ECONOMIC ISSUES OF NATURAL GAS TRADE IN NORTHEAST ASIA: POLITICAL BRIDGES AND ECONOMIC ADVANTAGES

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I. Introduction

Protracted talks—the so-called six-party talks—among the United States, South Korea (Republic of Korea; ROK), North Korea (Democratic People's Republic of Korea; DPRK), Russia, China, and Japan over the standoff on the Korean peninsula ended in September 2005 with a face-saving statement of principles. North Korea assented to give up its existing nuclear weapons and return to the Nuclear Non-Proliferation Treaty, and the United States expressed "respect" for North Korea's right to peaceful uses of nuclear energy and consideration of offers for renewed energy assistance and economic cooperation. The loose agreement was made possible by U.S. concessions that have encouraged North Korea to continue pressing for the delivery of light-water nuclear energy reactors promised in agreements signed in 1994. Detailed discussions of key implementation issues await a new meeting in November 2005, and timing concessions may bedevil future progress. The U.S. offer to "take steps to normalize" relations with North Korea seems to make more plausible a general security agreement that the conflict can be resolved during this go-round. North Korea, however, is going to want to see progress on the promise that the other parties—South Korea, Japan, the United States, Russia, and China—provide energy assistance. North Korea's Ministry of Foreign Affairs said that the United States "should not even dream of the issue of (North Korea's) dismantlement of its nuclear deterrent before providing light-water reactors (LWRs), a physical guarantee for confidence building" (Dinmore et al. 2005, 7). As experience has shown, the financing and timing of provisions of energy aid can be technically and diplomatically challenging. The United States has already made clear that its interpretation of an "appropriate" time for the provision of LWRs would be at a time following the complete dismantling of all North Korea's nuclear weapons and facilities.

But the conflict and its resolution beg the question of whether nuclear power is the top solution for the energy shortfalls on the Korean peninsula. To forge a compromise before the September 2005 six-party talks, South Korea offered to sell North Korea electricity from its own supplies. In June 2005, Minister of Unification Chung Dong-young announced that South Korea would provide North Korea with 2 million kilowatts of electricity in exchange for the DPRK's nuclear disarmament and the termination of the LWR project. South Korea argued that the remaining $2.4 billion South Korea intended for the LWR project could, instead, under its proposed plan be used to generate electricity, with transmission to the North beginning in 2008 (Lee 2005). The grid interconnection would include a 200-kilometer power supply line between Yangju and Pyongyang (Yonhap 2005). So far, the electricity trade plan seems to not only lack support from North Korea but also has met with criticism from some members of South Korea's Grand National Party.

Still, a more fuel diverse, multilateral approach to solving North Korea's energy woes might offer a more stable, commercially sound, and economically sustainable long-term solution to North Korea's energy problem than would the delivery of the LWRs. A diverse energy plan that involved Russian energy would benefit not only South Korea and North Korea but also the economies of the other parties to the talks—Japan, China, Russia, and even the United States—by enhancing worldwide energy supplies. The likely result of a plan involving the other four countries would be generally lower gas prices worldwide, although Russian producers in the Far East would obtain higher prices than would otherwise have been the case. Pipeline exports of natural gas, or shipments of nearby hydroelectric power or electricity produced from local Russian natural gas or coal, or both, could provide cheaper, safer, and less politically contentious energy supplies than a major nuclear energy program on the peninsula.

There is no question that one of the major challenges facing North Korea is its energy poverty. Lack of energy resources affects North Korea's ability to engage in manufacturing as well as to support critical agricultural activities needed to provide food for the population.

North Korea's energy reserves are limited to developable hydroelectric potential of approximately 10–14 gigawatts (GW) and coal reserves of between 1 and 10 billion tons (the U.S. Energy Information Administration [EIA 2004; Williams et al. 2000] estimates coal reserves of only 660 million tons). These resources were used to encourage development in the DPRK especially during the Cold War. "Most of the DPRK's energy infrastructure—coal mines, thermal power plants, hydroelectric plants—was built during the 1950s to 1980s with substantial financial and technical assistance from the Soviet Union and its allies" (Williams et al. 2000).

With no oil or natural gas reserves, however, the DPRK was forced to rely solely on foreign imports. During the Cold War, the DPRK received heavily subsidized oil supplies from the Soviet Union, as did Cuba and other client states. With the collapse of the USSR in 1990, the new Russia curtailed subsidized oil supplies to the DPRK and other former client states. Russian oil exports were shifted to a commercial cash basis, with prices set at prevailing market rates. Because the DPRK was short on credit and foreign exchange, it could not afford to continue importing at former levels. Oil imports from Russia fell by 90 percent in a few years, as did imports from the Middle East.

