility of how LNG is transported to the buyer. The delivery modalities defined in long-term contracts are either FOB or delivered ex-ship (DES).

 With FOB deliveries, the transfer of risk occurs when LNG passes the ship's rail at the port of shipment: at this point, all costs and liability of transporting the LNG to the port of destination transfers to the buyer. FOB delivery allows the buyer greater flexibility with regard to destination; however, the buyer must pay for shipping, insurance, regasification capacity and other costs. Buyers will most likely choose FOB delivery if they have options available that reduce insurance and transport costs in comparison with ex-ship delivery in the destination port. Delivery ex-ship usually provides less room for reselling, as the cargo is delivered at port after the liquefaction phase and transport to the import terminal. DES contracts with a destination clause therefore limit the flexibility to resell or redirect LNG. To redirect a cargo, the buyer must engage in LNG negotiation with the seller or incur reloading and shipping costs at the port of delivery.

In the late 1990s, the model of LNG projects based on long-term contracts and on cargoes being moved from the production site to a fixed destination started to be challenged. Driven by price deregulation in some key emerging markets such as the United States and Europe, traditional point-to-point trading with every cargo's destination specified began to be questioned by investors looking for a way to benefit from the flexibility of LNG to respond to demand changes. While there had been some spot cargoes shipped from Australia to Europe and from the United Arab Emirates to the United States, these were isolated incidents.

The real change began with Trinidad and Tobago in the late 1990s. Companies such as BG Group (BG) envisaged the possibility of arbitrage between the United States and other countries, notably Spain, where prices remained linked to oil prices, and unwanted cargoes could be absorbed by the US market, thanks to its scale, depth and liquidity. At that time, the US market was the residual market. This gave the opportunity to companies involved in the LNG business to optimise their portfolios, with cargoes actually going to a great variety of Asian, European and Latin American countries. The commercial structure of the different LNG trains (the liquefaction and purification facilities of LNG plants) of Trinidad and Tobago evolved: the first train was based on a merchant model, the other three on a tolling model, with gas producers acting as merchants and sometimes shippers, and buyers acting as shippers. This transformation was also helped by more flexibility in shipping: around 14 of the 101 ships delivered over the period 2002-07 were not committed to long-term agreements. At the same time, gas producers acquired shares in the LNG regasification terminals, notably in Europe, reinforcing the possibility for arbitrage.

Meanwhile, the capital costs of LNG liquefaction started to decline from 1990 to 2003, before increasing again (IEA, 2009). This created a surge of interest in the LNG business and would eventually lead to the emergence of new LNG plants in the early 2000s. The inflexible business model also began to weaken in the middle as some merchant companies emerged willing to take the advantages of price arbitrage opportunities. Those which survived the shift and the collapse of some companies such as Enron in the early 2000s are essentially the large IOCs, which are now known as aggregators. More recently, some pure trading companies have re-emerged.

In the years following, some LNG projects continued to diverge from the point-to-point model. Meanwhile, some also offered HH-indexed prices.

- Yemen LNG: Yemen LNG submitted and won a competitive bid to supply Kogas (Korea Gas Corporation), launched in August 2004. A sales and purchase agreement (SPA) was then signed with Suez LNG Trading for the US market, and it secured an additional LNG purchase commitment from its main foreign shareholder, Total. The deal with Total was on a DES basis, with LNG to be delivered at specific ports in the United States while the others were on an FOB basis. The deal to supply gas to the US market was renegotiated in 2009 to allow for the redirection of LNG to the more lucrative Asian markets. In practice, most of the LNG is now heading to Asia.
- Angola LNG: while the LNG plant was originally planned to serve the US market, it became obvious as early as 2010 that very little Angolan LNG would actually reach the US market, but would be redirected to more lucrative markets. There was no long-term agreement attached to this LNG plant, allowing it to shut down from early 2014 to the end of 2015 without having to supply cargo to buyers. The poor performance of the plant since its launch prevents any conclusions being drawn on what the sales strategy would have been, but cargoes targeted Asian as well as Latin American countries.

- That more traditional, non-US LNG projects also offered HH-indexed prices demonstrates that it is not something new. Indonesia's Tangguh LNG project signed an SPA with Sempra LNG on an HH basis for delivery of LNG to the latter's terminal in Mexico. Several other projects also have similar contracts, such as in Equatorial Guinea and Qatar. This should not, however, be viewed as a definitive move away from oil indexation, but rather as an opportunity to benefit from high HH gas prices, which were forecast to be at a premium to the Asian LNG price when the contracts were negotiated. Unfortunately, the timing was poor for projects employing HH indexation, as the HH prices plummeted as a result of the shale gas boom.
- Sabine Pass and the other US projects can be considered the ultimate move away from a pointto-point model with oil indexation, as they offer both HH-based indexation as well as FOB deliveries. In practice, Cheniere is not concerned about the destination or utilisation of the LNG plant since the capacity has been booked on a long-term basis. This means that it will always receive the tolling fee even if LNG remains undelivered because the buyer opts to not take it.

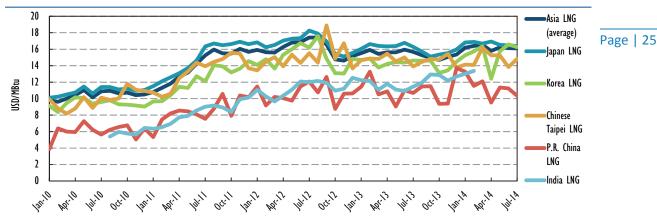
The collapse of HH gas prices in 2009, which took LNG sellers by surprise, partly explains why some LNG suppliers are now reluctant to introduce HH, or any gas-indexed pricing, in their long-term contracts. However, as of 2014, the market has changed: the United States is shifting from importer to exporter status. The LNG pricing structure is now switching from having HH-minus to HH-plus, with the introduction of constants which differ from one project to another to reflect the transportation costs, i.e. liquefaction and shipping. The value of the constant itself is an important game changer for LNG suppliers, as it ensures a minimum level for the LNG price regardless of what happens to HH. From a project-investment point of view, it has a similar function to the floor concept/S-curve mechanism, protecting the seller against low indexed prices that may affect the viability of the LNG project.

On the market side: Open wounds

Unlike Europe, Asian countries depend highly on LNG supplies; the exception is China, which already imports pipeline gas from Central Asia and Myanmar, and soon from Russia. This is the only country where there is competition between pipeline gas and LNG. Projects linking Japan, Korea and Russia with pipelines are more uncertain. Because of the relative difficulty of substituting one fuel for another in pipelines, and the high level of dependency of most Asian countries on LNG imports, the market power of suppliers in this part of the world is higher.

As previously mentioned, oil indexation has remained relatively unchallenged in Asia since it began some 40 years ago, and countries such as Japan paid only a slight premium in absolute terms over other countries to guarantee security of gas supplies. Indeed, Japan paid USD 0.8/MBtu more for its gas than Germany in 2003-04, but in relative terms this represents around a 20% premium. Oil indexation in LNG contracts would not be such an issue were it not for the very high gas prices it has generated in recent years. In 2012, the premium paid by Japan was on average USD 6.5/MBtu higher than Europe's (based on the average of NBP and the German border price). This gap had grown wider after European utilities renegotiated their long-term contracts over the period 2010-12, introducing partial spot price indexation (IEA, 2014a), but no such renegotiation has taken place among Asian utilities, at least not including spot indexation in existing contracts. In addition, the Fukushima accident put Japanese utilities on the hunt for LNG supplies, a position which made bargaining difficult. Consequently, in 2013, LNG imports in Japan amounted to over JPY 7 000 billion, which is JPY 1 000 billion higher than the previous year and JPY 2 400 billion higher than in 2008. One of the main reasons for the increase from 2012 to 2013 was actually the depreciation of the Japanese yen versus the US dollar. While the example of Japan is the most visible, other Asian countries all paid high prices, at around USD 15/MBtu in 2012 and 2013, for their LNG imports. Figure 10 shows the evolution of LNG import prices in selected Asian countries: Japan, Korea and Chinese Taipei are paying the highest prices, but China's and India's LNG import prices have been

increasing as well. With the exception of a few legacy LNG contracts at low gas prices, these two countries are also often paying market prices for their LNG.





Sources: Based on data from Japanese customs, the Korea International Trade Association, and the Bureau of Foreign Trade of Chinese Taipei.

High import prices create challenges for most developing Asian countries, as the LNG import price is quite often higher than prevailing domestic gas prices. How countries address the issue varies: the extra cost is usually absorbed in some way by the domestic national gas company or by some part of the country's budget. Only a few countries, such as Japan, Korea, Singapore, Chinese Taipei and some regions of China, have prices high enough to absorb high LNG prices. But this is not always sufficient and companies cannot always pass through the higher costs of LNG on to the end users, as illustrated by the losses of Japanese power companies since 2010, shown in Figure 11.

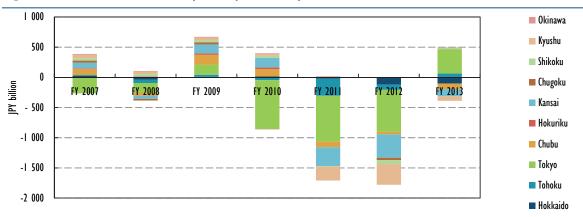


Figure 11 • Profits and losses of Japanese power companies, 2007-13

Note: FY = fiscal year.

Source: Based on data from the Federation of Electric Power Companies of Japan.

The financial situation of Japanese utilities may not be unique in the future: many Asian companies will increasingly have to face higher import costs due to rising volumes and a gap between market prices and domestic gas prices. It is particularly interesting to remember that, prior to 2008, very few people believed that spot indexation could represent more than 50% of the European wholesale market. A few factors triggered this change: one of them was the unsustainable financial exposure of many European utilities which were caught between their oil-linked, long-term contracts, competitors undercutting them with spot gas, and customers asking for spot indexation. Along with these circumstances, demand collapsed from late 2008 in most consuming regions, while LNG projects were coming on-stream and the United States no longer needed LNG; there was an

oversupply in global gas markets. Finally, liberalisation had created the conditions for a trading hub to develop that the IEA had already recognised: access to infrastructure and wholesale price deregulation. All these factors paved the way for renegotiation of long-term contracts and a (partial) switch away from oil indexation to gas-to-gas competition in many contracts.

Page | 26

Nevertheless, it is crucial to understand that markets can move from tightness to excess supply very quickly. For example, in the first half of 2014, a combination of cold weather in some parts of the world and drought in Latin America propelled gas prices to USD 20/MBtu. Six months later, mild weather in Europe and parts of Asia drove Asian spot prices to historical lows of just below USD 11/MBtu.

Contracted gas supplies in Asian countries

Understanding the uncertainties

Many changes will occur in Asia over the coming years as new supply comes online and some contracts from historical suppliers expire. What most LNG buyers and sellers are currently asking themselves is whether there will be an over- or under-supply of LNG, especially after the wave of LNG arrives from Australia in 2016-17. This is not an easy question; IEA analysis shows that most additional LNG will be absorbed by markets in Asia, Latin America and the Middle East. At the same time, some LNG will be able to come back to Europe, where more surplus on global gas markets is indicated. If it is a buyer's market as anticipated, buyers could potentially negotiate better conditions with some sellers.

It is therefore interesting to see the evolution of contracted LNG versus potential import needs for the key countries, and also to understand the uncertainties each country is facing (Table 2). Japan and Korea are almost entirely import-dependent; therefore, the main uncertainty is the evolution of gas demand. Energy policies and decisions in nuclear energy in particular will determine future gas demand and import needs. In Japan, methane hydrates could provide an alternative supply source in the longer term, but this is a remote possibility. Both Japan and Korea could also import pipeline gas from Russia, but this, too, is considered unlikely, at least in the short to medium term.

	China	India	Indonesia	Japan	Korea	Malaysia	Singapore	Chinese Taipei	Thailand	Viet Nam
Production	+++	++	+++	+*		+			+	+
Demand	+++	+++	++							
Coal/gas	+++	+++	+++	+	+	+				
Nuclear	++	+		+++	++			++	+	
Exports			+++			++				
Pipeline imports	+++	++		+	+		+			

Table 2 • Key long-term uncertainties	faced by Asian countries
---------------------------------------	--------------------------

Note: +++ = game changer; ++ = significant impact; + = limited impact; " " = no impact/irrelevant.

* Methane hydrates.

In contrast, all the other countries combine their demand with different types of supply uncertainty. China still relies considerably on its domestic production, but there is tremendous uncertainty regarding the evolution of unconventional gas production, notably that of shale gas. Coal gasification could also provide substantial volumes, but the sustainability of the process is questionable, as it generates CO₂ emissions in the absence of carbon sequestration and has a very high water need. Meanwhile, China will become a large importer of pipeline gas based on deals with Turkmenistan and Russia, which together bring the combined pipeline volume to over 100 bcm post-2020. The interplay between pipelined gas and LNG is therefore of crucial importance in China.

Box 2 • Shale gas production in China is a major uncertainty for future LNG needs

China is currently the largest shale gas producer outside North America. As the country needs to meet its ever-increasing energy needs while turning to greener fuels, it has engaged in a strong push to develop unconventional gas resources. The government has set aggressive targets for shale gas production: 6.5 bcm by 2015 and 60 bcm to 100 bcm by 2020. The 2015 target now seems reachable, thanks to the developments in Sinopec's Fuling area in the southwest of China, which was already producing 3.1 million cubic metres (Mcm) per day in June 2014. Sinopec is now more confident that it could produce 5 bcm by end-2015 through its Fuling block. The 2020 target was recently revised down to 30 bcm in light of development difficulties.

More pipelines and other infrastructure are under construction in Sichuan and will be finished before 2015. China still faces significant challenges in developing its shale resources. Chinese shale is deeper and tends to have more clay than US shale. Water will also be an issue because hydraulic fracturing requires large amounts of water, which is scarce in the Ordos and Tarim basins. Uncertainties regarding future liberalisation of prices and third-party access, along with the absence of detailed rules to regulate shale gas activity, are also important factors. The government offers subsidies of CNY 0.4 per cubic metre (CNY/m³) (USD 2/MBtu) for shale gas, and categorises shale gas as a special type of mineral. The current wellhead cost of shale gas in Sichuan is estimated to be close to USD 10/MBtu. The regulations can be seen as a way to trigger a more rapid development of shale gas, but their duration is still uncertain.

In 2012, the IEA issued the report *Golden Rules for a Golden Age of Gas* (IEA, 2012), in which it looked at the conditions necessary for a successful take-off of unconventional gas production across the world. In particular, different scenarios for unconventional gas production in selected regions, including China, were studied for how unconventional gas production would impact gas demand and supply.

The report posited two scenarios: a Low Unconventional Gas Case featuring difficulties for unconventional gas to take off, and a Golden Rules Case, in which China manages to tackle the difficulties mentioned above. While most of the unconventional gas production comes from shale gas, coalbed methane (CBM) and tight gas also play a role. The differences between the cases are striking: higher unconventional gas production would boost gas demand, but also significantly reduce the call on imports.

The difference in imports between the two cases is 143 bcm, which is equivalent to more than three times Europe's LNG imports, or to the LNG production of seven Gorgon LNG projects. This represents a considerable uncertainty for suppliers looking at China, especially considering the current contracted pipeline supply from Turkmenistan, Kazakhstan, Uzbekistan, Myanmar and Russia, at above 100 bcm.

Considering that imports in the Golden Rules case barely reach 120 bcm by 2035, this leaves, in theory, almost no room for LNG, so that China could easily benefit from arbitrage between sources of pipeline or LNG supplies, and potentially resell surplus LNG to other Asian countries in the same way as European countries are re-exporting surplus LNG. Should a trading hub exist in China at that time, it would provide an alternative price index.

India faces uncertainties similar to those of China regarding future domestic gas production, both conventional and unconventional. The country has also tried to import gas by pipeline, but without much success. Furthermore, many Indian gas users are very price-sensitive and coal remains the key competitor to natural gas in the power sector.

Southeast Asian countries still depend primarily on their domestic production, with the exception of Singapore, which has no domestic gas production and is progressively switching from pipelined gas to LNG imports. There is considerable uncertainty regarding the evolution of Indonesia's gas production in particular, as the country has important conventional and unconventional gas resources but faces barriers to develop them, such as difficult surface geography, weak infrastructure, as well as licencing and royalty issues. Both Indonesia and Malaysia export LNG and pipeline gas; but also import into other island regions. The continuation of exports depends on new gas to support existing or new projects. Generally, Southeast Asian countries have not yet contracted much LNG compared to the other Asian countries.

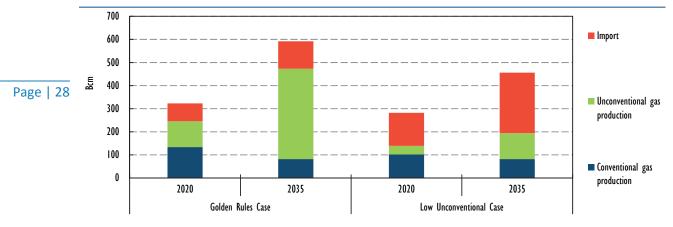


Figure 12 • Meeting Chinese gas demand under different gas production scenarios

Analysis of contracted gas supplies

The analysis of contract structures indicates that contracted LNG in Japan and Korea declines starkly in the middle of the next decade. Nevertheless, some of the expiring contracts – such as those from Qatar, Australia (some historical contracts with North West Shelf LNG [NWS] are expiring), Malaysia, or from global-portfolio players – are likely to be extended. There is more uncertainty for contracts with Oman, the United Arab Emirates, Indonesia and Brunei. In both cases, it is interesting to see the apparition of the United States as well as global-portfolio LNG, which has an important share in the case of Korea. Should Japan manage to renegotiate and extend a substantial share of its existing contracts, this should be sufficient to cover lower demand levels than those of today. However, it is likely that Korea will need more LNG in a scenario of growing gas demand.

As far as China is concerned, pipelined gas seems to be taking the lead from 2020 onwards, courtesy of contracted gas supplies from Turkmenistan and other Central Asian countries, Myanmar and Russia. Meanwhile, contracted LNG volumes actually flatten from 2015 onwards. These volumes do not take into account spot LNG, which China imports regularly. This makes future LNG needs in China one of the greatest uncertainties facing global LNG markets today (Box 2).

In contrast, India seems under-contracted, with very small LNG volumes contracted so far compared to its alleged need. To be able to receive more LNG, however, more LNG import infrastructure must be available, and only two out of the four operating LNG terminals currently operate without restrictions. Nevertheless, the biggest issue remains the price and the possibility to market the gas downstream.

While Singapore is securing LNG from global-portfolio players, most Southeast Asian players are still seeking it. Their greatest challenge is high market prices compared to domestic gas prices.

Asian companies are increasingly finding improved pricing and delivery terms. For example, shares in Australian upstream projects enable Japanese companies to obtain more favourable terms, such as full flexibility to deliver cargoes beyond the companies' terminals in Japan under certain conditions. For any other destination, the companies need approval from the seller and agreement on the sharing provision. For this reason, FOB contracts became an important dimension of portfolio management of Japanese companies (Figure 13). Meanwhile, the contracts signed for US LNG give them total flexibility as well as hub indexation.

Unlike in Japan, Korea already has many FOB contracts; FOB contracts from various destinations provided around 60% of all gas contracted by Korea in 2008. Kogas, its public gas company, has expanded its business scope from import and distribution of natural gas to exploration and production in upstream projects throughout the world. Investments in upstream projects started in 1996 when Kogas acquired 5% in the Oman LNG project. Later on, it invested in countries such as

Qatar, Myanmar, Yemen, Uzbekistan, Iraq, Canada, Indonesia, Australia and Mozambique. Contrary to Japan and Korea, the overwhelming majority of Chinese long-term contracts (around threequarters) are DES contracts.

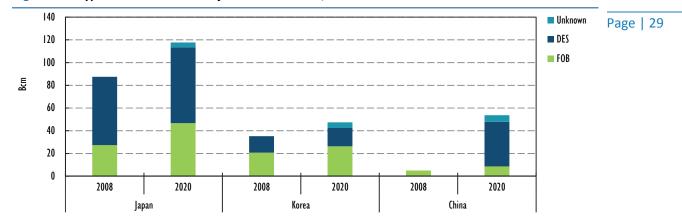


Figure 13 • Types of contracts for major Asian countries, 2008 versus 2020

In relation to the restrictive clauses, some of the global companies operating in Asia have been following a doubly strategy: trying to buy LNG without destination restrictions for their trading activities and introducing destination restrictions when they sell LNG to gas and power utilities. Some companies have struggled against the use of destination restrictions in Europe during the last decade; they are now trying to maintain contractual restrictions in Asia as an important instrument to minimise competition in other markets.

Japan

Japan is unique in its diversity of companies contracting LNG; this results in a myriad of small to medium-sized contracts with quantities varying from 0.1 bcm to 6.5 bcm. Gas is contracted either by gas companies or by power producers. In some cases, particular Japanese companies have contracted almost all the LNG of some projects (for example, NWS LNG in Australia).

A certain number of contracts have expired, and others will do so over the coming years, mostly from the historical Asian exports but also some from Middle Eastern countries. Japanese companies have therefore been looking for new supplies for many years and Australia is a natural target due to its proximity to Japan. After the Fukushima accident and the uncertainty of whether and when nuclear power plants will resume production, Japanese companies have contracted LNG, but often only for a short duration. Consequently, volumes contracted have already increased and will do so sharply over the period 2013-16, to peak over the period 2016-21 (Figure 14). The main sources will be Australian deliveries from LNG projects coming online, in which Japanese companies are equity partners, as well as US LNG. It may be that Japan will be slightly over-contracted in 2017-18, with LNG contracts peaking at 124 bcm. Although this excess LNG can be partially absorbed by potential future demand growth, it can also be redirected to other destinations, or companies can make use of the right of downward quantity tolerance. Additionally, some US LNG imports with no FDC could be redirected to other markets.

Quantities of contracted LNG decrease sharply from 2020 onwards, reflecting the expiration of some long-term contracts (Figure 14). Realistically, some contracts are likely to be extended, such as those from Qatar, Malaysia and Australia. Assuming that 75% of the current quantities are extended still leaves a comfortable supply for Japan, which could match the demand trajectory. But Japan is likely to demand other terms than the current oil indexation when it renegotiates, which may invite other suppliers with more attractive terms.

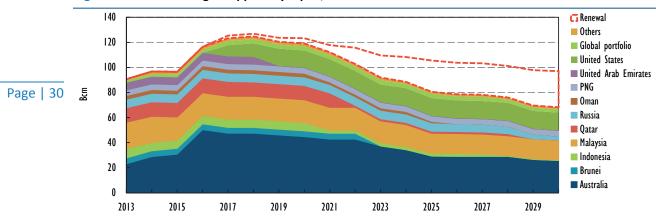
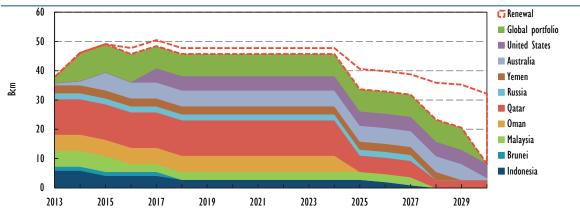


Figure 14 • Contracted gas supplies by Japan, 2013-30

Korea

Unlike in Japan, most of the LNG going to Korea has been contracted by Kogas. Private players (GS Caltex, SK E&S) as well as POSCO do import some LNG, but this is more limited as private players can only import LNG for their own consumption and not for resale. Korea has traditionally relied heavily on spot cargoes. Still, quantities of gas contracted have increased with regular demand increases. The increase in contracted LNG has been progressive and will continue over several years before flattening (Figure 15), not taking into account LNG from planned projects such as Canadian ones.





One supplier stands out: Qatar, providing around 12 bcm/yr over the current decade and part of the next. This contrasts with volumes from Indonesia and Malaysia, which have been declining since the mid-2000s, although some contracts from these countries have been extended by several years. Even though Korea is one of the few Asian countries to be a free trade agreement (FTA) country, with consequently more freedom to get US LNG, it actually contracts very little LNG from the United States. In contrast, a substantial amount of gas (7 bcm/yr to 8 bcm/yr) will be bought from companies with global portfolios, and it is likely that some US gas will arrive in Korea in this manner.

These quantities of LNG may be insufficient to cover demand even in the medium term, implying that Korea will continue to use spot LNG to some degree. Of note is the rapid drop of contracted LNG volumes towards 2024-25, a one-third reduction which indicates that Korea will monitor the market to replace or renegotiate expiring contracts, especially with Australia, Qatar, Malaysia, Yemen and Russia. Many of these contracts may be extended provided prices and conditions can be agreed upon; the Omani contract is more uncertain and depends on the evolution of the supply/ demand balance in the Middle East region. Still, even extending 75% of the contracts would not be sufficient to cover existing gas demand.

China

China's situation is more complex to analyse due to its uncertain future domestic production and the possibility to import both LNG and pipeline gas. Consequently, approaches to supply depend on the company. As shown in Figure 16, the share of LNG in total contracted supply will decrease over time as more pipelined gas is contracted from Central Asia and Russia and arrives over the period 2015-25. These volumes will increase over time and stabilise towards mid-2020, while Page 31 LNG volumes will progressively decline. Given China's increasing import dependency, there is room for either more LNG or pipelined gas.

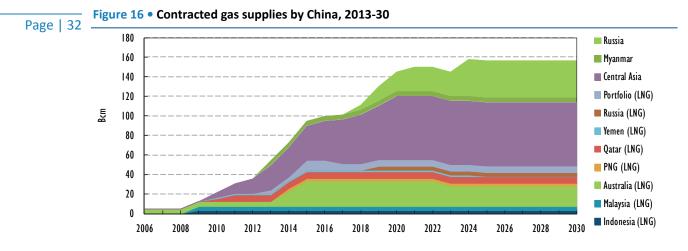
The Chinese gas industry is characterised by an oligopolistic structure dominated by three companies: China National Petroleum Company (CNPC), China National Offshore Oil Company (CNOOC) and Sinopec. Historically, CNOOC was the first company to import LNG and it still remains the main LNG importer, even looking ahead. CNOOC was joined several years later by CNPC through PetroChina, which is the only importer of pipelined gas based on deals signed mid-2014. Sinopec arrived on the LNG scene more recently, targeting mostly Australia with some success. CNPC and Sinopec have contracted roughly the same amount of LNG, but with more variety in sources for CNPC. CNOOC is the only company which has contracted portfolio LNG, from companies such as BG and GDF Suez. Some smaller Chinese companies have tried to contract LNG, but the deals were unsuccessful. Similarly, some preliminary deals agreed by the three main companies did not progress.

Import facilities are mostly built by and in accordance with import plans. In most cases, the National Development and Reform Commission (NDRC) does not give its permission to build unless there is a long-term contract attached, but this has not prevented the construction of LNG import terminals to move at a relatively rapid pace. As of mid-2014, 46 bcm/yr of regasification capacity had been built, while 23 bcm/yr is under construction and likely to be completed by 2017.

Give the size of its market and the prospective for growth, China has been able to benefit from attractively priced contracts (such as with Australia, Indonesia and Malaysia). Also in China's favour is the fact that it was a buyer's market when China contracted this gas in the early 2000s. This less costly LNG accounted for almost half of its 2012 LNG import portfolio, significantly reducing the overall import price to around USD 11/MBtu, a price much lower than that paid by traditional Asian importers. However, lower-priced imports represented only 33% of China's total LNG imports in 2013. Import prices therefore ranged from around USD 3/MBtu for old LNG contracts from Australia and Kazakhstan to almost USD 18/MBtu for spot purchases from Qatar, highlighting the large disparity in import prices (OIES, 2014). Given that China maintained DES contracts restricting redirection to other markets, it is sometimes difficult for the Chinese gas market to absorb the LNG due to relatively higher prices. Large volumes of contracted pipelined gas also indicate a strategy of securing gas supplies. Nevertheless, the contract between CNOOC and Tangguh was revised in June 2014 and the price increased from USD 3.4/MBtu to USD 8/MBtu, still at a discount to current market prices.

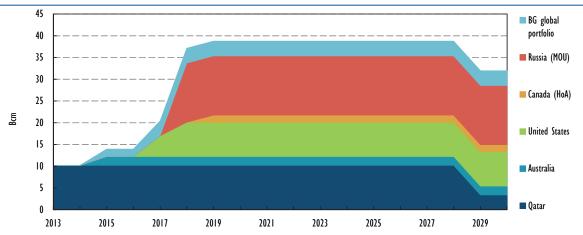
Among the recent and interesting developments is the Russia-China pipeline deal. The volumes agreed – 38 bcm/yr – represent already almost 1.5 times the current LNG imports into China. This is more than the exports of any LNG exporter as of 2014, besides Qatar. These volumes are likely to displace some new LNG. Another important aspect of the deal is the apparently low gas price at the border, which has been assessed by many analysts to range between USD 9.5/MBtu and USD 11/MBtu, with a consensus of around USD 10/MBtu. If correct, this makes it a relatively inexpensive source of gas, even taking into account a transport cost inside China to bring it to the northeastern markets. This gas is likely to reach the "city gate" - the sales point to Chinese distributors at around USD 12/MBtu to USD 13/MBtu. This provides a new benchmark for Chinese companies to negotiate future deals. In contrast, the other major source of pipelined gas, from Turkmenistan, has been reported at around USD 9.6/MBtu at the border, more expensive than other Central Asian gas due to the fees for transit through Uzbekistan and Kazakhstan. However,

the gas still needs to be transported across the whole country, unlike Russian gas, which means Turkmen gas arrives in Shanghai at almost USD 15/MBtu (OIES, 2014). While this seems quite expensive now, it must be remembered that in the early years of Turkmen imports (2010), the price was at "only" USD 7/MBtu.



India

While India has contracted around 10 bcm/yr of LNG from Qatar, it has also been importing a lot of spot LNG, as India's total LNG imports are usually around 15 bcm/yr. Looking ahead, Indian companies have only contracted US LNG, from Australia's Gorgon as well as from BG's global portfolio. The total of 22 bcm/yr seems significantly below what India needs in the longer term. A certain number of memoranda of understanding (MOUs) exist, with Rasgas, Gazprom, Eos Energy and Pacific Northwest LNG, which could potentially bring 26 bcm/yr, with half coming from Russia alone. Most of these contracts are FOB, giving India some flexibility. Of note is that one of the LNG terminals, Hazira, is a merchant one. Meanwhile, a pipeline deal with Iran, Turkmenistan or Russia still seems a far-away option.



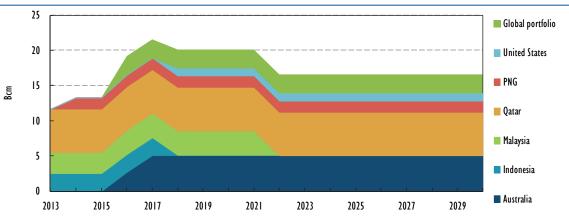


Note: HoA = heads of agreement.

The price issue is the most difficult one to resolve. India is engaged in a pricing reform aimed at progressively increasing domestic gas prices, but the pricing reform is stalled. In addition is the problem of affordability: the company GAIL is reportedly having difficulties selling its contracted US LNG downstream, even though this gas is supposed to be cheaper than oil-indexed gas.

Chinese Taipei

Chinese Taipei has a relatively diversified supply portfolio. As contracts with Indonesia and probably Malaysia will expire and may not be extended, while demand for gas increases, CPC has been contracting more gas from PNG, Australia's Ichthys and the United States. Contracted supplies will amount to roughly 20 bcm/yr as of 2020, with a 2.6 bcm/yr contract with Malaysia expiring by 2021, if the contract is not extended. This is likely to require the country to either contract more gas to replace this missing LNG – there were plans to import gas from the Browse LNG project in Australia – or rely more on the spot market. Of note is that most contracts are DES.





Singapore

Singapore has actually contracted very little gas, although it plans to increase its LNG contracts as it expands its LNG regasification capacity to 9 million tonnes per annum (mtpa). SLNG has therefore contracted 3 mtpa from BG over ten years. In late May 2014, Total signed a ten-year LNG SPA with Pavilion Gas for the supply of 0.7 mtpa to Asia, including Singapore, starting in 2018; several LNG cargoes will be supplied prior to 2018. In both cases, the LNG will be sourced from the companies' global LNG portfolios and contracts are valid for only ten years, which is not considered a very long duration in the LNG world. This reflects the desire of Singaporean authorities to get LNG supplies at competitive prices and sourced from different origins.

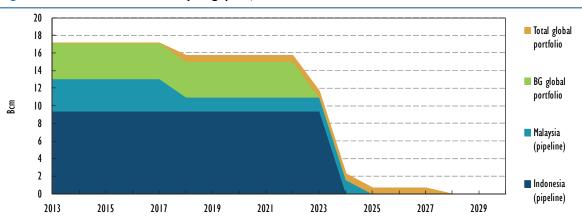


Figure 19 • Contracted volumes by Singapore, 2013-30

Singapore still has important long-term pipeline contracts to import gas from Malaysia and Indonesia, but some contracts will not be extended once they expire as Singapore seeks to import more LNG. Contracted supplies actually surpass demand needs, as Singapore consumes roughly 10 bcm. Singapore put in place a moratorium preventing gas companies from contracting new pipeline gas supplies to enable LNG imports to rise, but LNG imports have been steadily increasing so the moratorium is set to be lifted. As contracts for pipelined gas and LNG imports are set to expire at around the same time, it is likely that Singapore will seek to either extend some of the deals or investigate better conditions with new suppliers. Imports from Indonesia are set to expire first; Sembawang Corporation imports from the Koridor block (South Sumatra) operated by ConocoPhillips and Gas Supply Pte from the Natuna Sea block operated by Premier Oil BV. These contracts account for roughly 9 bcm/yr. Other contracts include Keppel Gas and Senoko Energy's contracts with Malaysia and represent roughly 3 bcm/yr.

Other ASEAN countries

PTT of Thailand signed an LNG SPA with Qatargas in December 2013 for the delivery of 2 mtpa of LNG. Under the SPA, PTT will start receiving LNG for 20 years from 2015 at its Map Ta Phut LNG terminal (the ASEAN's first regasification terminal). At the moment, PTT is purchasing LNG on a spot basis to cater for the country's LNG demand. PTT has also signed a preliminary term sheet with Anadarko's Mozambique LNG project, of which PTT is one of the shareholders. However, it remains to be seen whether the project will reach FID and whether the term sheet will eventually be converted into a binding SPA. In any case, this LNG is unlikely to be available before 2020.

Meanwhile, Indonesia is feeding the country's first LNG regasification terminal, which commenced operation in 2012, from its existing liquefaction terminals. Indonesia plans to begin importing LNG from the United States as early as 2018 if Cheniere's Corpus Christi LNG project takes FID and starts as planned, but this plan is optimistic as the project had not received the Federal Energy Regulatory Commission's (FERC) approval as of October 2014. Pertamina, the country's state-owned oil and gas company, signed a 20-year LNG SPA with Cheniere in December 2013 for the purchase of up to 0.76 mtpa of LNG and, subsequently, doubled the volume to 1.52 mtpa in July 2014.

Like Thailand, Petronas has been purchasing LNG on a spot and short-term basis for Malaysia's LNG regasification terminal in Malacca. However, the country will soon receive LNG on a long-term basis once the Gladstone LNG project in Australia commences operation in 2015. Petronas, which holds a 27.5% interest in the project, is also one of the project's LNG offtakers with a 3.5 mtpa commitment. Petronas has also signed a 20-year HoA document with Qatargas for delivery of 1.5 mtpa of LNG to Malaysia from 2013; however there is no news to date on the SPA from both companies, although Qatargas reported the delivery of its first cargo to Malaysia in 2013. At the same time, Malaysia's requirement for LNG may also come from domestic sources, as Petronas is currently constructing its Train 9 and Kanowit FLNG projects, anticipated to bring additional volumes of about 5 mtpa when coming online by 2016.

Unlike the above countries, there has been little news on the development of the LNG regasification terminal in the Philippines. Despite the greater attention given to Shell's plan to build a 4 mtpa LNG regasification terminal in Batangas, Energy World Corporation (EWC) is currently constructing the country's first LNG regasification terminal in Pagbilao. The sourcing of LNG for this terminal is unclear, although EWC indicated that the required LNG may come from its Sengkang LNG terminal, which is currently under construction in Indonesia.

Elsewhere, PetroVietnam Gas (PV Gas) is also trying to secure LNG for its planned LNG regasification terminal in Viet Nam. The company signed a master SPA with Gazprom in March 2014, which is needed for potential spot purchases between the two companies. PV Gas also signed a framework agreement with Shell in June 2014 for the supply of LNG to its Thi Vai LNG terminal. PV Gas had previously been in talks with Qatargas in 2011 for the purchase of LNG from Qatar; however, no progress has been reported since then.

New co-operation models

In reaction to the high prices experienced over 2011-14, some Asian buyers have been seeking new co-operation models and strategies to improve their bargaining power and lower the cost of LNG imports. As mentioned earlier, while spot indexation can be seen as a good way to provide less costly gas, there is no guarantee that oil-indexed gas will always be more expensive than spot-indexed gas. With HH gas prices at around USD 4.5/MBtu, US LNG would arrive in Eastern Asia at around USD 12/MBtu to USD 13/MBtu. Here again, there is uncertainty on the future price curve of the US gas supply.

Page | 35

Two types of initiatives exist: those by companies and those by governments. Among the initiatives by companies are massive investments in different parts of the world to secure LNG supplies. These investments span over North America, Australia, East Africa and Russia; they are presented in depth in the next section.

Also interesting are the new LNG agreements based on different terms, either of price or of deliverability.

- Asian companies have signed LNG deals with several US LNG projects (see sections on North America); these deals will be FOB and based on HH linkage. This gives Asian importers several options: bringing US LNG back to their domestic market, selling it to other overseas markets, or selling in the US market depending on the relative demand and pricing situations.
- BP Singapore and Kansai Electric finalised a preliminary 15-year supply agreement for 0.5 mtpa (0.7 bcm/yr) in November 2012, whereby LNG will be delivered based on a 100% HH indexation, even though it will come from BP's global portfolio. Later in September 2014, TEPCO also signed an LNG deal with BP Singapore for 17-year supply agreement with volume up to 1.5 mtpa (2 bcm/yr), which is also BP's global portfolio and HH-indexed pricing. Similarly, both BP and BG signed a deal with CNOOC using both HH and oil indexation, an interesting way of hedging on both indexation types.
- The tripartite LNG HoA of January 2013, executed by Chubu Electric Power Co., Kogas and Eni is the first international joint purchase of LNG in Asia, allowing the two Asian companies will be able to relocate LNG among themselves. The agreement consists of 1.7 mtpa (2.3 bcm/yr) of LNG that will be delivered via roughly 28 shipments between May 2013 and December 2017.
- TEPCO proposed earlier in 2014 to jointly procure up to 40 mtpa (54 bcm/yr) of LNG to cut costs. This joint procurement would involve both Japanese and overseas companies, and would cover both spot and contractual volumes. Joint procurement of LNG is also an idea being discussed among ASEAN countries.
- Tokyo Gas and Kogas have signed an MOU in September 2014 to further enhance co-operation in the LNG business such as optimising shipping resources and inventories, seeking opportunities for jointly procuring LNG and investing in upstream.

There have also been talks about co-operation at the government level. Officials from Japan, India, Korea and Chinese Taipei, which together import about 65% of the world's LNG, held talks in 2013 but no firm steps have materialised. India and Japan signed an agreement in September 2013 to study joint procurement of supplies, and the two countries will hold meetings to work out the details of joint purchases.

