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JAPANESE ENERGY SECURITY ENERGY MARKETS
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ENERGY COOPERATION IN NORTHEAST ASIA

JAPAN AND THE RUSSIAN FAR EAST: THE ECONOMICS AND
COMPETITIVE IMPACT OF LEAST COST GAS IMPORTS

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Introduction

The development of the Russian Far East's enormous energy potential has long been a topic of vast (and often) under-informed speculation. This study attempts to establish some of the basic parameters of the economics of the Russian Far East Natural Gas sector, focusing, as a basic potential demand market, on Japanese Gas Supply. It should be noted that for purposes of this paper we will include within the Russian Far East, potential gas export schemes from Irkutsk as well.

Our belief is that, unlike petroleum development, potential natural gas developments rely substantially on the size, distance and availability of potential demand markets. The chief difference of oil and gas markets is that gas needs substantial transportation, support and (at times) consumption infrastructure to be used as base energy supply. Unlike oil, without the probability of a potential natural gas market to underpin support of project costs, supply does materialize without a carefully considered, conscious and concerted effort to rationalize, prepare and prompt the development of a market to receive gas. The existence of a demand market for gas can bring into being new natural gas supply; oil field development is not dependent upon immediate access to a nearby demand center and is far more fungible in international trade. Without that implicit support of potential demand, prepared for actual commercial consumption, new gas supply will develop only slowly.

Everything in the scale of Russian Far East developments is big – the reserves, the distance, the extreme climate, the problems, the potential gains, the obvious costs and the long-term impact on Asia's gas importing markets. The enormous numbers bandied about in gas development projects in the Russian Far East make it necessary to narrow the possibilities down to the basic parameters of gas development, and how those fundamentals impact Russian Far East project proposals. As it stands now, only Japan, alone and by itself, has sufficient current gas demand baseload, and the ability to expand that quickly in the medium term (3-5 years) to provide the commercial support to underpin a Russian Pipeline Export project. Japan must be also considered as a necessary demand support for any Liquefied Natural Gas (LNG) project, as LNG hopes are pinned on the island of Sakhalin, on the doorstep of Hokkaido, the northernmost of the Japanese home islands.

Therefore, we are dealing with two allied and parallel subjects here: The potential and possible direction of future gas developments in the Russian Far East and more broadly how the

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economics underpinning traditional and future Japanese gas supply, will impact the future of Russian Far East project developments.

Our look at the Russian Far East will focus on: the known and potential gas/condensate and oil reserve base, with concentration on Sakhalin reserves; a summary of previous gas developments in the Soviet and Russian Far East; a review of current, active projects and an examination of the different commercial and political interests at work in gas development projects.

We conclude that the natural gas resources of the Sakhalin Islands area compare favorably with other substantial regional natural gas suppliers. Even at this early stage, 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 around 82 TCF. The gas resources in other Eastern Russian areas are less prolific and more distant to markets. Yakutia is thought to hold an additional 35.3 TCF while the Kovyktinskoye field in Irkutsk is estimated to have possible reserves of 52 to 105 TCF, according to Washington, DC-based consultants Planecon, Inc. These latter deposits, while large, may not be ample enough to encourage the massive investment needed to bring them to market.

The following tables outline the natural gas potential of the Russian Far East. Table 1 shows the estimated recoverable gas, oil and condensate reserves of the region. Table 2 outlines in more detail the reserves and production outlook for specific Sakhalin projects.

Table 1. Russian Far East Recoverable Gas, Oil and Condensate Reserves

	# of Fields	2-P Reserves	3-P Reserves
Natural Gas (TCF)	95	56.48	847.20
Condensate (NGL) (BN B/D)	95	3.00	11.60
Crude Oil (BN B/D)	60	2.60	66.60

Note: Proven and Probable reserves ("2P"); Proven, Probable and Possible reserves ("3-P"). The Russian system of classification uses A-E categories; A, B and C1 are roughly equal to the international classification of proven and Probable reserves.

Sources: ICPBS/Gapmer; Asia Pacific Consulting; Industry.

Table 2. Sakhalin Projects (Gas in TCF; Liquids in MM BBLs) (1)

Project/Fields	Status	Official Reserves (2-P)	Wood MacKenzie Estimates (3-P)	Operator's Forecast Lifetime Production
SAKHALIN I (Odoptu-More; Chiavo, Arkutun-Dagi)	1 st condensate/oil output mid-1999; gas by 2005	Gas: 6.7 Oil: 495 Cond.: 95	Gas: 14 Oil: 2,480 Cond.: 170	Gas: 15 Oil: 2,153 Cond.: 273
SAKHALIN II (Lundskoye, Piltun-Astokhs koye)	1 st oil mid-1998; gas post-2005	Gas: 11.9 Oil: 481 Cond.: 241	Gas: 16.1 Oil: 647 Cond.: 240	Gas: 13-14 Oil: 750 Cond.: 330
SAKHALIN III (Kirinsky Block)	PSA pending	N/A	Gas: 24 *Oil: 3,400	Max. 24/yr
SAKHALIN IV (E. Odoptu, Ayash Blocks)	PSA pending	N/A	N/A	N/A

Note: (1) Proven and Probable reserves ("2P"); Proven, Probable and Possible reserves ("3-P"). The Russian system of classification uses A-E categories; A, B and C1 are roughly equal to the international classification of proven and probable reserves.

(2) Oil includes potential condensate reserves. Estimates are for either oil/condensate or natural gas, but not both.

Sources: ICPBS/Gapmer; Asia Pacific Consulting; Industry.

Our look at Japanese gas supply will focus on: the parameters of gas development in the Russian Far East and its impact on potential Japanese imports; competition between types of gas transport; competition between the Russian Far East and other potential supply sources and the nature of, and great changes underway, in the Japanese gas market.

Why focus on Japan? The answer becomes clear when simply looking at a map. Only three potential markets can be reached by Russian Far East developments via pipeline: China, South Korea and Japan. The latter market still dwarfs the potential of the other two despite a long-running economic recession in Japan and a near decade of breakneck demand growth in the other two countries. Japan remains the region's largest single gas consumption market. In 1998, Tokyo accounted for nearly 27% of the region's total gas consumption of 9,143 billion cubic feet (BCF) or 25 BCFD. When only marketed gas sales are considered (excluding gas used for exploration, oil field operations or lost in transformation), Japan accounted for over a third of all gas sales in Asia Pacific. In that same year, Japan's LNG imports accounted for nearly 58.5% of all LNG trade and almost 78% of regional LNG demand and despite recession, Japan's LNG import rose some 4.7% in 1999. A single company, Tokyo Electric, imports more LNG than either of Asia's two other LNG markets, South Korea and Taiwan. While Tokyo's relative 'weight' in gas consumption has decreased as most of Asia enjoyed a near-decade of fast growth,

it is important to remember that while Japan may no longer be the only game in town, it certainly remains the most important single buyers' market.

In this study, we deal with China and South Korea in far less detail because neither, at least in this decade, can provide a sufficiently large enough market for pipeline imports nor provide broad enough commercial support to jump-start any Russian Far East pipeline project. The particular and peculiar elements of the gas market in China and South Korea will be briefly reviewed in two sections at the end of this study.

Finally, because of the paramount importance of the Japanese gas market, we have focused our study of Russian gas export prospects mainly on Sakhalin. Other pipeline proposals will eventually solidify, but the proximity of Sakhalin to the all-important Japanese gas markets gives developments there an advantage that competing Russian Far East projects will have difficulty overcoming through 2010. The “tyranny of distance” in gas markets, combined with commercial pressures, render an inescapable conclusion of Japan as buyer and Sakhalin as seller among the options currently in play for Russian gas, at least in the medium term.

We conclude that if even a limited national Japanese natural gas pipeline system is completed by 2010, Japanese buyers could have a number of choices for potential gas suppliers, but that sales from Sakhalin, either by pipeline or LNG, will still have a substantial capital cost advantage over most other suppliers. Sakhalin gas is the most economical by pipeline, reaching Japan for the equivalent cost of \$2.00 to \$2.80 per million Btu (British thermal unit) as compared to Yakutia gas at \$2.50 to \$3.70 per mmbtu or Irkutsk gas at \$2.30 to \$3.60 mmbtu. Sakhalin LNG costs are equally competitive at the equivalent of \$1.90 mmbtu, about equal to the costs for shipment from Bontang LNG in Indonesia and slightly cheaper than the \$2.15 mmbtu for shipments from Australia's Northwest shelf. By comparison, minimal delivered gas costs from Qatar, taking into account the comparable capital costs, would be \$2.45 mmbtu. Actual market LNG import prices in 1999 were generally higher than these estimated levels for Sakhalin costs of \$1.90 to \$2.80 per million btu, ranging between \$2.91 mmbtu for supplies from Abu Dhabi to \$3.31 from Arun in Indonesia, according to World Gas Intelligence.

