

## **Geopolitical Issues of Natural Gas Trade in Northeast Asia**

**Andrey Kovsh\***

*School of International Relations Saint Petersburg State University, Russia*

### **Abstract**

This work was supported by the Academy of Korean Studies of the Republic of Korea in year 2012-2013 (AKS-2010-CAA-2101) Energy security has assumed newfound geopolitical importance at the outset of XXI century (Moran and Russell, 2008). Diminishing fossil fuel supplies have led to fears of energy shortages, while rapid economic and population growth have fuelled the demand for cheap, clean and secure sources of energy. The provision of reliable and affordable energy, once the domain of domestic policy, has emerged as a key concern of policymakers. To ensure energy security, leaders confront a complex set of economic, political, and environmental issues that transcend national boundaries. Should they fail to meet this challenge, energy is one of the few issues in today's international system with a distinct possibility to incite conflict between major powers. At the same time, trade in energy resources has the potential to usurp pre-existing economic or cultural ties – and overcome deep-seated distrust – to create new geopolitical alignments and alliances.

**Keywords:** Natural Gas Trade, Geopolitics, Northeast Asia, Energy Import Dependency

**JEL Classification:** Q00

---

\* Corresponding Author, Email: akovsh@yahoo.com

## 1. Introduction

The different geopolitical ramifications of oil and gas dependency stem largely from the resources' different physical characteristics. For an equivalent volume, oil contains over one thousand times the energy of natural gas. To deliver a given amount of energy, an amount of gas three orders of magnitude larger than that of oil is required. Nevertheless, gas has emerged as a convenient fuel for uses including heating, electricity generation, public transportation, and numerous industrial processes, which has made it an essential resource across the globe (Terry, 2005).

The procurement of reliable and affordable natural gas supplies requires the intervention of foreign policymakers for three following reasons.

First, gas trade requires a much higher degree of interconnectedness between supplier and consumer than oil trade. Because of its low energy density, gas must be transported via pipeline to be cost-efficient, although plants and ships capable of refrigerating and LNG have introduced another mode of transportation. Pipelines impose severe limitations on the trade in gas, because pipelines are economic for trade over relatively small distances, so gas markets created by pipeline tend to be regional. Construction of a transnational pipeline requires enormous infrastructure investment, which in turn requires accessible credit, transparent licensing requirements, a stable political climate, and often the support of transit states. Due to the challenges of pipeline construction, buyer and seller governments must be involved from the outset (Mares, 2006).

Since LNG trade avoids the complications of transit states, it is tempting to think of LNG as a fungible commodity more similar to oil than pipeline gas. Yet the up-front costs to build the infrastructure necessary to trade LNG are often even higher than to build a pipeline. LNG trade requires complex refrigeration and liquefaction plants near the well-head, specially-designed tankers with refrigerated holds, and regasification terminals that can convert LNG back to a gaseous state safely and efficiently. To date, producers have been unwilling and unable to secure the financing to export LNG without first signing long-term contracts with importers. The need for these long-term contracts has precluded the development of an LNG spot market to date. So, we can see that LNG should be thought of as a "floating pipeline," that carries geopolitical consequences similar to those of real pipeline connections.

Second, natural gas is not a globally traded commodity and does not have a global price, unlike oil. Because transport is most economic over short distances, gas is traded regionally, and it is priced in the context of the neighborhood where it is sold. The wide range of gas prices creates an incentive for foreign policymakers to seek preferential prices.

Third, natural gas storage is more difficult and expensive than oil storage. Natural gas can be stored in large quantities in three locations: depleted gas/oil reservoirs, salt caverns, and aquifers (Douglas and Sarkees, 2004). All of these storage venues raise environmental concerns, and, unlike oil reserves, gas reserves must be withdrawn and recycled to avoid gas loss. The inefficiency of relying on gas reserves puts a premium on ensuring a stable, continuous gas supply.

Gas consumption is predicted to grow rapidly in the coming decades, rising over 50% in the next 20 years. Consumption may grow even faster, as fears of global warming lead to calls for gas, a naturally clean-burning fuel, to replace oil (Department of Energy, 2012). As a result, policymakers will remain sensitive to the pressures of securing long-term gas supplies.

Section 2 makes an overview on natural gas in Northeast Asia. Section 3 represents geographical implications on the regional level, and Section 4 raises a conclusion.

## 2. Natural Gas & Northeast Asia: an Overview

Today the issue of energy supply is one that plagues most of the economies of Asia. South Korea, China, and Japan are all expected to see oil and natural gas imports grow dramatically in the coming years. By 2020, energy use in all of Asia (including India and the industrialized nations of Japan, Australia, and New Zealand) is projected to rival that in North America and Western Europe combined, accounting for about one-third of total global consumption. Natural gas is expected to become a larger part of Asia's overall energy mix in the years to come.

### 2.1. Republic of Korea

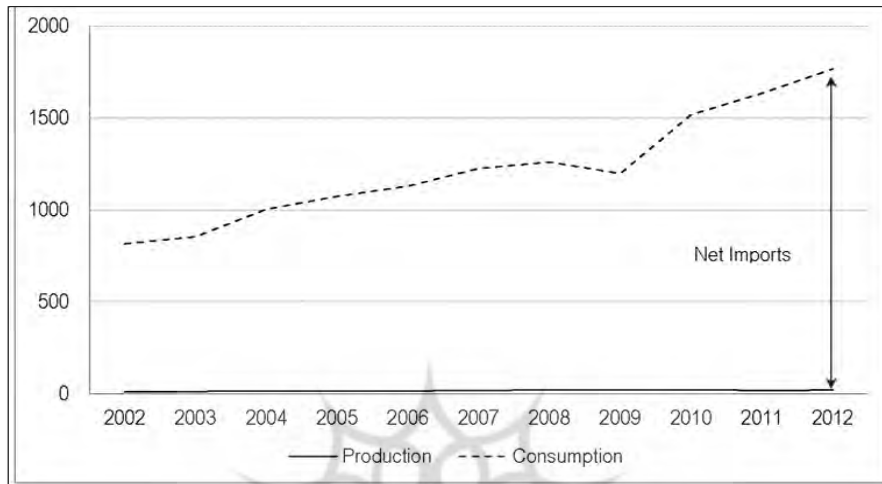
South Korea relies on imports to satisfy nearly all of its natural gas consumption. While the country has discovered proven reserves of 250 Bcf<sup>1</sup>, domestic gas production is negligible and accounts for less than two percent of total consumption (Figure 1). South Korea does not have any international gas pipeline connections,

<sup>1</sup> For a list of Abbreviation, see Table A-1.

and must therefore import all gas via LNG tankers. As a result, although South Korea is not among the group of top gas-consuming nations, it is the second largest importer of LNG in the world after Japan.