Developments in LNG trade 2013-14: A mixed picture

Since early 2013, two different trends have been observed in addition to those mentioned previously:

• Many companies tend to sign shorter-term deals with producers of brownfield LNG plants, typically for three to five years, signalling the market uncertainties in many regions.

• A few long-term deals were signed with major suppliers, allegedly based on some sort of oil indexation.

While the first development seems to reflect the current uncertainties for both buyers and sellers regarding the future evolution of international gas markets, a few long-term deals have been signed, some of which still used the old model.

Page 36 In 2013, Qatar signed three medium-term deals targeting Europe; all of them are DES contracts. Centrica signed for 3 mtpa of LNG from Qatargas for four and a half years. The deal started in June 2014, and is expected to cost GBP 4.4 billion (USD 7.1 billion), according to Centrica. The price quoted means an average of USD 10/MBtu and the contract is based on NBP prices. Qatargas also signed another 1.14 mtpa five-year SPA with Petronas starting in 2014. That LNG is also to be delivered to the UK market (Dragon LNG, where Petronas has shares). These contracts are not a fundamental change in terms of pricing, as Qatar was already selling LNG to the United Kingdom at prices close to NBP prices. Besides, the Centrica deal is the continuation of the existing 2.4 mtpa SPA signed in 2011, and is set to expire in June 2014.

Much more interesting is the five-year flexible SPA that E.ON signed with Qatargas for around 1.5 mtpa of LNG. This contract will be priced on a continental hub basis, probably Title Transfer Facility (TTF) as the LNG will be delivered at the Dutch Gate terminal. This represents a radical change, as Qatar had previously tried to maintain oil indexation in Continental Europe.

Meanwhile, China signed deals which were either totally or partially indexed to oil. The new SPA signed with the Russian Yamal LNG project shows that there is still resistance to moving away from oil indexation, as the CNPC contract signed is allegedly based on JCC. However, the details of the contract are strictly confidential – there is no indication on the slope. No information on the pricing mechanism of the contract with Gas Natural Fenosa has been disclosed, whereby gas is expected to be delivered to Europe. There is very scarce information on the type of indexation of the Russia-China gas pipeline contract: the price is understood to be around USD 10/MBtu, but it is unknown whether it is fixed or linked to other elements, although most analysts speculate it is based on oil indexation. Should this price level be confirmed, it could give some benchmark for future deals to be signed in the region.

Also very interesting are the deals signed by CNOOC with BP and BG. Both deals are understood to feature a partial spot (HH) and oil indexation, reflecting the hesitance of Chinese companies to entirely trust a new and somewhat unfamiliar pricing mechanism which does not reflect the supply/ demand balance of Asia or China, and the resistance of suppliers to move away from oil indexation.

These deals with China are a reminder of the tendency to sign more deals based on suppliers' global portfolios. These deals can be either long-term like those with China, Singapore, Korea or Japan as mentioned before or short-term with duration of less than four years such as BP's contract with Argentina's Enarsa, reflecting hopes of a rapid development of Argentina's unconventional gas resources, or Gas Natural's contract with Kogas for 0.4 mtpa for two years starting in 2014.

The LNG supply picture

In looking at which countries could supply significant volumes of LNG over the next ten years, four regions clearly take the lead: North America (the United States and Canada), Australia, East Africa (Mozambique and Tanzania) and Russia. This does not mean that no other region will be able to challenge these four, but its contribution would most likely be only modest over the next decade. Page 37

The next four sections analyse the comparative advantages and challenges for these four regions, looking at the supply picture in a general manner, but also at how Asian companies have positioned themselves in relation to these LNG export countries.

There are several aspects to consider when comparing LNG projects: capital costs, the distance from the main export markets (a significant part of the ultimate transport cost), the approval process for projects, and how far they are from FID as of mid-2014. This report focuses on the investments of Asian companies, separating the upstream from the LNG export facility and the long-term contracts, even though in some cases the investments in upstream are actually made jointly with the investments in the LNG liquefaction plants.

Investments of Asian companies in the four regions

Among the key conclusions is that the investment and influence of Asian companies on these four regional markets is different from one region to another, with the North American market showing the least Asian influence and East Africa the most.

Interestingly, North American projects, in particular US LNG projects, are most likely to be operating first, if the Australian LNG projects currently under construction are excluded. Even excluding the Sabine Pass project, it seems that construction work will also start on at least one US LNG project before the end of 2014. The Russian project Yamal LNG is also under construction. As far as Australian LNG projects are concerned, they seem to be moving away from FID – several projects were postponed recently, such as Bonaparte LNG. In an optimistic scenario, some East African LNG could arrive by 2020, or these projects could share the fate of the Nigerian projects that have been at the planning stage for a decade.

- North America offers a dual picture, as the story is guite different in the United States and Canada. The striking contrast between the two countries is the much stronger influence of Asian companies in Canada than in the United States. In the United States, gas exploitation would have continued even without investment by Asian companies, for although they have indeed invested significantly, providing cash to producers in need, it is a small share of total investments.
- In Russia, Asian companies are beginning to be significant buyers and in some cases even • investors for the potential Russian LNG projects discussed, even if their role is modest in accounting for the total Russian gas supply.
- In Australia, the involvement of Asian companies is quite significant, especially in the new LNG projects currently under construction but also in those still at the planning stage.
- In East Africa, the share and influence of Asian companies is very important, with Chinese, Indian, Singaporean and Thai companies already owning a share in upstream licenses and discoveries. This investment is notably quite strong in Mozambique, but not yet so in Tanzania, although it is anticipated that the region will continue to attract investments as more gas is discovered. East Africa could have the strongest relative investment from a regional point of view as a result.

To examine the involvement of Asian companies, a matrix comprised of upstream, LNG plants, and contracts has been designed. In many cases, the upstream part is integrated in the LNG plant itself,

but this is not always the case. This matrix helps to identify the strength of Asian companies as well as their respective strategic interests. Meanwhile, it also helps position the four regions in terms of attractiveness.

									Chinaga					
Page 38		China	India	Indonesia	Japan	Korea	Malaysia	Singapore	Taipei	Thailand	Viet Nam			
		North America												
	Upstream	v	~	X	~	~	~	Х	Х	Х	x			
	LNG	v	~	X	~	~	~	Х	Х	Х	х			
	Contracts	~	~	~	~	~	~	х	Х	Х	x			
					Rus	sia								
	Upstream	v	~	X	~	Х	х	х	Х	Х	X			
	LNG	v	X	X	~	Х	х	х	Х	Х	X			
	Contracts	~	~	X	~	~	x	x	Х	Х	~			
	Australia													
	Upstream	v	~	X	~	~	~	х	~	Х	x			
	LNG	~	X	X	~	~	~	х	~	Х	х			
	Contracts	v	~	X	~	~	~	~	~	Х	X			
					East /	Africa								
	Upstream	v	~	X	~	~	~	~	Х	~	x			
	LNG	~	~	X	~	~	x	~	Х	~	x			
	Contracts	✓ (?)	✓ (?)	X	✓ (?)	√ (?)	х	✓ (?)	Х	~	x			

Table 3 • Investments of Asian companies in selected regions

Notes: No long-term contract except for PTTEP has been announced for East African LNG, but some key investors are expected to take some of their equity gas back home. Symbols: \checkmark = investments have been made; X = investments have not been made; \checkmark (?) = investments may have been made but it is currently unclear.

Based on this matrix, the following conclusions can be drawn:

- China, Japan and Korea are the three countries with the strongest presence in the four regions, as well as investments in upstream, LNG plants and contracts in each region. Although they have not formally signed contracts for East African LNG, they are expected to do so, given their recent investments.
- Remarkably, Japan and China are both present in all the elements in every single region. It is
 of note that Japan has not one, but many (more than ten) different companies investing; these
 companies are mostly gas and power companies. Chinese investments are largely performed
 through its three national oil companies (NOCs), while India relies on different state-owned
 companies (ONGC and GAIL) or private companies (Reliance). Most other countries tend to
 invest through one national champion.
- China has not yet contracted any US LNG directly, even though it has done so indirectly by contracting gas from BP and BG, which will source the gas from their global portfolios. In contrast, it has contracted LNG from other regions. China is present in different Canadian LNG projects and has also invested in US and Canadian gas upstream.
- India is also relatively present in different regions and different parts of the LNG value chain. Interestingly, unlike many other Asian countries, its companies are not present in LNG export plants in Australia. They also have a very limited presence in the Australian upstream sector and one single LNG contract from this region.

- Despite significant investments in foreign regions, Korea has not yet invested in Russian LNG projects. Of note is that most of the investments are performed by Kogas, with some limited LNG volumes contracted by private players such as SK E&S. Kogas cannot invest massively due to the recent financial burden high-cost LNG has created. It is particularly interesting to see that Kogas has been withdrawing from some of its acquisitions in Australia, which now appears the most expensive LNG supplier. In 2013, Kogas withdrew from two long-term contracts with Australian projects. A 2009 agreement between Kogas and Gorgon's project sponsor Chevron did not concretise and another agreement for the Wheatstone project met the same fate. The company is also considering selling a share in the LNG Canada project venture. Meanwhile, the Korean government is pushing for upstream investments as the Ministry of Trade, Energy and Industry (MOTIE) raised a target in 2012 for developing its self-supply ratio of oil and natural gas to 35% by 2020.
- At the other end of the spectrum is Indonesia, which has not made substantial investment in
 other regions, apart from signing a deal with one of the US LNG projects. The country is said to
 be actively looking for additional LNG supply. This reflects the fact that Indonesia is still a net
 exporter of LNG and only recently joined the club of LNG importers, whereby some of its own
 LNG is actually transferred from one part of the country to the other. But as the gap between
 potential demand and supply widens, there is pressure to build up its LNG supply.
- The Southeast Asian countries also have relatively low investments abroad, with the exception
 of Malaysia's Petronas, even though they are now starting to catch up with the other, more
 established LNG players. These countries are, nevertheless, increasingly active as recent
 entrants in the club of LNG importers. The past years have therefore seen significant activity from
 Malaysia's Petronas, notably in Canada, Singapore's Pavilion and Thailand's PTTEP in East Africa.

LNG contracted by Asian countries

Another important aspect is how LNG from these four regions has been contracted and by whom. Australia and Russia are already LNG exporters, while this is not yet the case for North American (if one excludes the Kenai project) and East African countries. A distinction should therefore be made between existing contracts and those attached to future projects. Future projects are those currently under construction in Australia, as well as potential Australian projects, and all longterm agreements concluded so far in the three other regions.

In examining firm contracts versus total capacity, some striking differences appear among the four regions:

- Based on firm contracts, the most contracted projects are the Australian projects under construction. This does not come as a surprise, as these projects took FID a long time ago and needed these contracts to raise financing. Some 7 bcm of uncontracted LNG remains, whereas 76 bcm are already contracted. The United States takes second place for both firm or firm and preliminary contracts. They greatly outdistance potential Australian projects, Russia and Canada, while East African projects are not reported to have signed any firm agreements yet.
- The picture does not change significantly when looking at the firm and preliminary contracts: the United States reinforces its position, followed by Australia, Russia, East Africa and Canada.
- Existing LNG projects from Australia (NWS LNG, Darwin LNG and Pluto LNG) are already contracted at 90%. Japan and China are the historical buyers of these Australian LNG projects, with Japan dominant. Some of these contracts were recently renegotiateds and extended in 2009.

Similarly, 91% of Australian LNG under construction has been contracted under long-term contracts (Figure 20). The bulk of it, with the exception of small volumes to Chile and Mexico accounting for 6% of the capacity, is going to Asian countries, especially Japan and China.

Regarding the new volumes, distribution is more diversified with some of this LNG contracted by India, Korea, Chinese Taipei and Malaysia. Many companies are taking relatively small volumes, on the order of 1 bcm/yr to 2 bcm/yr, while others are taking more significant volumes of 4 bcm/yr to 5 bcm/yr. Some uncontracted volumes remain, notably due to Kogas having cancelled some long-term agreements with Gorgon and Wheatstone.

Page | 40 However, potential Australian projects which have not yet taken FID are still largely uncontracted: the only volumes contracted stem from the Arrow LNG project from Shell and PetroChina; both companies had planned to take the entire volume, but this project looks now uncertain to proceed. Other potential Australian LNG projects have no long-term contracts attached.

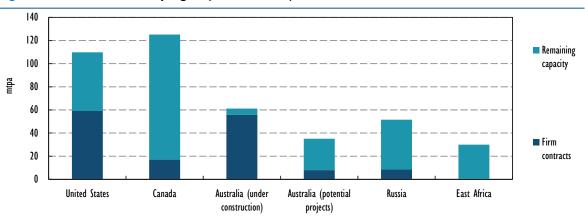


Figure 20 • LNG contracted by region (firm contracts)

Notes: Potential Australian projects include Arrow LNG, Pluto LNG train 2, Gorgon LNG train 4, Sunrise FLNG, Bonaparte FLNG and Browse FLNG.

Russian projects include Yamal LNG, Sakhalin-1 LNG, Vladivostok, Sakhalin-2 (expansion) and Baltic LNG.

US projects include Sabine Pass, Freeport LNG, Cameron LNG, Lake Charles, Cove Point, Jordon Cove, Oregon LNG, Corpus Christi and Magnolia LNG.

Canadian projects include Kitimat LNG, BC LNG, LNG Canada, Pacific NorthWest LNG, Prince Rupert LNG, WCC LNG, Woodfibre LNG Export, Triton LNG, Aurora LNG and Goldboro LNG.

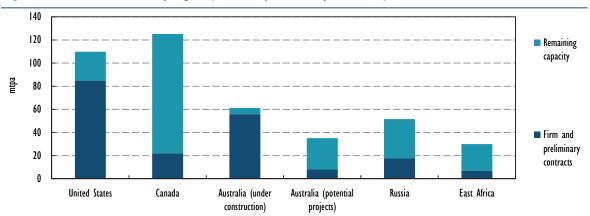


Figure 21 • LNG contracted by region (firm and preliminary contracts)

Notes: Potential Australian projects include Arrow LNG, Pluto LNG train 2, Gorgon LNG train 4, Sunrise FLNG, Bonaparte FLNG and Browse FLNG.

Russian projects include Yamal LNG, Sakhalin-1 LNG, Vladivostok, Sakhalin-2 (expansion) and Baltic LNG.

US projects include Sabine Pass, Freeport LNG, Cameron LNG, Lake Charles, Cove Point, Jordon Cove, Oregon LNG, Corpus Christi and Magnolia LNG.

Canadian projects include Kitimat LNG, BC LNG, LNG Canada, Pacific NorthWest LNG, Prince Rupert LNG, WCC LNG, Woodfibre LNG Export, Triton LNG, Aurora LNG and Goldboro LNG.

Page | 41

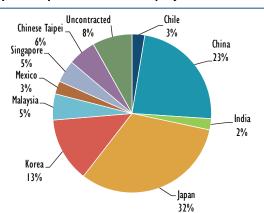


Figure 22 • LNG contracted by country in Australian LNG projects under construction

- As for Russia, not all the LNG of the projects moving forward has been sold: only 17% of the Russian LNG has been sold as of October 2014 under firm contracts. There is more diversity for Yamal LNG, as a portion of LNG from the project is expected to go to Europe and Gazprom Marketing and Trading (GM&T) has also contracted some of the gas without specifying its ultimate destination, which is expected to be Asia. Taking preliminary deals into account, 34% of Russian LNG has been contracted (Figure 21). This includes a reported offtake by Total of some Yamal LNG volumes, as well as Rosneft deals with Vitol, Marubeni and SODECO.
- US LNG is quite complex to analyse due to the number of projects and their different status. Of the six projects which were granted the US Department of Energy's (DOE) approval to export to non-FTA countries, 54% of this LNG had been contracted under firm long-term contracts as of October 2014. This number increases to 77% when taking into account the preliminary agreements. It is important to note the large quantities taken by aggregators, which are anticipated to arbitrage between the different markets depending on the price signals.
- Canadian projects remain largely uncontracted: only 14% of the 125 mtpa has firm long-term contracts. This figure only rises to 18% when taking preliminary deals into account. This reflects the difficulty of combining relatively high capital costs with an insistence on oil indexation for Canadian projects. Interestingly, one Canadian project is aiming at the European gas market.
- East African LNG projects are less advanced, and so far only a few non-binding contracts have been signed, all of which target Asia. But in the absence of concrete LNG projects, it is impossible to estimate the percentage of LNG contracted.

The forecasted overtake of Qatar by Australia as the world's largest LNG exporter by 2020, and the rise of the United States and possibly Canada and East Africa as LNG exporters illustrates the shift in the market shares of NOCs in gas-exporting countries in relation to IOCs. Until the late 2010s, it was expected that the NOCs would be able to keep increasing their share in the global LNG market. But among the main regions analysed later in this report (North America, Australia, East Africa and Russia), only Russia features the strong presence of NOCs, while IOCs, alongside buyers, dominate in the other regions. Through already-signed, long-term contracts, the IOCs will be able to maintain and increase their strong position in Asia.

Some IOCs may be keener to offer more flexibility in long-term contracts or be the source of flexibility themselves by taking some equity gas that they then market to different places. Recent contracts signed by companies such as BG and BP show that they are increasingly looking at optimising their global portfolio in view of changes on the supply and demand sides. But as previously mentioned, in Asia even FOB contracts contain restrictive conditions that can put buyers at a disadvantage in relation to the suppliers.

Box 3 • Asian LNG buyers' upstream Investment trend

Along with the growth in global LNG demand, there has been an increasing trend for many Asian LNG buyers to invest in upstream LNG projects in addition to purchasing LNG volumes. This phenomenon was observed in the past decade, notably with Japanese utilities investing in Australia: at least seven companies were involved in Australian LNG projects through the acquisition of small interests in the projects. Two of those projects are already operating and four are currently under construction. Considering that LNG projects are characterised by stable cash flow over a significant period, LNG buyers have opened the door to a new part of the LNG business and grasped an opportunity to be involved in the seller's world.

The history of upstream investment by Japanese utilities goes back to 1995, when Phillips Petroleum, now known as ConocoPhillips, discovered the Bayu-Undan gas-condensate field offshore in the Timor Sea within the Joint Petroleum Development Area, approximately 500 km northwest of Darwin, Australia. Since the discovery of the Bayu-Undan gas-condensate field and gas marketing process for the Darwin LNG project, the company successfully negotiated for LNG SPA in 2002 with two large Japanese utilities, TEPCO and Tokyo Gas. These two companies had been LNG buyers of ConocoPhillips' since receiving their first LNG cargo from the Alaskan Kenai project in 1969. But the commitment between the company and two LNG buyers was unusual, in that they not only agreed on LNG deals but also on a deal to welcome these buyers to jointly participate in the upstream project, including production and liquefaction. Finally, TEPCO and Tokyo Gas established a joint-venture company in Australia to take a 9.2% interest in the project and started their involvement in the upstream project as one of the joint-venture partners. This investment by Japanese utilities became symbolic in the LNG industry: the world's largest LNG importing country broke with the tradition of being just an LNG buyer to become a partner in the LNG project. Participation in LNG upstream projects by Asian LNG buyers has increased since the success of the Darwin LNG project, so that investment in upstream projects is becoming one of the recent trends for buyers when they negotiate LNG deals.

The question regarding the merits of buyers also becoming sellers as part of the upstream LNG project is whether this helps buyers to obtain better LNG deals. It is true that buyer participation in upstream projects is a benefit in terms of protection against price upswings, namely natural hedges. Whenever the LNG price goes up, buyers can expect a higher return of profit on the upstream side, and vice versa when the LNG price goes down. This mechanism will certainly reduce the buyer's risk whenever LNG prices are high.

In addition, the benefit of participating in upstream projects is the involvement in the development and the production phase of the project. By being project partners, buyers will obtain more real-time information regarding the project and have more ways to communicate with the project operator.

They could also learn the mechanics of the project and have a better understanding of the project's profitability. Moreover, buyer participation in upstream projects promotes closer communication between buyer and seller, building good relationships and maintaining the long-term contract's sustainability.

Another benefit for LNG buyers participating in upstream projects is their opportunity to sell LNG volumes in proportion to their equity interest, which is called equity lifting. Most of the SPA-contracted volumes are normally sold to the buyer under joint marketing arrangements by the project operator. Taking some equity in an upstream project offers an opportunity for buyers to be responsible for lifting and to sell their assigned equity volume of LNG on their own. This equity lifting could bring buyers to create their own SPA with free price setting and free destination. This new pattern for LNG trade would definitely contribute to the buyer's LNG procurement strategy.

Nevertheless, equity lifting is never easy and is not always beneficial. Unless the buyer takes large volumes of equity in an upstream project, equity-lifting volumes are usually quite limited and only account for a small percentage of the total contracted LNG volume. Additionally, equity lifting is time-consuming for buyers compared with joint marketing arrangements, since buyers have to handle limited volumes themselves, prepare their own SPA and co-ordinate their shipping schedule with the entire shipping schedule of the project. Also, price setting for their equity LNG has to be performed with concern for taxation.

Box 3 • Asian LNG buyers' upstream Investment trend (continued)

All countries are subject to taxation rules, so-called Transfer Pricing, so companies have to bear in mind that intra-group transactions should be independent and on an equal footing with market value. Otherwise, intra-group transactions with a lower market value price will incur a tax burden afterward. But overall, it is obvious that equity lifting is another good opportunity for buyers to tackle price setting of LNG on their own for the first time, and this opportunity undoubtedly came about as a result of upstream investment by buyers.

Investing in an upstream project also has downsides and associated risks for buyers. LNG projects are some of the most expensive and complex energy ventures in the world, entailing enormous capital expenditure. They can easily go over budget and encounter delays, or sometimes just sit idle for a long time with no investment decision taking place. Australian LNG projects are a good example where many Asian buyers invested in a number of projects and later had to face additional capital costs due to the cost overruns of, among other things, a labour shortage and volatile exchange rates. Moreover, in addition to requiring sizeable capital expenditures, the operational costs of LNG projects are considerable.

Upstream projects also involve technical risks. The oil spill accident which occurred in the Gulf of Mexico in 2010 is still fresh in the memory and considered to be one of the largest oil spill accidents in oil and gas history, causing casualties along with a massive environmental disaster. It is said that BP, the operator of this project, has paid more than USD 40 billion in damages and compensation, and the litigation continues. Risks are not only financial and technical; there are many associated risks when implementing an LNG project, such as the country risk, depletion of gas reservoirs and demand fluctuations. Accordingly, investment in upstream projects is for buyers who seek new challenges, but who are also ready to take risks.

In spite of all the risk factors, the trend of upstream investments by buyers is continuing. Although there is a move to scale back equity ownership, for example Kogas's attempts to sell some overseas assets in Australia and Canada, upstream investments have already become a business model with a strong position for Asian LNG buyers.

LNG pricing mechanisms

The pricing picture is evolving rapidly. As of October 2014, most US LNG is likely to be sold under some sort of HH indexation. It is worth mentioning, however, that significant volumes of LNG have been contracted by aggregators, whose sales behaviour is difficult to forecast. Some will sell the gas under long-term contracts to different companies based on their global portfolio, and therefore optimise between different LNG sources. Others may retain some LNG volumes to feed the markets where they operate and arbitrage between the different import regions, depending on pricing dynamics. In the event of a supply shortage in one region due, for example, to extreme cold weather, aggregators would benefit from higher margins. But in a situation like that of the summer of 2014 with low demand and a comfortable supply resulting in low spot prices, their margins would be considerably eroded, if not negative.

The picture is different in Canada, where the projects are greenfield, with higher capital costs and longer lead times. Project sponsors are offering oil-indexed pricing to potential Asian buyers in a move seen to reflect the projects' high capital costs, even though this is not quite in line with Asian buyers' preference for gas-indexed pricing. Only the Goldboro project located on the east coast of Canada offered E.ON a contract with LNG pricing based on the market prices of natural gas in the Western European market. In early 2014, Chevron warned Asian companies as well as other potential buyers seeking cheaper prices for Canada's LNG exports that the projects would not be built unless sales were indexed to oil prices.

Russia is known for its preference for oil indexation. Yamal LNG's first contract with CNPC is linked to JCC, but there is no information regarding the deal with Gas Natural Fenosa. The pipeline deal between Russia and China is also worth mentioning. There is very scarce information on the price level, which would be between USD 9.5/MBtu to USD 11/MBtu, according to various sources; the indexation is unknown. These relatively low gas prices will set a price floor for LNG supplies targeting China, even taking into account the cost of transporting the pipeline gas to cities. This cost is unlikely to exceed USD 2/MBtu.

Australian LNG projects are based on oil indexation, even though some uncontracted volumes mentioned earlier are likely to be sold as spot cargoes in Asia or Latin America.

Despite having no linkage to the US HH, it is anticipated that the LNG projects in East Africa are likely to have certain elements of HH pricing, considering the current trend by buyers towards HH-indexed pricing and competition with US LNG projects. In March 2014, Anadarko's CEO announced that its company had signed initial agreements with some buyers for its Mozambique LNG project based on a hybrid oil-indexed and HH-indexed pricing formula. Although expected, it is still considered a bold and interesting move from Anadarko, given no linkage between the project and the US gas index. There is no indication that any project in Tanzania has made a similar move.

Country	Pricing mechanism
United States	Spot-indexed (HH)
Canada	Oil indexation (likely to move to hybrid indexation)
Russia	Oil indexation
Australia	Oil indexation
Mozambique	Hybrid indexation
Tanzania	x (probably follows Mozambique)

			Ostahan 2014
Table 4 • Pricing mechanisms	s prevailing amon	g Live suppliers	, October 2014

Note: x = not applicable.

Page | 44

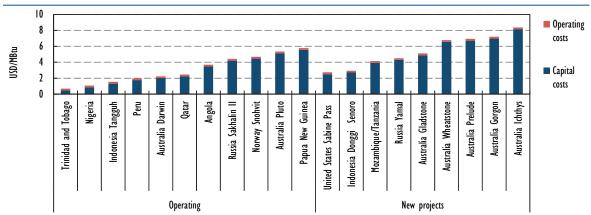
Break-even cost analysis

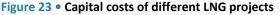
Liquefaction's capital costs

The project costs represent the size and difficulties of developing an LNG project and vary depending on several factors, such as the location of the liquefaction plant, distance from the feed-gas supply sources to the processing facilities, the design of the plant, the environmental conditions of the plant site, gas qualities, the technical or regulatory challenges of the gas fields, the availability of skilled labour, the construction period before operation, and the currency exchange risk. Upstream conditions such as gas quality or the availability to enhance profitability with liquids also have a major impact. The timing of the project's development is also an important factor, and economies of scale do not always help to reduce project costs. The projects under construction will bring large volumes of additional LNG to the global market, but this does not necessarily mean that the production cost is low. Moreover, global LNG development costs have more than doubled since 2003.

An assessment of the costs in the LNG chain can be made by calculating the costs in US dollars per million British thermal units. The capital costs are annualised assuming an investment period of 25 years and a discount rate of 8%. The liquefaction plant is assumed to be utilised at 90% of its maximum designed capacity. The operational costs are determined by a maintenance cost of USD 0.2/MBtu, plus a boil-off of 1% during liquefaction, priced at the local wellhead gas price. The revenues of liquids have not been taken into account, but it is recognised that they can significantly improve some projects' economics.

Most projects over the past decade had been relatively cheap to develop. The source of these projects was production from conventional gas fields, limiting project complexity. In contrast, newer projects are more expensive: Angola LNG and Russia's Sakhalin are respectively 50% and 75% more expensive than Qatar. The higher costs can be attributed to the greenfield nature of the projects and the environmental and regulatory difficulties. Norway's Snøhvit is almost twice as expensive as Qatar's LNG projects, and Australia's LNG projects are more expensive due to their greenfield nature. The Pluto project reached FID in 2007 and was initially planned to be completed by end-2010, but the first train was completed only in May 2012. As a consequence, the project costs increased from USD 11 billion to USD 15 billion, or about USD 5.4/MBtu.





Most Australian projects still under construction have even higher costs, up to USD 8/MBtu, and the three CBM-to-LNG projects adjacent to each other on Australia's east coast face cost overruns. The similar timing and location of the projects changed the initial decision of "no co-operation or co-ordination between the projects", to consolidation of gas pipelines that feed the gas for Gladstone and QCLNG in order to reduce costs. Santos expects further co-operation among the three CBM-to-LNG projects in Queensland, which also include Australia Pacific LNG. The total combined projects behind the LNG export terminal in Gladstone add up to USD 62 billion at a combined capacity of 21.3 mtpa. The costs per volume are reduced by its large capacity, but are still high at USD 5.1/MBtu. Gorgon saw a cost increase of USD 17 billion (or 46%) to USD 54 billion, up from the original estimate when the project was approved in 2009, due to soaring labour costs, bad weather and the appreciation of the Australian dollar. This implies a cost of USD 7.2/MBtu, or almost three times the cost of Qatar LNG. Based on this calculation method, the most expensive project is Ichthys LNG, where costs are now estimated at an astonishing USD 34 billion for 8.4 mtpa, or USD 8.4/MBtu. However, this does not take into account the production of liquids of this project.

In East Africa, LNG projects are still at the planning stage in Tanzania and Mozambique, after considerable finds were announced over the past four years. Currently, in both countries, two trains of 5 mtpa each are initially expected and could be expanded thereafter. The cost estimates are at USD 15 billion for two trains, which is still a very preliminary estimate. The relative attractiveness can be explained by having conventional gas fields, which can also add to the attractiveness of East African LNG projects; the massive size of the gas fields can also contribute to a further reduction in unit cost. But the projects are not only greenfield in technical terms, they are also greenfield from a regulatory and manning perspective. This adds the risk of project delays, and hence indicates potential project cost overruns. This assessment assumes that the project will finish 30% more expensive than planned. Accordingly, a price level of USD 4.2/MBtu is calculated, making the projects' costs comparable to those of Angola LNG and Sakhalin, but still much lower than those of the Australian projects.

The FID in December 2013 for Russia's Yamal LNG export terminal showed a cost of USD 27 billion, already more than a third higher than its earlier estimate of USD 20 billion. The harsh climatic conditions on this peninsula that is called "the end of the world" in the local language, could be a basis for further cost overruns similar to, for example, the Sakhalin project. Even while assuming an additional 30% increase of costs when the plant becomes operational, Yamal LNG would cost only slightly more than the estimated East African projects and be considerably less expensive than its Australian counterparts. Applying the methodology to calculate cost per unit of energy, Russia's newest LNG project would cost about USD 4.5/MBtu.

The Canadian project to export LNG from Kitimat on the Pacific coast is interesting. The capital cost for the liquefaction plant alone would not fully reflect the real costs, as it also requires the development of an extensive pipeline system to the existing gas fields much further inland. It is therefore estimated that its costs would be in line with other projects of this nature, like the average cost for Australia's Gladstone project. Although Gladstone is special, as it is based on CBM, the needed investments in the onshore pipeline are much larger in Canada. Hence, it is assumed that both projects would be developed at the same cost of about USD 5/MBtu.

Box 4 • Factors affecting US LNG project costs

Despite the big wave in greenfield projects, brownfield projects are logically cheaper. For example, take the Sabine Pass: the US projects have no particular feed-gas field dedicated to LNG production, but the entire US gas market is its supply source. Therefore, it needs no capital investment in upstream development or transmission pipelines. Rather, these projects help foreign customers buy gas from the market, liquefy it and ship it overseas. Additionally, LNG regasification facilities already exist at the Sabine Pass site, so only the liquefaction plant is still required. In this regard, Sabine Pass's capital costs seem to be very competitive at USD 5.6 billion for 4.5 mtpa, or USD 2.8/MBtu. Consequently, it is the least costly of the new LNG projects, at almost one-third the cost of the Gorgon LNG project.

However, costs in the United States are based on a new business model. In this new model the capital costs are set through a fixed levy. Depending on the contract, these levies are a separate use-it-or-lose-it charge of around USD 3.00/MBtu, and can increase over the years to adjust for inflation. Furthermore, there is a tolling fee of 15% on top of the HH price to cover the costs of pipeline transport from the fields to the terminal before it is shipped as LNG.

LNG transport costs

LNG shipping costs influence the flows and prices of LNG cargoes. Shipping costs are a key driver of the value created by moving gas between locations, and the price is spread among regions in the global LNG trade. Transport costs are therefore an important element in determining the extent to which global gas prices may converge in the future. With many new LNG projects under construction, the LNG flows around the globe could be shifting. While shipping costs are an important element in LNG flows, the expectations on the costs of new projects (like the cost overruns in Australia) and new contract structures (for example, US LNG) are assessed to determine the price needed for these new LNG cargoes to reach the Asian markets.

Who pays the costs depends on the contracts and the parties involved. In a destination ex-ship (DES) contract, it will be the supplier who incurs all the shipping cost, whereas in an FOB contract, it is covered by the consumer or trader. Large LNG portfolio players could reduce shipping costs by optimising their tanker fleet.

Shipping costs

Shipping costs consist of four components: the daily rate for the tanker, the fuel cost, the small losses resulting from boil-off, and the costs for berthing at the ports.

The daily rates for tankers for LNG spot trading started to rise after mid-2010 as the shipping market for conventional-sized LNG tankers began to tighten due to increasing LNG demand (mainly driven by the Asia-Pacific region and amplified by the call for large LNG imports in Japan after the Fukushima accident) and longer average tanker distances, making the tankers less available. After peaking at almost USD 150 000 per day in 2012, the incremental demand for spot cargoes began to decrease due to more available shipping capacity, as well as declining LNG output in 2012 and almost stable LNG trade in 2013. This caused prices to drop, which were further pushed down by the large expansion of the tanker fleet and narrowing of the west/east arbitrage window. As of July 2014, the shipping rate was less than half of its peak at USD 65 000 per day for a tanker carrying 130 000 cubic metres (m³) (the equivalent of 3 000 000 million British thermal units). Figure 24 shows the evolution of shipping rates from January 2011 to May 2014.



Figure 24 • Evolution of daily shipping rate for LNG spot cargoes

Box 5 • The Panama Canal

Note: USD thousand/d = thousand US dollars per day.

The expansion of the Panama Canal is likely to have a beneficial impact on shipping rates once it is completed in 2016, allowing conventional-sized LNG vessels to pass more easily between the Atlantic and Pacific Oceans, depending on the transit fees charged. Over the last decade, LNG trade has been shifting from the Atlantic Basin towards Asian markets. Although the increasing demand in Asia is expected to remain a key driver in global LNG flows, the Atlantic Basin is gaining interest again. The increasing demand for LNG in Latin America increases the possibility to gain from arbitrage between destinations, which contributes to the creation of a more global LNG market. This trend towards a global LNG market could be enforced by the cut in global shipping distances when the widened Panama Canal is opened. The USD 5.25 billion project to expand the Panama Canal is currently under way and will allow the transportation of 90% of the LNG vessels when it is completed in 2016. Only the biggest Q-Flex and Q-Max ships will not be able to cross the canal.

Nevertheless, the first few years from 2016 will be crucial to the LNG market, as the impact of expansion will hinge upon how the Panama Canal Authority addresses the current constraints on transit scheduling, night-time movement and simultaneous transit of LNG vessels from opposite directions. If only one LNG vessel is allowed to transit the expanded canal under the current circumstances, US LNG volumes will be limited to only 30 bcm/yr – about 60 bcm less than the total volumes approved from the Gulf Coast LNG projects at the moment.

The boil-off cost is unique to the LNG industry. A small portion of LNG cargo evaporates while it travels across the oceans; it is extremely difficult to avoid any evaporation loss. However, thanks to advanced technologies, the evaporation loss can be kept below 0.2% of the volume per day of a loaded tanker during its delivery journey. On the return journey, with some 5% of the LNG left in the tanker, there is also slight evaporation. The volume evaporated per day is less over larger distances as the volume in the tanker decreases. Nevertheless, on a round trip, the evaporated volume amounts to about 0.2% per 1 000 km of distance shipped. The evaporation loss causes the so-called boil-off cost, as less gas is available to sell at the destination.

The cost of the fuel is a key component of the total shipping cost, and it is heavily dependent on fuel prices. At current prices of around USD 600/tonne (USD/t) and an estimated consumption rate of 160 tonnes (t) of bunker fuel per day for a loaded tanker (compared to 50 t per day when berthed in a port), the fuel component could add up to half of the total cost on a round trip from Qatar to Spain.

Finally, **the cost for berthing in ports** is estimated to be on average USD 200 000 per port per day. These costs represent a very large factor for short shipping routes.

Other costs

The total cost for shipping LNG from an export terminal to a consumer region is not only determined by the shipping rate, fuel costs, port fees and distance, but also by additional costs that depend on the chosen route. Crossing the Suez Canal is estimated at a tariff of USD 650 000 for a round trip using a 130 000 m³ LNG tanker, or USD 0.22/MBtu. For the routes based on a Panama Canal crossing, a similar fee is estimated, as the exact price is not yet available.

Another potential new route for LNG tankers is the Arctic Ocean as its ice cover opens. The first LNG tanker to travel this route was the Russian ship Ob River in 2012, going from Norway to Japan. This trip is only one example of the increasing shipping traffic through this route, which is most feasible in summer. Nevertheless, ice breakers are still required, adding to the costs of taking this route. The Russian Northern Sea Route Administration gives rates of about USD 16/t of cargo for ice breakers to escort ships, depending on the LNG tanker's size, distance and ship strength. For an LNG tanker that could carry 130 000 m³ of LNG, the cost for breaking the ice would be USD 0.31/MBtu. Furthermore, the average speed to follow the Arctic route is much lower than the 18 knots on the usual sea lanes. The Ob River in 2012 showed a speed of almost 13 knots, which could serve as a reference for future shipping on this route. Furthermore, due to the greater resistance from ice floes in the shipping lane, the fuel cost is assumed to increase by 10%.

Comparing the expected new LNG exporting regions with the Asian demand centres, as shown in Figure 25, the LNG shipping costs vary considerably, from below USD 1/MBtu to as high as USD 4/MBtu. The following points have been chosen as reference points: Shanghai for China, Dahej for India, and Tokyo for Japan and Korea.

For China, the closest would be Australian Northwest Australian projects like Gorgon, at a distance of 3 300 nautical miles (NM), implying a shipping cost of just over USD 1/MBtu. Projects like Gladstone LNG on Australia's eastern coast are a little more expensive due to the larger one-way shipping distance of 4 100 NM. Canadian projects would result in shipping costs of USD 1.6/MBtu, compared to USD 2/MBtu for East Africa. The most expensive would be US LNG projects going through the widened Panama Canal at just over USD 3/MBtu due to the shipping distance of over 10 000 NM, still 3 800 NM less than the trip through the Suez Canal. Despite the considerably shorter distance from Russia's Yamal, (6 000 NM) the shipping cost to China from Yamal is only slightly lower than from the United States, at just over USD 3/MBtu due to the different circumstances on the Arctic route Alternative routes of transporting LNG to China, to either avoid the Panama Canal or the Arctic, would add up to USD 4 to 5/MBtu, illustrating the strategic importance of both routes for China.