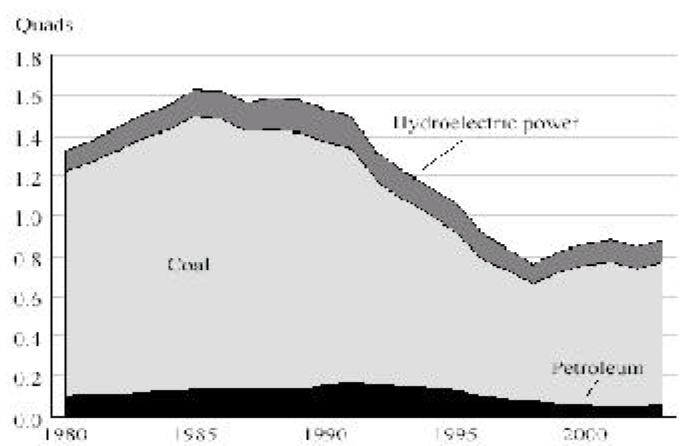
Supplying energy through central planning by the state also led to mismanagement and misallocation of resources, leaving comprehensive energy shortages throughout the country. A shortage of replacement parts for energy supply infrastructure such as generators, turbines, transformers, and transmission lines and for energy-consuming equipment such as boilers, motors, pumps, and chemical reactors contributed to an overall infrastructural collapse in the 1990s.

Williams et al. (2000) described the damage caused by natural disasters in North Korea during the 1990s:

> Natural disasters in the mid-1990s, while not the principal cause of many of the problems in the DPRK's energy system, nonetheless hit an already fragile system with debilitating blows. Severe flooding in 1995 and 1996 was followed by severe drought and a tidal wave in 1997. In addition to destruction of crops and agricultural land, these disasters impacted the energy system in numerous ways. Coal mines were flooded (some mines producing the best quality coal, near Anju, were on the coast below sea level to begin with). Hydroelectric production was affected by floodwaters that damaged turbines and silted up reservoirs, then by drought that reduced water supplies below the levels needed to generate power. Electric transmission and distribution lines were damaged, as were roads and transportation equipment. Heavy erosion and scavenging for food denuded landscapes, reducing the availability of biomass for energy use.

Thus, there was a severe contraction in the supplies and consumption of fuels and electricity in the DPRK between 1990 and 1996 (Williams 2000). Energy consumption in North Korea comes from three primary sources: coal, hydroelectric power, and petroleum. In 2003, coal accounted for approximately 82 percent of the 0.882 quads[1] consumed in the DPRK, followed by hydroelectric power at 12 percent, and petroleum at 6 percent (***Figure 1***). The DPRK imports most of its oil supplies from China.

Figure 1: **Consumption of Energy in North Korea, 1980–2003, quads**



Source: EIA (2003, tables E.2, E.4, E.6).
Note: A quad is 1 quadrillion British thermal units.

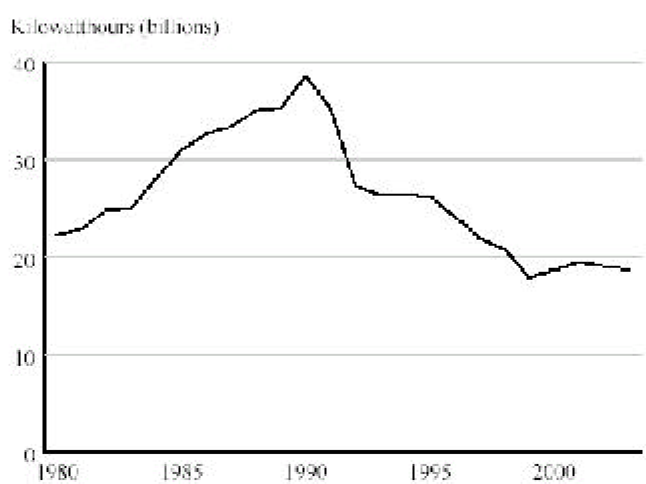
1. A quad is 1 quadrillion British thermal units.

In 1990, the industrial sector consumed just over one-half of all energy in the DPRK. In recent years, however, total energy consumption has been decreasing, especially from the industrial sector. As of 2004, only 27 percent of total energy consumption was in the industrial sector. Meanwhile, consumption from the residential sector has increased from 31 percent in 1990 to approximately 53 percent in 2004 (Von Hippel 2005).

According to the EIA, total electric generating capacity, split almost evenly between coal (4.5 GW) and hydroelectric (5 GW), has remained constant in North Korea since 1988, but total production has drastically decreased (EIA 2005b) (***Figure 2***). The Nautilus Institute reports a much lower figure of 4.7 GW with an average capacity factor of 0.65, which is low compared with best practice, perhaps providing another indicator of poor maintenance standards (Williams et al. 2000). In 1990, production totaled 38.47 billion kilowatthours (KWh), but that figure decreased to less than half of that (18.75 billion KWh) in 2003. Electricity production increased in only three of the years between 1990 and 2003 and by an average of only approximately 3 percent. In October 1994, the Agreed Framework between the United States and the DPRK included the creation of the Korean Peninsula Energy Development Organization (KEDO). The mission of KEDO was to build two 1,000 megawatt (electric) nuclear power reactors in North Korea and provide 500,000 metric tons of heavy fuel oil annually until the first reactor was completed (Mazarr 1995; Reiss 1995).