Korea Gas Corporation dominates South Korea's gas sector and the company is the largest single LNG importer in the world. In spite of recent efforts to liberalize the LNG

import market, KOGAS maintains an effective monopoly over the purchasing, import, and wholesale distribution of natural gas. In addition to operating three of Korea's four LGG receiving terminals, KOGAS owns and operates the 1,790-mile national pipeline network, and sells regasified LNG to power generation companies and private gas distribution companies.



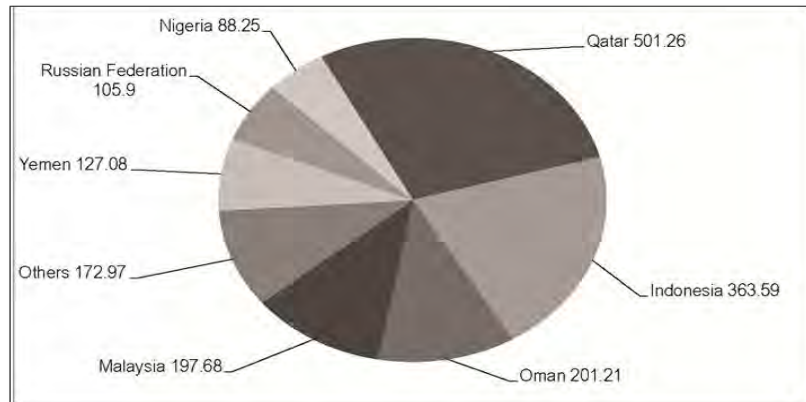
**Figure 1: Republic of Korea Natural Gas Production & Consumption, 2002-2012 (Bcf)**

*Source:* British Petroleum (2012)

The Korean central government is the largest KOGAS shareholder with 26.9% direct equity, and an additional indirect 24.5% via the Korean Electric Power Company. Korea has 30 private distribution companies, but each has an exclusive sales right within a particular region. These local companies purchase wholesale gas from KOGAS at a government-approved price, and sell gas to end-users. In the upstream, KOGAS has historically focused primarily on overseas LNG liquefaction projects, while the Korea National Oil Corporation has handled most exploration and production-related activities. As KOGAS seeks new opportunities for growth however, its focus on overseas upstream activities is increasing.

South Korea produced about 18 Bcf of natural gas (about 1.3% of consumption) in 2011 from the domestic gas field in production, Donghae-1 in the Ulleung Basin. KNOC will continue production operations until 2018, when the project will be converted into an offshore storage facility.

South Korea has four LNG regasification facilities, with a total capacity of 4.5 Tcf/y. KOGAS operates three of these facilities (Pyongtaek, Incheon, and Tong-Yeong), accounting for about 95% of current capacity. Pohang Iron and Steel Corporation and Mitsubishi Japan jointly own the only private regasification facility in Korea, located on the Southern Coast in Gwangyang. KOGAS purchases most of its LNG through long-term supply contracts. Almost two-thirds of natural gas imports came from Qatar, Indonesia, Malaysia, and Oman (Figure 2). KOGAS is planning a new 487 Bcf/y facility at Boryeong, whose first unit is scheduled for completion by 2013, second by 2019. KOGAS is currently constructing a new LNG receiving facility at Samcheok, on the Northwest coast. The first stage of 278 Bcf/y is slated for 2013 completion, with supplies of 350 Bcf/y to be met primarily through gas imported from Vladivostok, Russia starting in 2015.



**Figure 2: Republic of Korea's Natural Gas Imports by source, 2012 (Bcf)**

Source: British Petroleum (2012)

## 2.2. Japan

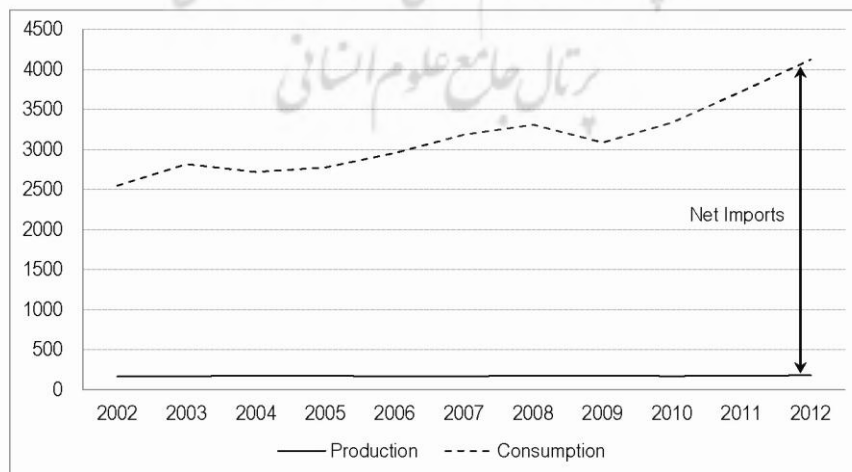
Japan had 738 Bcf of proven natural gas reserves as of January 2012. Natural gas proven reserves have declined since 2007, when they measured 1.4 Tcf. Most natural gas fields are located along the western coastline (Figure 2).

Companies created from the former Japan National Oil Company are the primary actors in Japan's domestic natural gas sector. Inpex, Mitsubishi, Mitsui, and various other Japanese companies are actively involved in domestic as well as overseas natural gas exploration and production. Osaka Gas, Tokyo Gas, and Toho Gas are Japan's largest retail natural gas companies, with a combined share of about 75% of the retail market (British Petroleum, 2012).

Japan is a large natural gas consumer, but it has a relatively limited domestic natural gas pipeline transmission system for a consumer of its size. This is partly due to geographical constraints posed by the country's mountainous terrain, but it is also the result of previous regulations that limited investment in the sector.

Reforms enacted in 1995 and 1999 helped open the sector to greater competition and a number of new private companies have entered the industry since the reforms (Akira, 2008).

Japan produced only 176 Bcf of natural gas in 2009) Japan's largest natural gas field is the Minami-Nagaoka on the western coast of Honshu, which produces about 40% of Japan's domestic gas. Exploration and development are still ongoing at the field which Inpex discovered in 1979. The gas produced is transported via an 808-mile pipeline network that stretches across the region surrounding the Tokyo metropolitan area. Inpex is building an LNG terminal with a 75 Bcf/y capacity at Naotsu port in Joetsu City which will connect its domestic pipeline infrastructure with its overseas assets by 2014. Japex has been involved in locating new domestic reserves in the Niigata, Akita, and Hokkaido regions of Japan, targeting structures near existing gas fields.



