

SCOMM

96:22

(7)

HOUSE COMMITTEE REPORT

Date Referred to Committee: January 16, 1996

FURTHER REFERRALS:

Resources
FinanceDate of Committee Action: 2/13/96The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:HJR 54

HOUSE JOINT RESOLUTION NO. 54

FAVOR TRANS-ALASKA GAS SYSTEM & LNG SALES

Encouraging the lessees of Alaska's vast North Slope natural gas reserves to reach agreement to market gas, expressing the legislature's support for an Alaska North Slope (ANS) gas transmission pipeline, and requesting the President of the United States and the Governor of the State of Alaska to publicly support and take action that will help expedite the construction of that system.

recommends it be replaced
with the following committee substitute

CSHJR54

☒ the same title
☐ a new title

☐ additional referral to _____ Committee

☐ attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept)

APPROVES PREVIOUS:

(Dept/Date)

☒ fiscal note(s) DNR

☐ fiscal note(s) _____

☐ zero fiscal note(s) _____

☐ zero fiscal note(s) _____

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>Don Briel</i>			☒	
<i>Betty Damm</i>	☒			
<i>Scott Damm</i>			☒	
<i>Don Rakeley</i>				☒
<i>Scott O'Leary</i>	☒			
<i>W. J. Williams</i>	☒		☒	
<i>Chris Smith</i>	☒			

CHAIR'S SIGNATURE

*Don Rakeley*2-13-96

TRANS-ALASKA GAS PIPELINE:

PARTNERS AND ISSUES

Provided by Yukon Pacific Corporation

PRIMARY PARTNERS:

- 1) **The people of Alaska** - this partner owns the gas reserves on State lands on the North Slope.
- 2) **The major oil companies** - Exxon, BP and ARCO in Prudhoe Bay and Phillips Petroleum, Mobil, Chevron and Exxon in Point Thomson. These companies have leased the rights and committed to produce the State's oil and gas.
- 3) **Yukon Pacific Corporation** - this partner has secured the permits for a trans-Alaska gas line in the congressionally designated pipeline corridor. This permitting process took ten years. They have also obtained an export license for the gas.
- 4) **Walter J. and Ermalee Hickel Foundation** - while Wally Hickel was Governor, he signed over his ownership interests in Yukon Pacific stock to a charitable foundation. This foundation is governed by a board which makes all decisions on allocation of the funds earned from 10% of the profits of Yukon Pacific. The board is chaired by Archbishop Hurley of Anchorage and the allocations are restricted to Alaskan charitable organizations. As state and federal expenditures for social programs are reduced, this foundation could identify and fill funding gaps.
- 5) **The State Legislature and the Governor** - these partners control the State's royalty gas, 12 1/2% of the produced gas which they could commit to this project. The sale of this royalty gas and state taxes are of great interest to State government for the purpose of balancing the state budget.
- 6) **Alaska Native corporations** - these corporations own land near Prudhoe Bay and near the gas pipeline corridor which could contain significant gas reserves. The production of these reserves could be facilitated by construction of the Trans Alaska gas pipeline.

SECONDARY PARTNERS:

- 1) **Alaskan workers** - this project would provide significant employment opportunities to Alaskan workers, estimated at 10,000 workers for initial construction and 600 full time workers during long term operations. Pipeline and facility maintenance would create further jobs as we have seen with the oil pipeline.
- 2) **Alaskan service companies** - this project would provide significant contract opportunities for oilfield, transportation and other associated companies.
- 3) **Alaskan communities** - these partners would benefit from local tax revenues, access to use of the gas along the pipeline corridor. AML has passed a resolution in support, (attached) as have other Alaskan local governments. Waste heat from the liquefaction plant would produce 250 to 300 megawatts of electricity which could be fed through interties to Alaskan communities, reducing their electrical rates.
- 4) **America** - This project would provide significant benefits to American workers in equipment manufacturing, transportation, etc. The export of Alaskan gas to Asian markets would also reduce our trade deficit with these companies.

IS THIS PROJECT COMPETITIVE?

The attached chart compares the cost of an Alaskan gas export project and estimated reserves with other projects which could supply gas to the Asian market. This clearly shows that this project is competitive. While we have the expense of building a pipeline, these other projects have significant development costs in production facilities which already exist at Prudhoe Bay.

This project will require a minimum market commitment of 14 million tons of gas per year to be economically feasible. However, the capacity of the system will be 28 million tons per year which could be produced if additional markets are identified. These additional markets could include facilities to refine value added natural gas products such as petrochemicals in Alaska. Any throughput of over 14 million tons per year further improves the economics of this project.

TIMING:

There exists a window of opportunity to market Alaskan gas in the Asian market to meet their demand requirements opening in 2003 to 2004. If these countries cannot obtain commitments for Alaskan gas, they will be forced to commit marketing agreements and financing to other projects even if they are more expensive. If this occurs, the next opportunity to sell Alaskan gas could be as far out as 2025 to 2030 if ever.

If this project is moved forward now, it would also provide substantial state revenues at a time when the Long Range Fiscal Planning Commission has projected that our reserves will be drawn down and personal and other taxes will have to be considered.

WHAT NEEDS TO HAPPEN TO MOVE THIS PROJECT FORWARD?

- 1) The major producers and Yukon Pacific need to negotiate an agreement to market Alaska's natural gas linked to the pipeline construction schedule. Yukon Pacific has offered and continues to offer to negotiate with the major producers and the state on pipeline ownership, profit sharing and all other issues.
- 2) Final engineering needs to be completed to identify methods for minimizing the cost of pipeline construction.
- 3) Financing needs to be identified. Financing from Asian market sources at lower interest rates could further lower the cost, improving returns to the producers, pipeline owners and the State of Alaska.
- 4) Alaska State government needs to facilitate bringing the parties together to conclude a marketing agreement and to consider committing Alaskan royalty gas to the project.
- 5) A project labor agreement needs to be negotiated to ensure maximum local and native hire.
- 6) The Governor of Alaska, working with the President of the United States needs to continue and to expand their efforts to promote this **American** gas project.

It is clear that the people of Alaska have a large stake in employment, state and local revenues, and access to the gas which this project represents. All efforts should be made to expedite a trans Alaska gas pipeline to meet the 2003 to 2004 Asian market window.

Grass Roots LNG Projects

Cost Comparison

Project	Production (MMTPA*)	Estimated Cost \$ Billions	Cost in \$ Billions per MMTPA	Capital ** per MMBTU
Alaska TAGS	15	13.6	0.91	0.70
TAGS at higher cost	15	15.0	1.00	
Qatargas	6	6.0	1.00	
Natuna Island	15	21.3	1.42	1.00
Sakhalin	6	7.9	1.32	1.00

* million metric tons per annum

** does not reflect capitalized interest, cost of gas, time value of money or operating exp

TAGS Competition is Other Undeveloped Gas Fields in:

	<u>Start-up Date</u>	<u>Annual Volume</u>
▲ Qatar (Qatargas & Rasgas) - Mobil	2005	6-10 MMTA
▲ Indonesia (Natuna Island) - Exxon	2004	15 MMTA
▲ Sakhalin (Russia) - Exxon x2, Marathon/Shell	2004	15 MMTA
▲ Yemen - Exxon	??	
▲ Papua New Guinea - BP	??	
▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

established by Congress be followed and the information and recommendations derived from that process be considered prior to congressional action that would affect those forests.

Congress has passed the National Forest Management Act and the National Environmental Policy Act, which establish an open public process for deciding how national forests should be managed. This process should be used to guide the congressional decision-making process.

5) Effect of National Policies on Forest-Dependent Communities

- The League urges the Alaska Legislature and the Governor to work with the congressional delegation and federal resource-management agencies to help broaden their understanding of the adverse impact of national policies on Alaska's forest-dependent communities. (11/ 93)

4. Oil, Gas, and Mineral Resources:

a. Arctic Oil Reserve (formerly Arctic National Wildlife Refuge (ANWR) - The League urges the Congress of the United States to open the Coastal Plain of the Arctic Oil Reserve to environmentally responsible oil and gas exploration, development, and production. The League urges the State of Alaska to redistribute federal mineral revenue sharing funds to local governments, and strongly supports the 90-10 split as required by the Statehood Act.

b. Exploration and Development - The League encourages the State of Alaska to promote environmentally responsible oil, gas, and mineral exploration and development that is not detrimental to Alaskan fisheries.

c. Export of Oil - The League urges Congress to lift the ban on the export of North Slope crude oil. (11/ 92)

d. North Slope to Valdez Natural Gas Pipeline - The League strongly endorses the construction of a natural gas pipeline and associated liquefied natural gas (LNG) facilities at the very earliest possible date.

In order to meet the Asian market need, the League encourages all potential participants in this vital project to direct future efforts towards using approved environmental permits and export authorizations which allow construction to proceed in the existing, Congressionally approved north-south transportation corridor. The League recognizes that the only market for this major undeveloped resource will open in Asia shortly after the year 2000 and that strong competition from other potential suppliers on the Pacific Rim and the Middle East exists to meet this demand. The League, therefore, strongly

By: Dan LaSota
Introduced: 1/25/96

RESOLUTION NO. 96-009

A RESOLUTION SUPPORTING HOUSE JOINT RESOLUTION NO. 54 PENDING IN
THE LEGISLATURE OF THE STATE OF ALASKA PERTAINING TO THE
DEVELOPMENT OF THE TRANS-ALASKA GAS PIPELINE AND LIQUID NATURAL
GAS SALES

WHEREAS, HJR 54 has been introduced in the Alaska State Legislature and has been referred to three committees; and

WHEREAS, HJR 54 , in part, calls for the Alaska State Legislature to "respectfully request the North Slope natural gas lessees to intensify their efforts to establish satisfactory contractual relationships for transportation and sale of Alaska North Slope Gas to Pacific Rim purchasers as soon as possible"; and

WHEREAS, the Assembly has recently adopted Resolution 95-081 calling for the Legislature to withhold financial incentives from North Slope Oil producers until they make Alaska North Slope Gas available for sale; and

WHEREAS, the Borough believes that development of the Trans-Alaska Gas Pipeline through the existing pipeline corridor is essential to the future economic health of the State of Alaska; and

WHEREAS, the Borough believes that it is also essential that labor for any project, especially of this scope, come from the skilled and ready work force that already exists in the State of Alaska; and

WHEREAS, the language of HJR 54 as it was introduced does not contain references to local hire or specify the desired location of the proposed Trans-Alaska Gas Pipeline.

NOW, THEREFORE, BE IT RESOLVED that the Fairbanks North Star Borough Assembly respectfully urges passage of HJR 54 with appropriate consideration given to Alaska hire and locating the project through the existing pipeline corridor.

BE IT FURTHER RESOLVED that copies of this resolution shall be sent to the Honorable Tony Knowles, Governor, State of Alaska, the Commissioner of Natural Resources, and members of the Alaska State Legislature.

Congress of the United States
House of Representatives
Washington, D.C. 20515
November 4, 1994

The Honorable William J. Clinton
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

We are writing to urge you not to attend the signing of the Natuna Sea natural gas agreement between the Exxon Corporation and the government of Indonesia.

Production in America's domestic oil and gas industry is at its lowest level since the Arab oil embargo. More than 430,000 jobs have been lost.

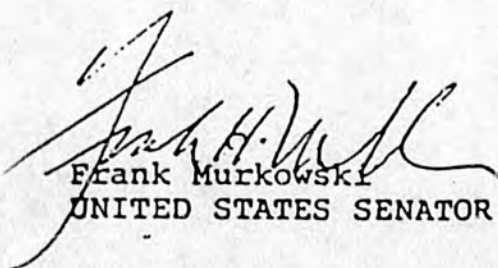
Proven natural gas reserves of more than 37 trillion cubic feet are waiting to be developed on Alaska's North Slope. The development of these reserves has the potential to create 30,000 American jobs immediately and generate \$500 million in Federal tax revenues. The trade deficit -- particularly with Japan -- would fall by as much as \$4 billion.

Exxon already owns 40 percent of the natural gas on the North Slope of Alaska. The Trans-Alaska Gas pipeline does not require any further licensing or approval and would be built in an existing pipeline corridor. It would greatly benefit from the support of your Administration, support which you have provided in the past for this clean, environmentally sound energy source.

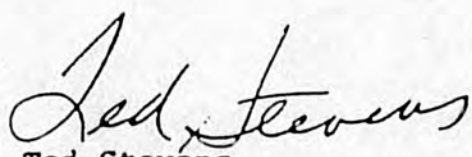
We ask that you not promote the export of American jobs by attending the signing of this agreement. The natural gas resources are readily available in America, and they can be developed in a far safer and more environmentally sound manner by our domestic industry.

We ask that you give your strong support to the development of Alaska natural gas instead.

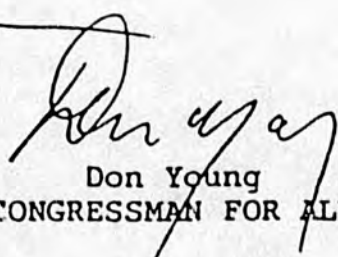
Cordially,



Frank Murkowski
UNITED STATES SENATOR



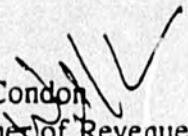
Ted Stevens
UNITED STATES SENATOR

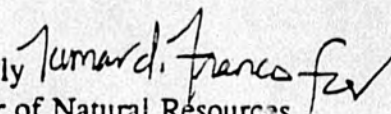


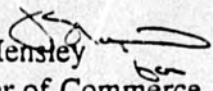
Don Young
CONGRESSMAN FOR ALL ALASKA

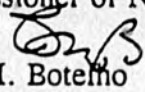
Memorandum
State of Alaska

To: Tony Knowles
Governor

From: Wilson L. Condon 
Commissioner of Revenue

John T. Shively 
Commissioner of Natural Resources

William L. Hensley 
Commissioner of Commerce
& Economic Development


Bruce M. Botelho
Attorney General

Date: January 22, 1996

Subject: Commercialization of North Slope Gas - What Should the State Be Doing?

I. INTRODUCTION.

What should the state government do to promote the project to pipe Alaska North Slope natural gas to tidewater, liquefy it, and tanker the liquefied natural gas (LNG) to customers in Japan, Taiwan and South Korea? The Departments of Revenue, Natural Resources, Commerce and Economic Development and Law have prepared this briefing paper to address this question. The three major North Slope oil producers (Arco, BP, and Exxon), and the Yukon Pacific Corporation (YPC), were consulted in the preparation of this paper.

Alaska North Slope proven natural gas reserves are very large: in the range of 35 trillion cubic feet (tcf). They include Prudhoe Bay at 26 tcf, Point Thomson at 3 to 5 tcf, and Kuparuk, Lisburne, and Endicott, together at 2 to 6 tcf. The amount of energy in these gas reserves is

equivalent to 6 billion barrels of oil - the amount of current remaining developed oil reserves on the North Slope.

Since 1970 various interested firms have continuously studied the possibility of commercializing these large North Slope gas reserves. First came the Gas Arctic Project of the early 1970's (a pipeline through the Arctic Refuge and up the McKenzie River to the mid-continent). Then followed the El Paso project of the mid-1970's (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to California). Next came the Alcan Project of the late 1970's and early 1980's (a pipeline to Fairbanks and then down the Alcan Highway to the mid-continent - some of the southern Canadian portions of this project were actually constructed). This was followed by the proposed Trans Alaska Gas System project (TAGS) in the early 1980's that has now evolved into the project proposed by YPC today (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to the Far East). During the 1980's and 1990's, while the TAGS sponsors were promoting their project to deliver Alaska LNG to the Far East, some of the Prudhoe Bay producers continued to study projects to deliver North Slope gas to the North American mid-continent. Recently, however, the major North Slope producers have clearly shifted the focus of their ANS gas commercialization efforts to the Far East.

Here's where things sit today. The producers recently released their findings on a proposed project that would market Alaska LNG in the Far East. Representatives of the major North Slope producers then visited potential customers in Far East markets. Representatives of YPC have just completed another of their many Far East marketing trips. Further, Phillips, a relatively minor

Prudhoe Bay producer with significant interests in a yet undeveloped North Slope gas and condensate field, Point Thomson, has recently proposed to commence the project by marketing gas from that field to expedite commencement of a North Slope to Far East LNG project.

At today's energy prices and projected construction costs, the economic feasibility of the proposed Alaska LNG project appears doubtful. Minimally, either increases in gas prices or decreases in projected construction costs must occur to make the project economically viable. If constructed, the potential revenues to the state over the life of the project under the current tax and royalty fiscal regime will be much smaller - by at least a factor of 10 - than the revenues the state will receive from North Slope oil developments over the life of those projects. However, as North Slope oil production continues its decline, proposals to commercialize the vast natural gas reserves on the North Slope inevitably draw increased attention. North Slope gas would make some contribution to state revenues, thereby somewhat offsetting the revenue loss of declining oil production. Further, many environmentalists contend that developing North Slope gas is much more environmentally responsible than further North Slope oil development.

We recommend the state address several issues now to enhance the chances that interested firms - including the North Slope lessees - will construct a North Slope gas project for three reasons. First, new marketing opportunities may soon open. Second, long lead times will be required to construct the project. Third, the competition from other countries to capture the gas marketing opportunities in the Far East are and will continue to be formidable.

We recommend you designate a working team from the pertinent executive departments to accomplish the following:

1. Determine if any modifications to the terms of the state's fiscal regime applicable to ANS gas production would significantly enhance the economic feasibility of the proposed project;
2. Carefully evaluate the costs and benefits of the potential modifications to the state's fiscal regime that would significantly enhance the economic feasibility of the proposed project;
3. Determine if there are any modifications to the federal tax structure pertaining to this proposed project the state could responsibly promote that would significantly enhance the economic feasibility of the proposed project;
4. Determine and pursue actions to facilitate federal action on permits and licenses needed for the proposed project;
5. Determine what actions the state could take with respect to its options to take its royalty share of North Slope gas production in-kind that would promote the construction of the project;

6. Determine what actions the state could take with respect to its royalty-in-kind options to maximize state benefits from the proposed project;
7. Determine and pursue actions to assist in marketing ANS gas to would-be customers in the Far East;
8. Assist in interesting would-be investors, particularly those from the Far East destination market countries, to commit to the project;
9. Evaluate whether the state should or should not invest in the proposed project;
10. Work with the Point Thomson working interest owners who have apparently expressed an interest in providing large volumes of gas for the proposed project well before 2010, the date the Prudhoe Bay producers have indicated as "most likely" for the commencement of gas deliveries from the Prudhoe Bay reservoir;
11. Work with the Prudhoe Bay producers to better understand the effect that large scale gas sales will have on future oil production from the Prudhoe Bay reservoir;
12. Evaluate the environmental considerations pertinent to the differing routes and terminal locations for the proposed pipeline project;

13. Work with the producers and YPC to ascertain what other steps the state might responsibly take to facilitate this project; and
14. Determine whether there are any other feasible commercialization options, including:
 - Marketing the gas in the Lower 48;
 - Converting gas on the North Slope to hydrocarbons that are liquid and can be transported in the TAPS pipeline; or
 - Generating electricity on the North Slope and using high efficiency transmission lines to move the electricity to market.

II. FACTORS INFLUENCING THE COMMERCIALIZATION OF NORTH SLOPE GAS.

Five major factors currently determine the feasibility of the large scale commercialization of North Slope gas. They are:

- The cost of developing the gas delivery system relative to expected gas prices
- The demand for the gas in the Far East markets and competition among potential supplies of LNG
- The pipeline economic disadvantage in competing for a place in the market
- How the sale of the gas would affect Prudhoe Bay liquid production
- The availability of an alternative North Slope gas supply prior to full scale Prudhoe Bay

gas availability

1. Cost Relative to Expected Gas Prices

Developing the transportation system to move North Slope gas to the Far East market will be very expensive. Here is what will be needed:

- Gas conditioning plant (approximately 10% of total cost)
- Pipeline to tidewater (approximately 40% of total cost for a Valdez route)
- LNG plant and marine terminal (approximately 25% of total cost)
- A fleet of LNG tankers (approximately 25% of total cost)

Both the producers and YPC currently estimate that the project would cost \$15 billion. There may be opportunities to reduce the cost by \$3 billion through infrastructure sharing, more efficient pipeline construction methods, larger LNG liquefaction trains, and a more economic ship design. The producers claim it would cost \$100 million for a detailed engineering study to assess whether significant savings are now possible. The producers differ in their assessments of the likelihood that they will soon actually undertake such a study.

Infrastructure sharing includes:

- Use of the Prudhoe Bay compression facilities, camps and power generation for the gas conditioning plant

- Conversion of some of the TAPS pump stations to compressor stations, and using the oil pipeline workpads and state highways for the pipeline
- Use of the Valdez marine terminal facilities, civil work and loading berth for the LNG plant¹

Pipeline construction advances include Arctic application of state-of-the-art ditching machines, use of high strength pipe, and pipe laying rates that are much faster than those used at the time TAPS was constructed.

Larger LNG liquefaction trains² (larger than currently available) can reduce per unit liquefaction costs.

In addition, the producers have been analyzing additional savings from pipeline routes to the northwestern Alaska coast at either Wainwright or Kivalina. These routes avoid mountains and are less than half the distance to Valdez. They would, however, require ice-breaking LNG tankers, which have never operated in pack ice before. By reducing the high fixed cost of the pipeline, the western route would afford the project the opportunity to commence operations in smaller stages and thus enhance the start-up economics of the proposed project. The staging advantage is discussed in more detail in Section II(3) below. The producers are still studying the

¹ There is some question as to whether an LNG plant located very close to the oil facilities might violate exclusion zone requirements for LNG siting established by the U.S. Department of Transportation.

² A train is an individual liquefaction and shipping unit.

relative advantages and disadvantages of the western routes.

On an overall project basis, the minimum cost efficient size of the project appears to require a sale and delivery of 2 billion cubic feet (bcf) per day. This results in annual deliveries of 14 million metric tons of LNG - the unit of measure used in the Far East LNG markets.³ The project requires a ten year lead time to achieve full operation; five years for construction, and five years to ramp-up to full production.

LNG is sold in the Far East markets on a per million British Thermal Unit (mmbtu) basis. Generally, pure natural gas - methane - has an energy content of about 1,000 btu per cubic foot; that is one million btus per thousand cubic feet (mcf). However, both the North Slope producers and YPC maintain that the North Slope gas would be "spiked" with ethane, propane, and butane to increase the energy value per unit of volume and thus to enhance its value.⁴ The producers estimate the gas used for the proposed project would be spiked to 1,170 btu per cubic foot for the first ten years, and 1,100 thereafter. In the economic analysis we have done for this paper, we have assumed an average energy content of 1,150 btu per cubic foot of natural gas for the duration of the project. This "spiking" enhances the value of the gas by 15%.

³ To put the likely size of a gas line project in context with the current North Slope oil production operations, a two billion cubic feet per day gas line would carry the energy equivalent of about 350,000 barrels per day of oil.

⁴ Ethane, propane and butane are more complex hydrocarbons often classified as "NGL's" at ordinary temperature and pressure. These substances are, however, gases. They have significantly higher energy content per cubic foot than methane.

If this project is constructed, how much will it cost to ship ANS gas to the Far East? If the project (1) costs \$15 billion (both the producers' and YPC's current estimate), (2) operates for 25 years with daily throughput of 2 bcf, and (3) earns a 4% after-tax real rate of return (11.4% nominal), then it will cost \$5/mmbtu to ship the ANS gas from the North Slope to the Far East.⁵ This cost includes a 50 cent/mcf operating cost and a 30 cent/mcf cost pertinent to the state's 20 mill oil and gas property tax.⁶ LNG today is selling for about \$3.50/mmbtu in the Far East, 30% lower than the \$5.00/mmbtu projected cost for transporting gas from the North Slope of Alaska to that market. At this price, these economic projections yield a negative wellhead value of \$1.50/mmbtu for the project. Put otherwise, based on these projected costs, a threshold gas price of \$5.00/mmbtu in the Far East markets is necessary to yield a zero wellhead value at the North Slope. It is obvious that if these costs are correct, then higher wellhead values would be required to induce investors to construct this project.

If the gas price remains at \$3.50/mcf in the destination market, how would it be possible to raise the wellhead value? By reducing the capital costs for the project by one third either by significantly lowering the rate of return on the project or by greatly reducing construction costs or

⁵ This assumes 75% debt, 25% equity, with a nominal rate of return of 12.9% on the equity and a rate for the debt two percentage points below the return on equity. YPC has suggested that 75-25 is a likely debt/equity ratio for the project. We have assumed equity and debt rates of return that may not accurately reflect those that would be obtained for financing the project. We believe, however, that a real after-tax rate of return of about 4% for the project is the lowest return investors would accept. See Appendix A for a more detailed discussion of the economic analysis pertinent to this project.

⁶ This 50 cent/mcf operating cost has been suggested as the likely operating cost by both the producers and YPC.

both.⁷

What about the LNG price in the Far East? For this proposed project to be economically feasible, that price would have to increase to at least \$5.00/mmbtu if the project and capital costs cannot be significantly reduced.

LNG in Japan currently commands a 15% premium over crude oil on an energy equivalent basis.⁸

This premium arises from several factors:

- Gas burns much more cleanly than fuels derived from crude oil.
- Gas powered units such as gas turbine electric generators are more efficient and require lower capital costs than their oil powered cousins.
- Recognizing the high costs of LNG projects, parties in the Far East markets have negotiated premiums for LNG with respect to crude oil at low oil prices, and corresponding discounts at high oil prices.

It follows that a \$5/mmbtu LNG price is equivalent to a price of \$25 per barrel (bbl) for crude oil.

⁷ Pursuant to the settlement agreement governing the TAPS tariff, the TAPS oil pipeline has been permitted to earn a 6.4% after-tax real rate of return (15% nominal). The gas pipeline should be less risky than TAPS. A strong argument can be made that a 4% after-tax real rate of return will be required for this project. See Appendix A for a more detailed discussion.

⁸ Currently crude oil prices in Japan are between \$17 and \$18 per barrel. There are 5.8 times as many btus in a barrel of crude oil as an mcf of gas. Thu the following equation -- $5.8 \times 3.5/17.5 = 1.16$ -- tells you that a btu of energy derived from LNG selling for \$3.50/mmbtu costs 16% more than a btu of energy derived from crude oil selling for \$17.50/bbl.

In other words, given the current relationship between oil prices and gas prices, oil prices would have to be \$25/bbl in order for North Slope gas to provide a 4.1% real rate of return on the proposed transportation investment and leave a zero North Slope wellhead value. Currently crude oil sells for about \$17-18/bbl in Japan. If LNG did not command a premium over crude oil, the equivalent oil price in the Far East would have to be \$29/bbl.

Appendix A sets forth a more detailed discussion of the economics of the proposed ANS LNG project.

2. Far East Demand for LNG and Competition Among Potential Suppliers.

Current LNG consumption in the Far East is about 55 million metric tons per year (mmt).⁹ LNG consumption has been increasing at 6% per year since 1980, and is expected to grow between 5% and 10% annually through 2010. However, exponential growth cannot continue in this market indefinitely. Therefore, we have used a 6% annual growth rate for LNG demand in the Far East for planning with respect to this proposed project. Six percent annual growth would result in LNG consumption in the Far East markets of about 100 mmt in 2005 and 130 mmt in 2010.

There is no unsatisfied demand in the Far East LNG markets before the year 2000. Contracts sufficient to fill all the anticipated increases in the Far East demand through the end of this decade are already in place.

⁹ The proposed North Slope to Far East gas transportation project operating at 2 bcf per day would supply 14 mmt - about 25% of the current supply. The 55 million tons of LNG consumed each year in Far East markets is the daily energy use equivalent of about a million and a half barrels of oil per day - about the volume that currently flows through TAPS.

The LNG market opportunities are significantly different than the market opportunities for crude oil. There are few LNG buyers. Because of the large up-front investments required for an LNG project, and to reduce risk, long term contracts must be in place before the producers, the buyers or YPC would commence construction of the ANS gas transportation project.

The competition for selling LNG to the Far East is considerable. The following table shows, by country, existing supplies.

CURRENT SUPPLY TO FAR EAST LNG MARKET	
Location	Gas Supply (mmt)
<i>Alaska (Cook Inlet)</i>	1
<i>Abu Dhabi</i>	5
<i>Brunei</i>	7
<i>Indonesia</i>	27
<i>Australia</i>	7
<i>Malaysia</i>	8
Total	55

Capacity to supply an additional 8 mmt from Malaysia and 6 mmt from Qatar is currently under construction. Relatively low cost expansion of existing LNG facilities in Australia, Indonesia, and Malaysia of 5 mmt each (a total of 15 mmt) are under serious consideration.

The following table summarizes the existing supplies, supplies currently under construction, and available low cost expansion opportunities at existing LNG plants:

CURRENT AND NEAR TERM LNG SUPPLIES TO FAR EAST MARKET	
Source	Gas Supply (mmt)
Existing Supplies	55
New Plants Under Construction	14
Low Cost Expansion Opportunities Available	15
Total	84

Including the North Slope, new grass roots projects could add the amounts reflected in the following table.

LARGE NEW LNG PROJECTS PROPOSED TO SUPPLY THE FAR EAST MARKETS	
Location	Gas Supply (mmt)
Alaska	14
Australia	13
Indonesia (Natuna)	15
Oman	6
Papua New Guinea	6
Qatar	15
Sakhalin	10
Yemen	5
Total	84

The Qatar, Oman and Yemen projects appear to be in the advanced planning stages. The Indonesian project is the giant Natuna field, for which Exxon is the proposed operator. Given the large size of both the proposed Natuna and Prudhoe Bay projects, there is - at most - room for

only one of these as a source of supply in the Far East LNG market in the near term. At full development it would appear that the proposed Natuna project is more expensive per mcf delivered than the proposed North Slope project. However, the Natuna project can be staged in increments: staging the North Slope project severely affects its economics, especially with a Prince William Sound terminal.

The gas reserves in most of the countries supplying the Far East LNG market are very large and are expanding. Much of this gas was found in the course of exploring for oil. These gas supplies are more than ample for current markets. If deliberate exploration for gas ensued, it is likely that these gas reserves would increase substantially. The following table shows 1993 year-end gas reserves for selected countries.

CURRENT RESERVES OF MAJOR FAR EAST MARKET LNG SUPPLIERS	
Country	Reserves (tcf)
Abu Dhabi	177
Australia	100
Indonesia	89
Malaysia	72
Qatar	236
Total	674

Alaska has about 35 tcf in discovered reserves on the North Slope.

If demand in the Far East LNG market continues to grow 6% annually, the demand in 2005 will

be 100 mmt. Given apparent lower cost supplies of 84 mmt from existing, under construction, and low cost expansion sources, this leaves 16 mmt for new grass roots suppliers. At a 14 mmt minimum, an Alaskan project would have to capture 88% of the projected unfilled demand in 2005 to be able to fit into the market. Using the same assumptions, the demand in 2010 would be 130 mmt. Of this, 46 mmt would be available for grass roots projects for which construction has not yet commenced; a new Alaska project coming on line in 2010 would have to capture 30% of this projected unfilled demand.

3. **The Pipeline Economic Disadvantage in Competing for a Place in the Market.**

Of all the grass roots projects, Alaska is the only one which requires a major pipeline to bring the gas to tidewater. Nearly half of the total anticipated construction cost for the proposed Alaska project is attributable to the pipeline. The pipeline is a burdensome one-time, up-front cost that places the proposed Alaska project at a competitive disadvantage.

The proposed Alaska gas project only achieves the economies of scale which make it feasible at its full 14 mmt proposed capacity. While many of the competing projects also have comparable per unit costs, they attain those costs at much lower production levels. This is particularly true for the projects proposed in Qatar, Oman and Yemen. The need to cover the costs for the one-time, up-front pipeline investment is what makes the proposed Alaska project different. It may only be economic if its sponsors can begin the project at full capacity. Placing 14 mmt at once in the Far East LNG market may be difficult, given that multiple buyers will need to simultaneously commit

to the project.

Increments to existing projects have a "nimbleness" advantage to big new baseload, grass roots projects. Suppose there is just enough room in the marketplace in 2005 for the proposed Alaska project - 14 mmt. If any small addition to an existing project captures *any* part of the 14 mmt demand in the marketplace, the Alaska project may not be able to make a go of it. Furthermore, proposed increments to already existing LNG projects in most cases have a per unit cost advantage over the per unit costs of new grass roots projects.

Projects without major pipelines do not necessarily require as high a proportion of their investment up front. Ships and liquefaction facilities can be added in increments. Pipeline capacity cannot easily be added in increments. Therefore, projects which require a high proportion of investments in pipelines must capture bigger increments in the developing markets to be economic. This necessarily provides any project without a substantial pipeline leg an advantage. For this reason the producers have looked - and will continue to look - carefully at the proposed western route. Even though the tanker costs, the offshore loading terminal costs and the risk of supply disruptions pertinent to the proposed western route would be higher, reducing the proposed project's pipeline cost might make it possible to achieve competitive costs at reduced production levels. The western route project might well be economic with initial volumes well below 14 mmt. Obviously if the required initial amounts are smaller, it would be much easier to fit such a project into the market.

The problem created by the large minimum size of the North Slope project is further exacerbated by the number of buyers that would be required to consume the proposed project volume. Most likely the need to find buyers for this new large volume all at once will require sales to several customers in more than one country, and the sale to any one customer is likely to be dependent on sales to all other customers. This could make marketing the ANS gas a complicated endeavor.

4. The Role of Gas in Prudhoe Bay Liquid Production.

Currently the highest and best use of the gas in the Prudhoe Bay reservoir is to facilitate the production of liquids. Gas reinjected into the reservoir increases liquid recovery as a result of several different recovery mechanisms. When does it make sense to sacrifice liquid recovery for gas production? The answer is: when substituting gas production for liquid production results in a more valuable stream of total outputs from the reservoir. Today the highest value is achieved by maximizing liquid production from the North Slope because the liquid streams are so much more valuable than the likely flow of gas. As liquid production rates decline, however, a time may come when the potential gas stream will become more valuable than that of the liquids sacrificed by sending the gas to market. The volume of liquids sacrificed declines every year the project is delayed.

The liquid recovery mechanisms at Prudhoe Bay all depend directly or indirectly on reservoir pressure. Production is facilitated by higher pressure, which pushes the oil out of the rock. The pressure in the reservoir depends mainly on the amount of oil, gas and water in the reservoir. Because of its compressibility, reinjection of produced gas is the primary mechanism used to

maintain pressure in the Prudhoe Bay reservoir. Injection of sea water and produced water are also major elements in the Prudhoe Bay reservoir pressure maintenance program.

A Major Gas Sale (MGS) of Prudhoe Bay gas would permanently remove the gas from the Prudhoe Bay reservoir and consequently accelerate the decline in reservoir pressure. The pressure in the Prudhoe Bay reservoir is currently declining at 30 pounds per square inch (PSI) per year. When production began in 1977, the Prudhoe Bay reservoir pressure was 4,200 PSI; today it is 3,400 PSI. The producers estimate that an MGS would triple the rate of annual decline to 90 PSI unless new steps were taken to mitigate some of the loss. There is no disagreement that in the short run (next 8-10 years) accelerated reservoir pressure decline would result in less ultimate oil production. There is some disagreement as to the timing and total volume loss associated with the proposed gas pipeline project, and on the manner in which the loss might be mitigated. However, there appears to be no guaranteed, low cost way to mitigate these losses.¹⁰

Thus the optimal date for an MGS depends on the expected performance of the Prudhoe Bay reservoir as well as predicted oil and gas prices. The longer the expected benefits from gas

¹⁰ Where maintaining high reservoir pressure is necessary to maximize liquid recovery, in some locations around the world the natural gas may be valuable enough to justify marketing it and replacing it in the reservoir with another gas - usually nitrogen cryogenically recovered from the atmosphere. The producers at Prudhoe Bay have considered this option, but the projected wellhead value of Prudhoe Bay gas has always been too low to justify it. Similarly, the Prudhoe Bay producers have considered attempting to mitigate pressure losses through expanded waterflood; they have concluded that would be destructive to gravity drainage in other parts of the reservoir and to oil well hydraulic performance. Finally, the Prudhoe Bay producers have considered injecting water into the apex of the gas cap (as opposed to the oil rim); this step, they believe, could eliminate much of the liquid recovery achieved by the vaporization of residual liquids in the gas cap that occurs with gas cycling.

pressure maintenance and gas cycling, the later the optimal date for commencing an MGS. However, very late in the life of the field, losses in liquid production as a result of an MGS become quite small relative to the value of a gas sale. In addition, the economies of scale realized by producing and selling both oil and gas from the same facilities are such that an MGS would probably extend the time during which oil production would continue to be economic. To the extent an MGS would extend field life, liquid losses would be negated. Likewise, there could be some accelerated oil recovery benefits realized due to increased gas handling capacity resulting from an MGS after 2015.¹¹

The producers now believe that 2005 would be the earliest appropriate time to possibly begin deliveries pursuant to an MGS. They contend that 2010 is the "most likely" time they would commence deliveries under an MGS. The producers have selected the year 2005 as the earliest appropriate time for three reasons:

- The liquid loss after 2005 from diverting gas for commercialization may be de minimis.
- The producers believe 2005 will be a good time to enter the markets (see section on demand above).