However, many logistical and political barriers existed to thwart the construction of the LWRs in North Korea. North Korea lacked the economic and logistical

Figure 2: **Electricity Production in North Korea, 1980–2003, billions of kilowatthours**



Source: EIA (2003, table 6.3).

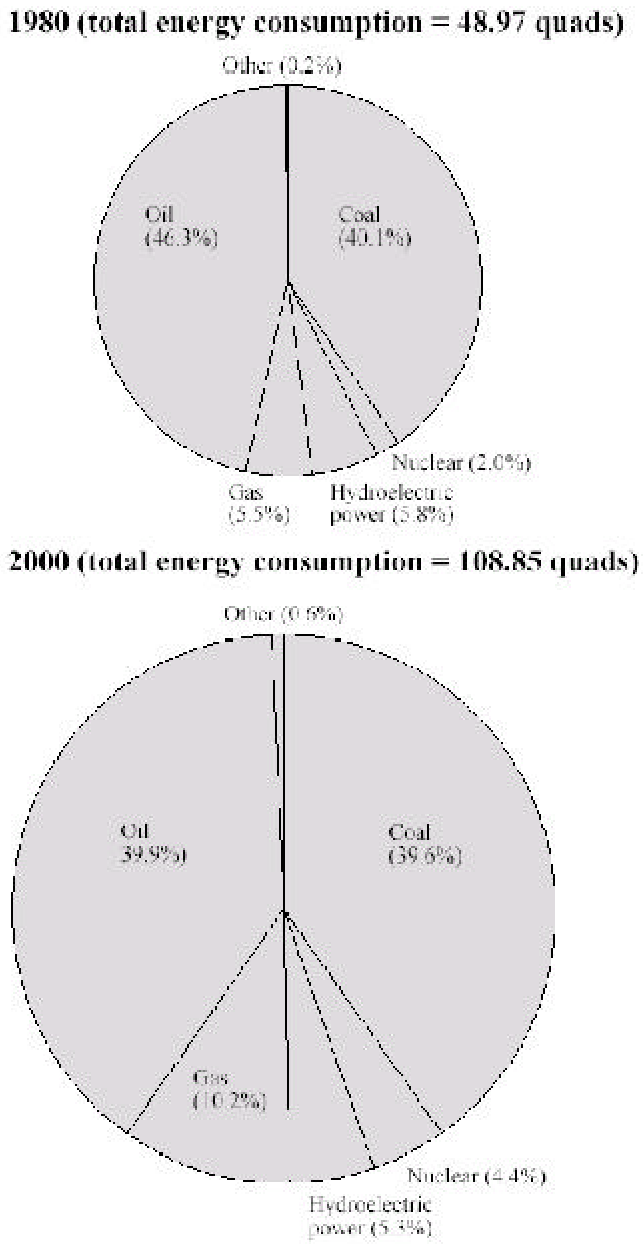
infrastructure to support the project. The program also faced financial hurdles as its 13 members failed to raise sufficient financial commitments to meet the $4.6 billion cost for the light-water nuclear program in North Korea. Of this amount, South Korea had pledged to underwrite 70 percent of the project, with Japan offering an additional $1 billion. This left the program with an 8 percent shortfall that has not been able to be resolved. Financing was such a challenge that it thwarted even the regular delivery of heavy fuel oil shipments to the DPRK (Reiss 2002). Further issues related to legal and financial protection from KEDO for contractors and subcontractors on the project were also unresolved. The DPRK's subsequent conflict with International Atomic Energy Agency over inspections and its surprise confirmation of its nuclear weapons program have put KEDO and its activities on hold, awaiting new agreements from ongoing six-party talks about the resolution of the North Korean problem. Still, the institutional framework of KEDO remains to be activated, and it potentially plays a role in reshaping the energy future for North and South Korea (Davis 2000).

In fact, the issue of energy supply is one that plagues most of the economies of Asia. Japan, China, and South Korea 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. According to the reference case projections in *International Energy Outlook 2002* (EIA 2002, Table 1), energy consumption in developing Asian countries alone could rise from about 18.6 percent of total global energy use in 1999 to 23.1 percent by 2010. This represents an average annual increase in energy demand of 3.8 percent per year, well above the projected global growth of 2.3 percent.

China alone can be expected to see its oil imports rise from approximately 1.4 million barrels per day (MMbbl/d) in 1999 to between 3 and 5 MMbbl/d by 2010 (Soligo and Jaffe 1999). China would also like its natural gas use to increase substantially to diversify its energy mix from 3 percent of energy demand in the late 1990s to more than 10 percent by the end of this decade. Such projections have raised fears in the Washington, Tokyo, and Seoul about competition or even confrontation over energy supplies and lines of transport.