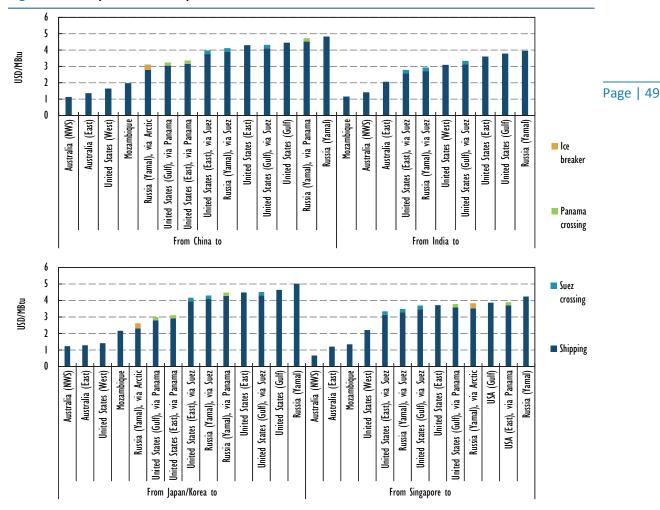


Figure 25 • Comparison of transport costs

For India, East African LNG projects in Tanzania and Mozambique are the closest, with shipping costs of just over USD 1/MBtu. Interestingly, the cost of shipping LNG from the United States to India depends on the location of the export terminal. From Sabine Pass at the Gulf coast, the shipping costs are the lowest on the Eastern route through the Suez Canal, while Jordan Cove is less expensive, crossing the Pacific Ocean. So, as India is located at a shipping distance of more than 10 000 NM from the United States (except from the US East Coast), the corresponding costs are high, at around USD 3/MBtu. Shipping LNG to India from the North American projects in the Gulf and on the Pacific coast is even more expensive than shipping LNG from Yamal to India through the Suez Canal, which comes to USD 2.7/MBtu.

The projects in the Pacific basin are all at about the same distance from **Japan** or **Korea**, of about 4 000 NM, giving shipping costs of about USD 1.3/MBtu from Australia and the west coast of North America, while US Gulf projects could reach Japan and Korea at about USD 3/MBtu through the Panama Canal. The distance of East Africa to Japan and Korea is the largest within Asia, at a cost of just over USD 2/MBtu, or twice as high as to India. Shipping Yamal LNG to Asia via the Arctic route is least costly to Japan and Korea, as it is the shortest route. Even including the additional costs on the icy route, the shipping costs are USD 0.4/MBtu lower than from the Gulf and US East Coast.

Singapore has the best geographical location for the Northwest Australian projects, with a distance of only 1 700 NM (USD 0.7/MBtu). Shipping East African LNG to Singapore is almost twice as expensive, while North American west coast LNG is carried at almost three times this price. The same costs account for shipping Yamal LNG to Singapore. It is interesting to note that

the US Gulf and East Coast projects, as well as Yamal LNG, could arrive in Singapore all within a shipping cost range of USD 3.3/MBtu to USD 3.9/MBtu, giving it from a shipping point of view a good arbitrage position between different sources.

Total costs

- Page | 50
 - Besides the project costs to make LNG and ship it to its destination, there are regasification costs. These costs vary across the regions and range between USD 0.7/MBtu to USD 0.9/MBtu, with European and Japanese regasification on the higher side, while other Asian plants are on the lower side of this price range. Adding up all costs, at what price could LNG be supplied to the Asian consuming regions?

То	To Europe (NW)		Eu	rope (S	W)	Europe (SE)				Japan	/Korea		
From	Direct	Via Suez	Via Panama	Direct	Via Suez	Via Panama	Direct	Via Suez	Via Panama	Direct	Via Suez	Via Panama	Via Arctic
United States (Gulf)	1.6			1.7			2.0			4.6	4.5	3.0	
United States (West)	4.1		2.8	4.0		2.8	4.3	4.0	3.1	1.4			
United States (East)	1.2			1.3			1.6			4.5	4.2	3.1	
Canada	4.3		3.0	4.2	4.2	3.0	4.5	3.9	3.3	1.3			
Norway	0.6			1.1			1.4			4.6	3.9	4.1	3.0
Nigeria	1.4			1.3			1.6			3.2			
Angola	1.6			1.4			1.7			3.1			
Tanzania	2.5	2.3		2.4	1.8		2.7			2.2			
Mozambique	2.5	2.3		2.3	1.8		2.6	1.5		2.2			
Algeria	0.7			0.3			0.6			4.1	3.1		
Egypt	1.1			0.6			0.4			4.5	2.7	4.3	
Papua New Guinea	4.0	3.5	4.1	3.8	3.0		4.1	2.8		1.2			
Middle East	3.3	2.2		3.2	1.7		3.5	1.4		2.0			
Malaysia	3.6	2.9		3.5	2.5		3.8	2.2		0.9			
Indonesia	3.6	3.1		3.5	2.6		3.8	2.3		0.9			
Australia (NWS)	3.4	3.1		3.2	2.6		3.6	2.3		1.2			
Australia (East)	4.0	3.7	4.0	3.8	3.3	4.0	4.1	3.0	4.3	1.3			
Russia (East)	4.3	3.6	3.9	4.2	3.1	4.0	4.5	2.8	4.3	0.5			
Russia (Yamal)	1.0			1.5			1.8			5.0	4.3	4.5	2.6
Trinidad	1.3			1.3			1.6			4.0	4.1	2.9	
Peru	3.0		2.2	2.9		2.2	3.2		2.5	2.6			

Table 5 • Shipping rates (USD/MBtu)

То		Ch	ina			Sing	apore			Brazil			In	dia	
From	Direct	Via Suez	Via Panama	Via Arctic	Direct	Via Suez	Via Panama	Via Arctic	Direct	Via Suez	Via Panama	Direct	Via Suez	Via Panama	Via Arctic
United States (Gulf)	4.5	4.3	3.2		3.9	3.7	3.8		1.7			3.8	3.3		
United States (West)	1.6				2.2				2.7		2.6	3.1			
United States (East)	4.3	4.0	3.4		3.7	3.3	3.9		1.5			3.6	2.8		
Canada	1.6				2.1				2.9		2.8	3.0			
Norway	4.4	3.7	4.3	3.3	3.9	3.1		4.2	2.0			3.8	2.7		
Nigeria	3.0				2.5				1.2			2.4			
Angola	2.9				2.3				1.2			2.2			
Tanzania	2.0				1.3				1.7			1.1			
Mozambique	2.0				1.3				1.7			1.2			
Algeria	3.9	2.9			3.3	2.3			1.5			3.2	1.9		
Egypt	4.3	2.5			3.7	1.9			1.9			3.6	1.5		
Papua New Guinea	1.2				1.0				2.8			1.9			
Middle East	1.8				1.2				2.5			0.6			
Malaysia	0.7				0.4				2.8			1.3			
Indonesia	0.8				0.5				2.8			1.4			
Australia (NWS)	1.1				0.7				2.6			1.4			
Australia (East)	1.4				1.2				2.6			2.1			
Russia (East)	0.5				1.0				3.5			1.9			
Russia (Yamal)	4.8	4.1	4.7	3.1	4.2	3.5		3.8	2.4			4.0	2.9		5.0
Trinidad	3.9	4.0	3.1		3.3	3.3	3.7		1.1			3.2	3.0		
Peru	2.9				3.2				1.5			3.9		3.6	

Table 5 • Shipping rates (USD/MBtu) (continued)

Figure 26 shows that the US LNG exports are among the highest of all new LNG options. But it should be noted that these exports are based on the new business model, so these costs represent both the minimum price at which it could reach its destination, as well as the final price (an HH price of USD 4.5/MBtu is assumed). The other projects, by comparison, offer only a theoretical minimum price to cover all the costs in the value chain; the consumer price is based on other parameters such as oil price linkage or on spot LNG prices. Nevertheless, the comparison shows a potential minimum price needed to make the projects break even.

The total cost throughout the LNG chain is lowest for East Africa, and these two projects already include an estimated cost overrun of 30%. The lowest costs for these projects are then determined by the shortest shipping route, which is to India, at about USD 6/MBtu. In other words, this is the minimum price to cover increasing demand in India through new LNG supplies. Other sources come at a higher price, ranging from more than USD 8/MBtu from Canada to USD 10/MBtu from Australia. US LNG would be available in India at USD 12/MBtu, or double the cost of LNG from East Africa.

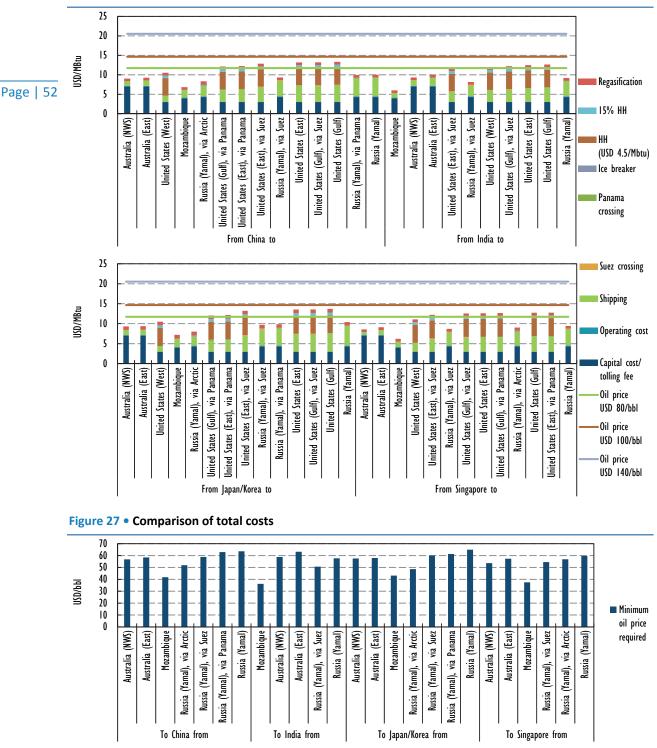


Figure 26 • Comparison of total costs

Interestingly, the cost advantage of shipping to Asian markets from Australia compared to from other new LNG exporters is offset by Australia's larger capital costs. To put it differently, the margins to be made on this LNG are lower than on that from East Africa and Russia's Yamal, which are both estimated at a 30% cost overrun, and from Canada. Nevertheless, the large cost overruns of the Australian projects still show a competitive edge for US LNG on a cost basis, with the lowest-costing Australian gas going to Singapore at USD 7.4/MBtu, compared to the lowest-costing US LNG going to Japan at USD 10.5/MBtu.

Box 6 • Comparing shipping costs to regions other than Asia

While Asia is the largest LNG importing region, other importing regions such as Europe or Latin America could occasionally divert gas away from Asia. Therefore, the comparison of the total costs for LNG from future suppliers is not only a question of route, since Latin America is increasingly buying LNG and paid as much as Asian buyers in winter 2013-14, while some of the fuel is still shipped to Europe. So how do the prices to Asia compare with the other LNG importing regions?

The integral costs of supplying LNG to Latin America and Europe are compared here with the lowest and highest integral costs to the Asian importing regions. The lowest integral cost to all importing regions in Asia is the LNG from East Africa, while the highest is from eastern Australia. The comparison is extended to US LNG exports, because these total costs represent the price to be paid, rather than a minimum cost level.

To simplify the comparison, it is assumed that the widened Panama Canal and the Arctic route are available at the time the new projects start exporting LNG. To limit the total number of routes, Europe is represented by the northwestern LNG import region in the North Sea where Belgium's Zeebrugge terminal, the Dutch Gate terminal in Rotterdam and the United Kingdom's Isle of Grain terminal are located. For Latin America, the port of Rio de Janeiro in Brazil is chosen as a reference for the continent's LNG imports. Finally, East Africa is represented by the project in Mozambique, as similar costs and distances apply for its neighbouring Tanzanian LNG project.

As expected, the supplies from eastern Australia to Europe and Latin America show higher integral costs than those from East Africa. Shipping Gladstone LNG to Europe is more expensive than to Latin America because of the large shipping distance, covering half the globe. There is little difference among the three possible routes to Europe (Suez, Panama and Cape of Good Hope), making total costs almost USD 12/MBtu. Gas can be delivered to Latin America at a cost of USD 10.5/MBtu, lower than to Europe but still higher than the USD 9.1/MBtu to Singapore (the lowest integral cost from eastern Australia to Asia) or USD 10/MBtu to India (the highest to Asia).

East Africa is the best-placed region from which to reach all importers at the lowest cost. In addition, with integral costs from East Africa to all LNG importing regions in the range of USD 6/MBtu to USD 7.2/MBtu, East Africa presents interesting arbitrage opportunities, especially when the supplies are delivered FOB. The lowest integral costs to Asia is to India, at USD 6/MBtu, while Japan showed the highest at USD 7.2/MBtu. To Europe, the least costly route from East Africa is via the Suez Canal. But despite the 300 NM-shorter route to Europe than to Japan, the costs for the Suez Canal crossing make the total the same, at USD 7.2/MBtu. The integral costs to Latin America amount to USD 6.5/MBtu, higher than to India and Singapore, but lower than to China and Japan. Interestingly, the total costs to Latin America are the same as to southeastern Europe (Turkey).

The costs for supplying Russia's Yamal LNG to Europe are estimated at USD 6.3/MBtu, or just over the lowest cost to Asia between East Africa and India (USD 6/MBtu) and East Africa to Latin America. This shows from a lowest-cost point of view that Russia's LNG is well located to supply Europe.

The US projects show the real price depending on the HH price level, which is here assumed at USD 4.5/MBtu. For the US Gulf projects, prices to Latin America and Europe are equal at USD 10.6/MBtu, while the prices to the Asian markets are in the range of USD 12/MBtu (to Japan via the Panama Canal) to USD 12.6/MBtu (to Singapore via the Panama Canal). Supplies from the east coast show a similar pattern, although Europe is slightly closer and thus less expensive than shipping to Latin America. The US West Coast, however, is different. Prices to China and Japan stand at about USD 10.5/MBtu, equal to the costs to Latin America (which includes a Panama Canal crossing). Delivering this LNG to Europe would cost USD 11.8/MBtu, being less expensive than to India (USD 12/MBtu), but more expensive than to Singapore (USD 11.1/MBtu). As the US LNG export contracts will be on a FOB basis, the supplies from the Gulf and East Coast projects could stay in the Atlantic Basin, where they could replace the currently higher-priced spot cargoes.

Compared to the United States, the Canadian projects would be based on oil-linked prices rather than linked to a gas hub, and the minimum price of its LNG to cover its costs is much lower than the total price of US LNG. So despite the larger investments due to the distance to the gas fields and the rest of the Canadian market, Kitimat LNG could be competitive from a cost perspective with US LNG projects. The competitiveness of Canadian LNG is robust across the consumption areas in Asia, whether it is China, Japan or Singapore.

Page | 54

Traditional LNG projects are mostly based on long-term contracts with an oil-linked price. The total costs expressed in an oil price indicate the minimum oil price level at which LNG could be supplied through a traditional oil-linked DES contract. Figure 27 shows that East African LNG projects are still very viable at low oil prices. It is the contrary for most other new LNG projects, which seem to be based on much higher minimum oil prices, ranging from USD 45/bbl for the Canadian project, up to over USD 60/bbl for Russia's Yamal. That some projects start at a higher oil price might indicate that companies expect oil prices to remain rather high. Given an oil price of around USD 100/bbl (or about USD 15/MBtu), the oil-linked price shows a large margin to be made on the most expensive projects, while first losses would occur when the oil price drops below USD 60/bbl, or USD 9/MBtu.

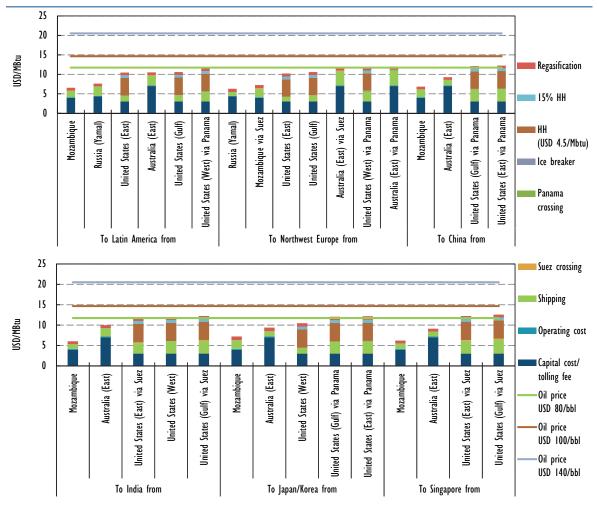


Figure 28 • Comparison of total costs to different LNG importers

North America

The supply picture

Where North America stands in the global LNG market

Page | 55

North American LNG exports have been limited so far to Kenai LNG exports, an LNG facility located in Alaska and which had been exporting LNG since 1969 and was temporary mothballed during 2013. LNG exports have been usually hovering between 0.5 bcm and 2 bcm, a very small part of the global LNG trade (less than 1%). But the total planned capacity for North American LNG exports (United States and Canada) stands today at more than 500 bcm/yr, more than half of the region's current gas production.

North American LNG export projects, in particular those of the United States, are today seen as a crucial source of new LNG supplies, potentially triggering changes in the world gas market by challenging the existing pricing system, as well as serving as a model for other would-be producers such as East Africa. But for this to happen, volumes exported under HH gas indexation need to be significant and competitive with prevailing oil-indexed LNG volumes from other suppliers. The investments made or currently being discussed by Asian companies in this region could therefore change the supply picture.

As of October 2014, only one single US LNG plant (Cheniere's Sabine Pass LNG project), representing roughly 20 bcm of annual supply, was under construction. This would not be enough to trigger changes on global gas markets; however, the six projects which have been approved by the DOE as of mid-2014 (including Sabine Pass) should bring roughly 90 bcm to global gas markets by the beginning of the next decade, compared to an expected global LNG trade of 500 bcm (IEA, 2014a). In contrast, despite a significant political backing, no Canadian project had moved forward in taking FID as of October 2014.

	China	India	Indonesia	Japan	Korea	Malaysia	Singapore	Chinese Taipei	Thailand	Viet Nam
				U	nited State	S				
Upstream	~	~	x	~	~	х	x	x	x	x
LNG	х	х	x	~	х	х	х	X	х	х
Contracts	х	~	~	~	~	х	х	х	х	х
					Canada					
Upstream	~	~	x	~	~	~	x	X	х	х
LNG	~	х	x	~	~	~	х	X	х	х
Contracts	~	~	x	~	~	~	х	X	х	х

Table 6 • Investments of Asian companies in the United States and Canada

Note: \checkmark = investments have been made; X = investments have not been made.

When looking at the North American gas supply picture, it is very important to differentiate between the United States, Mexico and Canada. Mexico is still a net gas importer and does not plan to export any gas at the moment, even though it has large shale gas resources. The difference between the two other countries is quite striking: US gas production increased by over 110 bcm since 2008 to approach 700 bcm, while Canada's gas production dropped by 30 bcm to 155 bcm. US gas production is still below its domestic demand, while Canada is still a net exporter of gas, with exports aimed only at the United States. The United States could very well have remained a pipeline export country, exporting more gas to Mexico and Canada and feeding its own demand growth, but the existing underutilised LNG import infrastructure, coupled with the high differential between US and Asian prices, has triggered interest in developing LNG export plants. To this one must add the recent tensions between Russia and Europe and the idea of decreasing Europe's dependency on Russia in exchange for North America gas. Meanwhile, Canada's exports to the United States have declined, with little potential for increase; finding new export outlets has become a necessity. Given Canada's geographical position, the only alternative is LNG exports. Canada is also closer to Asian markets than the US Gulf coast.

Page | 56

Asian countries have taken different approaches to investing in the United States and Canada, as outlined in Table 6.

LNG projects

In the United States, many projects are based on existing LNG import capacity, making capital cost investments much lower. In Canada, projects are of a greenfield nature: the country has only one single LNG import terminal while the United States has around 200 bcm/yr of such capacity (the United States imported 3 bcm in 2013).

In both countries, LNG export plants must be formally approved by the authorities. In the United States, a double approval is necessary: from the DOE and from the FERC. As far as the DOE's approval is concerned, a distinction was made between exports to FTA and to non-FTA countries. For the latter, the DOE has to determine how the LNG exports would affect US interests, while approval for the former is much easier to obtain. A DOE approval costs around USD 20 000. The FERC approval, however, is more complex as it looks at all the environmental aspects and can cost up to USD 100 million. The FERC approves (or denies) an application for the siting, construction, expansion, as well as operation of any LNG export plant, according to the Natural Gas Act. The FERC also monitors all construction activities to make sure the companies involved comply with all permits, plans and regulations. Companies first have to engage in the pre-filing environmental review process, which gives federal and state agencies the opportunity to give comments. Then, companies can submit the draft resource reports as inputs for the environmental assessment and environmental impact statement. These reports touch on many issues, among which are water use, fish, wildlife, socioeconomics, land use, air and noise quality.

In May 2014, the US government completely changed the approval process for LNG export projects by putting the FERC's environmental review first; the DOE will only consider those projects which have completed this process. As of October 2014, a total of 400 bcm of LNG export capacity – around 60% of US LNG production – had applied for exports to FTA countries. Companies have applied to export around 370 bcm to non-FTA countries. Given that most LNG importers are non-FTA countries, it makes sense for companies to seek to export to a wide number of countries. Over the period May 2013 to September 2014, seven projects³ were authorised to export LNG to non-FTA countries, in addition to the DOE's previous authorisation of Sabine Pass in 2011. This means that around 109 bcm/yr of LNG export capacity has already been approved as of October 2014. Nevertheless, only four facilities had received the FERC approval as of mid-October 2014: Sabine Pass which is under construction, Cameron LNG, Freeport LNG and Cove Point, equating to around 66 bcm/yr. As of October 2014, two projects had taken FID – Sabine Pass and Cameron LNG. However, only Sabine Pass was under construction.

The caveat exists that the DOE can revoke the export licence any time if it deems that the project is no longer in the public interest. Nevertheless, the likelihood of this option being exercised is considered very remote, based on two reasons. First, it will be hard to prove the basis of "not in the public interest", and the DOE has also mentioned that it would not revoke an export permit except in the event of extraordinary circumstances. Second, most of the major LNG importers,

³ Freeport LNG had two applications for the same LNG plant, but different trains. This is considered as one project.

notably European countries, are in the midst of discussing FTAs with the United States and will no longer be subject to this condition, should they sign an FTA agreement. However, another component is still missing: the FERC approval, which can take considerable time given that it involves looking at all environmental aspects. Finally, building the project may prove harder than many think if the same trend of spiralling costs as observed in Australia also takes place in the United States, although it should be recalled that most projects are based at existing import terminals, with much gas transport infrastructure already in place.

Project	Non-FTA capacity (bcm/yr)	Major stakeholders	FID (expected)	DOE's approval	FERC's approval
Sabine Pass	22.5	Cheniere	Jul 2012	May 2011	Apr 2012
Freeport LNG	18.4	Freeport, Macquarie	2014	May, Nov 2013	Jul 2014
Lake Charles	20.4	Energy Transfer, BG	2015	Aug 2013	Pending
Cove Point	7.9	Dominion	2014	Sep 2013	Sep 2014
Cameron LNG	17.4	Sempra Energy	Aug 2014	Feb 2014	Jun 2014
Jordan Cove Energy	8.2	Veresen	2015	Mar 2014	Pending
Oregon	13.4	Leucadia National Corporation	2015	Jul 2014	Pending
Carib Energy	0.4	Crowley	2014	Sep 2014	Waived
Total	108.6				

Table 7 • US ING pr	ojects with DOF's appr	oval for non-FTA cou	ntries as of October 2014
	ojecto with DOL 5 appi		

Source: based on data from companies' websites.

Canada has outpaced the United States in its number of approved export applications. As of October 2014, 11 LNG projects, including US projects Jordan Cove Energy and Oregon LNG, have been approved by Canada's National Energy Board (NEB) while nine projects have been submitted and are under review. The last five projects, applications of 6 mtpa each, have all been submitted by the same company, Steelhead. The nine Canadian projects already approved represent an LNG export capacity of around 157 bcm/yr. Most projects are quite large, while three projects have a capacity of around 3 bcm/yr. However, the projects still require approval from the federal government and other provincial authorities, including the First Nations, before they can proceed with construction.

The two countries have different competitive advantages when it comes to building new LNG projects. Both have large gas resources, particularly of unconventional gas, and benefit from liquid and transparent gas markets based on spot markets, but the similarities stop there: an extensive gas infrastructure is already mostly in place to support the LNG export plants in the United States, while it remains to be built in western Canada.

In the United States, liquid and transparent gas markets allow the US projects to offer LNG contracts with HH-indexed pricing and no take-or-pay obligation, two items that are particularly attractive for Asian buyers. Those US projects are based on existing LNG receiving terminals that have been scarcely operational since the shale gas boom, and can be fed with existing infrastructure. This makes these projects very competitive against other conventional projects in terms of capital costs (see previous section). In the "tolling agreement", buyers will pay fixed capacity charges to the projects, and have the option to receive and ship LNG on their own to any destination as the LNG is sold on a FOB basis. A distinctive point is that there is no traditional take-or-pay obligation in the agreement. However, buyers must pay a fixed capacity charge even if they decide not to use their contracted liquefaction capacity but instead sell the gas on the domestic US market for economic reasons. These contracts could open up an opportunity for a new pricing scheme in the long term, challenging the traditional oil linkage. The capital cost for developing brownfield US LNG plants also contributes to the success of the country's LNG export industry. It remains to be

seen how greenfield projects such as Corpus Christi will compare in terms of costs. The projects which have received DOE or FERC approval so far are brownfield, while most of the rest are greenfield. The evolution of the Corpus Christi project, a greenfield project which has already sold most of its LNG, will therefore be interesting to observe.

Page | 58

Conversely, Canada faces the challenges of higher capital costs, an apparent insistence on oil price indexation, timing and environmental impacts. All LNG projects in the west coast are greenfield and will therefore require significant capital investment to develop the upstream part, build hundreds of kilometres of pipeline and build greenfield LNG plants. The relatively higher costs have caused some companies to pull back: in February 2014, Suncor announced that it had pulled out from the LNG race, while Petronas has reduced its stake in its project to 62% and is seeking to further decrease it to 50%. In February 2014, the government of British Columbia announced an LNG tax proposal, consisting of a two-tiered tax plan. Under the tax plan, LNG plants would be subject to 1.5% tax on their net income during the first tier, and the rate could be increased up to 7% during the second tier once the plants have recovered their capital costs. Companies warned the government of British Colombia, eager to take benefits from the upcoming LNG wave, not to dissuade companies with a high taxation rate for the second tier, and sought further clarification from the government before making FID. Kitimat LNG's project developers are offering oil-indexed pricing to potential Asian buyers in a move seen to reflect the project's capital costs. However, it is not in line with Asian buyers' preference for gas-indexed pricing. Chevron, the co-developer of the project, admitted there were issues with regard to the prices, but insisted that deviation from oil price indexation would make the project uneconomical.

Project	Capacity (bcm/yr)	Major stakeholders	FID (expected)	NEB's approval	Targeted online date
Kitimat LNG	13.6	Chevron, Apache	2014+	Oct 2011	2018+
BC LNG	2.4	LNG partners, Haisla First Nations	2014+	Feb 2012	2018+
LNG Canada	32.6	Shell, PetroChina, Kogas, Mitsubishi	2014+	Feb 2013	2019+
Pacific Northwest LNG	16.3+	Petronas, Japex, Petroleum Brunei, IOCL, Sinopec	2014	Dec 2013	2018+
Prince Rupert LNG	28.6	BG	2015	Dec 2013	2021+
WCC LNG	40.8	Imperial Oil, ExxonMobil	х	Dec 2013	2021+
Woodfibre LNG	2.9	Woodfibre	2015+	Dec 2013	2017+
Triton LNG (FLNG)	3.1	AltaGas, Idemitsu	2014+	Apr 2014	2017+
Aurora LNG	16.3+	CNOOC, INPEX, JGC	2015+	May 2014	2021+
Total	156.6+				

Note: x = not applicable.

Source: based on data from company websites.

Still, there is some good news on the Canadian side, as in 2013 the 10 mtpa Goldboro LNG project announced a deal with E.ON for LNG volumes of 5 mtpa (6.8 bcm/yr) for 20 years. Unlike most projects, it is located on the east coast. Pieridae Energy, the project developer, plans to take FID in 2015 and to commence commercial operations in 2020. The project is one of the export applications currently being reviewed by the NEB. Established only in 2011, Pieridae Energy is a newcomer to the industry, but its CEO was the founder of Galveston LNG, a former parent company of Kitimat LNG. As mentioned in the previous section, Canada is also strategically placed compared to the United States for supplying Japan, Korea, China and Singapore, even though Australia or East Africa can be slightly cheaper. Canada comes out more expensive compared with India. Strong government support is also crucial, as Canada needs to find new outlets for its natural gas.

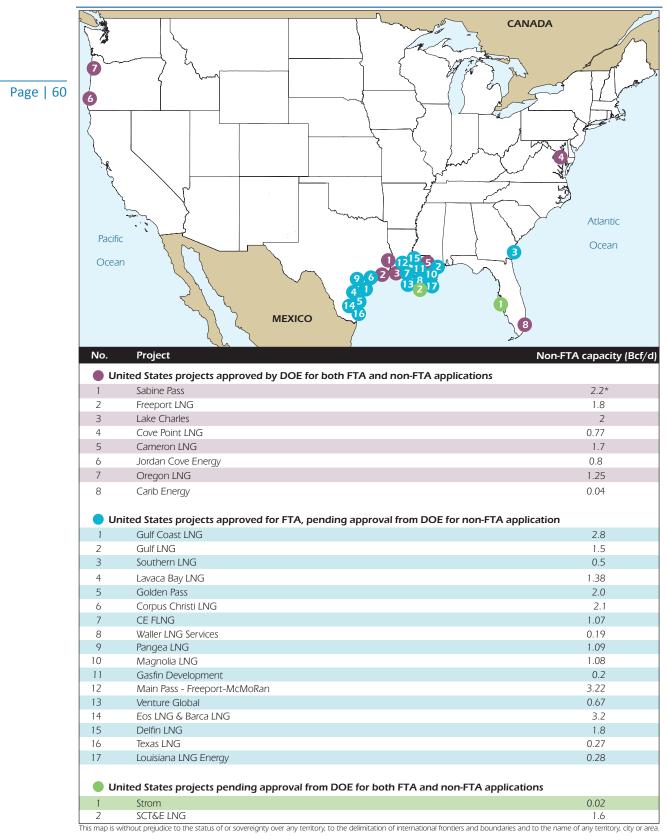
Investments of Asian companies

The upstream investments from Asian companies started in earnest in 2009, when exporting LNG from North America still seemed a distant prospect while the shale gas revolution was in full swing. Over the past five years, Asian companies have increasingly been investing in shale gas projects in North America, first to gain experience in shale gas development and potentially export cheaper LNG to Asia, but also, after learning the technology, to have a partner that may help them develop their own domestic resources. Then, as the prospect of North America becoming an LNG exporter increased, the investments in LNG projects started as well, but in a very different manner, either through investing directly in the LNG project or by contracting LNG supplies. Several Asian governments are also keen to pursue these investments in order to secure new LNG supply, while many Asian NOCs aim to continue investing in North American acquisitions.

There are striking differences between the United States and Canada in terms of investments in natural gas and LNG by Asian companies. In the North American region it is therefore very important to make the distinction among upstream investments, notably in shale gas, investments in LNG export capacity, and the contracted LNG, as they can differ greatly.

Companies tend to have an integrated approach in Canada, investing all along the gas value chain from upstream to contracting LNG to export it back home. LNG investments foreseen in Canada, notably in western Canada, are linked to a specific shale gas basin; many Asian companies are investing in both upstream and the corresponding LNG export facilities. This is relatively similar to what would happen in other LNG export countries, except that previously, LNG projects involved seller and buyer, and sometimes buyers were offered some equity – though a small portion – to entice them to purchase LNG from the project. Here, Asian companies such as PetroChina, Kogas and Mitsubishi are expected to have offtake volumes equivalent to their shares in the Canadian LNG projects. Japex, Brunei, IOCL and Sinopec are the current offtakers besides Petronas in the Pacific NorthWest LNG project. These arrangements can be expected to attract potential buyers. With higher investment costs compared to their US counterparts, this arrangement may improve the chances of success of the Canadian LNG industry, as the partners will try to reduce the cost as much as possible while at the same time ensuring reasonable returns on the projects.

Meanwhile, most US LNG export plants are not attached to any particular shale gas basin even though they are benefiting from the US shale gas revolution and a few Asian companies are trying to create that link through parallel investments in upstream assets. There are actually very few Asian companies participating in US LNG projects, mostly Japanese. The investment behaviour of the different Asian countries has also been quite varied, notably when contracting LNG. Kogas was one of the first Asian companies to sign a deal with US Cheniere to import US LNG, while also investing in Canada's upstream and LNG projects. It was then followed by India's GAIL. It is interesting to notice that Japanese companies started taking shares later, in the second wave of US LNG projects which were approved. Their interest seems to be concentrated more on Canada than on the United States. Chinese companies have been quite active in upstream investments, but their absence from any signed direct deal regarding US LNG is quite striking. Nevertheless, they have signed deals with BP and BG, which will eventually source part of the gas from the United States. Among the last companies to sign for US gas was Indonesia's Pertamina. It is also important to note that Asian companies are not the only ones interested in US LNG, as many European gas companies such as Centrica, GDF Suez, EDF, Endesa and Gas Natural have contracted US LNG, while many aggregators such as BG, BP and Total have done the same. There is no majority share of Asian companies when it comes to US LNG contracted, but as there is no destination clause, this does not preclude most of this gas ending up in Asia due to more attractive prices.





Note: bcf/d = billion cubic feet per day.

* Sabine Pass obtained non-FTA approval for 2.2 bcf/d and is awaiting approval from the DOE for another 1.38 bcf/d. Source: IEA (2014a), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris.

Upstream investments

Roughly 20% of the USD 133.7 billion invested in US tight oil and shale gas from 2008 to 2012 came from abroad. Asian companies are not the only ones having invested in North America: European IOCs have as well, but this results from the lack of opportunities elsewhere and the fact that large IOCs missed the early investment opportunities in North American shale gas and tried to catch up. Japanese companies have invested USD 5.3 billion, Indian companies USD 3.55 billion, and Korean companies USD 1.55 billion, while China already has already invested about USD 5.5 billion in US natural gas.

Page | 61

The relatively low US gas prices since 2009 affected many producing companies in North America, especially in 2012. As a result of these market conditions, several companies started joint ventures with Asian companies to solve some of their financial difficulties and to generate capital investments. Remarkably, the new partners in these ventures are rather independent mid-sized players such as Chesapeake Energy, Devon Energy, Encana, Pioneer Energy Services and Hunt Oil rather than major oil companies. This reflects the more limited cash reserves of these companies compared to the IOCs and their lower ability to survive in a lower price environment. The investments of Asian companies provide these cash-strapped companies the financial means to pursue their investments and develop their shale gas resources.

Japan

Japan has been fairly active in the field of US and Canadian unconventional resources. Most of the investments have been made through joint-venture structures with first movers in the relevant basins, in order to benefit from low North American gas prices with the ultimate aim of exporting the gas back to Japan. In 2011, Itochu paid USD 1 billion for a 25% share in natural gas explorer Samson, from which Itochu is guaranteed 1 mtpa of North American LNG. Meanwhile, INPEX and JGC Corp. agreed to take a joint 40% stake in shale gas resources owned by Nexen Inc., also with the intention of developing a liquefaction project in Canada. At the same time, a group of Japanese utilities (Chubu Electric, Tokyo Gas and Osaka Gas) acquired stakes in Penn West Energy's shale gas project in Cordova (in British Columbia, Canada). They in fact acquired stakes in Cordova Gas Resources, owned by Mitsubishi which in turn owns 50% of PWE's project. Meanwhile, Mitsubishi and INPEX are involved in upstream ventures in western Canada's oil and shale gas developments; Mitsui and Sumitomo also have stakes in US shale gas ventures.

Japanese companies are also trying to establish an integrated natural gas industry in Canada. But some are also considering doing the same in the United States; for example, Osaka Gas is reported to be looking for a shale gas acquisition. Having a stake in a gas field would help Osaka Gas hedge its fuel expenses by offsetting the feedstock costs when HH prices rise. Such acquisitions are helped and guaranteed by Japanese banks. Moreover, the Japan Oil, Gas and Metals National Corporation has been guaranteeing loans for projects that could help Japan diversify its gas sources and secure gas supplies at lower prices. The company also announced in 2013 that it will guarantee 75% of the bank's loans to Japanese companies involved in developing LNG projects that help reduce Japan's import fuel costs as long as their rate is lower than Japan's average LNG import costs from the previous year.

Korea

Korea's investments in North America's upstream sector have been more limited. It is essentially Kogas which is investing in shale gas assets, mostly in Canada. For example, Kogas is developing Canada's Horn River and West Cutbank development project. Kogas plans to invest USD 1.1 billion over the next five years to extract over 1 trillion cubic feet (tcf) of natural gas from land leases held by Encana. Kogas also has a 10% stake in Cordova Gas Resources, along with Japanese gas companies.

China

Chinese NOCs have been conducting overseas investments in oil and gas for years – since the 1990s in Latin America and Africa. Chinese companies invested an estimated USD 73 billion in global upstream merger and acquisition (M&A) deals between 2011 and 2013, with a particular focus on unconventional gas. Indeed, while many investments targeted oil and conventional gas assets Page 62 (for example, in Turkmenistan), Chinese NOCs have also started early investing in unconventional gas assets in North America. Unlike many other Asian companies, the Chinese NOCs have a clear interest in learning unconventional gas extraction techniques, an area in which Chinese NOCs are relatively inexperienced, to exploit their own estimated large unconventional gas resources.

> This practice is backed by the Chinese government. In April 2010, the National Energy Commission declared securing energy supply through international co-operation – i.e. investments abroad – one of its major targets. This is a late blessing of what the three NOCs had been effectively doing for years. Nevertheless, it must be noted that North America is just one of many areas in which Chinese NOCs have invested in upstream assets. Then, in July 2013, China expressed the desire to increase its investment in US shale gas during talks between the two countries. The Chinese authorities' aim is to gain experience in shale gas so they can redeploy the best US practices and technologies domestically, as well as to gain experience in working with American companies that they could later use in the Chinese domestic market by working with these companies as joint ventures.

> An additional motive could be to bring these gas supplies back to China. Given the current challenges faced by China to develop its shale gas resources, including regulated prices with a reform only at the starting point, huge infrastructure needs, the absence of a service industry, limited skilled engineers, and limited water resources, importing US shale gas may actually prove in some cases to be more cost-effective than developing domestic shale gas.

> Of particular interest is the acquisition of Nexen by CNOOC for USD 15.1 billion. Beyond this deal, Chinese companies have also taken over shares in North American upstream assets. There is no clear preference for US or Canadian assets. CNPC acquired 49.9% in Cutbank Ridge from Encana, and Sinopec performed several acquisitions such as 50% of the oil and gas from Chesapeake's Mississippi Lime acreage, 1.2 million acres in Niobara and Utica from Devon Energy, and it is taking over DayLight.

India

Indian companies have also been quite active in investing in US upstream development, probably to counterbalance their difficulties within India. Reliance Industries (RIL) has been investing billions in US shale gas assets, to the extent that these assets have been more profitable than its exploration and production business in India. In 2013, RIL announced investments of USD 5.1 billion in the next three years in its US shale gas business, taking the total investment in the business to USD 10.8 billion. RIL's US shale gas business comprises three upstream joint ventures with Chevron Corp., Pioneer Natural Resources and Carrizo Oil and Gas Inc., and a midstream joint venture with Pioneer.

GAIL also invested in the US shale gas segment when it acquired a 20% stake in Carrizo Oil and Gas' Eagle Shale Ford for USD 95 million in 2011. Of the total value, it made a cash payment up front of USD 63.7 million, while another USD 31.3 million was linked to Carrizo's further drilling and development cost, as well as being linked to its long-term contract of LNG capacity at Sabine Pass. This will help GAIL to acquire the necessary experience for future shale gas exploration in India.