¹¹ As the field matures more and more gas is produced with each barrel of oil. Currently approximately 7.5 billion cubic feet of gas are produced each day with the oil at Prudhoe Bay. Oil production capacity is constrained by the ability to process and reinject this large volume of associated gas. Depending on the North Slope equipment scheme ultimately installed, some gas handling capacity is freed up as some gas is diverted for sale. Increasing the gas handling capacity at Prudhoe Bay would certainly result in acceleration of oil recovery, but probably not in significant additional oil recovery. Gas handling capacity probably cannot increase, however, until the waterflood/EOR project ends (around 2015), because of the bottleneck caused by the limited gas dehydration capacity of the flow stations/gathering centers.

- The intra-field compensatory agreements between the oil rim and gas cap owners will mostly be completed then.¹²

Regarding the liquid losses, the producers now estimate that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of the Prudhoe Bay field. They estimate a loss of 100 million barrels of oil for a 2010 sale. The significance of those losses will depend on the relative prices of oil and gas as well as actual operation and development decisions made over the next ten years. For instance, if we assume the wellhead values of Prudhoe Bay oil currently forecast by the Department of Revenue, then the gas must be worth at least 40 cents per mcf at

¹² The Prudhoe Bay field is unitized with two participating areas: the oil rim and the gas cap. BP owns a relatively higher percentage of the oil rim (51%), and Arco and Exxon own relatively higher percentages of the gas cap (42% each). The gas cap currently has 70% of the gas resources and the oil rim 30%. Thus BP still owns 25% of the overall gas reserves, and has no apparent motive for being disinterested in commercializing the Prudhoe Bay gas absent negative impacts on oil production. Pursuant to an order from the Alaska Oil and Gas Conservation Commission, the working interest owners are currently attempting to unitize the two properties.

In 2005 the fuel gas supply option, whereby the oil rim owners are obligated to secure a certain volume of gas from the gas cap owners to fuel field operations, lapses.

Also, major gas sale delay credits cease in 1997. These are reimbursements of payments of the oil rim owners to the gas cap owners for early investments made by the gas cap owners in anticipation of an early gas sale. The oil rim receives some of their already-paid reimbursements back if there is an MGS before 2005.

In addition, through another agreement, in 2005 the gas cap owners will beg to supply half the gas needed to make miscible injectant for enhanced oil recovery operations. Currently the oil rim owners supply all of the gas. This will release oil rim gas for sale.

There are other incentives in the unit operating agreements for the oil rim owners to support an MGS. Upon an MGS, the gas cap owners will pick up significantly higher proportions of the operating costs of the field. Further, once an MGS occurs the oil rim owners get allocated proportionally more liquids.

the wellhead to offset the value of the barrels lost as a consequence of a gas sale commencing in 2005. To offset the loss of barrels for a gas sale commencing in 2010, the gas wellhead value must only be 15 cents/mcf. The likely level of gas prices is discussed more fully above. These "loss" estimates assume a five year ramp-up to 2 bcf of gas per day sold from Prudhoe Bay. Appendix C describes the derivation of these loss projections.

5. Point Thomson - A Potential Supply Source Prior to Prudhoe Bay Gas Availability?

Phillips Petroleum has recently suggested the use of gas from the Point Thomson field to jump start the proposed ANS gas project. The Point Thomson reservoir, a large gas and gas condensate reservoir which overlies a very thin oil rim, is located 60 miles east of Prudhoe Bay. The Department of Natural Resources estimates the reservoir contains 3 tcf of recoverable gas reserves; some producers have estimated the reservoir contains 5 tcf. The reservoir is included in the Exxon-operated Point Thomson Unit.

Phillips, one of the Point Thomson working interest owners - which has interests with co-lessees Mobil and Chevron (together these companies are often referred to as MPC with respect to their jointly leased North Slope properties) - is willing to commit its gas now to the YPC project. Together MPC owns the leases which cover 47% of the surface acreage included in the unit and claim to have a higher percentage of the recoverable reserves in the unit. Phillips believes it may be able to supply up to 1 bcf per day of natural gas from this reservoir for up to five years. If

supplying this amount was indeed feasible, early Point Thomson production could assist in making it possible to commence a North Slope gas project before significant volumes of gas are required from the Prudhoe Bay reservoir. Early gas sales from Point Thomson could allow a gradual phase in of gas sales from Prudhoe Bay.

There are many technical questions that would have to be addressed with respect to this Point Thomson proposal. The Point Thomson reservoir is a very high pressure retrograde condensate reservoir; that means liquids drop out of the gas recovered from the reservoir when the pressure of the gas drops. Under the Phillips proposal would the gas be kept at high pressure and moved to Prudhoe Bay for liquid recovery? Can gas production at the volumes Phillips proposes occur without dropping reservoir pressure to the point where there are significant volumes of liquid lost in the reservoir? Since the Point Thomson reservoir pressure is so high (almost right at 10,000 PSI), doesn't it make sense to produce the reservoir until the pressure drops to the 4,000 - 5,000 PSI range before reinjection and cycling commence to avoid the very high reinjection costs that a 10,000 PSI reservoir would require? If the answer to that question is "Yes," doesn't that suggest that the Phillips proposal may have merit in promoting the development of the Point Thomson resource?

The cost of bringing Point Thomson reserves to the Prudhoe Bay area would, of course add to the cost of the pipeline portion of the project.

III. OTHER CONSIDERATIONS.

1. What's in it for the State.

On the revenue side, under the applicable fiscal regime the State will receive severance taxes, royalties and property taxes from the gas project. The property tax will be the most significant. With \$11 billion of assessed property (which excludes the ships), the 20 mill Oil and Gas Property Tax will yield \$220 million per year initially; the tax revenue from this tax will decline with the depreciation of the property. Half of the revenue from this tax will go to cities and boroughs. This tax will affect the economics of the project two ways. First, because it applies during the construction period, it is a large additional up-front cost imposed on the project; second, once the project is operating, the annual property tax bill will add 30 cents per mcf to the operating costs of the project on an equivalent amortized basis.¹³

If the netback from the Far East yielded a 50 cent/mcf wellhead value, taxes and royalties would total \$60 million annually. Based on current cost projections, a 50 cent wellhead value would be achieved only if LNG prices were \$5.50/mmbtu in the Far East (and oil prices were \$27.50/bbl - see discussion in Section II(1) above). Under the current applicable state corporate income tax statute, the state would receive about \$30 million per year in corporate income taxes from the project. Thus, if world energy prices increase by 60 percent, the state could expect about \$190 million per year in taxes and royalties from the project during the early years of operation. That amount would, of course, decline as the value of the gas pipeline depreciated.

¹³ The \$5/mmbtu LNG cost discussed on page 10 in Section II(1) includes the amount of this tax.

Construction of a pipeline to transport gas from the North Slope to Valdez would create 10,000 construction jobs and 600 permanent operational jobs. A pipeline following the TAPS corridor would also make natural gas available to Fairbanks, Valdez and other smaller communities along the route.

An MGS would enhance the economics of other gas deposits on the North Slope.

In addition, as discussed above, the commercialization of gas late in the life of the Prudhoe Bay reservoir would probably enhance oil production economics as well.

2. The Role of Yukon Pacific.

YPC has been active in promoting an ANS LNG project that would use the TAPS route to Valdez. YPC is a subsidiary of CSX Corporation, a conglomerate with holdings concentrated in transportation. CSX owns one of the nation's largest railroads, and it owns Sealand. As a consequence of other business involvements, CSX has had significant experience in marine transportation and in certain aspects of the gas business.

YPC has spent large amounts of time and money obtaining several of the major permits necessary to transport and market gas. These include:

- Presidential finding for the project.
- Project-wide environmental impact statement.

- Federal right-of-way.
- State right-of-way.
- Department of Energy authorization for export of gas.
- Final environmental impact statement for a liquefaction plant at Anderson Bay near Valdez.
- FERC order granting authorization for LNG facility siting.

Although the degree to which some of these permits may be exclusive is questionable, there is considerable time, expense, and expertise invested in their procurement.

The North Slope producers clearly have the right to utilize the Prudhoe Bay gas for oil production as long as they are not wasting the gas. They also have the right to market the gas. If Prudhoe Bay gas commercialization yielded a higher net present value than utilizing the gas in the field to maximize oil production, the state might be able to take action to compel the producers to market the gas. In the absence of some sort of successful state action to compel Prudhoe Bay gas sales, YPC must depend solely on the oil rim and gas cap owners to obtain Prudhoe Bay gas.

There are disagreements among YPC and the producers. YPC has argued that based on the public statements made by the producers, there is no reason the gas should not be currently available for sale. YPC has also argued that: (1) the Prudhoe Bay producers will not sell the gas because of intra-owner conflict in the field resulting from the disparate oil/gas ownership; (2) specific companies are improperly advancing their own interests either in the field or in other places in the

world with a decision not to sell even though, according to YPC, selling would maximize the overall benefits from the Prudhoe Bay Reservoir; and (3) the State should take action to force the Prudhoe Bay producers to enter into an MGS. We believe there are sound engineering and economic reasons behind the current plans for short term and mid term gas use at Prudhoe Bay.

IV. WHAT SPECIFIC ACTIONS HAVE THE VARIOUS PARTIES URGED THE STATE TO CONSIDER?

Following are some of the ideas interested parties, including YPC and the producers, have urged the state to study:

1. Taking action to force the Prudhoe Bay producers to sell their Prudhoe Bay gas;
2. Using the state's royalty-in-kind share of Prudhoe Bay gas to promote the proposed project;
3. Marketing the state's royalty-in-kind share of Prudhoe Bay gas along with the producers to promote the project;
4. Agreeing to commit the state's royalty-in-kind share of Prudhoe Bay gas to the project at a fixed (and possibly discounted) price;
5. Altering the 20 mill Oil and Gas Property Tax so it does not impose another large front-end cost on the project; and
6. Altering the state's basic fiscal arrangements so that the state takes an equity interest in the entire project up stream from the LNG tankers, and, in exchange, agrees to forego royalties, severance tax and the 20 mill Oil and Gas Property Tax.

These questions should all be addressed in conjunction with the implementation of the 14 recommendations set forth on pages 4, 5 and 6 of this briefing paper.

APPENDIX A

Alaska North Slope Gas Transportation System Feasibility

The Relationship Between Required Rate of Return and Far East Market LNG Prices

At today's energy prices and projected construction costs, the proposed North Slope gas project is economically feasible if and only if the project's would-be investors are willing to accept a fairly low rate of return for the project. Consequently, it is unlikely these firms will be willing to provide the necessary financing to construct the project unless they are convinced of one or more of the following:

1. The project is, in fact, a very low risk project;
2. The price of LNG in the Far East is likely to increase significantly in the next few years thereby providing a much higher return for the proposed project than would be available at current prices; or
3. The project construction costs will be significantly lower than the current estimate of \$15 billion.

An investor's willingness to invest depends on the balance of anticipated risk and reward from the investment. Citizens are willing to invest in passbook savings accounts with their relatively low returns (approximately 4.5% today) in part because the U.S. government insures that depositors will get their money back virtually any time they want it. On the other hand, high-risk investments command higher returns to compensate investors for the risk. For example some

computer venture start-ups are currently yielding returns near 25% to their investors. For large projects, a firm's willingness to invest will depend on the perceived risk and reward of the project compared to other opportunities for investing available funds. A firm will invest in projects with the highest anticipated return balanced against the anticipated risk. Projects compete for financing based on their perceived risk and rates of return.

For example, to assure a 7% nominal rate of return (1.5% after-tax real), the proposed North Slope LNG project would need a \$3.65/mmbtu price floor in the Far East and a zero wellhead netback (the current Far East LNG price is \$3.50/mmbtu). But, one can get this same return by making a riskless investment in the government bond market.

We do not know precisely the risk would-be investors will perceive in the proposed North Slope gas transportation project. Will the project face a significant marketing risk? It is highly likely that if the project is constructed there will be little risk that the project will not have guaranteed customers. The contracts for LNG sales in the Far East would almost certainly be in place prior to construction commencement. How about the risk of very low energy prices? Far East LNG contracts are almost universally pegged to the price of oil and other energy supplies, but if oil prices fall below a certain level, the gas prices may be subject to renegotiation. To insure a 2% after-tax real rate of return, this project needs a \$3.90/mmbtu price floor in the Far East. What happens if the project costs \$18 billion rather than \$15 billion? Then the very low return realized at today's energy prices would become negative.

Will the perceived risk of this proposed project require a return equal to or greater than: (1) a thirty year treasury bond; (2) a AA corporate bond; (3) a BBB corporate bond; (4) the return equity investors currently receive for investing their funds in developed, stable utility companies; or (5) the return earned by investors in the Trans Alaska Pipeline System (TAPS) as a consequence of the tariff settlement agreement?

The charts that follow use "after-tax real" rates of return. It may be helpful to explain briefly the relationship between "after-tax real" and "nominal" rates of return. After-tax real rates of return are the returns realized after making an allowance for inflation and income taxes.

The after-tax real rate of return is the difference derived by subtracting the inflation rate from the product of the nominal rate of return multiplied by the difference obtained by subtracting the tax rate from one. It may be easier to understand this equation by expressing it algebraically as follows:

$$\text{After-Tax Real Rate of Return} = [\text{Nominal Rate of Return} \times (1 - \text{Tax Rate})] - \text{Inflation Rate}$$

To work through an example, take the applicable 30 year U.S. Government Bond rate, which currently provides a return of 6%. Further, assume an effective combined corporate income tax rate of 38.0% (35% federal and 4% composite state)¹ and an inflation rate of 3%.

¹ Since the state tax is deductible for federal taxes the combined rate is 38%.

After-Tax Real Rate of Return = [Nominal Rate of Return * (1 - Tax Rate)] - Inflation Rate

$$= [0.06 * (1 - 0.38)] - 0.03$$

$$= 0.0072, \text{ or } 0.72\%$$

The following table compares the nominal returns in today's marketplace with the corresponding after-tax real returns. Again the basic assumptions are: a 38% effective combined corporate income tax rate and a 3% inflation rate.

NOMINAL AND REAL RATES OF RETURN		
	Nominal Rate of Return	Real After Tax Rate of Return
30 Year Treasury	6.0%	0.72%
AA Corporate Bond	6.8%	1.22%
BBB Corporate Bond	7.4%	1.59%
Rate of Return Received by Equity Investors in Developed, Stable Utility Projects	10.5%	3.51%
Rate of Return Selected for Illustrative Purposes for the Proposed ANS Gas Transportation Project	11.4%	4.07%
Rate of Return Permitted TAPS Owners under TAPS Tariff Settlement	15.0%	6.40%

On the basis of this information, is a 4% after-tax real rate of return required to attract investors to the proposed ANS gas transportation project? Is it too high? Is it too low? The following

analysis uses that rate of return for illustrative purposes. There are many good arguments that this 4% after-tax real rate of return is in the neighborhood of the return investors would require to invest in the proposed North Slope LNG project. One could certainly make the case that the proposed Alaska to Far East LNG project would be less risky than TAPS. There is virtually no risk that the gas cannot be produced from the reservoir. There would be a set contract in place guaranteeing a price. Construction of the TAPS project proved that such a large Arctic project can be done. The builders of the proposed LNG project can profit from the TAPS construction experience.

Figure 1 below shows the price LNG must receive in the Far East to yield various after-tax real rates of return on the proposed project.

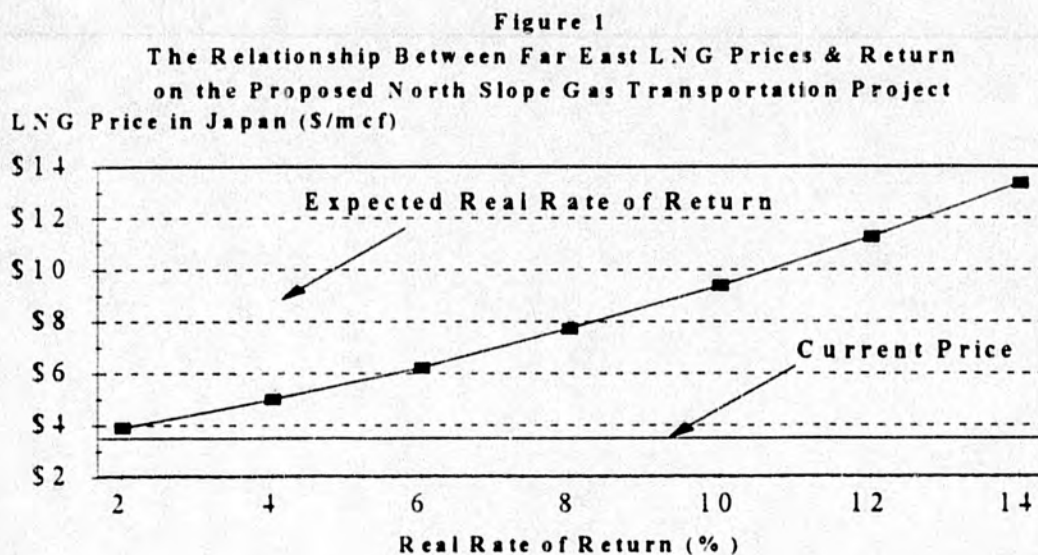


Figure 1² shows that to obtain a 2% after-tax real rate of return on the proposed \$15 billion transportation project with a twenty-five year project life, the price of LNG in the Far East would have to be \$3.90/mmbtu; at this price the project would yield a zero wellhead value. The current price in Japan is \$3.50/mmbtu. This equates to an after-tax real rate of return on the project with a zero wellhead value slightly under 2%. Using the same assumptions, Figure 1 shows that a 4% after-tax real rate of return with a zero wellhead value requires a \$5.00/mmbtu sales price in the Far East.

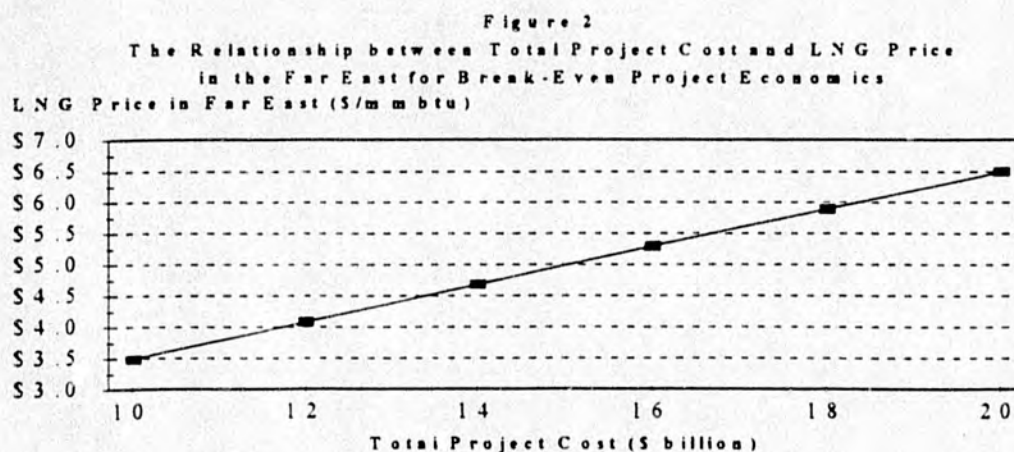
In addition to using equity to finance part of the project, the investors will probably make arrangements to issue debt to finance a portion as well. For many reasons, the interest rates on the debt issued to construct the proposed LNG project will probably be lower than the return required to attract equity capital.

For the analysis in this briefing paper, we have assumed the project would be financed by 75% debt and 25% equity. The debt/equity ratio could vary widely. We have assumed a nominal rate of return on the equity portion of the investment of 12.9%; for the debt we have assumed a nominal rate of return 2% below the equity rate. These assumed rates of return may not accurately reflect those that would be obtained for financing the project. We believe, however, that a combined real after-tax rate of return of about 4% for the project is the lowest return investors would accept.

² These figures include a \$0.50/mcf operating cost and a \$0.30/mcf 20 mill oil and gas property tax payment.

At a 4% real after-tax rate of return on the project, a price of \$5.00/mmbtu in the Far East would be required to yield a zero wellhead value. If the project were 100% debt financed, the required Far East price would be \$4.50/mmbtu. If the project were 100% equity financed, the required Far East price would be \$6.40/mmbtu.

Figure 2 depicts the break-even gas price required in the Far East at different project construction costs. For this comparison the assumed financing arrangements are: (1) 75% debt and 25% equity; (2) the equity portion requires a 5% real after-tax rate of return; (3) the debt portion of the project is financed at a rate 2% less than the nominal equity return; and (4) the inflation rate over the life of the project is 3%. At the current project cost estimate of \$15 billion, the required destination price in the Far East is \$5.00/mmbtu. Figure 2 shows that it would take a one-third reduction in project construction costs, to \$10 billion, for the current price in the Far East, \$3.50/mmbtu, to yield a zero wellhead value on the North Slope.



APPENDIX B

Technical Description of Gas Line Rate of Return Model

The gasline rate of return (ROR) model computes a levelized per mcf amount that computes break-even transportation costs for the entire system, including the tankers, at a specified rate of return. The model uses a cost of service methodology. The levelized cost is the total discounted cost divided by the total discounted volume. There are six cost components: depreciation, operating costs, property tax, income tax, interest, minimum cents per mcf severance tax¹, and after tax margin (profit or the return on base equity investment).

The after-tax margin is the product of the nominal rate of return and the undepreciated equity capital. The income tax allowance is the product of the tax gross-up factor and the after tax margin. The tax gross-up factor is that number which when multiplied by the after tax margin yields the state and federal corporate income tax amounts given the cost of service for the given year.²

In this model we assumed no inflation for the system components and 3% for the economy as a whole. We have also assumed 75% debt and 25% equity, with the cost of debt at two percentage

¹ The minimum cents per mcf severance tax is 6.4 cents. We have assumed an economic limit factor of 0.8.

² Given a state corporate income tax rate of 9.4% and a federal corporate income tax rate of 35%, the tax gross-up factor is:

$$(.094 + (.35 \times (1 - .094))) / (1 - (.094 + (.35 \times (1 - .094)))) = 0.6981$$

points below the nominal rate of return.

Other key assumptions include:

- \$15 billion in capital costs
- \$11 billion in non-ship capital subject to the property tax
- 2 million mcf per day for 25 years
- 5 year ramp-up
- \$0.50/mcf operating costs
- 1.1 mmbtu to mcf ratio

The model is shown on the following table.

Gasline ROR Model

Operating cost	0.5
Capital cost	15000
% non-slop	0.733333333
Years	25
Real Equity ROR	5
Nominal Equity ROR	12.903
Nominal Debt ROR	10.903
Tax Gross-up factor	0.6981
Percent Equity	0.25
Percent Debt	0.75
ITTT Adj	1.15
Return on Capital due costs	1101

Year	Gas Volume (mcf/yr)	Gas Volume (bbl/yr)	Operating Cost	Depreciation	Undepreciated Amount - for Property Tax	Property Tax	Depreciation (for return)	Undepreciated Amount - for return	Return on Base (after tax margin)	Income Tax Allowance	Interest	Severance Tax	Cost of Service	Discount Factor	Discount Cost	Discount Volume
0	0.1	116	71	6000	15000	220	191	4851	626	437	1132	7	3195	0.911	3195	117
1	0.8	292	116	6000	11100	211	191	4657	601	419	1132	11	3123	0.811	2851	211
2	1.2	418	219	6000	11800	202	191	4463	576	402	1132	20	3151	0.718	2518	321
3	1.6	581	292	6000	11200	191	191	4269	551	385	1132	26	3180	0.634	2275	482
4	2	710	365	6000	12600	185	191	4075	526	367	1132	31	3508	0.579	2032	421
5	2	710	365	6000	12000	176	191	3881	501	350	1132	31	3156	0.513	1773	371
6	2	710	365	6000	11100	167	191	3687	476	332	1132	31	3105	0.451	1517	312
7	2	710	365	6000	10800	158	191	3493	451	315	1132	31	3154	0.402	1350	291
8	2	710	365	6000	10200	150	191	3299	426	297	1132	31	3103	0.356	1177	260
9	2	710	365	6000	9600	141	191	3105	401	280	1132	31	3251	0.316	1026	210
10	2	710	365	6000	9000	132	191	2911	376	262	1132	31	3200	0.280	895	201
11	2	710	365	6000	8400	121	191	2716	351	245	1132	31	3149	0.248	780	181
12	2	710	365	6000	7800	111	191	2522	325	227	1132	31	3097	0.219	679	160
13	2	710	365	6000	7200	106	191	2328	300	210	1132	31	3046	0.191	592	142
14	2	710	365	6000	6600	97	191	2134	275	192	1132	31	2995	0.172	515	126
15	2	710	365	6000	6000	88	191	1940	250	175	1132	31	2943	0.152	449	111
16	2	710	365	6000	5400	79	191	1746	225	157	1132	31	2892	0.135	390	99
17	2	710	365	6000	4800	70	191	1552	200	140	1132	31	2841	0.120	340	87
18	2	710	365	6000	4200	62	191	1358	175	122	1132	31	2789	0.106	295	77
19	2	710	365	6000	3600	53	191	1164	150	105	1132	31	2738	0.091	257	68
20	2	710	365	6000	3000	41	191	970	125	87	1132	31	2687	0.083	223	61
21	2	710	365	6000	2400	35	191	776	100	70	1132	31	2635	0.071	191	51
22	2	710	365	6000	1800	26	191	582	75	52	1132	31	2584	0.065	168	48
23	2	710	365	6000	1200	18	191	388	50	35	1132	31	2533	0.058	146	42
24	2	710	365	6000	600	9	191	194	25	17	1132	31	2481	0.051	127	37
Total															25828	1196

levelized mcf amt	5.71
lttu adj	1.15
break-even price (\$/mmbtu)	4.99

APPENDIX C

Technical Explanation for Estimating the Value of Lost Oil

Currently the highest and best use of gas at Prudhoe Bay is to facilitate oil production. The producers have estimated that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of Prudhoe Bay, and a 2010 sale would result in a 100 million barrel loss.

The significance of those losses depend on the relative values of oil and gas. Because of the time value of money these values are dependent on the time profile of the losses. The projected time profile of these losses is shown below.

The loss in oil reserves is a function of cumulative gas removed from the reservoir over time. A uniform series time rating function relates the loss of an mcf of gas to both an immediate loss of oil and a loss of oil through time.

We estimated time series of reserves losses for both 2005 and 2010 sales. These losses were multiplied by the respective predicted oil price for the subject year and discounted at 10%. The total discounted losses were divided by the total discounted volume of gas. This represents the wellhead price of gas that would make the producers indifferent to the reserve losses.

For a 2005 sale the gas price is \$0.40/mcf, and for 2010 the price is \$0.15/mcf. The derivation of these amounts is shown on the following tables.

Value of Lost Oil - 2005 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price (\$/bbl)	Oil (bbls)	Disc Oil Loss
2005	146	0.953	139	16.61	1	16
2006	292	0.867	253	17.03	2	30
2007	438	0.788	345	17.43	3	41
2008	584	0.716	418	17.91	4	51
2009	730	0.651	475	18.75	6	73
2010	730	0.592	432	19.34	7	80
2011	730	0.538	393	19.81	8	85
2012	730	0.489	357	20.59	9	91
2013	730	0.445	325	21.15	10	94
2014	730	0.404	295	21.83	12	106
2015	730	0.368	268	22.42	13	107
2016	730	0.334	244	23.03	14	108
2017	730	0.304	222	23.65	15	108
2018	730	0.276	202	24.29	17	114
2019	730	0.251	183	24.94	18	113
2020	730	0.228	167	25.62	19	111
2021	730	0.208	151	26.31	20	109
2022	730	0.189	138	27.02	21	107
2023	730	0.171	125	27.75	23	109
2024	730	0.156	114	28.50	24	107
2025	730	0.142	103	29.27	25	104
2026	730	0.129	94	30.06	26	101
2027	730	0.117	86	30.88	28	101
2028	730	0.106	78	31.71	29	98
2029	730	0.097	71	32.57	30	95
			5679		384	2258
					value	0.40

Value of Lost Oil - 2010 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price (\$/bbl)	Oil (bbls)	Disc Oil Loss
2010	146	0.953	139	19.34	0	0
2011	292	0.867	253	19.81	1	17
2012	438	0.788	345	20.59	1	16
2013	584	0.716	418	21.15	2	30
2014	730	0.651	475	21.83	2	28
2015	730	0.592	432	22.42	3	40
2016	730	0.538	393	23.03	4	50
2017	730	0.489	357	23.65	4	46
2018	730	0.445	325	24.29	5	54
2019	730	0.404	295	24.94	5	50
2020	730	0.368	268	25.62	6	57
2021	730	0.334	244	26.31	6	53
2022	730	0.304	222	27.02	7	57
2023	730	0.276	202	27.75	7	54
2024	730	0.251	183	28.50	8	57
2025	730	0.228	167	29.27	8	53
2026	730	0.208	151	30.06	9	56
2027	730	0.189	138	30.88	9	52
2028	730	0.171	125	31.71	10	54
2029	730	0.156	114	32.57	11	56
2030	730	0.142	103	0.00	0	0
2031	730	0.129	94	0.00	0	0
2032	730	0.117	86	0.00	0	0
2033	730	0.106	78	0.00	0	0
2034	730	0.097	71	0.00	0	0
			5679		108	882
				value		0.16

YUKON PACIFIC CORPORATION

Presentation to the House Oil and Gas Committee and the House Resources Committee

February 1, 1996

TAGS—"What's in it for the State"

We would like to start with one simple message. The "value" of TAGS to the State of Alaska is positive and any delay to bringing the gas line to fruition erodes the "value" of the project. Whatever value you choose to assign to the project, a five year delay reduces the present value of those future cashflows by 38%¹, or if the project starting today is worth \$1.00, delaying those cashflows 5 years reduces the project's value to 62¢. So if you leave with nothing else today, please understand that sooner is better than later and delay is costing the State of Alaska.

We do not intend to schedule out the various revenue streams accruing to the State of Alaska as a result of TAGS, but conceptually, let's identify some potential sources.

Values from the Well-head

- Royalty
- Severance
- Incremental Corporate Income Tax

Values from the Transportation System

- Property Taxes
- Corporate Income Taxes

Other Potential benefits

- Personal Income Tax—Construction/Operation

- Increased and/or accelerated PBU oil production through additional gas handling capacity and extending field life.

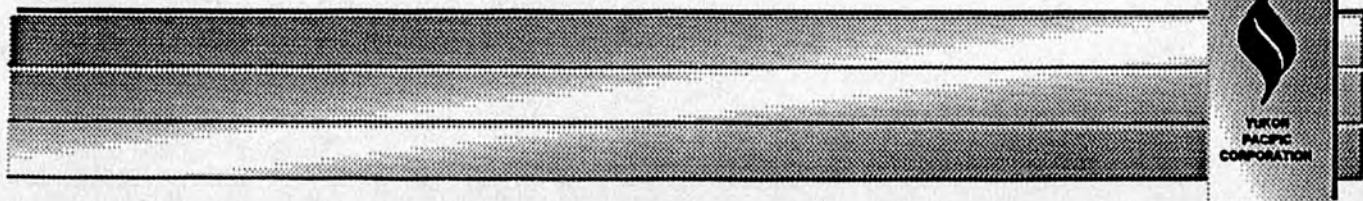
- Increased exploration activity for oil & gas on the North Slope.

- New development opportunities: Point Thomson Unit

- Gas supplied along the pipeline corridor

- Power generation from waste heat at the LNG facility.

¹Discount factor calculated as $1/(1+i)^N$, where $i = 10\%$ and $N = 5$ years, then $DF = (1/(1+.1)^5)$, or $DF = .62092$. $1 - .62092 = .37908$



Now, let's make sure everyone has a firm picture of where we are and what we are asking from the State of Alaska.

During the previous hearings, testimony was provided which seemed to imply that given certain assumptions, TAGS economics are marginal. Well that's a "glass is half empty approach". We are here to tell you that the "glass is half full". And better yet, we believe that the glass can be filled to the top.

- The market is there and will invest.
- Any potential oil loss will be more than off-set by the benefits of TAGS and the PBU's reluctance to let gas come off the slope before 2005 can be addressed using Point Thomson.
- WE NEED ACCESS TO THE GAS to secure our place in this market window.

The State of Alaska owns the gas in the ground. The producers have an obligation to produce that gas. The producers are saying that ANS gas commercialization is not economic. They don't get to decide. They can choose whether or not to invest in the transportation system but they can not decide whether or not the gas should be "produced". This should be in the hands of the State of Alaska.

The producers (and the State) for that matter have no risk. If YPC is successful in securing market commitments and proceeding with TAGS, every one wins. The oil companies earn a netback, the State of Alaska gets the various benefits of TAGS and YPC, and its partners and the State of Alaska will have a world class LNG project which will be a cornerstone of Alaska's economy for 50 years.

If we are wrong, the fall back position is that proposed by the oil companies (i.e., sometime around 2010). No one will have lost any ground. But remember, time is money and we are all wasting both.





FEB 12 1996

217 Second Street, Suite 200 ■ Juneau, Alaska 99801 ■ Tel (907) 586-1325, Fax (907) 463-5480

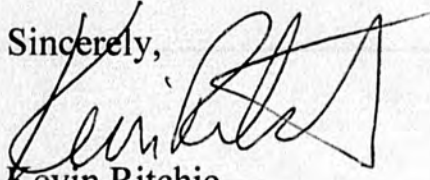
February 9, 1996

Representative Norman Rokeburg, Chair
House Oil and Gas Committee
Alaska House of Representatives
Room 110 State Capitol
Juneau, Alaska 99801-1182

Dear Representative Rokeburg:

We are writing to you in support of HJR 54 regarding the North Slope's natural gas reserves to market gas and develop a gas transmission line. Although the Alaskan Municipal League has not taken a specific position on HJR 54, I have attached an excerpt from the League's policy statement regarding municipal support for the development of a North Slope to Valdez Natural Gas Pipeline. The League strongly endorses the construction of natural gas pipeline and associated liquefied natural gas facilities at the earliest date.

Sincerely,



Kevin Ritchie
Executive Director

Enclosures

cc: Paul Fuhs
Legislative Committee, Land Use, Resources, & Economic Development

ALASKA MUNICIPAL LEAGUE

Economic Development and Resource Management

1996 Policy Statement

established by Congress be followed and the information and recommendations derived from that process be considered prior to congressional action that would affect those forests.

Congress has passed the National Forest Management Act and the National Environmental Policy Act, which establish an open public process for deciding how national forests should be managed. This process should be used to guide the congressional decision-making process.