Natural gas is expected to become a larger part of Asia's overall energy mix in the years to come, expanding from 5.5 percent of total energy used to more than 10 percent between 1980 and 2000, and is expected to continue to make significant gains. From 1990 to 2000, natural gas consumption grew at an average annual rate of 6.7 percent in Asia, with demand growing fastest in South Korea (20.1 percent per year), Thailand (11.9 percent per year), and Malaysia (8.8 percent per year). Although the consumption of coal in Asia increased from 1980 to 2000 (from 19.63 to 42.47 quads), coal's share of total energy has remained relatively stable (*Figure 3*).

Figure 3: **Structure of Primary Energy Consumption in the Asia-Pacific Region, 1980 and 2000, quads**



Source: EIA (2003, tables E.4–E.7).
Note: A quad is 1 quadrillion British thermal units.

Several major Asian countries are either investigating or have initiated programs to enhance natural gas use. Japan's Ministry of Economy, Trade, and Industry (METI), for example, would like to see natural gas use in Japan rise from the 2000 levels of 13 percent of total energy to 20 percent by 2020. China has targeted natural gas use to expand from 3 percent in 2000 to 10 percent by 2020 (Xu 1999). In India, natural gas supplies constituted about 7 percent of India's total energy consumption in 2000, but this could double in the coming decade as gas use in the electricity sector rises rapidly (EIA 2005a, 8). Furthermore, new LNG terminal facilities and pipeline projects aimed at bringing international and disconnected domestic supplies to market are under consideration in Japan, China, and India.

Natural gas demand in South Korea is expected to increase dramatically over the next decade. In 2003 natural gas consumption was 18.4 million tons, but consumption is expected to grow at an average of almost 4 percent until 31.7 million tons are demanded in 2017. The majority of that growth is predicted to come from city gas, which is expected to grow at an average rate of more than 5 percent annually. "Commercial use of natural gas is expected to increase at a faster rate than residential use, mainly due to the introduction of various applications for LNG; such as micro co-generation," according to Korea's Ministry of Commerce, Industry, and Energy (MOCIE 2004, 13). Industrial use of natural gas is expected to increase at the fastest rate over the time period (6.93 percent per year). Meanwhile, average natural gas demand for electricity generation is projected to grow at a modest 0.32 percent per year through 2017, with fluctuations caused partly by irregular plans for power plant construction.

In 2003 South Korea imported most of its LNG from Indonesia (29 percent), Qatar (26 percent), Oman (22 percent), and Malaysia (19 percent). However, long-term contracts already entered into by South Korea show that distribution will be changing. Just under 30 percent of total contracted LNG in 2017 will come from Qatar, followed closely by 25 percent from Oman. Indonesia's total share of contracted LNG will decrease to only 6 percent while Malaysia's share will decrease to 9 percent (MOCIE 2005). Rapidly increasing demand means that South Koreans are likely to face a severe shortage of natural gas in the near future. In February 2005 a long-term contract was signed by KOGAS to guarantee imports of 5 million metric tons per annum (MMTPA) for 20 years—2 MMTPA from Yemen, 1.5 MMTPA from Malaysia, and 1.5 MMTPA from Russia) (MOCIE 2005). In addition, production from the domestic field, Donghae-1, is expected to begin in 2008. Even so, in 2017 South Korea will face a shortage of more than 15 million tons based on current long-term contracts and demand as projected by MOCIE.

South Korea, China, and Japan have looked to Russia as a possible source of oil and gas supply. At a historic meeting between Chinese and Russian leaders in July 2001, President Jiang Zemin of China spoke of an agreement to pursue an oil pipeline project to bring Siberian oil to eastern China. Jiang and Prime Minister Mikhail Kasyanov of Russia signed an agreement for a feasibility study of a pipeline with the capacity of 400,000 barrels per day from Angarsk in Irkutsk to eastern China. Eastern Siberia's Yurubcheno-Takhomskaya zone is estimated to hold up to 11 billion barrels of crude and 36 trillion cubic feet of gas. Japanese and South Korea leaders have held similar high-level talks about related or competing Russian oil and gas export projects.