The Rules of the Game – The Changing Parameters of Gas Supply

Natural Resources

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In looking at the potential development of gas supply in the Russian Far East we should realize one basic fact: that natural resources, as a concrete reality, rather than an abstract idea, are distinctly ‘un-natural’ in that they require three man-made inputs: labor, capital and technology. The challenge of Russian Far East gas development is that substantial investment of all three items will be needed before the first commercial gas is exported and sold.

The Russian Far East has long been a focus of Japanese oil and gas supply ambitions, stretching back to the early 1970s, when the Soviet Union was still a political entity. The Cold War, together with unresolved issues from the conclusion of World War II, were among the political and historic issues that hampered Soviet-Japanese joint development projects for a generation. Four small islands to the north of Japan’s Hokkaido continue to fester as a source of dispute between the two countries. While the economic worth of these small islands – known to the Japanese as the Northern Territories and considered a part of the Kurile Islands by the Russians—is slight, they have long been a minor but continuing irritant to political and economic relations.

From 1970 until the collapse of the Soviet Union, Japanese companies, particularly the powerful trading houses (Sogo Shosha) poured hundreds of millions of dollars into a range of oil/gas developments. For this huge amount of investment, they received comparatively little in return – limited oil imports and no viable gas project.

‘Non-Economic Factors’

The energy security focus of Japan’s politics has kept the Russian Far East alive as a commercial possibility for over three decades, but with little tangible success. Now, commercial factors are emerging that favor natural gas use inside Japan and may stimulate more timely development of these Russian gas reserves. In some sectors, utilization of gas can provide higher efficiencies than oil (i.e. the substitution of combined cycle gas turbines for power generation versus conventional steam, thermal plants, based on direct burning of crude oil). As Japanese electricity markets are increasingly deregulated, economic incentives for gas use may increase.

A number of factors may promote gas use in Japan. Increasingly, Japanese utilities no longer can automatically pass on fuel costs to final consumers, making energy efficiency a prime concern. The country’s continuing spate of nuclear plant mishaps has kept green and environmental issues high in public consciousness, and increasingly cast doubt on the ability of

the Japanese government to complete its current nuclear power plant construction program. Moreover, the Kyoto Accord is taken very seriously in Japan and efforts to reduce emissions will lead to a favoring of gas over oil for power generation. It is likely, and particularly if preparations for the market are made now, that natural gas use will be a major beneficiary of the Kyoto agreement, particularly if nuclear energy expansion plans cannot be implemented because of safety concerns and popular opposition.

New emerging supplies are also refocusing attention on gas' potential. In recent years, there has been a spate of large gas discoveries in the Asia Pacific in Malaysia, Indonesia, Australia and Papua New Guinea while at the same time, new LNG projects have been proposed from the Middle East. The collapse of the Soviet Union has sparked renewed interest in developing the gas and crude oil reserves of nearby Sakhalin, as well as the Russian Far East in general. The increasing instability seen in Indonesia, previously thought of as the most secure gas supplier to Tokyo, has refocused effort on consideration of other gas suppliers. The increase in the number of competing suppliers is lowering prices for LNG, opening the prospects of new, cheaper suppliers in the coming years.

“Lowest Cost” Supply

In sum, the timing is right for Japanese companies to press for cheaper LNG terms. ‘Non-economic factors’ will never completely disappear – for example, strict adherence to the Kyoto accords will shape Japanese energy choices in the future as much as the bugaboo of energy security did the past-- but increasingly, market forces have come to matter.

The trend to search out and acquire, ‘lowest cost’ supply, particularly for natural gas, is being driven by a series of profound shifts in the Japanese economy. One major force for Japanese companies to pick lowest cost supply is that the domestic market will no longer accept, passively and without question, some of the highest utility rates in the world. Increasingly, utilities in Japan must re-examine, in the most basic way, how they do business –including lowering costs and financing capital improvements.

Japan’s long-running recession, after the ‘Bubble Economy’ burst, has had another unforeseen consequence. It has opened door to sectoral deregulation that is needed to spur efficiency and economic growth, and free Japan from its lingering downturn. Both business and government have embraced utilities' deregulation, though enthusiasm for it varies widely.

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Recently, large commercial power companies were given the right to choose suppliers; smaller power consumers will follow by 2001. Similarly, certain, larger volume gas buyers can now pick their supplier. The government has guaranteed third party access to distribution systems.

The new era of low-cost supply has also introduced competition not only on a geographic basis, but in cross sales, i.e. power companies selling town gas and town gas companies selling electricity. Further, the opening of the power sector to non-power companies, through Independent Power Projects (IPPs) has not only attracted interest from trading houses (traditionally the conduit for gas supplies to utilities), but foreign companies such as Enron, as well as oil/gas companies such as Shell, ExxonMobil, Chevron and Texaco. Competition will rise, and pressure for lower gas prices will increase, as new companies enter traditionally closed sectors.

The growing pressure for lowest cost gas supply has been underscored by the new moves towards the convergence of the power and gas industries. This trend, well established in the US, growing rapidly in Europe and emerging now in Asia Pacific, is based on the consideration of gas and power as integrated entities. The idea of 'convergence' is that gas supply can not be considered alone, but only in relationship to power generation, as gas turbines can compete effectively on commercial and environmental grounds against fuels in this sector. Power represents the largest single use of natural gas in most economies and in almost all Asia Pacific gas markets. On this basis, convergence advocates argue, the push for lower cost natural gas will come from those companies which attempt to secure lowest cost base fuel, in an effort to compete efficiently against traditional power utilities. While still in its preliminary stage in Japan, 'convergence' will provide a powerful pressure to seek new methods of gas pricing and a continuing effort to lower gas import price levels.

Natural Gas Is Not Degraded Oil

When we examine the problem of development of Russian Far East gas reserves, we should consider the nature of gas. It is important to recognize that natural gas is a separate and distinct form of hydrocarbon energy from oil, and that it has its own special rules, strengths and weaknesses.

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The chief difference of gas and oil is that of support costs. The support infrastructure for natural gas production, transportation, distribution, and at times, consumption is considerably greater and more expensive than oil infrastructure. Oil can be stored in any container; it does not have to be stored under pressure and is a natural liquid. Oil is a base material and almost always needs a means of transformation, i.e. a refinery; in order to be converted into economically useful petroleum products. While flammable, crude oil is not volatile and will not easily ignite or explode.

The physical nature of natural gas dictates that it must always be stored in seal-tight containment. It is transported under pressure, or cooled to a liquid form. It is generally used as a basic source of heating value, rather than a base material to be transformed into a multitude of end products. Gas has its own virtues as well. It is extremely clean, is more efficient than either oil or coal in converting its energy values into generated electricity, and it is far more plentiful in the Asia Pacific, including the Russian Far East, than oil. Gas also often contains Natural Gas Liquids (NGLs), which include condensate and Liquefied Petroleum Gas (LPG) both associated gas products with high value.

In this review, we will focus on only two forms of gas transportation and use, LNG and gas pipelines, as being the primary contenders for Russian Far East gas exports, particularly when targeting Japan. Other gas or gas associated forms exist (synthetic oil products, di-methyl ether; NGLs, gas hydrates), but currently these are either peripheral to our supply concerns or have not yet reached fully commercial development. If gas exports from the region commence by 2010, they are likely to be either in the form of LNG cargoes or pipeline sales.

The Russian Far East

Soviet-Japanese Developments: The Waiting Game

Japanese companies have been attempting to develop oil, gas and coal reserves in the Russian Far East (as well as East Siberia) for 30 years. In the 1970s, the main focus for gas development was for Sakhalin Island, the Vilyui gas/condensate deposits of Yakutia and some selected East Siberian gas finds (one which in Irkutsk, ultimately evolved into the current Kovyktinskoye, or Kovykta, project currently under consideration).