India's NOC, ONGC, has been trying to acquire US and Canadian upstream assets, but the company faces difficulties due to investments in Iran.

Other countries

So far there have been relatively limited investments by companies from other Asian countries, outside of Malaysia's state-owned oil and gas company Petronas, which is heavily involved in integrated investments in Canada (see sections below).

Investments in LNG export plants

While their investments in US LNG export plants have been limited, Asian companies have a much more significant and visible presence in Canadian ones.

Looking at the shareholding of the different US LNG export plants, Asian companies do have some presence. Osaka Gas and Chubu have a 25% stake each in Freeport LNG, while JLI and Mitsui have a 16.6% stake each in Cameron LNG. Together, these plants represent less than 40 bcm/yr. However, investments have also been made through financing. Singapore has been focusing on securing stable energy supplies, as demand is expected to increase. In the national strategy, the sovereign wealth fund Temasek is playing an important role as the investment arm of the Singapore government. Temasek, together with the Asian private-equity fund RRJ Capital, took a combined stake in Cheniere. Cheniere operates the Sabine Pass LNG terminal in Louisiana and plans to build the Corpus Christi LNG export plant. Cheniere has also received substantial investment from China Investments Corporation (CIC). However, Temasek sold its share in mid-2013.

Meanwhile, the Canadian projects are linked to specific upstream assets; this actually makes these projects relatively similar to traditional LNG projects. Several projects have investments from Asian companies:

- LNG Canada: PetroChina (20%), Kogas (20%), Mitsubishi (20%) along with Shell (40%)
- Pacific NorthWest LNG: the project features a 100% Asian-company ownership with Petronas (62%), Sinopec (15%), JAPEX Montney (10%), Indian Oil Corporation (10%) and PetroleumBRUNEI (3%)
- Triton LNG: Idemitsu Kosan (50%) along with AltaGas Ltd (50%)
- Aurora LNG: this project also features a 100% Asian-company ownership with Nexen (a wholly owned subsidiary of CNOOC), INPEX, and JGC.

These projects represent around 90 bcm/yr of the 157 bcm/yr which have been approved by the NEB. There is, however, little investment from Asian companies in the projects which are still under NEB review. It is worth noting that many project sponsors plan to open the shareholding to other participants.

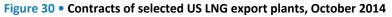
Investments in LNG contracts

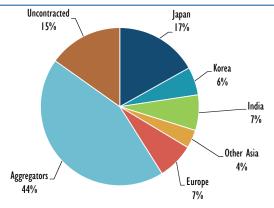
United States

Many long-term agreements signed so far for US LNG export projects show great interest from various Asian companies, with a noticeable absence of direct investments from Chinese and Singaporean companies as of October 2014. There is quite a significant share of portfolio players, which will be able to send these gas supplies to the most interesting market. It is also noteworthy that the Cheniere-type agreement means that the buyer does not have any FDC, but can also redirect the LNG to any chosen destination.

Not all projects have long-term agreements, but those which do will help raise financing for those which have not been able to secure such agreements. So far, eight US LNG projects representing a total LNG export capacity of 135 bcm/yr (100 mtpa) have secured long-term contracts. Beyond the six projects with the DOE's approval (Sabine Pass, Freeport LNG, Lake Charles, Cove Point, Cameron LNG and Jordan Cove), two other projects have contracted a large share of their capacity: Corpus Christi (Cheniere) and Magnolia LNG (LNG Limited). This means that 85% of this capacity has been contracted so far, including non-binding agreements.

The greatest share of US LNG has been contracted by aggregators (BG, BP, Gas Natural Fenosa, GDF Suez, Total, Woodside, Gunvor, LNG Holdings and AES). Some uncontracted LNG remains, but it is expected to be contracted eventually, given the pace at which US LNG has been sold and the number of FIDs expected to be taken in late 2014. Of note is that Asian companies represent roughly one-third of the total amount contracted, while European utilities⁴ such as Centrica, Endesa, Enel, EDF and Iberdrola have contracted around 10 bcm. Japan has the highest contracted share among Asian countries, followed by India, which is short of gas supplies and trying to contract additional amounts of LNG, and Korea. So far, there have been no long-term contracts signed by Singapore and China for North American LNG. However, companies in both countries have been signing deals with aggregators which are likely to source their gas from some US LNG export plants with which they have long-term contracts. Indonesia's Pertamina is moving to contract more US LNG after a long-term contract signed with the Corpus Christi LNG project.





Canada

Page | 64

Only three LNG projects in Canada have binding or non-binding LNG contracts: Kitimat LNG, Pacific Northwest and Goldboro. Altogether they represent 32 mtpa of LNG export capacity, roughly onequarter of the planned capacity in Canada.

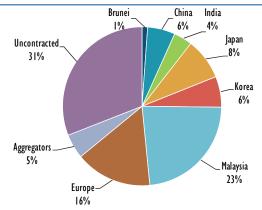


Figure 31 • Contracts of selected Canadian LNG export plants, October 2014

Other projects have not announced any agreement yet. Pacific Northwest project sponsors will be the offtakers so that this project's capacity is already contracted. Regarding the other two projects, only half of the capacity has been contracted. This means that a total of 22 mtpa has been contracted

⁴ GDF Suez could be considered both a European utility and an aggregator. Given its interests in LNG in several parts of the world, it has been placed in the aggregator category.

under firm and preliminary agreements. The contracted quantities with binding contracts are even lower, as they represent only 17 mtpa. Of note, 5 mtpa are going to Western Europe while the rest would go to Asia. Due to the involvement of Petronas, Malaysia is leading in terms of contracted LNG, followed by Europe's E.ON. Japanese, Chinese, Indian and Korean companies have more limited shares.

Russia

Page | 65

The supply picture

Russia pivotal to the Asia-Pacific market and LNG

Russian LNG projects are moving ahead, both on the exploitation and contractual fronts. It seems likely that they will contribute a part of the new LNG supply to arrive over the medium to long term. So far, the contracts signed seem to be more JCC-indexed.

There has been increased interest from the Russian government in the Asian market and LNG exports. In 2007, Russia's Eastern Gas Program began developing an integrated gas production, transportation and supply system in East Siberia and the Far East, to promote gas exports to China and other Asia-Pacific countries via pipeline and LNG. The state-owned Gazprom was appointed Program Execution Co-ordinator by the government. The 2009 "Energy Strategy for the Period up to 2030" set the numerical targets to increase the share of the Asia-Pacific region in Russia's total gas export structure from 0% in 2008, to between 11% and 12% in 2013-15, 16% to 17% in 2020-22 and 19% to 20% in 2030. In the draft of new Energy Strategy to 2035 currently being finalised, the Russian government intends to lower its mid-term goal and raise the longer-term goal. With particular reference to LNG exports, in its March 2013 "State Program on Energy Efficiency and the Energy Sector in 2013-20", Russia set a target of 10.2% LNG in Russian total gas exports; three new LNG plants with overall capacity of 35 mtpa (47.6 bcm/yr) are expected by 2020. This goal is included in the revised 2014 version of the programme.

Reasons behind this strategic policy drive towards Asian markets include not only the desire to develop and monetise gas resources in East Siberia and the Far East, and to foster its economic growth and regional development, but also to diversify away from Europe, where the potential for increased exports is relatively limited.

Despite these initial ambitious goals, Russia's efforts have been lagging. The current share of Russian gas exports to the Asia-Pacific region (that is, Russian LNG exports in total Russian gas exports) remains at about 7%, coming from its only operating Sakhalin-2 LNG plant, which commenced production in 2009.

From the end of 2013 until now, Russia's leading companies, including Gazprom, Novatek and Rosneft, have moved Russia's investment projects more actively; this may bring about a breakthroughs and increase exports to the Asian market from East Siberia and the Russian Far East. Key drivers have been liberalisation of LNG exports and a pipeline gas export deal with China.

LNG export liberalisation

The federal law No. 318-FZ,⁵ which entered into force 1 December 2013, opened the door to LNG exports by non-Gazprom companies, abolishing the monopoly on LNG exports which Gazprom had heretofore enjoyed.⁶

⁵ www.rg.ru/2013/12/04/gaz-dok.html.

⁶ Gazprom had a de facto monopoly on the export of Russian gas until 2006. This is stipulated in the Federal Law on Gas Export of 18 July 2006. Sakhalin-2 has a special legal status (PSA).

To be more precise, this law gives LNG export rights to: 1) subsoil users that hold gas extraction licenses (as of 1 January 2013), who envisage building an LNG plant or producing gas to be liquefied; or 2) companies (and their subsidiaries) in which the state controls more than 50% of the shares, which are developing offshore gas fields in the subsoil of internal waters, the territorial sea, and the continental shelf of the Russian Federation, including the Black and Azov seas, or gas production from projects developed under a production-sharing agreement (PSA) which was concluded by the time of entry into force of the law. This means that in addition to Gazprom, the following companies could develop LNG projects: Novatek, Rosneft, and possibly GazpromNeft and Zarubezhneft if they obtain offshore licenses and have gas available that could be exported as LNG.

Their performance in recent years shows that the non-Gazprom producers – the "independents" such as Novatek which produced 62.2 bcm in 2013 or the oil-producing companies such as Rosneft (38.2 bcm in 2013) – provided almost all the incremental gas supply, while Gazprom's production was stable if not declining. Liberalisation for "independents" could thus boost Russia's gas exports.

Box 7 • Pipeline gas supply from Russia to China

On 21 May 2014, Russia and China concluded a USD 400 billion, 30-year deal on the delivery of 38 bcm of gas per year via a Russia-China gas pipeline, expected to start in 2019 (both sides reportedly have the right to delay implementation up to two years based on the readiness of infrastructure and gas consumption), after negotiations dragged on for years. Details of the contract were not disclosed.

According to Gazprom, gas will be delivered from the Yakutia (Chayanda gas field) and Irkutsk (Kovykta gas field) gas production centres via the "Power of Siberia" gas transmission system (see Box 9). Gazprom intends to launch Chayanda gas field in late 2018 and Kovykta not earlier than 2021. Given that Chayanda plateau production is designated at 25 bcm/yr, the contracted 38 bcm/yr might be reached only after the launch of Kovykta field if Gazprom does not take any gas from independents.

This project requires construction of the "Power of Siberia" gas pipeline and its branch line to China, exploration of gas fields in East Siberia, and the construction of a gas processing plant. Total investment on the Russian side could be more than USD 70 billion. In order to raise the competitiveness of this project, Russia will reportedly introduce a zero mineral-extraction tax rate for the gas fields where the gas for China will be sourced, and China, for its part, could eliminate an import duty on Russian gas.

Russia is eager to move on to the next step, to supply more gas (additional 30 bcm/yr in 30 years) from its West Siberian gas fields to Western China (via "Western [Altai] route"), which would enable Gazprom to divert its surplus European volumes to China. (Russia's original intention in the Russia-China gas deal was to prioritise this route over the Power of Siberia pipeline. This route is less costly than Eastern route.) To date, there has been no obvious development of this route.

LNG projects

Following the example of Gazprom's Sakhalin-2, five LNG projects in Russia are currently competing against one another to export to the Asian market as a result of LNG liberalisation: Gazprom's Sakhalin-2 third train and Vladivostok LNG, as well as Novatek's Yamal LNG, Rosneft's Far East LNG and Alltech-Rosneft's Pechora LNG.

Yamal LNG project

The most advanced LNG export project among the five projects is Novatek's Yamal LNG, which took FID immediately after enforcement of the LNG liberalisation law. The Yamal LNG project envisages the construction of three 5.5 mtpa (7.5 bcm/yr) LNG trains with overall capacity of 16.5 mtpa (22.4 bcm/yr). Overall capital expenditures of the project are estimated at USD 26.9 billion. The consortium of Yamal LNG holds the license (valid until 2045) for exploration and production at the South-Tambeyskoye field, which is jointly owned by Novatek (60%), Total (20%) and CNPC

(20%). The commercial launch of the first LNG train is scheduled for 2017, which seems very optimistic as it implies only three years for construction. Yamal LNG has already pre-sold almost all its projected production. Buyers include Total, CNPC, Gas Natural Fenosa and Gazprom Marketing and Trading (GM&T) Singapore.

The Russian government strongly supports this project and construction of related infrastructure. Governmental support rests on the 2010 Comprehensive Plan geared to develop production of Page | 67 LNG on the Yamal Peninsula, selecting it as a pilot project in the Arctic Ocean. This programme was revised immediately after the FID was taken to defer its period of reaching designated capacity from 2016-18 to 2018-20 (governmental order No. 2413-r).⁷ This project is incentivised by a zero mineral-extraction tax rate to natural gas and gas condensates (production up to 250 bcm or 12 years' operation), zero-rate export duties for LNG and gas condensate, VAT exemption for imported equipment which has no equivalent manufactured in Russia, as well as preferential tax treatment for property and corporate tax.



Figure 32 • Russian LNG projects

Note: DPRK = Democratic People's Republic of Korea.

⁷ Governmental order No.2413 on amendments to the governmental order on the development of LNG production in the Yamal peninsula dated 19 December 2013; http://government.ru/media/files/41d4ad1ad99d96ff0f7f.pdf.

Box 8 • The Gydan Peninsula LNG project

Novatek has the licenses (valid through 2031) for the Geofizicheskoye and Salmanovskoye (Utrenneye) fields on the Gydan Peninsula. This project, together with the Yamal LNG project, is included in governmental order No. 2413-r, and its development period is expected to be 2018-22 for the first train, 2019-24 for the second train, and 2020-25 for the third train. The capacity is the same as that of the Yamal project. To date, no concrete programme has been set out and there is no foreign partner. The project's destiny is likely to hinge upon the success of the Yamal project and future LNG demand in the Asian market.

The Far East LNG project (Sakhalin-1 LNG)

Rosneft and ExxonMobil plan to construct a 5 mtpa (6.8 bcm/yr) LNG plant on the basis of Sakhalin-1 gas, although at the moment this project is to be handled separately from the Sakhalin-1 project, whose partners are ExxonMobil (30%), the Japanese consortium SODECO (30%), Rosneft (20%) and ONGC (20%). LNG liberalisation made this project possible along with Yamal LNG. The expected cost is reported to be USD 15 billion. Rosneft is considering further expansions with additional LNG trains, envisaging its other fields in the Okhotsk Sea. One of the potential locations for an LNG plant is believed to be the town of Ilyinskoye on the southwest coast of Sakhalin Island. Gas has already been pre-sold to both Japanese companies under HoAs of 1.25 mtpa (1.7 bcm/yr) to Marubeni and 1 mtpa (1.4 bcm/yr) to SODECO; another HoA designates 2.75 mtpa (3.7 bcm/yr) to Vitol to be delivered from 2019.

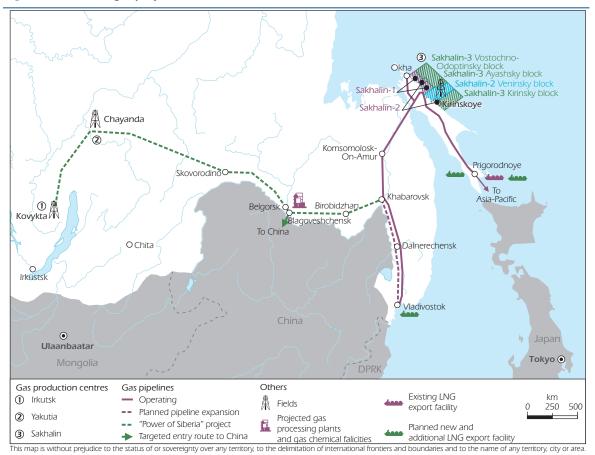


Figure 33 • Russian gas projects in East Siberia and the Far East

Source: based on Gazprom data.

In October 2013, Rosneft and ExxonMobil started front-end engineering design (FEED) work to be completed by the end of 2014. As the FID is expected at the beginning of 2015, construction work could start in the same year. Construction and commissioning of the LNG plant, loading line and offshore facilities are targeted for 2018-19. This project might face challenges of access to the trans-Sakhalin pipeline and financing.

Pechora LNG project

Russian private company Alltech has undertaken the Pechora LNG project in the north of the Nenets Autonomous District, based on its licenses for the development of Kumzhinskoye and Korovinskoye gas-condensate fields. Reported reserves of those fields are 160 bcm (according to the Russian specification). A framework agreement of co-operation on Pechora LNG between Alltech and Rosneft in May 2014, envisaging the creation of the joint venture (Rosneft 51%, Alltech 49%), stimulated realisation of this project; it might have a license to export LNG under the LNG liberalisation law. Originally, Alltech envisaged processing 5.9 mtpa (8 bcm/yr) per year; however, the designated capacity and launch date of the joint venture will be defined after the realisation of preliminary FEED.

Sakhalin-2 project and the future plan of its third train

The only project operating to date is Sakhalin-2 LNG with two trains, which was launched in 2009 by Sakhalin Energy. The shareholders of Sakhalin Energy are Gazprom (50% plus one share), Royal Dutch Shell (27.5% minus one share), Mitsui (12.5%) and Mitsubishi (10%). The designed capacity of the LNG plant is 9.6 mtpa (13.1 bcm/yr). Sakhalin Energy exports LNG to Japan, Korea, China, India, Thailand and Chinese Taipei, with Japan and Korea taking the bulk. The plant has been operating above its initial capacity, with exports in 2013 accounting for 10.76 Mt (14.63 bcm), about 4.5 % of global LNG supply.

The Sahkalin-2 consortium is now in talks to build a third train to increase capacity by 5 mtpa (6.8 bcm/yr). Pre-FEED started in mid-2012, and a detailed road map for preparing the FEED was signed in February 2014. FID is expected to be made in 2015. The producing LNG in the third train is planned for the end of 2019 or early 2020. The cost of this third train is believed to be USD 5 billion to USD 7 billion, which is the most cost-effective of the existing Russian LNG projects. The only challenge for this project is the gas source.

Vladivostok LNG

The Vladivostok LNG is a priority project for Gazprom. The Gazprom LNG Vladivostok project company (a special-purpose company) was established in 2013 to implement the project. Gazprom envisages the construction of two or three trains of 5 mtpa (6.8 bcm/yr) each, starting with the first train of the Vladivostok LNG plant in late 2018 and the second in late 2020. The construction cost of the LNG plant is reported to be USD 13.5 billion. In February 2013, Gazprom approved the investment rationale for the project to build the LNG plant and plans to complete FEED in the third quarter of 2014. Gazprombank joined the project as a shareholder with 49% of the stakes, undertaking the responsibility of completely financing the project. Gazprom intends to sign the relevant PSAs with potential LNG buyers.

Vladivostok LNG and the piped gas supply to China may have strong synergies in terms of gas source and transportation if Vladivostok LNG uses East Siberian gas as a source alongside gas from Sakhalin, and transports it via Power of Siberia pipeline. There are, however, several challenges to realising this project.

Box 9 • The "Power of Siberia" gas pipeline

Gazprom envisages constructing the 4 000 km gas transmission system Power of Siberia in the framework of the Eastern Gas Program. In the first stage, the plan is to construct a 3 200 km pipeline from the Chayanda gas field (Yakutia) to Khabarovsk and the Vladivostok gas trunk line. The FID on this part was adopted in October 2012. The line from Chayanda to Blagoveshchensk on the Russia-Chinese border is expected to commence operation in 2018. The second stage of the Power of Siberia will extend 800 km from Kovykta to Chayanda gas fields. To date, there is no information regarding the timing of the launch of the second stage. A ceremony marking the beginning of construction of the first stage took place in September 2014. The final throughput of the Power of Siberia pipeline is planned to be 61 bcm.

Although much of the route passes along the existing oil pipeline (East Siberia and Pacific Ocean [ESPO] pipeline) and enables streamlining of infrastructure and power supply costs, the pipeline needs to pass through swampy, mountainous and seismically hazardous areas. Given that it took more than six years to construct the 4 740 km ESPO pipeline and more than three years to construct 1 240 km in Gazprom's last experience in the Yamal peninsula (Bovanenkovo-Ukhta gas transmission system), a launch in 2018 seems challenging.

Rosneft is eager to get access to the Power of Siberia pipeline, proposing 18 bcm of gas; the Russian Minister of Energy Novak mentioned the possibility of giving access to independents at a maximum of 25 bcm.

Box 10 • Other Russian LNG project: Baltic LNG

Gazprom envisages constructing an LNG plant in the Leningrad region with production of up to 10 bcm/yr, aiming to export to Europe and to make swap deals with Latin American countries, in addition to supplying the Kaliningrad region. Gazprom is planning to commission this LNG plant in 2020. The investment rationale is being developed and the construction site is being chosen. Although this project is not designed to supply the Asian market, it is worth attention because it might affect the world LNG market if realised.

Challenges facing Russian projects

Most Russian projects benefit from their geographical proximity to the Asian market. There is no choke point in LNG transportation, and the cost of transportation from the Russian border can be kept relatively low. However, these advantages do not assure the involvement of Asian companies in Russian projects. Asian companies continue to pay more attention to Australian, North American and East African projects, although Russian LNG projects need co-operation with foreign, especially Asian companies for technology, financing and purchase agreements. There could be several challenges to strengthening Asian investors' and buyers' confidence in Russian projects.

Keep costs under control

The economic competitiveness of gas sources from East Siberia and the Far East is challenged by their remoteness and geographical difficulties. Many measures, such as tax breaks, were taken for the Yamal LNG; however, there is no precedent of an LNG plant being constructed on permafrost. The competitiveness of the Vladivostok LNG project has been controversial because its possible gas sources in East Siberia and the Far East are very far from its LNG plant. Cutting costs is also a challenge for Far East LNG: in order to decrease estimated costs, Rosneft wants to use Sakhalin-2's trans-Sakhalin gas pipeline, which Gazprom has denied. Rosneft filed a lawsuit against Sakhalin-2 operator Sakhalin Energy to secure non-discriminatory access to its capacity. Rosneft and Gazprom

are reportedly on track to make an agreement to allow Rosneft access to the pipeline; however, it is unclear how to secure the throughput of the pipeline for Sakhalin-2, including the third train and Far East LNG.

Given the situation in Yamal LNG, introduction of exploration cost deduction from the tax regime and governmental support might be a key to resolve this problem.

Commission on schedule

Commissioning timing is another of the major topics of dispute. Although the Yamal project started construction under strong governmental support, its launch in 2017 appears challenged, considering the technical difficulties related to permafrost. The timely commissioning of Far East LNG, Vladivostok LNG, the Sakhalin-2 third train and Pechora LNG is also questionable: FID of each project has not yet been made, and some of these projects have gas source-related challenges.

Clarify gas sources

In order to supply gas to its East Siberian and Far Eastern projects, Gazprom envisages relying on the offshore Sakhalin-3 fields (Kirinskoye field and Yuzhno-Kirinskoye field), and the onshore Chayanda and Kovykta fields. However, the planning, timing and capacity are still uncertain.

Gazprom had tried to take Sakhalin-1 gas for Sakhalin-2's third train, but there have been no negotiations after Rosneft and ExxonMobil announced their strong desire to develop the Far East LNG project. Although Sakhalin-3 gas fields are now considered as the gas source of Sakhalin-2's third train, it is doubtful whether gas production of Sakhalin-3 Kirinskoye will be enough for one train. The launch of Sakhalin-3 Yuzhno-Kirinskoye field has not yet been fixed in accordance with the changing evaluation of its oil reserves. Some delay will therefore be incurred if Sakhalin-2's third train relies only on Sakhalin-3's gas production.

According to Gazprom, the first two trains of Vladivostok LNG will be fed with gas from the Sakhalin gas production centre (Sakhalin-3), and the third train will be fed from the Yakutia and Irkutsk centres (Chayanda and Kovykta fields). However, as mentioned above, Sakhalin-3 cannot assure the Vladivstok LNG project's timely commissioning in 2018. In addition, if the project for piped gas to China is realised, all Chayanda gas could be delivered to China via the Power of Siberia, and the third train should be waiting for the launch of Kovykta gas field.

	Source of gas	Earliest launch of each gas field	Gas production plateau
Sakhalin-2 LNG	Sakhalin-2	2009	
Sakhalin-2 third train	Sakhalin-3 Kirinskoye	2014	5.5 bcm
	Yuzhno-Kirinskoye	2019+	16 bcm
Vladivostok LNG	Trains 1 and 2: Sakhalin-3 (Kirinskoye/Yuzhno-Kirinskoye)	2014/2019+	5.5 bcm/16 bcm
	Train 3: Chayanda/Kovykta	2018/2021+	25 bcm/35 bcm
Piped gas to China	Chayanda	2018	25 bcm
	Kovykta	2021+	35 bcm

Table 9 • Gas sources of Gazprom's projects

Harmonise and prioritise projects

Competition among Russian projects is making Asian investors' heads spin. Far East LNG and Sakhalin-2 third train are competing over whether Far East LNG will use the Sakhalin-2's gas pipeline and the two projects could be realised in parallel, or only one or the other of Far East LNG or Sakhalin-2 will be realised. Gazprom's projects, including piped gas supply to China, are competing with each other for gas sources; gas exploration plans and gas supply plans are not harmonised.

In addition, Gazprom and Rosneft disagree on access to the Power of Siberia pipeline. Strategic decisions on prioritisation could improve the competitiveness and credibility of Russian LNG projects.

Difficulties related to financing

Since March 2014, the United States and the European Union have imposed sanctions against Russian companies and individuals, including the energy companies. They include limited access for several Russian companies to long-term credits and the ban on EU or US companies delivering services, goods or technology related to deepwater, Arctic offshore or shale projects to Russian companies and individuals. (Sanctions which are imposed by the European Union and the United States differ on several points). Although the duration of the sanctions is unknown, and the impact of these sanctions on the current LNG projects might be relatively small compared to the oil sector, the sanctions are likely to increase the costs of financing for those companies and might cause further project delays. This may have an effect on the competitiveness of Russian projects.

Investments from Asian companies

As of 2014, only Japanese, Chinese, Indian and Korean companies, the four biggest gas consumers in Asia, have an established presence in Russian LNG projects. The activities of Asian companies in the Russian energy sector have not been tangible on the whole, compared to in other continents.

Japan

Japanese companies are moving ahead of other Asian companies thanks to their participation in the Sakhalin projects since the 1990s. Sakhalin-2 was the first in which Asian companies became involved in Russian LNG.

Upstream and LNG investments

Sakhalin-2 is the most conspicuous instance of Japanese involvement. Japanese companies Mitsui and Mitsubishi entered into the consortium from the early planning stages with Royal Dutch Shell, and the consortium signed the first production-sharing agreement (PSA) in 1994 with the Russian government. The share of Japanese companies is 12.5% for Mitsui and 10% for Mitsubishi, after Gazprom joined this project in 2009. The Japanese engineering companies Chiyoda Corporation and Toyo Engineering Corporation served jointly with Russian companies as engineering, procurement and construction (EPC) contractors for LNG plants since 2003. For the construction of the LNG plant, oil and gas pipelines and a marine platform (Phase 2 of this project), the Japanese Bank for International Cooperation (JBIC) loaned up to USD 3.7 billion in project financing, co-financing with a syndicate of commercial banks in 2008. Japanese LNG carrier companies – Nippon Yusen Kaisha (NYK), Mitsui O.S.K. Lines (MOL) and Kawasaki Kisen Kaisha (K Line) – together with their respective Russian partners, constructed three LNG tankers for this project.

The Japanese consortium SODECO (comprised of METI: 50%, JAPEX: 15%, Itochu: 18%, Marubeni: 12% and INPEX: 6%) was established in 1995 and entered into the PSA of the Sakhalin-1 project with other foreign and Russian partners, holding a 30% stake. Although Sakhalin-1 has not begun full-fledged gas production, the Far East LNG project could release its gas reserves. SODECO and Indian ONGC may also join this project.

Japanese companies are actively engaged in the feasibility study of the Vladivostok LNG project. In 2011, Gazprom, together with the Agency for Natural Resources and Energy under the Japanese Ministry of Economy, Trade and Industry, and a consortium of Japanese companies, called the Japan Far East Gas Co., Ltd, which was specially established for this study (Itochu, JAPEX, Marubeni, INPEX, CIECO), conducted a preliminary feasibility study on the LNG plant project near Vladivostok, in accordance with the intergovernmental memorandum.⁸ Based on the study's results, in March 2012 Gazprom decided to develop the investment rationale for the project. In March 2013 the action plan for construction of the LNG plant was approved, together with the plan for establishing the project's resource base. However, there has not been a gas SPA or agreement on further investment between Gazprom and the Japanese consortium.

Japanese companies do not have any stakes or SPAs in the Yamal project; however, the JGC Page 73 Corporation and Chiyoda Corporation, under the leadership of the consortium Technip France, became a contractor of engineering, procurement, supply, construction and commissioning of an integrated LNG facility in the Yamal LNG project. On top of that, a joint venture between Japanese Mitsui O.S.K. Lines (MOL) and the China Shipping (Group) Company will serve as one of the LNG shipping carriers, signing shipbuilding contracts with Korean Daewoo Shipbuilding &Marine Engineering to build three ice-class LNG carriers.

Long-term LNG contracts

Several Japanese companies have contracted for about 5 mtpa (6.8 bcm/yr) of LNG under longterm contracts and another few volumes on the spot market from the Sakhalin-2 project. In 2013, 8.67 Mt (11.8 bcm) of the 10.76 Mt (14.6 bcm) total production was exported to Japan. This constitutes more than 9% of Japanese total gas supply, and the share of Russian gas in the total Japanese supply is increasing steadily. Japanese companies has already pre-bought Far East LNG under a HoA to SODECO (1 mtpa) and Marubeni (1.25 mtpa) in June 2013. This LNG is expected to be delivered starting in 2019.

China

The involvement of Chinese companies in Russian LNG projects became definite only in 2014, with stakes being taken in the Yamal LNG project and the sealing of the first long-term contract. Chinese involvement brings great financial investment to this sector.

Upstream and LNG investments

The first prominent example of Chinese involvement in Russia's LNG projects is Yamal LNG. The CNPC entered into the Yamal LNG consortium in 2014, taking 20% of stakes. In addition, in May 2014, the China Development Bank Corporation, Vnesheconombank, Gazprombank and Yamal LNG signed a memorandum on project financing for the Yamal LNG project. Participation of Chinese companies in the Yamal project is backed by both governments. In January 2014, the agreement between the Russian government and the Chinese government on co-operation was enacted, aiming to establish favourable conditions for investment co-operation in the Yamal LNG project. This agreement is in effect through 31 December 2045. In addition, a subsidiary of the Chinese state oil giant, CNOOC, will build equipment for the liquefaction process for the Yamal LNG project. Also, a joint venture with China LNG Shipping and Canadian Teekay LNG Partners with six LNG tankers and a joint venture between China Shipping (Group) Company and Mitsui O.S.K with three tankers might serve as LNG carriers for Yamal LNG project. All tankers will be constructed by Korean Daewoo Shipbuilding and Marine Engineering.

Ahead of this project, in 2007, the China Petroleum and Chemical Corporation (Sinopec) had entered into the exploration of the Veninsky block of Rosneft's Sakhalin-3 project. Rosneft has a 74.9% stake in the project, with the remaining 25.1% going to Sinopec, although Sinopec is to

⁸In 2011, Gazprom and the Agency for Natural Resources and Energy under the Japanese Ministry of Economy, Trade and Industry signed the Agreement of Co-operation to prepare a joint feasibility study on the options for natural gas utilisation near Vladivostok, as well as for natural gas and gas chemicals' transportation from the Vladivostok region and their sales among potential customers in the Asia-Pacific countries.

finance 75% of geological exploration expenditures. This project, however, has not yet realised commercial production.

Long-term LNG contracts

Page | 74

In May 2014, Yamal LNG and CNPC sealed a binding contract for the supply of 3 mtpa (4.1 bcm)
 of LNG for 20 years. It is a landmark contract, because it is the first long-term LNG SPA between Chinese and Russian companies. This is another case in which the LNG price will be indexed to the JCC in the Asian market.

India

Upstream and LNG investments

ONGC Videsh entered into the Russian upstream sector, becoming a partner in the Sakhalin-1 consortium in 2001, acquiring a 20% interest in the Sakhalin-1 project. However, there is no tangible co-operation between Indian and Russian companies in Russian LNG projects so far. The following examples demonstrate that dialogue towards future co-operation has, nevertheless, begun.

- In May 2014, Rosneft and ONGC Videsh signed an MOU for co-operation in exploration, appraisal and hydrocarbon production on the continental shelf of the Russian Federation.
- In June 2014, Gazprom International and Oil India signed an MOU confirming both companies' willingness to develop a mutually beneficial relationship in prospecting and appraisal work, and their intention to co-operate in joint projects involving the geological exploration, extraction and transportation of hydrocarbons and the exchange of information and technologies.

Long-term LNG contracts

In June 2014, Gazprom signed a firm contract with the Indian company GAIL on delivery of 3 mtpa (4.1 bcm/yr) of LNG for 25 years. The price is reportedly to be indexed to crude oil. The gas source of this contract is not declared, but it is likely to be Yamal LNG. This is because in May 2014, the HoA for the supply of LNG between Yamal Trade and Gazprom Marketing and Trading Singapore was signed, with a possible supply of up to 3 mtpa (4.1 bcm/yr) of LNG for more than 20 years for delivery to the Asia-Pacific region, primarily to India.

In 2012, Gazprom Marketing and Trading Singapore signed an MOU with four Indian customers – in addition to GAIL, Indian Oil Corporation, Gujarat State Petroleum and Petronet LNG – for the delivery of 2.5 mtpa (3.4 bcm/yr) of LNG to each, or a total of 10 mtpa (13.6 bcm/yr) for 25 years, envisaging supplying mainly from Shtokman LNG. Given that Shtokman LNG has been indefinitely postponed, those contracts are likely to change shape in the near future, as the above-mentioned example.

Korea

Despite its geographical proximity, Korean companies have invested neither in the upstream gas sector, nor in LNG plants. The only co-operation between Korean and Russian companies is the contract of LNG tankers for the Yamal LNG project. Daewoo Shipbuilding and Marine Engineering has a contract to deliver up to six ARC7 ice-class LNG tankers.

Kogas has a long-term contract with Sakhalin-2 for 1.5 mtpa (2 bcm/yr) for 20 years until 2028. In 2013, Korean companies imported 1.98 Mt (2.7 bcm) of LNG from Russia, approximately 5% of its total supply.

Box 11 • Pipe dreams? Gas pipelines from Russia to Korea, Japan, Mongolia and India

To Korea: In 2008, Gazprom and Korea's Kogas agreed to a 30-year supply of up to 10 bcm/yr of Russian gas to be delivered to the Korean Peninsula, with the start-up marked for 2015. It was rescheduled for 2017 after the DPRK's controversial nuclear programme stalled talks. However, there has been no concrete action since 2011 and this project's success strongly hinges on the political situation in the DPRK.

To Japan: The idea of building a gas pipeline from Sakhalin or Vladivostok to Japan comes up from time to time: about ten years ago, ExxonMobil and other gas suppliers floated plans to build a pipeline between Sakhalin and Japan, but the proposal went nowhere. Against the backdrop of increased gas demand and a burgeoning trade deficit after the Fukushima accident, the idea of a gas pipeline has resurfaced.

To Mongolia and India: Mongolia and India await progress in the construction of the gas pipeline from Russia to Mongolia and India. A branch line to Mongolia may not be difficult, should Russia and China agree to supply gas via the western (Altai) route. However, there could be physical and geopolitical challenges to constructing a pipeline between China and India, either through the Himalayas or linking the pipeline to the Turkmenistan-Afghanistan-Pakistan-Indian (TAPI) pipeline yet to be constructed.

Australia

The supply picture

Where Australia stands in the global LNG market

Australia is currently the fastest-growing LNG producer in the world. It will rise from third-largest LNG supplier in 2012 to largest by 2020. Since the year 2000, Australia has played an important role as an LNG exporter, particularly for Asian countries (Figure 34). In 2001, the global LNG trade amounted to 143 bcm, while Australian LNG exports were over 10 bcm (7.4% of the total). Between 2001 and 2012, the share of Australian LNG varied from 6.4% to 9.5%, but the absolute volume of LNG exports has continued to rise, reaching 30.5 bcm in 2013. In other words, Australian LNG exports almost tripled over 13 years, contributing to the significant growth of the world LNG industry. In 2009, Australia's export volume increased by 4 bcm due to the fifth train of the North West Shelf (NWS) LNG project reaching plateau production. The Pluto LNG project came online in May 2012 and added 5.9 bcm/yr of LNG capacity, while world LNG trade declined in 2012.

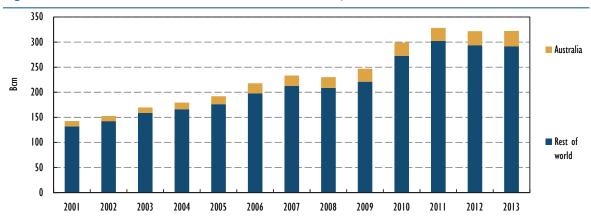


Figure 34 • World LNG trade and the share of Australian LNG, 2001-13

	State (plant site)	Project	Capacity (bcm)	Major stakeholders	Online
2 76	Western Australia	NWS LNG	22.2	Woodside (16.67%), Shell (16.67%), Chevron (16.67%), BHP (16.67%), Japan Australia LNG (16.67%)	1989 (T1-T3), 2004 (T4), 2008 (T5)
	Northern Territory Darwin LNG		4.8	ConocoPhillips (57.16%), Santos (11.39%), INPEX (11.27%), Eni (10.98%), Tokyo Electric (6.13%), Tokyo Gas (3.07%)	2006
	Western Australia	Pluto LNG	5.9	Woodside (90%), Tokyo Gas (5%), Kansai Electric (5%)	2012

Table 10	LNG projects in	operation in Australia
----------	-----------------	------------------------

New LNG projects in Australia

Page

Although no train was completed in 2013, two trains, one each from Gorgon LNG and Queensland Curtis LNG (QCLNG), are expected to come online in late 2014 to early 2015. The big expansion of Australian LNG production capacity is anticipated from late 2015, with two more trains from Gorgon LNG, in addition to the already completed second train from QCLNG, the first train from Gladstone LNG (GLNG) and the first train from Australia Pacific LNG (APLNG). The second train from APLNG and the first train from Wheatstone LNG are expected to come online in 2016. With the second train from Wheatstone LNG, Prelude FLNG and two trains from Ichthys LNG also coming online by 2017, Australia's LNG production capacity will reach 117 bcm/yr (over 86 mtpa). This would make Australia the world's largest LNG exporter, ahead of Qatar, although project developments could be delayed by various constraints. Conversely, there may also be decisions to further expand projects such as Pluto LNG, Gorgon LNG and three CBM-to-LNG projects before 2015.

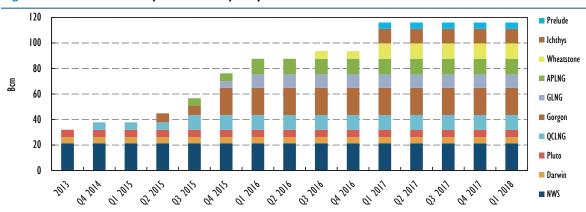


Figure 35 • Australian LNG production capacity increase to 2018

Seven LNG projects representing 84 bcm/yr of LNG export capacity are currently under construction, which would make Australia the largest LNG exporter in the world by 2018 – if all projects are completed in time. After Gorgon LNG took FID in late 2009, six LNG projects reached FID in Australia from October 2010 to January 2012 and substantial construction work began. In other words, one Australian LNG project reached FID every three months on average during that period. By comparison, only four projects representing 42 bcm/yr reached FID globally from 2008 to September 2010. This is a substantial expansion of LNG production capacity, and the pace of expansion recalls the series of FIDs reached in Qatar in 2005, which made Qatar the largest LNG exporter in the world by the end of 2011. In addition to those LNG projects which reached FID during the period, there were two already under construction in Australia, Pluto LNG of Woodside, which started operation in May 2012, and Gorgon LNG of Chevron, which is still under construction and is expected to begin operating in early 2015.