**Figure 3: Japan's Natural Gas Production & Consumption, 2002-2012 (Bcf)**

Source: British Petroleum (2012)

Because of its limited natural gas resources, Japan must rely on imports to meet its natural gas needs. Due to environmental concerns, the Japanese government has encouraged natural gas consumption in the country. Japan is the world's largest LGG importer, holding about 33% of the global market in 2011.

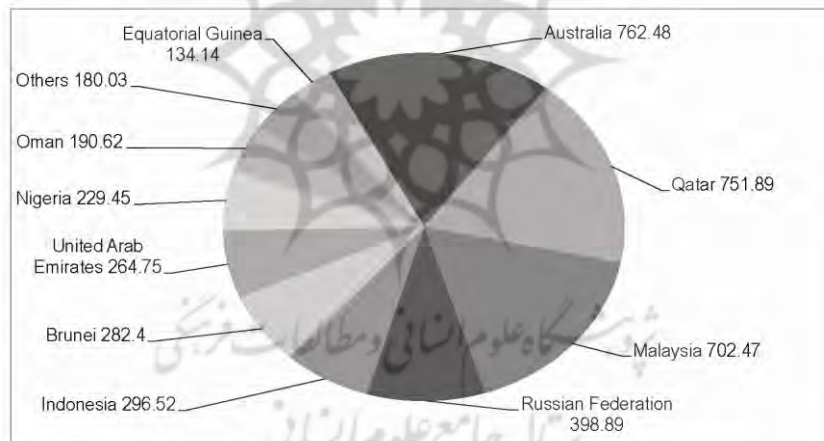
Japan has 32 operating LNG import terminals with a total gas send-out capacity of 8.7 Tcf/y, well in excess of demand in order to ensure flexibility. The majority of LNG terminals is located in the main population centers of Tokyo, Osaka, and Nagoya, near major urban and manufacturing hubs, and is owned by local power companies, either alone or in partnership with gas companies.

These same companies own much of Japan's LNG tanker fleet. Five new terminals are under construction and anticipated to come online by 2015 and could add between 200 to 300 Bcf/y of capacity. After the Fukushima incident, Japan is replacing lost nuclear capacity with more short-term and spot cargo LNG which made up about 20% of total LNG imports in 2011. Most of Japan's LGG import infrastructure was not damaged by the earthquake since a majority of

these facilities are located in the south and west of the country, away from the earthquake's epicenter.

Most of Japan's LGG imports originate from regional suppliers in Southeast Asia, although the country has a fairly balanced portfolio with no one supplier having a market share greater than roughly 20%. Japan's top 5 gas suppliers make up 73% of the market share. Japan began importing LGG from Russia's Sakhalin terminal in 2009, and the two countries are discussing ways to increase gas imports to Japan via a proposed pipeline or more LNG shipments. Additional supplies to Japan could stem from other new projects in Papua New Guinea or North America.

Japanese electric and gas companies and trading houses have signed contracts with various large LNG projects in Australia, most significantly the Chevron-led Gorgon project, which will provide up to 2 Bcf/d of LNG to Asian markets by 2014. In 2012, Mitsui and Mitsubishi purchased a 15% stake in Australia's Browse LNG project that will supply at least 1.6 Bcf/d of natural gas.



**Figure 4: Japan's Natural Gas Imports by source, 2012 (Bcf)**

Source: British Petroleum (2012)

Japanese regulations permit individual utilities and natural gas distribution companies to sign LNG supply contracts with foreign sources, in addition to directly importing spot cargoes. The largest LNG supply agreements are held by Tokyo Gas, Osaka Gas, Toho Gas, Chubu Electric and TEPCO, primarily with countries in Southeast Asia and the Middle East (Figure 4).

**2.3. China**

Although natural gas use is rapidly increasing in China, the fuel comprised less than 4% of the

country's total primary energy consumption in 2009 (Figure 5).

China held 107 Tcf of proven natural gas reserves as of January 2012. China's natural gas production and demand have risen substantially in the past decade. China became a net natural gas importer for the first time in the beginning of 2000-s and imports have increased dramatically alongside China's thirst for natural gas and rapidly developing infrastructure.

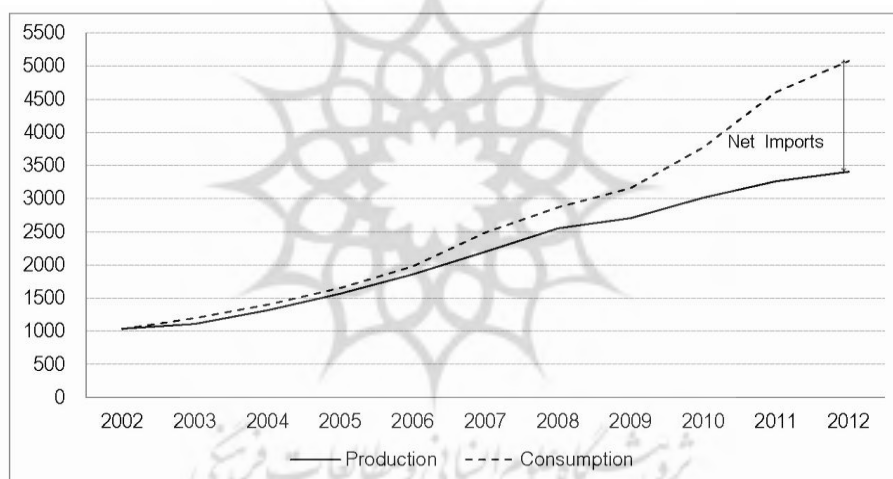
The Chinese government anticipates boosting the share of natural gas as part of total energy consumption to 10% by 2020 to alleviate

high pollution from the country's heavy coal use and diversify the fuel mix in all end-use sectors. There is an assumption that China's gas demand to more than triple to over 11 Tcf/y by 2035, growing about 5% percent per year. To meet this demand, China is expected to continue importing natural gas via LNG and a number of potential import pipelines from neighboring countries Victor et al. 2006). It will also have to tap into its expanding domestic reserves.

The natural gas sector is dominated by the three principal state-owned oil and gas companies: CNPC, Sinopec, and CNOOC. CNPC is the country's largest natural gas company in both the upstream and downstream sectors. CNPC data shows that the company accounts for roughly 73% of China's total natural gas output Sinopec operates the Puguang natural gas field in Sichuan Province, one of China's most promising upstream assets. . CCCC led the development of China's first three LNG import terminals at Shenzhen,

Fujian, and Shanghai and manages much of the country's offshore production. CCCC typically uses PSC agreements with foreign companies wanting to co-develop upstream offshore projects and has the right to acquire up to a 51% working interest in all offshore discoveries once the IOC recovers its development costs.