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The Japanese experience was disheartening. The original Sodeco consortium, formed under the aegis of the Japan National Oil Corporation (JNOC) and involving a large number of Japanese trading houses, refiners and other companies, linked forces with a major international oil company, Gulf (since taken over by Chevron in the early 1980s) as far back as 1972 but never reached even a concrete planning stage. The reasons are varied. Soviet permission to proceed with field development was delayed as Moscow asked Japanese companies to carry most of the Soviet share of project development costs. A shortage of hard currency on the Soviet side led to payment through barter, and Japanese companies, even large diversified trading houses found that counter trade offerings of raw materials –mainly timber, minerals, fish and furs—were of uncertain quality, often delivered far behind schedule and sometimes damaged in transit. The Soviet Union’s invasion of Afghanistan in 1979 led to a total freeze of Japanese trade and development credits. In response, Moscow put all joint development projects on indefinite hold.

A second focal point for Japanese project efforts (together with US gas company El Paso) was a proposal to develop the gas/condensate reserves of Vilyui, first as the ill-fated “North Star” LNG project and later as a gas pipeline that would stretch from Yakutia to Japan. Other small project proposals existed including studies for gas and oil developments in East Siberia.

Yet after a hundreds of millions of dollars investment, and efforts stretching nearly 20 years, the Russian Far East yielded little of commercial value to Tokyo. The maximum oil exports from that region to Japan have never exceeded 70 MBD, with most of that volume coming from long-operating wells onshore Sakhalin. By the end of Soviet Russia in 1989, all Japanese-sponsored oil and gas projects were essentially dead.

South Korean companies initiated the next chapter in energy developments, for what is now called the Russian Far East. Prospects returned to life as Seoul oddly enough revived interest in gas development in the region by focusing on the distant prospect of developing the Kovykta (Irkutsk) gas/condensate reserves, with a preliminary feasibility study begun in 1993. Later in 1995, China, for the first time, indicated that it would be interested in pipeline natural gas imports and later signed preliminary accords with the Russian government and a series of Russian companies to further study these development proposals.

In the mid-1990s, Japanese commercial interest in Sakhalin was revived, resulting in two of three Sakhalin Production Sharing Agreements (PSAs) under current implementation. The three existing programs include: Sakhalin-I, led by Exxon (now ExxonMobil); Sakhalin–II, led

by Marathon & Shell and Sakhalin-III, led by Mobil (now ExxonMobil). A provisional PSA development, Sakhalin-IV, which would also be led by ExxonMobil, still must be fully approved by the Russian government. Japanese interests in Sakhalin I and II are substantial and it is expected, as Sakhalin III and IV progress, that Japanese companies will farm into these projects.

Japanese involvement with Sakhalin-I is under the umbrella of the older, but reorganized Sodeco consortium, held 42.9% by JNOC, with the majority share split among 13 Japanese companies. Despite a 30% share in the project, Sodeco is generally considered a passive partner in the decision-making for this project. The consortium consists of a wide range of companies – utilities, trading houses and refiners. The Japanese participation in Sakhalin-II includes Mitsui (25%) and Mitsubishi Corp. (12.5%). These Japanese companies have allowed Shell and Marathon to take the lead in field development, with Shell also shouldering the burden of planning for gas exports. Both trading houses are major powers in Japanese LNG and have shown at least limited interest in expanding their presence in the domestic gas sector. Sakhalin-III currently has no Japanese participation, and consists of ExxonMobil, Texaco and Russian companies, but it is likely that Japanese companies will buy into the development at some later date.

It should be noted that two very basic factors shape all Sakhalin hydrocarbon developments. The first is that primary development will be for the Japanese market. To the extent that gas exports emerge over this decade to South Korea at all, they are likely to be a supplement to a Japanese targeted customer baseload.

Moreover, liquids sales from the Russian fields will be handled before gas sales. This is because sales of crude and condensate allow for a quick buildup of revenue flow for multi-billion dollar projects, easing the financial strain on development consortia, until first gas sales are made. This is true whether discussing a Mideast Gulf gas pipeline project or Asia-Pacific LNG development. Since most ‘oil finds’ in the Russian Far East are usually combinations of oil and associated gas, the latter often containing substantial volumes of recoverable condensate, the dictum will be followed – both Shell/Marathon in Sakhalin-II and ExxonMobil in Sakhalin-I, have concentrated initially on production of liquids.

That said, an inverse principle comes into play – that while liquids development comes first, there must be gas development and exports to make any of these projects work commercially in the longer run. The reason why is simple – there exists, even based on our

limited current knowledge, far more gas than liquids in Sakhalin and the Russian Far East in general. The presence of NGLs, including condensate, in gas reserves can make a good project even more profitable, but it cannot make an uneconomical gas project good. The basic gas economics must be solid for a project to proceed. Condensate is a byproduct of gas production and gas sales come first --otherwise, the tail wags the dog.”

The following tables show current oil and condensate production from Yakutia and Sakhalin and the forecast for future production of natural gas, oil and condensate from the region.

Table 3a. 1997 Russian Far East Gas Oil/Condensate Production

	Gas (MM CFD)	Oil/Condensate (MBD)
Sakha Republic (Yakutia)	150	5
Sakhalin	174	35
Total	324	40

Source: ICPBS/Gapmer

Table 3b. Russian Far East Gas, Oil/Condensate Production Forecast

	1997	Projected 2005	Projected 2010
Natural Gas (BN CFD)	0.324	1.55-1.93	1.93-3.29
Condensate (MBD)	5	20-30	40-60
Crude Oil (MBD)	35	300-395	460-580
Exportable Gas Surplus (BN CFD)		0.97-1.35	1.16-.232
Exportable Oil/Condensate Surplus (MBD)		200-260	260-340

Source: ICPBS/Gapmer

A Pause – Why Did Earlier Projects All Fail?

It is worth examining in some further detail, why Japanese development efforts of 1970-1990 failed in order to understand whether it is possible to overcome these problems in the coming decade.

The first and foremost problem for past efforts was politics. The general tenor of the Cold War made both the Soviets and Japanese suspicious of each other’s intentions. As a result, the Soviets attempted to limit Tokyo’s access to most prospective areas, and the Japanese moved cautiously on trade and investment credit. The 1979 Afghanistan invasion led to a virtual freeze

on all major hydrocarbon projects, as the US pressured Japan to stop funding developments. In addition, the Kurile Islands/Northern Territories issue remained a persistent, though minor irritant. In fact to this day, no formal treaty ending WW II between these two countries has been signed though a cease-fire accord was agreed in the mid-1950s.

The problems of development were compounded by the Soviets' lack of hard currency. Many projects were based on barter and counter-trade and Japanese companies worried about repayment, as there were few goods that Tokyo wanted from the Soviet Union other than raw materials.

For oil and gas projects, the basis of development was funding on a success and repayment program. Typical was Sodeco, which was paid a percentage of future oil following commercial production from the block. Sodeco made significant discoveries in the 1970s, including Odoptu and Chiavo, but once finds occurred, the Soviets proved reluctant to push for fast track commercial development, even when the Japanese offered near total funding of development costs. While Japanese company executives suspected that the Soviets wanted them only to discover new reserves, but not develop them, the Soviets accused the Japanese of not promoting technology transfer in exploration programs.

Finally, and fundamentally, failures occurred because both sides failed to address the Russian Far East's most basic characteristic – It is 'Hard Man's Country'.

Hard Man's Country

The vast distances involved for Russian Far East gas development are daunting. Sakhalin reserves are no less than 1,000 kilometers (km) to the northernmost island of Hokkaido and roughly 2,300 km to Tokyo. And, these estimates assume the most direct route; yet pipeline routes are not decided solely by drawing a crayoned line on the map. Actual gas pipeline distances could be considerably greater once terrain, climate and natural hazards are weighed.

As much as distance, there are also problems of climate and terrain. Temperatures for the 'Taiga', which comprises much of the Russian Far East, can range from -30C in winter to +30C in summer. Pipeline gas must be maintained, over long distances at a relatively stable temperature, implying substantial piping insulation. While for the most part proposed pipeline routes do not cross mountain ranges, the relatively flat terrain will still need a substantial number of pumping stations to 'push along' gas flows, even if the pipeline is designed for relatively low

gas pressure. Seasonal changes present construction problems – the ‘Taiga’ freezes solid at depths very close to the ground surface; when summer temperatures melt the ice, the region quickly converts into a swampy, wet morass, impeding movement of both man and machine. Offshore conditions are not easy either. The severity of weather offshore Sakhalin results in an exploration frontier similar to the northern fringes of the North Sea – ice is normally present for 4-6 months a year and can average up to 2 meters thickness. Shallow offshore waters often freeze solid to the seabed, and have a ‘shearing’ effect on offshore fixed facilities, adding to development costs. Storms and substantial ice floes limit offshore exploration activity to less than 6 months a year.