5) Effect of National Policies on Forest-Dependent Communities

- The League urges the Alaska Legislature and the Governor to work with the congressional delegation and federal resource-management agencies to help broaden their understanding of the adverse impact of national policies on Alaska's forest-dependent communities. (11/ 93)

4. Oil, Gas, and Mineral Resources:

a. Arctic Oil Reserve (formerly Arctic National Wildlife Refuge (ANWR) - The League urges the Congress of the United States to open the Coastal Plain of the Arctic Oil Reserve to environmentally responsible oil and gas exploration, development, and production. The League urges the State of Alaska to redistribute federal mineral revenue sharing funds to local governments, and strongly supports the 90-10 split as required by the Statehood Act.

b. Exploration and Development - The League encourages the State of Alaska to promote environmentally responsible oil, gas, and mineral exploration and development that is not detrimental to Alaskan fisheries.

c. Export of Oil - The League urges Congress to lift the ban on the export of North Slope crude oil. (11/ 92)

d. North Slope to Valdez Natural Gas Pipeline - The League strongly endorses the construction of a natural gas pipeline and associated liquefied natural gas (LNG) facilities at the very earliest possible date.

In order to meet the Asian market need, the League encourages all potential participants in this vital project to direct future efforts towards using approved environmental permits and export authorizations which allow construction to proceed in the existing, Congressionally approved north-south transportation corridor. The League recognizes that the only market for this major undeveloped resource will open in Asia shortly after the year 2000 and that strong competition from other potential suppliers on the Pacific Rim and the Middle East exists to meet this demand. The League, therefore, strongly

encourages all potential participants in the project, including the State of Alaska, to immediately convene to develop a unified proposal to present to Asian LNG buyers so that all Alaskans will directly benefit from this unique opportunity. This may facilitate other projects in other communities.

e. **Strategic Minerals** - The League supports the state's efforts to identify and advocate the availability of minerals in Alaska for strategic purposes.

f. **Mineral Development** - The League supports private development of state-owned minerals.

5. **Impact:**

a. **Waste Disposal** - The League encourages the state to adopt and maintain acceptable standards concerning waste disposal from processing of all resources.

b. **Full Utilization of Resources** - The League encourages the state to adopt and maintain acceptable standards concerning utilization of all natural resources.

c. **Navigable Waters of Alaska** - The League encourages the State to establish state jurisdiction over all aspects of management of navigable waterways inside the three-mile state coastal water zone in the entire State of Alaska. (11/ 93)

6. **Human Resources:**

a. **Alaska Hire** - The League supports and encourages, within the confines of the Constitution and human resource limitations, any efforts on the part of the Governor and the legislature to implement a local hire policy, particularly within state government, which would not preempt municipal policies and ordinances.

b. **Training Incentives** - The League supports the development of incentives that would encourage contractors and other employers to train and apprentice local workers and would encourage their employment.

c. **Rural Housing Assistance Program** - The League urges expansion of the Rural Housing Assistance Program as currently structured under the Alaska Housing Finance Corporation.

SOUTHWEST ALASKA PILOTS ASSOCIATION

P.O. Box 977
Homer, Alaska 99603

Tel: (907) 235-8783
Fax: (907) 235-6119

February 8, 1996

Representative Norm Rokeberg
Chairman, House Oil and Gas Committee

Dear Chairman Rokeberg:

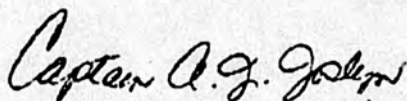
The Southwest Alaska Pilots Association supports HJR 54, which encourages the legislature and administration to do all they can to help support construction of a trans-Alaska pipeline system to Valdez for the export of Alaska North Slope natural gas.

The Southwest Alaska Pilots currently provide pilotage services to tankers calling on Prince William Sound and Cook Inlet. We view construction of a natural gas transportation system as an important work opportunity for us in safely piloting LNG tankers into Alaskan waters. We currently pilot the LNG ships into the Phillips Petroleum facility in Kenai. LNG is a clean cargo, and in our experience, the ships are well maintained and professionally operated.

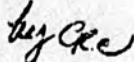
This project is also important for all the people of Alaska because of the jobs it would create, the state revenues it would generate, and the positive effects it would have on Alaskan communities near the pipeline corridor which would have access to the gas.

Thank you for your efforts and the efforts of other legislators and administration officials in helping bring this project about.

Sincerely,



Captain A.J. Joslyn
President, SWAPA



TONY KNOWLES
GOVERNOR



P.O. Box 110001
Juneau, Alaska 99811-0001
(907) 465-3500
Fax (907) 465-3532

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

February 12, 1996

The Honorable Norman Rokeberg
Chair, House Oil and Gas Committee
Alaska State Legislature
State Capitol, Room 110
Juneau, AK 99811-1182

Dear Chairman Rokeberg:

As you may remember, several weeks ago I directed four members of my cabinet to assess the steps necessary to develop, transport, and market Alaska's enormous natural gas reserves. As this process continues, I have requested Department of Revenue Commissioner Condon to take the lead on behalf of my Administration.

House Joint Resolution 54 by Representative Gene Kubina has the support of my Administration because it will play a significant role in encouraging meaningful dialogue between the various parties.

A project of this magnitude would have a tremendous impact on the state's economy, providing many jobs and much needed state revenue. I urge your favorable consideration.

Sincerely,

A handwritten signature in dark ink, appearing to read "Tony Knowles".

Tony Knowles
Governor

Tentative List of Witnesses For HJR 54

Date: 13 February '96

Where: House Committee on Oil & Gas

1. Fairbanks North Star Borough Assembly
Mayor Samson or Dan Lesotta, Assembly
2. Juneau Borough Assembly
Dwight Perkins, Assembly
3. Alaska Truckers Association
Frank Dillon
4. Alaska Teamsters
Barbara Huff or Jerry Hood
5. North West Pilots Association
Paul Fuhs
6. Yukon Pacific Corporation
Wayne Lewis

COMMERCIALIZING ALASKA'S NORTH SLOPE GAS

PRIMARY POINTS OF LEGISLATIVE HEARINGS PREPARED BY YUKON PACIFIC CORPORATION

Joint legislative hearings were held by the House Oil and Gas Committee and the House Resources Committee concerning commercialization of Alaska's North Slope gas on February 1st and 2nd in Juneau, Alaska. On February 1st the Committees heard a presentation from Yukon Pacific and on the 2nd they heard a presentation from the three major producers on the North Slope - Exxon, Arco and BP. Commissioner of Revenue, Wilson Condon also addressed the Committees on the 2nd to give his perspective on the economics of the project and projected revenues to the state and local governments. Similar, although less extensive hearings were held by the Senate Resources Committee in Anchorage on January 29th.

Listed below are the primary points of these presentations, so that the reader can understand the various perspectives, points of agreement, and problem areas which must be addressed for this project to move forward. This is written in executive summary format. Comments are offered when they provide clarification and are identified as such.

Anyone wishing to hear the actual tapes of the hearings can obtain them from the Committees. The hearings were also broadcast and recorded by KTOO as part of their "Gavel to Gavel" coverage. Copies of the videotapes can be obtained from them at 586-1670.

This should not be viewed as a debate. It should be viewed as an opportunity to identify the necessary next steps to make this project a reality.

February 1st, 1996 Yukon Pacific Corporation

- 1) Jeff Lowenfels, President and CEO of Yukon Pacific (YP) began his presentation by outlining the history of YP's participation in this project, primarily their efforts to secure all the permits and an export license (which took 10 years) and their efforts to market Alaska's gas in the Asian markets. (56 trips in 23 months) The people of Alaska have a major stake in this project. They own the gas on the North Slope, and

also have an interest in jobs, state revenues, and access to the gas in the pipeline corridor.

2) Korea, Taiwan and Japan are very interested in purchasing Alaskan gas. However, while YP has the permits, they do not have an agreement from the producers to market the gas leased from the State on the North Slope.

YP sees a unique market window for Alaska gas opening in 2003-2004. (See appendix I) Several other proposed "grass roots" or newly developed projects in other countries are competing for this window. (See attached appendix II) YP sees this as a perishable opportunity because even though demand for gas in Asia will continue to rise, if new projects get in ahead of Alaska, it will be cheaper to expand these other projects than to bring Alaskan gas into the market at a later date. This could push Alaskan gas sales into 2025-2030 if ever. Comment: The issue of timing market entry is the greatest point of disagreement between YP and the producers. (See producer point 8)

3) YP believes that an agreement between the producers on payment between themselves for reinjected gas which calls for resolution of accounts in 2005 (the Issues Resolution Agreement), is an impediment to beginning deliveries of Alaskan gas in the 2003-2004 window. Point Thomson, leased by Phillips, Mobil, Chevron and Exxon, could provide early delivery of gas to TAGS if the Prudhoe producers cannot supply gas until 2005 or later. Comment: The state cannot commit its royalty gas from Prudhoe Bay to TAGS since it is not considered "produced" until it leaves the production unit.

4) Alaska is competitive with other grass roots projects. (See appendix III) While the Alaska project must build an 800 mile pipeline, the other projects must create all the production infrastructure which already exists at Prudhoe Bay. For instance, the Natuna project in Indonesia has a production rate of 15 million tons/year and a minimum cost of \$20 billion. TAGS has a design production rate of 15 million tons per year and a cost (high estimate) of \$15 billion.

5) All efforts need to be made to reduce the costs of the project to make it more competitive. This includes construction techniques, shared facilities with the oil pipeline, and seeking financing from Asian gas buyers who have access to capital at lower interest rates. (See producer point 2) In addition, while 14 million metric tons/year are needed as a minimum to make TAGS economically feasible, the

production capacity of the proposed system is nearly 28 million metric tons/year. Any production over 14 million metric tons/year further improves the economics. If Alaska secures a position in the market in the 2003-2004 window, it will be in a position to add production more cost effectively than other new projects.

6) YP envisions including additional equity partners in the ownership of TAGS, including the producers and buyers of the gas in Asia. YP would hold approximately 25% of the project. (10% of YP's ownership is held by a charitable foundation which was created when Walter Hickel dedicated his ownership in YP to the foundation when he was Governor. The foundation is governed by an independent board of directors and disbursements are restricted to Alaskan organizations.) Although YP is not requesting state investment in TAGS, they are open to this possibility.

7) State government actions are important to the project including establishing a balanced budget and adopting a tax treaty to ensure tax stability during the duration of the project. The Legislature and the Governor can also be very helpful in bringing the parties together to reach agreement on a plan to meet the 2003-2004 market window.

February 2nd, 1996 The producers presentation:

1) Judd Miller of Exxon, John Morgan of BP and Ken Thompson of ARCO opened their presentation by indicating that they have been continuously working on commercializing Alaskan North Slope gas for many years and have considered a trans-Canada route to the US, a plan to turn the gas into natural gas liquids (NGLs) so that it could be shipped down the TAPS line, a Northwestern route to Wainwright or Kivilina, and a Southern route to Valdez in the existing pipeline corridor.

The Northwestern route would require an act of Congress, a 2.7 mile long, 18 foot diameter tunnel through rock to reach suitable water depths offshore, and increased operating costs due to ice operations. The trans-Canada route is too long and expensive and US gas prices are too low. Transforming natural gas into NGLs is speculative technology and is at least 10 to 20 years out. The Southern route to Valdez with a natural gas line leading to a liquefaction plant is the most feasible near term alternative and this is where they are concentrating their efforts, although they do not believe this alternative is economically feasible yet either.

2) One of the most important issues is identifying further reductions in construction costs. Through shared facilities with TAPS, they now feel a natural gas line could be built for \$12 billion and they are continuing to look for further cost reductions. Also needed is market certainty to commit to taking the large volumes of gas required to make a project this large economically feasible, and tax and regulatory stability from the State of Alaska. Until further progress is made in these areas, it will be difficult to justify the next level of expense - detailed engineering of the project which will be quite expensive.

The producers see the liquefaction plant located at the oil terminal using new technology to maintain safety. Sales of gas to communities along the pipeline corridor would also help economic feasibility.

3) Although many studies have been undertaken in the past, they have been followed by periods of relative inactivity. What is needed is a concentrated continuous effort, in conjunction with the state to bring this project online.

4) The producers now have a common reservoir model to evaluate potential oil loss from gas production. This loss has been "portrayed out of proportion" and is considered minimal when compared to the billions of barrels of production from the North Slope and is not considered to be a driving factor in their decision to produce gas.

5) The producers do not feel that their inter-company agreements for reinjection of gas on the North Slope are an impediment to gas sales.

6) The producers have also been to Asia in October to visit potential buyers. The Asian buyers see Alaskan gas having many positive attributes. First all the production infrastructure in place - all the wells are already in place. Competing projects have not completed extensive drilling and their reserves are still speculative. There are also opportunities for integrating gas operations with existing oil transportation infrastructure. A trade imbalance exists and this project could help improve the trade balance with the US. Alaska is closer to the Asian markets than the middle East so there are fewer ships required and significantly lower shipping costs.

The negatives include: fiscal uncertainty related to a balanced budget; Alaskan gas requires an 800 mile pipeline estimated to cost \$5 billion; it will be difficult for the market to absorb 14 million metric tons/year rapidly; and Alaska is viewed to have a "country risk" due to lawsuits

filed by environmentalists against the granting of permits for resource development. The buyers can't make commitments to buy the gas, build new power plants, and then have the operations shut down by a law suit.

7) Yukon Pacific is seen as having an advantage in having secured the necessary permits for the Valdez route. More discussions are necessary to determine the value of these permits. The producers are concerned that YP will charge so much for their permits that it will make the project economically unfeasible. If that is the case, the producers will pursue duplicate permits on their own. They would expect this process to take at least 5 years. Comment: See YP point 6 on their willingness to negotiate majority ownership by the North Slope producers in their proposed gas line.

8) Natural Gas projects have complex financial structures. The State of Alaska may want to consider investing in the project. The producers would also not rule out investment by CSX Corporation, parent company of Yukon Pacific in the project if it is put together by the producers.

9) Asian countries utilize a mix of energy sources which LNG competes against. This limits the maximum price LNG can command. Asian energy demand is growing by 5-10% per year. The Asian countries are interested in purchasing energy from the US as it is seen as politically stable and they want to diversify their LNG sources so they will not be over-dependent on any one source. Energy sales are being de-regulated in Asian markets which may improve opportunities for marketing Alaskan gas.

Whereas oil markets are short term, LNG sales are supported by long term contracts, sometimes 20-30 years. The producers see expansion of existing LNG development meeting Asian market demand before new "grass roots" projects are developed. (See appendix IV) Asian buyers were receptive to the time frame of 2005 to 2010 for large volumes of gas. Market opportunities for Alaskan gas will improve further beyond this timeframe as energy demand increases.

10) The producers emphasized the need for discussions with the administration and the legislature to see what can be done to move the project forward.

11) In response to a question from Rep Bettye Davis regarding working together with YP, since they hold the permits, which would allow the

project to come on line sooner, the producers stated that they will initiate discussions with permitting agencies in 1996-97, that they have had discussions with YP and see the need for further discussions with them to determine the value of the permits. If the cost of doing business with YP makes the project less competitive, they will seek their own permits. If having the permits helps the project, there may be a way to work through YP to expedite the project. They also would not rule out investment by CSX or other investors.

12) In response to a question from Rep Bunde regarding problems getting permits with the Clinton administration in office for possibly another 6 years, the producers agreed this was a problem and suggested a cooperative approach with the state similar to the recent efforts to open ANWR and to lift the oil export ban.

13) In response to a question from Rep Green, the producers stated that they were pursuing an Alaska gas project with as much effort as they are their other grass roots projects in the world. Exxon has 6 such projects. ARCO does not currently have a competing project although they have recent discoveries in Indonesia which may show enough gas to warrant an effort to produce and market them. Shell and Mobil are the real competition, the major producers of gas in the world.

14) The producers committed to answering further questions from legislators submitted in writing.

February 2nd, Wilson Condon, Commissioner of Revenue

1) Commissioner Condon referenced the briefing paper prepared for the Governor containing 14 points on what the state can do to help advance this project. The Governor instructed the Commissioners to go forward with the recommendations listed in the paper.

2) The feasibility of the project is tied to the delivered price of the LNG in the Asian market. Current prices are \$3.50 per million BTU (MMBTU). It is linked with the price of oil with a 15% premium allowed for natural gas due to its environmental attributes. At a project cost of \$15 billion a price of \$5.00/MMBTU would be required to provide a sufficient return on investment to attract financing for the project.

If the cost of the project is brought down to \$13.4 billion, \$4.50/MMBTU would be required. A project cost of \$12 billion would require a \$4.00/MMBTU price. A \$10 billion project would meet today's price.

3) The state can create an investment climate to lower the risk of investment. In this case, investors may be willing to accept a lower rate of return on investment.

4) If the price of gas were \$.50 above the transportation cost (a \$.50 wellhead value), State revenues would be as follows: the 20 mill tax rate on oil and gas production facilities would produce \$220 million with half of that going to municipalities (this figure would decline over time due to depreciation); at a \$.50 wellhead value, the state would receive \$30 million in royalties, \$30 million in severance tax, and \$30 million in corporate income tax for a total of approximately \$200 million to the state and \$100 million to municipalities.

5) Ramping up the delivery schedule following startup of the project would help the economics of the project tremendously.

6) The state can help by identifying ways to help the producers or YP reduce the project cost to make the project more feasible.

7) In response to a question from Rep Rokeberg regarding a "tax treaty", Commissioner Condon stated that neither the producers nor YP has a specific proposal, but the range of possibilities is contained in their briefing paper.

8) Rep Ogan posed a question: The Natuna project is estimated to cost \$20 billion, scheduled to meet the earlier market window. Why would the companies move forward with this project if they didn't think it was competitive? Wouldn't the demand in the market correct the price to bring forward the supply? Since these are long term contracts, the project that gets in first will be able to expand to meet further demand. Commissioner Condon responded that gas supply and demand will set the price but will be moderated by competition from other energy sources such as oil. Environmental problems can be solved by investments in scrubbers, etc. We need to look at the total energy picture. Nevertheless, Alaska needs to move forward with its project just as these other countries are.

9) In response to a question from Rep Rokeberg concerning a reference in the Administration's briefing paper on the Issues Resolution Agreement, whether it is affecting the marketing of Alaskan gas and whether it should be looked at further, Commissioner Condon stated that disputes have arisen concerning NGL's and reinjection of the gas which are covered by these internal agreements. The State is being

vigilant to the effects it could have on the State's interests which can be affected when the companies have a dispute.

10) Rep Rokeberg raised the question of the possibility of using Point Thomson for early production during ramp up so that we didn't have to get tied up in these internal agreements. Commissioner Condon responded that this should be looked into.

11) Rep Green asked what effect production rates above 14 million metric tons/year would have on economics of the project. Commissioner Condon responded that this would help tremendously because you would be spreading the costs of construction over more units of product.

12) Commissioner Condon also committed to respond to further questions put to him by Committee members in writing.

SUBJECTS IDENTIFIED FOR FURTHER INQUIRY:

Overall, the tone of the hearings was very positive with many points of agreement between Yukon Pacific, the producers and the Administration. Several questions remain.

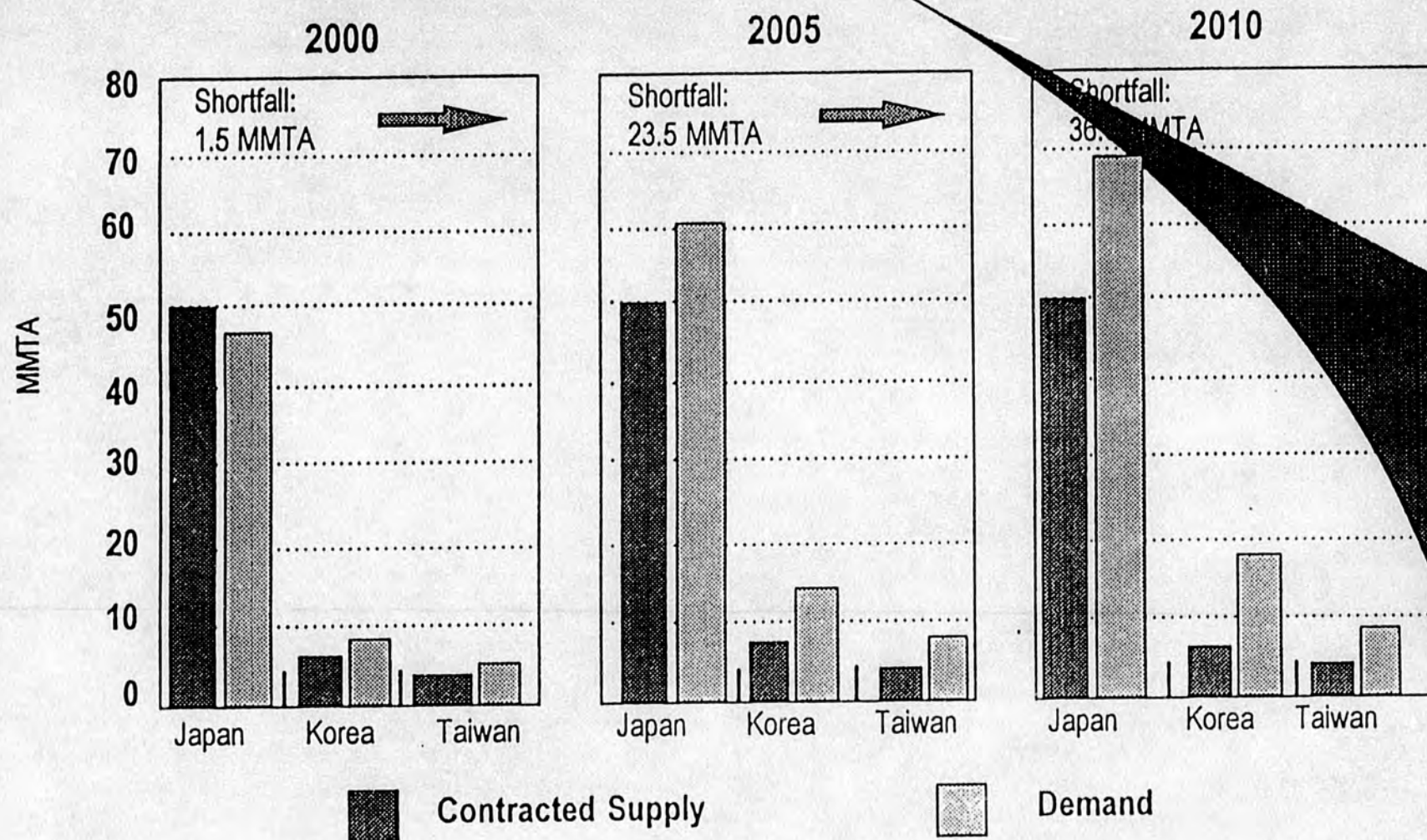
1) Of greatest importance is for the Legislature and Administration to make an independent assessment of the market timing issue. Is there a window to get into the market in the 2003-2004 time frame? Is this a perishable opportunity? If we don't get in early, will expansion of other projects keep us out of the market for a long time to come?

2) Do the internal agreements between the North Slope producers such as the Issues Resolution Agreement keep one or all of the companies from committing their gas to an Alaskan project before 2005? If so, can the State promote 2005, not 2010, as the start-up date?

3) What is the status of the Point Thomson gas field? Is further field delineation drilling scheduled and what are the State's interest in encouraging production of this gas field? What role could Point Thomson play in early delivery of gas to an Alaskan project?

3) Yukon Pacific has the permits, the producers have the gas. What can state leaders do to encourage these partners to work together to get Alaskan gas into the market as soon as possible? Is 2005 an acceptable compromise between a 2003-2010 time range?

Contracted Asian LNG Supply vs. Projected Demand



TAGS Competition is Other Undeveloped Gas Fields in:

	<u>Start-up Date</u>	<u>Annual Volume</u>
▲ Qatar (Qatargas & Rasgas) - Mobil	2005	6-10 MMTA
▲ Indonesia (Natuna Island) - Exxon	2004	15 MMTA
▲ Sakhalin (Russia) - Exxon x2, Marathon/Shell	2004	2 MMTA
▲ Yemen - Exxon	??	2 MMTA
▲ Papua New Guinea - BP	??	2 MMTA
▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

Grass Roots LNG Projects

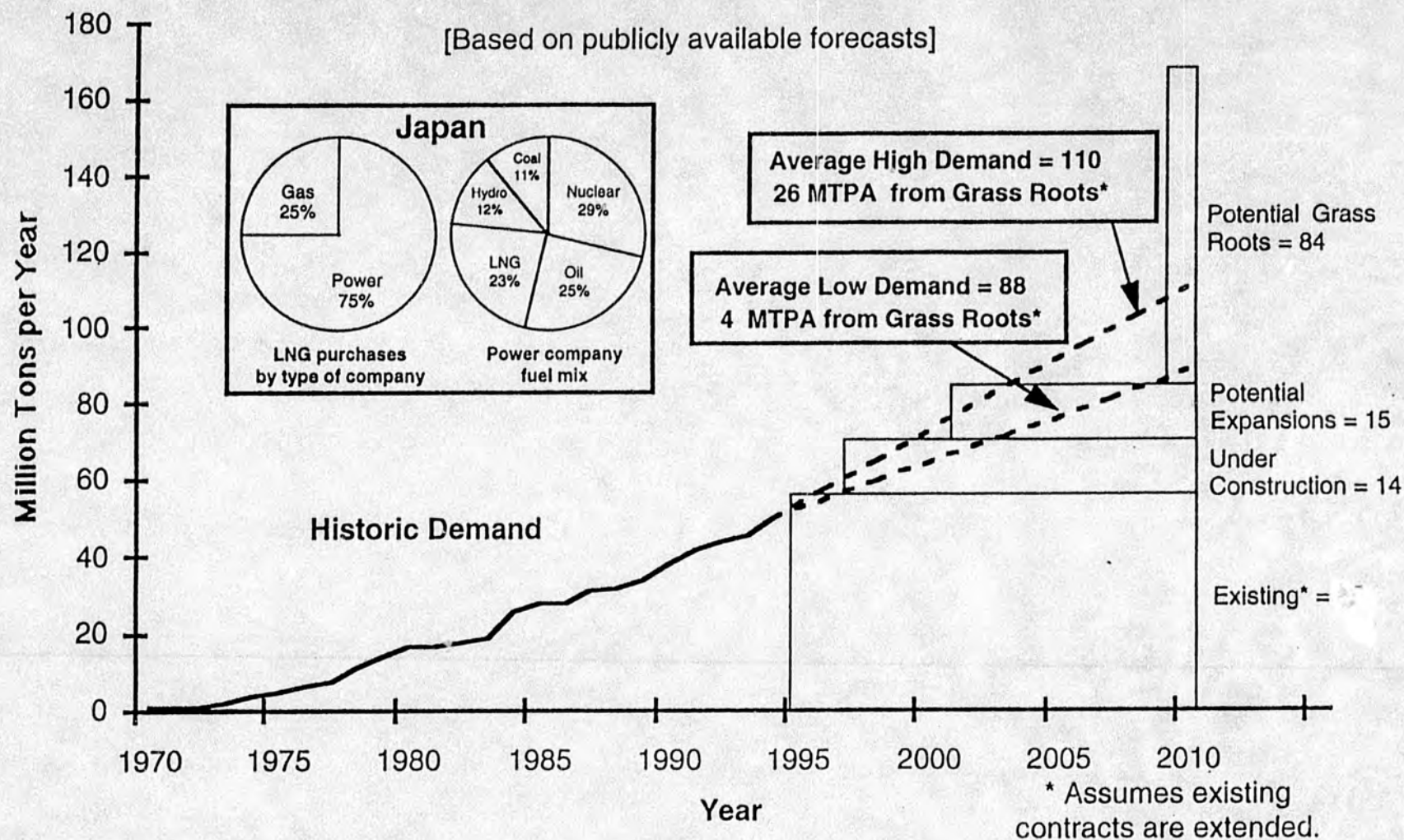
Cost Comparison

Project	Production (MMTPA*)	Estimated Cost \$ Billions	Cost in \$ Billions per MMTPA	Capital ** per MMBTU
Alaska TAGS	15	13.6	0.91	0.70
TAGS at higher cost	15	15.0	1.00	0.77
Qatargas	6	6.0	1.00	0.77
Natuna Island	15	21.3	1.42	1.06
Sakhalin	6	7.9	1.32	1.01

* million metric tons per annum

** does not reflect capitalized interest, cost of gas, time value of money or operating exp

Far East LNG Demand & Possible Need for Grass Roots Projects



APPENDIX IV



Alaska State Legislature
Representative Eugene Kubina
Minority Whip

During Session:
Alaska State Capitol
Juneau, Alaska 99801-1182
(907) 465-4859
Fax (907) 465-3799

During Interim:
P.O. Box 2463
Valdez, Alaska 99686
(907) 835-2111
Fax (907) 835-2097

Sponsor Statement

HJR 54-Marketing of North Slope Gas

The marketing of North Slope natural gas, and the construction of a transportation pipeline, could be the most significant industrial project to be undertaken in Alaska for decades to come.

The financial returns to the state would be significant: 10,000 temporary construction jobs, over 600 permanent private sector jobs, and substantial revenues per year from gas sales to help address the state's current fiscal gap.

HJR 54 addresses four key issues concerning this project:

First. HJR 54 requests the President of the United States to include an Alaskan gas line as part of our nation's trade issues. North Slope gas sales could improve the nation's trade balance by an estimated four billion dollars per year.

Second. HJR 54 places the Alaska State Legislature on record as requesting the Governor of Alaska to give the creation of a gas pipe line a top priority within his Administration.

Third. HJR 54 indicates the strong support by the Alaska State Legislature to see the marketing of North Slope natural gas and the construction of a gas transmission pipeline and related facilities.

Fourth. HJR 54 encourages the establishment of an immediate North Slope natural gas forum between the various principles involved in the oil and gas industry (both in production and transportation), the state government, and the federal government.

There are many questions that need to be answered about the development and marketing of the vast fields of natural gas on the North Slope. Given the ownership issues, the complex market factors, and the various timelines

faced, it is crucial that an ongoing formal dialogue between the various parties be established to help resolve the various issues.

Of key importance here is timing. The global market for natural gas is quite competitive, and there are a number of new projects being considered to meet international demands within the next decade. If Alaska is going to compete for this natural gas market, immediate steps to begin the process may be necessary. That is the goal of House Joint Resolution 54.

End of statement.

9-LS0715\W:
Chenoweth
2/12/96

CS FOR HOUSE JOINT RESOLUTION NO. 54()
IN THE LEGISLATURE OF THE STATE OF ALASKA
NINETEENTH LEGISLATURE - SECOND SESSION

BY

Offered:
Referred:

Sponsor(s): REPRESENTATIVES KUBINA, Green, Barnes, Navarre, Mackie, Grussendorf, Phillips,
B.Davis, Willis, Sanders, Davies, Robinson, Rokeberg, Ogan

A RESOLUTION

1 Encouraging the lessees of Alaska's vast North Slope natural gas reserves to reach
2 agreement to market gas, expressing the legislature's support for an Alaska North
3 Slope (ANS) gas transmission pipeline, and requesting the President of the United
4 States and the Governor of the State of Alaska to publicly support and take
5 action that will help expedite the construction of that system.

6 BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

7 WHEREAS Alaska has at least 26,000,000,000,000 cubic feet of natural gas reserves
8 in the Prudhoe Bay field and perhaps two to three times that amount of potential natural gas
9 reserves; and

10 WHEREAS, beginning in the period 2002 - 2005, there may be an increasing gap
11 between supply and demand for natural gas in the Pacific Rim; and

12 WHEREAS market and economic studies indicate favorable conditions for the sale of
13 liquefied natural gas (LNG) to these Pacific Rim markets; and

14 WHEREAS major permits for one possible pipeline route from the North Slope to
15 Valdez have been completed; and

1 **WHEREAS** the sale of Alaska gas to Pacific Rim markets will improve the nation's
2 trade imbalance without adversely affecting other industries or labor; and

3 **WHEREAS** the design, sourcing, and construction of a LNG project could infuse several
4 billion dollars into the United States economy; and

5 **WHEREAS** the construction of such a pipeline would provide approximately 10,000
6 temporary construction jobs for two years and over 600 permanent private sector jobs in Alaska;
7 and

8 **WHEREAS** the State of Alaska will earn substantial revenue each year from projected
9 gas sales, which would help fill the state's fiscal gap; and

10 **WHEREAS** a gas pipeline across Alaska could make available environmentally friendly
11 energy along the pipeline route and encourage development that will increase local employment
12 and local tax revenue; and

13 **WHEREAS** the Alaska Municipal League's 1996 policy statement includes the following
14 language: "The League, therefore, strongly encourages all potential participants in the project,
15 including the State of Alaska, to immediately convene to develop a unified proposal to present
16 to the Asian LNG buyers so that all Alaskans will directly benefit from this unique opportunity";
17 and

18 **WHEREAS** natural gas stored as a cryogenic liquid is an efficient and safe means of
19 transporting large quantities of gas with no significant risk to the public; and

20 **WHEREAS** securing a market for Alaska North Slope (ANS) gas will be important;
21 there is strong competition for Pacific Rim markets from competing projects in Malaysia,
22 Australia, and other nations; and

23 **WHEREAS** Alaska faces competition from other projects and must, therefore, move to
24 secure a place in Asian markets; and

25 **WHEREAS** Taiwanese and South Korean buyers have issued letters of intent to purchase
26 ANS liquefied natural gas from Yukon Pacific Corporation; and

27 **WHEREAS** Japanese buyers must also commit to buying ANS LNG to make an Alaskan
28 project feasible;

29 **BE IT RESOLVED** that the Alaska State Legislature respectfully requests the North
30 Slope natural gas lessees to intensify their efforts to establish satisfactory contractual
31 relationships for transportation and sale of ANS gas to Pacific Rim purchasers as soon as
32 economically possible; and be it

1 **FURTHER RESOLVED** that the State of Alaska respectfully requests the President of
2 the United States to demonstrate national support for an ANS gas transmission project to Asian
3 LNG buyers; and be it

4 **FURTHER RESOLVED** that the Governor is respectfully requested to

5 (1) assure the Asian LNG buyers that the state will provide continuity and
6 stability in regards to North Slope natural gas supply, tax structure, and regulatory policy;

7 (2) continue support of the Joint Pipeline Office, which administers an
8 innovative, efficient, and cost-effective permitting system; and

9 (3) meet with all parties to determine how the state can help facilitate the ANS
10 gas transmission pipeline; and be it

11 **FURTHER RESOLVED** that the Alaska State Legislature strongly supports the
12 construction of an ANS gas transmission pipeline and offers its assistance to the parties involved
13 in order to speed completion of an ANS gas transmission project.

14 **COPIES** of this resolution shall be sent to the Honorable Bill Clinton, President of the
15 United States; the Honorable Al Gore, Jr., Vice-President of the United States and President of
16 the U.S. Senate; the Honorable Bruce Babbitt, Secretary of the Interior; the Honorable Ted
17 Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young,
18 U.S. Representative, members of the Alaska delegation in Congress; to John Snow, Chairman
19 and Chief Executive Officer, CSX Corp.; to Jeff Lowenfels, President, Yukon Pacific
20 Corporation; to Mike Bowlin, Chairman and Chief Executive Officer, Atlantic Richfield
21 Company, and J. K. "Ken" Thompson, President, ARCO Alaska, Inc.; to John Browne, Chief
22 Executive Officer, British Petroleum, and John Morgan, President, B.P. Exploration (Alaska),
23 Inc.; to Lee R. Raymond, Chairman and Chief Executive Officer, Exxon Corporation, and Jim
24 Branch, Alaska Production Manager, Exxon Alaska; to Shigenobu Yamamoto, Consul General
25 of Japan; to Byuung Hak Min, Consul General of the Republic of Korea; and to Jyhyuan Lo,
26 Director General of the Republic of China.