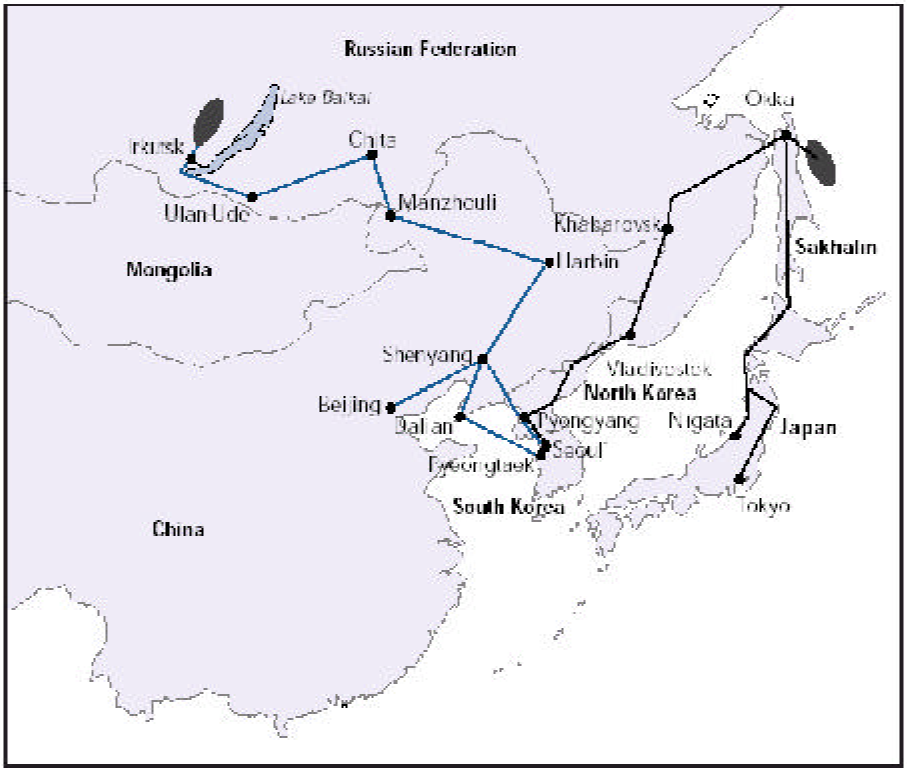
In eastern Russia, the hydrocarbon reserves in the Sakhalin Island area compare favorably with other substantial regional natural gas supplies. Preliminary estimates indicate that proven and probable gas reserves in Sakhalin could be as high as 50 to 65 trillion cubic feet (tcf). By comparison, Indonesia, the world's largest LNG exporter, has proven reserves of approximately 82 tcf. The gas resources in other eastern Russian areas are less prolific and more distant to markets. According to a regional specialist (Sagers 1999) with PlanEcon, Inc., Yakutia is thought to hold an additional 35.3 tcf, and the Kovyktinskoye (Kovykta field) in Irkutsk is estimated to have possible reserves of 52 to 105 tcf.

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 Koreas, 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. ***Figure 4*** shows the two Russian gas fields—the Kovykta field in Irkutsk province of eastern Siberia and Sakhalin in Russia's Far East—with the potential to supply South Korea with competitively priced pipeline natural gas.

Although the current geopolitical landscape in Northeast Asia presents barriers to expedient development of Russian oil and 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 oil and gas supply potential as an energy bridge to a peaceful region.

The economic analysis of this paper will assess the impact that increasing supplies of Russian natural gas could have on Northeast Asia. Our results show that Russia and

Figure 4: **Potential Natural Gas Pipelines to South Korea**



Source: Ball (2003, 67).

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 Koreas, 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.

II. Modeling Approach and Base Run Results

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 from Altos Management Partners, a flexible modeling system widely used in industry. 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.[2] 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 non-negative. 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 percent, while property tax plus insurance are taken to be 2.5 percent 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 percent 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 percent 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

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2. The absence of intertemporal arbitrage opportunities within the model period is a necessary but not a sufficient condition for maximizing the present value from resource supply. Because future exploitation is always an alternative to current production, a maximizing solution also requires that a value of the resource beyond the model time horizon be specified. In our model, the required additional conditions are obtained by assuming that a backstop technology ultimately limits the price at which natural gas can be sold.

percent. In addition to differing levels of leverage, the different categories of investments are assumed to have differing required rates of return on equity (ROE), again as a reflection of differing risks. Specifically, for the United States the required ROE for pipeline capacity is 12 percent (real), and the ROE on upstream investments is 15 percent (real). The real interest rate on debt is set at 8 percent for all projects. The assumptions regarding required returns are based on numerous statements made during meetings with industry reviewers.

For countries other than the United States, we allowed various political factors, such as government stability, bureaucratic quality, corruption, internal conflict, and ethnic tensions, to affect risk-adjusted rates of return. We used two sources of information to calculate risk-adjusted returns for gas investments. The first was a composite measure of political risk borne by a private investor in each host country; the composite measure was constructed with data from the *International Country Risk Guide* (ICRG), published monthly by the PRS Group, Inc. The criteria extracted from the ICRG were government stability, government attitude to inward investment, internal conflict, corruption, law and order, ethnic tensions, and the ability of the bureaucracy to govern without drastic changes in policy or interruptions in government services. The second data source was a series on the "risk premium on lending" obtained from the World Bank (2005). These two data sources were used to derive a set of country-specific risk premiums for investments in gas infrastructure relative to the United States. Specifically, regressing the average risk premium from 1999 to 2003 on the gas investment risk index (GIRI) scores yields a rule by which GIRI scores can be mapped to interest rates.[3] This allows the factors underlying the GIRI scores, which are specifically targeted to measuring current political risks in the natural gas industry, to be converted to an interest rate. The resulting differential risk premiums were then added to the real rates of return required on each type of gas investment in the United States to derive corresponding real rates of return for each country.