Project	Capacity (bcm)	Major stakeholders	Online
Gorgon LNG	21.4	Chevron (47.333%), Shell (25%), ExxonMobil (25%), Osaka Gas (1.25%), Tokyo Gas (1%), Chubu Electric (0.417%)	2015
Queensland Curtis LNG (CBM)	11.6	BG (upstream 93.75%, T1 90%, T2 98.75%), CNOOC (upstream 5%, T1 10%), Tokyo Gas (upstream 1.25%, T2 5%)	2014-15
Gladstone LNG (CBM)	10.6	Santos (30%), Petronas (27.5%), Total (27.5%), Kogas (15%)	2015-16
Prelude FLNG	4.9	Shell (67.5%), INPEX (17.5%), Kogas (10%), CPC (5.0%)	2017
Australia Pacific LNG (CBM)	12.2	ConocoPhillips (37.5%), Origin (37.5%), Sinopec (25%)	2015-16
Wheatstone LNG	12.1	Chevron (64.136%), Apache (13%), Kufpec (7%), Shell (6.4%), Kyushu Electric (1.464%), Pan Pacific Energy (8%)	2016-17
Ichthys LNG	11.4	INPEX (62.245%), Total (30%), CPC (2.625%), Tokyo Gas (1.575%), Osaka Gas (1.2%), Kansai Electric (1.2%), Chubu Electric (0.735%), Toho Gas (0.42%)	2016
Total	84.2		

Source: based on data provided by company websites.

New technical challenges

Australian LNG projects are tackling new technical challenges. Three out of seven projects currently under construction are CBM-to-LNG projects; they are the world's first CBM-to-LNG projects. Another ground-breaking project is Shell's Prelude FLNG, an FLNG project which is being constructed in the shipyard in Korea. Gorgon LNG, one of the world's largest natural gas projects and the largest single resource development in Australia's history, is investing in the world's largest commercial-scale CO₂ injection project to reduce greenhouse gas emissions. Australia is therefore pioneering new LNG technologies, and the world could learn from its experience in the years ahead.

All three CBM-to-LNG plant sites are on Curtis Island off the coast of Gladstone. QCLNG is the world's first CBM-to-LNG project to reach FID. The project is attracting much attention because its success may be duplicated in other regions where the potential of CBM is important. GLNG missed being the world's first CBM-to-LNG project to reach FID, but it still contributes Australia's fame as the first country to export CBM-made LNG. APLNG is the third CBM-to-LNG project in Australia. These three projects have onshore gas transmission pipelines of 340 km, 420 km and 520 km respectively and gather CBM production from a large area.

Shell's Prelude FLNG will be the world's first floating production, storage and offloading (FPSO) unit for LNG, and will be located 200 km off the coast of Western Australia, in the federal government jurisdiction. The FPSO vessel is equipped with production facilities, eliminating the need to build several hundred kilometres of gas transmission pipeline to an onshore liquefaction plant. Shell has been the pioneer of this state-of-the-art technology for decades and has long awaited its application. FPSO technology could be a game changer in the LNG industry if it proves that a stable supply of stranded LNG is possible in the long term. It could be a viable option for many stranded gas fields which have been stalled by high project costs or environmental constraints.

Gorgon LNG will also be a technically challenging project. Located on Barrow Island, where very strict environmental regulations are applied, its natural gas has a CO_2 content as high as 14%. Most of the CO_2 arising from natural gas production will be injected into the aquifer below Barrow Island, making it one of the largest CO_2 sequestration projects in the world. Gorgon LNG also includes a 200 km offshore gas transmission pipeline and a gas processing facility for its domestic gas supply obligation.

By contrast, Ichthys LNG and Wheatstone LNG are more conventional projects. Ichthys LNG features an offshore gas transmission pipeline of 885 km. INPEX's original plan was to build a liquefaction

plant in Western Australia, which is geographically much closer to their gas fields than the Northern Territory. However, negotiations with the Western Australia state government as well as with the residents over the most appropriate plant site selection failed, and the Northern Territory offered attractive concessions to INPEX, resulting in an extraordinarily long transmission pipeline (885 km) being built to Darwin. A floating facility was also an option, but it was not economically attractive. For Wheatstone, a 225 km offshore gas transmission pipeline will be built, along with a gas processing facility for domestic gas supply obligations, at Ashburton North on the Pilbara coast of Western Australia.

Page | 78

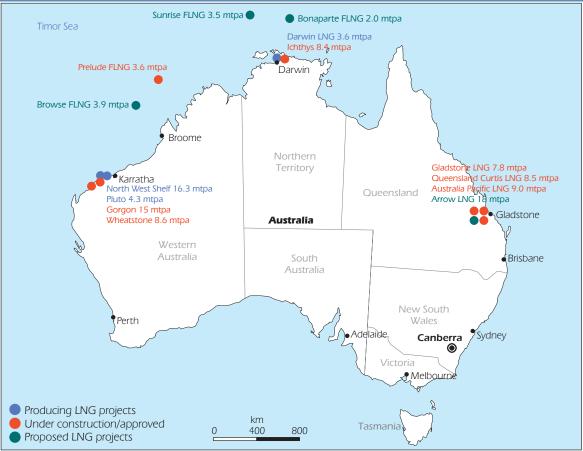


Figure 36 • Australian LNG projects

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The advantage of investing in Australia

There are several reasons for the rapid development of LNG projects in Australia. The primary reason is that Australia provides a more investor-friendly environment than most other LNG-producing countries. Australia surely has plenty of proven gas reserves (over 3 trillion cubic metres [tcm]), but other countries, such as Russia, Qatar and Iran have much larger natural gas resources. And while Australia is geographically close to the growing Asian market, the Far East of Russia, Indonesia and Malaysia are much better located within the region. As far as reliability of LNG supply is concerned, no major supply disruption from the traditional suppliers to the Asian market has been recorded ever since LNG exports started in 1989 even during severe cyclone seasons. Then why do Australian LNG projects attract Asian buyers?

What is really driving the development of Australian LNG projects is the fact that Australia has supplied a competitive LNG price on a delivered basis for the past decade. As shown in the Japanese imported LNG prices, Australia supplied LNG at lower than all other imported average prices for more than a decade up to 2009. It is unknown how competitive the price of LNG from

all the LNG projects currently under construction in Australia would be, compared to existing and future LNG supplies from other regions over the long term. However, it is also realistic to assume that LNG producers of new projects in Australia offered more competitive deals than their competitors worldwide at the time contracts were made, while making sure that they would get a decent return on investments from these projects. That Asian buyers have committed themselves to the purchase of LNG from these projects and contributed to their development seems to argue in favour of this assumption.

The second reason for the rapid development of LNG projects in Australia is its good business environment, in which stakeholders can make decisions much more quickly than in other regions. Although there are some hurdles to clear, such as native titles and environmental impact assessments, there is no state-owned national oil and gas company in Australia to hold controlling stakes in local projects. Therefore, there is only minimal state intervention in LNG marketing activities and project stake sales in Australia. Although the Foreign Investment Review Board needs to approve most large acquisitions of Australian assets by foreign entities, this is very rarely invoked in reality. This business environment helps projects reach FID fairly quickly. In most cases where an NOC is involved in LNG projects, such as Algeria and Nigeria, the decision-making process is very slow, resulting in slower project development and marketing activities. As a result, those projects are likely to miss marketing windows and fail to obtain timely LNG sale and purchase agreements.

In summary, Australia has been the major LNG supply source to Asia for the last decades because quick decision-making enables Australia to match the pace of rapidly growing demand in Asian LNG markets. To achieve further growth of this industry towards the end of this decade and beyond, Australia should at least maintain its offer of competitive LNG and its attractive investment environment.

Challenges for the future market

In reality, no country has ever experienced seven LNG projects under construction at the same time. Australia had already built three LNG projects, but such a huge expansion of the Australian LNG industry was not expected; in fact, there is now a critical labour shortage for the development of these projects. This shortage of skilled labour is significantly increasing labour costs and, accordingly, leading to a rise in overall project costs.

Project costs represent the size and difficulties of developing an LNG project and vary depending on several factors, such as the location of the liquefaction plant, distance from the feed-gas sources to the processing facilities, the design of the plant, the environmental conditions of the plant site, the technical or regulatory challenges of the gas fields, the availability of skilled labour, and the construction period before operation. The timing of project development is also important, and economies of scale do not always help to reduce project cost. While LNG demand has been growing rapidly, particularly over the last ten years, the costs of LNG projects have also been rising. Globally, LNG development costs had more than doubled since 2003, but this trend is even more evident in Australia. In fact, project development costs tripled or quadrupled in Australia over the same period.

Of all LNG projects currently under construction, nearing completion or very close to being approved, Australian LNG projects tend to be more expensive than those in other regions of the world. Furthermore, many projects in Australia have already been subject to cost overruns. The costs of the Pluto project, completed in May 2012, increased to USD 15 billion from the initial estimate of USD 11.2 billion when the FID was taken. In addition, four out of seven projects under construction in Australia have already announced cost increases from the initial estimates when the FIDs were made.

The capital costs per tonne of LNG production for APLNG, Pluto, Wheatstone, Prelude, Gorgon and Ichthys are between USD 2 833 and USD 4 048, whereas the equivalent for Angola LNG and Donggi Senoro LNG are substantially lower, between USD 1 400 and USD 1 731. Furthermore, Sabine Pass LNG in the United States is unique in the LNG business model. It has no particular feed-gas field dedicated to LNG production, but the entire US gas market is its supply source. It therefore requires no capital investment in upstream development or transmission pipelines. Sabine Pass LNG simply helps its customers buy gas from the market, liquefy it and ship it overseas. Additionally, LNG regasification facilities and shipping infrastructure already exist at the Sabine Pass site, so only the liquefaction plant is still required. For these reasons, Sabine Pass's capital cost per tonne of LNG production is very competitive, at less than one-third that of the Gorgon LNG project.

Australian LNG projects which have reached FID have nearly found firm LNG buyers in long-term commitments. Estimated construction costs have already been reflected in the sales price offered, and the buyers must have agreed on the purchase price or formula because the Australian LNG looked more competitive and realistic than that of its competitors at the time of bargaining. However, if the project costs of Australian LNG continue rising towards 2020, future LNG projects may no longer be able to offer LNG at a competitive price on the Asian market, impairing growth of the Australian LNG industry. It has been observed recently that, even for the projects already under construction, the construction cost review among project partners may identify that the entire construction cost is surpassing what was estimated at the time of FID, due to a stronger Australian dollar and higher material and labour costs. The general trend of high and increasing construction costs for Australian LNG projects could therefore impair project profitability and the competitiveness of Australian LNG, causing investors to lose interest with the possible exception of brownfield expansion of ongoing projects.

Investments from Asian companies

As an LNG producer, Australia is still a young country with a short LNG history. Its first LNG project, NWS LNG, started production and exportation in 1989, 25 years after the first commercial LNG production was recorded in Algeria, and 20 years after the first LNG cargo arrived in Japan from Alaska. But what is important is that all three Australian LNG projects which are currently in operation have investments in upstream by Japanese companies, as well as many long-term contracts agreed with Asian countries such as Japan, China and Korea.

NWS LNG, located in North Western Australia, started operations in 1989. This project is a large joint venture with Australia's Woodside as an operator, and Shell, Chevron, BP, BHP Billiton and Japan Australia LNG (itself a joint venture between Mitsui and Mitsubishi), with all partners holding equal equities. It started with three trains, adding a fourth train in 2004 and a fifth train in 2008, for a total LNG production capacity of 22 bcm/yr. The project is remarkable not only for its upstream investment by Japanese companies, but also for the 12 Asian companies holding long-term contracts for LNG. With an international reputation for its safe and reliable delivery of LNG to customers for many years, this successful project has opened the door for more foreign investments in LNG projects in the future.

The second project is the Darwin LNG, located in the Northern Territory, with one train of 4.8 bcm/yr; it started operations in 2006. A unique feature of this project is its natural gas supply source, the Bayu-Undan gas field, located in the Joint Petroleum Development Area, 500 km off the coast of the city of Darwin, where Timor-Leste and Australia jointly govern hydrocarbon developments. The operator of the project is ConocoPhillips, with various partners such as Eni, Santos, INPEX, Tokyo Electric and Tokyo Gas. Tokyo Electric and Tokyo Gas are also buyers of LNG from the Darwin LNG project. This project is significant because it marks the first time Japanese buyers have invested in upstream interests.

The third project is Pluto LNG, with a single train of 5.9 bcm/yr, located in North Western Australia, close to NWS LNG. Pluto LNG started operating in May 2012. Woodside holds a 90% interest as the operator, while Tokyo Gas and Kansai Electric each have a 5% interest and are also the main buyers of LNG from this project. Following the success of NWS LNG, Woodside has successfully secured foundation Asian buyers and started producing from its second LNG project.

Japan

Page | 81

It is noteworthy that the three projects discussed above have been supported by independent oil companies with a small but important presence of Japanese buyers investing in upstream interests. These upstream investments by Japanese buyers in Australia have broken with tradition: not only are the buyers purchasing LNG, but they are investing in the project in the role of seller; in short, they are creating a new business model.

Thanks to their successful proactive involvement in both upstream and downstream developments in past projects, Japanese companies plan to invest in new projects as well. Among seven new LNG projects currently under construction, Japanese companies have invested in at least six, in both or either upstream and downstream infrastructure. After the success of Darwin LNG and Pluto LNG, more upstream investments by Japanese utilities will be seen.

Another notable project financed by a Japanese company as project operator, the Ichthys LNG, led by INPEX, is currently under construction in the Northern Territory, with two trains of 11.4 bcm/yr. This project is symbolic in the LNG industry for its having a Japanese company as operator for the first time in such a large-scale LNG project, leading all the development from gas exploration to offtake. INPEX has been investing in this project since 1998, when it first participated in an open bid and acquired the permit. After the first drilling campaign in 2000, the presence of gas and condensate in all exploratory wells was confirmed. After approval was granted by federal and state governments, FID was reached in 2012 and construction started soon after, with completion targeted for the end of 2016. This project is notable not only for its operation by one single Japanese company, but also for the involvement of many Japanese companies all along its value chain. Starting with the construction phase, INPEX awarded the engineering, procurement and construction (EPC) contract to the joint venture formed by JGC, KBR and Chiyoda. JGC and Chiyoda are world-leading, integrated engineering companies with many projects executed in many countries around the world. Also, USD 20 billion in project financing has been finalised, one of the largest ever arranged in the international financial market. This financing includes a loan agreement with the Japan Bank for International Cooperation (JBIC) of up to USD 5 billion, co-financed up to USD 16 billion in total by other financial institutions, including seven Japanese commercial banks. Needless to say, most of the LNG sales purchase agreements have already been signed by several Japanese utilities and LNG will be shipped to Japan once production starts.

Korea

Korea, which has been importing LNG from Australia since the early years of Australian LNG production, has a long-term contract with NWS LNG. However, the import volume did not exceed 1 bcm until 2009. Although the world's second largest LNG importer after Japan, Korea is different from Japan in that there it has a limited number of participants in the LNG industry. With Kogas, a public gas company established by the Korean government in 1983, having exclusive LNG importation rights, Korea imported LNG for the first time in 1986 from Indonesia and subsequently diversified its supply sources to other regions, including Australia. In addition to buying LNG from Australia, Kogas bought a 15% interest in GLNG, led by Santos, as well as signing a long-term contract to buy 4.8 bcm over a 20-year period after production starts. Subsequently, Kogas announced another upstream investment for the purchase of 10% interest from Prelude FLNG, the world's first FLNG development led by Shell. This project is recognised as one of the greatest technical challenges in

the LNG industry; after completion, it will be the largest offshore floating facility in the world, with a capacity of 3.6 mtpa (4.8 bcm). The facility is currently under construction at the shipyard of Samsung Heavy Industries in Korea.

Although Korea appeared keen on investing in various LNG projects in Australia, some deals did not succeed. Kogas agreed on non-binding LNG contracts with Chevron for Gorgon LNG in 2009 and Wheatstone LNG in 2010, but the deals collapsed after the Korean government did not give the final approval. These failures have suspended Korean investment in Australia, with Korean companies focusing on other potentially competitive US projects.

China

China began importing Australian LNG from NWS LNG, based on a long-term contract, in 2006. It was the first LNG import ever for China, which opened its first LNG receiving terminal in Guangdong in 2006, operated by CNOOC. Chinese LNG imports from Australia have increased significantly, from less than 1 bcm in 2006 to about 5 bcm in 2012, which makes it the world's second largest importer of Australian LNG. Moreover, CNOOC and NWS LNG signed conditional joint-venture agreements in 2003 that allowed CNOOC to acquire an interest in NWS LNG, which entitles CNOOC to hold gas and associated liquids approximately equivalent to a 5.3% interest in the project.

China is investing in several Australian LNG projects currently under construction. It is interesting that all investments by Chinese companies are in CBM-to-LNG projects in eastern Australia. In the QCLNG, led by BG, CNOOC signed a binding agreement in 2013 and acquired a 50% interest in the first train of the liquefaction facility, along with a long-term LNG contract for 6.8 bcm (5 mtpa) for over 20 years, starting in 2015. Sinopec, one of the three major state-owned companies in China, joined the APLNG project, with its interest totalling up to 25%. The company also signed a long-term LNG contract in 2011 for the purchase of 5.8 bcm (4.3 mtpa) over 20 years, and subsequently added another contract for the purchase of 4.4 bcm (3.3 mtpa) of additional LNG sooner or later. Another Australian project with investments by a Chinese company, Arrow LNG, is still waiting to be listed as new potential project. It is another CBM-to-LNG project in Queensland, with a proposed production capacity of 10.8 bcm/yr, based on two trains in the first phase, which could be expanded up to 24 bcm/yr, to a total of four trains. This project was originally initiated by Australia's Arrow Energy, but this company was taken over in 2010 by a joint venture between Shell and PetroChina. PetroChina agreed to offtake 5.4 bcm/yr from the first train on a long-term basis, with Shell taking the remaining volume.

Chinese Taipei

Chinese Taipei has been a foundation buyer of LNG since 1990, and has agreed to three longterm contracts with Indonesia, Malaysia and Qatar so far, with other volumes imported on a spot basis. CPC, a state-owned company, is the only company to import LNG to Chinese Taipei and its import volumes are increasing every year. Catching the tide of recent development of Australian LNG projects, CPC has made investments to acquire upstream interests in two projects, Prelude FLNG and Ichthys LNG. The share of interest in each project is 5% for Prelude FLNG and 2.625% for Ichthys LNG. CPC also signed long-term LNG contracts with these two projects with 2.7 bcm/yr (2 mtpa) from Shell's global portfolio, including Prelude FLNG, and 2.3 bcm/yr (1.75 mtpa) from Ichthys LNG.

Before making these two investments, CPC had signed a contract for purchasing up to 3 mtpa of LNG over 15 to 20 years from one of the largest LNG projects in Australia, Browse LNG. Driven by Woodside, this project was initially planned to produce 16.3 bcm/yr with four liquefaction trains. Although it completed FEED in early 2012, Woodside decided not to build Browse LNG as the project did not meet its economic criteria. The contract signed between Woodside and CPC expired in June 2012 without further extension due to the uncertain time frame of the project.

Malaysia

Malaysia's NOC Petronas has thus far made one major investment in Australia. With Santos as its operator, Petronas decided to participate in GLNG as a partner in 2008, acquiring 40% of project interests at the beginning and subsequently diluting its share to 27.5% by sharing with other project partners Total and Kogas. Two liquefaction trains with 10.6 bcm/yr (8.6 mtpa) in total are planned, with production expected to start in 2015. As a stakeholder in this project, Petronas signed a long-term LNG contract with Santos in 2010 for the purchase of 3.5 mtpa over 20 years. The LNG venture was Malaysia's first LNG investment in Australia, and the first venture into unconventional gas for Petronas.

Page | 83

India

No Indian companies have invested in Australian upstream projects to date, and it is conceivable that opportunities for investment in the near term will be limited, considering the current situation of cost overruns in Australia. India has imported LNG from Australia in the past, but these volumes were low and imported on a spot basis. In 2009, Petronet, an Indian oil and gas company formed by the Indian government, signed a long-term LNG contract with ExxonMobil from the Gorgon LNG for 2.0 bcm/yr (1.5 mtpa) over 20 years.

East Africa

The supply picture

Africa is not new to the LNG industry. The region became the world's first LNG exporter with the commencement of Algeria's Arzew LNG plant in 1964. Over the years, more countries in the region joined the exclusive group of LNG exporters, with Angola being the latest addition when its LNG plant came online in 2013. Up to now, all of the countries involved have been located in the northern and western parts of Africa. But the recent substantial discoveries of natural gas in Mozambique and Tanzania will not only allow East Africa to finally join the LNG exporters' group, but also enable it to surpass other parts of Africa to become one of the largest LNG exporters in the world through the huge discoveries of natural gas reserves in the two countries. To date, more than 150 trillion cubic feet (tcf) of recoverable natural gas resources have been discovered in Mozambique and around 40 tcf of resources in Tanzania, around the same as the gas reserves of Australia. These resources are more than enough to cover the annual gas demand in France for 100 years.

Like in other regions, the industry's main participants are also involved in the development of LNG projects in East Africa, which can be construed as a sign of confidence in the future natural gas industry in the region. While Eni and Anadarko are leading LNG project development in Mozambique, Statoil and BG will spearhead the development of the LNG plant in Tanzania. In both countries, the LNG plants will be developed in joint ventures. In Mozambique, the liquefaction plant will be jointly built by Anadarko and Eni and with an initial capacity of 20 mtpa (four trains of 5 mtpa each) when operational. The joint LNG plant will receive gas from both Areas 1 and 4, which is sufficient to support the plant's eventual capacity of up to 50 mtpa. Besides the joint LNG project with Anadarko, Eni is also considering building a separate floating LNG project for its Area 4. Eni's plan for a floating LNG facility appears to be gaining momentum, as it has been announced that the company is on track to award the EPC contract for the planned 2.6 mtpa FLNG project in 2015. There is also a plan to expand the initial one-train project to three trains to bring the total capacity to 7.8 mtpa, double the capacity of Shell's Prelude FLNG project in Australia (3.6 mtpa capacity).

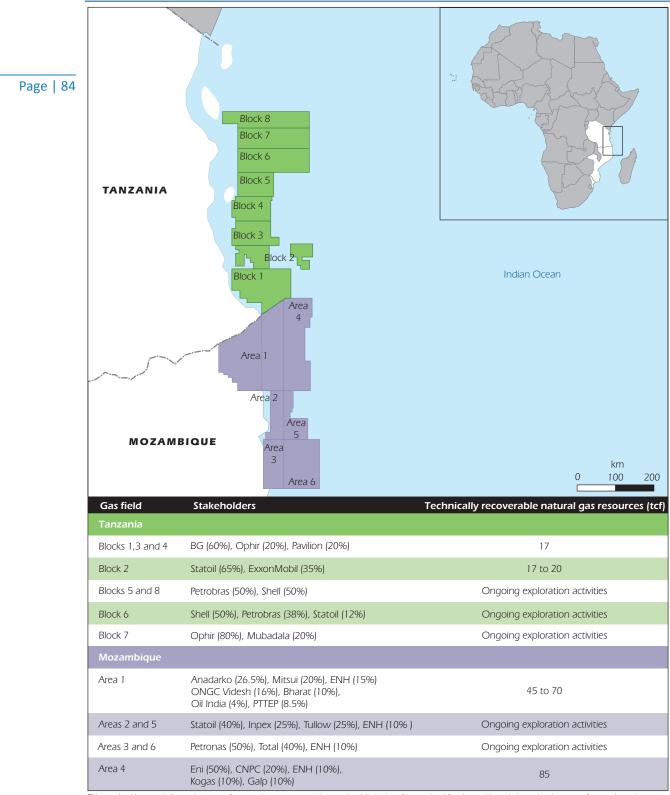


Figure 37 • Gas reserves in Mozambique and Tanzania as of October 2014

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Meanwhile, in Tanzania, Statoil and BG also plan to jointly develop an LNG project with 10 mtpa capacity from the two trains planned. The recent gas discoveries in Tanzania's Block 1 by BG and Block 2 by Statoil in June 2014 increase the probability of a third train for the project, bringing the total project capacity to 15 mtpa. Statoil and its partner ExxonMobil have been involved as

operators in other LNG plants and thus will add credibility to the LNG project. ExxonMobil's experience in developing and operating Papua New Guinea's first LNG project that commenced in April 2014 could be a valuable asset; Papua New Guinea and Tanzania are completely new to the LNG business and in both cases there is virtually no infrastructure available to support the project's initial development.

In spite of the advantage that Tanzania's LNG players have in developing and operating an LNG Page 85 plant, Mozambique is poised to become the first country to export LNG from East Africa. As highlighted in the Medium-Term Gas Market Report 2014 (MTGMR 2014) (IEA, 2014a), huge gas reserves and a favourable domestic gas policy towards LNG exporting and policy implementation suggest that Mozambique has the upper hand for realising LNG development in East Africa. In contrast, Tanzania may be faced with local opposition to the LNG plant's site, as the government was reportedly promising the residents in Mtwara that the LNG plant would be built in that area, while the companies involved prefer to build it in Lindi. Tanzania's domestic gas policy does not help, either: the "Natural Gas Policy of Tanzania 2013", approved by Tanzania's cabinet in October 2013, states that the domestic market will be given first priority over the export market in gas supply. As the total resources are not as great as in Mozambique, a potential disruption of gas exports in favour of the domestic market would make foreign investors think twice before investing in the country. The negative impact of this policy was demonstrated in the gas shortage situation in Egypt, during which one of its LNG plants was shut down due to insufficient feed-gas and the other one declared force majeure as the national government diverted the export supplies to the domestic market.

Investments from Asian companies

Asian companies made a number of huge investments in East Africa in 2013. CNPC bought a 28.57% interest in Eni East Africa for USD 4.2 billion, which is equivalent to a 20% interest in Mozambique's Area 4. ONGC Videsh also participated in the race through purchase of Anadarko's 10% interest in Mozambique's Area 1 for USD 2.64 billion. INPEX, too, joined its fellow Japanese company, Mitsui, in Mozambique by acquiring Statoil's 25% share in Areas 2 and 5.

Meanwhile, in Tanzania, Pavilion, the LNG investment arm for Singapore's Temasek, agreed to pay Ophir USD 1.3 billion for a 20% interest in Blocks 1, 3 and 4. GAIL, which also participated in the bid but was outbid by Pavilion, is negotiating with Ophir for the purchase of a 10% interest from Ophir's remaining equity portion in those three blocks.

These investments indicate Asian companies' confidence in East African LNG development after the huge gas discoveries made by Anadarko and Eni in Mozambique's Rovuma Basin and by Statoil and BG in Tanzania in 2012 and 2013. Considering East Africa's strategic location for Asian buyers, it is not surprising to see involvement from every key LNG import country, particularly India, the first to show interest. The involvement of key LNG importers is anticipated to have a positive impact on the LNG agenda in East Africa, since the companies will want to ensure a positive return on their investments, along with obtaining the lowest possible cost for delivery of LNG to their respective countries.

Japan

Mitsui has been present in Mozambique since 1986, but it was not until 2008 that it made its presence significant when it became a founding partner in the Anadarko project by acquiring a 20% interest in Area 1. Mitsui is a seasoned player in the LNG industry and has a strong presence in all major producing countries through equity participation in LNG projects in Qatar, Abu Dhabi, Oman, Indonesia, Australia, Russia and Equatorial Guinea. Mitsui is also heavily involved in LNG trade and supports Anadarko by selling large volumes of LNG, especially to Japanese buyers.

Meanwhile, INPEX entered the Mozambique natural gas industry in 2013 by acquiring a 25% interest from Statoil. Like Mitsui, INPEX is involved in LNG projects worldwide, notably in the Asia-Pacific region. INPEX is the operator for Australia's Ichthys LNG project, which is expected to be online by 2017, and the company is one of the shareholders in Australia's Prelude LNG. INPEX is also constructing an LNG regasification terminal in Niigata, Japan, that will receive LNG from its overseas projects. However, INPEX's strength is in upstream exploration and production activities, especially in North America, Europe, the Middle East, Africa, Indonesia, Australia and Japan.

Page | 86

The involvement of Mitsui and INPEX in Mozambique indicates that some of its LNG will definitely be directed to Japan, especially considering that Japanese buyers are looking to diversify their LNG supply portfolio in a quest to stabilise supplies and make gas prices more competitive. This is in line with the statement by Mitsui that it plans to sell at least 5 mtpa to Japan; likewise, the main Japanese buyers – Tokyo Electric, Tokyo Gas and Osaka Gas – have identified Mozambique for potential LNG supplies.

Korea

Kogas, the world's largest LNG buyer, joined the Eni-led consortium in 2007 with a 10% interest in the exploration and production activities in Mozambique's Area 4. Unlike for Australia's and Canada's projects, in which Kogas is considering reducing its interest due to potentially low profitability, it hopes to enlarge upon its current 10% interest in Mozambique's giant Area 4 gas field in light of its promising outlook.

Kogas is also involved in the gas pipeline project in Mozambique. It is currently constructing a 59 km gas pipeline in Maputo in a joint venture with ENH that will supply gas to the city from 2014 to 2033.

China

CNPC, China's largest oil and gas producer and supplier, began its strong presence in Africa with involvement in Sudan's oil and gas industry in 1996, and since then has been expanding into other African countries, including Algeria, Chad, Libya, Niger, Nigeria, South Sudan and Tunisia. CNPC's latest entry in Africa was its acquisition of Eni's assets in Mozambique in 2013, for a 20% interest in Area 4. CNPC is also involved in other LNG projects through equity participation in Australia's Browse LNG project in December 2012, and through the purchase of a 20% interest in Russia's Yamal LNG project in 2013.

India

In 2008, Bharat Petroleum acquired a 10% interest from Anadarko for participation in Mozambique's Area 1, joining its fellow Indian company Videocon, which acquired the same interest from Anadarko earlier. In 2013, ONGC Videsh, together with Oil India, which holds a 4% interest, successfully ventured into the project after taking over Videocon's shares. ONGC Videsh then increased its shares by another 10% through acquisition of Anadarko's equity portion, bringing the total percentage held by Indian companies in Area 1 to 30%.

In Tanzania, GAIL is still negotiating with Ophir for the remaining shares in Tanzania's gas field after losing the bid to Pavilion for the 20% interest in Blocks 1, 3 and 4.

Indian companies are expected to target LNG produced in East Africa, given its proximity to India. Indeed, India is closer to the region than the other Asian markets. The savings of the shorter shipping distance compensate for the probable lower price paid by the Indian buyers, judging by the historical price differences with the Far East market and repeated calls by Indian buyers for competitive LNG pricing.

Thailand

PTT is a relatively new player in the LNG industry. It made its entrance through its Map Ta Phut LNG regasification terminal in 2011, the first of its kind in Thailand and Southeast Asia. PTT was reportedly in the midst of discussions with Anadarko on the potential of LNG from Mozambique and had signed a preliminary supply agreement with Anadarko in late 2013.

PTTEP, the exploration and production arm of PTT, has an 8.5% interest in Area 1 through acquisition of Cove Energy in 2012. PTTEP became the successful bidder at USD 1.9 billion after Shell pulled out of the race.

Singapore

Singapore's Pavilion surprisingly agreed to buy 20% of Ophir's shares in Blocks 1, 3 and 4 in Tanzania. Together, these blocks hold an estimated 17 tcf of gas resources. Pavilion is a newcomer to the LNG industry; it was set up by Temasek in 2013 as its LNG investment arm. The incorporation of the company is motivated by Singapore's ambition to become Asia's LNG hub.

Malaysia

Petronas, Malaysia's state-owned oil and gas company, has a strong presence in Africa through its involvement in upstream and downstream activities across the continent, notably in South Africa (where it has an 80% share in Engen Limited), Sudan and Egypt.

Petronas made its entrance in Mozambique in 2002 when it was awarded rights to the Zambezi Delta Block, and in 2008 it was awarded a contract for Areas 3 and 6 with an 80% interest. Petronas's shares were reduced to 50% when it entered into a farm-in agreement⁹ with Total in 2012, giving Total a 40% interest in those blocks. To date, no gas discoveries have been reported from these areas, but they hold great potential based on the huge findings in Areas 1 and 4.

Petronas is also involved in Australian and Canadian LNG projects, Mozambique's main competitors in the world LNG market. Malaysian LNG plants in Bintulu, of which Petronas is the operator, produced 25.1 mtpa of LNG in 2013, making it the world's second largest LNG exporter behind Qatar and just ahead of a fast growing Australia.

Outlook for East African LNG

The potential for East Africa to become one of the world's leading LNG players based on its competitive advantages over other regions is promising. Its geographical location is perfect for serving Latin American, European and Asian markets, and has proven to be a key attraction for both investors and offtakers. As the closest Asian market, India is perceived as a natural market for East African gas. Unlike existing LNG projects in the Asia-Pacific region, where shipping distances to the Far East and Southeast Asian regions are shorter than to India, East Africa can afford to offer lower prices to Indian buyers thanks to freight savings of approximately USD 0.5/MBtu. Participation by several Indian companies in Mozambique, and the ongoing discussion between GAIL and Ophir for a stake in Tanzania, exemplify this benefit. East Africa's geographical situation also offers arbitrage opportunities based on current price divergences, particularly during winter in the northern hemisphere.

⁹ An arrangement whereby an operator buys in or acquires an interest in a lease owned by another operator on which oil or gas has been discovered or is being produced. Often farm-ins are negotiated to help the original owner with development costs and to secure for the buyer a source of crude oil or natural gas (www.mineralweb.com/library/oil-and-gas-terms/farm-in-definition).

Equally important as security of supply for LNG buyers is supply diversity, especially in the Asia-Pacific region where supply alternatives via pipeline are not as extensive as in North America and Europe. It is for this reason that Asian buyers are extending their LNG supply portfolios into East Africa. That East African projects have conventional gas fields adds to their attractiveness, as unconventional gas, with the exception of US shale gas, generally incurs higher costs and is more difficult to produce. The gigantic size of Mozambique's gas fields will further reduce unit costs, giving an advantage to developers.

At the same time, the current arrangements applied by the project developers indicate that the conventional merchant-mode business model will be employed in East Africa, whereby the project developers take on all the risks involved in producing LNG, including supplying feed-gas to the plant, before selling it to buyers on DES or FOB bases. The majority of US LNG projects employ a different business model, the tolling model, whereby LNG buyers have to pay a tolling fee to the LNG project developers for the liquefaction of LNG and are subject to the risks involved in securing the natural gas, including security of supply and price volatility.

While both models have advantages and disadvantages, East Africa may benefit more from LNG buyers with a traditional mentality who prefer the conventional business model. Moreover, some LNG buyers may feel that the take-or-pay (ToP) mechanism is the lesser of two evils compared to the fixed liquefaction fee of around USD 3/MBtu. There are typically two types of settlements under the LNG contract's ToP mechanism: the first type requires the buyer to pay the contract price for volumes not taken. The buyer is then compensated by the seller once the "distressed cargo" is disposed, while the second type of settlement will allow the buyer to receive the volume not taken at a later date after incurring the ToP penalty. The preference for this model has already been demonstrated by PetroChina, a subsidiary of CNPC, when its representative stated at a conference in the United States that, while the country is keen to buy LNG from the United States, it does not favour the current business model for US LNG projects but prefers the traditional one.

Another Chinese company, CNOOC, exemplified this preference by signing an HoA with BP for a 20-year contract, with the price reportedly set against the HH index. Although BP indicated that the supply will come from its global portfolio, most or all of the volumes are likely to be sourced from Freeport LNG, from which the company has offtake volumes of 4.4 mtpa. The deal provides a dual advantage for CNOOC, as it will be able to get US LNG on an HH basis, minus the risks of supply security and a fixed liquefaction fee.

However, East Africa also faces numerous challenges that may undermine its efforts to become one of the world's largest LNG suppliers:

 Timing: East Africa's natural gas development comes at a critical time when LNG buyers are looking for lower LNG prices following the US shale gas boom. Furthermore, the global LNG market is forecast to be long when many new LNG projects come on-stream post-2016. Australia's LNG projects currently under construction are fortunate, as they managed to secure contracts before the US shale gas boom; this is not the case for East Africa and newly proposed LNG projects in Australia and Canada.

The success of East African LNG projects may therefore hinge on whether it is decided to expedite the projects to capture whatever demand remains from the market share, or to wait and hope that not all proposed LNG projects will be online as predicted and there will be uncontracted demand to capture, including from existing contracts that will expire by 2020, at more favourable terms. Anadarko seems to prefer the former: it announced its plan to sign a HoA with potential LNG buyers in 2013 and 2014, for FID in late 2014, to reach its target of shipping the first cargo in 2018. Anadarko's CEO announced in March 2014 that the company had sold two-thirds of its Mozambique LNG plant capacity to Asian customers and is on course

to announce FID by the end of this year. However, since all the contracts signed are on nonbinding terms, it remains to be seen whether all potential customers will eventually sign longterm agreements with the project in view of the strong supply competition from other regions, notably North America.

- High capital costs: In the United States, LNG plant developers are not involved in the upstream investment, and construction of liquefaction plants and costs are lower because most of the projects are based on converting existing regasification terminals; this is not the case for East Africa. Apart from projected freight savings from shorter shipping distances to Asia compared to those for the US projects, East African developers must manage high capital costs. The LNG plants' unitisation initiative, though initially propelled by the concerned governments, is a good move by LNG project developers to reduce development costs through the sharing of LNG production facilities, and shortens the construction period compared with building separate LNG plants.
- Financing: The development of LNG projects requires huge capital investments, and most of the time developers will look for external financing in addition to contributions by all project partners. Normally, lenders will review the terms and conditions of the long-term sales agreements to ensure projects have a stable stream of revenue before giving approval for financing. ToP is a mandatory clause in this approval process and, traditionally, lenders are comfortable with oilindexed pricing as it allows them to forecast the project's income throughout the project's tenure.

In contrast, the current trend is towards more flexible terms whereby ToP and all rigid terms such as oil-indexed pricing and fixed destination are becoming obsolete, which can be seen in all LNG contracts signed by the US projects. It will be interesting to see how LNG developers achieve a balance between satisfying lenders' financing requirements and attracting potential buyers with terms acceptable to them.