China's primary natural gas-producing regions are Sichuan Province in the southwest (Sichuan Basin); the Xinjiang and Qinghai Provinces in the northwest (Tarim, Junggar, and Qaidam Basins); and Shanxi Province in the north (Ordos Basin). China has dived into several offshore natural gas fields located in the Bohai Basin (Yellow Sea) and the Panyu complex of the Pearl River Mouth Basin (South China Sea) and is exploring more technically challenging areas, such as deepwater and unconventional resources, with foreign companies.



**Figure 5: China Natural Gas Production & Consumption, 2002-2012 (Bcf)†**

*Source:* British Petroleum (2012)

China had nearly 27,000 miles of main natural gas pipelines at the end of 2011. China's natural gas pipeline network is fragmented, though NOCs are rapidly investing in the expansion of the transmission system to connect more supplies to demand centers along the coast and in the southern regions as well as integrating local gas distribution networks. The government plans to construct another 24,000 miles of new pipelines by 2015. While the major NOCs operate the trunk pipelines, local transmission networks are operated by various local distribution companies throughout China. This has prevented the emergence of a national gas transmission grid.

CNPC is the primary operator of the main

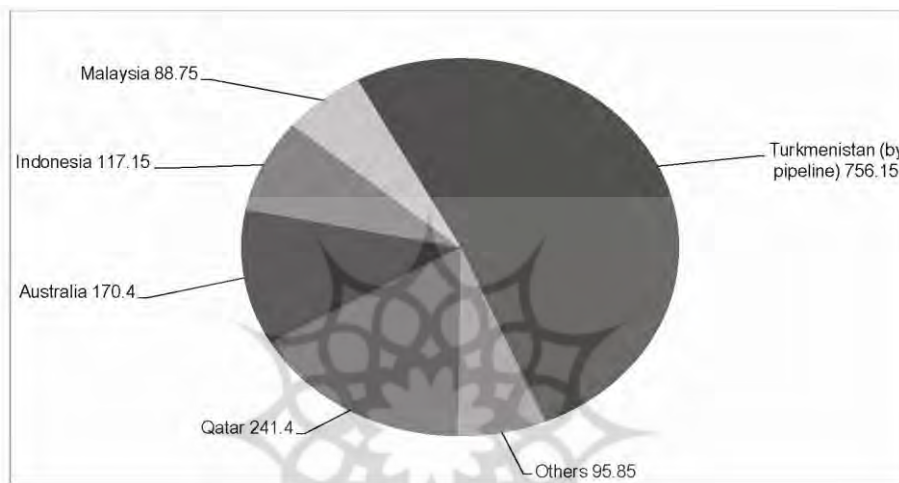
gas pipelines, holding over three-quarters of the market share. CNPC moved into the downstream gas sector recently through investments in gas retail projects as well as investments in several pipeline projects to facilitate gas transportation for its growing gas supply. CNPC developed 3 parallel pipelines, Shan-Jing pipelines, linking the major Ordos basin in the North with Beijing and surrounding areas. The third Shan-Jing pipeline began operations in 2011. Sinopec is also a major player in the downstream transmission sector, operating pipelines in the Sichuan province. In 2010 the NOC commissioned the 1,000 mile, 425 Bcf/y pipeline running across 8 provinces from its recently operating Puguang field to

Shanghai. Today China lacks gas storage capacity, causing it to consume almost all of the gas it supplies. The government intends to increase storage capacity from nearly 70 Bcf to 1,100 Bcf in 2015.

Roughly half of China’s natural gas imports are in the form of LNG. Re-gasification capacity was almost 1,000 Bcf/y (2.7 Bcf/d) in mid-2012. Another 2 Bcf/d is being built by 2015. China’s LGG imports are expected to rise as more terminal capacity comes online, though higher market-based LNG prices based versus lower prices from domestic gas sources as well as pipeline gas from Turkmenistan could cause

more competition for LNG.

Chinese NOCs must secure supply prior to gaining government approval to build a re-gasification terminal, and these firms are faced with competition from other regional buyers, mainly in Korea and Japan. Therefore, CNOOC, Petro-China, and Sinopec have signed several long terms supply contracts totaling about 3.8 Bcf/d. These contracts are primarily with Asian firms sourcing LNG from Indonesia, Malaysia, and Australia. Qatar Gas is also supplying LNG to China through long-term contracts and spot cargoes (Figure 6).



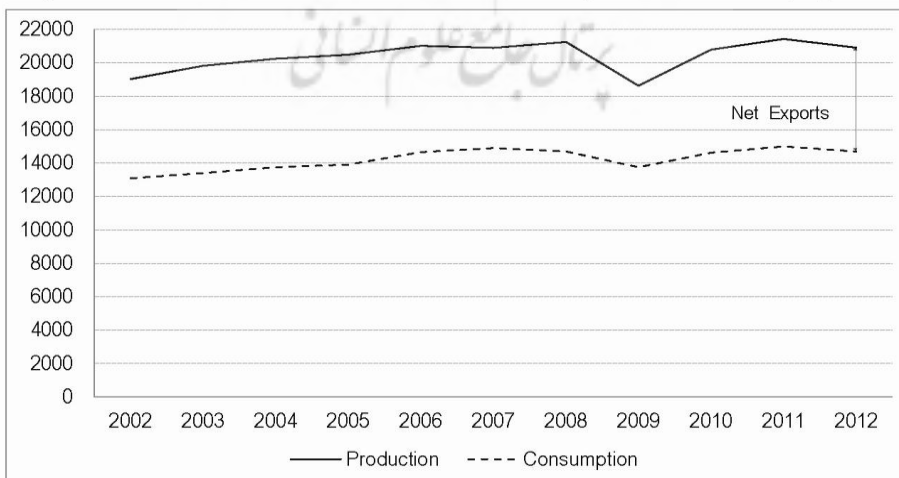
**Figure 6: China’s Natural Gas Imports by source, 2012 (Bcf)**

Source: British Petroleum (2012)

**2.4. Russia**

Russia holds the largest natural gas reserves in the world, and is the largest producer and exporter of dry natural gas with 1,680 (Tcf), and Russia’s reserves account for about a quarter of

the world’s total proven reserves (Figure 7). The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezhye fields alone accounting for about 45% of Russia’s total reserves.