FISCAL NOTE

STATE OF ALASKA

BILL NO. HJR54

1996 LEGISLATIVE SESSION

Revision Date: Original Dept Affected Natural Resources
 Title: Encouraging the lessees of Alaska's vast BRU: Management & Administration
North Slope natural gas reserves to reach agreement to... Component: Commissioner's Office
 Sponsor: Rep(s) Kubina, Green, Barnes, Navarre...
 Requestor: House Oil & Gas Component Serial No. 423

Expenditures/Revenues

(Thousands of Dollars)

OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES						
TRAVEL	10.0	10.0	10.0	10.0	10.0	10.0
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	10.0	10.0	10.0	10.0	10.0	10.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	10.0	10.0	10.0	10.0	10.0	10.0
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	10.0	10.0	10.0	10.0	10.0	10.0

Estimate of any current year (FY96) cost: \$ none

POSITIONS

FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS:

(Attach a separate page if necessary)

Approximately \$10.0 in annual travel costs will be required by the Commissioner of the Department of Natural Resources to implement the intent of page 3, lines 8-14 of the resolution, which will require travel to "meet with all parties to determine how the state can help facilitate the ANS gas transmission pipeline".

Prepared by: Nico Bus, Acting Director Phone: 465-2406
 Division: Support Services Date: 8-Feb-96
 Approved by Commissioner: [Signature] Date: 8-Feb-96
 Agency: Natural Resources

PREPARER TO PROVIDE ALL DISTRIBUTION COPIES TO GOVERNOR'S LEGISLATIVE OFFICE

By: Dan LaSota
Hank Hove
Jay Quakenbush
Karen Parr
Bob Logan
Paul Chizmar
Layne St. John
Cheryl Kilgore
Hank Bartos
Ladd McBride
Larry Hackenmiller

Introduced: 01/25/96
Adopted: 01/25/96

RESOLUTION NO. 96-009

**A RESOLUTION SUPPORTING HOUSE JOINT RESOLUTION NO. 54 PENDING IN
THE LEGISLATURE OF THE STATE OF ALASKA PERTAINING TO THE
DEVELOPMENT OF THE TRANS-ALASKA GAS PIPELINE AND LIQUID NATURAL
GAS SALES**

WHEREAS, HJR 54 has been introduced in the Alaska State Legislature
and has been referred to three committees; and

WHEREAS, HJR 54 , in part, calls for the Alaska State Legislature to
"respectfully request the North Slope natural gas lessees to intensify their efforts to
establish satisfactory contractual relationships for transportation and sale of Alaska
North Slope Gas to Pacific Rim purchasers as soon as possible"; and

WHEREAS, the Assembly has recently adopted Resolution 95-081 calling
for the Legislature to withhold financial incentives from North Slope Oil producers until
they make Alaska North Slope Gas available for sale; and

WHEREAS, the Borough believes that development of the Trans-Alaska
Gas Pipeline through the existing pipeline corridor is essential to the future economic
health of the State of Alaska; and

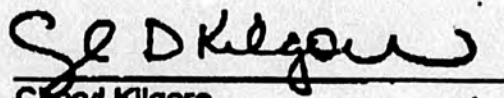
WHEREAS, the Borough believes that it is also essential that labor for any project, especially of this scope, come from the skilled and ready work force that already exists in the State of Alaska; and

WHEREAS, the language of HJR 54 as it was introduced does not contain references to local hire or specify the desired location of the proposed Trans-Alaska Gas Pipeline.

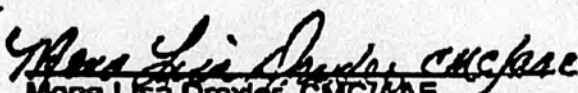
NOW, THEREFORE, BE IT RESOLVED that the Fairbanks North Star Borough Assembly respectfully urges passage of HJR 54 with appropriate consideration given to Alaska hire and locating the project through the existing pipeline corridor.

BE IT FURTHER RESOLVED that copies of this resolution shall be sent to the Honorable Tony Knowles, Governor, State of Alaska, the Commissioner of Natural Resources, and members of the Alaska State Legislature.

PASSED AND APPROVED THIS 25TH DAY OF JANUARY, 1996.


Cheryl Kilgore
Presiding Officer

ATTEST:


Mona Lisa Draxler, CMCAAE
Municipal Borough Clerk

Ayes: LaSota, Santos, Hackenmiller, Parr, Hove, McBride, Logan, St. John, Quakenbush,
Chizmar and Kilgore
Noes: None

VALDEZ CHAMBER OF COMMERCE
VALDEZ, ALASKA
RESOLUTION NO. 95-03

A resolution of the board of directors of the Chamber of Commerce of Valdez, Alaska representing its membership of which the majority consists of businesses operating in our community and surrounding areas, supporting the construction of the natural gas pipeline in the corridor established by the existing oil pipeline.

Whereas, the state of Alaska is currently reviewing its financial position and attempting to balance the budget,

Whereas, the timeline for start up operations would be accelerated due to the existing infrastructure and permits in hand,

Whereas, the earlier operations date would bring new revenue dollars into the state coffers through taxation and production that would assist with balancing of the state budget,

Whereas, the economies of more communities would benefit by use of the existing corridor,

Whereas, an ice free port entry for the shipping vessels reduces the potential risk factor,

Whereas, the safety response equipment, levels of expertise already in existence in Valdez is proven, tested, effective and efficient reduces catastrophic state wide impact,

Whereas, this route minimizes the need of any new excavation of land,

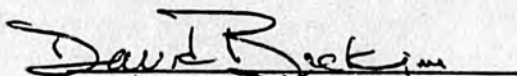
Whereas, use of the existing corridor would draw less criticism from environmental and animal activist groups that would impact the tourism industry of our state,

Therefore, let it be resolved the Valdez Chamber of Commerce supports and endorses the construction of a natural gas line in the corridor already established by the oil pipeline constructed for transportation of oil.

PASSED AND APPROVED BY THE BOARD OF DIRECTORS OF THE
VALDEZ CHAMBER OF COMMERCE OF VALDEZ, Alaska, this 11th
day of July, 1995.

Valdez Chamber of Commerce

ATTEST:


David Beck, Chairman


Jean Stewart, President

TRANS-ALASKA GAS PIPELINE:

PARTNERS AND ISSUES

Provided by Yukon Pacific Corporation

PRIMARY PARTNERS:

- 1) **The people of Alaska** - this partner owns the gas reserves on State lands on the North Slope.
- 2) **The major oil companies** - Exxon, BP and ARCO in Prudhoe Bay and Phillips Petroleum, Mobil, Chevron and Exxon in Point Thomson. These companies have leased the rights and committed to produce the State's oil and gas.
- 3) **Yukon Pacific Corporation** - this partner has secured the permits for a trans-Alaska gas line in the congressionally designated pipeline corridor. This permitting process took ten years. They have also obtained an export license for the gas.
- 4) **Walter J. and Ermalee Hickel Foundation** - while Wally Hickel was Governor, he signed over his ownership interests in Yukon Pacific stock to a charitable foundation. This foundation is governed by a board which makes all decisions on allocation of the funds earned from 10% of the profits of Yukon Pacific. The board is chaired by Archbishop Hurley of Anchorage and the allocations are restricted to Alaskan charitable organizations. As state and federal expenditures for social programs are reduced, this foundation could identify and fill funding gaps.
- 5) **The State Legislature and the Governor** - these partners control the State's royalty gas, 12 1/2% of the produced gas which they could commit to this project. The sale of this royalty gas and state taxes are of great interest to State government for the purpose of balancing the state budget.
- 6) **Alaska Native corporations** - these corporations own land near Prudhoe Bay and near the gas pipeline corridor which could contain significant gas reserves. The production of these reserves could be facilitated by construction of the Trans Alaska gas pipeline.

SECONDARY PARTNERS:

- 1) **Alaskan workers** - this project would provide significant employment opportunities to Alaskan workers, estimated at 10,000 workers for initial construction and 600 full time workers during long term operations. Pipeline and facility maintenance would create further jobs as we have seen with the oil pipeline.
- 2) **Alaskan service companies** - this project would provide significant contract opportunities for oilfield, transportation and other associated companies.
- 3) **Alaskan communities** - these partners would benefit from local tax revenues, access to use of the gas along the pipeline corridor. AML has passed a resolution in support, (attached) as have other Alaskan local governments. Waste heat from the liquefaction plant would produce 250 to 300 megawatts of electricity which could be fed through interties to Alaskan communities, reducing their electrical rates.
- 4) **America** - This project would provide significant benefits to American workers in equipment manufacturing, transportation, etc. The export of Alaskan gas to Asian markets would also reduce our trade deficit with these companies.

IS THIS PROJECT COMPETITIVE?

The attached chart compares the cost of an Alaskan gas export project and estimated reserves with other projects which could supply gas to the Asian market. This clearly shows that this project is competitive. While we have the expense of building a pipeline, these other projects have significant development costs in production facilities which already exist at Prudhoe Bay.

This project will require a minimum market commitment of 14 million tons of gas per year to be economically feasible. However, the capacity of the system will be 28 million tons per year which could be produced if additional markets are identified. These additional markets could include facilities to refine value added natural gas products such as petrochemicals in Alaska. Any throughput of over 14 million tons per year further improves the economics of this project.

TIMING:

There exists a window of opportunity to market Alaskan gas in the Asian market to meet their demand requirements opening in 2003 to 2004. If these countries cannot obtain commitments for Alaskan gas, they will be forced to commit marketing agreements and financing to other projects even if they are more expensive. If this occurs, the next opportunity to sell Alaskan gas could be as far out as 2025 to 2030 if ever.

If this project is moved forward now, it would also provide substantial state revenues at a time when the Long Range Fiscal Planning Commission has projected that our reserves will be drawn down and personal and other taxes will have to be considered.

WHAT NEEDS TO HAPPEN TO MOVE THIS PROJECT FORWARD?

- 1) The major producers and Yukon Pacific need to negotiate an agreement to market Alaska's natural gas linked to the pipeline construction schedule. Yukon Pacific has offered and continues to offer to negotiate with the major producers and the state on pipeline ownership, profit sharing and all other issues.
- 2) Final engineering needs to be completed to identify methods for minimizing the cost of pipeline construction.
- 3) Financing needs to be identified. Financing from Asian market sources at lower interest rates could further lower the cost, improving returns to the producers, pipeline owners and the State of Alaska.
- 4) Alaska State government needs to facilitate bringing the parties together to conclude a marketing agreement and to consider committing Alaskan royalty gas to the project.
- 5) A project labor agreement needs to be negotiated to ensure maximum local and native hire.
- 6) The Governor of Alaska, working with the President of the United States needs to continue and to expand their efforts to promote this **American** gas project.

It is clear that the people of Alaska have a large stake in employment, state and local revenues, and access to the gas which this project represents. All efforts should be made to expedite a trans Alaska gas pipeline to meet the 2003 to 2004 Asian market window.

Grass Roots LNG Projects

Cost Comparison

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▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

ALASKA MUNICIPAL LEAGUE

Economic Development and Resource Management

1996 Policy Statement

established by Congress be followed and the information and recommendations derived from that process be considered prior to congressional action that would affect those forests.

Congress has passed the National Forest Management Act and the National Environmental Policy Act, which establish an open public process for deciding how national forests should be managed. This process should be used to guide the congressional decision-making process.

5) Effect of National Policies on Forest-Dependent Communities

- The League urges the Alaska Legislature and the Governor to work with the congressional delegation and federal resource-management agencies to help broaden their understanding of the adverse impact of national policies on Alaska's forest-dependent communities. (11/ 93)

4. Oil, Gas, and Mineral Resources:

a. Arctic Oil Reserve (formerly Arctic National Wildlife Refuge (ANWR) - The League urges the Congress of the United States to open the Coastal Plain of the Arctic Oil Reserve to environmentally responsible oil and gas exploration, development, and production. The League urges the State of Alaska to redistribute federal mineral revenue sharing funds to local governments, and strongly supports the 90-10 split as required by the Statehood Act.

b. Exploration and Development - The League encourages the State of Alaska to promote environmentally responsible oil, gas, and mineral exploration and development that is not detrimental to Alaskan fisheries.

c. Export of Oil - The League urges Congress to lift the ban on the export of North Slope crude oil. (11/ 92)

d. North Slope to Valdez Natural Gas Pipeline - The League strongly endorses the construction of a natural gas pipeline and associated liquefied natural gas (LNG) facilities at the very earliest possible date.

In order to meet the Asian market need, the League encourages all potential participants in this vital project to direct future efforts towards using approved environmental permits and export authorizations which allow construction to proceed in the existing, Congressionally approved north-south transportation corridor. The League recognizes that the only market for this major undeveloped resource will open in Asia shortly after the year 2000 and that strong competition from other potential suppliers on the Pacific Rim and the Middle East exists to meet this demand. The League, therefore, strongly

By: Dan LaSota
Introduced: 1/25/96

RESOLUTION NO. 96-009

A RESOLUTION SUPPORTING HOUSE JOINT RESOLUTION NO. 54 PENDING IN
THE LEGISLATURE OF THE STATE OF ALASKA PERTAINING TO THE
DEVELOPMENT OF THE TRANS-ALASKA GAS PIPELINE AND LIQUID NATURAL
GAS SALES

WHEREAS, HJR 54 has been introduced in the Alaska State Legislature and has been referred to three committees; and

WHEREAS, HJR 54, in part, calls for the Alaska State Legislature to "respectfully request the North Slope natural gas lessees to intensify their efforts to establish satisfactory contractual relationships for transportation and sale of Alaska North Slope Gas to Pacific Rim purchasers as soon as possible"; and

WHEREAS, the Assembly has recently adopted Resolution 95-081 calling for the Legislature to withhold financial incentives from North Slope Oil producers until they make Alaska North Slope Gas available for sale; and

WHEREAS, the Borough believes that development of the Trans-Alaska Gas Pipeline through the existing pipeline corridor is essential to the future economic health of the State of Alaska; and

WHEREAS, the Borough believes that it is also essential that labor for any project, especially of this scope, come from the skilled and ready work force that already exists in the State of Alaska; and

WHEREAS, the language of HJR 54 as it was introduced does not contain references to local hire or specify the desired location of the proposed Trans-Alaska Gas Pipeline.

NOW, THEREFORE, BE IT RESOLVED that the Fairbanks North Star Borough Assembly respectfully urges passage of HJR 54 with appropriate consideration given to Alaska hire and locating the project through the existing pipeline corridor.

BE IT FURTHER RESOLVED that copies of this resolution shall be sent to the Honorable Tony Knowles, Governor, State of Alaska, the Commissioner of Natural Resources, and members of the Alaska State Legislature.

Congress of the United States
House of Representatives

Washington, D.C. 20515

November 4, 1994

The Honorable William J. Clinton
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

We are writing to urge you not to attend the signing of the Natuna Sea natural gas agreement between the Exxon Corporation and the government of Indonesia.

Production in America's domestic oil and gas industry is at its lowest level since the Arab oil embargo. More than 430,000 jobs have been lost.

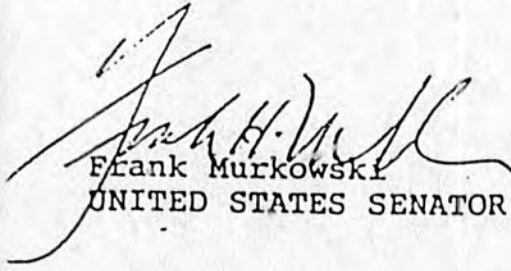
Proven natural gas reserves of more than 37 trillion cubic feet are waiting to be developed on Alaska's North Slope. The development of these reserves has the potential to create 30,000 American jobs immediately and generate \$500 million in Federal tax revenues. The trade deficit -- particularly with Japan -- would fall by as much as \$4 billion.

Exxon already owns 40 percent of the natural gas on the North Slope of Alaska. The Trans-Alaska Gas pipeline does not require any further licensing or approval and would be built in an existing pipeline corridor. It would greatly benefit from the support of your Administration, support which you have provided in the past for this clean, environmentally sound energy source.

We ask that you not promote the export of American jobs by attending the signing of this agreement. The natural gas resources are readily available in America, and they can be developed in a far safer and more environmentally sound manner by our domestic industry.

We ask that you give your strong support to the development of Alaska natural gas instead.

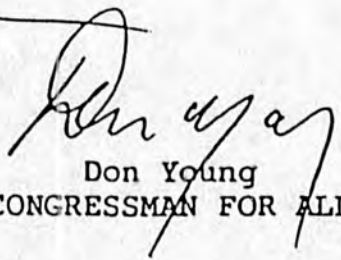
Cordially,



Frank Murkowski
UNITED STATES SENATOR



Ted Stevens
UNITED STATES SENATOR



Don Young
CONGRESSMAN FOR ALL ALASKA

**THE FOLLOWING PAGES
WERE TREATED AS A UNIT
IN THE ORIGINAL FILE**

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Committee Questions and YPC Responses



Senate Resources Committee Questions and Yukon Pacific Corporation Responses

Q HOW CURRENT ARE THE PERMITS THAT YOU HAVE? WHAT PORTION OF THEM ARE FEDERAL PERMITS AND WHAT PORTION ARE STATE PERMITS?

A See exhibit 1. All permits are current.

Q WHAT IS YOUR PROPOSED METHOD FOR FINANCING THE LIQUEFACTION FACILITIES, PIPELINE AND TRANSPORTATION SYSTEM?

A *It is far too early to "propose" a method for financing TAGS. We will modify your question just slightly, respond and then explain.*

Revised Question:

Q IF YOU HAD THE GAS SUPPLY, HOW WOULD YOU PROPOSE TO FINANCE THE LIQUEFACTION FACILITIES, PIPELINE AND TRANSPORTATION SYSTEM?

A *Limited recourse financing using any number of variations of the Japanese Import Model.*

In large-scale projects like LNG "grass-roots" projects, it is very difficult for project sponsors to fully undertake all of the various project risks. Therefore, it is important to establish a cooperative financing structure in which the related parties, such as gas producers, gas buyers, engineering procurement and construction EPC contractors, ship builders, shippers, governmental organizations and financial institutions, share the various types of project risk.

Historically, the Japanese have played a very important role in assuming certain aspects of risk for all of the LNG projects delivering gas to their country.

Japanese Governmental Organizations:

For decades the Japanese Government has been directly supportive of and involved in importing natural resources which are essential for the development of the Japanese economy through not only funding but also in guaranteeing certain aspects of LNG projects. Japanese governmental institutions which have provided these funding/guaranteeing sources include: The Export Import Bank of Japan (JEXIM), Overseas Economic Cooperation Fund (OECF), Japan National Oil Corporation (JNOC) and The Japan Development Bank (JDB).

Japanese Buyers:

Japanese buyers participate in the financing of LNG projects as equity participants of LNG importing/financing companies, as borrowers of import credit of JEXIM and, as guarantors of limited recourse financing. Most importantly, Japanese buyers provide off-take guarantees under long-term sales contracts which support the establishment of a project finance structure.

The limited recourse financing structure also contemplates that the commercial banks will also assume some part, but not all of the project risk. In order for the commercial banks to assume these risks certain project attributes would be expected. These would include, but not be limited to the following:

- 1) Adequate gas reserves committed to the project,*
- 2) Development and completion of the project by the project sponsors,*
- 3) LNG sales contracts including reasonable pricing formulas and "take of pay" clause.*

See exhibit 2 for a diagram of how the TAGS financial structure might look employing these attributes and for other examples of how various LNG projects have been financed making use of these financing schemes.

Q WHAT IS YOUR ESTIMATED TIMELINE AND COST FOR CONSTRUCTION FOR THESE FACILITIES?

A *See exhibit 3 for TAGS construction timeline and project cost.*

Q CAN YUKON PACIFIC AND ITS PARTNERS FINANCE AND CONSTRUCT THE FULL SYSTEM WITHOUT EQUITY INVESTMENTS BY THE PRODUCERS?

A *Yes, provided the required volume of gas is committed to the TAGS project because the 25 year gas sales contracts with Asian buyers are the basis for financing.*

Q WHAT WELLHEAD RATE CAN YOU PAY TO MAKE THE INVESTMENT VIABLE?

A *It depends. There are many variables which will impact the project's viability. As examples, market ramp-up and cost of capital will greatly influence TAGS economics. These factors and the ultimate price the market agrees to pay will dictate the value available to the wellhead. See exhibit 4 for a generic comparison of TAGS economics vs. other competing projects.*

What we would envision, however, is the netback to be expressed as a function of the sales price. As an example the netback calculation might look something like this:

$$(\text{Sales Price}_{\text{Tokyo}} - \text{Marine}) \times 12.5\% = \text{Wellhead value}$$

Sales Price _{Tokyo} =	\$4.00/MMBTU
Marine =	\$1.00/MMBTU
Wellhead Value =	\$.375/MMBTU

Q

WHAT DOES THE MARKET PROJECT FOR SUPPLY AND DEMAND OF GAS?

A

See exhibit 5.

Q

WHAT IS THE EXPLANATION OF THIS DISCREPANCY?

A

First, the discrepancy can best be depicted by a listing of the proposed projects which are competing for the same markets and the stated time they seek to begin deliveries as shown on exhibit 6.

*Second, the view taken by YPC seeks to ensure that Alaska benefits from the undeniable market demand. The earlier date **minimizes risk to Alaska** from a competing project taking the market share. All of the competing start-up projects also have the potential to **expand**, with the very real prospect of blocking Alaska from ever getting its gas into the market at all. See exhibit 7.*

*Third, YPC is **not** bound by the 1991 Issues Resolution Agreement (IRA) which modified the Prudhoe Bay Unit Operating Agreement. YPC believes the economic trades formalized by this agreement and not the "market window" are part of the reason for the discrepancy in proposed start dates for North Slope gas sales.*

*Fourth, YPC is not convinced by the PBU producers oil loss scenarios if gas sales occur. Gas sales result in **certain** revenues. Oil loss is speculative, far out in time if it should occur, and can be mitigated if it does. Loss of oil, gas and condensate from Point Thomson **which cannot be developed without a gas line**, must also be factored in. See exhibit 8.*

Fifth, a successful Alaska gas project is not only designed to provide gas to Asian markets. Perhaps the most commonly overlooked and important benefit to Alaskans is to provide low cost energy to Stevens Village, Fairbanks, Glenallen and Valdez. Even Anchorage may need North Slope gas as projected supplies run out in about 15 years. In other words, waiting may not only cause a loss of the Asia markets, it may result in an inability to provide much needed inexpensive fuel to Alaskans.

Q

CAN GAS FROM POINT THOMSON START FLOWING AS EARLY AS 2003-2004 IN THE GAS PIPELINE, WITH COMMITMENT THAT PRUDHOE BAY GAS WILL FOLLOW WITHIN TIME CERTAIN?

A

YPC believes this is possible. Phillips Petroleum alluded to this fact at the Juneau AOGA meeting held in January and has discussed the concept with the Division of Oil and Gas. Obviously, more work needs to be done, but it is surely worth the attempt because it ensures an early start without disrupting the Prudhoe Bay Unit WIO's stated plans to start gas sales from Prudhoe Bay Unit between 2005-2010. See exhibit 9.

Q

WHAT, IF ANYTHING, WOULD HELP ADVANCE THE DATE FOR THIS PROJECT BY ONE YEAR TO 18 MONTHS?

A

*First, **serious** progress on solving the State's fiscal gap including a **commitment** from the State to enter into a tax treaty regarding the North Slope gas project. This would help alleviate producer concerns which appear to be a major impediment to TAGS progress.*

Second, continued study and encouragement of the Point Thomson possibility and use of the JPO to ensure consistent and efficient permitting for that project. This can be the State's first real attempt to partner with the industry to develop a new oil and gas unit.

Third, serious assistance by the State to resolve PBU problems in a non-confrontational way. Again, this will allow the State and the industry to demonstrate real commitment to partnering.

Fourth, a joint marketing trip by the PBU operators, the Point Thomson operators and the permit holders for the project to obtain commitments and hold meaningful discussions on market participation in price reduction opportunities including: shortening the "ramp-up" period to full production, project financing, use of larger ships and precommitments to quantities beyond the 14 million tonnes per year needed for economic viability.

*Fifth, continued commitment by both the Knowles and Clinton administrations to actively support and promote the **only** U.S. start-up LNG export project competing in the international marketplace.*

*Sixth, encourage producers to conduct studies of various aspects of the project **in parallel** instead of "in series" as they currently do.*

*Missing from this list is any request to have State officials visit market countries to assist in marketing. This is **not** an inadvertent omission. Past State visits by DNR & DOC Commissioners, for example, have been disastrous to TAGS marketing efforts. The State's role is here in Alaska. Help is not needed in the marketplace. State officials should work on balancing the budget, gas development and partnering concepts, and not complicate ongoing marketing efforts.*

YPC Permits and Authorizations



TAGS PERMITS AND AUTHORIZATIONS

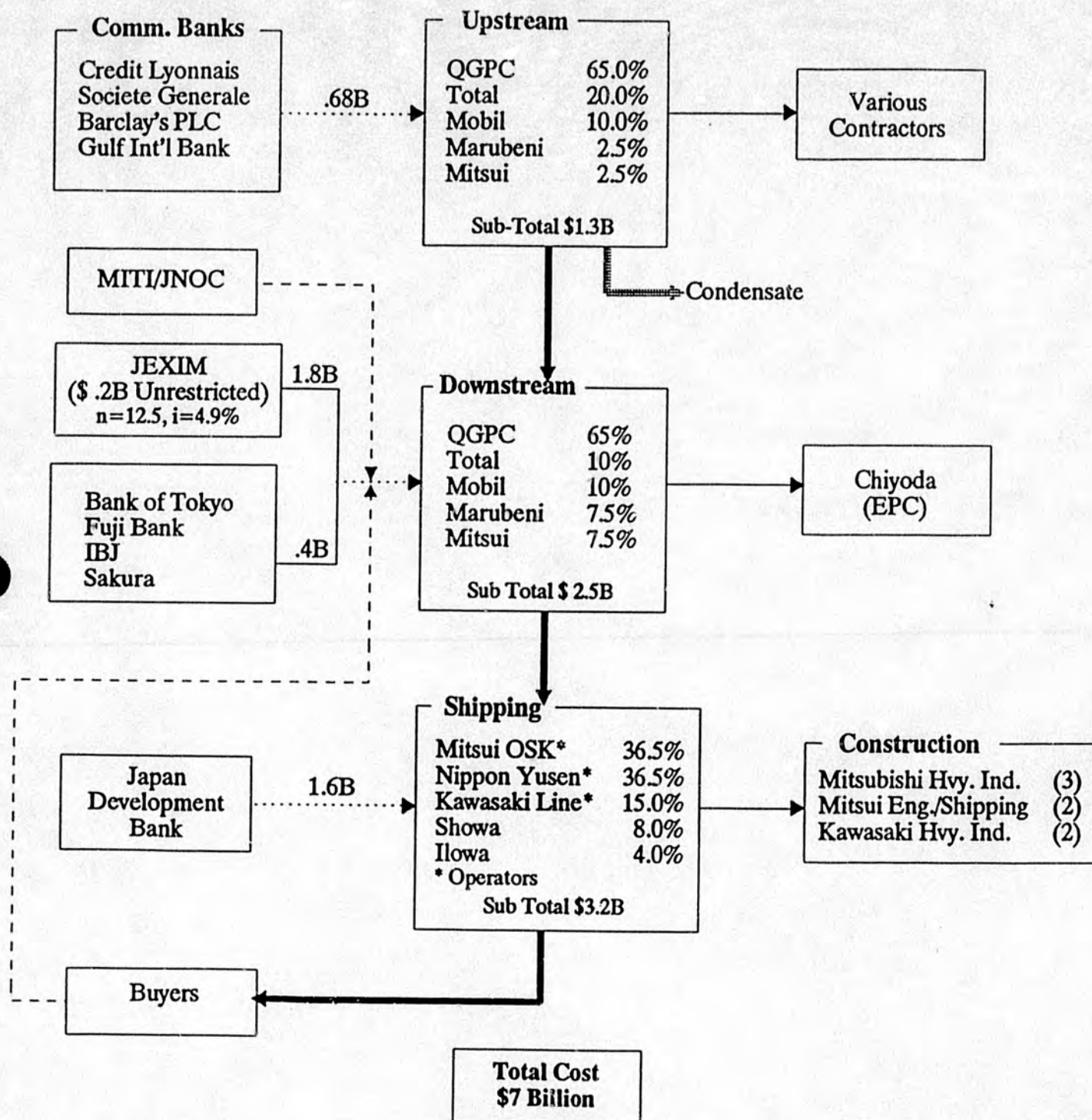
Over the past twelve years YPC has secured or satisfied all of the necessary legal approvals and requirements to export North Slope natural gas to Asia. These include:

1. **Presidential Approval:** *Presidential Finding Concerning Alaska Natural Gas: Removes impediment to Alaska natural gas exports required by Section 12 of the Alaska Natural Gas Transportation Act (15 U.S.C. 719j), January 13, 1988;*
2. **Project Wide Environmental Impact Statement¹:** *Trans-Alaska Gas System Final Environmental Impact Statement, June 1988 (17 Federal and State agencies);*
3. **Ahtna Right-of-Way¹:** *Grants to Yukon Pacific Corporation the right to designate and acquire certain rights in any and all lands acquired by or otherwise available to Ahtna under the Alaska Native Claims Settlement Act of 1971 which are reasonably necessary to construct, maintain operate or terminate the pipeline, October 14, 1988;*
4. **Federal Right-of-Way¹:** *Right-of-Way Grant for the Trans-Alaska Gas System from The United States of America to The Yukon Pacific Corporation, October 17, 1988;*
5. **State Right-of-Way¹:** *Trans-Alaska Gas System Conditional Right-of-Way Lease, December 10, 1988;*
6. **DOE's Authorization for Export of Gas¹:** *DOE/FE Opinion and Order No. 350, Order Granting Authorization to Export Liquefied Natural Gas From Alaska; Limiting of FERC's jurisdiction, November 16, 1989;*
7. **Confirmation of Order 350¹:** *DOE/FE Opinion and Order No. 350-A, Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification, March 8, 1990;*
8. **Anderson Bay Final Environmental Impact Statement¹:** *Yukon Pacific Corporation LNG Project: Final Environmental Impact Statement, March 1995;*
9. **Order Granting NGA Section 3 Authorization for the Siting, Construction and Operation of LNG Facility:** *Federal Energy Regulatory Commission's approval of Anderson Bay, Port Valdez, Alaska as the place of export, May 22, 1995;*

● LNG Project Financing



Qatargas Project Scheme 6 MMT



Legend

— Gas Flow	— Contracts
- - - Guarantee	 Debt

Advisors

JP Morgan - Project Wide
Citibank - QGPC

SUCCESSFUL FINANCING
OF
LNG "GRASS-ROOTS" PROJECTS
FOR THE FAR EAST MARKET

INTRODUCTION

1. BASIC PROJECT STRUCTURE
2. FINANCING SOURCES
3. RISK SHARING
4. PROJECT FINANCE FOR LNG
"GRASS-ROOTS" PROJECTS

APPENDIX FINANCING STRUCTURES OF
INDONESIA LNG PROJECTS

- (i) The First Indonesian LNG Project
- (ii) LNG Expansion Projects in Indonesia

INTRODUCTION

With the rapid increase of demand of LNG as a clean energy source in the Far East market today, many "grass-roots" projects, such as Alaska North Slope Project, Indonesia Natuna Project, Sakhalin Project, and Oman Project, are under contemplation.

Needless to say, LNG "grass-roots" projects, which consist of gas gathering units, gas treatment facilities, pipelines, liquefaction plants, LNG tankers and the other related facilities, require huge amounts of capital and involve high risks. For materialization of such a large-scale LNG "grass-roots" project, therefore, successful arrangement of the financing will be very significant. This paper, as a general study on financing of large-scale LNG "grass-roots" projects for the Far East market, examines several selected problem areas to be solved concerning project structure and financing structure for the successful financing from the lenders' viewpoint.

For your reference, financing structures of Indonesia LNG projects are set out in the Appendix.

1. BASIC PROJECT STRUCTURE

Before going to the detailed study of financing, it is very important to build up a solid basic project structure. Without this step, the process in structuring a finance scheme would become inefficient.

For designing of a basic project structure, it is necessary to make clear the roles of key players, such as gas owners, LNG buyers, governments (or governmental organizations) of the host and buyers' countries, and so on. Within this stage, key players' commitment should be confirmed in the following manner:

- (1) Gas owners should clearly show their commitment to the project including capital contribution, based on a corporate consensus, and inform of a detailed development plan including various studies on the project.
- (2) LNG buyers' commitments, in a form of Letter of Intent, should be secured.
- (3) Governmental support from the host and buyers' countries should be clearly stated.
- (4) Mutual agreements between gas producers and related parties in buyers' countries on cooperation for risk sharing in the project should be concluded.

In many LNG projects for the Far East market, Japanese Trading Companies, called "Sogo Shosha" have played a very important role, ranging from the coordinator/promoter of the project to the participant in finance, as shown in Exhibit 1. The role and the form of involvement in the project of Sogo Shosha also should be determined in this stage.

MAJOR JAPANESE TRADING COMPANIES
AND
LNG PROJECTS

TRADING COMPANY	LNG PROJECT (YEAR OF FIRST SHIP)	ROLES
MITSUBISHI CORP.	• Alaska Kenai Project(1969) • Brunei Project (1972) • Malaysia Project (1983) • Indonesia Arun Expansion Project (1984) • Australia Project(1989)	Sales Agent ("SA.") Equity Participation(25%), SA. Equity Participation(17.5%), SA. Equity Participation in Indonesia LNG(10%), SA. Equity Participation in Mi/Mi, SA.
MITSUI & CO., LTD.	• Abu Dhabi Project (1977) • Australia Project (1989) • Qatar Project	Equity Participation(24.5%), SA. Equity Participation in Mi/Mi, SA. Equity Participation(7.5%), SA.
NISHO IWAI	• Indonesia Project (1977)	Equity Participation in JILCO (10%), SA.
MARUBENI CORP.	• Qatar Project	Equity Participation (7.5%), SA.
C. ITOH & Co.	• Algeria Project • Sakhalin Project	Spot Sales Arrangement Equity Participation (28.828%) in SODECO
SUMITOMO CORP.	• Australia Bonapart Project.	Promoter

2. FINANCING SOURCES

As shown in Exhibit 2, most of the existing LNG projects for the Far East market depended a lot on import credit/overseas investment credit provided by The Export Import Bank of Japan (J.EXIM). It is because both credits have advantages compared to other sources in respect of cost and availability for massive amounts of funding.

Import credits are provided to Japanese corporations for the import of LNG (see the finance scheme of the First Indonesian LNG Project [Exhibit 7]), while overseas investment credits are provided to Japanese corporations for their overseas investment activities as project sponsors (see finance scheme of Indonesian Train E Project [Exhibit 8]). However, the terms in both credits will be basically the same.

Japanese commercial banks have been also involved in most of the LNG financing on both a corporate guarantee basis and a limited recourse finance basis.

In co-finance with J.EXIM, Japanese commercial banks provided their loan for 30-40% of the total amount (The share of commercial banks is determined under the Japanese Government guideline). And Japanese commercial banks sometimes participated in the special purpose company for LNG import and/or financing as equity holders.

In limited recourse finances (so called "project finance") as well, Japanese commercial banks have played leading roles and provided considerable amount of loans, which we will refer to later.

For future LNG "grass-roots" projects as well, J.EXIM and Japanese commercial banks are considered to continue to play major roles, but (i) Korean sources, and (ii) international financing institutions should also be examined as potential financing sources.

FINANCE SOURCES USED FOR EXISTING LNG PROJECTS

— For The Far East Market —

PROJECT (Year of First Ship)	JAPAN-EXIM		Commercial Syndicated Loan	Sponsors Loan/Equity	Other Sources
	Import Credit	Overseas Investment Credit			
1. Alaska (1969)				○	
2. Brunei (1972)		○	○	○	US EXIM (Export Credit)
3. Abu Dabi (1977)	○	○	○	○	
4. Indonesia - Original - (1977)	○		○ *		OECP (YEN Credit)
5. Malaysia (1983)	○	○	○	○	US EXIM (Export Credit)
6. Indonesia - Expansion - (1984)	○		○ *		
7. Indonesia - for Korea - (1984)				○	
8. Australia - Phase II - (1989)	○	○	○	○	
9. Indonesia - for Taiwan - (1990)		○	○		

* EXIM Co-Finance

(i) Korean Sources

The existing LNG projects for Taiwan and Korea have not involved their own countries' finance sources, and they were financed by international commercial banks on a limited recourse basis.