- Lack of infrastructure and labour force: Both Mozambique and Tanzania are considerably undeveloped territories with no or very limited infrastructure to support extensive resource development. The remoteness of the proposed locations for LNG development amplifies the magnitude of this obstacle, which will hinder the region's efforts to become the world's primary LNG supplier by 2018. Eni and BG have already voiced their concerns; Eni mentioned specifically that it will be very challenging to meet the 2018 target given the current state of infrastructure. At the same time, the East African region is competing with other new LNG projects in North America and Australia for skilled labour, as it takes time for a region to train its own labour force for this industry. Intensive and synchronised efforts among governments, project developers and the private sector to develop competent workers and the required infrastructure is thus vital for the development of LNG projects in these countries.
- Energy poverty and potential domestic demand: In both countries a substantial proportion of
 the population does not have access to modern energy supplies. The government objectives
 for energy access and domestic development are completely legitimate. In a number of oil
 and gas-exporting countries that had been in a similar starting position at the time of the
 discoveries, such objectives are often associated with fossil-fuel subsidies, which are known to
 have many unintended effects, as highlighted in the IEA World Energy Outlook 2011 (WEO 2011)
 (IEA, 2011). The WEO 2011 lists ten negative impacts and concludes that fossil-fuel subsidies
 result in an economically inefficient allocation of resources and market distortions, while often
 failing to meet their intended objectives. Thus, it is incumbent upon Mozambique and Tanzania
 to develop a natural gas framework that will benefit both present and future generations;
 they have the advantage of being in the early stages of their natural gas development, with
 the opportunity to learn from other countries' experiences with fossil-fuel subsidies.
- Political stability: Tanzania has been enjoying stability since its independence in 1961 and is considered a model of peace and political stability for other African countries. In contrast,

Mozambique was involved in a two-decade civil war beginning in 1975 and ending with the General Peace Agreement of October 1992. Since then, Mozambique has been enjoying peace and even appeared on the list of the 50 most peaceful countries in the world, surpassing Tanzania in a 2012 report published by Global Peace Index. However, this current state may be threatened by the conflict between the government and the country's largest opposition party, Renamo; the 1992 peace pact was broken in October 2012 when government forces attacked the base of Renamo's leader. However, the undeclared war that started in central Mozambique in 2013 appears to be resolved through the recent peace deal signed in September 2014. The conflict's impact on the development of the nascent natural gas industry is unknown, although it can be expected that any government in power will support the industry for the anticipated revenue and financial benefits it will bring to the country. Political unrest may, however, cause international investors to think twice.

There is no doubt that natural gas development will bring tremendous benefits to Mozambique and Tanzania, which are currently among the world's poorest countries. Given their gas resources, they could become the largest exporters from Africa. However, proactive and concerted actions are needed from all relevant stakeholders to overcome the challenges and ensure that East African LNG becomes available by the end of this decade.

Enhancing market efficiency: Regulatory measures in importing countries

In 2013, the IEA issued a report, *Developing a Natural Gas Trading Hub in Asia* (IEA, 2013c), which looked at what was necessary to develop a trading hub in Asia. The main lessons from the report p are that a competitive market (be it national or regional) would be required in order for such a trading hub to be developed. This market would need to meet a set of institutional and structural requirements to create the confidence to attract new participants (namely, financial) and to encourage market players to use a trading hub for balancing their portfolios.

Among the first steps for this process to be completed are a "hands-off" government approach, an unbundling of transport and commercial activities, and price deregulation at the wholesale level. Once these conditions are met, sufficient network capacity and non-discriminatory access must be made available. A competitive number of market participants with the involvement of financial institutions is also required.

One of the main conclusions of the IEA report is that such a process would take time: experience from Europe and North America shows that a decade is necessary. Considering that in even the most mature Asia-Pacific markets the basic requirements for a wholesale market are missing, the development of a trading hub might take even longer. Singapore seems to be the front-runner in this race, but, given the size of the Asian market (current and future) there is room for others as well.

Progress made in Asian countries since early 2013

This section examines the progress made by various Asian countries in liberalising their gas (and sometimes wider energy) sectors since the publication of *Developing a Natural Gas Trading Hub in Asia* (IEA, 2013c) in February 2013.

Requirement	China	India	Japan	Korea
Hands-off government approach	-	-	-	-
Separation of transport and commercial activities	+/-	-	+/-	-
Wholesale price deregulation	+/-	-	-*	-
Third-party access (TPA)	??	??	-*	-
Sufficient network capacity	-	-	+	-
Competitive number of market participants	-	+	+	-

Table 12 • Competitive market requirements of Asia's largest LNG importers

Notes: + = currently contributing towards a competitive natural gas market; - = currently not contributing towards a competitive natural gas market; +/- = making progress; ?? = currently unclear.

* Japan is undertaking a gas reform which would result in wholesale price deregulation and efficient TPA; it can be considered to be at the very early stages of the process.

Japan

After the Great East Japan Earthquake occurred in March 2011, followed by the Fukushima nuclear accident, Japan has been paying more attention to energy security. This triggered discussions on restructuring the current electricity and gas systems. Self-sufficiency declined while dependency on fossil fuels increased, impacting not only Japan's energy balance but also its trade balance, as Japan encountered trade deficits in 2011 for the first time in 31 years.

To set the basic direction of its energy policy, Japan issued the Basic Act of Energy Policy in June 2002 and established its first Strategic Energy Plan in October 2003 with the purpose of ensuring the steady implementation of its energy policy based on mid- to long-term perspectives. This plan was reviewed roughly every three years to reflect the changes in the energy market. The current Strategic Energy Plan was reviewed in April 2014, the first revision after the Great East Japan Earthquake. The new energy plan gives a direction to each energy source, for example a reduced dependency on nuclear power generation through energy savings and the introduction of renewable energy, as well as the improved efficiency of thermal power generation. In addition, the new energy plan indicates the importance of system reforms for both electricity and gas. System reforms are expected to increase competition in the domestic energy market and promote the efficiency of the energy industries, as well as contribute to the revitalisation of local industry. The nuclear accident revealed the inflexibility of Japan's power system: the low capacity of the interconnections between different regions and the mechanism for broad-area operation of power grids. It also drew attention to other issues caused by the Japanese power sector's regional monopoly system: little competition in the current electricity market and strong price control by power companies. Moreover, the discussion of electricity system reform has also created an opportunity for the discussion of gas system reform.

Progress of electricity system reform

To improve the flexibility of the electricity system and create a more competitive market in Japan, the cabinet approved the Policy on Electricity System Reform in April 2013. It is based on three major objectives:

- securing a stable supply
- suppressing electricity rates to the maximum extent possible
- expanding choices for consumers and business opportunities.

With a greatly decreased reliance on nuclear power in Japan after its nuclear accident in 2011, it became necessary to diversify its power sources and introduce a more distributed power supply system to improve stability. Keeping electricity rates modest and enabling all consumers to choose suppliers at their own discretion in a liberalised market situation are also key objectives of this system reform.

The policy consists of three stages: the first stage is to set up an independent body to co-ordinate supply and demand across the nation's power grid in 2015; the second stage is to fully liberalise Japan's retail market by around 2016; and the third stage is to further secure the neutrality of transmission and distribution sector through the legal unbundling and full liberalisation of electricity rates between 2018 and 2020. The reform has already made a step forward, with the first and second stages already approved by parliament in November 2013 and June 2014. It is planned to submit the bill to parliament for the final stage in 2015. As for the first stage, an independent body, tentatively named the Organisation for Cross-regional Coordination of Transmission Operators (OCCTO), will gather information from power companies under supervision of the government; this function is expected to strengthen nationwide supply-demand balancing in both normal and emergency situations, and to strengthen the transmission infrastructure, such as frequency converters and interregional power lines.

Full liberalisation of the electricity market in Japan would also offer the opportunity to break down the regional monopoly by power companies in the future. Liberalisation of the electricity market in Japan started in 1995 when independent power producers (IPPs) were allowed to provide electricity to power companies, and also power supply businesses for specific electric utilities were allowed to supply electricity directly to customers in a defined area. A degree of liberalisation has taken place since then, with suppliers currently allowed to sell electricity to

users requiring more than 50 kilowatts (kW), although market competition was not yet completed. It is expected that freeing up the whole retail market will allow for more healthy competition in the market with the entry of new suppliers such as from the gas, oil and telecommunication sectors providing customer with variable rates and services. Finally, it is hoped that securing the neutrality of the transmission and distribution sector through the legal unbundling and full liberalisation of electricity rates as the third stage of reform will bring further liberalisation to the market. The transmission and distribution divisions of each power company will be unbundled, thus the transmission and distribution networks will be neutrally provided to other electricity suppliers for their use, encouraging more competition.

Page | 93

It is uncertain whether electricity system reform would really bring a more competitive market to Japan with new entrants and investments. With all nuclear power plants currently offline, utilities are facing higher fuel costs for thermal power generation, and it is uncertain whether the reform could reduce electricity rates in the end. However, the ten utilities currently monopolising the regional market will definitely face challenges from new entrants in the whole free retail market, and will have to compete with them as never before.

Gas system reform

Japan's electricity system reform triggers gas market reform

Japan's electricity system reform has accelerated discussions on the reform of the gas market, which should be consistent with the electricity system reform in terms of full retail liberalisation, accessibility, neutrality of the network and competitiveness of the market. As gas was already playing a major role in the Japanese energy sector even before the nuclear accident, securing a stable and low-cost gas supply as well as developing a strong infrastructure and competitive gas market has become a top priority.

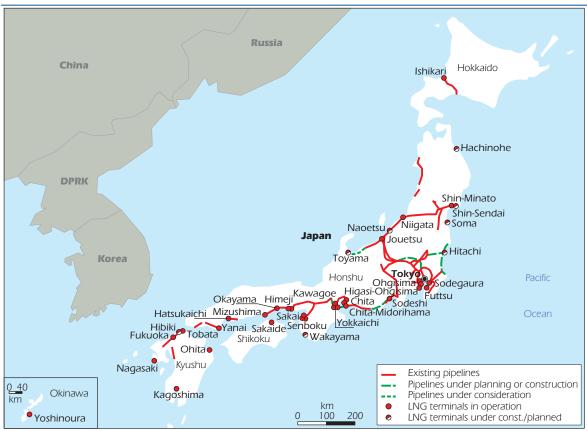
In order to realise a well-established gas system in the near future, the reform under discussion has four objectives:

- establish new services and businesses
- lower gas tariffs by promoting competition
- develop a gas supply infrastructure
- protect consumer benefits and security.

However, care needs to be taken to ensure that the gas industry continues to operate under different circumstances and features from the electricity industry in Japan. While the electricity industry is monopolised by ten regional power companies and a few other suppliers, there are as many as 207 gas companies in Japan, 1 600 including all the small-scale utilities supplying gas to their customers regionally. Unlike electricity distribution, which covers a wide territory, gas supply areas are more regionally based and scattered, with each company operating only within its territory and sometimes with no pipeline connecting to its neighbours. Liberalisation would open the door to new entrants to invest in the gas market, although the framework needs to be well-conceived to trigger real competition in the market and develop infrastructure, along with a safe and stable gas supply.

In addition to institutional liberalisation, accessibility to existing networks and facilities is important for gas system reform. As mentioned, gas operations are very regional. Pipelines are one of the most important facilities to provide gas to all users. It would be necessary to develop pipeline network connections to improve security measures in an emergency, although there are questions regarding who will invest in such infrastructure and who will manage it after operations start. LNG receiving terminals are also important facilities for the gas business. As Japan is highly Page | 94

dependent on gas imports, LNG receiving terminals have been built and in operation since 1969. There are currently 31 LNG receiving terminals in Japan, most operated by large-scale gas and power companies. In order to promote the participation of new entrants and diversify gas sources, TPA to LNG receiving terminals was recommended in the early 2000s. In 2004, under the control of METI and in collaboration with the Japan Fair Trade Commission, the existing guidelines that promoted fair gas trade were revised to support better accessibility to LNG receiving terminals for third parties, for example by developing an operation manual for the utilisation of LNG receiving terminals. More than 70% of the existing 31 LNG receiving terminals have already adopted the operation manual and provide TPA, although there seems to be no record of TPA to the facilities as of October 2014.





This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA (2014b), Natural Gas Information 2014, OECD/IEA, Paris.

The first exchange of LNG futures contracts

Along with the discussion of gas system reform, the Japanese government considered establishing an exchange for the trade of LNG futures contracts. Taking into account that Japan, along with other Asian buyers, has been buying LNG at relatively high prices (so-called Asian Premium), Japan has been working on securing gas with more transparency and competitive prices. Also, this could be an important step towards the transition of the Japanese or even the whole Asian market from a contract of oil-linked long-term mechanism to a one based on gas-to-gas competition.

Development of an exchange of LNG futures contracts in Japan could be seen as a natural development, since the country is the world's largest LNG importer, consuming around 40% of global LNG demand since its import volume rose more than 20 bcm/yr after the Fukushima nuclear accident in 2011. While the country has been the largest LNG importers for years, it is

paying one of the highest gas prices in the global LNG market, with most of the long-term contracts based on oil-linked formulas. Since current LNG transactions suffer from low liquidity and inadequate volumes for risk hedge measures to be taken against price volatility, developing an exchange of LNG futures contracts could create a place to hedge price fluctuation risk in LNG transactions. It is also expected to deliver a new, reliable price formula that reflects the real supply-demand balance of the LNG market rather than using a formula reflecting oil markets.

Page | 95

Box 12 • The LNG futures market initiative

The Japanese government began publishing a price index based on spot cargoes in April 2014 with the purpose of adding transparency to an opaque market and amidst concern about rising fuel costs in the wake of the shutdown of nuclear power plants after the nuclear accident. This move by the Japanese government is most likely the first time that an average spot price has been publicly released based on actual transactions. A spot cargo is defined by LNG contracts as the procurement of only one cargo per contract, not including any term contracts. The price of this cargo is deemed to be determined by LNG supply and demand, namely a fixed price, unlike the price of oil-linked LNG. Such a price index is determined through surveys of LNG importers in Japan, mostly power and gas companies, as very few other companies are buying LNG. If the LNG is to be delivered on a cost, insurance and freight (CIF) or FOB basis, the price should be converted into DES. Meanwhile, spot cargoes for which the price is linked to a specific index such as HH, NBP or JKM, are excluded from the statistics. The price will be the simple average and not the weighted average of the difference prices, and will be reported only if there are more than two transactions by more than two companies. It is expected that this information is gathered by the government from related companies every month. The risk with this methodology is that there might be very few such cargoes, as the definition is quite restrictive. As mentioned earlier, Japan has contracted a large amount of supply. This price index is nevertheless was deemed the first step towards creating an LNG futures market, as other price indexes reported in the region were considered not transparent enough.

The next step leads to the creation of an LNG futures market. The LNG futures market should first of all serve as a risk-hedging place enabling market participants to hedge unpredictable risks such as price and supply/demand changes. A reliable price indicator is required to reflect the supply/demand of LNG that would later serve as a benchmark in future long-term contracts (or in renegotiations of existing contracts). First, a cash-settled market should be created. This should also encourage the development of physical deliveries using the price of the LNG futures market. The participation of overseas players is encouraged, and this market could enable USD-denominated transactions.

Developing an exchange of LNG futures contracts is not easy. Above all, the existence of a reliable spot market is required. A mature futures market is always linked to spot market for the benefit of arbitrageurs. The expansion of transactions in the spot market would thus bring more players, including buyers, sellers and other investors, to the futures market and create an appropriate price signal reflecting the real value of the commodity in the market.

The problem for the LNG market is that the spot market is relatively undeveloped. There should be not only the possibility to make long-term contracts but also more supplies of spot cargoes to encourage LNG transactions and activate the spot market. To become an LNG trading hub with many LNG transactions, the development of infrastructure such as an adequate capacity of LNG storage is also necessary, along with the establishment of standard rules for the use of LNG storage by third parties who intend to invest in LNG futures contracts.

Korea

Korea is still trailing behind other mature Asian gas users in terms of the criteria necessary to develop a natural gas trading hub, namely wholesale price deregulation, access to infrastructure, sufficient network capacity and a competitive number of market participants. There has been relatively little development over the past year and a half in gas market liberalisation, despite

increased awareness of the high costs of natural gas imports. This drove the state-controlled Kogas to change its method of securing gas supplies.

Similar to Japan, Korea's gas demand has been met mostly by LNG imports with no pipeline connection with any other country. Due to Korea's variable seasonal gas demand and its priority of security of supply, Kogas had been relying heavily on spot and short-term supplies (around Page 96 20%) but is now trying to reduce this share. Meanwhile, long-term contracts linked to oil prices have been driving Korea's LNG import price to high levels, prompting Kogas to reconsider its strategy by teaming up with private companies.

- In January 2013, Kogas and Japan's Chubu Electric signed an LNG SPA with Italy's Eni for the purchase of 28 LNG cargoes for the period May 2013 to December 2017. This is the very first international joint purchase of LNG in Asia, and it was the first significant step towards the world's largest LNG importing countries agreeing to purchase LNG together.
- Also in October 2013, Kogas stated that the company was discussing joint LNG purchases with SK E&S, (formerly K-Power), one of the two Korean private companies that import LNG directly, bypassing Kogas, to reduce the LNG purchase price.

In spite of these changes to Kogas's LNG procurement strategy, liberalisation of the Korean gas sector has not been moving ahead. Since the establishment of Kogas in 1982, the Korean gas sector has developed in pace with increasing gas consumption, with demand reaching a record 52.9 bcm in 2013. Kogas, the largest LNG importer in the world, was given exclusive rights for the procurement of LNG and wholesale supply to the domestic market, while private city gas companies are in charge of retail. After revision of the Petroleum Administration Law in 1998, private companies were also allowed to import LNG, but only for their own consumption. Consequently, POSCO and K-Power started to import LNG in 2005 and 2006, respectively, but this does not create a competitive number of market participants. Korea is said to be working on a law to permit new entrants to buy and trade LNG in the country. Such a law could improve the conditions leading to the liberalisation of Korea's gas market, but so far reforms have failed due to opposition from unions and Kogas's management.

Since 2001, when the Korean government announced an initiative to split Kogas into three privately owned marketing companies and one publicly owned infrastructure company, there has been little progress. Under the supervision of MOTIE, security of supply remains a top priority for the Korean gas sector and Kogas is playing a pivotal role in avoiding supply shortages.

So far, Kogas' three LNG receiving terminals have not been approached by any third party. A negotiated third-party access (TPA) was introduced in 2006 for companies wanting to directly import LNG and needing to use Kogas facilities, but in practice it seems difficult to negotiate with Kogas and to comply with all the conditions for using their facilities, such as submitting an application five years in advance. The nationwide transmission pipeline, completed by Kogas in 2002, is also governed under a negotiated TPA regime, but there seems to be no third-party access to their network so far.

Since wholesale prices must be approved by the ministry and retail prices by local government, Korean gas prices are regulated with limited competition. The current wholesale pricing system, which consists of the material cost plus supply margin, allows Kogas to pass its LNG costs on to consumers and guarantees its operating costs. This means that there has been no price deregulation at the wholesale level, which is raising Korean gas prices. However, passing on these high prices to the end users is less and less accepted by the government, especially as private direct importers are signing contracts for less expensive gas. Direct imports by private companies could therefore be allowed in order to motivate Kogas to find less costly supplies, which would be a first step towards liberalisation, but effective TPA to infrastructure is needed.

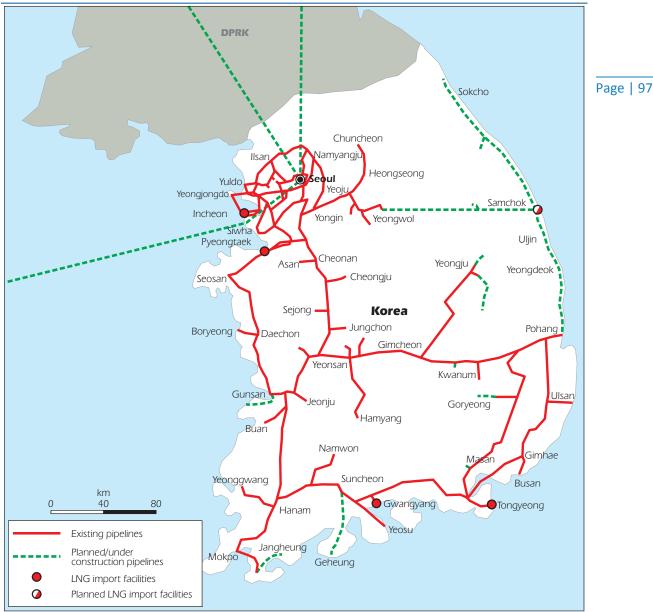


Figure 39 • LNG receiving terminals and main gas pipelines in Korea

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA (2014b), Natural Gas Information 2014, OECD/IEA, Paris.

Should changes be implemented at the wholesale price level, Kogas's financial situation would suffer, creating problems for a stable gas supply. It is therefore necessary for the company to find more affordable gas supplies.

China

China has been trying to address the many challenges it faces as its imports grow steadily. The IEA *Medium-Term Gas Market Report 2014* (IEA, 2014a) forecasts China as the second largest net importing region by 2016, after Europe. By 2019, China will import over 120 bcm. But recently, reforms are being taken to tackle the issues related to a larger import dependency. The combination of unbundling to open up for TPA to pipelines and a price reform leading to deregulation of the wellhead price is expected to stimulate China's production. However, despite progress towards a less regulated market, unbundling alone will not necessarily lead to third-party access; regulation

needs to be developed to make sure that efficient and transparent TPA to both pipeline and LNG infrastructure is available for all market players. The development of a spot market while unbundling production from transport activities, as happened in the United States in the 1980s, is limited by the fact that prices are now being linked to oil, rather than being set by the supply and demand balance for gas. Of note is that there has been no progress in developing a trading hub in Shanghai over the past two years.

Pricing reforms

Page | 98

One of the issues has been the inability to pass on the higher costs of imports to the consumers. Historically, Chinese natural gas has been priced on a cost-plus approach. In this regime, the wellhead price was regulated on a national level, as well as its consequent pipeline tariffs to reach the city gates. After the wholesale transaction, the price was adjusted by the provincial government based on economic disparity and local distribution costs. This resulted in large price differences between consumption sectors and between the several regions within China. But China's strong demand growth outpaced increases in domestic production, resulting in greater imports sourced through pipelines from Turkmenistan and Myanmar, and through LNG. The prices of these imports were higher than the regulated tariff for domestic production. For example, at the beginning of 2013 the average Chinese city-gate gas price stood at about USD 7.7/MBtu. Even at the Chinese border, the gas via pipelines was already more expensive, as Turkmenistan gas was priced at around USD 9.6/MBtu while Myanmar gas had an average price of USD 11.8/MBtu, both linked to oil. The costs of imported gas at the city gate are therefore higher due to the cost of transport within China. Some LNG import contracts linked to oil, saw even higher prices for spot cargoes, up to an average of USD 17.6/MBtu in 2013 from Qatar.

These higher prices for gas imports are not reflected in the fixed, regulated city-gate prices. The inability to pass on higher supply prices to the consumer has caused increased losses for companies like CNPC, China's largest importer of gas. In 2012, its loss was approximately USD 336 million (CNY 2.1 billion). As the government has targeted the share of gas in the primary energy mix to increase to 10% by 2020 from 5.9% today in order to tackle air pollution, the profitability of the business will further deteriorate. In addition, China has large shale gas resources which are expected to have a higher production cost than that of conventional gas. The government set a price premium for shale gas of around USD 2/MBtu in 2012; higher prices would also boost domestic gas production.

However, increasing energy prices could have a generally negative effect on the competitiveness of industries, which is an important aspect of overall economic growth. For China, though, the concerns about the need for cleaner air and security of the energy supply seem to take higher priority than maintaining artificially low prices while an increasing share of its population is becoming more able to pay higher prices. These circumstances caused the NDRC to continuously adjust the pricing regime.

Before changing the pricing regime of the whole country, a new pricing scheme was developed and tested in Guangdong province and the Guangxi Zhuang autonomous region. It consisted of netback market value pricing, by linking it to oil products. In this system, the city-gate price was set at 90% of the price determined by 60% high-sulphur fuel oil and 40% liquefied petroleum gas (LPG) traded in Shanghai.

Based on this pilot and on experiences with reforms in the power and water sectors, a nationwide price reform was implemented in July 2013. The change in pricing method would be gradual, with adjustments to both the method and the level of the price. The reform started with non-residential users, who were divided into two tiers, each with a separate pricing mechanism. While the pricing of the first tier remained based on the regulated pricing method, this price was increased by 15.4%, to an average of USD 8.9/MBtu (CNY 1.95/m³). This first tier covered the

supplies of 2012. The second tier covered the incremental supply of 2013 compared to 2012, which was priced according to the oil indexing from the pilot. The prices in the second tier were on average 40% higher than the increased regulated tariff, varying from 20% to 60% among citygate prices in the country. However, it should be noted that around 90% of the total volume was still priced at the first tier, as the second tier only applied to incremental supplies.

The NDRC aims to steadily raise the prices in the lower tier so that the price levels in both bands Page 99 will eventually converge, resulting a fully oil-linked gas price by 2015. Other price adjustment periods indicated that the reform could take longer, implying fully oil-linked pricing not before 2017. Nevertheless, the latest price increase of the lower tier took effect on 1 September 2014, raising it by 20.4% to USD 10.73/MBtu (CNY 2.35/m³).

This price reform has only been implemented for the non-residential sector, mainly industrial users and power generators. Although it covered about 80% of demand in 2012, it can be argued that industry is carrying the burden of the extra cost. The next step, price reform for the residential sector, was announced in March 2014. This reform consists of three price tiers, in which the price would be higher the greater the consumption. The first and lowest tier remains at the former price level and covers about 80% of residential consumers. The second and third tiers are set at higher consumption levels, with approximately 20% and 50% higher prices than the first tier.

Providing TPA

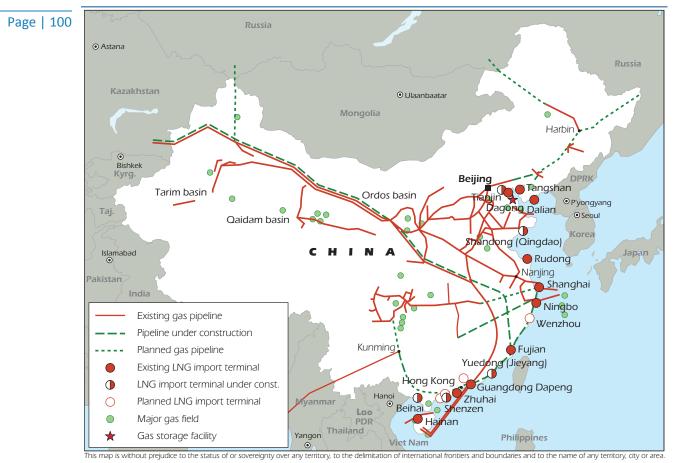
China announced that it would carry out multiple market-oriented reforms in its energy sector by 2020, according to a reform package called Decisions on Major Issues Concerning Comprehensively Deepening Reforms issued after the Third Plenary Session of the 18th CPC Central Committee in November 2013. This will induce private investments, notably in monopoly sectors such as pipelines. The document announced a potential separation of the transmission sector, which would be a radical change for Chinese industry and also for CNPC, which owns most of the pipeline network. Access would also be improved to some upstream resources for non-state-owned companies, notably for shale gas and other unconventional gas types. Finally, restrictions on market access to competition-based operations would also be removed, such as those in the downstream gas sector.

Increases in consumer prices, while the transport tariffs are still regulated, would also imply an increase of the wellhead price. It is estimated that the reform translates into an average price increase of around 25% for gas production. This increase will stimulate domestic production and could particularly stimulate the targeted development of shale gas.

Natural gas is produced mainly by CNPC, which has a share of approximately 75% of domestic production; the company is also the biggest owner and operator of pipelines, in which it has a share of around 90%. The production of small and mid-sized gas producers is therefore limited, as their main option is to sell their supplies to CNPC or to develop the gas for local consumption. This led China's National Energy Administration to make changes in the structure of the upstream and midstream gas sector, to further stimulate exploration and production on top of the price reform. The structural reform was announced in February 2014, stating that gas pipelines' operators should provide access to third parties under fair conditions.

The backbone of China's gas production is found in the Sichuan, Ordos and Tarim basins. These basins are not only important for conventional gas production, but they also contain a large share of the expected shale gas reserves. The Ordos and Tarim basins are linked to Beijing and Shanghai by the West-East pipeline system, which consists of three pipelines. Considering its key value as a link between the producing and consuming regions, this pipeline will be the first to be opened for third parties. To do this, CNPC has to separate its pipeline activities from its producing and marketing activities. The assets of the first and second West-East Gas pipelines are being transferred to a new company, the Shanghai-based PetroChina Eastern Pipelines Co., with an asset value of

CNY 82 billion (USD 13.1 billion). This new company would then be opened to private parties. In this opening, one option is to sell the company by public tender on an asset exchange. The public tender aims to involve the private sector in the traditionally government-controlled business.





Note: Lao PDR = Lao People's Democratic Republic; Kyrg. = Kyrgyzstan; Taj. = Tajikistan. Source: IEA (2014a), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris.

Another option is to sell the company to an affiliate, potentially United Pipelines Co. Ltd., as it has enough capital to buy such a huge asset. Although private parties will be more involved in gas transport, both options would still result in 50% ownership by CNPC, either because it would hold this portion of shares in the new company or because it already owns half of the affiliate. A final decision on how to open the new company to other parties is expected in the last quarter of 2014. Nonetheless, for CNPC, the sell-off is a way to raise capital to be invested in new production activities, where competition might begin as shale gas production is already open to private firms. The structural reform of opening up the West-East pipeline system to third parties could therefore lead to an increase in drilling activities and domestic production. Nevertheless, it should be noted that unbundling transport activities from the production companies does not necessarily mean better TPA.

India

Pricing reforms

India has two pricing mechanisms: the administrative price mechanism (APM) and non-APM. Gas priced at APM level is produced by NOCs and supplied to certain categories of consumers, such

as fertiliser producers or power plants. In 2010, the APM price was increased from USD 1.9/MBtu to USD 4.2/MBtu. Non-APM gas is more expensive and comes from either domestically produced gas from New Exploration Licensing Policy (NELP) and pre-NELP fields or imported LNG.

There have been further attempts to change the pricing regime. On 1 April 2014, the current agreement with Reliance Industries (RIL) for gas from the KG-D6 field expired. The price was linked to global oil prices, but with a cap at USD 60/bbl, which capped the field's gas price at Page | 101 USD 4.2/MBtu. In 2013, the Rangarajan committee recommended linking domestic gas prices with international prices. In July 2013, the Indian government announced a change in the pricing model driving the production-sharing contracts. The idea was to use an "arm's-length" gas price, similar to the spot prices in Europe and North America. As such, because a price does not exist in the Indian gas market, an alternative of an arm's-length price for an Indian gas producer was proposed using an average of two prices:

- an estimated netback price of Indian LNG imports at the wellhead of exporting countries, subtracting costs of liquefaction and transport for the past 12 months
- the volume-weighted price of HH, NBP and the Japan Custom-cleared Crude prices also for the past 12 months. This price would apply equally to all sectors.

The reform was expected to take effect in April 2014, but was postponed to an undetermined date due to the elections in spring 2014. Since then, the new government led by Prime Minister Modi decided in July 2014 to push back its decision by three months in order to have a wider consultation among stakeholders.

Providing third-party access

The Indian gas pipeline sector has moved from pure state ownership to a mixed structure of state and private ownership, with companies such as RIL and Gujarat State Petronet Limited building their own pipeline. The Natural Gas Act requires the Petroleum and Natural Gas Regulatory Board (PNGRB) to regulate access to pipelines and ensure fair trade and competition, specify a pipeline access code and determine transportation rates. There is a distinction regarding pipelines built before October 2007 (when PNGRB was appointed) and later: the new pipelines have to go through a bidding process. The tariffs are decided based on the successful bid, while for the existing pipelines the tariff is decided based on a 12% return on historical cost of capital plus reasonable OPEX. There is, unfortunately, very little information on whether access to pipelines works well in practice.

Meanwhile, a draft regulation on establishing and operating LNG terminals had been proposed by the board in 2013 to make it mandatory to offer at all times 20% of short-term uncommitted regasification capacity or 0.5 mtpa (whichever is higher). LNG import terminal operators did not appear enthusiastic about complying.

Singapore

The IEA 2013 Developing a Natural Gas Trading Hub in Asia report (IEA, 2013c) highlights that Singapore is the front-runner to develop a competitive natural gas market and trading hub in Asia, although the prospects for a competitive wholesale natural gas market in the region are limited at the moment.

Singapore has a free-market approach towards both its power and natural gas markets. Liberalisation of the electricity and natural gas sectors are cornerstones of the Singaporean energy policy. The Gas Act of 2001 has set the Singapore gas sector on a firm course towards deregulation with the unbundling of transport and commercial activities, and oversight is entrusted to the independent energy regulator EMA (Energy Market Authority) (IEA, 2013c). The EMA regulates

the access of parties to the pipelines and requires pipeline owners to make the capacity available in the pipelines to third parties without undue discrimination. Pipelined gas imports into Singapore are delivered to gas-receiving facilities, at which time they become subject to a gas licence under the Gas Act. The free-market approach allows prices in Singapore to be set according to supply and demand.

Page | 102 The latest developments in 2013 and 2014 suggest that Singapore remains the strongest candidate for Asia's first natural gas hub, although there are still challenges to be overcome. In May 2013, Singapore began diversifying its gas supply with the opening of its Jurong LNG regasification terminal. It had an initial capacity of 3.5 mtpa, was expanded to 6 mtpa in early 2014, and the plan is to further expand its capacity to 9 mtpa. Singapore has also scheduled the construction of a second LNG terminal to support the country's hub plan, as announced by the country's prime minister during the opening ceremony of Jurong LNG terminal in February 2014.

The Jurong LNG's capacity expansion, together with the plan for the second terminal, is expected to further Singapore's objective of creating a trading hub in the region; Singapore's current LNG demand is only half of the Jurong LNG terminal's 6 mtpa capacity, hence the remaining available capacity will support the increasing LNG trading activities in the region. In April 2013, Singapore's state investment company, Temasek, incorporated a new subsidiary, Pavilion, with the goals of investing in various parts of the LNG value chain and becoming involved in LNG trading. The company was off to a good start barely one year after its establishment: in November 2013, Pavilion purchased a 20% stake from Ophir for its gas fields in Tanzania; in May 2014 the company entered into a joint-venture agreement with BW Group to acquire, manage and charter maritime LNG assets; and in June 2014 it signed a ten-year deal with Total for LNG delivery to Singapore, as well as for trading opportunities in the region. Prior to the incorporation of Pavilion, Temasek made a brief foray into the LNG market when the company, together with private-equity firm RRJ Capital, purchased Cheniere's USD 468 million's worth of shares in 2012 before eventually selling all shares in August 2013.

Many LNG players have already established their presences in the country – in 2013, Shell moved its gas business activities from The Hague to Singapore, while BG recently announced in April 2014 its decision to move the company's global LNG office to Singapore. Other LNG players are also setting up their trading desks in the country. The country's position as one of the world's major oil hubs facilitates progress towards it also becoming a natural gas hub: the infrastructure and financial requirements are already available.

At the same time, Singapore is implementing several measures to encourage the use of LNG in the country. A moratorium on new pipeline gas imports has been put in place by the EMA to protect the development of the LNG market in Singapore. However, the EMA plans to lift the moratorium by 2018, or when BG, the country's sole aggregator, manages to find buyers for its 3 mtpa contracted volumes. The EMA is also in the midst of securing new LNG aggregators for Singapore's next allocation of LNG: in June 2014, the EMA launched a request for proposals to appoint up to two aggregators for the next tranche of LNG; their decision is expected to be made by the end of 2015. Meanwhile, Singapore reached a milestone for its LNG market in June 2014 when the country's first LNG power plant commenced operation. Like Jurong LNG terminal, the 800 MW LNG power plant is located on Jurong Island and is currently the largest consumer of LNG in the country.

Indonesia

The Indonesian government is heavily involved in the natural gas market through state-owned companies Pertamina and Perusahaan Gas Negara (PGN), which monopolise the industry's upstream and downstream operations, respectively. At the same time, the Indonesian market is vertically

integrated, as PGN also dominates the domestic sales of natural gas. Although the 2001 market reform aimed at, among other things, ensuring TPA to the pipelines, it is far from being achieved, as PGN, the country's largest natural gas transportation and distribution company with a more than 80% market share, strongly opposes to the idea.

Indonesia has a domestic market obligation policy which favours domestic demand above exports and requires producers to sell at least 25% of the gas produced in Indonesia to the domestic Page | 103 market (IEA, 2008). This priority has been reinforced recently through a National Energy Policy calling for an end to gas exports to make more gas available for domestic consumption. This new measure coincides with the end of Indonesia's LNG export contracts, but it also affects its pipeline export contract to Singapore (Antaranews, 2014). Moreover, a lack of access to the existing pipelines in Indonesia is limiting the development of new small gas fields, as separate pipelines are required to connect them to the existing demand centres, making the projects unprofitable (CSTM, 2011).

At the same time, wholesale price deregulation remains a distant target for the country due to currently subsidised domestic natural gas prices. However, Singapore's effort to establish a natural gas hub in the region may indirectly impact Indonesia's natural gas market and expedite the ongoing removal of fossil-fuel subsidies by the government under its Medium-Term Development Plan.

Malaysia

Malaysia's natural gas industry faces a situation similar to that of Indonesia. Domestic consumers are enjoying subsidised natural gas in the form of a regulated price: despite recent price increases in January 2014, the new price of about USD 5/MBtu is much lower than the price range of the Asian LNG trade. As the government does not compensate for the price difference, Petronas, by virtue of being the state-owned company, remains the sole supplier of natural gas to the market despite the implementation of TPA at Malacca regasification terminal and Peninsular Gas Utilisation (PGU) pipelines for market players, including power companies, to source their own natural gas.

However, as LNG imports are priced differently (benchmarked against regional market prices) and subsidies for pipelined gas are eliminated, TPA implementation can be expected to expedite the liberalisation of the natural gas market in Malaysia. Technically, there is segregation of the transportation and commercial activities of natural gas – Petronas is responsible for the commercial activities, while the transport of natural gas via regasification terminals and pipelines is handled by its subsidiary, Petronas Gas, which is also a public listed company. In spite of the apparent autonomy of Petronas and Petronas Gas, segregation is perceived as lacking since the former is the majority shareholder and provides the workforce for the latter.

Thailand

Thailand produced about 38 bcm of natural gas in 2013. Unlike Indonesia and Malaysia, Thailand is a net gas importer and became the first ASEAN country to import LNG with the commencement of its Map Ta Phut LNG terminal. The Petroleum Authority of Thailand (PTT), state-owned until 2001 when it became a public limited company, controls both the transportation and commercial activities of the natural gas market and also owns the country's first LNG regasification terminal.

The gas market in Thailand is also vertically integrated, and is dominated by two players: PTT on the supply side and the Electricity Generating Authority of Thailand (EGAT) on the demand side. PTT, with few minor exceptions, acts as the sole purchaser, transporter and distributor of natural gas in Thailand. It purchases all indigenous gas from the producers, including its subsidiary PTT Exploration and Production (PTTEP), and transmits this through its pipeline system to consumers.

Thailand's pipeline network stretches 3 100 km, linking all commercial offshore gas fields to EGAT's power plants, its own five gas separation plants as well as some 200 industrial users. Consumer prices are regulated by the National Energy Policy, which takes into account the purchase price from natural gas producers and the cost of LNG imports. Domestic natural gas retail prices are below the international market level.

Page | 104 Retail consumers are charged a pooled price based on weighted-average producer gas prices indexed to fuel oil prices and economic indicators (EIA, 2013). The price of natural gas for vehicles (NGV) is regulated at below the production cost and the government does not compensate PTT, a similar situation to that of Petronas in Malaysia. However, PTT is able to reduce its losses through government tax exemptions for NGV.

Requirement	Brunei	Indonesia	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam
Hands-off government approach	-	-	-	-	-	+	-	-
Separation of transport and commercial activities	-	-	??	-	-	+	-	-
Wholesale price deregulation	-	-	-	-	+	+	-	-
Sufficient network capacity and TPA	-	-	+	-	-	+/-	-	-
Competitive number of market participants	-	+	+	-	-	??	-	-

Table 13 • Competitive market requirements in the ASEAN

Notes: + = currently contributing towards a competitive natural gas market; - = currently not contributing towards a competitive natural gas market; +/- = making progress; ?? = currently unclear. Cambodia and Lao PDR are not listed, as the countries currently do not produce or consume natural gas.