**Figure 7: Russia Natural Gas Production & Consumption, 2002-2012 (Bcf)**

Source: British Petroleum (2012)

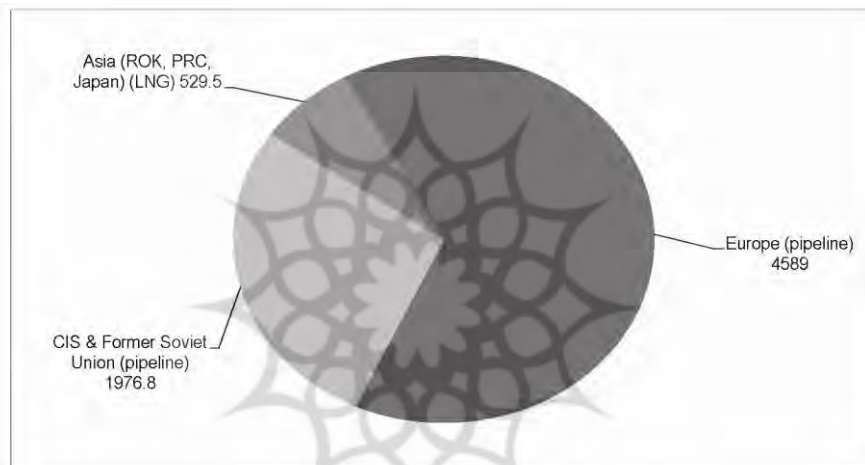
The state-run Gazprom dominates Russia's upstream, producing about 80% of Russia's total natural gas output. Gazprom also controls most of Russia's gas reserves with more than 65% of proven reserves being directly controlled by the company additional reserves being controlled by Gazprom in joint ventures with other companies. Gazprom's position is further cemented by its legal monopoly on Russian gas exports (Guillet, 2007).

A number of ministries are involved in the gas sector. The Ministry of Natural Resources issues field licenses, monitors compliance with license agreements, and levies fines for violations of environmental regulations. The Finance Ministry is responsible for tax policy for the energy sector, while the Ministry of

Economic Development has influence over regulations of tariffs and energy sector reforms. The Ministry of Energy oversees energy policy.

Russia exports significant amounts of natural gas to customers in the Commonwealth of Independent States about 35% of total exports. In addition, Gazprom (through its subsidiary Gazprom export) has shifted much of its natural gas exports to serve the rising demand in countries of the EU, as well as Asian countries.

About 70% of Russia's non-CIS exported natural gas is destined for Europe, with Germany, Turkey, and Italy receiving the bulk of these volumes. The remainder of Russia's European gas exports is sold to the newest EU members such as Czech Republic, Poland, and Slovakia (Figure 8).



**Figure 8: Russia's Natural Gas Exports, 2012 (Bcf)**

*Source:* British Petroleum (2012)

In addition to dominating the upstream, Gazprom dominates Russia's natural gas pipeline system. There are currently nine major pipelines in Russia, seven of which are export pipelines. The Yamal-Europe I, Northern Lights, Soyuz, and Bratrstvo pipelines all carry Russian gas to Eastern and Western European markets via Ukraine and/or Belarus (Balmaceda, 2008). These four pipelines have a combined capacity of 4 Tcf. Three other pipelines – Blue Stream, North Caucasus, and Mozdok-Gazi-Magomed – connect Russia's production areas to consumers in Turkey and Former Soviet Union republics in the east.

As well Russia is an exporter of LNG. The majority of the LNG has been contracted to Japanese and Korean buyers under long-term supply agreements. The Sakhalin Energy's LNG plant has been operating since 2009 and it can export up to 10 million tons of LNG per year on two trains.

Project partners have considered additional trains and plan to have a third train in operation between 2016 and 2018. However, the new trains would require additional sources of gas in addition to Lunskeye and Piltun-Astonkshkoye fields.

To this end, Gazprom is exploring the Kirinskoye Block in Sakhalin III.

Russia's natural gas exports to Eastern and Western Europe that are transported through pipelines traversing Ukraine and Belarus have in the past been affected by political and economic disputes between Russia and these natural gas hubs. This resulted in natural gas being cut off to much of Europe. Some European countries are seeking out alternate sources of natural gas and alternate pipeline routes to ensure security of natural gas supplies (Moran and Russell, 2008).

Actually, with a monopoly on Russian gas exports, recent Gazprom's behavior is near



synonymous with Russian energy policy. There are three assumptions compete to explain Gazprom's behavior.

The first explanation is the neo-imperialist theory of Gazprom's behavior. It has elicited the most attention in recent years, mainly because it inspires the most fear amongst buyer states. This theory rests on the assumption that the state controls Gazprom, an assumption supported by the government's 50.1% ownership stake in Gazprom. Today we could clearly see that gas exports have replaced military might as Russia's favored mode of exerting foreign policy influence in its near abroad.

The second one is simple rational corporatism when the Kremlin and Gazprom management both insist that like any well-run company, Gazprom's ultimate goal is to maximize profits. What at first appear to be heavy-handed business tactics laden with political overtones are actually rational corporate decisions. Regulation that forces Gazprom to subsidize domestic gas consumption wins popular support for Kremlin politicians, but drives Gazprom's aggressive sales tactics abroad, where it recoups its losses by exporting gas at higher prices.

The third view of energy policy posits that it is the product of individuals seeking to protect their own immediate interests through bureaucratic bargaining.

And here we can see rent-seeking, personal connections and corruption as the key drivers behind a Russian gas export policy that often lacks a larger sense of cohesion. Indeed, taking into consideration the current situation in Russian economy we can consider Russia's contemporary power structure as bureaucrat-oligarchy where power has not been wrested from the oligarchs by the Kremlin; instead, new oligarchs have emerged that have one foot in industry and one foot in government. And this marriage of industry and politics under Putin's administration has fueled rampant corruption (Shevtsova, 2005).

Given that many of the actors that shape Russian energy policy hold multiple positions with conflicting goals, policy is likely to reflect the interests' of individuals rather than the state. Policy decisions are more likely to reflect a broadly acceptable distribution of gas rents, rather than the protection of a national foreign policy interest or even the profitability of Gazprom as a whole. From the other hand, some critics argue that any large organization cannot escape an inherently anarchical decision-making process (March and Olsen, 1979).

In a large, complex organization like Gazprom, decision-makers address problems by selecting the most convenient solution from a 'garbage can' of available solutions, often producing what appears to be an irrational decision to outside observers.

However, these three theories of Russian energy policy are not mutually exclusive and a deep understanding of Russia's energy policy requires using all three.

### 3. Geopolitical Implications on the Regional Level

The advent of trade in LNG has led to new geopolitical partnerships. But, there is a widespread assumption that without a history of antagonism or a pipeline connection, gas dependency does not pose a major risk of foreign policy bias.