In addition, nature provides cataclysmic upheavals at regular intervals from earthquakes, to massive flooding, tornadoes and in some southern border regions, dust storms. Any pipeline project must take all these phenomena into account and armored pipe will have to be installed in certain areas. In addition, any pipeline linking the Russian Far East to Japan will have to traverse seismically active zones, while skirting deep-sea trenches. Nor are pipelines alone affected – the 1994 earthquake which struck Sakhalin registered 8.2 on the Richter scale, and a 7.3 Richter scale earthquake the following year caused extensive damage to oil and gas wells as well as multiple fractures to existing oil pipelines.

Minimal transportation and spotty communications infrastructure aggravate problems of climate and terrain. Proposed pipelines entail routes where there few roads, no railroad and only limited (and weather restricted) airstrips. While none of these problems are insurmountable, the transport of tons of specialty pipe, as well as heavy machinery and the food, equipment and shelter for thousands of construction workers in a harsh and unpredictable climate, certainly adds substantially to both field development costs as well as the cost of laying pipe. The problems of infrastructure are compounded by the minimal rail and road links the region has with either the Maritime province to the East, or the relatively developed region of East Siberia, to the West.

As we have underlined before, gas development is a long-term phenomenon, both in development lead-time, and in the establishment and implementation of sales contracts. The increasing political instability in the Russian Federation has particular significance for gas projects, whether based on pipeline gas or on LNG. Projects have been delayed in the infighting between local governments and the central authorities; exploration and development efforts have been hampered by the inability of Moscow to fast-track approval of new PSAs. Yet instability

depresses gas promotion efforts in particular as developers must be assured that they can recoup, over a moderately long period of time (normally 5-8 years), the enormous sums of capital expended on development. Buyers, particularly Japanese gas buyers, must be reassured that after committing themselves to import of Russian gas, that a future upheaval will not suddenly cut off future supply. The current confused state of Russian politics leaves most buyers uneasy about this very basic point.

Weighing Costs

Economic Factors in Pipeline Gas

Capital costs in gas pipeline projects center on five major factors: the cost of field development, the length of the transmission line and route, the type of pipeline designed, including special features needed for specific terrain, the carrying capacity and pressurization of the trunkline and finally the size and sophistication of the receiving market.

Capital costs in field development can vary extensively, depending both on the nature of natural gas reservoirs, the size and sophistication needed in gas gathering facilities and gas treatment plants, distance from support bases and terrain/climate. For the inland gas finds of the Russian Far East, costs vary widely, but all fields are likely to have substantial development costs. The development costs of the Kovtkya/Irkutsk development could fall in the range of \$1.5 to \$2.0 billion. The Vilyui fields of Yakutia could be even higher at \$1.2-2.4 billion. Even Sakhalin-I and II have high development price tags. Exploration and development (E&P) costs for the first totaled \$420 million through 1999 and for the second reached \$950 million by the same year. Once gas field preparation is added to the preliminary costs of getting oil/condensate production online, both projects should range in the \$1.3-1.6 billion range, possibly more. The financial commitment by the Sakhalin-III group simply for exploration is a minimum of \$353 million. If discoveries are made and prove commercial through appraisal, total E&P costs will rise at least to the level of Sakhalin-I/II and probably will exceed those levels, as the PSA block is in deeper water and more difficult exploration conditions.

Numbers bandied about on the capital costs for a major transmission line from the various fields differ substantially. Sakhalin projects have an inherent advantage in that the island is a neighbor to Japan, but even in this case the length of trunkline would have to stretch some

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850 KM to reach Japan’s Hokkaido, and 1,500 KM to reach central Honshu, the heartland of Japanese gas demand. A pipeline southwest to Shenyang in Northeast China would stretch a minimum 2,400 KM, but would vary from 3,500-4,500 KM before it could reach large urban centers in eastern, particularly coastal zones, that could absorb sufficient gas volumes. These Sakhalin/Japan options, for a 42-56"/1.07-1.42 M (interior diameter) pipe could range from \$950 million to \$1.4 billion, depending on where landfall would be in Japan, and excluding the considerable cost of laying a domestic gas transportation system, itself a multibillion dollar undertaking. Sakhalin sales to China would cost substantially more, even if only to Shenyang in the Northeast. A major trunkline from Irkutsk to China, South Korea and possibly Japan (3,340-6,800 KM) has been estimated at costing from \$6.0-14.5 billion, depending on whether a route traversing Mongolia is used, and whether Japan is the primary sales target. Estimates for a Vilyui pipeline (5,500-6,500 KM), again using a standard 42-56" interior diameter pipe, also range enormously from \$6-15 billion, depending on the final destination market and length. The cost for a 2-train LNG project with each train of 2.5 to 3 MMTA would be in the range of \$3-4 billion. Some comparative costs for LNG projects from various locations follows below:

Table 4. LNG Comparative Costs

Country/Project	Export Capacity (MM MTA)	Distance to Japan (km)	Capital Cost (US\$)	Operating Since
Qatar/Qatargas	7.1 (3x)	6,400-6,520	\$6 BN w/ship & 3 rd train	1996
Australia/NW Shelf	8.7 (3x)	4,500-5,300	\$7.8 BN w/ship & debottleneck	1989
Indonesia/Bontang	21.5 (8x)	3,500-4,200	\$7-8 BN w/new trains, debottleneck & shipping	1977 1999 'H-train, latest
Russia/Sakhalin-II (1)	6-8 (2x)	800-2,500	\$6-7 BN w/pipe to S. Sakhalin, NGL plant & shipping	2005-6 target; 2006-8 more likely

Note: (1) While max. distance is from LNG plant on southern tip of island, minimum distance is from production fields to Hokkaido.

Project promoters frankly admit that these figures represent guestimates. In order to gain more realistic cost estimates we must first establish Japan as the top export market priority;

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second we must consider what Japan could do to reduce the delivered cost of gas, once supply reaches landfall on one of Japan's major islands.

Other factors impact capital costs for pipelines. A high pressure line can reduce operating costs considerably – according to figures from Agip, examining a 1,000 km, high pressure 56" (1.07 M) pipe, carrying costs for a daily average 2.9 billion cubic feet a day (BN CFD) would be \$0.22/MM BTU, compared to costs of \$0.31/MM BTU for the same pipe carrying low pressure gas. Yet capital costs can increase by 30-40% for the same length of pipe. Pressure and pumping rates impact costs, both capital and operating. The peculiar climatic conditions of the Russian Far East suggest that at least in sections, the line would have to be armored, and heavily insulated, or suspended (as in the Alaska oil pipeline TAPS) above frozen tundra, in order to minimize environmental impacts. Of course, pipeline capital costs rise when pipe is laid offshore, even with new and efficient pipelaying techniques. As noted earlier, pipelines approaching Japan from the West must deal with the enormous depths of the Sea of Japan marine trench or route around this obstacle. Sakhalin-based pipelines could avoid this difficulty, but all offshore pipelines will be costly, and if targeted for a Japanese market, will have to take substantial and costly precautions to prevent pipeline rupture from undersea seismic disturbances, as much of Japan experiences regular earth tremors. These technical problems can be overcome, but at substantial increases to capital costs.

The size and sophistication of the transmission line and receiving market and the extent of the national distribution reticulation system also play a part in capital costs, though these costs are generally assumed by the buyer, not seller of gas supply. Japan has by far the largest and most sophisticated gas market of the three potential export countries we have considered. The question remains what will Japan itself do to expand and further build that market. The foremost decision that must be made soon is the construction of a national gas transportation network. This would not only knit together the two major gas consumption areas at present – the Kanto plain surrounding Tokyo, and the Kinki region surrounding Osaka and bordering the Inland Sea – but make it possible to move gas from a pipeline landfall point to major consumption areas.

Reducing the cost of moving gas domestically is a prime consideration for any export pipeline to Japan, and only Tokyo can make the necessary and hard decisions to promote the development of a pipeline market. Yet, the benefits of decreased cost in domestic distribution would benefit LNG imports as well, which for the most part are restricted to 'beachhead' areas,

close to end-users. Costs for such a national transmission system are quite high at \$7 to \$10 billion for a minimum linkage of the Kanto and Kinki regions to a pipeline landfall point.