The leverage for each type of investment is taken to be the same in each country.[4] A primary justification for assuming that some types of investments are more highly leveraged is that returns on those investments are usually regulated. On one hand, a lower variability of cash flow in a regulated activity raises its debt capacity. On the other hand, regulation also limits the extent to which average returns can rise. In

3. The main motivation for using an average risk premium as the dependent variable in this regression is that it helps minimize the effect of short-term macroeconomic instabilities. In addition, many countries have incomplete time series. Using the average of the non-missing values in a five-year window produces a larger sample.

4. Thus, given the debt-equity ratios assumed for each project type, the risk adjustment affects the required return on pipelines the least, followed by LNG infrastructure, and, finally, mining operations.

reality, the debt capacity of similar types of projects may vary across countries, but, without data on these variations, we chose to leave them uniform.

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. Nevertheless, equity returns, being a residual claim, are vulnerable to *ex post* changes in rules. Debt returns, being a legal obligation, are much less vulnerable to such sovereign risks. Third, World Bank data reflect currency risk, among other factors. Many of the large international energy bond deals are syndicated in the United States under U.S. law and floated in U.S. dollars; thus currency risk will affect the ROE to the extent that earnings are exchanged for dollars before repatriation.

Our approach is deliberately conservative.[5] We limit the impact of variation in returns because the model generates long-term forecasts. Serious questions can be raised about the predictability of future risk premiums. For example, what would people have said in 1985 about the likely risk premium relevant for investing in China in 2005?

Results of the Model vis-à-vis Russia

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 from 2006 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.[6]

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

5. For more details on the modeling approach, see Hartley and Medlock (2005).

6. Demand growth in Iran and Saudi Arabia also limit exports from the Middle East. Thus, despite Middle Eastern countries' prominence in the future of global natural gas supply, their export capacity is limited by their domestic requirements.

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 beginning in 2012 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.[7] 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 Kovytka 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.

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7. Beginning in 2008, production from the Barents Sea will also move to Europe via a pipeline through St. Petersburg.

Political relations between Canada and the United States and between states within the United States are much closer and more stable than relations among Russia, China, North Korea, and South Korea. 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.

Transport of Natural Gas without a Pipeline in North Korea

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[8] (in real terms) when the China option is exercised.

The model indicates that, particularly beyond 2010, 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.

Transport of Electricity from Russia

Instead of transporting gas from Sakhalin to Japan and Korea or from east Siberia to China, Russia could use the gas to generate electricity, which could then be transported to the Northeast Asian demand centers. Electricity links could be either high-voltage direct current (HVDC) or high-voltage alternating current (HVAC), but a number of factors favor HVDC transmission.

The comparison between gas and electricity transport options may depend on a number of factors that can be ascertained only through detailed modeling of the Japan's,

8. British thermal unit.

Korea's, and China's electricity supply systems. For example, one would need to examine the effect on network stability of a new transmission line. Other factors, such as environmental and strategic considerations as well as (in the case of Japan) the likely effect of the new facility on competition among the major electric utilities, may also play a critical role in comparing the overall social costs and benefits of the favored electricity transport alternative relative to the favored gas transport alternative. Nevertheless, we can outline some of the key issues involved.

Electricity Transport Options

Electricity can be transported over long distances by either HVAC or HVDC, but a number of factors favor the HVDC option. The first is a direct cost comparison in treating the two transmission augmentations as stand-alone investments. For the same transmission capacity, a DC line has lower construction costs than an AC line. HVAC transmission lines are three-phase and therefore require at least three conductors. However, a double three-phase line is needed to make the reliability of AC transmission equivalent to two-pole DC transmission. A typical DC line has two conductors (one for the return current flow) and thus requires smaller towers. Of particular relevance for Japan and South Korea where the costs of land are high, the DC line also requires a smaller right-of-way. The right-of-way for an AC line designed to carry 2,000 megawatts (MW) is roughly 70 percent wider than the right of way for a DC line of equivalent capacity. An offsetting factor is that the terminal stations for a DC line cost more. A longer transmission link implies that the saving in line construction costs can offset the additional cost of the stations. The so-called break-even distance occurs when the investment costs of the two types of lines are equal. The break-even distance increases with the amount of power to be transferred. In the case of links between Russia and South Korea or Japan, the distances and capacities of the lines suggest (depending on construction, land, and other costs) that the investment costs for HVDC are likely to be substantially lower.

Operating costs, in the form of transmission losses, are also lower on optimized DC lines than on optimized AC lines of the same power capacity. An offsetting factor is that the DC system has additional losses in the terminal stations where DC is converted to or from AC. The trade-offs between losses and capital costs will depend on factors specific to each project, including the cost of a right-of-way. For typical systems designed to transfer 2,000 MW of power, however, the losses in the HVDC system will be lower for distances above approximately 200 kilometers.