Commonly accepted thinking posits a direct causal relationship between dependence on energy imports and foreign policy affinity importers show towards suppliers. At the same time, other dynamics suggest energy import dependence may lead states to demonstrate less affinity towards suppliers than they would absent an energy trade relationship. States seek to avoid dependence on foreign commodities, evidenced by the widespread nature of protectionist tariffs and quotas.

Not all types of energy dependency are alike. Gas markets differ radically from oil markets, and gas is used for different purposes than oil. Thus, there is a reason to expect gas dependency to generate foreign policy effects different from those of oil dependency. A variety of factors accentuates and mitigates the effects of energy dependency. These include, but are not limited to, the mode in which energy supplies are transported, an importer's status as an end buyer or transit state, and the total energy matrix of the importer's economy (Hayes, 2007).

As the gap between consumption and production levels in Asia expands, the region's economic powers appear to be increasingly anxious about their energy security, concerned that tight supplies and consequent high prices may constrain economic growth. China, Japan, and South Korea have been moving aggressively to shore up partnerships with existing suppliers and pursue new energy investments overseas, often downplaying doubts about the technical feasibility and economic profitability of new development.

South Korea, China, and Japan have looked to Russia as a possible source of gas supply. In eastern Russia, the hydrocarbon reserves in the

Sakhalin Island area compare favorably with other substantial regional natural gas supplies. Preliminary estimates indicate that proven and probable gas reserves in Sakhalin could be as high as 50 to 65 Tcf. By comparison, Indonesia, the world's largest LGG exporter, has proven reserves of approximately 82 Tcf. The gas resources in other eastern Russian areas are less prolific and more distant to markets. The scattered natural gas resources of Irkutsk have been cited as a possible source of gas supply via pipeline to northern China and on to the Koreans, but the project must overcome high transport costs, questions of reservoir size, and internal Russian political questions over the dispensation of the resources located in the Kovykta field.

Although the current geopolitical landscape in Northeast Asia presents barriers to expedient development of Russian gas pipelines to Asia, the economic and social benefits that could be reaped by all parties involved argue for diplomacy and commercial programs to get such projects off the ground. The entire world's existing supplies would feel less strain from Asia if Russia's eastern region hydrocarbon export supplies could be developed. Eastern Russia holds the potential to ease pressures for competition for resources in Northeast Asia, but a multinational framework is likely to be required to promote the development of these resources in a manner that leads to security and stability of the region. So far, rivalry between China and Japan for bilateral arrangements coupled with the remaining political problems on the Korean peninsula have blocked any progress on creating a constructive Northeast Asia energy dialogue about how to best tap Russian gas supply potential as an energy bridge to a peaceful region.

Strategically, Russian natural gas supplies could become an important source of diversification, particularly for Japan. China and South Korea, from dependence on energy supplies from the Persian Gulf. More generally, increased volumes of Russian gas to Asia could have considerable ramifications for LNG pricing to Asia.

We try to make an economic analysis assess the impact that increasing supplies of Russian natural gas could have on Northeast Asia. Our results show that Russia and key consumers like China, South Korea, and Japan will all benefit economically from increased Russian natural gas exports to the region via export routes that involve cross-border trade. In particular, our analysis shows that an inability to ship natural gas via North Korea will greatly increase the

costs of natural gas imports to South Korea and China and leave Russia without competitive market outlets for a substantial portion of its eastern resources. If a North Korean pipeline route for Russian natural gas shipments is blocked permanently, LNG supplies from the Middle East and Australia will dominate the gas markets in Northeast Asia, leaving less of a market share for Russia and raising costs overall to Northeast Asian consumers. By contrast, Russian pipeline supplies, carried to China and the Koreans, would ensure that Russian gas could take a greater market share and obtain higher prices as it displaces even higher cost supplies from elsewhere. Thus, prices to consumers in China and South Korea would be lower.

To examine the role that Russian gas will play in international gas markets, we use a dynamic spatial general equilibrium model to simulate the future development of regional gas markets in a global setting. The model is based on the software platform Marketbuilder. The software calculates a dynamic spatial equilibrium where supply and demand are balanced at each location in each period such that all spatial and temporal arbitrage opportunities are eliminated. The model thus seeks an equilibrium involving the evolution of supply sources, demand sinks, and the transportation links connecting them so as to maximize the net present value of new supply and transportation projects while simultaneously accounting for the impact of these new developments on current and future prices. Output from the model includes regional natural gas prices, pipeline and LNG capacity additions and flows, growth in natural gas reserves from existing fields and undiscovered deposits, and regional production and demand.

The model solves not only for a spatial equilibrium of supply and demand in each year but also for new investments in resource development, transportation, liquefaction, and/or re-gasification capacity. The investments are assumed to yield a competitive rate of return, such that the net present value of the marginal unit of capacity is nonnegative. The project life of all new investments is assumed to be 100 years, and the tax life is assumed to be 20 years. The tax levied on income earned from projects is assumed to be 40%, while property tax plus insurance are taken to be 2.5% of income.

The model uses a weighted average cost of capital to determine the net present value of each increment of new capital. The debt-equity ratio is allowed to differ across different categories of investment. Pipeline investments

are taken to be the most highly leveraged (with 90% debt), reflecting the likelihood that pipeline transportation rates will be regulated and hence the income stream will be very predictable. LNG investments are assumed to have a higher equity level (30% equity). Most of these will be undertaken only if a substantial fraction of the anticipated output is contracted in advance using bankable contracts. Mining investments are considered to be the most risky category, with an assumed debt ratio of only 40%. In addition to differing levels of leverage, the different categories of investments are assumed to have differing required rates of return on equity, again as a reflection of differing risks. Specifically, for the United States the required ROE for pipeline capacity is 12% (real), and the ROE on upstream investments is 15% (real). The real interest rate on debt is set at 8% for all projects.

We also do not allow country risk premiums to affect the return to debt.

There are a number of justifications for assuming a uniform return to debt but a variable equity return. First, debt financing is backed by either government guarantees (in the case of national energy companies, for example) or the balance sheet of the firm undertaking the project. Accordingly, the premium on debt primarily reflects default risk, not project risk. Second, many of these projects include government guarantees, export credits, and other complex financing arrangements that lower investor exposure and reduce any risk premium that third parties may otherwise require.

The model suggests, absent potential policy constraints, that Russia will play a pivotal role in price formation in a more flexible and integrated global natural gas market. Russia is projected to produce more natural gas annually than any other country until 2040, although beyond 2038 the Middle East as a region is predicted to supply more. Although Russia is the largest single national source for natural gas throughout most of the model period, Russia is simultaneously a large consumer. Hence, it does not loom as large in exports as it does in production.