Another major factor in the economics of gas projects is the transfer price of field gas to the consortium selling that gas to export markets. Wellhead gas sales prices to the consortium must be low enough to attract buyer interest but high enough to allow for a commercial rate of return on project capital. If we assume that Russian Far East interior finds are priced at wellhead somewhere in the range of \$0.50-0.80/MM BTU, most development consortia believe that supply can be delivered at market-related prices. Yet some estimates for minimum wellhead prices range far above this level, to as much as \$1.10/MM BTU. Most LNG projects are based on wellhead gas prices in this range. While Russian officials, guarding the economic interests of the host country, may believe that is too low a base price, raising wellhead price levels substantially above that level may simply scupper export projects before they even get off the ground. For Russia, the benefit will not be high gas prices but employment, tax revenues, hard currency earnings as well as infrastructure spin-off.

As touched on before, we must consider the minimum flow and sales volume for the baseload needed to initiate a gas development. Most interior pipeline proposals are based on the assumption that the initial phase of development would have a minimum delivered gas capacity of at least 1 BN CFD, followed by a second phase of equal size. If we assume a two-train 5 MM MTA LNG project design for Sakhalin, delivered gas per each 2.5 MM MTA train would be in the range of 350 MMCFD, depending on conversion loss and distance to market.

To export such large gas volumes, developers must lock in major gas buyer commitments ahead of time before developing the field. The volumes of gas needed simply to fill any of these pipeline projects would be enormous, ranging from 0.2-1.0 trillion cubic feet (TCF), depending on distance, pressure and pipe diameter. In sum, gas development in the Russian Far East is not for the faint-hearted planner.

Another economic factor in weighing gas project profitability is the presence of NGLs, and, in this regard, all Russian gas proposals are relatively fortunate, as reserves contain considerable volume of both LPG and condensate. Yet most pipeline projects, based on reserves far in the interior of the Russian Far East, have only limited domestic markets for LPG or condensate sales. Once immediate market needs are satisfied, these liquids must be transported

substantial distances for incremental sales. Only Sakhalin has relatively easy access to large-scale markets for the easy (and low cost) export of NGLs.

A further consideration is project security. While LNG facilities are as delicate and vulnerable as pipeline infrastructure, once LNG is loaded it is relatively free of the danger of sabotage. Pipelines, by their very nature, are immobile and relatively easy to damage. Putting aside the problem of North Korea and its future behavior, the problem of pipeline security may come to the fore if various secessionist movements, not only in the Russian Far East, but also in Western China, decide that denying transportation of gas across their region has economic and political advantages. This stands at present as a remote possibility, but must be considered in supply economics.

Finally, a major consideration in gas development economics is whether whole or stripped gas will be supplied. Whole gas is gas cleaned of impurities, containing some NGLs. Stripped gas cleaned of impurities contains only hydrocarbon compounds C1-2, or ethane and methane, with no LPG (C4-5) or condensate content (C5 and above). Pipelines can transport whole gas, containing some heavier liquids; at least for relatively short distances of up to 1,500 km. LNG must be manufactured from essentially dry gas. Whole gas can be used for a fuller range of demand sectors than dry gas, which tends to be restricted to power generation and town gas consumption.

Economic Factors in LNG Gas

The traditional Japanese LNG model emphasized long-term buyer commitments, relatively high delivered cost for gas supply, careful long range planning for production, buyer offtake commitments and financing. The model began to break down in the mid-1990s as South Korean buyers demanded – and were conceded – substantial changes in the purchasing accords first with Oman, then followed by Qatar. Ceiling/floor price limits were abandoned; the buyer was allowed to provide its own LNG transportation; pricing formulae were sharply modified from the Japanese model and Korea Gas Corp. (KORGAS), the monopoly LNG importer for South Korea, was allowed a direct participation in all phases of the LNG consortium supply gas sales. It is implicitly acknowledged in Japan that the old way of conducting the LNG business is dead – but what will replace it?

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While Japanese LNG buyers are unsure as to the final form of a new model for LNG purchase contracts, they are clear what such issues that model will have to address. The new model LNG accord must cut delivered gas cost, increase supply and pricing flexibility, and take into account substitution cost competition for end-users. The justifications of ‘non-economic’ factors, such as security of supply, or LNG’s green premium, no longer outweigh the competitive force of lower costs for alternative fuels.

The need to cut overall LNG costs for Japanese buyers has spanned a number of different initiatives. First, Japanese buyers, using their substantial market weight, are demanding LNG contract terms at least equal, if not more favorable, to those already granted South Korea. This round of ‘clawback’ contracts began in 1998 and is likely to continue as contracts come up for renewal through 2003.

A more pro-active move is the Japanese push for shorter term contracts, and a mix of short- (1-2 year) and medium-term obligations (3-5 years) to complement their baseload of 20-year term contracts. After opposing shorter-term buyer obligations, Japanese buyers, under the twin pressures of deregulation and convergence, are beginning to see the benefits of less expensive, shorter-term contracts outweighing supply security concerns. Flexibility in pricing and in offtake volumes will increasingly become the norm for the new model Japanese LNG contract

Finally, while no concrete project has yet emerged, the development of IPPs in Japan has opened the door for the first fully vertically integrated power project in Japan. LNG sellers have long discussed the idea of capturing value down the supply chain by owning a fully integrated LNG to power vertical supply chain. This would allow a company, or consortium to discover and develop gas finds into a LNG project, sell and transport LNG to its own power subsidiary and onsell electricity generated by that plant. While a grand idea, the concept will be difficult to implement, and so far no fully integrated LNG-power project has been completed, but several Japanese companies, both utilities and trading houses, have begun to lay plans.

Pipeline vs. LNG

We would like to briefly compare the advantages and disadvantages of pipelines and LNG in gas transportation. Both modes of transport present specific strengths and weaknesses.

For Pipelines

In terms of capital costs, LNG is cheaper on long-haul sales, while pipelines, without specialized trunkline features, are less expensive for up to 6,500 KM onshore and 4,000 KM offshore. This general rule must be sharply modified in the case of the Russian Far East, as the optimum conditions for an onshore pipeline – flat terrain, mild climate, support infrastructure, do not exist and any pipeline route to Japan must contain an undersea segment, at considerably higher cost than onshore construction. Due to the special and harsh conditions for pipeline construction, the ‘economic edge’ for pipeline distances is eroded considerably. Yet the overall rule holds true – we believe that for distances of 2,500 KM or less, pipelines hold the cost edge.

Yet a related, though integral, part of this calculation becomes the cost of a national transmission network within Japan’s borders. However, whether that can be assigned to the overall cost of pipeline imports is debatable, because such a network would also greatly benefit LNG distribution. Either way, the fact remains that no pipeline exports to Japan could be made without some form of national trunkline. All pipeline gas sales would have to be moved from a landfall point, whether in Hokkaido or another island, to the major demand markets of the country. We exclude this substantial cost of a distribution system from pipeline project costs, because it is obvious that the buyer, not the seller, will have to foot this large bill.

If we assume that some, even if a limited, national gas transportation system is completed by end-decade, Japanese buyers can have a number of choices in potential suppliers. Yet we believe that sales from Sakhalin, in either transportation mode, still have a substantial capital cost edge. Sakhalin gas is clearly the most economical by pipeline, reaching Japan for the equivalent cost of \$2.00 to \$2.80 per million Btu (British thermal unit) as compared to Yakutia gas at \$2.50 to \$3.70 per mmbtu or Irkutsk gas at \$2.30 to \$3.60 mmbtu. Equivalent Sakhalin LNG costs are equally competitive at \$1.90 mmbtu, about equal to the equivalent costs for shipment from Bontang LNG in Indonesia and slightly cheaper than the \$2.15 mmbtu for shipments from Australia’s Northwest shelf. By comparison, minimal delivered gas costs from Qatar would be \$2.45 mmbtu assuming comparable capital expenditures. Actual market LNG import prices in 1999 were generally higher than these estimated levels for Sakhalin costs of \$1.90 to \$2.80 per million btu, ranging between \$2.91 mmbtu for supplies from Abu Dhabi to \$3.31 from Arun in Indonesia, according to World Gas Intelligence.