It might be thought that the analysis of two competing systems transmitting the same power over the same distance is not relevant in the case of Japan and South Korea. After all, both Japan and South Korea already have high-voltage transmission systems in place. Thus, an HVDC link would require an entirely new line, but an AC link might be able to use much of the existing transmission network. The existing network has been built to accommodate the existing generating plants, however, and any increase in required transmission capacity is likely to require substantial upgrading of many links, potentially creating an opportunity to use an HVDC linkup.

Another consideration is that new HVDC links would likely do more to promote network stability than would additional high-capacity AC lines. Potential instabilities in an AC transmission system can be grouped into problems with frequency control, voltage levels, or unplanned outages. Because a DC link is an asynchronous connection and the conversion stations at either end of the link include frequency control functions, an HVDC link can assist with frequency control in the parallel AC system. A DC link also allows for a redistribution of the power flow in the AC network in response to swings in loads and generation inputs. The DC link is decoupled from the AC system, allowing power transmission on the DC link to be freely and rapidly adjusted up to the design limits of the DC converter stations. HVDC links also can be controlled to carry a specific maximum amount of power. The outage of parallel AC lines then cannot overload the DC line. This may make the overall system more fault tolerant. An HVDC line can also assist with controlling reactive power in the AC system. Insofar as new HVDC lines enhance the stability of the overall transmission system, they may also allow the existing AC network to transfer additional power between regions more safely. New high-capacity HVDC links may perhaps be most beneficial in China, where the interconnections between regions are now very weak or nonexistent.

In Japan, a new HVDC link could provide another benefit. Japan’s electrical system is divided between a 50 hertz (Hz) region, including Tokyo and regions to the north, and a 60 Hz region including Nagoya, Osaka, and regions further west and south. The advantages of being able to transfer power between the two frequency regions has led to the development of three zero-distance DC links with a total transfer capacity of 900 MW. This compares with an installed generating capacity in the Tokyo electric utility area of 63,000 MW and in the Chubu utility area immediately to the west of 32,000 MW. By contrast, the existing system also allows the Tokyo utility to transfer 4,000 MW with its neighbor (Tohoku) in the 50 Hz system and the Chubu utility area to exchange up to 2,500 MW with its neighbor (Kansai) in the 60 Hz region. Clearly, the Tokyo and Chubu utilities now have little ability to share power or to compete with each other.

The International Energy Agency (IEA 1999, 70) notes that Japan’s electricity prices are the highest in the Organization for Economic Cooperation and Development (OECD). The IEA attributes these high prices to a number of factors, including expensive land, difficult geographical conditions, high taxes on fuels, high safety standards, and low load factors. The IEA (1999, 89) also argues, however, that more competition in electricity generation is needed in Japan. The separation of the electricity supply system into two separate and weakly linked 50 Hz and 60 Hz systems is one significant barrier to such competition. This is particularly so given that Tokyo and Yokohama are in the 50 Hz region, but the next largest population centers are in the 60 Hz region.

A 2,000–3,000 MW HVDC link from northern Japan could be terminated with two frequency converters at a location near to the existing Shin-Shinano frequency converter.[9] This would allow the power from the northern areas to be used in either the 50 Hz or the 60 Hz region, depending on where the demand for electricity is greatest. In effect, the transfer capability between the two regions might be increased from 900 MW to something much closer to 3,000 MW. A greatly increased capacity to transfer power between the two frequency zones could significantly lower costs. Dramatically expanding the amount of power exchange between the two frequency regions would greatly increase competition in electricity generation between the two largest utilities.

Cost of Transporting Electricity versus Cost of Transporting Gas

Arrillaga (1998, 275–76) briefly discusses the comparative costs of transmitting gas via pipeline and transmitting electricity via an overhead HVDC line. He argues that the variable cost of transporting gas is substantially higher than the cost of transmitting electricity via HVDC, with the cost advantage of electricity transmission increasing with the price of land. Because the gas transmission alternative does not involve stations for converting power between DC and AC, the cost of the plant is higher for the HVDC alternative. Arrillaga presents some rough calculations for cost of two greenfield projects (that is, two systems designed simply to move energy from point A to point B with no other issues involved). His numbers suggest that for transmitting 2,000 MW over a distance of 1,000 kilometers, the HVDC alternative is likely to be slightly less costly.

One other factor might favor the transport of electricity rather than gas. In addition to its substantial gas reserves, Siberia also has large coal reserves and considerable untapped hydroelectric potential. For example, Ivanov (1999) notes:

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9. A further advantage of placing the terminal near the existing Shin-Shinano frequency converter is that there is substantial pumped storage capacity in the vicinity. The pumped storage would allow power from the link to be stored at times when it is not needed by end users. The transmission link probably could be operated profitably at full capacity most of the time, allowing maximum value to be obtained from the initial capital investment.