Russia is also strategically positioned to move large amounts of gas to consuming markets in both the Atlantic and Pacific, giving Russia the potential to play an important role in linking prices between the two regions. Under the base runs of the model, eastern Siberian gas begins flowing into northern China at the beginning of the next decade and eventually flows into the Korean peninsula.

Furthermore, in the 2030s, Northeast Asian demand grows sufficiently to draw supply from as far as Western Siberia. The model actually indicates that it may be economically beneficial to construct a pipeline linking west Siberia and east Siberia much earlier than planned; this would allow East Siberian supplies to flow west to the mid-2020s. This development reflects the growing demand for natural gas in Europe; the maturing of the North Sea fields; and the fact that potential alternative sources of supply for Europe, such as Africa or the Middle East, are more risky than Russia. Another contributing factor is that Australia is well placed to supply additional LNG to Northeast Asia up until 2030.

Once Russian pipeline gas simultaneously flows both east and west, production in the western Siberian basin will become the arbitrage point between Europe and Asia, thus linking gas prices in the two regions. The model also indicates that Russia will enter the LNG export market in both the Pacific and Atlantic basins. In the Pacific basin, production in the Sakhalin region will be exported as LNG but also will flow to Japan via pipeline beginning in 2010. In the Atlantic basin, production in the Barents Sea will eventually provide gas exports in the form of LNG beginning in the mid-2020s. This will provide another link in gas prices in North America, Europe, and Asia. Specifically, when gas is flowing out of Russia in all three directions simultaneously, the “netback” price from sending the gas in any of the three directions must be the same. Russia benefits not only from its location and size of resources but also because it was one of the first major gas exporters and has access to a sophisticated network of infrastructure already in place.

In terms of geography and economic and geologic fundamentals, the relationship between Russia and Northeast Asia resembles the relationships between regions in North America, such as Alberta and Chicago or South Texas and Miami, that currently are linked by long-haul pipelines covering distances not too dissimilar from Kovytko to South Korea. Thus, it is not surprising that the base run of the model predicted substantial gas pipeline development in Northeast Asia.

Early in the model time horizon, reserves in east Siberia can satisfy Northeast Asian demand at a price that is competitive with imported LNG. Toward the end of the time horizon, the cost of adding to east Siberian reserves exceeds the cost of shipping gas from west Siberia, which results in gas flowing from west Siberia into the then-developed Northeast Asian pipeline grid. Ultimately, pipeline gas from

Russia makes up a substantial fraction of Northeast Asian demand.

Accordingly, political tensions could easily stymie development of a pipeline connecting east Siberian gas resources to China. Moreover, any pipeline from Russia to South Korea would most likely have to pass through North Korea, perhaps making that an unlikely event unless the conflict on the peninsula can be resolved.

We used the model to investigate the effect if the North Korea conflict prevents the construction of critical international pipelines in Northeast Asia.

Obviously, countries that would otherwise benefit from such pipelines are affected by their absence. In general, both the exporting country and the importing country are worse off, although the welfare losses need not be shared equally as they depend on alternative sources of supply for the importing country and alternative export markets for the exporting country. In addition, although elimination of large international pipelines will influence those nations directly involved, we also find that there are secondary effects on countries not directly involved in the projects.

In this scenario, we rule out the construction of any pipelines through North Korea although we allow for the possibility that undersea pipelines could be built connecting South Korea to either China (and ultimately east Siberia) or Japan (and ultimately Sakhalin). The high cost of construction in Japan precludes a national pipeline grid, let alone a further extension of such a grid to serve South Korea. On the other hand, when a pipeline through North Korea is ruled out, an undersea pipeline from China to South Korea does provide a viable alternative to LNG imports.

If a pipeline can be built through North Korea, pipeline imports from Sakhalin Island completely displace LNG imports into South Korea from the beginning of next decade. The increased pipeline imports are accompanied by an expansion of the internal South Korean pipeline grid to carry imported gas to cities at the southern end of South Korea.

If a pipeline cannot be built through North Korea, however, South Korea remains a substantial importer of LNG. Pipeline imports from China commence early in the next decade and within a few years rival LNG imports for market share.

The continued importation of LNG into southern terminals obviates the need to extend the national pipeline grid within South Korea. The China pipeline option is more expensive than a pipeline through North Korea, however,

so gas prices in South Korea are higher by approximately \$1.10 per MMBtu (in real terms) when the China option is exercised.

The model indicates that precluding the North Korean pipeline has widespread effects. In light of the price increases, it is not surprising to find that demand for natural gas in South Korea declines. Before 2030, demand also declines in China. The higher Korean prices translate into higher prices in China in these earlier years. To understand why demand in China does not decline in all periods, we also need to look at the supply responses. It is not surprising that Russia has the largest supply decline of any producer country because there will be fewer profitable outlets for Russian gas if pipelines cannot traverse North Korea.

As a result, Russia, Central Asia, and Europe experience very slight expansions in demand as additional Russian gas sent westward tends to lower prices.

Nevertheless, the Russian LNG supply from Sakhalin Island expands, particularly after 2020, which tends to reduce LNG prices in the Pacific and allow Chinese demand to increase.

The increased demand for Pacific Basin LNG has other consequences.

Additional LNG supply is forthcoming from Australia, Papua New Guinea, Indonesia, and Brunei, particularly in the earlier years before the large increase in Sakhalin supply enters the market. Japan experiences one of the largest declines in LNG imports as the decreased Korean demand for Sakhalin gas allows more to be piped to be Japan.

An absence of natural gas pipelines on the Korean peninsula also affects the Americas. LNG imports into the Pacific coast would decline up until the late 2030s, when not only Sakhalin Island but also Iran supply more gas to the Pacific basin market. Within North America, demand is met in part by expanded domestic production (particularly before 2025) as well as by increased imports of LNG into Atlantic terminals facilitated by an expansion of LNG supply from Venezuela.

Finally, we can say that current and projected increases in the demand for natural gas as well as the desire on the part of producers to monetize stranded natural gas resources, has expanded the depth and geographical extent of both sides of the LNG market. Expanding the market alternatives available to both producers and consumers of natural gas reduces the risk of investing in infra structure, thereby encouraging further development of the natural gas market. Moreover, with a greater number of available supply alternatives and growth in the size of

end-use markets located around the globe, the average distance between neighboring suppliers falls, increasing the opportunities for price arbitrage. The resulting increase in trading opportunities increases market liquidity.

An increase in market liquidity could produce a relatively rapid shift in the market equilibrium away from long-term bilateral contracts to a world of multilateral trading and an increased number of "spot market" transactions. The explanation is that market structure is partly endogenous. Expectations about the future evolution of the market influence investment and trading decisions today, and these, in turn, further influence market developments tomorrow. Once market participants begin to expect a change in market structure, their investment decisions accelerate the change.