The following table calculations take in account the following:

Estimates of wellhead costs factors in the cost of producing, transporting and storing NGLs, both condensate and LPG and this raises overall gas field operating costs substantially. Yet 'wet' gas discoveries containing sizable volumes of NGLs tend to be developed, either for pipeline or LNG projects, before 'dry' gas finds. The presence of NGLs allows project to upfront revenue by producing condensate and LPG before first gas volumes are sold; these sales allow for increased rates of return on capital, as well as increased overall revenue. While wellhead operating costs rise through NGL recovery, NGL sales further increase overall project profitability. NGL production costs include stripping 'wetness' from gas, piping liquids ashore, separating LPG from condensate and the storage of both hydrocarbon liquids.

The choice of process technology used has only slight impact on liquefaction operating costs for gas conversion to LNG. Limited, though discernable, differences in liquefaction costs are attributable to the age of the liquefaction train and the climatic/geographic conditions surrounding the LNG production site. While older trains are often 'retrofitted' to upgrade conversion efficiency, the newest generation of grassroots liquefaction trains shows small reductions in manufacturing costs, not only due to more modern equipment, but also through new operational procedures that take advantage of local climatic conditions. This produces small differences for liquefaction costs according to age and location of LNG complexes.

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Table 5. LNG Breakout of Costs (US\$/MM BTU) (1)

Country/Project	Wellhead Gas Cost	Liquefaction Cost	Transport Cost	Regassification	Min. CIF Gas Cost
Qatar/Qatargas	0.55-0.75	0.40-0.60	1.10-1.20	0.40-0.60	2.45
Australia/NW Shelf	0.65-0.95	0.40-0.60	0.75-0.95	0.35-0.55	2.15
Indonesia/Bontang	0.60-0.80	0.45-0.65	0.55-0.75	0.30-0.60	1.90
Russia/Sakhalin-II (2)	0.70-1.00	0.30-0.45	0.50-0.60	0.40-0.50	1.90

Note: (1) Assumed US\$18-22/BBL oil price.

(2) Sakhalin LNG assumes no Japan gas network.

Table 6. Russian Pipeline Breakout of Costs (US\$/MM BTU) (1)

Project	Wellhead Gas Cost	Distance to Japan (km)	Transport Cost (Japan Landfall)	Domestic Transport	LNG Equivalent
Sakhalin (Sak. I/II)	0.70-1.00	850	1.10-1.40	0.20-0.40	2.00-2.80
Sakha-Vilyui	0.80-1.30	6,000-6,500	1.50-2.00	0.20-0.40	2.50-3.70
Irkutsk-Kovytka	0.60-1.00	6,200-6,800	1.50-2.20	0.20-0.40	2.30-3.60

Note: (1) Assumed US\$18-22/BBL oil price.

(2) Japanese national transmission network capital costs excluded from transport calculations.

Table 7. LNG Comparative Costs - 1999 Actual

Country/Project	US\$/MM BTU	Price Change Vs. 1998	'000 MT	MT Change Vs. 1998
Abu Dhabi/Das Island	2.91	-11.57%	4,751	+3.62%
USA/Alaska	2.84	-8.18%	1,221	-6.29%
Australia/NW Shelf	3.27	-4.06%	7,226	+1.26%
Brunei/Lumut	2.97	-4.28%	5,483	+0.62%
Indonesia/Arun, Bontang	3.31	+21.35%	18,386	+2.20%
Malaysia/MLNG-I/II, Bintulu	2.98	-6.06%	9,903	+0.67%
Qatar/Qatargas	3.07	-4.60%	4,394	+58.69%
Total	3.13	+2.87%	51,364	+4.67%

Note: (1) In 1998, average CIF Price was \$3.03; for 1997 was \$3.90. Average annual prices for LNG imports in recent years generally ranged from \$3.20-3.50/MM BTU. If crude prices for the 2000-2005 period settle into a \$18-22/BBL range, average Japanese LNG import prices will decline slightly as new 'clawback' contracts are signed.

Source: Word Gas Intelligence, 2/25/2000.

Pipelines can add incremental volume to carrying capacity at a relatively small capital cost and with a minimal increase in operating costs. Measures to add carrying capacity include increasing pumping, gas compression and eventually double-looping the gas pipeline. LNG manufacturing capacity, i.e. liquefaction, is generally available for incremental sales, but the

bottleneck is transportation, both in the availability of highly specialized LNG tankers and the scheduling for both loading and discharge of cargo into specialized LNG receiving terminals.

As mentioned earlier, gas used for LNG must be severely stripped, in order to be converted from a gas into a liquid. If NGLs are left within the gas, the resulting LNG can become dangerously unstable. Gas pipelines, by contrast, can carry whole gas, as well as limited, intermingled volumes of NGL, at least for shorter (500 KM or less) distances. Pipeline gas can be used not only for power generation and town gas, but also for petrochemical and fertilizer production.

While both LNG and pipeline gas have commendable safety records, particularly in countries such as Japan where great effort is expended in assuring safety, the fact remains that LNG is highly explosive. Safety measures to prevent LNG mishaps include self-sealing and armored tanks, and substantial explosion barriers. This is another, not inconsequential, capital cost. Still, Japan has not experienced any major gas accidents though the country's 22 LNG receiving terminals could be targeted in an attack on Japan in times of war.

Pipelines have two odd, but beneficial, impacts on both buyer and seller. The receiving market for pipeline gas often sees demand expand rapidly, once supply is made freely available. Market development accelerates, often allowing for a faster-than-anticipated growth in demand, particularly among smaller volume buyers. In Japan, gas development has been hampered not only by the lack of national transmission capacity, but by the fact that gas users must cluster around LNG receiving terminals. If Russian gas exports arrive in Japan by end-decade, this will lead to a revolution in the nature of gas consumption there. A parallel impact for gas pipelines is that they have substantial and desirable infrastructure spin-off in the supplying country. This development impact is not only seen in the area surrounding a gas field development, but along the path of a long distance gas pipeline and the idea of a gas pipeline spearheading overall economic development in the sparsely populated Russian Far East, has an inherent attraction to Moscow.

LNG Has Its Strengths As Well

While both pipelines and LNG need 'baseload sales' in order to go ahead with development, pipelines need a much steadier and more invariable volume consumption over a period of time. Pipeline operators generally cannot interrupt service, at least in Asia Pacific, and

buyers are tied to taking contracted gas volumes whether needed or not. Thailand's state power firm Egat in 1995 and in the crash of 1997-1998 attempted to cut back purchases leading to great friction with its upstream gas providers. By contrast, South Korea, which felt the full impact of recession in 1998, was able to juggle its LNG shipments by canceling, delaying or rescheduling short- and medium-term contracts and in general 'squeeze through' despite a period in which domestic LNG needs were vastly reduced.

In short, LNG is a mobile gas delivery system, while pipelines, by their very nature, are a fixed form of gas transport. Alternative buyers for LNG cargoes are limited by both the availability of specialized shipping as well as berthing times at LNG regassification terminals, but at least there is some choice for a seller to divert gas sales to an alternative buyer. Pipeline sales have little such flexibility. Because of this, LNG supply can be varied and rescheduled; pipeline supply is invariable and a buyer must be able to cover its offtake commitment or pay for it without using the gas, with the latter situation subject to 'take-or-pay' clauses that are particularly inflexible in pipeline gas sales.

The fixed nature of pipeline sales also means that a pipeline gas exporter often competes against itself in terms of attempting to increase gas price levels, or overall sales volume. A LNG seller can play markets off against each other, though buyers, particularly South Korea, have learned this trick as well. Pipeline gas exporters usually can only achieve their end of increasing gas sales volumes, once baseload sales are clinched, by cutting price for incremental contracts.

While capital costs per volume gas unit can be much lower in pipelines than LNG, this advantage rapidly dissipates once pipeline distances extend to greater length. In the specialized situation for Russian Far East pipeline routes, capital costs for pipelines rise sharply due both to the enormous distances that must be crossed and the specialized features needed in the trunkline for demanding terrain and a severe climate.

By the end-1990s, LNG project promoters had made substantial progress in limiting capital costs substantially. If the recently opened Trinidad LNG project is any indication, further cost cutting, both for capital and operating expenses is on the way. When LNG is compared to long-haul pipelines in harsh climates, such as the Russian Far East, capital cost savings with pipelines are not as substantial as in other markets.