In Korea, however, there is The Export Import Bank of Korea, a governmental financing institution for international business, which is a very similar organization to J.EXIM. Through its activity for providing import credit for the purchasing of natural resources, K.EXIM might be one of the potential financing sources for future LNG projects which involves Korean LNG buyers.

(In Taiwan, there are no special governmental financial agencies to support
the international trade and business.)

(ii) International Financing Institutions

International Financing Institutions such as World Bank, IFC, ADB have never been involved in the existing LNG projects for the Far Eastern market. It is because the World Bank and ADB are historically concentrated not on natural resource development projects, but on infrastructure projects in the developing countries when the projects are not justified according to commercial investment criteria.

However, they have mentioned recently that because of both environmental and economic reasons, they have an interest in being involved in natural gas development projects and LNG projects.

3. RISK SHARING

In large-scale projects like LNG "grass-roots" projects, it is very difficult for project sponsors to fully undertake project risk in various categories. Therefore, it is significant to establish a cooperative financing structure in which the related parties, such as gas producers, gas buyers, engineering procurement and construction (EPC) contractors, ship builders, shippers, the governmental organizations and financial institutions, share the various types of project risk. As you can see in Exhibit 3, project sponsors succeeded in sharing major risks with other parties in some recent projects.

Other than project sponsors, we can identify several parties who may take project risks to some extent in LNG projects for the Far East market.

(a) Japanese Governmental Organizations

The Japanese Government has been supportive of importing natural resources which are essential for the development of the Japanese economy. Support of this kind has been provided through its financing agencies and its petroleum agencies.

As you can see in the examples described in the Appendix, such agencies have been deeply involved not only in funding but in guaranteeing for the existing LNG projects. Following is a list of Japanese governmental institutions which should be examined as prospective funding/guarantee sources for LNG projects.

- The Export Import Bank of Japan (J.EXIM)
- Overseas Economic Cooperation Fund (OECF)
- Japan National Oil Corporation (JNOC)
- Overseas Petroleum Development Co., Ltd. (JNOC's Subsidiary)
- Japan Petroleum Exploration Co., Ltd. (JNOC's Subsidiary)
- The Development Bank of Japan (For LNG tanker finance)

(As for details of these institutions, please refer to the enclosed information)

MAJOR PROJECT RISK TAKERS IN THE FINANCE FOR EXISTING LNG PROJECTS

— For The Far East Market —

PROJECT (Year of First Ship)	(A) GOVERNMENT OF BUYERS' COUNTRY*	(B) BUYERS	(C) COMMERCIAL BANKS	PROJECT SPONSORS		
				GOVERNMENT OF HOST COUNTRY*	JAPANESE (TRADING FIRMS)	OIL COMPANY
1. Alaska (1969)						○ (Phillips, Marathon)
2. Brunei (1972)				○ (Brunei Government)	○ (Mitsubishi)	○ (Shell)
3. Abu Dabi (1977)				○ (ADNOC)	○ (Mitsui)	○ (BP, TOTAL)
4. Indonesia -Original- (1977)	○	○				
5. Malaysia (1983)				○ (PETRONAS)	○ (Mitsubishi)	○ (SHELL)
6. Indonesia -Expansion- (1984)	○	○				
7. Indonesia -for Korea- (1984)						○ (Mobil)
8. Australia -Phase II- (1989)			○		○ (MIMI)	○ (Shell, BP, Chevron, BHP) Woodside
9. Indonesia -for Taiwan- (1990)			○			

*Including Governmental Organization

(b) Japanese LNG Buyers

If you review some Indonesian LNG projects, you may notice that Japanese LNG buyers played important roles as a risk taker. In these projects, Japanese buyers (most of them are utility companies) participated in the financing as equity participants of LNG importing/financing companies, as borrowers of import credit of J.EXIM, and as guarantors of limited recourse financing. Moreover, Japanese buyers almost always took a part of marketing risk by providing off-take guarantee under the long-term sales contracts, which support the establishment of a project finance structure.

(c) Commercial Banks

Japanese commercial banks took major project risks in recent LNG projects, such as the Australia North West Shelf Project and the Indonesia "Train E" Project. We will discuss the so-called "project finance" where financial institutions will take some of the project risks in the next section.

4. PROJECT FINANCE FOR LNG "GRASS-ROOTS" PROJECTS

Generally speaking, the term "project finance" is used to refer to a financing structure in which the financing is not primarily dependent on the credit support of the sponsors. But here in this paper, we would like to define it as a financing structure where commercial banks take some part of (not all of) the major project risks.

It is true that "project finance" schemes are well applied to large-scale LNG "grass-roots" projects, but there are some required conditions for commercial banks to build up a financing scheme for these projects on a "project finance" basis or a limited recourse finance basis.

The followings are deemed to be basic requirements for "project finance."

- (a) Adequate reserve should be confirmed on a recoverable basis by the reputable independent consultant.
- (b) Development and completion of the project should be guaranteed by gas producers.
- (c) LNG sales contracts including pricing formula should be concluded on the acceptable terms and conditions to the lenders. ("take or pay" clause should be required)
- (d) Project assets should be granted as a first ranked mortgage to the lenders and all rights, and benefits under the related project agreements should be also assigned to the lenders.
- (e) Adequate level of debt service coverage ratio in project cashflow projection should be secured in lenders' analysis as well.
- (f) Cash flow mechanism and cash flow priority including establishment of escrow account should be satisfactorily arranged for the lenders.

On the premise that these required conditions are fulfilled, it will be possible to employ a project financing structure for future LNG "grass roots" projects for the Far East market with the following risk sharing pattern in each risk category:

(a) Reserve Risk

If the adequate reserve of natural gas is proven on a recoverable basis by an internationally reputable consultant, reserve risk can be shared among gas producers, financial institutions including commercial banks, and possibly buyers.

(b) Natural Gas Development and Plant Construction Risk

Natural gas development and plant construction risk, such as cost overrun and delay in completion and shortfalls in expected capacity/efficiency of production, should basically be undertaken by gas producers.

However, some part of this risk (especially, completion risk of liquefaction plant) can be shared with financial institutions if terms and conditions in EPC contracts are acceptable and partial guarantees are provided by producers. In this case, it is preferable for financial institutions that turnkey lumpsum EPC contracts will be reputable and experienced.

(c) Operating and Marketing Risk

LNG buyers and financial institutions involved in the projects require reliable operating capabilities of a project company or its operating and maintenance agreement concluded with an experienced operator in technical and commercial aspects.

As for marketing risk, the financial institutions require a long-term sales contract with "take or pay" clause which is consistent with the amount and period of the debt service.

(d) Political Risk

In any cross-border financing, financial institutions will take political risk which occurs under a collapse of the existing political/legal order in the host/borrowers country, such as alternation in exchange, transfer, and tax regulations, nationalization of the project assets and so on.

Especially for projects in developing countries, financiers are more careful to study those risks. In this part, the support of both governments of LNG exporting and importing countries will be expected.

(e) Force Majeure Risk

We understand that so-called force majeure risk should basically be shared among all related parties in a sense of co-operation. The range of force majeure, however, is carefully discussed and agreed by all related parties, and those risks are particularly acute to the pre-completion phase of the project.

(f) Credit/Financial Risk

Some part of projects risk above mentioned are resorted to project sponsors (gas producers and equity participants). Therefore, financiers assess the credit worthiness and management capabilities of the sponsors that they rely on to ensure the success of the project.

In this way, project risks in LNG projects can be shared by the related parties. EXHIBIT 4 shows the summary of this.

RISK SHARING FOR FINANCING

ITEMS OF RISKS	RISK TAKERS
(a) Reserve Risks	• Gas Producers • Financial Institutions
(b) Construction and Development	• Gas Producers • EPC Contractors • Financial Institutions
(c) Operating & Maintenance	• Gas Producers • Financial Institutions
(d)/(e) Political Risks/Force Majeure Risks	• Government of Host Country • Government Agencies of Financers Country • Financial Institutions • Gas Producers
(f) Credit/Financial Risks	• Financial Institutions

APPENDIX

FINANCING STRUCTURES OF
INDONESIA LNG PROJECTS

- (i) The First Indonesian LNG Project
- (ii) LNG Expansion Projects in Indonesia

(i) The First Indonesian LNG Project

On December 3, 1973 the first Indonesian LNG sales contract was signed between Pertamina and Japanese LNG buyers, the outline of which is shown in Exhibit 5.

The project cost for the construction of liquefaction facilities and LNG tankers was more than US\$ 1 billion and it was not easy for the Indonesian government/Pertamina to procure such a huge amount. They tried to find a way to raise funds in a cooperation with Japanese LNG buyers getting support from Japanese governmental authorities and Japanese related parties.

Such cooperation for financing was quite different from the past LNG projects at that time, where gas producers and/or liquefaction company had financed for the projects by themselves and sold LNG to buyers.

The scheme and main features of financing for the project are illustrated in EXHIBIT 6 and 7.

The financing for the building of LNG tankers was arranged by a shipper, named Burmast East Shipping Corp., and ship builder, General Dynamics, utilizing a guarantee facility provided by the Maritime Administration of the US Department of Commerce.

And LNG receiving terminals in Japan were build and funded by LNG buyers. Financing for the main body of the project consisted of Yen Credit of Overseas Economic Cooperation Fund, one of the Japanese government authorities, and import credit of The Export Import Bank of Japan (J.EXIM) through Japan Indonesian LNG Co., Ltd. (JILCO), which was established specially for the purpose of financing for the first Indonesia LNG project.

OECD Yen Credits are Japanese official overseas development aid and basically to be provided for the construction of infrastructure projects. It was quite exceptional that Yen Credit was provided to a natural resource development Indonesian LNG project. Such special yen credit could be provided only if a project is very significant for both the recipient country and Japan. The repayment term of the yen credit extended 25 years with a grace period of seven years and the interest rate was fixed on 3% p.a.

The co-financing of EXIM with commercial banks made loans to JILCO for this project. Import credits are usually borrowed by importers(trading firms and/or buyers of natural resources) and re-lent to exporters. In the case of the Indonesian LNG project a project company was set up, and risk-taking by the utility companies was in the form of guaranteeing the EXIM co-financing syndicate. This project was the first case where Japanese utilities companies exposed themselves to such risk-taking, although partly covered off through official support programs. Their actual assumption of risk was limited to 40%, because Japan National Oil Corporation(JNOC), a government agency, guaranteed 60% of the loans.

A project company is sometimes set up when a number of entities import products from the same overseas project. The establishment of such a company has several merits; the clerical control of the loans can be facilitated, coordination among the related parties can be easier, and importers sometimes prefer guarantees to loans when indicating their obligations on their balance sheet.

Project companies are usually set up with a small equity capital. JILCO's paid-in capital was Japanese Yen 1.5 billion. The parties that have an equity share in a project are generally importers and trading firms. In the case of JILCO, many companies other than importers cooperated because the project was of national importance.

The amount of the JILCO import credit was equal to the total cost of the construction of the liquefaction facilities (except portions covered by yen credits). This was rather unusual. The reason for EXIM's approval of the full amount was that all LNG from the liquefaction facilities was to be exported to Japan, which was in urgent need of LNG.

As a measure to ensure the repayment of JILCO loans, a certain percentage of LNG sales proceeds is credited to the escrow accounts in the US from which principal and interest are repaid. The reliability of the cash flow of this project to these accounts was enhanced by the fact that development of natural gas fields, construction and operation of the liquefaction facilities, construction and operation of LNG tankers and other activities were undertaken by parties with excellent technological know how and experience; and by the fact that the Japanese buyers themselves had concluded the take-or-pay contract.

The JILCO's loans were made in US dollars, but a certain percentage of EXIM co-finance was denominated in yen. Accordingly, JILCO took a foreign exchange risk.

The First Indonesia-Japan LNG Sales Contract

1. Buyers and their respective purchase quantity:

(thousand tonnes per year)

Chubu Electric Power Co., Inc.	1.700
Kansai Electric Power Co., Inc.	2.400
Kyushu Electric Power Co., Inc.	1.500
Nippon Steel Corporation	600
Osaka Gas Company, Ltd.	1.300
TOTAL	7.500

2. Take or Pay : Buyers assume take-or-pay obligation subject to availability.
3. Transport : Pertamina's responsibility. Title of LNG passes on delivery into a buyer's receiving facility.
4. Term : 1977-99
5. Price : Price is escalated according to the movements of Indonesian crude oils and transport costs.

Finance for The First Indonesian LNG Project

1. Share of Loan :

Exim Banks	80%
Commercial Banks	20%

2. Amounts:

ARUN	US\$523 million equivalent (mixture of yen and US dollars)
BADAK	US\$375 million equivalent (mixture of yen and US dollars)

3. Interest Rates(JILCO's funding cost):

Commercial Banks	
US Dollar	LIBOR + margin
YEN	Long-term prime lending rate + margin
EXIM	Fixed

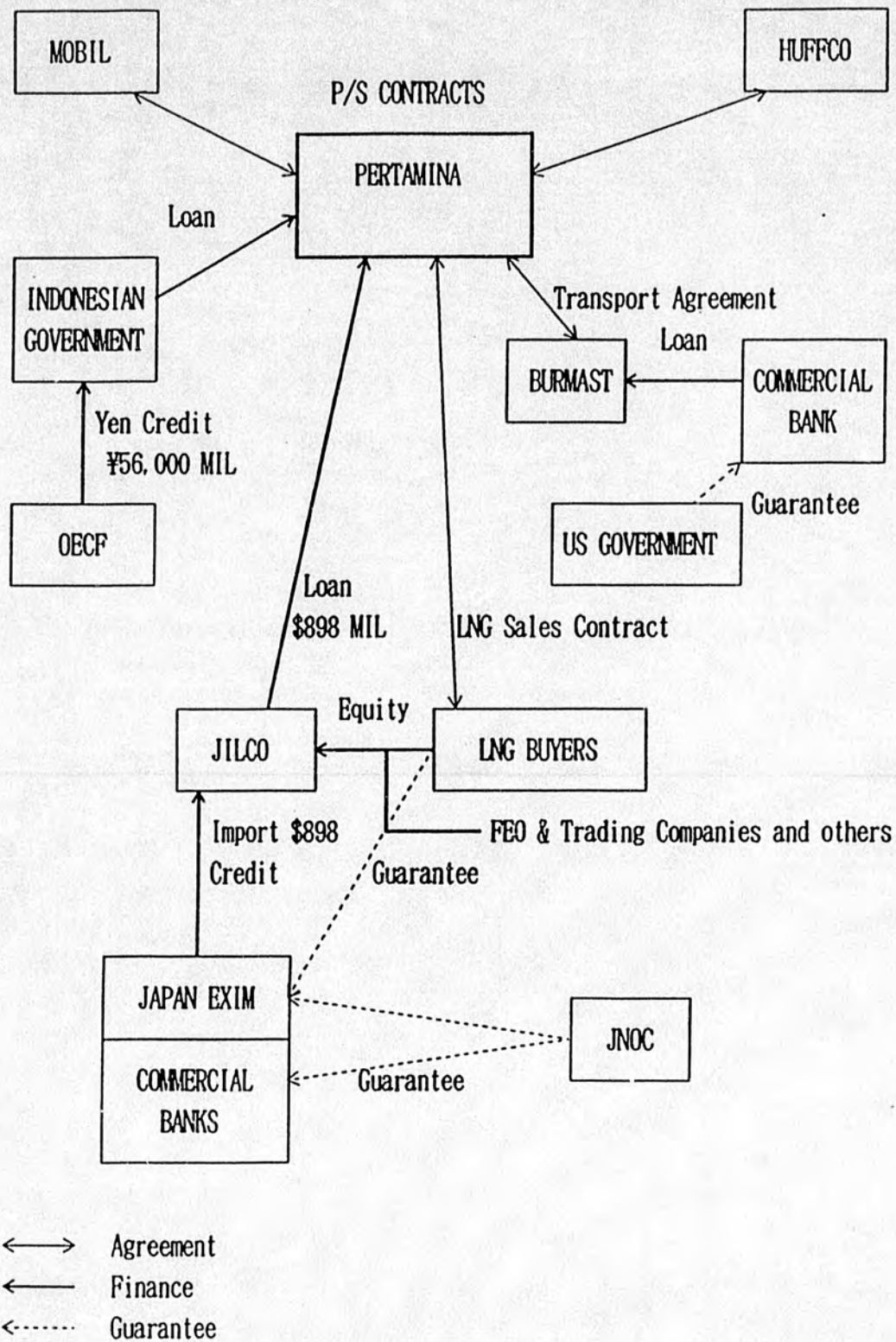
Terms :	
ARUN	16 years
BADAK	15 years

Guarantee :	JNOC	60%
	LNG Buyers	40%

Escrow Account :	Certain percentage of sales proceeds is credited to the escrow account.
------------------	---

Overseas:	Certain percentage of the loans was insured.
Investment:	
Insurance:	

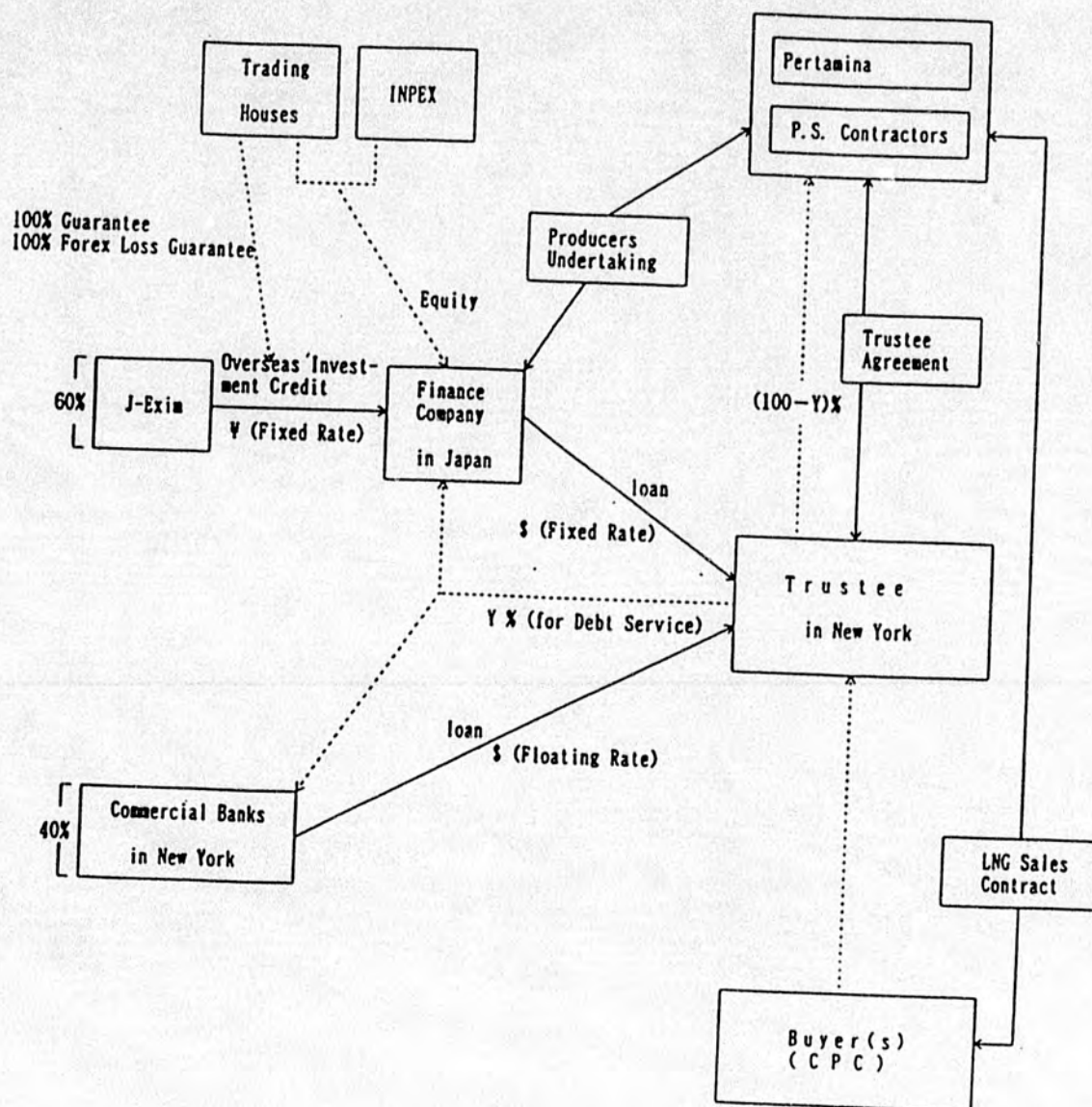
Finance Scheme of The First Indonesian LNG Project



"Trustee Borrowing Scheme" for Indonesian Train E Project

EXHIBIT 8

Trustee Borrowing Scheme



REFERENCE MATERIAL

- (1) INFORMATION OF THE EXPORT IMPORT
BANK OF JAPAN
- (2) INFORMATION OF JAPAN NATIONAL
OIL CORPORATION
- (3) INFORMATION OF THE DEVELOPMENT
BANK OF JAPAN
- (4) INFORMATION OF THE EXPORT IMPORT
BANK OF KOREA

TAGS Construction Costs and Timeline

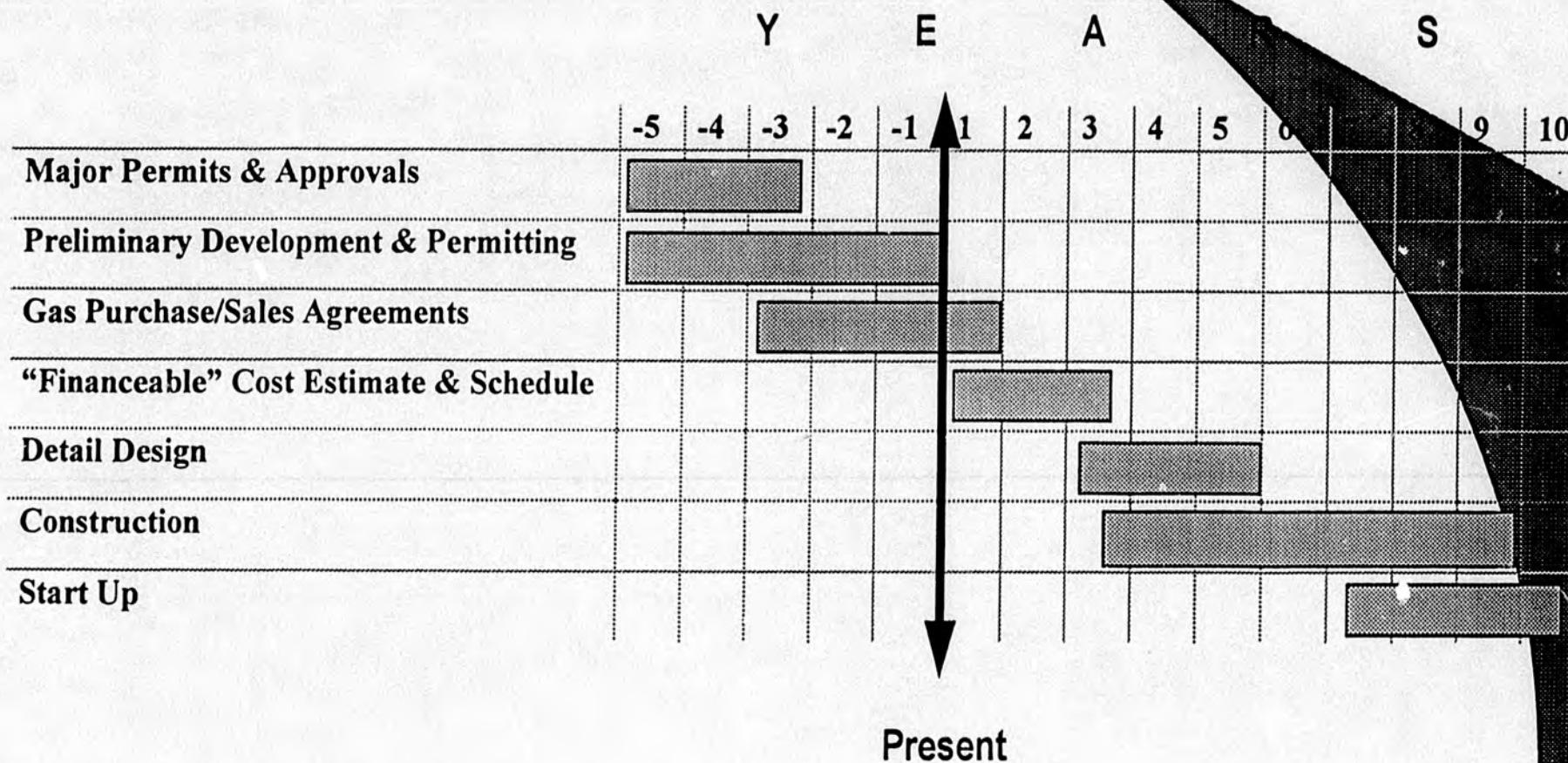


TAGS Capital Cost Estimates

(1991 \$ billions)

	<u>Total</u>
Alaska Facilities	10.0
Shipping	<u>3.4</u>
	\$13.4

TAGS Project Timetable



TAGS Competition:

Cost Comparisons



Grass Roots LNG Projects

Cost Comparison

Project	Production (MMTPA*)	Estimated Cost \$ Billions	Cost in \$ Billions per MMTPA	Capital ** per MMBTU
Alaska TAGS	15	13.6	0.91	0.70
TAGS at higher cost	15	15.0	1.00	
Qatargas	6	6.0	1.00	
Natuna Island	15	21.3	1.42	1.00
Sakhalin	6	7.9	1.32	1.00

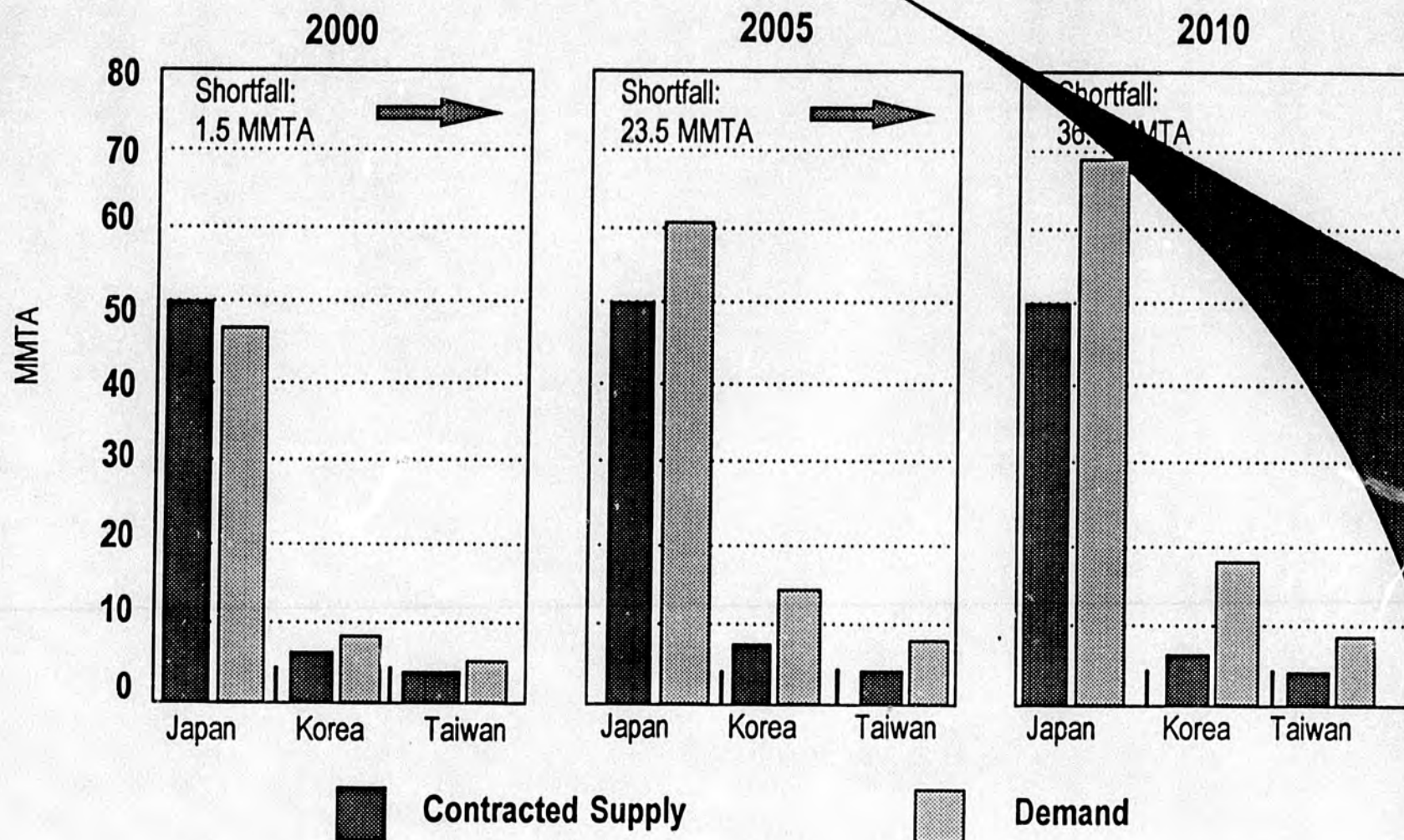
* million metric tons per annum

** does not reflect capitalized interest, cost of gas, time value of money or operating exp

Asian LNG Market: Demand Projections



Contracted Asian LNG Supply vs. Projected Demand



Financing of LNG Projects

- A Case study for Natuna Gas Development Project from a financier's viewpoint -

The Industrial Bank of Japan, Limited

IBJ

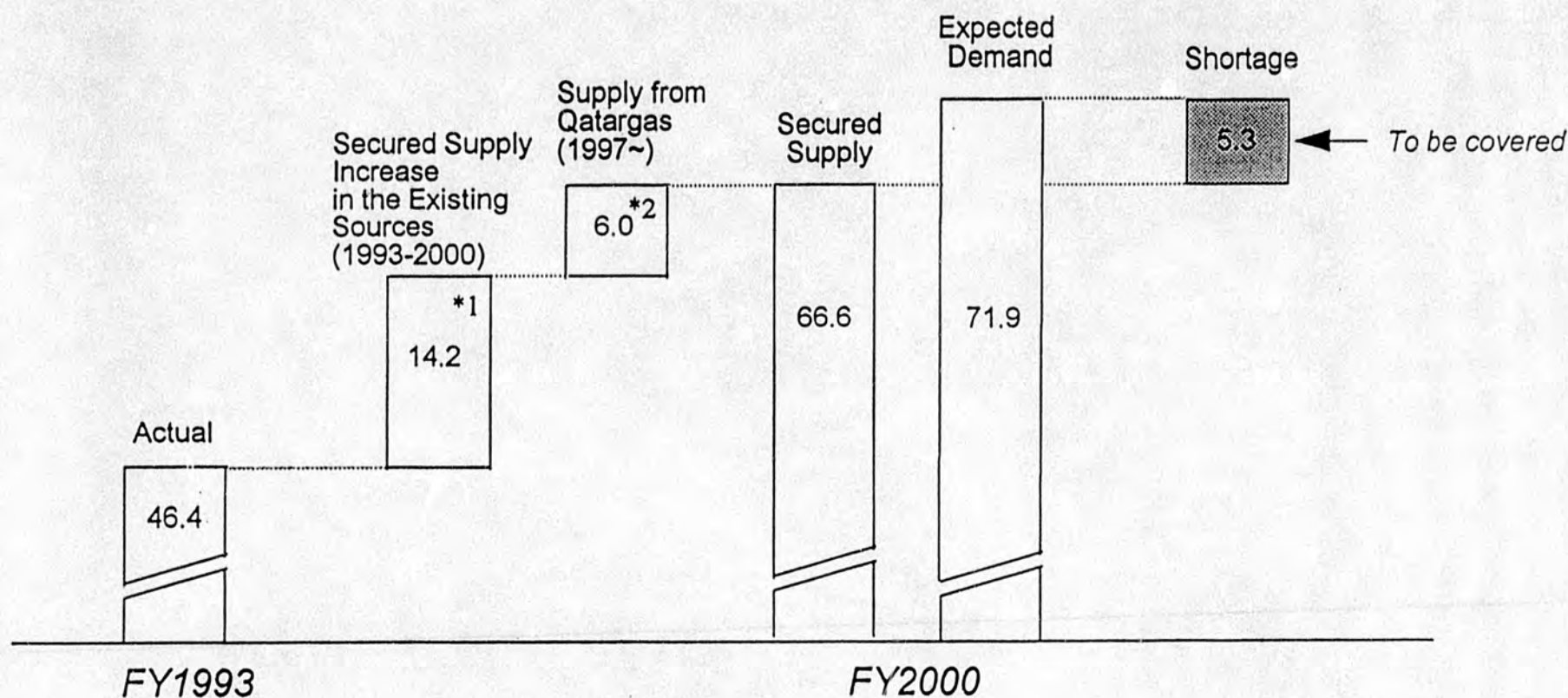
I. A Financier's view on East Asian LNG Supply and Demand

- Supply-Demand Balance Before Year 2000

- Supply-Demand Balance After Year 2001

Fig.1

LNG Demand & Supply in the Far East ***-Japan, Korea, Taiwan, FY2000- (Million Tons)***