#### 4. Conclusion

Natural gas dependency is a complex phenomenon, with no one-size-fits-all framework to predict the foreign policy implications of dependency (Ian, 2002). Likewise, there is no formula for what is an acceptable level of gas dependency. Myriad factors shape the policies of import dependent states towards their energy suppliers, some drawing them closer and some driving them apart. These factors can change slowly, over a number of years or decades, or almost overnight. Most major gas trade relationships coexist with significant economic, cultural, or military ties, making it even more difficult to isolate the effects of gas dependency on foreign policymaking.

Nonetheless, the factors that shape gas dependency can provide policymakers useful insights into how gas dependency influences intrastate behavior, signaling when dependency may be worrisome and when it is not.

Policymakers should note that gas dependency has a more pronounced direct correlation with foreign policy affinity than oil. This stems from the fact that gas tends to be traded regionally, while oil is traded on a global market.

Four variables predict that gas dependency will lead importers to display increased foreign policy affinity towards a supplier. First, end-buyers of gas display a direct correlation between levels of dependency and foreign policy affinity towards suppliers. In other words, as the level of gas dependency rises, so does the level of foreign policy affinity the importer shows towards the exporter.

Second, LNG importers display a direct correlation between levels of dependency and foreign policy affinity towards suppliers. LNG is more fungible than gas traded by pipeline, reducing importers' fears of shutoffs or price hikes. Third, importers that share borders with their suppliers tend to display a direct correlation between levels of dependency and foreign policy affinity towards such suppliers.

Fourth, there exists a direct relation between a state's total primary energy dependency on a given gas supplier, and the state's foreign policy affinity towards that supplier. This confirms that regardless of whether states view gas dependency as a percentage of total gas consumed, or total energy consumed, the geopolitical effects run in the same direction.

On the other hand, two variables predict that gas dependency will lead importers to display less foreign policy affinity towards their suppliers. First, transit states tend to display an inverse correlation between levels of gas dependency and foreign policy affinity towards a given supplier. In other words, as the level of gas dependency increases, the level of foreign policy affinity the transit state shows towards its supplier decreases. Transit states exert more leverage over their suppliers than do end-buyers, which tends to complicate the trade relationship and may lead to gas feuds between the parties. Second, states that receive their gas via pipeline also tend to display less foreign policy affinity towards their suppliers.

Because of the enormous investment required to construct and operate a pipeline, and the difficulties inherent to altering a pipeline route, disputes arise between supplier and consumer when both parties believe they have more bargaining power.

Conversely, importers' concerns over gas import dependency can be allayed when domestic firms have a stake in the upstream sector in the exporter state.

When the importer's firms control or influence production or upstream gas transportation, it makes it more difficult for an exporter to cut supplies unilaterally.

These factors could be compared on a case-by-case basis to judge whether gas dependency is likely to increase or decrease an importer's foreign policy affinity towards a supplier. For some importers, where all the variables align to indicate a direct relationship between gas dependence and affinity towards exporter, it appears safe to assume that gas trade has benefited the bilateral relationship. For others, all the variables align to indicate an inverse relationship between dependency and foreign

policy affinity towards exporter. Here, it appears the gas trade will be a problem both countries will struggle to manage for the indefinite future. Yet, in most of the world's most important gas relationships, the variables point both ways. Understanding these gas relations must be done in the context of the countries' broader bilateral relationship; it is to be hoped that the framework provided by this thesis serves as a useful starting point.

## References

1. Akira, M. (2008), Natural Gas in Japan, Chapter in Stern, Jonathan, ed. Natural Gas in Asia, Oxford: Oxford University Press.
2. Balmaceda, M. (2008), Energy Dependency, Politics and Corruption in the Former Soviet Union: Russia's Power, oligarchs' Profit, and Khrushchev's Missing Energy Policy, New York: Routledge Press.
3. British Petroleum (2012), Statistical Review of World Energy, London.
4. Department of Energy (2012), Energy Information Agency. World Energy Predictions, Washington D.C.: DOE.
5. Douglas, G. and M. Sarkees (2004), "Measuring Alliances: The Correlates of War Formal Interstate Alliance Data set, 1816-2000," *Journal of Peace Research*, 41(2), 211-222.
6. Federal Energy Regulatory Commission, (2004), Current State of and Issues Concerning Underground Natural Gas Storage, Staff Report, September 2004.
7. Guillet, J. (2007), "Don't Blame Gazprom for Europe's Energy Crunch," *Foreign Policy*, www.foreignpolicy.com/story/cms.
8. Hayes, M. (2007), Flexible LNG Supply and Gas Market Integration: A Simulation Approach for Valuing the Market Arbitrage Option, Program on Energy and Sustainable Development (PESD) at Stanford University, Working Paper.
9. Ian, J. (2002), Principle Component Analysis, Chapter in Springer Series in Statistics. 2nd Ed. New York: Springer Publishing.
10. March, J. and J. Olsen (1979), Ambiguity and Choice in Organizations, Bergen: Universitetsforlaget Publishing.
11. Mares, D. (2006), Natural Gas Pipelines in the Southern Cone, Chapter in Victor, David, et al., eds. Natural Gas and Geopolitics. Cambridge: Cambridge University Press.
12. Moran, D. and J. Russell (2008) (eds.) Energy Security and Global Politics: The

Militarization of Resource Management. New York: Routledge, Phpstory\_id=3696.

13. Shevtsova, L. (2005), Putin's Russia, Washington D.C.: Carnegie Endowment for International Peace, 49.
14. Terry, K. (2005), Understanding the Resource Curse, in Tsalik, Svetlana and Anya Schiffrin, eds. Covering Oil: A Reporter's Guide to Energy and Development. New York: Open Society Institute.
15. Victor, D., A. Jaffe and M. Hayes (2006), Natural Gas and Geopolitics, Cambridge: Cambridge University Press, p. 11.

## Appendix A

**Table A-1: List of Abbreviations**

Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/y	billion cubic per year
Bcm	billion cubic meters
Bcm/y	billion cubic meters per year
CIS	Commonwealth of Independent States
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
FSU	Former Soviet Union
IOC	International Oil Company
KEPCO	Korean Electric Power Company
KNOC	Korea National Oil Corporation
KOGAS	Korea Gas Corporation
LNG	Liquefied Natural Gas
NOC	National Oil Company
POSCO	Pohang Iron and Steel Corporation
PSC	Production sharing (agreement)
ROE	Return on Equity
Tcf	trillion cubic feet
Tcf/y	trillion cubic feet per year

Source: Author