While LNG transport is mobile, LNG supply arrives 'lumpy', in large chunks, which presume the existence of a few major gas offtakers. This is why power generation, rather than

town gas, has traditionally dominated the Japanese LNG import market. In contrast, despite large initial baseload volumes, incremental sales from pipelines tend to be smaller and more easily absorbed in a market. Yet changing commercial practices for LNG, particularly the emergence of ‘regular spot’ sales, and the lifting of destination restrictions of buyer offtake has introduced a substantial degree of volume flexibility in LNG sales. If these two current trends continue to expand LNG sales on an occasional basis, or at smaller than normal cargo size, it may make incremental LNG use as easy as incremental purchase of pipeline gas. But, the nature of the distribution network will play a key role.

No fully integrated international pipeline system exists today in Northeast Asia. Any spot trade in natural gas, therefore, is mainly limited to LNG. The trading of gas on pipeline systems across the Asia-Pacific region is so far limited to Australia, though some trading could eventually begin in South Korea and Thailand, which have national gas transmission networks. Until a national transmission network is established in Japan, such efforts to encourage gas trade through ‘Third Party Access’ to transportation systems will remain limited.

While ‘economy of scale’ is generally believed to be important to both LNG and pipeline projects, LNG appears to benefit from upscaling projects more readily. At times, increasing capacity baseload, to compensate for extra-long carrying distances appears counter productive for pipeline projects, as it puts enormous pressure on project promoters to secure ever larger baseload sales contracts. LNG planning, unlike pipeline planning, has also considered going in the opposite direction – of building LNG complexes, in a modular fashion, that would allow for quick expansion of a project’s overall working capacity, should markets warrant that.

Finally, the concept of vertical integration can work well for LNG, though a ‘showcase’ project has yet to be commissioned in Asia Pacific. International gas export pipelines do not lend themselves easily to such vertical integration. Gas developers can only hope to reap their profits from the provision and transport of gas supply up to a certain point in distribution – whether to a national gas transport network or to an urban reticulation network. Few governments around the world will allow a gas developer to control direct interests from gas production through to the point of final end-user sale, at least for major long-distance trunklines.

The construction of a domestic gas transmission system would do more to assist Japanese companies in seeking lower cost gas deliveries than any other single investment, while – almost incidentally – also help dampen the country’s energy supply concerns by helping to secure new

and easily expandable sources of natural gas –regardless of whether supplies would be spot or long term contract LNG or pipeline deliveries.

The Politics of Future Gas Infrastructure

There are several groups with conflicting interests that make up the Japanese gas sector. LNG importation firms, natural gas distribution companies and power companies have often been in disagreement on matters of basic industry policy. Power companies, led by Tokyo Electric (Tepco) until recently the world's largest private electric utility and still the single largest company importing LNG, have asserted their interests sometimes to the disadvantage of the town gas companies, led by Tokyo Gas and Osaka Gas.

Still all of these companies are entrenched members of status quo policies. Tepco, together with a few other major utilities, dominate power generation in Japan. They are generally centered on the largest urban concentrations of the Kanto plain (Tokyo) and the Kinki region (Osaka) provide the biggest voice in speaking for power companies. Yet town gas companies are similar – Tokyo Gas and Osaka Gas, together with Toho, account for about 80% of all Japanese town gas sales.

Japanese gas users, whether for power generation or town gas, have traditionally clustered around receiving terminals, which for the most part, are concentrated on the East Coast of Honshu and southern Kyushu. Gas distribution networks, to the limited extent that they do exist, are found in the Tokyo and Osaka regions. Northern Kyushu, Southern and Western Honshu (as well as parts of the other two major home islands) only take smaller volumes of LNG that is consumed nearby relatively small and limited regassification plants. Until recently, these more rural areas produced town gas by burning naphtha, condensate or LPG, until MITI pressure reduced this practice.

The diversity of the gas sector and its interest can be seen in the current under-developed state of domestic gas transportation. The two metropolitan areas act as LNG magnets, but are not yet linked. The only gas pipeline of any length transports the limited field output of Niigata across the Japanese Alps to Sendai and then runs south along the coast to the Tokyo metro grid.

It is often said that Japan's rough terrain, expensive real estate and high construction costs have prevented the development of a connected grid. A study by Petroleum Intelligence Weekly in the early 1990's estimated average Japanese cost per kilometer for transmission-sized

(24" or larger) pipelines in urban/suburban areas 5 times that of the US and more than two-thirds higher than Western Europe. But reasons blocking the development of natural gas infrastructure may go beyond these considerations. South Korea has similar terrain and high costs but is progressing quickly on a national transmission system.

A more reasonable explanation is that entrenched participants in the market do not want to see heightened competition.¹ Japanese power companies do not want to see gas companies cooperating by gas volume exchanges and allowing the gas business to grow through easy transport. Many gas companies fear a national grid because they believe that the largest companies, Tokyo Gas And Osaka Gas, will use their control of the major LNG terminals/facilities, to undercut them in their local markets.

Yet the end-users will no longer passively accept automatic pass-on costs, which have made Japanese retail gas and electricity rates among the world's highest. Further, the earlier mentioned twin trends of deregulation and convergence are changing the mindset among utility executives, though progress with some of the more conservative companies has been slow.

Change is already afoot. Town gas companies are entering the power sector. Electric utilities have entered wholesale contracts for regassified LNG and oil refiners are breaking into power co-generation. The emergence of IPPs leaves further room for interfuel and cross sectoral competition. Government guarantees of 'Third Party Access' to power and gas distribution have been made and inevitably will accelerate the pace of change in both power and gas sectors.

Why then, Not China?

While Beijing appears to be interested in importing energy supplies from the Russian Far East, it remains to be seen whether this effort will make commercial, or even political, sense. The question of Chinese investment in Russian gas begs the related query why China would prefer to invest in distant Russian supply before first exploiting its own prolific domestic gas reserves.

Many observers of Sino-Russian gas cooperation have not addressed the basic problems that have so far hampered gas development within China. The most fundamental problem is that

¹ Gas in Japan traditionally was 'Daiymo-nized'. As in the period of the Shogunate, powerful local lords (read, gas companies) journeyed to Edo (Tokyo) to pledge allegiance to the all-powerful Generalissimo, the Shogun (read MITI). These 'Daiymo' varied from extremely large and potent lords, to petty fiefs, but had one thing in common – so long as their loyalty to the Shogunate regime was assured, they could wield virtually unchallenged power within their locality.

the Chinese natural gas market remains bound and gagged by a host of government regulations, including near total price controls for gas production, transportation, wholesale and retail sales. While CNOOC, which produces gas offshore, and approved IPP projects remain outside this all encompassing web of government regulations, CNPC, which controls the rump of Chinese gas reserves and infrastructure in the northern and western sections of China, remains bound. With a wellhead sales price of slightly over 50 cts/MM BTU, it makes little sense for CNPC to actively search for gas, develop finds, or build the necessary transmission infrastructure to bring gas to market. Investments in the gas sector have been made grudgingly and at a rate which assures that the development of a national gas market will be delayed until the very end of this decade, or perhaps post-2010.

China's gas market woes spring not from the lack of a potential domestic gas reserve base, but from structural and regulatory constraints. Until price decontrol is introduced on a national basis, gas development will continue to lag. A large-scale project in Sichuan province, funded in part by the World Bank, aims to overhaul and expand the provincial gas transmission and reticulation system, as well as develop new gas finds in the western half of the region. The quid-pro-quo is that Sichuan first, and the country as a whole later, will gradually bring gas sales prices in line with world levels. While such deregulation is under implementation in Sichuan, there are few signs that the central government is willing to bite the bullet and free gas prices across China. And until that occurs, Chinese gas development on a national scale will lag – natural gas accounts for roughly 2% of China's base energy mix, while it averages nearly 9% in Asia Pacific.

Some idea of the enormous potential that China possesses in a gas resource base can be seen in Tables 8 through 10 below. If either the certified gas reserves of CNPC, or the estimated '2-P' reserves for all of China, are examined, it becomes obvious that China has plentiful known gas reserves within its borders. Excluding non-conventional gas reserves, such as coal bed methane, and without even making a specific effort to explore for gas until recently, China has recoverable gas reserves that exceed India, Bangladesh, Thailand and Brunei, all major gas producers. Some reserve estimates (such as BP's 1999 Statistical Review) put Chinese proven reserves ahead of Australia. Only Malaysia, Pakistan and Indonesia clearly have a larger volume of proven reserves than China - what then happens, when Beijing finally applies itself to establishing a gas sector by biting the bullet of reform?