Others

With the exception of the Philippines, the natural gas price is also regulated in other countries in the region. At the same time, the state of the natural gas industry is still heavily dictated by the governments in the respective countries. On a positive note, the governments acknowledge the issues regarding natural gas and are taking steps to improve the industry, particularly in the area of natural gas pricing mechanisms.

The way forward

For gas importing companies and governments, the aim is clearly to lower gas import bills through diversification of indexation as well as improved flexibility. In the global picture, this could lead to a scenario of converging prices - leaving a gap equivalent to the cost of transporting and liquefying the gas between the importer and the exporter; but not all the conditions are in place Page | 105 for this scenario. There are essentially two ways of achieving such a target:

renegotiation of existing (and expiring) contracts

negotiation of new supply deals with new LNG exporting regions.

The mind-set affecting the market at the time of (re)negotiation will determine what sort of indexation buyers will get, along with their respective supply and demand situation. Those buyers also active in LNG export projects will especially need to balance their need for high revenues with their search for competitive LNG suppliers. There are many differences between Asian markets and European or North American markets that could affect this (re)negotiation process, and Asian buyers should also be mindful of the implications of using an HH indexation in longterm contracts.

Ultimately, setting up a trading hub (or several of them) in Asia would enable introduction of a price indexation that truly reflects the region's dynamics and not that of another region or another fuel. To implement a trading hub, however, Asia will need to overcome challenges specific to the LNG business.

The ASEAN region offers a specific environment in which the advantages and specificities of LNG and pipeline gas through the TAGP could be combined. Within this context, there is also a role for small-scale LNG producers in remote places and small demand centres.

What could lead to an accelerated price convergence case?

In the WEO 2013, the IEA presented an accelerated price convergence case, whereby the pricing differences among the three different regions would be lower than in the New Policies Scenario (Figure 41) (IEA, 2013a). Four main conditions are necessary to achieve such a scenario:

- Significant LNG volumes from North America, primarily from the United States, with levels exceeding 100 bcm by the late 2020s. This would strengthen the position of Asian buyers during negotiations with other suppliers in order to get other indexations than JCC.
- New supply contracts based on hub pricing, or even partly oil-indexed in Asia, not indexed to the traditional JCC mechanism and more hub pricing in Europe.
- Accelerated regulatory changes in the Asian gas sector as explained in the previous section, that promote the creation of a liquid and transparent trading hub, replicating the European experience.
- Lower costs of liquefaction and shipping, in order to reduce the overall cost of the delivered gas.

A potential scenario of pricing convergence would be triggered by North American LNG being exported and influencing other regional prices via LNG trades. In that case, HH would become a reference point for global pricing. A certain convergence would appear between 2015 and 2020, when large amounts of US LNG are expected to come to global gas markets, and would be largely completed by the mid-2020s. The consequences for regional prices would be two-fold: higher prices in North America, triggered by additional LNG exports, and reduced import prices in both Europe and Asia, compared to the New Policies Scenario. This would also result in higher volumes of LNG being traded – an additional 30 bcm by 2020 and an additional 60 bcm by 2035, coming predominantly from North America and East Africa.

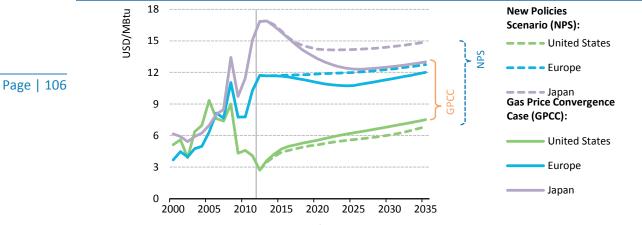


Figure 41 • Gas prices in the New Policies Scenario and the Gas Price Convergence Case

Such a scenario would also result in higher global gas demand, estimated to be 2.1% higher by 2035. This increased gas demand would displace that of coal, which would be 46 million tonnes of coal-equivalent lower by 2035. Despite improved pricing, however, gas will not be able to substantially displace coal in some key Asian power sectors. The largest increase in gas demand is nevertheless seen in Asia, where gas demand would be 4% to 5% higher than in the New Policies Scenario. In other parts of the world it is only at 3%, while demand in North America does not change due to the higher prices triggering a lower demand in most sectors, apart from generally increased consumption due to higher production and LNG exports.

Despite higher gas demand, the import bill would be reduced for all the major importing countries and regions; nevertheless, it is again very important to remember that future fuel prices are very uncertain and there is no guarantee that a system of gas-to-gas competition would always result in lower gas prices than an oil-linked one. More intensive competition would impact the decisions taken on new upstream and infrastructure spending and drive gas prices closer to costs.

Additional supplies coming from North America would also displace other suppliers' gas, notably those at the higher end of the international cost curve. Nevertheless, an import price above USD 12/MBtu in the Asia-Pacific region is estimated to be sufficient to bring in adequate supplies to meet even higher demand. As explained in this report's supply sections, additional gas would be sourced from Russia and East Africa, and once cost pressures have eased, Australia. It must be noted, however, that lower international gas prices would put some pressure on earnings.

Of note is that there is no complete convergence of regional gas prices, unlike for oil, as the transport and liquefaction costs of gas are much more important than for oil. In the case where Asia is heavily reliant on North American LNG exports, and Asian gas prices remain linked to HH gas prices through formulae similar to that used by Cheniere, the gap between US and European and Asian gas prices cannot go below what is necessary to cover liquefaction and transport on a sustained basis without triggering losses on one part of the value chain. Consequently, it is unlikely that prices will go well below HH + USD 3/MBtu to USD 4/MBtu in the case of European gas and HH + USD 5/MBtu to USD 6/MBtu in the case of Asian gas, as shown in Figure 41.

The question is whether these conditions are likely to be fulfilled.

 US LNG export plants appear to be relatively advanced as of October 2014, with two plants having already taken FID and a total of three having all the necessary approvals. Volumes of 100 bcm/yr seem therefore relatively reachable, even by mid-2020s. This does not take into account potential Canadian volumes.

Source: IEA (2013a), World Energy Outlook 2013, OECD/IEA, Paris.

- Most LNG originating from the United States and contracted by Asian companies and European utilities will be linked to HH. Much LNG has also been contracted by aggregators, who can resell the gas under different pricing conditions and benefit from arbitrage between different destinations. It will be interesting to see under which conditions this LNG may be resold to Asian companies based on the aggregators' portfolios. BG and BP are said to have sold LNG to Chinese companies based on their global portfolios, but on a mixed indexation involving oil and HH. There is no tangible sign that the other LNG exporters will follow this trend and accept HH indexation, with the exception of Canada's project Goldboro. Other suppliers are more likely to opt for hybrid indexation if they cannot get buyers to buy at oil-indexed gas prices.
- Regulatory changes are happening in many Asian countries, notably China and Japan as explained in the previous section. Singapore is already well on track in meeting the conditions necessary to create a liquid and transparent trading hub. However, there is still considerable work to be done in the other countries in terms of wholesale price deregulation and third-party access (TPA) to pipelines and LNG import infrastructure. The European and North American experiences show that a decade is often necessary to put in place the right conditions, but Asian countries could potentially move faster by using lessons learned from other countries.
- Lower liquefaction costs remain a key issue. As explained in the section on Australian LNG, capital costs have risen sharply for many reasons, including labour shortages, environmental constraints, appreciation of the Australian dollar and the remoteness of the sites. For the US projects, given their specific business model, the capital cost is 0.15% of HH plus the tolling fee. For new projects, this tolling fee goes as high as USD 3.5/MBtu. High liquefaction cost is not an issue only for Asia, as it affects both buyers and sellers: buyers need affordable gas supplies and sellers a minimum return on their investments, hence the necessity for both sides to find a point of agreement.
- Shipping, as discussed previously, is also an important cost item dependent upon many factors. As transport costs can reach USD 5/MBtu in extreme cases, shipping represents a conspicuous element in the total delivered cost. The daily charter rate of USD 65 000 and bunker fuel costs of USD 600/t together represent roughly 80% of the total transport cost (around USD 2.7/MBtu) for an average shipping route (up to 40 days return). Bunker fuel will be around 50% and the daily charter rate around 30%. With daily charter rates at USD 30 000, the transport cost would be USD 0.5/MBtu on such a journey. Halving the bunker fuel cost would have an even greater impact for this journey: USD 0.65/MBtu.

In the previous scenario, HH is driving other market prices, but there could be an alternative – at a later stage – with Asia also developing its own hub, or even several hubs given the size of the market. In this case, Asian gas prices would be reflecting Asia's supply/demand situation rather than that of another market (North America), or the price of another commodity (oil). The evolution of Asian gas prices in the longer term could be different from the *WEO* gas price convergence case should a liquid trading hub develop and gas prices be driven by regional supply/demand, even though some influence of North American supplies would still be felt.

Keeping in mind that the ultimate goal of many buyers and governments is to lower their gas bills, there are two main items to consider:

- the renegotiation of existing long-term contracts (in particular those which will be expiring soon)
- the negotiation of the pricing formulae and levels for new LNG supplies.

In spite of the current trend towards replacing oil indexation with the US HH in the LNG price formula for Asian buyers, oil indexation is forecast to prevail at least throughout the next decade, while hybrid pricing using oil and HH indexation will become more popular in new LNG contracts. The conventional thinking of LNG's traditional buyers, the lack of alternative supplies by pipeline, plus the insistence of LNG suppliers on oil indexation for their project economics will ensure the co-existence of the indexation.

However, there could be ways to reduce the burden of high oil prices feeding to LNG prices while maintaining oil indexation. Mechanisms such as the S-curve could play an important role in contract negotiation/price review, should the sellers refuse to change the pricing formula to include some hub indexation. This would be similar to the LNG market situation in the early 2000s, when price ceilings and slopes as low as three were applied. Though the slopes will not be as low as those applied in the 2000s, they will be offset by the HH element in the pricing mechanism, based on today's low HH price level. Regardless of the current trend, the long-term solution for Asia, which is East Africa's target market, is gas pricing based on regional hubs, as this would reflect the real supply-demand fundamentals of the region.

For HH indexation to gain ground in Asia and worldwide, US LNG needs to have buyers and other regions need to accept either hybrid or hub indexation. Asian companies investing in these projects could help manoeuver in this direction.

The first Asian trading hub is likely to be influenced by LNG prices from other regions, i.e. HH and NBP, or will derive its pricing using the average of LNG import prices, instead of becoming the price-setter itself. The price being referenced to another hub's index is not a new thing in the region; many spot contracts were priced at NBP-plus for LNG cargoes originating from the Atlantic region, especially during the winter season when LNG cargoes are diverted from Europe to Asia. Although price referencing may be against the original concept of the hub, the hub's establishment will still be significant for Asia's LNG industry, especially for its spot activities. Currently, there is no spot index available for Asia, although there are several indices published by price-reporting agencies such as Platts' Japan Korea Marker (JKM) and ICIS Heren's spot indices. As these indices are not a true benchmark like HH or NBP and are mostly based on market talks, the gas index offered by Asia's first hub would be very much welcomed by LNG buyers in the region. In spite of its initial limited scope for spot trade, if proven a successful and reliable benchmark, it could later entice LNG players in the region to benchmark their long-term prices against the hub. This would in turn increase the hub's liquidity and may eventually transform the hub into the region's price-setter. In the longer term, coal markets are likely to play a role in gas price formation in Asia given the region's intensive coal trade and the competition between coal and gas in the power generation sector.

For market players, a major advantage of having access to a liquid futures market is that futures allow them to manage certain pricing risks. Futures contracts allow for buying and selling gas at a fixed price at some later point in time. This means that utilities can lock in gas prices much earlier and diversify or spread their pricing risk. In contrast, the final price of oil-linked, long-term contracts is frequently set only the last business day before physical delivery of the gas begins. End users that buy gas from utilities often require more certainty earlier about the price they will be paying for their gas, so utilities can have high risk exposures since the price for which they buy long-term oil-linked gas and sell it can deviate. Futures contracts can help utilities decrease exposure between purchase and selling prices.

Since the proposed futures contracts will be exchange-traded, deals are being cleared and mark-tomarket risk is thus eliminated. This will contribute to the overall reliability of the newly established market. An additional advantage is that the contracts will be cash-settled. This increases the attractiveness of the market to financial institutions, since they will not run the risk of possessing physical quantities of energy when they do not find a counterpart to sell to in time. The participation of financial institutions in such a recently established futures market should be encouraged to increase market liquidity, and cash settlement is one way to increase the market's attractiveness.

Despite the absence of such a hub at the moment, it will be interesting to see whether new LNG projects' contracts with Asian buyers reflect the regional hub's pricing, if it materialises in the future. Current LNG market development indicates that it is still highly unlikely, at least for long-term contracts: Singapore's LNG contract with BG, the aggregator for the country's LNG demand

of up to 3 mtpa, was reportedly based on oil indexation, while its recent deal with Total through Pavilion Gas is based on HH without any indication of future regional hub indexing in the contract.

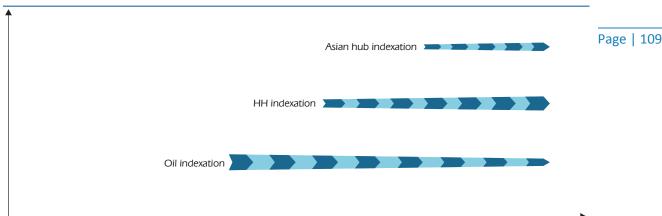


Figure 42 • Potential evolution of pricing mechanisms in Asia

The emergence of an Asian hub relies heavily on Asian countries: in particular it is their willingness and effectiveness to liberalise the gas (and almost certainly also power) sector that will decide whether or not regional hub pricing will develop. Among other things, a dialogue among Asian countries could achieve the following aims:

- promote the exchange of best practices on regulation of gas markets to develop a more conducive market environment for gas trading
- enhance co-operation on and encourage investments in gas infrastructure developments, in particular in the Southeast Asian region where there is great potential for optimisation of LNG and pipelines
- explore the development of pricing mechanisms reflecting demand and supply, in order to have a price reflecting the market gas conditions in Asia, and not those of either another commodity or a gas price not relevant for the Asian market.

A scenario in which oil indexation remains active in existing contracts and possibly in new contracts based on hybrid indexation, but with potential revisions of the formula and inclusion of different slopes possibly new indexation methods, could therefore be anticipated. At the same time, HH indexation could begin to play a role in Asian gas pricing with increased US LNG exports later this decade. Finally, in the early to mid-2020s, an Asian indexation (or different ones depending on whether several countries successfully develop a trading hub) could be used in some contracts. This last step implies having established the trust of suppliers.

Are we entering a renewal phase for Asian market players?

As analysed in the section "Challenges to the Status Quo", the amount of LNG imported by the major importers such as Japan and Korea on the basis of existing contracts will decline in the early part of the next decade, while China's contracted LNG quantities will flatten from 2015 onwards. India is also largely uncontracted compared to its potential demand, while many Southeast Asian countries are still looking for LNG.

There are two ways to bridge the gaps:

- extend existing long-term contracts
- enter into new contracts linked to planned LNG projects.

One major uncertainty is the extent to which the existing contracts with current suppliers, notably Qatar, Australia, Yemen and Russia, would be extended. In principle, there are enough resources to support the extension of LNG export contracts, but much also depends on the negotiation process during the renewal phase. As described in the previous section, this would be an opportunity for buyers to ask for different pricing and flexibility conditions. It is questionable whether the arrival of US LNG on global gas markets would be sufficient to change the pricing dynamics, and, should an Asian trading hub emerge by 2020-25, it is not certain it would become a new reference in long-term contracts that suppliers would accept. Additional uncertainty comes from the expiring contracts of the United Arab Emirates, Oman, Brunei and Indonesia, as these countries are facing dwindling gas production and/or rapidly increasing gas demand. Consequently, these contracts are not expected to be extended on a base-case scenario. Finally, Asian players could use equity gas in projects which are still at the planning stage and have an influence on price indexation.

The other option is for Asian countries to contract LNG from one of the many planned projects discussed in previous sections, and to secure conditions on pricing and flexibility that they are happy with. For new LNG supplies to arrive in the early part of the 2020s, LNG export plants need to take FID in the period 2015-17. Depending on market conditions at that time – whether it is a buyer's or a seller's market – buyers may be able to renegotiate contracts and prices that reflect market realities better than the existing deals.

This renewal phase or the negotiation of new contracts could therefore provide a window of opportunity for Asian buyers, depending on the perceived tightness of global LNG markets at that time. The chance to renegotiate contracts depends, of course, on the supply-demand balance and the market value of LNG at the moment contracts expire. As of 2014, it appears that the LNG market is more favourable for buyers. Asian buyers could therefore take advantage of contract renewals to renegotiate better deals, with the hope of narrowing the large price difference between Asia and the rest of the world. Four large regions are hoping to sell their LNG to Asia and compete for buyers; buyers have become more demanding and no longer want to commit to large quantities at oil-indexed prices.

Looking forward, there has been much debate on whether the LNG market will face surpluses in 2016-17 after most of the Australian LNG capacity, as well as some US LNG, has come online.

In Japan, around half of the long-term contracts on a volume basis will expire over the next decade. In particular, there is a rapid drop in contracted LNG imports from 2020 onwards. The quantities that are up for renewal and that could be extended amount to 38 bcm by 2030. As mentioned earlier, the evolution of Japan's gas demand is a major uncertainty because the amount of nuclear generation to be reinstated is yet to be determined, and energy efficiency and renewables could reduce gas demand in the longer term. It is unlikely, however, that gas demand will decline as much as contracted supplies when potential contract extensions are not taken into account. How much Japan will really need therefore remains difficult to judge over the longer term, creating difficulties for companies which do not wish to be over-contracted. The creation of a liquid Asian gas market would help companies by giving them the possibility of reselling the LNG in Asia, while US LNG could be diverted to other markets.

Similarly, some LNG contracts are expiring in Korea over the period 2012-19, but these volumes are already being replaced by new volumes from global-portfolio players, the United States and Australia. However, there is also a very substantial drop in contracted LNG over the period 2024-28. The quantities that are up for renewal and could be extended, amount to 32 bcm for Korea by 2030. The drop is quite acute in 2024, notably from Qatar and Oman. There is some uncertainty whether Oman's LNG supplies would be extended. Regarding Qatar, the problem is not the capacity of the country to continue delivering LNG, but the companies' ability to agree on pricing and delivery terms. However, the Korean government predicts that gas demand will continue to grow at 1.7% per year until 2035 (to around 70 bcm) according to its proposed long-term energy

Page | 111

plan, which means that additional LNG supplies need to be found, unless the Korean gas market grows less than expected.

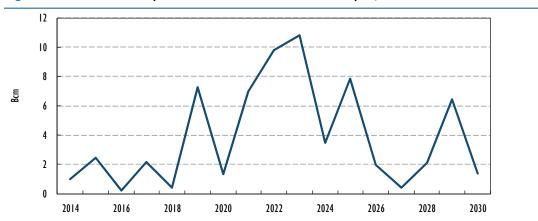
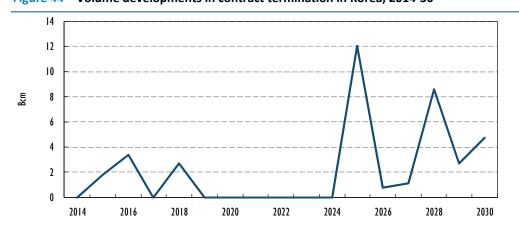


Figure 43 • Volume developments in contract termination in Japan, 2014-30

Figure 44 • Volume developments in contract termination in Korea, 2014-30



In other Asian countries, the issue is not so much long-term contracts expiring – most countries have signed 20-year contracts over the past decade (the oldest started in 2005) and are still actively looking for new ones – but how big the gap between supply and demand will be.

This is particularly the case for China, where uncertainties in both demand and supply (domestic gas production, LNG imports and pipeline gas imports) are great. With the exception of the NWS contract expiring in 2029, most contracts will expire after 2030. The two questions are how much China needs to import by 2020 and 2035 and, should an Asian trading hub in or outside China exist by 2025, whether China would be able to assure its imports through long-term contracts. Import needs depend significantly on domestic production performance, and how imports will be split between pipeline gas and LNG. Against this backdrop, Russian gas may have set a price benchmark even though there is much uncertainty on the price level and its evolution. This could be an argument that Chinese gas players may use in negotiations for future gas supplies.

Renegotiation: Why Asia is not quite Europe

To some extent, Europe could provide some lessons to Asian countries. As a big importer, it has had to diversify its gas supplies and it also went through the process of renegotiating long-term contracts relatively successfully. However, there are some significant differences between Asia and Europe.

The existence of hub prices

Page | 112

While Europe has several distinct hub prices, this is not the case in Asia. Indeed, when European buyers renegotiate their contracts, they can argue that these hub prices reflect the new market conditions and the supply-demand balance in a certain region or country. But Asian buyers would find it harder to argue that HH or NBP are relevant for Asia and reflect the region's supply and demand dynamics.

Moreover, European gas companies have profited from 20 years of experience with trading hubs, dating from 1994, when the British virtual trading point, the NBP, was established. Other hubs were established in Northwestern Europe starting in the late 1990s, although some disappeared quite quickly. The Dutch TTF, set up in 2003, has now emerged as the most liquid trading hub in Continental Europe. Many other hubs have been created, sometimes more than one in a single country (i.e. France and Germany), while the United Kingdom, the Netherlands and Italy, which are all relatively large markets, each have a single trading hub. The existence of a unique transmission system operator (TSO) in these countries is an advantage that many Asian countries could also replicate.

Unlike the HH, the NBP is a virtual trading point. It is associated with a determined market area, and natural gas can enter any point in the area and exit through any other point. Virtual hubs are used as a daily balancing tool for the corresponding area. The only European physical market, Zeebrugge, has seen its importance diminish over the past few years, and in 2012 the Belgian regulator and the TSO decided to move to a virtual hub.

These trading hubs are supported by exchanges and clearing houses. The NBP is supported by the Intercontinental Exchange (ICE), which decided to use it as the pricing and delivery point for its natural gas futures contracts and TTF is supported by APX-Endex.

The renegotiation clauses

Since 2009 and the economic crisis, European gas players have been striving to renegotiate longterm contracts with their suppliers. Contractual oversupplies, lower gas demand, and price gaps between inexpensive LNG supplies on the world's gas markets at that time (at around USD 5/MBtu) as well as on European spot markets on the one side, and the long-term oil-indexed contracts on the other (at around USD 10/MBtu), led most European gas companies to ask for contract renegotiations. This process of renegotiation has continued since 2010 due to the deterioration of hub gas prices related to weak European energy demand and a loss of competitiveness of gas against coal in the absence of a meaningful carbon price.

There were some renegotiation clauses in most European contracts, as the contracts were signed for 20 years. Over such a long time frame, upward or downward changes in the market were bound to happen. The parties therefore usually agreed to conduct regular price reviews that would enable them to adjust the price formula.

The price review clause entitles the parties to adjust the price in cases of significant changes in the economic circumstances in the market where the gas was delivered that were not reflected in the price formula.

There is no standard price review clause; rather, these clauses depend on the particular project and the relationship between buyer and seller, as well as whether the contract was signed in a seller's or a buyer's market. Still, a price review clause will usually include the following elements:

- a trigger event, describing the circumstances which can trigger a review of the price
- a procedure to follow to adjust the price (or what is to be adjusted, the coefficient applying to the oil price or the whole formula), and how the adjusted price is to apply under the contract
- what happens if an agreement is not reached between the parties.

There can be periodic review clauses or special triggers, in which case the trigger has to be specified and agreed upon by the parties. An example of a trigger event could be if circumstances beyond the control of the parties change significantly compared to the underlying assumptions in the prevailing price provisions. Each Party is then entitled to an adjustment of the price to reflect such changes. The price provisions shall, in any case, allow the gas to be economically marketed based on sound marketing operations.

These triggers usually have to be unforeseeable, out of the control of the parties, and have a significant impact on the market. The wording is of particular importance, as even words such as "the market" can be interpreted differently depending on where the buyer usually sells its gas. "Significant" can also lead to different interpretations.

Price review clauses would often include a most favourable customer clause, a most favourable supplier clause and a market parity clause, which could read as follows:

- The price paid by the buyer shall not be materially higher than that paid by other buyers from the project (this would guarantee a rebate if the seller is offering lower prices to another buyer).
- The price paid by the buyer shall not be materially less than the price paid to the buyer's other suppliers.
- The price shall be based on the pricing of similar sales.

In most Asian legacy contracts, the reviews take place every four or five years. Sometimes there are no price reviews, as they can be seen as a good way for the buyer to get lower gas prices at the moment the contract is negotiated. They are often governed by English or American law so that the arbitration tribunal would sit in London or New York.

Asian buyers are now discussing introducing more precise terms regarding price review clauses in the new contracts being signed, and introducing triggers rather than time reopeners. While the way to change conditions in Asian contracts differs from the European way, Asian buyers are trying to increase the potential to change contract conditions. They would also like the final destination clauses to be partially removed from long-term contracts. This would be of particular importance for the renegotiation of long-term contracts with Qatar and Australia.

Box 13 • Sellers can also renegotiate their long-term contracts

In the current high-price environment, it may seem illogical that LNG sellers would want to renegotiate an LNG contract price because it is too low. Nevertheless, this has happened recently on several occasions.

Yemen's government has pushed towards a renegotiation of long-term contracts with three buyers of LNG due to low sales prices. The three buyers are Korea's Kogas, GDF Suez and Total. The price previously paid by Kogas was USD 3.15/MBtu, one of the lowest in the world. The contract contains a Brent-based price formula with a floor and ceiling and a five-year renegotiation clause. Yemen LNG argues that when the deal was signed in 2005, it was comparable and, in some ways, better than other SPAs with Korea. In late 2013, the contract was renegotiated and Kogas will now pay around USD 14/MBtu to reflect current oil prices.

Meanwhile, talks with Total and GDF Suez, which had their contracts linked to HH prices, are still ongoing. Yemen LNG sales to these two buyers were originally earmarked for the United States and Europe, but following the sharp decline in HH prices, Yemen LNG renegotiated the agreements with Total GDF Suez to divert LNG cargoes to the higher-paying Asian market.

Indonesia has also successfully renegotiated the sales price for Tangguh LNG. Both sides agreed to increase the price from USD 3.3/MBtu to USD 8/MBtu. It will continue to increase and be based on JCC. Ultimately, the price can be expected to reach USD 12/MBtu, more in parity with the average prices paid by China.

The role of the European Commission

The European Commission (EC) has taken a leading role in the liberalisation of the energy sector. Not only did it set up directives to be implemented in the various member states, but decisions can be binding on member states. The EC also has the power to conduct sectoral inquiries. EU law also includes regulations, which are directly applicable to market participants. There is no equivalent, even at a sub-regional level, in Asia.

The European Union is based on the principles of the internal market and the EC started liberalising the energy sector during the 1980s. In 1988, it initiated the internal energy market as the basis for further works. But the first push towards liberalisation in the midstream and downstream sectors happened in 1998 with the first Directive 98/30/EC (EC, 1998) which aimed to create a single internal market for gas within all member states. This was two years after the first Power Directive. This required, among other things, TPA to transmission networks, storage and LNG facilities, either on negotiated or regulated access, as well as account unbundling for the monopoly activities within the vertically integrated companies. The Directive also gave access to consumers by initiating the opening of the gas market: power generators and final end users consuming more than 25 Mcm per year were eligible to choose their suppliers. The Directive also set objectives: the opening of the gas market should initially represent at least 20% of annual gas consumption, then 28% and 33% respectively 5 and 20 years after the entry into force of the Directive. It is worth noting that some countries, such as the United Kingdom, were already more advanced, having fully opened their gas markets.

The process was accelerated following the request from the European Council to complete the internal energy market. The second Directive was issued in 2003, with legal unbundling and the establishment of regulatory authorities in all member states. It also further improved TPA requirements and prescribed the principles of network tariff calculation that had to be regulated, i.e. efficient costs based upon actual costs, appropriate rate on investments and incentives to construct new infrastructure. Meanwhile, the market was opened to all non-residential users in 2004 and gas markets were fully opened in July 2007.

The third legislative package on market opening (the "Third Package") was adopted in 2009 and all member states were required to transpose it into national law by March 2011. This Directive aimed at the further improvement of TPA, and more independent regulators from private or public interest. It also prescribed "ownership unbundling as the most effective tool by which to promote investments in infrastructure in a non-discriminatory way, fair access to the network for new entrants and transparency in the market", while allowing for two other forms of unbundling, the independent system operator (ISO) and the independent transmission operator (ITO).

During recent years, the EC has been focusing increasingly and specifically on whether some suppliers used their dominant position in the EU gas market to thwart competitors and push up price. FDCs were abolished in the early 2000s, as they prevented gas-to-gas competition. FDCs allowed a seller to sell gas to different buyers at the same point at different prices.

The EC's effort to correct uncompetitive practices has not been an isolated proceeding against particular companies, but integrated within structural antitrust policy. The Commission is able to play this role because it holds significant powers not only to monitor but also to enforce compliance with EU competition laws.

The Asian market will need to cope with expanding demand, especially in China, India and Southeast Asia. The import and transport infrastructure developments required to meet this demand will be significant. There is also no overarching body which could establish the necessary rules, even though several bodies of co-operation and co-ordination on energy issues exist:

 The ASEAN Ministers on Energy Meeting (AMEM) enables co-operation on energy issues in the ASEAN region. It also aims to attract private sector investment in the energy sector. One of the projects supported by AMEM is the TAGP. Meanwhile, an ASEAN Gas Consultative Council (AGCC) was established to advise the ASEAN Council on Petroleum (ASCOPE) in the implementation of the TAGP. The AMEM will issue agreements and declarations, notably a five-year plan of action on energy co-operation, but these plans do not have the same binding requirements as EU directives.

Page | 115

 ASCOPE is the association of NOCs in the ASEAN region; this industry association does not have strong regulatory powers. ASCOPE was established in October 1975 as an "instrument for regional co-operation on petroleum and energy matters among member countries and also to support them to increase their capabilities, through mutual assistance, in all aspects and phases of the petroleum industry."

Market players

Another striking difference between Asia and Europe is that most market players in Europe tend to be pan-European now, while in Asia they are mostly operating within their own domestic markets. The situation in Asia is actually close to what the situation was in Europe in the very early stages of liberalisation, with vertically integrated companies operating mostly in their home country with few operations outside. The liberalisation process drove them to seek market shares outside their own national markets.

Another difference is that gas companies have progressively evolved to become gas and power companies, enabling them to benefit from arbitrage and to use their gas for their own gas-fired plants. This trend is not observed outside of Japan.

Unbundling also created new players in the European market, namely, the transport companies, which are sometimes fully independent from the companies with sales activities. Liberalisation also brought some trading companies as well as banks into the energy business.

HH price indexation in new contracts: Caveat emptor

While HH indexation currently appears to be very attractive, it is crucial to not confuse price level and price formation. A hub indexation does not always translate into low prices, as highlighted in the IEA publication *Developing a Natural Gas Trading Hub in Asia* (IEA, 2013c); this is something that is either ignored or misunderstood by suppliers and buyers. The US HH reached USD 8/MBtu in early 2014, while in some areas of the United States the gas price went over USD 100/MBtu as a result of the extreme prolonged and widespread cold weather. In Asia, the high spot LNG price is not driven by oil indexation – it went as high as USD 20/MBtu during winter 2013-14, which is a USD 2/MBtu to USD 3/MBtu premium over long-term contract prices based on oil-indexed pricing. However, the Asian spot LNG price also hit its lowest level (USD 3/MBtu) in 2009 during the economic downturn, which resulted in discounts of more than USD 7/MBtu over long-term contract prices. During the summer of 2014, Asian spot prices went down to below USD 11/MBtu.

Cheniere's formulae give the price at which the buyer is buying the gas outside the liquefaction plant: HH * 115% + tolling fee. The transport cost is paid by the buyer.

- Over 20 years, HH gas prices are likely to evolve and to increase. In the EIA's latest Annual Energy Outlook (EIA, 2014), HH gas prices (2012) are expected to increase to USD 6/MBtu by 2030 and USD 7.7/MBtu by 2040 (EIA, 2014).
- While most people tend to consider the tolling fee as fixed, this is not entirely true. The tolling fee varies from USD 2.25/MBtu for one of BG's contracts, to USD 2.49/MBtu for Gas Natural Fenosa and USD 3/MBtu for the others. But a portion of the fee is subject to inflation,

approximately 15% for BG, 13.6% for Gas Natural Fenosa, 15% for Kogas and GAIL and 11.5% for Total and Centrica. Based on an inflation rate of roughly 2% per year, the tolling fee would increase by around 8% by 2040 if the portion is 15%. The tolling fee will thus be subject to inflation uncertainty.

Page | 116

The transport cost is also an important variable, with the most important items being the daily charter rate and the fuel cost, making up 80% of the total transport cost. There are equal probabilities that the transport cost could decrease or increase over the next 25 years, taking all the parameters into account.

As explained earlier in this report, the introduction of HH (or any gas hub) pricing in an LNG contract has taken place before in several LNG projects targeting the North American market. To some extent, having such an indexation is no longer prohibited by LNG project developers, but the difference would be that the hub-indexed LNG would be delivered in Asia rather than to a North American or European destination. Anadarko in East Africa has signalled that it has signed initial agreements with some buyers for its Mozambique LNG project based on a hybrid price of oil indexation and HH formula, while BP Singapore signed a preliminary agreement with Kansai Electric, Total a ten-year SPA with Pavilion Gas, and BP and BG contracts to China will be based on a mix of oil and HH indexation. BP, BG and Total will supply LNG from their global portfolios, although it is worth noting that these suppliers have offtake volumes from the US LNG projects (Freeport LNG and Sabine Pass).

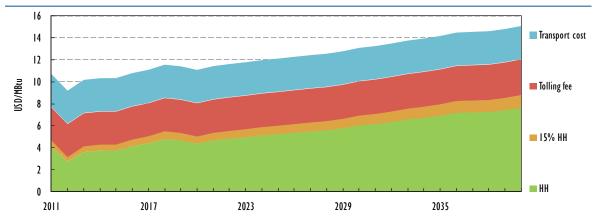


Figure 45 • Evolution of HH-delivered gas prices (transport cost at USD 3/MBtu)

Notes: HH gas prices are 2012 prices from EIA (2014), Annual Energy Outlook 2014, EIA, Washington, D.C., www.eia.gov/forecasts/aeo. Fifteen percent of the tolling fee is subject to inflation.

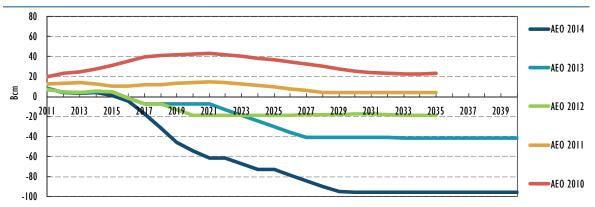


Figure 46 • US LNG exports according to different forecasts (EIA 2010 to 2014)

Note: "AEO" = refers to Annual Energy Outlook publications, which can be found at www.eia.gov/forecasts/aeo/.

From a buyer's standpoint, it may be better to have an HH element even with a higher constant, in view of the current sentiment in the market and in governments that HH indexation always results in a lower price than oil indexation. However, as the HH risk not fully known to the Asian buyers, many projects, including in East Africa, can be expected to have hybrid pricing in their LNG contracts combining both HH and oil indexation.

Page | 117

The practical aspects of establishing a trading hub in Asia

Among all the steps described in the previous report, some will require practical implementation taking into account the specificities of the Asian market. Trading hubs so far have developed on the basis of imported pipeline gas or gas produced domestically. How will it work with LNG cargoes, as these do not provide a constant flow? Additionally, LNG cargoes differ from each other in quantity and quality. These differences will become even more acute as US lean gas is delivered to Asia. LNG also needs to be stored, which raises the issue of the boil-off.

Key differences between Asian gas markets and European and North American ones

In a region where long-term contracts based on an oil indexation formula are still predominant, and security of supply remains the main focus, it is difficult to envision establishment of the natural gas hub in Singapore, or in any other place in the region, having the same roles and characteristics as the hubs in the United States and Europe:

- Lack of competitive alternative supply. Although Asia is eager to follow the United States and Europe in establishing natural gas trading hubs, the region is lacking significantly in alternatives gas via pipeline, with the notable exception of China and potentially India. Most of the region's major importers (Japan, Korea and Southeast Asian countries) rely heavily on LNG and hence have less bargaining power with LNG suppliers. In the case of Singapore, although the majority of the country's gas imports arrive by pipelines from Indonesia and Malaysia, the gas is fully indexed to oil and changes to the price structure are unforeseen, given Singapore's relative lack of influence in Indonesia's and Malaysia's natural gas export industry. Indonesia's natural gas exports to Singapore account for one-fifth of its total exports and about 10% of total production. Meanwhile, Malaysia's natural gas exports to Singapore are only 4% of its total gas exports and only 2% of its total production, based on 2012 figures.
- Limited scope. The potential hub(s) will mainly serve spot-trading activities rather than the whole natural gas trade, and may therefore be considered insignificant, especially for the LNG market. Based on the GIIGNL's 2013 report, spot and short-term volumes account for less than one-third of the total LNG trade in 2013, and although the percentage for spot volumes alone is not available, it could be as low as 10% of the total trade. Hence, the ambition to see the hub provide a reliable index for the whole natural gas/LNG trade remains remote, at least in the first years of the hub's establishment.
- Lack of base gas field supply. While the United States' HH is supported by indigenous gas fields, the United Kingdom's NBP by its own gas production and gas imports from Norway, and Netherlands' TTF by its domestic gas production, many potential candidates for Asia's first natural gas hub, with the exception of China, India and Malaysia rely solely on gas imports.

Dealing with LNG cargoes

One of the challenges when dealing with LNG will be to move from cash-settled standardised futures contracts to forward contracts that result in physical delivery. A clear distinction between

the trade of LNG cargoes and the gas that is traded at markets in the United States and Europe is that LNG is actually not a commodity. Several technical problems will need to be solved, such as having different calorific values or quantities, as cargoes have different sizes. LNG is often discussed in tonnes; this should be converted into a heating value.

Page | 118

In contrast, the gas traded at the NBP is already in the gas grid, where gas qualities are already standardised (where it is not, a penalty is imposed). When working with standardised gas qualities and quantities, it is much easier to create standardised futures or forward contracts that still result in physical delivery instead of a cash settlement. These physical contracts are obviously much easier to trade than physical futures or forward contracts that refer to delivery of a very specific cargo of LNG. Furthermore, it is not even possible to define the exact quality and quantity of gas a year before the LNG cargo is to be shipped (and there is still some uncertainty as to whether the cargo will be rerouted at the last minute).

Growing amounts of US LNG may actually bring more quality standardisation, as the gas will be lean. Meanwhile, countries with significant LNG storage at regasification terminals could use these to supply the physical market. There is also the question of period of transaction: Japanese authorities are planning to have three-month futures, and handling one-month futures may be difficult as one month is needed to make sure that the terminal is available (the flow of LNG cargoes is determined and co-ordinated). This is one possible area for improvement in the future.

Given that the product will be an LNG cargo, there is also the possibility of having the cargo delivered to other places in Asia. In such a case, an adjustment should be made based on the difference in transport costs, including freight and boil-off.