*1

Including Indonesia Badak Train H

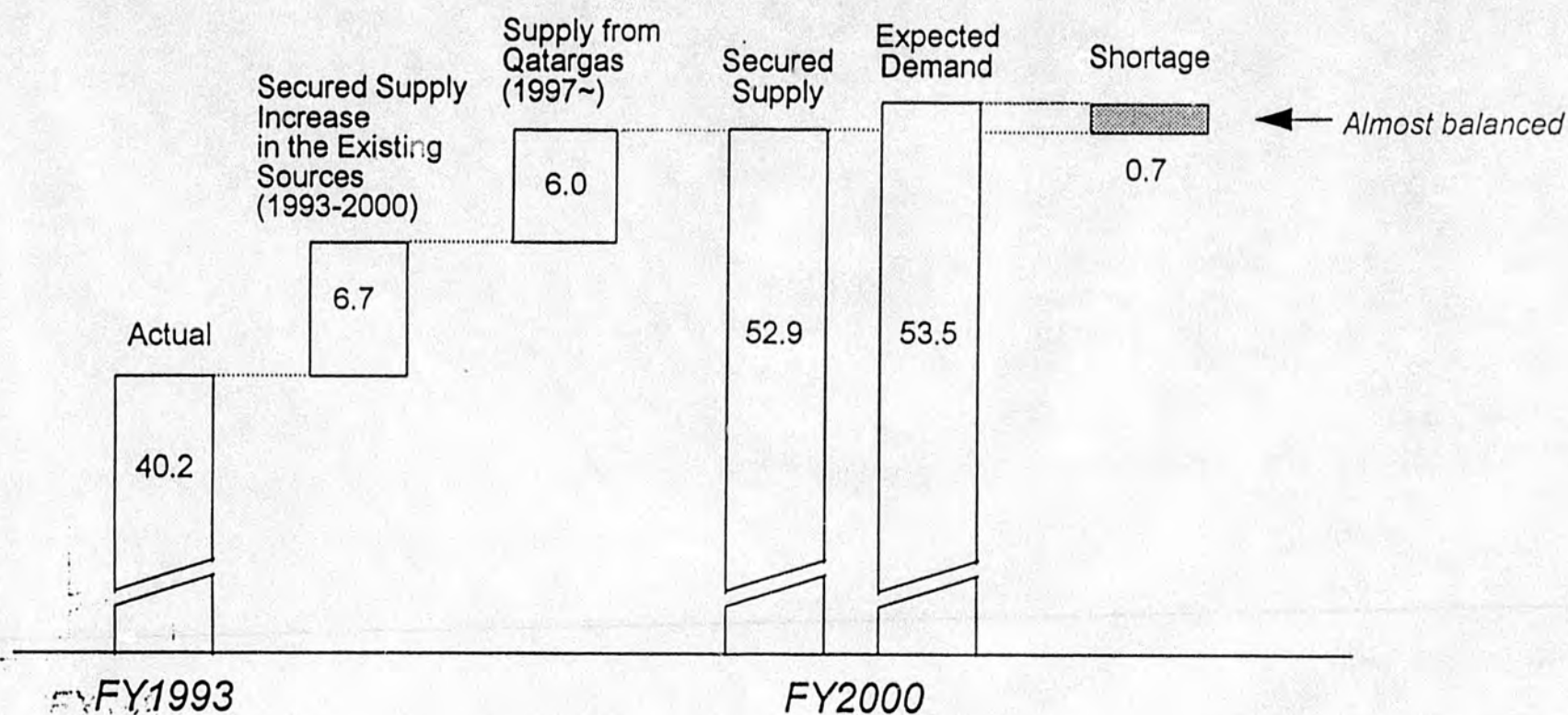
*2

Excluding Qatar Ras Laffan Project

<Source: IBJ Estimation>

Fig 2

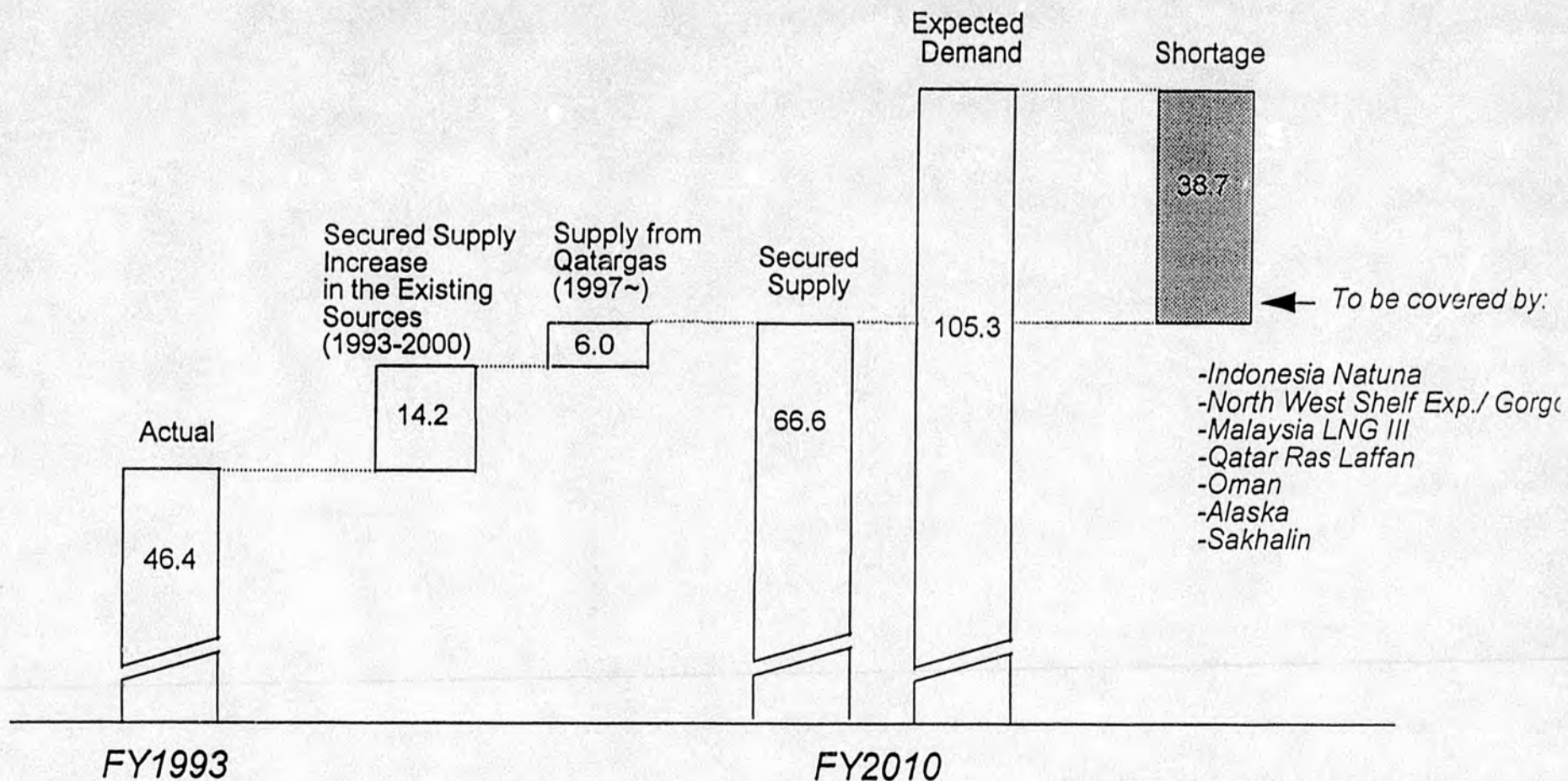
LNG Demand & Supply -Japan FY 2000- (Million Ton)



<Source: IBJ Estimation>

Fig 3

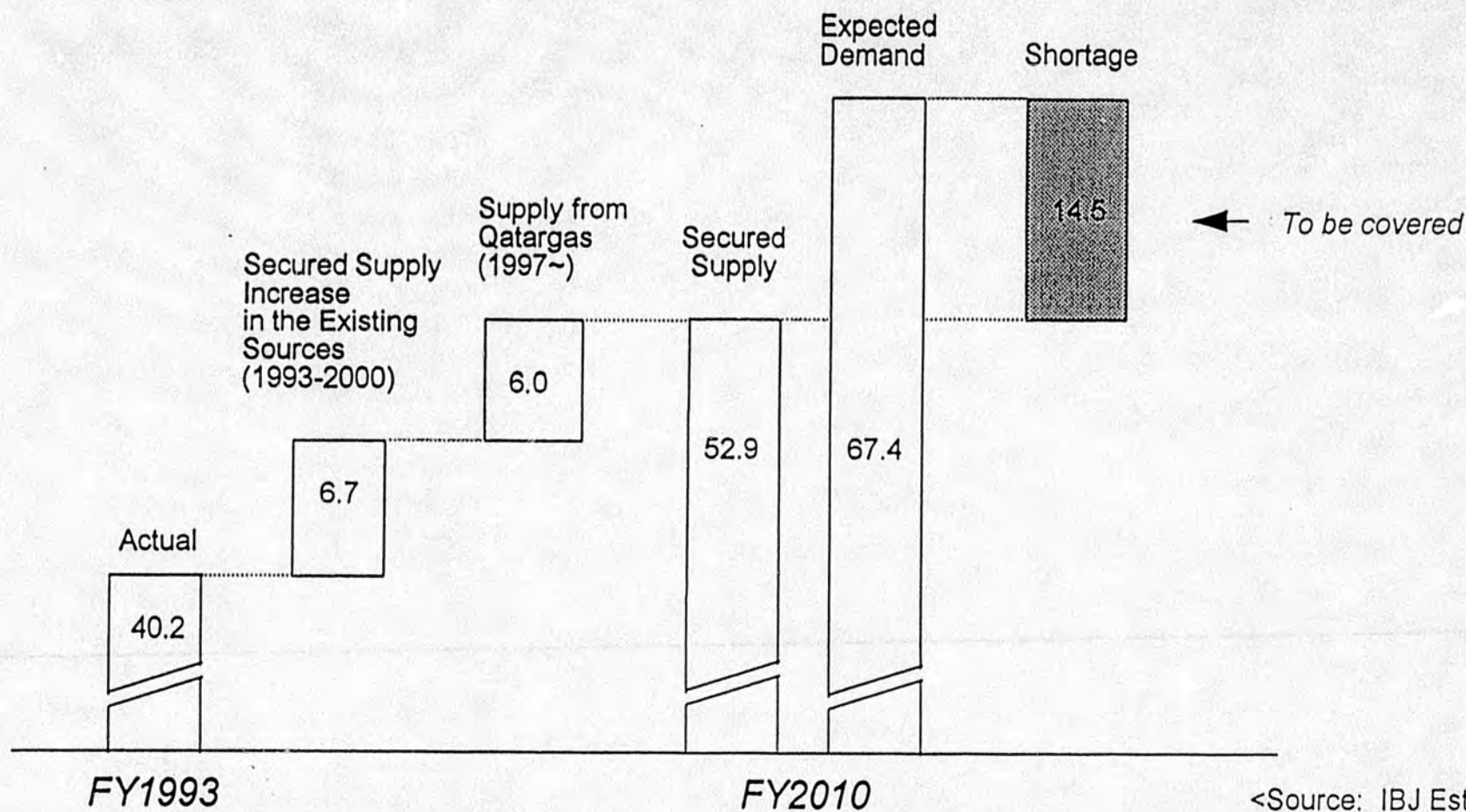
LNG Demand & Supply in the Far East ***-Japan, Korea, Taiwan, FY2010-*** (Million Tons)



<Source: IBJ Estimation>

Fig.4

LNG Demand & Supply -Japan FY 2010- (Million Ton)



<Source: IBJ Estimation>

Fig.5

Existing LNG Contracts/Commitments for 2000

As of October 1995 (Unit: Million Tons per Year)

	Tohoku Electric	Tokyo Electric	Chubu Electric	Kansai Electric	Chugoku Electric	Kyushu Electric	File. Cos. Total	Tokyo Gas	Osaka Gas	Toho Gas	Saibu Gas	Medium City	Gas Cos. Total	Nippon Steel	Japan Total	Korea	Taiwan	Grand Total	Expiration of S'A
Alaska		0.82					0.82	0.27					0.27		1.09			1.09	Mar-04
Brunei		3.72					3.72	1.14	0.68				1.82		5.54			5.54	Mar-13
Abu Dhabi		4.45					4.45						0.00		4.45			4.45	Mar-19
Indonesia	3.22	0.51	3.80	3.45	0.00	1.56	12.54	0.92	3.01	0.92	0.00	0.29	5.14	0.60	18.28	5.30	4.15	27.73	
(Badak/Aruni, Badak Y/G)			2.15	2.57		1.56	6.28		1.30	0.25			1.55	0.60	8.43			8.43	Dec-10
(Badak II)			1.65	0.88			2.53		0.44	0.55			0.99		3.52			3.52	Mar-11
(Arun II)	3.22	0.51					3.73						0.00		3.73			3.73	Dec-04
(Arun III)							0.00						0.00		0.00	2.30		2.30	Nov-06
(Badak III/E)							0.00						0.00		0.00		2.25	2.25	Dec-09
(Badak IV/F)							0.00	0.92	1.27	0.12			2.31		2.31			2.31	Dec-13
(Korea II)							0.00						0.00		0.00	2.00		2.00	Jun-14
(Hiroshima/Nihon)							0.00					0.29	0.29		0.29			0.29	2016
(Badak VI/II)							0.00						0.00		0.00	1.00	1.90	2.90	2019
Malaysia	0.50	4.80	0.00	0.42	0.00	0.00	5.72	3.55	0.60	0.28	0.27	0.38	5.08		10.80	2.00	2.25	15.05	
(MLNG I)		4.80					4.80	2.75			0.21		2.96		7.76			7.76	Dec-03
(MLNG II)	0.50			0.42			0.92	0.80	0.60	0.28	0.06	0.38	2.12		3.04	2.00	2.25	7.29	Mar-15
Australia		1.05	1.05	1.05	1.05	1.05	5.25	0.68	0.68	0.21			1.57		6.82			6.82	Dec-08
Qatar (Qatargas)	0.52	0.20	4.00	0.29	0.12		5.13	0.35	0.35	0.06			0.76		5.89			5.89	Dec-21
TOTAL	4.24	15.55	8.85	5.21	1.17	2.61	37.63	6.91	5.32	1.47	0.27	0.67	14.64	0.60	52.87	7.30	6.40	66.57	

Fig. 7

Major Gas Development and LNG Projects with IBJ Involvement

Project (year / country)	Major Promoters	IBJ's Involvement
Indonesia LNG (Original) (1974, US\$1,547M)	Pertamina, JILCO (Kansai Electric Power, Chubu Electric Power, Kyushu Electric Power, others)	-Managing bank of J-EXIM joint finance for JILCO
Indonesian LNG expansion projects: -Badak (1981, US\$996M) -Arun (1981, US\$840M) -Badak Capital Investment (Phase I & II) (1986-87, US\$200M) -Badak, Train E (1988, US\$316M)	JILCO, Pertamina INALCO (Tohoku Electric Power, Tokyo Electric Power, Mitsubishi Corp.), Pertamina Pertamina Pertamina, Huffco, Total, INALCO	-Managing bank of J-EXIM joint finance for JILCO -Managing bank of J-EXIM joint finance for INALCO -Agent and lead manager of syndicated project loan -Arranger and lead manager of the trustee borrowing scheme
Malaysia LNG (Sarawak LNG) (1980, US\$1,233M)	Petronas, Shell, Mitsubishi Corp.	-Financial advisor for Petronas -Financial advisor for Malaysia LNG Sdn. Bhd. -Managing bank of J-EXIM joint finance for Petronas -Participated in J-EXIM joint finance for Mitsubishi Corp.
North West Shelf Gas (Phase I) (1981, Australia, A\$2,000M)	Woodside Petroleum Ltd. (WPL), BHP, Shell, BP, Chevron	-Lead manager of Euro-syndicated project loan for WPL
North West Shelf Gas (Phase II) (1985, Australia, A\$10,000M)	Woodside Petroleum Ltd. (WPL), BHP, Shell, BP, Chevron, Mitsui/Mitsubishi	-Lead manager of Euro-syndicated project loan for WPL -Lead manager of EXIM co-finance syndicated project loan for MIMI (Mitsui/Mitsubishi) -Arranger and lead manager of Euro-syndicated project loan for PTT
Thailand B Structure (1991, US\$500M)	Petroleum Authority of Thailand (PTT), Total, British Gas	-Lead arranger and coordinator
Malaysia LNG Dua (1994, US\$2,513M)	Petronas, Shell, Mitsubishi Corp., Sarawak State Gov.	-Core bank and lead manager
Qatargas (1994, Qatar, US\$2,850M)	QGPC, Total, Mobil, Mitsui & Co., Marubeni	

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A SELLER'S VIEW OF ASIA-PACIFIC
LNG MARKET BY 2010

by

H. BAHARUDDIN

**Senior Vice President
Director Corporate Affairs
PERTAMINA
Jakarta, Indonesia**



FIRST DOHA CONFERENCE ON NATURAL GAS

PANEL SESSION 2 - March 13, 1995

PRESENTATION BY MR H. BAHARUDDIN
PERTAMINA - INDONESIA**"A SELLER'S VIEW OF ASIA-PACIFIC LNG MARKET BY 2010"**

Thank you very much for giving me the opportunity to exchange a few ideas with you today on the future of Asia-Pacific LNG market. You will not be surprised if I start my remarks today by saying that I anticipate a bright future for LNG exports as far as we can see forward, that means between today and 2010.

I. A BRIGHT FUTURE FOR LNG EXPORTS

LNG merits in terms of economics and environment are being recognized by a growing number of government planners and industrial investors in this part of the world. I therefore believe that at least 3 countries - China, Thailand and India - will soon follow the example of Japan, Korea and Taiwan, and become LNG importers in a very near future.

LNG demand forecast in Asia-Pacific

Japan will remain by far the biggest LNG buyer in the world. 14 Japanese companies are or will soon be importing LNG. In 1993, Japanese LNG imports came close to 40 million tons, 47% of which supplied by Indonesia.

To assess future demand, we can use MITI's long term plan which seems to me rather on the low side when it comes to LNG : 53 to 54 million tons in the year 2000 and 58 to 60 million tons in 2010. These projections assume a 2% per annum growth in LNG demand for power generation and a 4% per annum growth in LNG consumption by city gas companies.

One major Japanese trading company is sharing the same view regarding city gas while expecting a higher growth - above 3% per annum - in power generation LNG use. This, I believe, is a more likely demand scenario : 61 or 62 million tons in 2005 and 70 million tons in 2010.

The second biggest LNG importer in Asia-Pacific region is Korea. Korea Gas Corporation is using itself 2 demand scenarios which appear very reliable. These scenarios are running until 2006 and therefore need some extrapolation. The forecast is as follows : 11 to 13 million tons in the year 2000, 14 to 17 million tons in 2005, and maybe 18 to 21 million tons in 2010.

Assessing Taiwan future demand is more difficult due to the uncertainty regarding new power plant projects. LNG, coal, nuclear, what will be their respective shares in the year 2000 is still unclear. If we exclude any new LNG-fired power plant after 1999, Taiwan LNG imports could rise to 6 or 7 million tons and remain at this level. However, based on existing development plans for LNG-fired power plants, the forecast could reach much higher figures : 9 million tons in 2005, and 12 in 2010.

Among the new LNG customers in Asia-Pacific, China probably offers the biggest potential. Up to 2 million tons of LNG could be imported in the Southern provinces as early as in the year 2000, rising to 4 to 8 million tons in 2005 and 8 to 16 million tons in 2010. Uncertain forecast, indeed, but looking at the current economic growth and the huge size of its population, China is deemed to become a big LNG player.

Thailand's LNG requirement will obviously depend on the availability of domestic gas resources and pipeline alternatives. Imports are planned to start in 2001 and could reach 3 to 5 million tons in 2005, 6 to 10 million tons in 2010.

In India, a number of LNG projects is reported but LNG development needs to be compared with the economics of importing gas by pipeline from the Middle-East. The minimum case could see no LNG import until 2010, while the maximum case could be 4 million tons in 2005 and 10 in 2010.

In summary, I would assess Asia-Pacific LNG imports as follows:

- between 70 and 75 million tons in the year 2000,
- about 85 up to 105 million tons in 2005, and
- a wide range of approximately 100 to 140 million tons in 2010.

It means a lot of potential ... and also a lot of uncertainty!

However, demand figures cannot be discussed independently from supply forecast. Demand does not depend only on consuming countries' plans but also on the availability of reliable and economical resources on producers' side.

Supply and demand gap

Based only on existing capacity and taking into account the possible depletion of some gas fields, the supply from the 6 existing Asia-Pacific LNG producing countries should remain around 50 million tons over the period 1995 - 2010.

The most economical way to reduce the gap with demand is probably through the expansion of existing capacity. Such plans are underway or under review and could add another 14 million tons in the year 2000, increasing to about 21 million tons through the period 2005 - 2010.

It gives us, over the period 2000 - 2010, a total Asia-Pacific LNG supply between 65 and 70 million tons from the existing plants including their projected expansion.

This will not be sufficient to meet the rising demand. With expansion projects only and without grass-root projects, our forecast shows that the supply and demand gap would reach 4 to 9 million tons in the year 2000. This gap would then further increase to a range of 15 to 35 million tons in 2005 and 30 to 70 million tons in 2010.

These figures are big and challenging for the LNG industry. It is clear that several grass-root projects will have to be developed in the coming years to overcome the supply and demand gap. No less than 10 grass-root projects are in today's picture, some of which are mega-size projects, such as Natuna and Qatar.

I am not here to discuss the comparative chances of all expansion and grass-root projects in the world. I shall leave this task to independent analysts.

As for Indonesia, our aim is to balance the increase of our LNG exports with the satisfaction of growing domestic gas requirements. I would like to give you now a very brief overview of our current LNG development plans.

Indonesian projects

First, we plan to expand the capacity of our Bontang LNG plant on the Eastern coast of Kalimantan. This expansion, supported by the increase of our gas reserves in this area, will enable us to extend our first two long term contracts with Japan.

Then, our next challenge will be to extend all our other long term contracts and to supply new markets in and outside Indonesia. For this, we plan to build a new LNG plant on Natuna Island with a capacity of 15 million tons. This project is very ambitious, specially in terms of financing requirements and technological innovations. We are planning a start-up in 2005, at a right time to ease the growing supply and demand gap.

In any case, the success and timing of development for any grass-root project will depend on what slice of demand it can secure, and when. What is certain today is that all these new projects will require a lot of efforts and imagination from the part of their developers in order to be both economically viable and competitive.

II. THE VIABILITY OF NEW LNG CHAINS

Rising cost and increased value

My intention here is not to enter into the detail of a subject well known by all the participants: the rising cost of new LNG projects and the increased value of LNG in the market.

These discussions tend to be usually one-sided, sellers claiming that they are justified to seek a price increase and buyers stressing the necessity for LNG to remain competitive versus other sources of energy.

Obviously, in this debate, everybody is right to a certain extent. What really matters is to seek the optimum price which can satisfy both parties' concerns. But the negotiation of a higher price is necessarily limited. Imagination and a spirit of innovation are also required, in order to explore new areas.

JAPAN LNG DEMAND

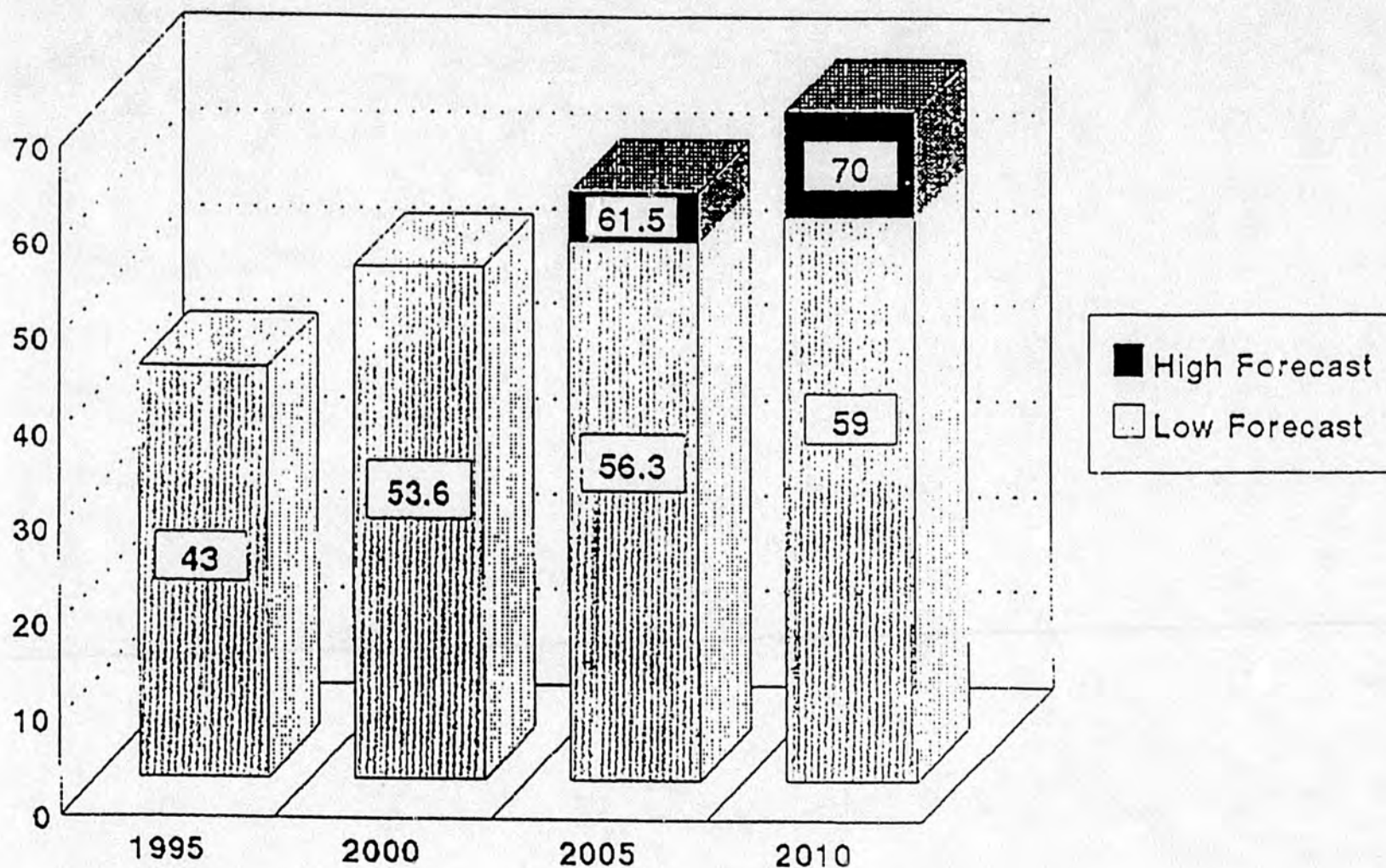
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Million Tons

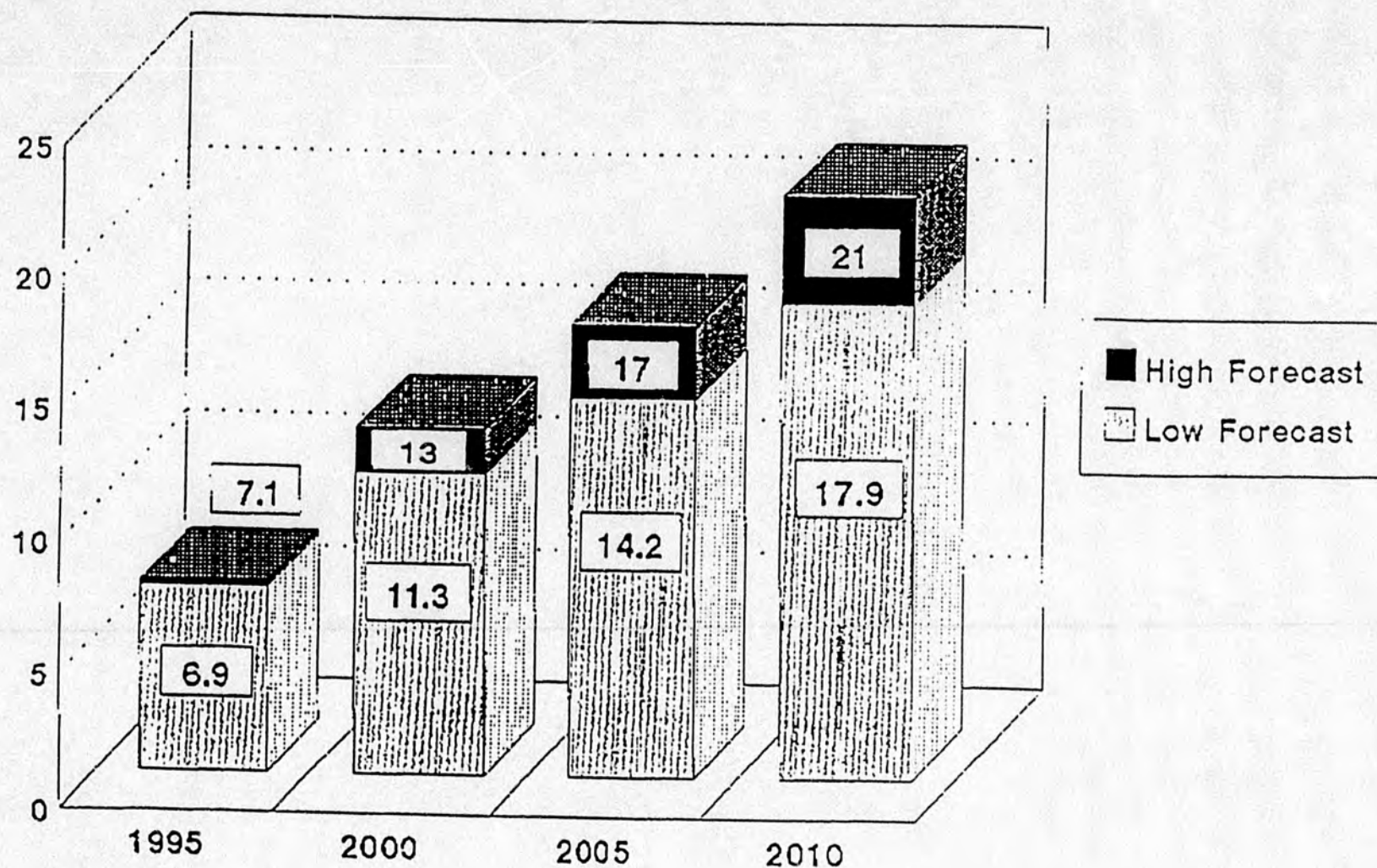


PERTAMINA

March 1995

KOREA LNG DEMAND

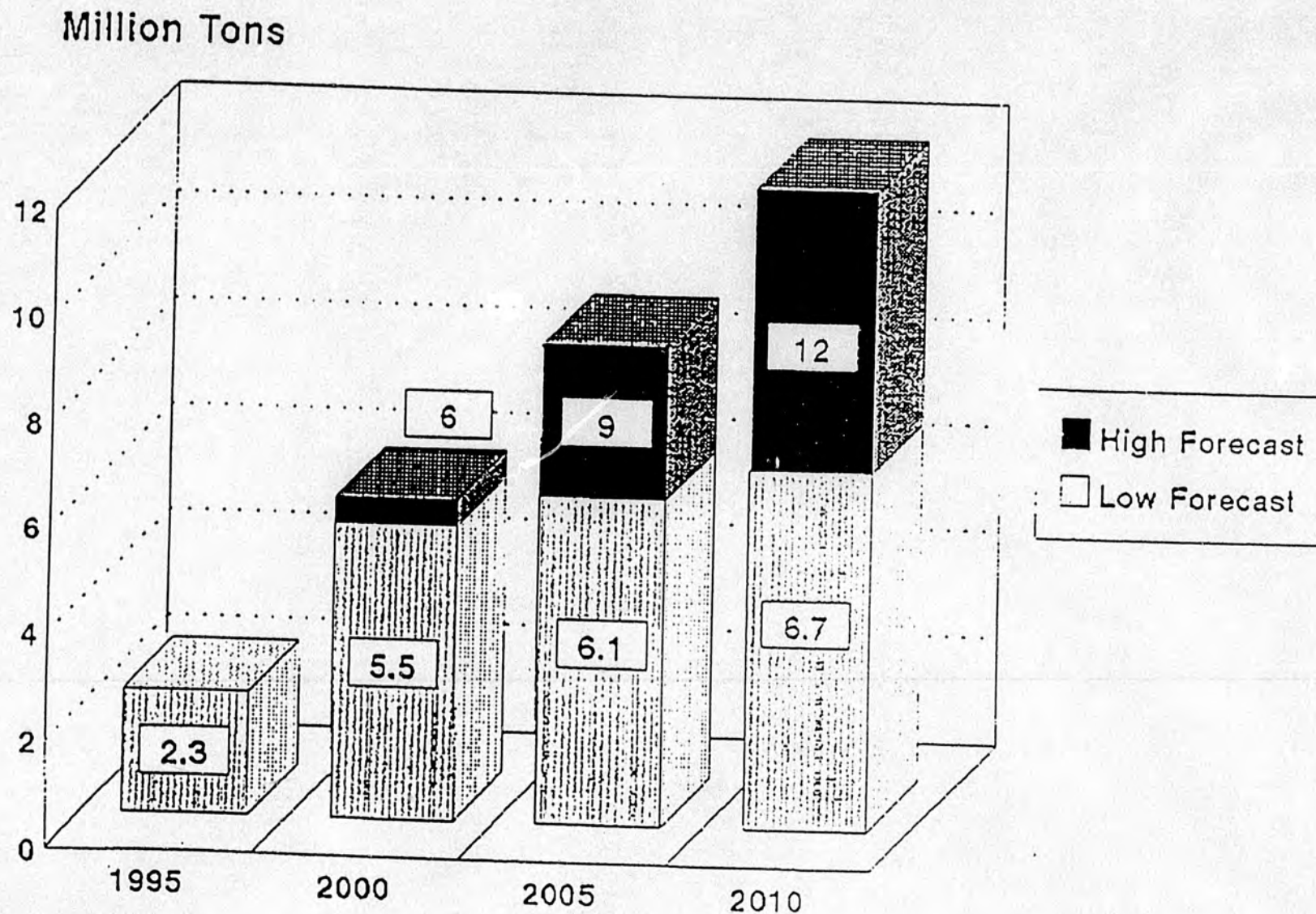
Million Tons



PERTAMINA

March 1995

TAIWAN LNG DEMAND

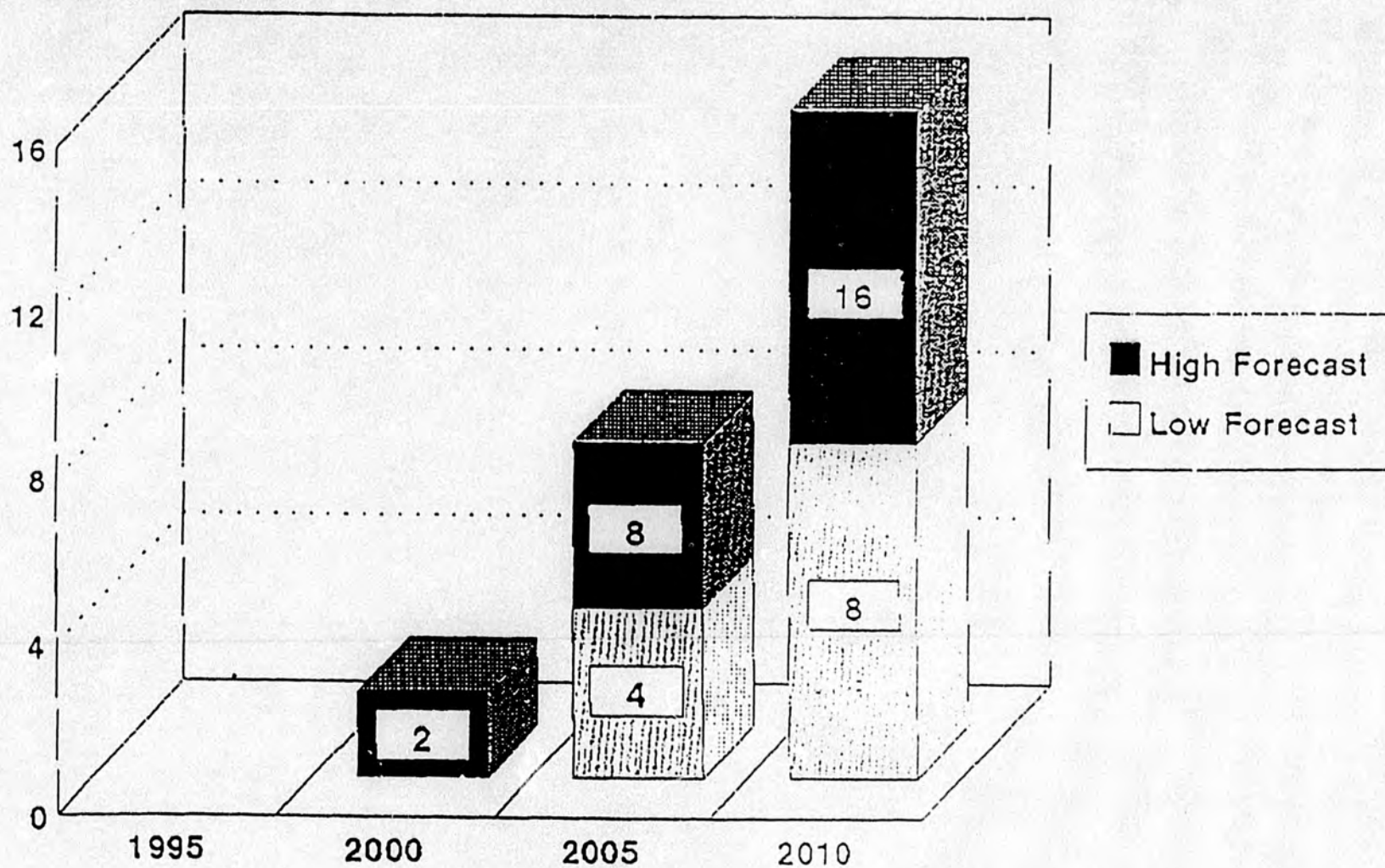


PERTAMINA

March 1995

CHINA LNG DEMAND

Million Tons



PERTAMINA

March 1995

TABLE 1
ANALYSIS OF ASIA-PACIFIC LNG MARKET BY 2010

	Low Demand				High Demand			
	1995	2000	2005	2010	1995	2000	2005	2010
Probable Demand								
Japan	43.00	53.60	56.30	59.00	43.00	53.60	61.50	70.00
Korea	6.90	11.30	14.20	17.90	7.10	13.00	17.00	21.00
Taiwan	2.30	5.50	6.10	6.70	2.30	6.00	9.00	12.00
China			4.00	8.00		2.00	8.00	16.00
Thailand			3.00	6.00			5.00	10.00
India							4.00	10.00
Total Demand	52.20	70.40	83.60	97.60	52.40	74.60	104.50	139.00
Firm Capacity								
Abu Dhabi	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Alaska (Kenai)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Australia	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Brunei	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
Indonesia	26.00	26.00	22.00	18.00	26.00	26.00	22.00	18.00
Qatargas		6.00	6.00	6.00		6.00	6.00	6.00
Malaysia	10.50	17.00	17.00	17.00	10.50	17.00	17.00	17.00
subtotal	54.50	67.00	63.00	59.00	54.50	67.00	63.00	59.00
Net Demand/(Excess Supply)	-2.30	3.40	20.60	38.60	-2.10	7.60	41.50	80.00
Possible Expansions & Grass-Roots Projects								
Expansions								
Australia (Perseus)			2.00	2.00			2.00	2.00
Indonesia - Badak		2.60	5.00	5.00		2.60	5.00	5.00
Qatargas		4.00	4.00	4.00		4.00	4.00	4.00
Grass-Roots Projects								
Alaska (TAGS)			6.00	14.00			6.00	14.00
Australia (Peter/Tern)			2.00	2.00			2.00	2.00
Malaysia III			6.00	6.00		6.00	6.00	6.00
Natuna			6.00	15.00			6.00	15.00
Oman			6.00	6.00		6.00	6.00	6.00
Qatar-Ras Laffan			6.00	10.00			6.00	10.00
Sakhalin I			6.00	6.00			6.00	6.00
Sakhalin II				6.00				6.00
Yemen				5.00				5.00
Possible Supplies	0.00	6.60	49.00	81.00	0.00	18.60	49.00	81.00
Excess Capacity	2.30	3.20	28.40	42.40	2.10	11.00	7.50	1.00

Norway's landing operations, but their utilization of pipeline capacity of under 50% is far lower. Originally designed to land gas from major gathering pipelines jutting into the North Sea, the three principal terminals are part of a plan that aims to stimulate offshore development, but could also be harnessed, albeit with substantial investment, as yet another beach head for spot gas sales from the North Sea. For now, though, potential producers claim that monopoly customer Gasunie's price terms are too low to warrant increased exploration and production, and no plans to connect additional UK sector fields are currently near fruition (WGI Nov.10,p4). Last year sales through the three principal terminals totaled 2.5-bcm, representing only 40% of capacity. The system brings Wintershall's Windermere gas from the southern UK North Sea to the Continent. The Uithuizen terminal serves the 36-inch

NOGAT gathering pipeline owned partly by Occidental. The Callantschoog terminal serves the NGT and WGT gathering lines and a 24-inch pipeline from the K-15 field. The Maasvlakte terminal serves Amoco's offshore P-15 oil and gas assets.