By 2010, the total newly commissioned hydro capacity in Eastern Siberia and the Far Eastern region is likely to reach 4 GW. . . . During the following decade, new capacity is expected to total just 2.2 GW . . . [however] the potential for electric power exports will be further enhanced with the commissioning of the Bureyskaya HPP. . . . By 2020, if adequate investment is secured, . . . up to 50 TWh [trillion watthour] of electricity [will be available] at competitive prices. . . . Electricity exports from the eastern regions of Russia to neighboring countries may be estimated at 20–22 TWh by 2010 and 50–60 TWh by 2020.

Using HVDC to transmit the power to the large demand centers of China, South Korea, and Japan is the only feasible way of exploiting the hydroelectric resources in Siberia and the Russian Far East. Hydroelectricity also provides a significant advantage for the consuming countries. Water can be stored in dams and released only when the generated electricity has maximum marginal value. In effect, hydroelectric capacity (so long as it is not a run-of-river scheme where there is no discretion over when the water can be run through the turbines) allows electricity to be stored and supplied during peak periods when the cost of thermal generation is very high. Adding hydroelectricity to a system that is otherwise strongly based on thermal generating plants thus allows for substantial savings in the overall cost of electricity supply.

The substantial coal resources in Siberia might provide another reason for building HVDC links between Russia and the countries of Northeast Asia. Some of these deposits are high-quality, low-sulfur coal that could be transported by rail and ships to China, Korea, and Japan. Some of the deposits, however, are lignite, which cannot be transported safely (because it spontaneously combusts) and must be used to generate power on site. For example, the massive coal field at Kansk-Achinsk has lignite in seams 80–100 meters thick—in some places it is more than 200 meters thick—and at comparatively shallow depths, making it suitable for low-cost open-cut mining. This region is located in central Siberia about 2,300 kilometers northwest of Beijing. Substantial coal resources in the Russian Far East and on Sakhalin Island would also provide similar opportunities for generating electricity for Korea and Japan. The coal and hydroelectric resources in Siberia and the Russian Far East could therefore supplement the natural gas reserves and provide huge amounts of relatively low-cost electricity that could be transported to Northeast Asia.

Several arguments favor transporting natural gas rather than electricity. First, natural gas is used for more than generating electricity, and Russian gas may help to meet these other needs at the lowest possible cost. Second, technical problems associated with HVDC transmission may be greater than with gas transmission. The electricity transmission capacity within Siberia is limited. Both the Russian Far East and China do not yet have unified electricity transmission grids. Furthermore, interconnection of electricity transmission systems requires cooperation between system operators. This is much harder to achieve across international boundaries. Arrillaga (1998, 273–74) also notes that, for power transfers above 5,000 MW, ultrahigh voltages above 1,000 kilovolts (kV) are likely to be optimal. The highest voltages currently in use are 600 kV. Although 800 kV is likely to be achievable with current technology, further development is required to extend HVDC transmission to 1,000 kV and above. Given past progress, however, these technical problems probably could be solved within the relevant time frame required for such a project.

Another important difference between transporting gas and transporting electricity is that transporting gas may lead to less disruption of the existing network of electricity generating stations. If Russian gas simply displaced LNG imported from elsewhere, at least some of the same power stations could be used. A large influx of power on a new HVDC link would be far more disruptive to the existing grids in Northeast Asia. Insofar as new gas supplies displace other fuels, however, the importation of gas from Russia may also be somewhat disruptive. Furthermore, the optimal locations of combined-cycle plants are likely to change when new sources of gas become available. The availability of pipeline gas may also alter the demand for electricity from some large industrial users. In some applications, natural gas could displace electricity as an energy input, wholly or in part. Co-generation of electricity by large industrial users may also become more feasible and could potentially displace some of the new capacity the utility companies had been planning to install.

Most significant, one of the main potential difficulties associated with building either HVDC links or major gas pipelines could be avoided by using LNG. New long-haul pipelines or HVDC transmission lines would tie Northeast Asian electricity industries much more firmly to Russian suppliers than would the use of LNG. Grand projects to trade energy between Russia and the countries of Northeast Asia may involve unacceptable risks for the Asian countries under today's circumstances. Although relying on LNG would come at some cost to the Northeast Asian economies, having the ability to choose an alternative source of supply may be an insurance premium that they believe is worth paying.

III. Conclusion

As our modeling exercise illustrates, substantial economic incentives to energy cooperation among the countries of Northeast Asia could integrate North Korea into multilateral frameworks. Without resolution of the Korean peninsula issues, energy trade flows will not evolve to the most economically efficient solutions for the region. Continuation of the Korean peninsula conflict will thwart Russia in maximizing its potential as a producer and exporter of natural gas and allow nearby and distant LNG suppliers to beat it to key growth Asian markets. In addition, the barriers to pipeline development in the region will result in higher LNG prices to South Korea and China, and overall effects on global LNG markets will create more competition for supplies as far off as in the Atlantic basin. Promotion of regional electricity grids could also favor Asian consumers by promoting market competition and breaking up monopoly centers.

The commercial potential for cross-border energy projects that could be tied to overall diplomatic geopolitical solutions for the region is strong and therefore should be studied as a possible alternative for implementation of conflict resolution on the Korean peninsula.

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