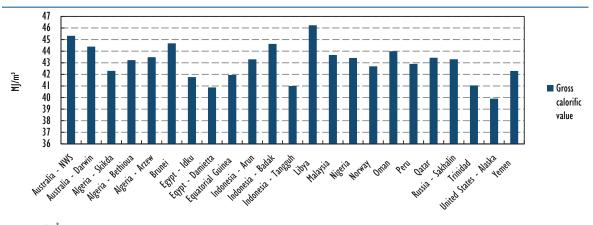


Figure 47 • Gross calorific values from different LNG sources

Note: MJ/m³ = megajoules per cubic metre. Source: GIIGNL (2014), *The LNG Industry in 2013*, GIIGNL, Paris, www.giignl.org/system/files/giignl_the_lng_industry_2013_0.pdf.

National versus regional hubs

When the creation of a trading hub in Asia is considered, the primary question is where it should be established. Although one concept involves one dominant trading hub acting as the marker for the whole region, it is possible for several trading hubs to coexist. Given the expected future size of the Asian market – over 1 tcm by 2035 – there is definitely room for several trading hubs.

A better question is whether one trading hub should be developed for each country, as seems to be the current idea, with each country developing its hub around an existing or future LNG import terminal. Or, as Asia is still at the preliminary stages of development, it may be worth considering whether it would be possible to create regional hubs that would cover several countries, even though this may not be easy logistically.

Europe has developed several trading hubs, notably in Western Europe, over the past 20 years. Two hubs currently dominate for volumes traded and liquidity – the British NBP and the Dutch TTF – while others are still developing in terms of liquidity. But European countries have pursued a relatively nationalistic approach when developing trading hubs. Most major countries have their own trading hub, and some even have several hubs like Germany, France and Belgium. While this can be justified for a relatively large market, the British example shows that one trading hub suffices for a country consuming up to 100 bcm.

Page | 119

Besides the question of volumes, there is obviously the question of trusting a hub created and operated in another country.

An ASEAN way?

The preceding analysis has shown that Asian market fundamentals are significantly different from those in Europe and North America, where the development of trading hubs started in countries with large domestic gas production, markets were already quite mature in terms of demand, the transmission infrastructure had been largely built, and the EC had started to put in place some rules for third-party access (TPA), wholesale price deregulation and unbundling. Finally, even though some Eastern European countries had relatively lower gas prices, notably for residential gas users in the early 2000s, these prices were progressively increased so that price subsidies have now disappeared in Europe and North America.

Another fundamental difference is that Asian countries currently rely and will continue to rely on LNG much more than on pipeline gas, even though China will import substantial volumes of pipeline gas and most Southeast Asian countries are already interlinked by pipeline and plan to increase these linkages through the TAGP. Despite the increase in regasification capacity, the current infrastructure of the LNG supply chain limits the ability to respond to changes in demand or supply; even with an increase in the number of short-term available LNG carriers, the current LNG contracting structure is dominated by long-term contracts that limit the availability of spot LNG on world markets. This provides a significant barrier to cost-efficient responsiveness of LNG supply to changing demand patterns in downstream Asia-Pacific markets (IEA, 2013c).

This raises the question of whether a specific Asian-tailored solution could be developed, notably for Southeast Asia.

Dealing with fossil-fuel subsidies

Fossil-fuel subsidies, including gas subsidies, remain a challenge in most non-OECD Asian countries, with the exceptions of Singapore and Chinese Taipei. Even though there has been some progress, they are far from removed. Not only do they generate higher demand through wasteful consumption, but they also deter investment in upstream, transmission or import infrastructure, while hampering improvements in energy efficiency. In this region, hundreds of millions of inhabitants lack access to modern energy.

It is now widely recognised that subsidies are not sustainable, but the issue is highly sensitive in many other parts of the world such as African and Middle Eastern countries. Many governments have already put in place some measures targeting oil or, sometimes, electricity subsidies (IEA, 2013b). But as many countries are moving towards gas imports, low gas prices result in heavy burdens for the state budget when gas has to be imported at market prices, so these governments are starting to reconsider gas subsidies as well. As market prices will be two or three times higher than domestic prices, the issue will need to be solved in the coming years and will become an even greater incentive for these countries to look for more affordable gas supplies.

Many countries have tried to put in place price reforms by increasing prices, either uniformly or partially, but these processes are usually slow, especially when prices start from a low base. China has been in the process of increasing prices while still offering some protection to residential customers (many industrial users pay prices around USD 20/MBtu). In India, the pricing reform seems stalled as of mid-2014. In Indonesia, PGN's average selling price amounts to USD 6.85/MBtu. There had been a significant reduction in subsidies in 2008, but although the government is committed to phasing out fossil-fuel subsidies by 2014, many doubts remain regarding whether the removal plan will materialise. In Malaysia, while the government had a plan to phase out subsidies over 2010-14, it failed to fully materialise, as changes to the gas subsidies occurred only once instead of the planned four times before the government subsequently suspended the programme in 2011. However, the programme appears to be revived after the country's general election when the government revised the gas price upward to the current level of MYR 15.2 per million British thermal units (around USD 5/MBtu) in January 2014.

It would be interesting to see the evolution in demand with the removal of subsidies. While they generally encourage wasteful consumption and inflate demand, very often subsidies are not paid from the central budget but achieved through price regulation. Such price regulation supresses supply side investment and create shortages by constraining supply. In such a country the impact of subsidy removal on consumption is ambiguous. But some industries may be prepared to pay for gas at market prices because it is still less expensive than using alternative fuels such as refined products.

Providing blanket subsidies to an entire population is a very inefficient way to make energy affordable for the poor. Energy subsidies are highly regressive, and only a low proportion of them reach the very poor, who often lack access to modern energy services. When subsidies are withdrawn, welfare assistance must therefore be provided to a targeted population to avoid restricting its access to modern energy services. In Indonesia, reforms were accompanied by cash hand-outs to poor households and were therefore successful. Increasing specific consumer prices is one option, and targeting inefficiencies in the system is another. In many countries, the average efficiency of gas-fired plants is around 35%, which leaves considerable room for improvement. Depending on the speed at which their import dependency increases, countries may have different options in dealing with gas subsidies. It is important that the subsidy issue in general be addressed in a wider political context.

Combining LNG and the TAGP

During the 1990s, the economic development of the ASEAN region resulted in a growing energy demand. Despite some slowdown in the 2000s after the economic crisis, the energy demand of the region is forecast to continue growing over the period to 2035 as the region's economy triples and the population expands by almost one-quarter. Consequently, its energy demand is foreseen to increase by over 80% between 2011 and 2035, a rise equivalent to the energy demand in Japan. Gas demand in particular will increase from 150 bcm today to 250 bcm by 2035, an increase largely supported by LNG imports (IEA, 2013b). Meanwhile, coal demand will triple over 2011-35 and the share of renewables in the primary energy mix will fall as the rapidly increasing use of modern renewables is offset by the reduced use of traditional biomass for cooking.

While the region was initially a net exporter, it is in transition to become a net gas importer. On a country-by-country basis, however, some countries have been importing LNG or pipeline gas already, while for others, such as Viet Nam and the Philippines, it depends on the development of new import capacity. In the early stage, the plan was to rely on pipeline supplies, but LNG moved faster as pipeline supplies stalled. The ASEAN region already has an extensive pipeline system, as can be seen in Figure 48. It consists of both pipelines within countries and cross-

border pipelines; the currently existing cross-border pipelines are only bilateral. Examples are the gas sales agreements between Malaysia and Indonesia, between Singapore and Malaysia and between Singapore and Indonesia.

New pipeline supplies were (and are still) expected from the large East Natuna gas field in the Natuna Sea amidst Indonesia, Malaysia and Singapore, even though the development of the field is challenging due to its very high CO₂ content. As a source of supply for the region's growing natural gas demand that fuels its economic growth, the TAGP project was announced during the 17th ASEAN Minister of Energy meeting in 1999. The TAGP plans to connect the existing pipelines to create a fully integrated network, connecting the gas reserves in the gulf of Thailand, Indonesia, Myanmar and the Philippines to the rest of the region, aiming at enhancing security of supply and greater economic co-operation within the ASEAN region. The project was formalised through an MOU signed during its 20th meeting in 2002. Therefore, progress has been slow.

At the same time, ASEAN countries have long been present in the global LNG market through participation of three countries, Brunei, Indonesia and Malaysia, as LNG producers. Malaysia is currently the second largest LNG exporter in the world behind Qatar, producing 25.1 mtpa of LNG in 2013. Indonesia, which was the world's largest LNG exporter for three decades before Qatar surpassed it in 2006 remains a major LNG exporter and was the fourth largest LNG exporter in 2013 behind Australia, followed by Brunei at the tenth position.

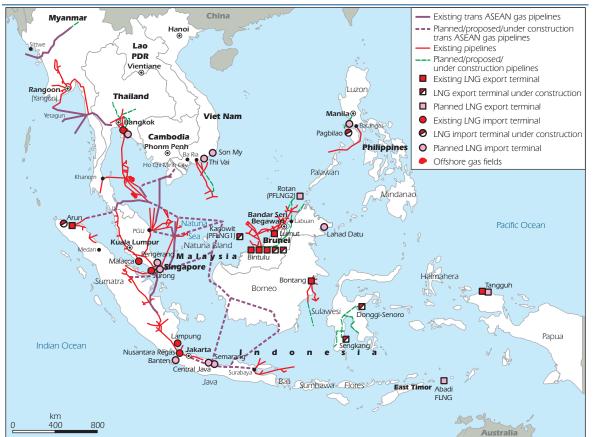


Figure 48 • Existing and proposed pipelines of the TAGP

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

But over recent years, natural gas demand has increased substantially, causing several countries in the region to move towards LNG imports through newly-built terminals. At the same time, the TAGP project was losing steam. The region therefore gradually established itself as an LNG importer as well. The opening of an LNG regasification terminal in Thailand in 2011 marked the first entry by the region into the global LNG market as an LNG buyer, and subsequently Indonesia, Malaysia and Singapore followed suit.

However, these LNG terminals suffer from the inefficiencies of the global LNG market and are sometimes too large for some smaller domestic demand centres. A 400 MW gas-fired plant would need around 0.4 bcm/yr to run 5 000 hours. This means it requires around four LNG cargoes per year. This also affects the size of the corresponding regasification plant: as power producers are often anchor customers, large industrial users are also needed in order to increase the potential demand in the area to get a more significant size.

Within this new context, the TAGP project could still be a valuable solution, providing flexibility and diversity of supplies within the region, with both LNG and the development of East Natuna, and the TAGP as the backbone. For example, the TAGP could facilitate gas exchanges within the region for optimal allocation, either through time swaps or cargo swaps of LNG, or via additional LNG imports through terminals in neighbouring counties.

However, there are several challenges to creating the TAGP, mainly related to cross-border issues:

- technical issues such as challenges to developing East Natuna and dealing with different gas qualities
- differences in market structures and pricing between countries
- moving from the existing bilateral cross-border pipelines system to an integrated and harmonised system
- harmonising regulation such as TPA rules and regulatory authorities.

All these issues limit the access of buyers and/or sellers from non-neighbouring countries to the imagined single network. In other words, many fundamental issues limit TPA and hence the move to an efficient working integrated network. However, small-scale LNG projects could help the development of smaller-sized LNG imports.

Technical supply issues

Indonesia's East Natuna field has been a difficult field to develop, despite its large quantity of 1.3 tcm of natural gas. The basin in which it is located is Indonesia's most northern territory in the South China Sea, far from the consuming areas at approximately 1 100 km from Jakarta. The western part of the basin contains already-producing gas fields, connected with a 640 km subsea pipeline, one of the longest in the world, to Singapore.

Furthermore, the estimated 70% CO_2 content of the field also increases production costs. Plans for the development of the field include the sequestration of 90% of the CO_2 and its injection into two neighbouring deep saline reservoirs. The offshore location for these special techniques drives up costs further.

To make the production outlook even more challenging, Indonesia terminated the contract with ExxonMobil in the joint venture with state-owned Pertamina, leaving the latter in charge of production.

When East Natuna's gas is delivered into an interconnected TAGP, technical issues will occur in aligning the gas quality in the entire system. In Singapore, for example, imported natural gas must comply with the gas specifications set out in the Gas Network Code before it can be injected into the transmission system. The minimum methane level in Singapore is set at 80% of the volume and a maximum of 5% of CO₂. In Thailand, natural gas from onshore fields in the northeastern part contain on average 76% methane and 13% CO₂, while that from offshore fields in Myanmar contains 72.4% methane, 6.2% CO₂ and 16% nitrogen (APEC, 2011).

The lack of a uniform bandwidth of gas qualities hinders an interchangeable flow within a single interconnected network. This issue applies not only to the different existing gas qualities within the region, but to LNG imports entering the region. When the TAGP aims to facilitate exchanges of LNG between terminals or between LNG and pipeline gas, the gas qualities in the system should be harmonised. As gas qualities differ by gas field, LNG gas qualities are also different depending on their origin. To avoid becoming an obstacle to new LNG supplies, gas qualities should be managed at the import terminals before the gases are injected into the TAGP.

Page | 123

Differences in market structures and domestic policies

Within the ASEAN region, different market structures can be found. National monopolies, vertically integrated companies and an unbundled system coexist side by side. For example, Thailand and Indonesia have vertically integrated companies, while Singapore is on a firm course towards deregulation with the unbundling of transport and commercial activities. Most countries do not provide efficient and transparent TPA, even if there is a regulation supporting this principle.

To be able to fulfil the aim of the TAGP of a single network in ASEAN, the regulatory oversight should be harmonised. Other limitations to the development of the TAGP are national policies that favour domestic energy use before considering exports (i.e. domestic market obligations). These policies limit the most efficient allocation of gas within the region.

The most common form of favouring domestic energy users is through subsidies. Most countries use energy price regulation, and in particular subsidies, to protect gas consumers from higher international market prices. This trend will only worsen as countries increasing their LNG imports. In Malaysia, where the gas market is dominated by the vertically integrated Petronas, domestic prices are regulated by the government to stimulate the competitive advantage for industries and attract foreign companies to the country.

Connecting these different markets through a single pipeline network will provide access to the different countries. However, the current differences between national market structures limit access to the markets of other countries in the region, as the interests and risks of the parties involved differ. The absence of TPA to the transmission grid in some countries hinders the creation of an integrated network in which gas would flow to the place where the highest prices are paid, which would create additional challenges for the countries with artificially low prices.

Existing cross-border pipelines are bilateral

Despite differences in market structure, several cross-border pipelines are already in place. These are generally point-to-point pipelines, linking production locations to the demand centres in the same or neighbouring countries. Connecting bilateral pipelines to an integrated system will require current point-to-point flows to accommodate transit flows as well, with consequences on the current operation of the pipelines.

- A large bilateral project can be found in the Malaysian-Thai Joint Development Area (JDA), where gas production takes place in an offshore facility formed by overlapping continental shelf claims into an economic area under a joint authority. The Trans Thailand Malaysia (TTP) pipeline connects this JDA with the mainland of Thailand and extends further onshore into Malaysia. In Malaysia, the pipeline is connected to the Peninsular Gas Utilisation system, a gas network throughout Malaysia's peninsula. The TTP pipeline is owned and operated by the buyer of the gas from the JDA, through a 50-50 joint venture between Thailand's PTT and Malaysia's Petronas.
- Another production-to-consumer pipeline is the West Natuna Sea gas pipeline, which runs about 650 km from Indonesian waters to Singapore. It delivers gas from the West Natuna fields to

the market, under a 20-year long-term gas contract between Pertamina and a Singapore government-linked company aggregator. The parties involved in the ownership of the pipeline are three production-sharing contract groups, and Pertamina is the single buyer of the supply. The pipeline is operated by one party that acts on behalf of the others. As several parties are involved in the total project, the pipeline has been built as a multi-user pipeline system. This does not automatically imply free access to other parties, as gas may only be transported after the conclusion of a system standard gas transportation agreement with the capacity owners.

 A different operating regime is used for the Block-B gas pipeline. This pipeline also runs subsea, connecting Indonesia's South Natuna Block-B fields with the onshore gas processing location in Kerteh, Malaysia. The pipeline is situated in Indonesian and Malaysian waters, with different operators on both sides. This requires equal pipeline system operating and service arrangements for both sides.

These examples illustrate that different operating systems coexist next to each other within the region. The way the pipelines are operated is important, as it could have serious implications for the competition on the other part of the pipeline. As a high level of capacity utilisation is important for the profitability of gas infrastructure, lower utilisations in part of the system could result in higher costs for others. This could be influenced by the way transport tariffs are set. Especially for the transit tariffs, different views exist on setting the right price. Like in Europe, a rate of return for a transport system operator is determined by the regulator. Other views include a tariff based on a share of the value-added trade or pricing against an alternative. When connecting the existing bilateral pipelines in the region to an integrated network, the regulations applicable to gas transport should be harmonised and include how conflicts should be dealt with. This requires close cooperation on a regulatory level. Also, operators should work closely together in managing the cross-border flows and therefore need to increase transparency on the flows through their respective parts of the system.

Harmonising regulation

Because different operating and regulatory systems coexist in the ASEAN region, the operation of pipelines should be harmonised to address trade-offs from actions in one country on another. Transport tariffs and transparency on gas flows are therefore important for a well-functioning, integrated system.

Furthermore, establishing and harmonising TPA is required for efficient and effective gas flows through the system. Although TPA is in place in Singapore, other national market structures limit access. This limitation is emphasised by domestic gas stimulation measures in some countries.

There is hence a need for an effective and stable regulatory oversight that provides TPA to the TAGP in order to make the network function efficiently. When the TAGP would not be subject to TPA, the potential for optimal allocation of gas flows would be limited to a group of point-to-point flows.

The role of small-scale LNG and break-bulk LNG

One of the potentially ground-breaking changes in the Asian region is the development of smallscale LNG and break-bulk LNG. "Small-scale LNG" is a term which seems to have various definitions in the industry: for some, it means a step in the classic chain whereby LNG is used as a fuel by industrial users, road and maritime transport. It is also used to designate smaller LNG regasification terminals or ships. As the use of LNG in the end-user market is not the focus of this report, the second definition is taken here, that is, LNG projects having a much smaller size and allowing the import or export of LNG through smaller ships. Meanwhile, break-bulk LNG is the process of breaking larger conventional cargoes into smaller ones. This is the extension of the LNG chain with another step.

Box 14 • Experiences with small-scale LNG

In the 1990s, some mid-sized Japanese companies invested in small-scale LNG carriers. First, they decided to import LNG from Southeast Asia using smaller LNG cargoes (the average size was 20 000 m³) (GTT, 2011). Six vessels were built: Aman Bintulu, Aman Hakata, Aman Sendai, Surya Aki, Sun Arrows and Surya Satsuma. Smaller gas companies decided to develop a coastal network, as the development of the pipeline network was not always easy or possible. Small satellite terminals (Hokkaido, Aomori, Okayama, Ehime and Takamatsu) are fed with LNG from the bigger ones, a strategy that could also be replicated in other parts of Asia. The size of these terminals is between 0.03 bcm and 0.14 bcm, around 50 times smaller than the conventional ones with a capacity ranging from 2 bcm to 8 bcm. The LNG cargoes feeding those terminals were also proportionally smaller, on average 2 000 m³.

Such a network has been replicated in Norway, which also has a small market and for which building a pipeline network would not make sense due to geographical and environmental constraints.

It is worth mentioning that two Central American islands made a different choice by opting for conventional but small LNG import terminals: the Dominican Republic and Puerto Rico. Both opted for LNG imports to reduce their dependency on expensive oil products to generate electricity. Some decades ago, Puerto Rico decided to open its power sector by allowing private power producers. As a result, one gas-fired plant was developed back-to-back with an LNG terminal, which started in 2000. This project was the first to simultaneously finance and build LNG and power as a single facility (Haug and Cumberland, 2013). The Dominican Republic started importing LNG in 2003 through the Punta Caucedo LNG terminal, but never got the expected project financing, partly due to lower payments for power generation and divergence between the evolution of LNG prices and power sales. The project has had to be carried on its owner's balance sheet since it was completed.

Given the geography of the Asian region, notably of Southeast Asia, having smaller cargoes which can supply islands or remote regions would be an advantage. In particular, Malaysia, the Philippines, Indonesia and Thailand would benefit from this technology approach; similarly, Central America is a region where this model would fit well (Box 14). These regions all have potential demand centres for which it would be difficult and costly to develop an adequate pipeline network.

A move to small-scale or break-bulk would be a departure from conventional LNG import terminals and the conventional LNG supply chain with an offshore LNG regasification terminal. But this is not a new format. In the early stages of the LNG industry, LNG carriers and terminals were smaller. The LNG carriers built in the 1960s and 1970s varied in size between 30 000 cubic metres (m³) and 90 000 m³. Also, Japan used many small-scale vessels in the 1990s. Today, an LNG cargo averages 160 000 m³. This model would certainly depart from the conventional LNG SPAs, which usually link an LNG liquefaction plant to a regasification terminal. The traditional point-to-point model has seen many modifications over the past decade, with the emergence of spot cargoes, arbitrage between different destinations and the rise of aggregators, which all points to a different way of using the traditional LNG chain.

- LNG re-exporting has emerged since 2009 due to the low demand for gas in some regions, coupled with the high differential between Asian gas prices on one side and European or North American gas prices on the other, prompting companies to resell their gas to Asian markets. This trend emerged first in the United States and is now mostly seen in Europe.
- The past ten years have seen the rise of FSRUs in developing countries. Smaller in size, they enable countries to have faster access to LNG imports as the construction requirements on the site are much more limited than for an offshore terminal.
- Small liquefaction plants have also been developed to serve the downstream market. This trend is seen particularly in China, where the LNG mainly serves the transport sector (road and soon maritime).

- There is some possibility of having a partial (un)loading of an LNG cargo, even though this must be examined very carefully as the liquid gas would move with the rolling movement of the ship at sea. Significant liquid movement can create a high impact pressure on the tank surface, an effect called "sloshing" which can cause structural damage to the LNG containment vessels.
- Page | 126
- Transhipment of LNG enables the transfer of a cargo between two oceangoing LNG carriers. Elengy performed the first transhipment of LNG in August 2013. This brings a new level of flexibility to the LNG business. Another such operation took place with Qatar's 215 000 m³ Al Gharrafa after the ship collided with another ship in early 2014 off the shore of Singapore.

Small-scale or break-bulk LNG could provide an alternative for small buyers who have no track record of LNG imports and do not provide a significant demand centre, but are still interested in benefiting from the advantages of a cleaner-burning fuel. Sellers would usually prefer to sell larger volumes of gas over a long period of one or two decades, although in the case of Japan many smaller contracts of less than 1 bcm/yr exist. They would also prefer sales counterparts who are economically robust. But as import needs in smaller countries increase, those countries face the issue of building significant LNG import facilities or being ignored as too small. Apart from countries such as the Dominican Republic or Puerto Rico, LNG importers have traditionally been large countries.

Small-scale and break-bulk LNG import projects would have the following characteristics:

- Smaller terminals. A smaller terminal leads to faster build times. Due to its smaller size, the capital and operational costs are more affordable for small players and the projects can be built in less time.
- Ships. An average cargo ship has a capacity of 160 000 m³. The biggest cargoes are carried by Qatar's Q-Max, with a carrying capacity of 266 000 m³. At the other end of the spectrum, some small-scale LNG barges with capacities between 1 000 m³ and 30 000 m³ are being built. Ships as small as 1 000 m³ can be found in Norway or Japan and are used for coastal trade. The smallest (below 15 000 m³) can have a different design with cylindrical tanks.
- **Distance**. Besides the smaller size of regasification facilities and cargoes, these shipments would typically travel over shorter distances, as is the case in the Baltic region. These LNG cargoes would no longer travel thousands of nautical miles, but rather hundreds. The smallest ships built decades ago were adapted to the trade in the Mediterranean Sea, with short distances between North African producers and European buyers.
- Customers. Small-scale LNG would be able to supply one single gas-fired power plant needing a few million cubic metres over the year, without having to develop a large LNG regasification terminal or find additional gas users, for which a transmission and potentially a distribution network would need to be built. This would be an advantage in regions where the gas network is still insufficiently developed, non-existent or too expensive to develop. Against this backdrop, LNG represents the most flexible means by which Asian countries could access imports when they do not possess gas resources or when they are located far away from markets. A smaller size would be more adapted to feed-gas-fired plants with a capacity of 10 MW to 50 MW, which would typically need 10 Mcm to 50 Mcm of LNG per year.
- **Operations**. The example of the Dutch Gate terminal features a traditional LNG import terminal with the capacity to redistribute LNG to smaller ships or directly to end users. Japan did the same decades ago. The LNG can either be loaded then or unloaded later to a smaller ship. It could also serve for road or maritime transport applications and be loaded on small trucks for inland distribution. Finally, it could also be regasified and sent to the distribution network. While moving to break-bulk services, small-scale LNG ships could undertake several unloading operations to multiple small-scale regasification terminals within a region. Different LNG users should be able to have access to the terminal through contracting for certain LNG services

(unloading, reloading LNG into a ship, trans-shipment, bunkering, LNG storage, LNG regasification and send-out of pipeline gas or LNG). The operator of the LNG terminal could be different from the users (like Vopak in the Dutch Gate terminal) and earn revenues from regulated LNG terminal activities.

• Economics. Such a development could be looked at from a regional point of view in order to have synergies among small buyers. The economics of using small-scale and break-bulk LNG, possibly in co-ordination with further transport by truck, would have to be compared with developing a standard pipeline network. Also, for the terminal owner, it would make sense to have the booking commitments of several companies in order to raise financing. The specificities of LNG such as boil-off in storage and transport should also be taken into account regarding who pays for them.

In addition to economic aspects, another important item is the interaction between the liquefaction terminal and the buyer(s). There are essentially two options:

- the LNG is imported directly through a normal regasification terminal and then divided and split into several cargoes and redistributed to small-scale LNG terminals in the region, like a milk delivery round/routine
- it is imported directly to a small-scale LNG terminal.

In any case, contracts will likely need to be adapted to fit this new business, not just from an operational but also from a legal point of view.

Developing small-scale and break-bulk LNG in Asia would not be a fast process, as the infrastructure and ships need to be built, but should countries choose this option, first steps have to be taken now.

Enabling measures to establish a natural gas trading hub in ASEAN countries

While the ASEAN is currently developing the TAGP project, Singapore is trying to establish the first natural gas hub in Asia but is also involved in the TAGP. The two projects could therefore have a symbiotic relationship rather than competing against one another; the success of the TAGP project will further the probability of natural gas hub in Singapore through increased liquidity, which is a key issue for Singapore – as highlighted in the IEA report *Developing a Natural Gas Trading Hub in Asia* (IEA, 2013c) – due to its small natural gas market (around 10 bcm). Singapore can also benefit from the TAGP project in the form of enhanced supply security and diversity through connections with natural gas fields and other LNG regasification terminals in the region. The cross-border issue of different price regimes is currently one of the key hindrances to the success of the TAGP project, so the establishment of a hub in Singapore would support the project by providing a reliable single price reference for all transactions via the TAGP.

Nevertheless, as highlighted before, surrounding ASEAN countries are far from fulfilling the criteria set by the IEA report, namely a hands-off government approach, the separation of transport and commercial activities, sufficient network capacity and non-discriminatory access, wholesale price deregulation, a competitive number of market participants, and the involvement of financial institutions. Significant improvement is therefore necessary.

In addition, the introduction of LNG break-bulk activity will benefit both projects; the hub can fulfil demand from ASEAN countries that have technical or commercial constraints preventing their receiving LNG via normal LNG carriers, which will result in increased liquidity as well as improved security of supply for the region – the main objective of the TAGP project. A good example of this business model is the Gate LNG terminal in the Netherlands that is currently upgrading its facility to include break-bulk activity to serve relatively small demand from Scandinavian and Baltic countries.

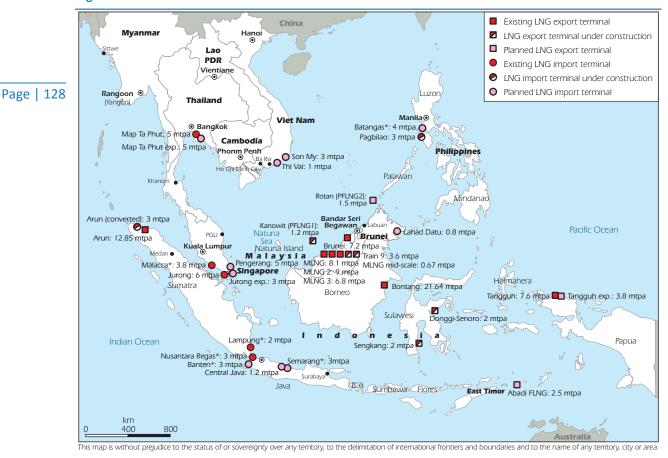


Figure 49 • LNG terminals in the ASEAN

* FSRU.

Is the idea of a natural gas trading hub well received by ASEAN countries?

Besides working to meet all the requirements for a natural gas trading hub, Singapore, being fully dependent on natural gas imports, is understandably promoting the project, as the use of gas instead of oil indexing may reduce the country's gas bills. Naturally, ASEAN countries that export natural gas – namely Brunei, Indonesia and Malaysia – are expected to have, at best, a neutral response to the idea. This is rooted in the widely held misconception that a hub gas/spot index will always be lower than the oil-linked formula, and hence the resistance from natural gas exporters as it could mean less profit for them. At the same time, they may perceive that the creation of a hub would benefit only consumers through increased liquidity and transparency.

Nevertheless, Malaysia and the Philippines may also follow Singapore's lead in establishing a natural gas hub, albeit at a much more limited scope.

 Vopak, the owner and operator of the Gate LNG terminal in the Netherlands and the Altamira LNG terminal in Mexico, plans to build an LNG terminal in Pengerang, Malaysia, for LNG trading in the region. The Pengerang LNG terminal will be equipped with a reloading facility for trading-related activities and may also have an LNG bunkering facilities, as well as the capability to do break-bulk activities via smaller LNG vessels. The company is anticipated to have no issues with these innovative roles, based on its experience at the Gate LNG terminal. The plan is well received by the Malaysian government: it includes plans for the terminal in the country's Economic Transformation Programme (ETP). Meanwhile, the Philippines is also poised to become an LNG hub when the first LNG regasification terminal, currently under construction by the Energy World Corporation, comes online. According to the company's website, the terminal is expected to start operations by 2015 and will become an LNG hub to serve demand from the surrounding region. However, it remains to be seen how the terminal will be able operate as a hub since there is currently no information available regarding the hub's plan from the company. The Philippines is a very small market (4 bcm) and there is still a long way to go before the TAGP reaches it. It is still uncertain whether such a project would be economical.

The plan by both terminals in Malaysia and the Philippines to establish an "LNG trading hub" seems justifiable, especially for spot-trading opportunities, in view of the current seasonal price variability that exists in Asia: the price gap between summer and winter prices has been as high as USD 9/MBtu in recent years. The LNG hubs could also cater for any unforeseen demand by buyers due to their strategic locations, particularly for Singapore and Malaysia, which are situated in the midst of India and Far East markets. Provided that a standardised contract from the hub is available, LNG buyers from these markets can purchase and receive LNG in less than one week based on the required shipping days, compared to the typical one month required to purchase LNG from LNG producers. The reloading facilities at these terminals will also overcome the fixed-destination constraint, which is typical in Asian LNG contracts, and thus could be anticipated to spur spot-trading activities in the region.

Acronyms and abbreviations

Acronyms and abbreviations

	ACQ	annually contracted quantity
Page 130	AEO	Annual Energy Outlook
	AGCC	ASEAN Gas Consultative Council
	ASCOPE	ASEAN Council on Petroleum
	AMEN	ASEAN Ministers on Energy Meeting
	ASEAN	Association of Southeast Asian Nations
	CAPEX	capital expenditure
	CBM	coalbed methane
	CNOOC	China National Offshore Oil Company
	CNPC	China National Petroleum Company
	CO ₂	carbon dioxide
	DES	delivered ex-ship
	DOE	Department of Energy (United States)
	EU	European Union
	EWC	Energy World Corporation
	FDC	final destination clause
	FERC	Federal Energy Regulatory Commission
	FID	final investment decision
	FLNG	floating liquefied natural gas
	FOB	free-on-board
	FSRU	floating storage and regasification unit
	FSU	Former Soviet Union
	FTA	free trade agreement
	GIIGNL	International Group of Liquefied Natural Gas Importers
	GPCC	Gas Price Convergence Scenario
	GSP	Government Selling Price
	HH	Henry Hub
	HoA	heads of agreement
	IGU	International Gas Union
	IEA	International Energy Agency
	IOC	international oil company
	ISO	independent systems operator
	ITO	independent transmission operator
	JOC	Japan Customs-cleared Crude (oil price) or Japan Crude Cocktail
	JDA	joint development area
	JKM	Japan/Korea Marker
	LNG	liquefied natural gas
	LPG	liquefied petroleum gas
	M&A	merger and acquisition
	METI	Ministry of Economy, Trade and Industry (Japan)
	MOTIE	Ministry of Trade, Energy and Industry (Korea)
	MOU	memorandum of understanding
	MTI	Ministry of Trade and Industry (Singapore)
	NBP	National Balancing Point
	NDRC	National Development and Reform Commission (China)
	NP	no price

New York Mercantile Exchange		
National Energy Board (Canada)		
nautical miles		
national oil company		
New Policies Scenario		
North West Shelf LNG		
Organisation for Economic Co-operation and Development		
Organisation of Petroleum Exporting Countries		
operating expense		
regulation below cost		
regulation cost of service		
sales and purchase agreement		
social and political regulation		
Trans-ASEAN Gas Pipeline		
take-or-pay		
third-party access		
transmission system operator		
Title Transfer Facility		
United Kingdom		
United States		

Currency codes

CNY	Yuan renminbi
GBP	British pound
JPY	Japanese yen
RYM	Malaysian ringgits
USD	United States dollar

Units of measure

References

Antaranews (2014), Singapore to Stop Gas Imports via Pipelines from Indonesia, Antaranews,
Indonesia, www.antaranews.com/en/news/92436/singapore-to-stop-gas-imports-via-
pipelines-from-indonesia.

Page | 132

APEC (Asia-Pacific Economic Cooperation) (2011), *The Impacts and Benefits of Structural Reforms in Transport, Energy and Telecommunications Sectors*, APEC Secretariat, http://publications.apec.org/publication-detail.php?pub_id=1113.

CSTM (Centre for Studies in Technology and Sustainable Development) (2011), *Regulatory Reform in the Indonesian Natural Gas Market*, University of Twente, the Netherlands, www.crninet.com/2011/b6a.pdf.

EC (European Commission) (1998), Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas, OJ L204/1, European Commission, Brussels, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:1998:204:TOC.

EIA (Energy Information Administration) (2014), *Annual Energy Outlook 2014*, EIA, Washington, D.C., www.eia.gov/forecasts/aeo.

- EIA (2013), *Country Analysis Brief Overview: Thailand*, EIA, Washington, D.C., www.eia.gov/countries/analysisbriefs/Thailand/thailand.pdf.
- EIA (2005), Annual Energy Outlook 2005, EIA, Washington, D.C., www.eia.gov/forecasts/aeo/archive.cfm.
- GIIGNL (International Group of LNG Importers) (2014), *The LNG Industry in 2013*, GIIGNL, Paris, www.giignl.org/system/files/giignl_the_lng_industry_2013_0.pdf.
- GTT (2011), Going Small with GTT, GasTech, Amsterdam, www.gtt.fr/wpcontent/uploads/2012/09/going-small-with-gtt-gastech-2011-2011-09-29.pdf.
- Haug, D.L. and S. Cumberland (2013), LNG for power in small emerging markets, Arctas Capital Group, www.gastechnology.org/Training/Documents/LNG17-proceedings/3-7-David_Haug.pdf.
- IEA (International Energy Agency) (2014a), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris.
- IEA (2014b), Natural Gas Information 2014, OECD/IEA, Paris.
- IEA (2013a), World Energy Outlook 2013, OECD/IEA, Paris, www.worldenergyoutlook.org/publications/weo-2013.
- IEA (2013b), Southeast Asia Energy Outlook, World Energy Outlook Special Report, OECD/IEA, Paris, www.iea.org/publications/freepublications/publication/world-energy-outlook-specialreport-2013-southeast-asia-energy-outlook.html.
- IEA (2013c), *Developing a Natural Gas Trading Hub in Asia*, Partner Country series, OECD/IEA, Paris, www.iea.org/media/freepublications/AsianGasHub_WEB.pdf.
- IEA (2012), Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report, OECD/IEA, Paris,www.worldenergyoutlook.org/goldenrules.
- IEA (2011), World Energy Outlook 2011, OECD/IEA, Paris, www.worldenergyoutlook.org/publications/weo-2011.

- IEA (2009), *World Energy Outlook 2009*, OECD/IEA, Paris, www.worldenergyoutlook.org/publications/weo-2009.
- IEA (2008), Energy Policy Review of Indonesia, OECD/IEA, Paris.
- IFRI (French Institute of International Relations) (2011), *Decoupling the Oil and Gas prices: Natural Gas Pricing in the Post-Financial Crisis Market*, IFRI, Paris, www.ifri.org/.../kanaipresentation.pdf.
- IGU (International Gas Union) (2014), Wholesale Gas Price Survey 2014 Edition, IGU, Oslo.
- MineralWise (2014), "Farm-In: Definition", date of access July 2014, www.mineralweb.com/library/oil-and-gas-terms/farm-in-definition.
- OIES (Oxford Institute of Energy Studies) (2014), *The development of Chinese gas pricing: drivers, challenges and implications for demand*, OIES, Oxford, www.oxfordenergy.org/wpcms/wp-content/uploads/2014/07/NG-89.pdf.
- OIES (2011), *The transition to hub-based gas pricing in Continental Europe*, OIES, Oxford, www.oxfordenergy.org/wpcms/wp-content/uploads/2011/03/NG49.pdf.

iea linergy Agency bookshop

www.iea.org/books

PDF versions at 20% discount

International Energy Agency 9 rue de la Fédération 75739 Paris Cedex 15, France

> Tel: +33 (0)1 40 57 66 90 E-mail: books@iea.org



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

IEA Publications 9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by IEA, November 2014

Cover design: IEA. Photo credits: LNG port: photo by Ahmad Afifi Isa on Flickr, https://creativecommongs.org/licenses/by/2.0; tanker in LNG port: photo by Michael Scott on Flickr, https://creativecommons.org/licenses/by/2.0/; LNG tanker: ©Tokyo Gas Co., Ltd.

The Asian Quest for LNG in a Globalising Market

Global gas markets may be at the threshold of a new age. An unprecedented gap between regional gas prices has triggered fundamental changes for future global gas market dynamics. This price gap comes at a time when the industry is expanding liquefied natural gas (LNG) export capacity by one-third, with most of this capacity targeting the Asian market. Not only is the demand for gas growing quickly in Asia, but high prices make this region the preferred destination for LNG sellers.

It would be a mistake, however, to expect such a situation to continue unchanged. Growth will depend on whether countries can afford more expensive gas, its competitiveness against other fuels, and the price level that could trigger an increase in unconventional gas production.

The high prices in Asia have been a result of the close link to oil prices in global LNG markets. This model might see some cracks as a greater quantity of new supplies offer a Henry Hub price with destination flexibility. A regional hub pricing signal in Asia is lacking, but market reforms do show first signs of progress in that direction. That new LNG is being sold on different terms does not mean the end of oil indexation over the medium term, and a mix of oil, Henry Hub and Asian hub indexation could be expected to govern contracts over the longer term.

In sum, new LNG supplies that are redrawing the global gas map, combined with the Asian demand growth and market reforms, challenge Asia to attract LNG in this globalising market.