While pale in comparison to the potential influence of Norway, the Netherlands, and the UK, Denmark's facilities near Nypro in Jutland are also being expanded to accept additional Danish gas. Chances for imports from other countries are considered remote but still possible. Expansion of terminal facilities at Nypro to nearly 10-bcm/yr should be completed by Jan. 1997 to take new flows from the Harald and Trym fields. Purely a standby treatment facility and metering point, the Nypro plant is tailored for production on the Danish continental shelf, which stood at 4.6-bcm/yr, or 450-million cfd, in 1994.

Korean LNG Demand Surges Beyond Expectations

In what is a most welcome development for aspiring liquefied natural gas producers worldwide, rapidly expanding urban gas use and burgeoning electric power needs are powering South Korea's LNG demand well beyond previous expectations. State Korea Gas Corp., now preparing its biennial forecast, is expected to show a substantial rise

in LNG imports to more than 15.5-million tons a

year by 2000 — almost

double 1994 consumption

levels. Only two years ago

KGC predicted, as a mid-

point case, that Korean gas

use would rise to 12.1-

mmt/yr by 2000, based solely

on LNG imports. The

company is now revising its

figures in a report that is to

be formally released by end-

year, and the preliminary

conclusion from this crystal-

ball gazing exercise shows a

substantial increase in the

country's potential gas

demand. State utility Korean

Power, a key incremental

buyer, has yet to add its

final input, but the message

is clear — the potential gas

needs of South Korea are far

outstripping most previous

predictions by LNG analysts.

From

1990's level of 2.33-mmt, imports

more than doubled by 1994

to 5.86-mmt. By 2000, they should

more than double from

year's estimated 6.86-mmt to 15.5.

The new forecast is some 28% above

levels predicted in

1993 and exceeds that year's "high

growth" scenario by 1-

mmt/yr. It is remarkable that for the first time ever, this year's city gas use, which is mainly residential but also commercial, almost equals South Korea's gas consumption for power generation. According to Korean analysts, city gas should account for 53.5% of all gas use by 2000. What is notable about the consumption boom is that resi-

dential city gas use, under

a massive government

program to substitute oil

with piped gas for space

heating, still has further

room to expand. While

power generation should

soon be replaced as the top

use for LNG, future incre-

mental demand growth

should also begin to develop

in non-traditional consump-

tion sectors. Korea Gas

Union General Secretary

Ho-Kyong Kim, in a recent

paper presented in Jakarta,

predicted that non-power

gas use would continue to

rise, supported by the need

for further air conditioning

during Korea's torrid sum-

mers and the expansion of

gas use for transport in

order to cap Korea's grow-

ing urban air pollution prob-

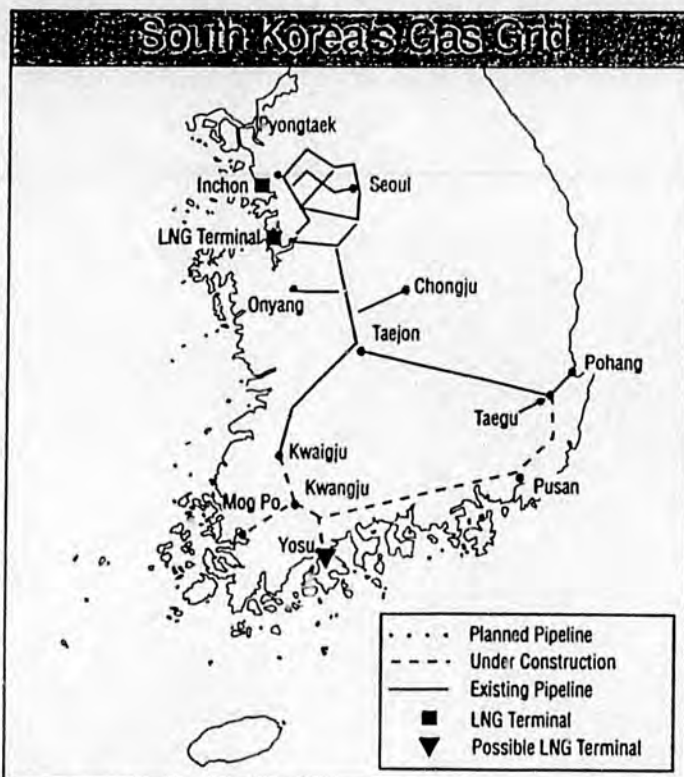
lems. In 1994, city gas

accounted for 41.8% of

Korea's 5.86-mmt/yr of

gas demand.

Residential demand made up two-thirds of city gas use in 1994, and of that total some 80% was used for home heating. But Korean authorities do not believe this represents a mature market now that nearly one-half of urban



households have access to gas by pipeline. The KGU predicts "a great increase in city gas demand in chilling" for office air conditioning (all new office buildings must be led with gas) and ice storage. Further, Kim points out, as pollution controls become ever more severe, natural gas powered vehicles will have to be encouraged to improve air quality levels. Presently, Korea already uses only unleaded gasoline and is reducing diesel sulfur levels to 0.1% in 1996, and 0.05% by 1998. The government is expected to promote natural gas vehicles actively in metropolitan Seoul by 2000 in order to maintain cleaner air standards.

The boom in gas use reflects a concerted government emphasis on building gas transport, storage, and utilization infrastructure. Construction of Korea's second LNG receiving terminal is under way, and completion of a further expansion of the national pipeline network is now slated for 1998. A three-tank expansion is ongoing at KGC's Pyongtaek LNG terminal near Seoul, and another berth is under construction. This should comfortably allow for the annual import of up to 8-mmt of LNG. A second LNG terminal, at Incheon, also near the capital, should be completed by end-1996 and allow for an additional 4-mmt of imports. A third terminal, long under consideration, is now being mulled over for Yosu, at the southern tip of the peninsula.

The original nearly 1,600 kilometer national gas transmission system should be completed by 1996, and small but substantial additions to the original plan are scheduled to be finished by 1998. They include a high pressure foot diameter pipeline to the northern part of metropolitan Seoul, where incipient gas demand already has outstripped supplies. In addition, a similar high-pressure line to Taegu in the southeast is planned as well as one to Kwangju at the southwestern end of the peninsula (see map). Some 25% of South Korean households in the countryside are presently sold an LPG/air mixture in a tank, which is likely to be grad-

ually phased out as the natural gas pipeline system is completed. South Korea has built a national gas pipeline system in less than a decade, under original cost estimates, across rugged terrain, and has coped with extreme seasonal climate variations — a feat that compares quite favorably to any other country's efforts in Asia.

Swinging The Balance Of Buying Power

With such ambitious growth plans spreading throughout Korea, the balance of LNG buying power is shifting away from Tokyo and toward Seoul. This presents KGC with both opportunities and problems. The state gas company finally must move to secure further long-term base supply and cannot content itself with trolling for cheap spot LNG cargoes. The sustained buildup of Korean LNG use has been nothing short of spectacular. Growth rates in the next decade are less certain, but if LNG imports were to increase by only 50% through 2005, Seoul would already be importing more than 23-mmt. In 1993, KGC's 3.9-mmt/yr of imports represented slightly under 10% of Japanese consumption. If Mitsubishi's forecast of Japanese demand in 2000 is accurate and Tokyo imports 50-mmt — which some forecasters think is optimistic — Korean purchases would still be nearly one-third of those made to Tokyo.

Korea is gaining so much critical mass that it should soon be able to guarantee the purchasing baseload needed to launch substantial capacity increases in LNG facilities. Yet KGC must change its thinking if it is to achieve this goal. Even if all present memorandums of understanding result in firm supply contracts and if present forecasts of Korea's gas needs for 2000 are correct, KGC needs to commit to at least one new 2.5-mmt/yr train immediately, and a second one of similar capacity by 2000. That's a tall order for any company.

Monopolistic Gazprom Pushes For Competitive Markets In Europe, On Its Own Terms

When forming a list of Europe's biggest proponents of market liberalization, Russia's Gazprom, which is the world's largest gas monopoly and is determined to stay that way, hardly seems a likely catalyst for change. But with an aggressive campaign to expand its downstream, Gazprom has surprisingly emerged as one of the most important drivers of the seemingly relentless march toward gas-on-gas competition in Europe. Although the firm is making some sacrifices in terms of prices, its aggressive push into Western Europe through new pipeline infrastructure, joint-venture marketing, and co-sponsorship of the UK-Belgium Interconnector shows that in a perfect Russian world, this high-risk ploy of choosing me over price will help Gazprom dominate the European gas market. Competitors Algeria and Norway have taken a much different approach, trying to expand the

status quo by signing up more and more long-term take-or-pay contracts. However, the much-heralded Interconnector linking the deregulated, low-priced UK gas market with continental Europe is expected to bring further competitive pressure to bear on continental gas markets when it comes on stream in 1998 (p7). Gazprom's eagerness to develop direct access to as many delivery points as possible in Europe implies the firm's recognition that even under a more liberal market, being there from the beginning is a distinct advantage.

As US and UK experience has shown, the most profitable role to play in an increasingly competitive environment is that of marketer. With that in mind, Gazprom has decided to bite the bullet by teaming up with new players to compete head-on with established European buyers — many of which have long-term sales contracts with the Russian giant. In the past five years, Gazprom has set up

Session 1

**Diversification of Gas Supply
- A View from Korea**

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Diversification of Gas Supply - A view from Korea

- 1. Natural Gas Demand Outlook In Korea**
- 2. New Environment for LNG Industry In Korea**
- 3. LNG Import and Contract Status**
- 4. Potential Export LNG Projects**
- 5. Trans-Asian Natural Gas Pipeline Study**
- 6. Conclusion**

1. Natural Gas Demand Outlook In Korea

Since natural gas was introduced to the Korean energy market, the natural gas demand has been increased rapidly over the years. The main consuming sectors are power generation and residential use owing to the government's strong commitment to environmental protection. In the industrial sector, consumption of natural gas is expected to increase steadily with the extension of the supply pipelines and intensified regulations for environmental protection.

Korea is continuing the construction and expansion of new LNG receiving terminal and the nationwide transmission pipeline network for natural gas transportation covering most of the nation's territory as its supply zones. By 2000 when the network is completed, the nation will see that almost all the city gas distribution is provided with natural gas. This conversion from manufactured city gas to natural gas will be the main cause of the acceleration of demand growth in natural gas during the remaining years of the century.

After completion of the nationwide pipeline network, increased demand of natural gas will be foreseen in the sectors of direct heating/cooling systems for commercial buildings and co-generation for plants and business buildings. In parallel with the construction of pipeline network, Korea will continue to construct large scale combined cycle gas turbine power plant. Thus the increased demand of natural gas will be expected in the power generation sector as well.

As shown in the table 1, The role of natural gas in primary energy supply of Korea will be steadily increased and take a share of about 10.5% of the total energy market by 2010 from the current share of 3.9% over the period. The share of oil, which currently occupies a predominant position in the structure of the nation's primary energy consumption, will be lowered to 53%.

Due primarily to the government's policy of lowering Korea's dependence on oil and its move towards increased use of gas as a fuel for power generation for environmental reasons, the gas consumption is expected to increase over the foreseeable future.

Table 1. Outlook for Primary Energy Mix in Korea

Fuel	Year 1992 (Actual)	1997	2000	2010	Growth rate of yearly average '90-'00 '01-'10	
Oil, MM Bbl	514.2 (61.8%)	704.5 (50.8%)	768.9 (58.4%)	905.1 (53.0%)	5.2%	1.7%
LNG, MM ton	3.5 (3.9%)	9.9 (7.9%)	13.9 (8.8%)	21.6 (10.5%)	17.2%	4.4%
Coal, MM ton	26.2 (14.9%)	42.2 (17.2%)	48.4 (17.3%)	59.9 (16.5%)	8.8%	2.2%
Anthracite, MM ton	13.6 (5.4%)	5.5 (1.5%)	3.6 (0.9%)	1.2 (0.2%)	-15.7%	-10.4%
Nuclear, MM kWH	56.5 (12.2%)	72.4 (11.2%)	97.4 (13.2%)	171.4 (17.9%)	7.0%	5.8%

Source : KEEL, Long-term Energy Outlook, April 1994.

Note : () is the component ratio.

As seen previously, the share of natural gas out of Total Primary Energy Supply (TPES) is forecasted to grow from 3.5 million tons (or 3.9 percent of TPES) in 1992 to 21.6 million tons (or 10.5 percent of TPES) in 2010. The growth rate of yearly average is expected 17.2 % over the period 1992 - 2000 and 4.4 % over the period 2000 - 2010.

The high growth of natural gas share will mainly depend on both of the extension of nationwide transmission pipeline network and the environmental concerns and policies that will make it difficult to use oil and coal for electricity generation.

The baseline projection in Table 2 and Figure 1 shows that natural gas demand is expected to grow up to 11.4 million tons in 1998 and 13.9 million tons in 2000, then to 17.9 million tons in 2006.

Table 2. Natural Gas Demand Outlook

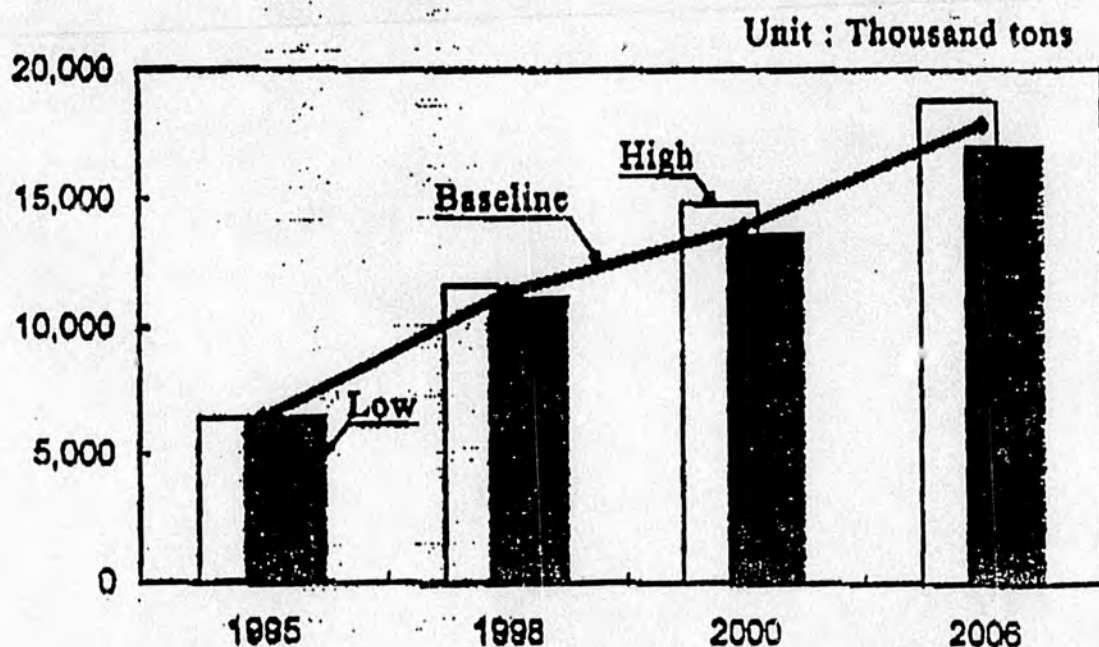
Unit: Thousand tons

	1995	1998	2000	2006
Baseline projection	6,453	11,410	13,950	17,900
Low demand scenario	6,453	11,170	13,600	17,000
High demand scenario	6,453	11,640	14,840	18,800

Source : Korea Gas Corporation.

2010
21.6 = 3.7
month
1.25%

Figure 1. Natural Gas Demand Outlook



The baseline projection represents the compromised results of current trends in city gas consumption and the technical allowances for the construction periods of planned gas-fired power plants. The high and low projections then represent the progressive and conservative estimates respectively, for the period.

2. New Environment for LNG Industry in Korea

In 1993, the Korean government established a new economic development plan that will allow participation of the private sector in Social Overhead Capital (SOC) projects such as natural gas supply and electric power generation. The Government has made related decrees and regulations for the implementation of SOC projects by private sector.

The Government also amended the regulations of foreign capital inducement law to allow the foreign investors will participate in the SOC projects, including LNG import and private power generation. (Only joint investment is allowed in case of power generation)

On the occasion of private sector's participation in SOC projects, private enterprises will enter into the LNG industry, such as the construction and operation of LNG receiving terminal and regasification facilities and electric power industry as well, to become new independent power producers.

Though Korea Gas Corporation is the only LNG importer currently operating in Korea, private enterprises, such as Daewoo, will become the potential importers under new business environment for LNG industry in Korea, who are planned to construct and operate the integrated LNG receiving terminals and combined cycle gas turbine power generation plants. Korea Electric Power Corporation (KEPCO) is another potential importer, who has been purchased the required natural gas from Korea Gas Corporation. KEPCO consumed some 2.5 million tons of natural gas in 1994 for gas-fired power generation and they are going to increase the use of natural gas for combined cycle gas turbine power plant, and in some existing oil-fired power plant that were and will be changed the fuel oil by natural gas.

3. LNG Import and Contract Status

Table 3 shows Korea's LNG import for each year since the first import in 1986. Korea imported 5.93 million tons of LNG from three countries in 1994. Some 5.37 million tons were imported from Indonesia under two long-term contracts. 291 thousand tons were imported from Malaysia under a short-term contract while 271 thousand tons of LNG were purchased on a spot order basis from Brunei.

Table 3. LNG Imports by Sources

Unit : Thousand tons

From	'86	'87	'88	'89	'90	'91	'92	'93	'94
Indonesia	117	1,682	2,063	2,014	2,291	2,642	3,191	4,108	5,366
Malaysia						58	117	290	291
Australia								56	
Brunei									271
Total	117	1,682	2,082	2,014	2,291	2,700	3,308	4,454	5,928

In 1995, Korea plans to import 6.4 million tons in a total of 118 shipments. This will consist of 4.93 million tons from Indonesia, 840 thousand tons from Malaysia, 728 thousand tons from Brunei under each contract summarized in Table 4 LNG Contract Status and 112 thousand tons will be imported from Australia and other countries.

Table 4. LNG Contract Status

From	Quantity	Period	Remarks
Indonesia	2.3 million ton/year	'86 - 2007	CIF
	2 million ton/year	'94 - 2014	FOB
Malaysia	2 million ton/year	'95 - 2015	FOB
Brunei	1.68 million ton/year	'94 - '96	CIF

The summary of long-term and short-term contracts for LNG imported to Korea is presented in the above Table 4.

The first long-term (20 years) contract for the procurement of LNG to be imported to Korea was concluded in August 1983 with Pertamina of Indonesia. It was for the importation of 2.3 million tons of LNG annually over the period 1986 - 2007 and the LNG is supplied from sixth train at Arun, Indonesia. A further contract for an additional 2 million tons per year from Indonesia over the period 1994-2014 was signed in May 1991.

In addition, another contract was executed to import 2 million tons of LNG annually from Malaysia over the period 1995 - 2015. The price terms of the first contract is based on CIF, while the latter two contracts are based on FOB. Korea also made with Brunei a short-term contract for 1.68 million tons of LNG during 3 years (1994-1996).

As shown in Table 5 below, the contracted volumes are almost keep up with the import requirements of LNG until 1998. However, Korea's projected LNG requirements of 13.9 million tons in 2000 are well excess of contracted volumes of 8.3 million tons from Indonesia, Malaysia and Brunei. In the long term, additional contracted volumes from grassroots LNG projects are necessary to keep up with the increased LNG import requirements of Korea.

Table 5. Contracted volumes and Import requirements

Unit : Thousand tons

Year	'96	'98	'99	2000
Import requirements	9,198	11,057	12,627	13,512
Contracted volumes				
- Indonesia	5,812	6,364*	6,812	5,300
- Malaysia	2,428	3,299*	2,786	2,000
- Brunei	700	700	1,000	1,000
Balance to be contracted	258	694	2,029	5,212

Note : * marked volumes included about 1.5 million tons of LNG import under short-term contract from Indonesia and Malaysia.

Source : Ministry of Trade and Industry, 1995

4. Potential Export LNG Projects

There are a number of potential LNG projects under consideration. However, The question of when the new projects will be materialized and realize the production will depend on the interplay of many factors, especially delivery cost and reserves.

Table 6 shows the potential export LNG projects that will be able to export to Korea. I briefly review the potential LNG projects from the standpoint of diversification of natural gas supply to Korea.

Table 6. Potential Export LNG Projects

Project	Type of project	LNG Plant Capacity MM ton/Y	Year of First Production	Distance km
ASIA-PACIFIC				
Australia				
Gorgon	Grassroots	4 - 6	2005	7,200
North Shelf	Expansion	2.5 - 5	2000	7,200
Bonaparte	Grassroots	5	2015	7,200
Indonesia				
Badak G	Grassroots	2.5	1997	4,400
Natuna	Grassroots	7 - 14	2002	4,400
Malaysia				
MLNG III	Expansion	5	2000	4,200
Brunei				
Brunei	Expansion	2.5	2003	4,200
Papua New Guinea				
Gulf of Papua	Grassroots	5	2010	
Russia				
Sakhalin II	Grassroots	6	2005	2,200
MIDDLE EAST				
Qatar				
Qatargas	Grassroots	4 - 6	1997	11,500
Ras Laffan	Grassroots	6 - 10	1999	11,500
Oman				
Oman LNG	Grassroots	6	2003	11,300
NORTH AMERICA				
Alaska				
TAGS	Grassroots	7 - 14	2005	7,300

Recently, Korea Gas Corporation committed to purchase 2.4 million tons of LNG annually based on FOB basis over 25 years starting 1999. It is reported the price terms are not concluded yet. There is another option for another 2.5 million tons a year proposed by Qatar.

✓ Korea has recently signed a letter of intent for the purchase of 3 million tons of LNG annually from Oman. Production is expected to come from non-associated gas discoveries in central Oman and 7 Tcf of proven gas reserves have been dedicated to this project by Oman government. A two train liquefaction plant to produce 6 million tons per year is expected to be built near Muscat.

✓ Korea has signed a memorandum of understanding with Yukon Pacific Corporation to take 2 million tons annually with a second 2 million tons option from the Alaskan TAGS(Trans-Alaska Gas System) pipeline and LNG export project. North Slope has 37 Tcf of proven natural gas reserves and TAGS will export 14 million tons of LNG annually from liquefaction plant located at Anderson Bay, near Valdez. Yukon Pacific announced the estimated project cost for the entire facility at \$13.4 billion(US/1991). The TAGS project has received major necessary statutory and regulatory approvals from US federal government. This project, however, could be realized when joint purchasing of the produced LNG is agreed and committed by LNG buyers of Asian countries such as Korea, Japan and others.

Indonesia (Natuna) and Malaysia have potential gas reserves to support grassroots LNG plants. These reserves, however, may be used to feed existing LNG export facilities. Meanwhile, the third Malaysian LNG project is expected to start up in the late 1990s. Deliveries to Korea are projected to begin soon after 2000.

Australia's Gorgon project is expected on stream by 2005, serving Korea. A volume of 2.5 million tons annually to Korea may be anticipated by 2010. There is another small gas reserves sufficient to support a 2 million tons per year LNG project which is located in offshore areas of Bonaparte Gulf. This project will be realized beyond 2015.

Interest in Papua New Guinea offshore resources has revived recently. Considerable work is needed to develop the fiscal and organizational regime needed to support an LNG project within the country. This project is assumed to come on-line by 2010.

Recent indications of substantial gas reserves offshore of Sakhalin Island could be at least partially used to supply a new grassroots LNG project, which could be exported to Korea and Japan. The LNG export from Sakhalin II project are assumed to begin 2005.

Korea has established a Korea-Russia consortium in order to carry out a preliminary feasibility study on developing gas fields in Yakutsk, East Siberia, with the aim to supply natural gas to Korea by trans-continental pipeline. As an alternative way of supply, the study may include a scheme that the produced gas could be delivered to liquefaction plant which will be assumed the location near Vladivostok harbour by 4,000 km pipeline. The proven natural gas reserves is 35 Tcf and the completion of this project is assumed beyond 2010.

Iran, with the second largest natural gas reserves in the world, will become another possible future LNG exporter in the Middle East, although Iran has made several exports deals by pipelines. Iran is carrying out a joint feasibility study with Gaz de France on the economical method of delivering natural gas to Europe, either pipeline or LNG. Iran has 730 Tcf of proved natural gas reserves.

5. Trans-Asian Natural Gas Pipeline Study

As previously explained, Korea is carrying out the preliminary feasibility study to develop Yakutsk gas field and import the natural gas by trans-continental pipeline or combination of pipeline and LNG ship transportation. Korea also reviews a scheme to transport the natural gas by means of pipeline passing through North-Korea as a part of so-called Trans-Asian Natural Gas Pipeline Network. This scheme is prepared as one of long-term security plans of natural gas supply to Korea for the coming century.

The "Trans-Asian Natural Gas Pipeline Network" has been studied by Japan for the purpose of increasing the use of undeveloped large natural gas reserves in the Asia-Pacific region including Siberian Russia and central Asia.

Besides the enormous project cost, there are many technical difficulties to be overcome including the politics of pipelines crossing several international borders. Thus it is important to make a consensus on the role of energy supply and demand between the countries in the region for the development of the Trans-Asian Natural Gas Pipeline Network. I think it is necessary to establish an international forum, in cooperation with all the countries in the region, in order to undertake the study of construction for the Trans-Asian Natural Gas Pipelines.

The development of the Trans-Asian Natural Gas Pipeline Network will promote the natural gas industry in the region, and will also play a important role in securing the natural gas supply for the countries currently importing LNG beyond 2010.

6. Conclusion

As long as current trends of energy market continue, Korea will make its effort to promote the use of natural gas as an alternative to oil and coal in the power generation, residential and commercial sectors, and as a clean energy to improve the environment. To this end, Korea keep on the construction works for expansion of LNG receiving terminals and nationwide pipelines, as well as building new facilities.

Energy security as it applies to natural gas is being taken increasingly seriously, because natural gas supply to Korea currently depends on imported LNG under long-term and short-term contracts from LNG projects in three ASEAN countries. Thus, Korea needs making efforts to diversify the sources of natural gas importation.

In view of long-term stable supply of natural gas, Korea will promote new export LNG projects dedicated to Korea. The Korean private enterprises, who newly enter into LNG business and become the potential importers, will also take the leading role in developing new LNG project. Furthermore, Korea is now making a great efforts into the study of preliminary feasibility on the development of gas field in Yakutsk and trans-continental gas pipelines lead to Korea.

In realizing these projects, Korea needs to collaborate with the countries in the Asia-Pacific and Middle East regions, especially Japan, in all phases of the project development in order to take maximum advantage of synergy and to solve any technical difficulties, political and financing matters.

While trying not to be over optimistic, the author believes that the Korea gas industry holds the capability to meet the challenge, and go forward by coping with the effective market.

TAGS Competition:

**Projects, Start-up
Dates, Annual Volumes**



TAGS Competition is Other Undeveloped Gas Fields in:

	<u>Start-up Date</u>	<u>Annual Volume</u>
▲ Qatar (Qatargas & Rasgas) - Mobil	2005	6-10 MMTA
▲ Indonesia (Natuna Island) - Exxon	2004	15 MMTA
▲ Sakhalin (Russia) - Exxon x2, Marathon/Shell	2004	15 MMTA
▲ Yemen - Exxon	??	15 MMTA
▲ Papua New Guinea - BP	??	15 MMTA
▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

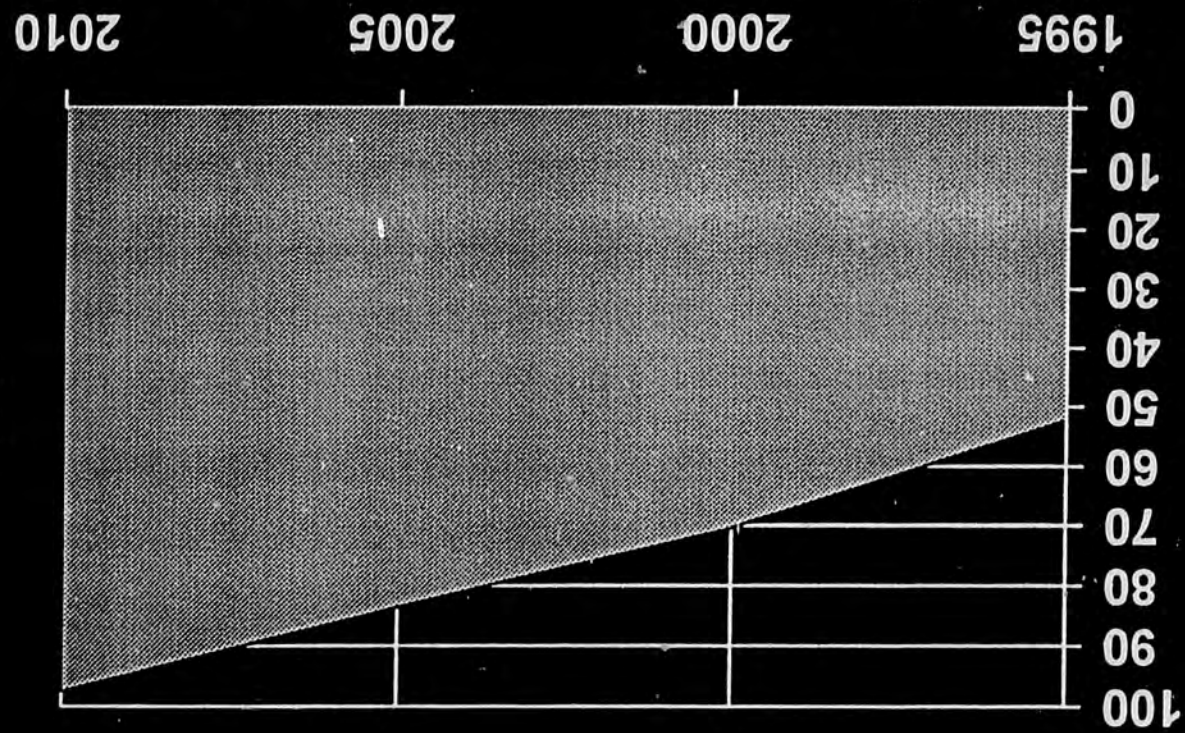
Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

The Post-2000 Demand Window:

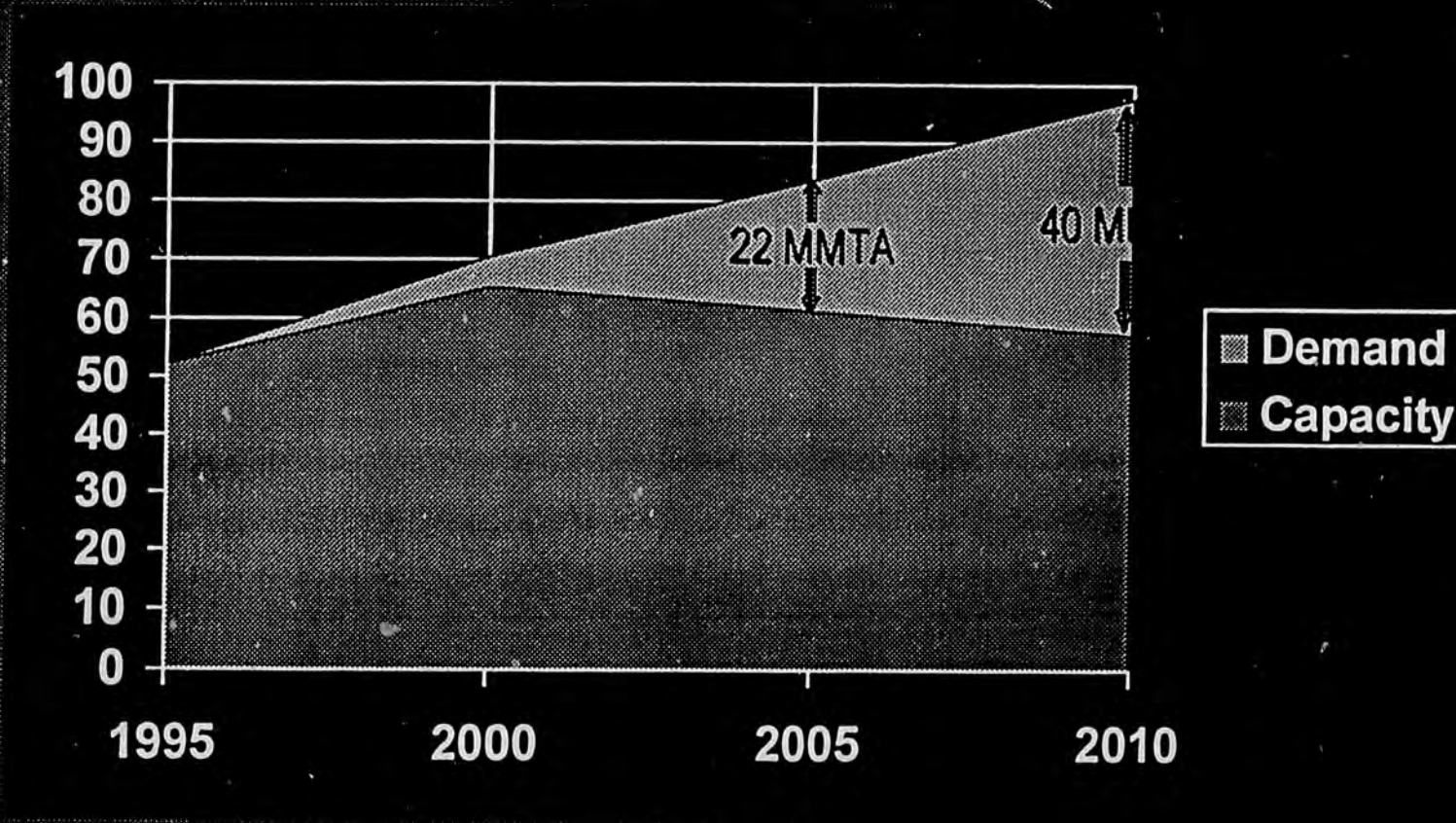
The Effects of
Competition on an
Alaskan Project