Table 8. CNPC/China Gas Reserves (In TCF)

	By 1/1/1997	By 9/1/1999
Reserves	12.870	22.336
Revisions	1.441	0.127
Extension Finds	3.144	2.268
Improved Recovery	0.302	0.035
Production	(0.623)	(0.482)
Total	17.134	24.284
Of which: Proved Developed Reserves	- 9.289	- 12.142

Note: Proved developed reserves are only gas reserves proven at fields already developed. Proven reserves also include gas finds that have been evaluated, but where field development has yet to begin.
Source: CNPC; as audited by DeGoyler and MacNaughton.

Table 9. CNPC Proven Gas Reserves By Region

Region	Reserves 9/1999 (TCF)
Gansu (Ordos)	5.8
Sichuan	6.8
Tarim	3.6
Qinghai	2.9
Daqing/Jilin	1.7
Xinjiang (Non-Tarim)	1.2
Other	2.3
Total	24.3

Source: CNPC; as audited by DeGoyler and MacNaughton

Table 10. China - Remaining Recoverable Gas Reserves (As of 1/99)

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Basin/Region	'2-P' Reserves (TCF)
TOTAL ONSHORE	30.6
Junggar	0.5
North China Basin (incl. Shengli, Dagang, Liaohe, Huabei, Zhongyuan, Jidong)	2.2
Ordos	7.1
Qaidam	1.9
Sichuan	14.6
Songliao (incl. Daqing, Jilin)	0.6
Tarim	2.3
Turpan-Hami	1.0
Others	0.4
TOTAL OFFSHORE (CNOOC)	7.3
Gulf of Bohai	0.4
Dongfang	3.1
Jinzhou 20-2	0.3
Pinghu	0.3
Yacheng	2.9
Others	0.3
TOTAL	37.9

Note: Reserves of less than 0.2 TCF excluded.

Sources: Wood MacKenzie, CNPC, Industry, Asia Pacific Energy Consulting Estimates

If we assume that China eventually takes the path of sectoral reform including price decontrol, a further problem looms. Who will pay for and build the much needed gas transmission infrastructure?

Currently, China operates only a handful of gas transmission lines and has only just begun to build urban reticulation in major cities. Recent statements by officials of the State Development Planning Commission confirm national support – and funding for two major transmission lines – the Tarim basin to Shanghai trunkline, which is currently being built in stages, as well as the less ambitious Chongqing-Wuhan transmission line, utilizing newly developed gas reserves in Sichuan.

The country's first major urban gasification program, targeting Beijing (and originally intended to reduce air pollution if China had won the right to host the 2000 Olympics Games) is 2-3 years behind schedule, despite the completion of a gas trunkline by 1998 providing supply from the Shaanxi, Gansu and Shanxi fields to the west of the capital. The lag in completing distribution pipes within the city, as well as pumping and metering stations, has kept the capital's gas use at a minimum, despite gas availability. Bitter bickering has broken out between city, provincial and national governments as to who will fund the program's completion. On a

national scale, the same problem arises – the central government can order the construction of gas infrastructure, but often has been unwilling to fund it.

Who then pays – the municipal, provincial or central governments, the newly established city gas companies, or the national integrated oil/gas companies, such as CNPC and Sinopec? What answer ultimately wins out will have major ramifications – the bill for establishing a basic national gas transport network, as well as gas distribution in major cities, will run to tens of billions of dollars over this decade.

Further limiting the Chinese market for Russian gas imports is the prospects that LNG will supply southern China. The central planning authorities have authorized the import of LNG from foreign sources, with one receiving terminal planned for Guangdong province in the south and another in the eastern seaboard province of Jiangsu, north of Shanghai.

While no LNG exporter has yet concluded with Chinese buyers, Malaysia, Indonesia, Australia, Oman and Qatar are all competing for the first foothold in the emerging Chinese LNG market. It is likely that first imports will begin by 2005, or shortly thereafter, at one or both proposed terminals, and quickly build to an initial 5-8 MM MTA of LNG imports, representing roughly 664-1,062 MM CFD of clean gas supply. While it is possible that a LNG project based on Sakhalin could in the future export cargoes to these coastal provinces, the LNG initiative cuts off these regions as areas of potential gas demand for pipeline imports. This means that an export pipeline, which would have to begin at a minimum of 1,000-2,000 MM CFD of supply capacity, would not have the potential buying interest of a major segment of the Chinese domestic market.

China therefore, is no easy ‘Shangri-La’ market for Russian pipeline exports, at least not in the medium term. The problems to overcome are clear: sector over-regulation, price controls, the need to build national gas transportation, as well as specific urban distribution networks and potential competition from both domestic production as well as imported LNG.

Why Then Not South Korea?

Seoul poses a similar number of problems as a market for Russian pipeline gas exports, though it can always serve (at minimum) as a secondary market for Sakhalin LNG sales.

To begin, while South Korea has substantial gas infrastructure in place, including a national transmission network and two (soon to be three) LNG receiving terminals, the overall size of the South Korean market is too small to support a pipeline export market alone. In 1998 –

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a peak gas demand year, gas consumption totaled slightly more than 1.5 BN CFD, less than China's 1.87 BN CFD, and less than a quarter of Japan's 6.3 BN CFD in gas use. Even under the unlikely scenario that South Korea backed out half of its current and future LNG purchase commitments, and saw gas demand expand by 8% annually through 2005, the national market would be hard pressed to absorb 1-2 BN CFD of pipeline gas by mid-decade.

The second difficulty, and most obvious geopolitical obstacle to the easiest and least expensive overland pipeline route, is the continued existence of a hostile and potentially unstable North Korea. While a pipeline can be routed to South Korea from China to the West, or Japan to the East, either route would add an additional cost in building an offshore pipeline segment, and would be vulnerable to sabotage.

A further potential obstacle to the sales of Russian gas to South Korea is the poor financial health of South Korean trading houses ('Chaebol') as well as energy sector companies. Many of these trading houses have considerable debt on their books and may be reluctant to take on a capital-intensive pipeline investment. Meanwhile, Korgas, the country's sole gas importer, is in the middle of a government-mandated reorganization.

If Sakhalin-II finally commissions an LNG export facility, as currently planned, South Korea would be a likely buyer, though not necessarily providing sufficient demand to support a project on its own.

Policy Implications for Russian Gas Exports

These changes have broad impacts on the future of Russian gas exports. We outline some of the impacts below:

- Lowest price, or cost, will drive decision making rather than 'non-economic' factors. Economic efficiency, rather than government policy, will underpin gas import choices.
- Japan's newly competitive gas/power environment will assure realistic weighing of costs. There will be no repeat of the Japanese-Soviet fiascos of 1970-1990.
- Without improved domestic transport for gas, pipeline imports are almost impossible and LNG imports become more expensive than need be. The key infrastructure support for increased gas use in Japan remains a national gas grid.

- Investment in such a national gas grid is an investment in increased efficiency, more active competition and diversification of gas suppliers. It will not only encourage gas use overall, but will allow natural gas may break out of its current specialized role as peak power generation fuel.
- By making the Japanese market more attractive, a commitment to a national pipeline grid will jumpstart Russian export projects, with Japan as first priority. For pipeline exports this network is an absolute necessity.
- While the cost for a national gas grid will be great, it will cost substantially less than some of the long-distance pipelines proposed even now (i.e. the most recent Mitsubishi plan submitted to the government). We believe that cost estimates for a national gas transportation system will fall substantially once a serious and commercially oriented, detailed study finally is undertaken. It certainly is both more realistic and can have a far greater positive influence on the overall Japanese economy due to multiplier impacts.

Conclusions

- The key to low cost gas supply is the building of a national gas transportation network. It will spark infrastructure spin-off, cut distribution costs sharply and spur pipeline projects aimed at the Japanese market (Ex: South Korea, Thailand).
- Gas supply can never be all LNG or all pipelines. Even developing countries are beginning to realize this, as have developed markets (Ex: India, the US and Western Europe).
- Price is the prime imperative, the 'Primus inter Pares', of judging potential gas supplies, not 'non-economic factors'.

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- Technical and commercial innovation can change price competitiveness of different forms of gas supply and different gas suppliers. We must keep aware of the great changes bubbling through the gas sector.
- Alternative gas uses will become commercial at some time in this decade and change the face of supply economics
- Most of all, Japan should not only think about tomorrow; it should finally act on determining the shape of its future energy imports. Japan has the rare chance, at a time of great change, to shape the overall whole of gas development for Asia Pacific.