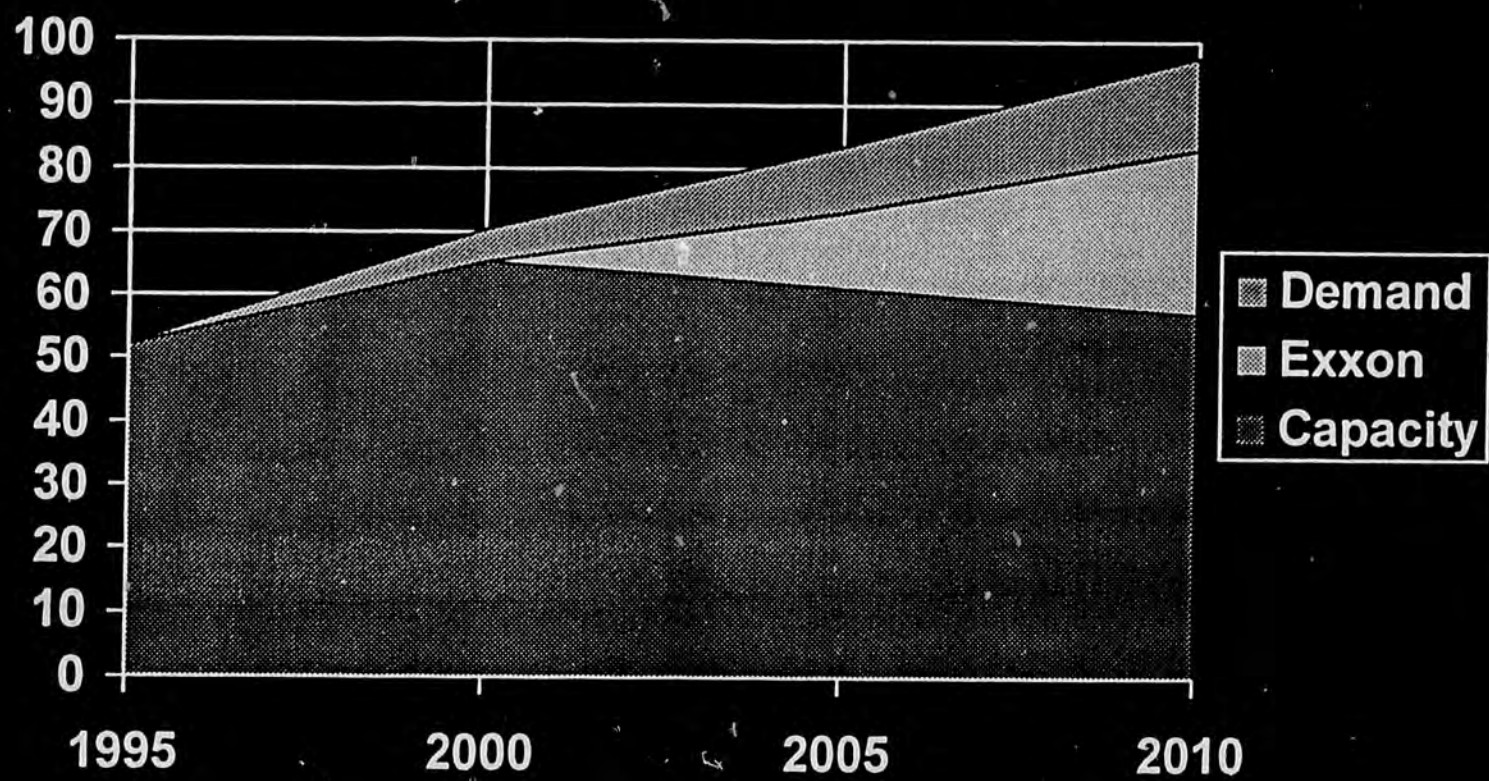


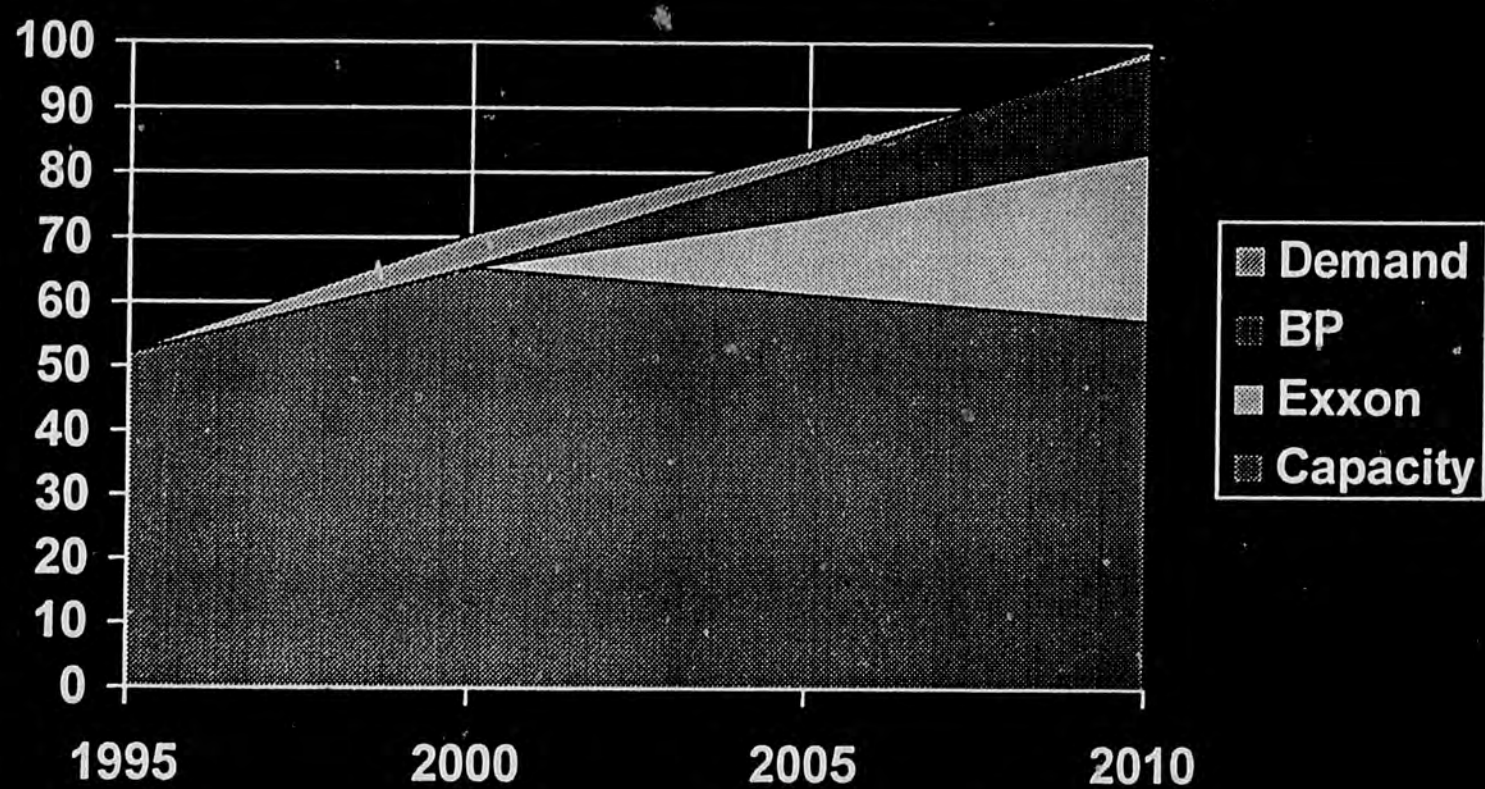
■ Demand



Asia Market



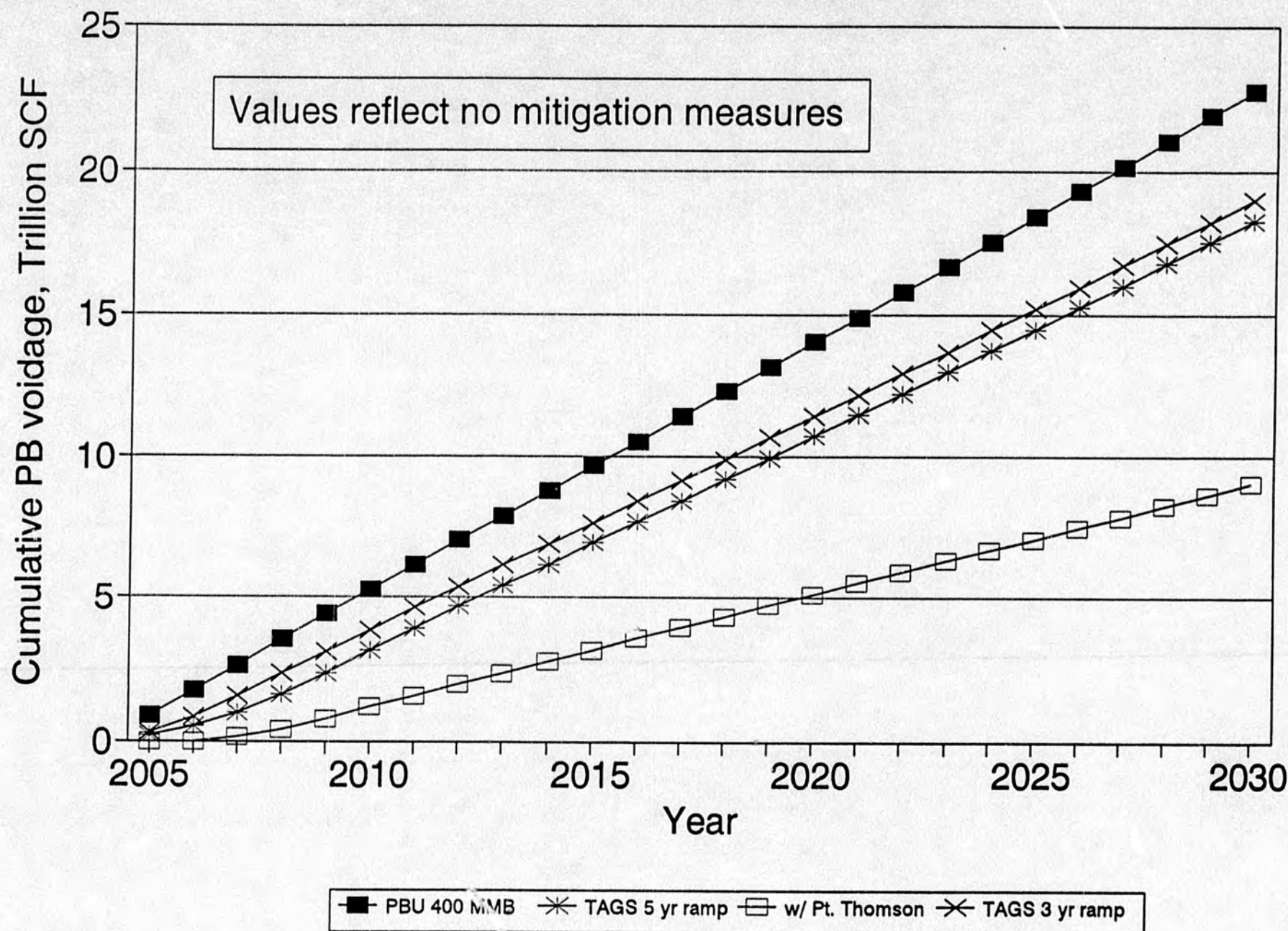






Oil Loss vs. Gas Sales

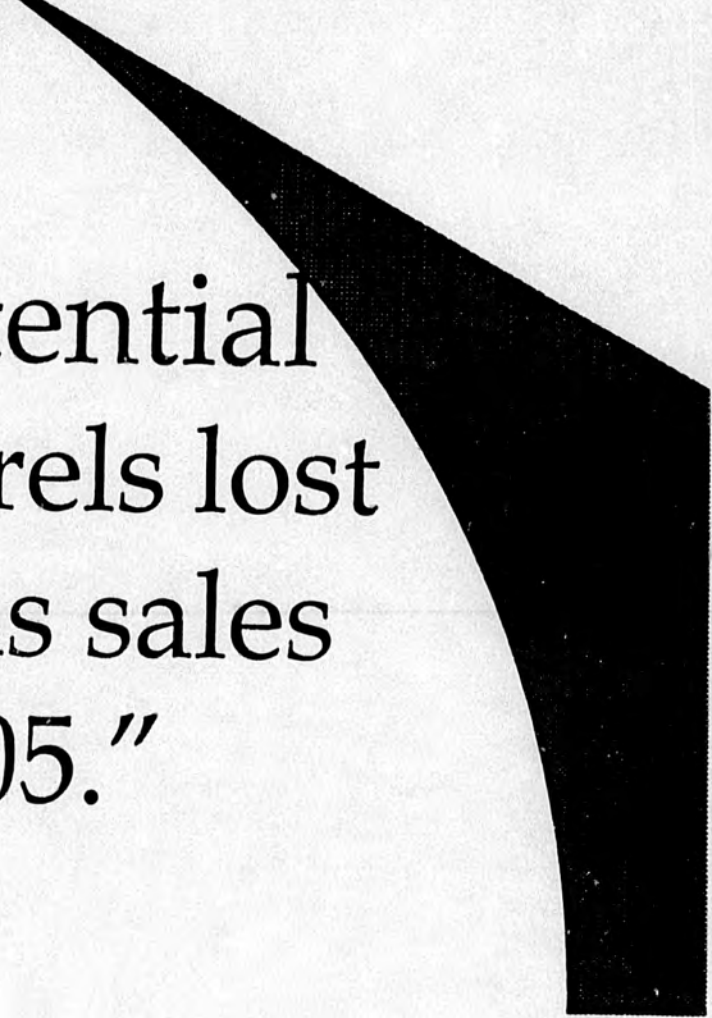
PBU Oil Pool, Cumulative Reservoir Voidage Due To MGS Scenarios

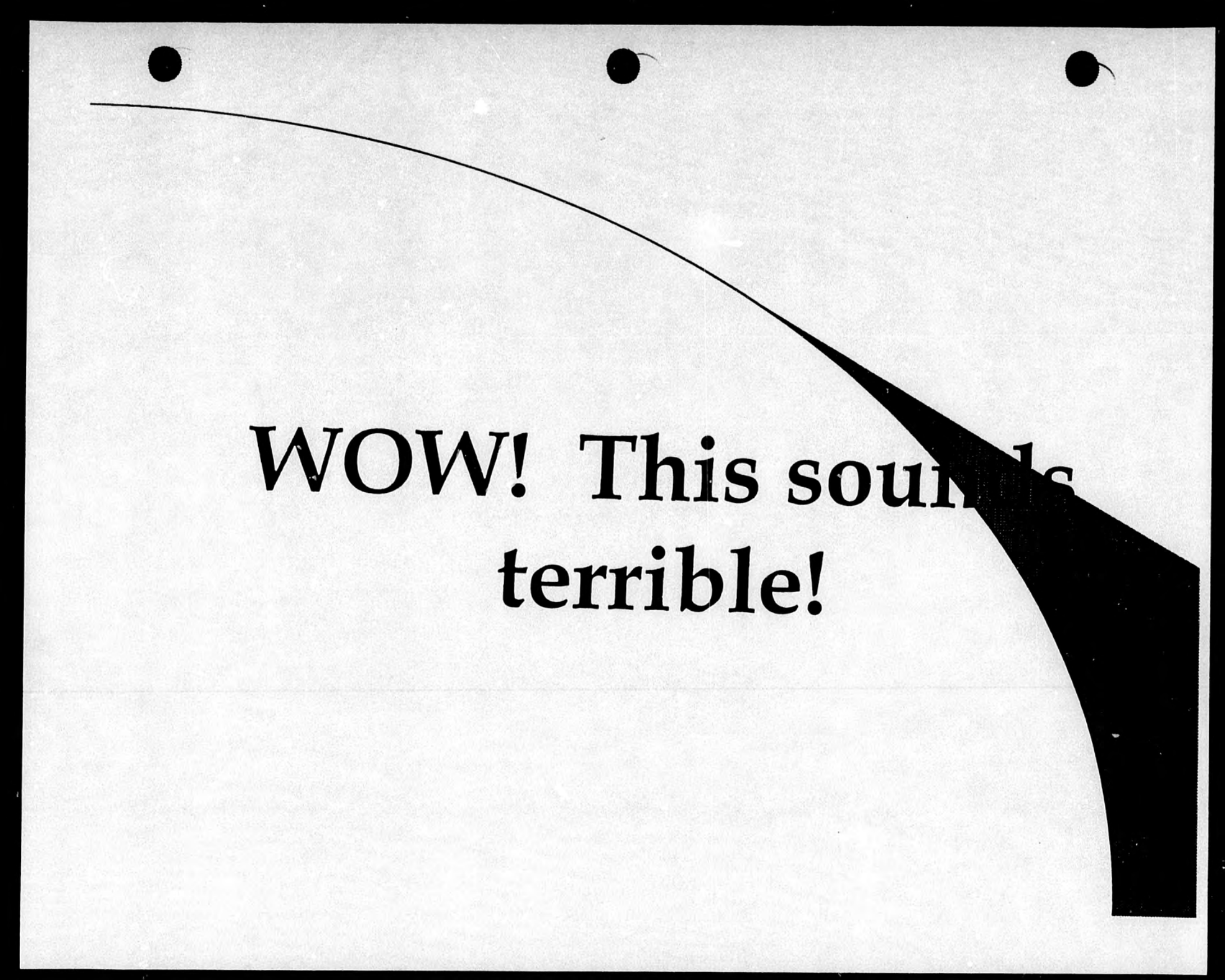




Risks?

Oil Loss: “potential
400,000,000 barrels lost
from PBU if gas sales
begin in 2005.”





**WOW! This sounds
terrible!**

Not Really.

Gas revenues *more* than offset
any "potential" oil loss...which
is "uncertain" at best.

Oil Loss?

Key Questions:

- ▲ What is the schedule of loss-i.e. *when does it occur?*
- ▲ What gas "ramp up" rate is used?
- ▲ What mitigation can be used to minimize on oil?
- ▲ When does TAPS shut down?
- ▲ What are the PBU economics supporting viability through 2030 without gas sales?
- ▲ Can Point Thomson gas solve the PBU problems?

Oil Loss?

Extremely "Uncertain":

"...Commissioners, in any forecasting process when you go out and look at the future, as one steps out in time uncertainty grows, asymptotically -- or exponentially, I should say.

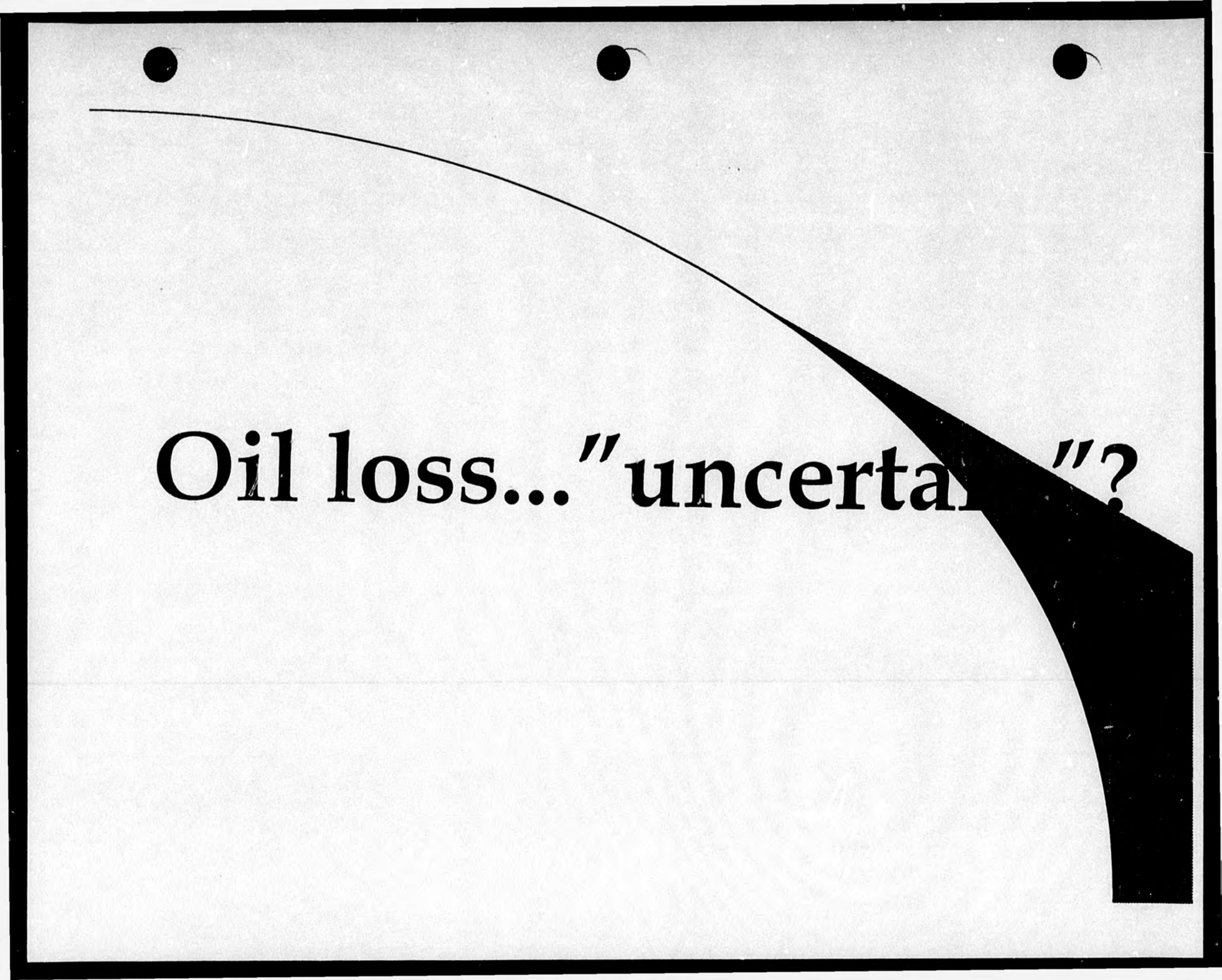
Do we have a forecast for the year 2020?

Yes. Do we have a lot of faith in it?

There's a lot of uncertainty there...."

PBU's 1991
Legislative
Testimony

Oil loss at PBU is *highly*
"uncertain" but the loss of both
Point Thomson *and* Prudhoe
gas revenues without a gas project
is *absolutely certain!*



Oil loss..."uncertain"?

Gas revenues are certain!

- ▲ Gas revenues are set by contract for 25 years (i.e., no risk).
- ▲ BP says, "Money flows to the gas offering the greatest returns for lowest risks."

We agree!
Gas sales = lowest risk.
Hands Down

What do you get *without* gas sales?

- ▲ "Uncertain" oil recovery?

What do you get *with* gas sales?

- ▲ Certain revenues for 25 years from PBU gas sales
- ▲ Probable revenues from 5-7TCF of gas and 300 MMB at Point Thomson
- ▲ Non-PBU revenues (taxes...)
- ▲ Stimulation of State economy (jobs!)

market before new greenfields. So that's the time frame you wanted, a sort of estimate I would put it in the, the potential, the first potential would be in that time period, probably towards the back end of that 2005 to 2010 period.

- 7) Does that also jive with your plans as the Prudhoe curve kicks in and the oil supply depletes on the slope makes the gas available?

KT:

When you look at that time frame there, it does and also we find that it's minimal oil loss and it does not play into the decision whatsoever, in fact, we keep coming back to moving forward on this project. We need three things; fiscal certainty, further cost reductions and confirming the market. And to describe a little bit more about the market that John was mentioning - we've looked at a lot of supply and demand forecasts for LNG now for several years and we've worked internally in a lot of detail, we've also worked with external consultants who have an objective view of that too and here's what we're seeing is we see that existing projects and those currently under construction today should be able to supply the market way past 2000 and those same projects do have potential expansion, and those expansions and construction would be able to be far less and more competitive than Alaska North Slope Gas. Those potential expansions would cover all of the supply through and past 2005. So we have confirmed that past 2005 or 2010 is an area that we are looking at in more detail and we will be visiting the market directly this fall. Arco, BP and Exxon will be jointly visiting Japan, Korea and Taiwan to further test their views and to talk to them about the progress we have made and about those next steps forward. And those next steps forward will be working with the state and federal government for fiscal certainty, looking for further cost reductions and in their view also confirming the market that we see in the post 2005 to 2010 or so.

- 8) How much natural gas will be utilized to pump back into the fields and still sell, how much would you sell, how much would you need to pump back into the North Slope to keep pushing oil?

KT:

The question still comes back...that's not the key issue about LNG. The key issue is fiscal certainty, market and cost, that's when LNG will become competitive and it's not the amount of oil we see in this time frame, it's minimal oil loss, so that has not driven the decisions on this. What's driven the decisions are those three things I mentioned.

JM:

We don't believe there's an issue of any significance. If we can define this project in that time scale we're talking about, the interrelationship with oil production is unlikely to be of significance.

- 9) So it's not one or the other is what your saying, because it was my understanding earlier about two (2) years ago that you'd have to give up something to produce LNG, we'd have to give up our oil. Your saying that's not the case.

ARCO/BRITISH PETROLEUM PRESS BRIEFING - JULY 19, 1995

Ken Thompson (KT):

Thank you for coming this morning. North Slope oil and gas producers Arco, BP and Exxon have completed a study of options for transporting North Slope gas to Pacific Rim markets and have briefed Governor Tony Knowles and Alaska's Congressional delegation, Senators Ted Stevens and Frank Murkowski and Representative Don Young on the results of their study. Good progress has been made on project definition and cost. While the study has identified cost savings, none of the options under consideration is currently commercially viable. The companies noted that commercializing North Slope Gas will be one of the most expensive and complex business undertakings in history. Significant uncertainty remains in the areas of fiscal and regulatory conditions, market timing, product pricing and project cost. A project of this size, cost and complexity will require the involvement and cooperation of many parties, including the state and federal governments. Arco, BP and Exxon are committed to continuing to seek ways to make North Slope gas commercially competitive and will set up discussions with the state and federal governments on how we can work together to establish certainty for an appropriate tax and regulatory framework for a commercial project.

And we would be happy to take any questions that you may have.

- 1) Could you discuss the route options? One, have you decided on one, if not, are you considering more than one? Or may be you could just talk about the route options.

John Morgan(JM):

Yes, the reason we have looked at alternative routes here, they are both part of our effort here to try to get the cost of this project to be lower. The route that most people think of is the obvious one which is down alongside the existing TAPS line it essentially is a long pipeline and very expensive. What that does is drive you to have a very big project, which then introduces greater difficulty in terms of marketing the gas - you need to sell it quickly to get a fast build up to make the economics work. As a result of that we began to look whether there would be alternative pipeline options which would be cheaper and those are the western route options, one of them coming out close to Wainwright and the other one close to Kivalina. We've done initial scoping on those routes and at the moment think they are both feasible, both in terms of pipeline logistics and the marine conditions at ports there, so that's the initial process and we have now to decide whether to examine those routes in more detail with more specific engineering and I'm sure that will be one of the things that is part of our conversation with the Governor and his team and the state as we move forward. So there is no decision at this point on the line. The route that is undoubtedly best worked is the route that runs along side TAPS and the decision is whether to work the other routes in more detail.

KT:

I'd like to mention adding to that, that as we studied the current LNG projects that are already existing we found that Alaska North Slope gas is not competitive compared to those. One thing that we have that the others do not have is an 800 mile pipeline or one of the shorter lines to the west. Most of those projects are pretty close to the coast in areas where they can be loaded on tankers. That's an incremental cost that is pretty substantial and does add cents per million

KT:

I might mention a few years ago there was discussion by some that there would be LNG sales by 1997 or 1998. If that were to have been the case, there would be very, very substantial oil loss which we feel would not have been good for the producers nor for the state nor the people of Alaska. Looking at a time frame post 2005, that oil loss, if any would be minimal and it switches more to the fundamentals of the LNG business which we're trying to make happen and resolve those three issues.

- 10) Was there a change in technology then because it was my understanding that you use natural gas to pump more oil out of the ground, so what's changed?

KT:

It's not an issue of technology, it's an issue of just depletion of the remaining oil reserves in that time frame there, plus looking at the LNG business in that timeframe.

- 11) a) I have a two part question: Is it fair to say that if you were to choose the western route that this would be a smaller project in terms of tons of LNG per year as verses, say, the TAGS proposal? And then I have a second question, too.

JM:

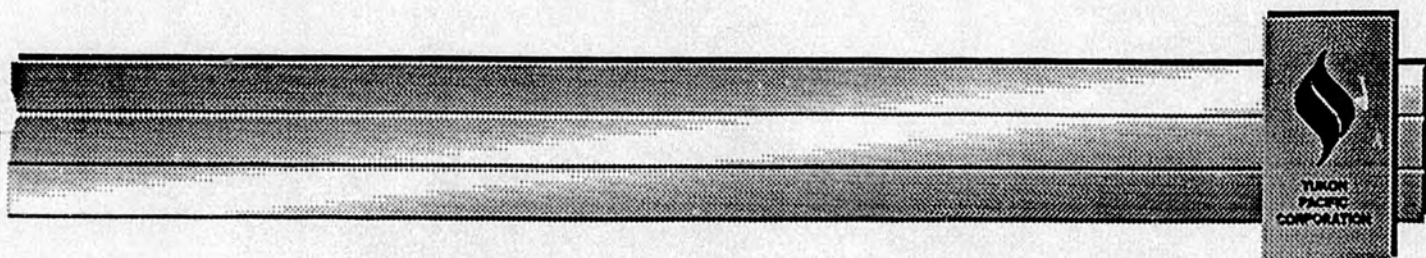
Well, I think as I was suggesting earlier, one of the key reasons to look at the western routes is to try and reduce the cost of the overall project. Now either that's partly reducing the cost of the pipeline because it's a shorter line because the size of the southern route line drives the cost of the LNG price that you need in order to get a profit So if you can reduce the cost of the pipeline there is a serious possibility that you may be able to use the cost of the therefore make the market problem of having this very large wall of gas that you want to sell in the market at one time go way to some extent. We can't tell you at this point we are sure we would be able to do that that's why I think we have to now consider where we want to go the next step in engineering to look at studies on the western routes to see whether it really does offer that kind of potential.

- 11) b) So if I understand you correctly, I'm not quite sure you answered the question, if you were to go with the western route, either one of those two options, would you, I think TAGS is proposing up to 14 million tons per year, would your project be smaller than 14 million tons, would it be say half as much or are you looking at equally as large a project in terms of bringing LNG to?

JM:

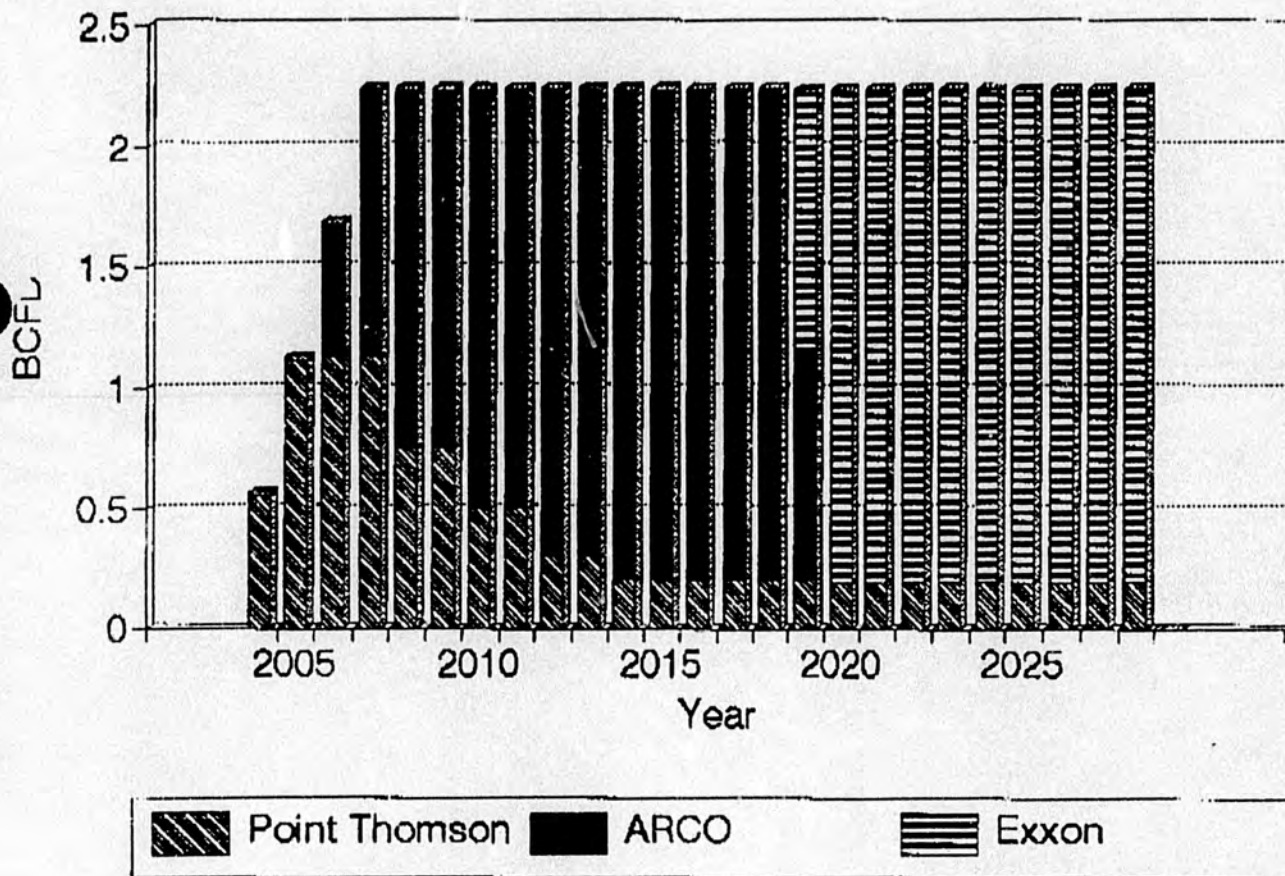
Try answering it this way...since one of the reasons we are looking at the western routes is to see if we can reduce the cost, it is likely that if conditions of going the western route that we had found a way of building a smaller project. I'm not going to tell you it's going to be half the size, I frankly don't know. But that is one of the reasons to examine that. So it is likely, the western route solution would be linked to a smaller scale project, and one that was more easy to make work from a financial and economic point of view than the southern route.

Possible North Slope Gas Supply Scenarios



Trans-Alaska Gas System

Supply by Field/Producer



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WERE TREATED AS A UNIT
IN THE ORIGINAL FILE**