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Republic of the Philippines
Department of Energy

Development of Offshore Gas Reserves - Philippines

Final Report

30 September 1994

Prepared by:

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Prepared for:

Office of Energy, Environment, and Technology
Bureau for Global Programs, Field Support and Research
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ACRONYMS

ADB	Asian Development Bank
ARI	Advanced Resources International, Inc.
Bcf	billion cubic feet
Bechtel	Bechtel International, Inc.
BNPP	Bataan Nuclear Power Plant
BSA	Benjamin Schlesinger and Associates, Inc.
CC	combined cycle
CNG	compressed natural gas
DOE	The Philippine Department of Energy
ERB	Energy Regulatory Board
FSU	floating storage unit
FT	firm transportation
GDP	gross domestic product
GT	gas turbine
IPP	independent power producer
IT	interruptible transportation
kV	kilovolt
LNG	liquefied natural gas
LPG	liquefied petroleum gas
Mcf	thousand cubic feet
MGC	Manila Gas Corporation
MMBtu	million British thermal unit
MMcf	million cubic feet
MW	megawatt
NAPOCOR	National Power Corporation
NEDA	National Economic Development Authority
NPC	National Power Corporation
O&M	operation and maintenance
PGPC	Philippine Gas Pipeline Company
PNOC	Philippine National Oil Company
RCG	RCG/Hagler, Bailly, Inc.
ROR	rate of return
ROW	right of way
Shell/Oxy	Shell Exploration B.V. and Occidental Philippines, Inc.
Tcf	trillion cubic feet
TLP	tension leg platform
USAID	United States Agency for International Development
WestJec	West Japan Engineering Consultants, Inc.

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EXECUTIVE SUMMARY

The discovery of what is currently estimated to be between 2 and 4 trillion cubic feet (Tcf) of natural gas in the Malampaya/Camago reservoir off the coast of Palawan Island, some 400 kilometers (km) southwest of Manila, represents a significant opportunity for the Republic of the Philippines in terms of providing the foundation for a domestic natural gas industry and contributing toward energy independence. Shell Exploration B.V. and Occidental Philippines, Inc. ("Shell/Oxy"), the developers of the Malampaya/Camago reservoir, are conducting an appraisal program of the reserve base and are now seeking a long-term gas sales agreement with the Philippine government (and/or other creditworthy entity). Deliveries of 450 million cubic feet (MMcf) per day of gas could begin as early as the 1998-2000 time frame, i.e., enough gas to support approximately 3,000 megawatts (MW) of combined cycle combustion turbine base load power generation.

The Philippine Department of Energy (DOE) is leading the government's efforts to ensure that the Malampaya/Camago reserves are developed in a manner that best serves the interests of the Philippine people. The DOE assembled a Gas Negotiation Multi-Agency Committee ("the Committee") consisting of personnel from the DOE and the National Power Corporation ("NAPOCOR" or "NPC") to negotiate with Shell/Oxy. The Committee and Shell/Oxy have met several times over the past two years to exchange information, but have not held formal negotiations.

RCG/Hagler, Bailly, Inc. (RCG) subcontracted Benjamin Schlesinger and Associates, Inc. (BSA) as part of RCG's contract with the U.S. Agency for International Development (Contract No. USAID PCE-5743-Q-00-2074-00, Delivery Order No. 2) to assist the DOE in preparing a contract negotiating strategy for the Malampaya/Camago gas. BSA's approach in developing this negotiating strategy has centered around determining:

- What is the value of the Malampaya/Camago gas to the Philippine economy?

- What is the best way to exploit that value to serve the interests of the Philippine economy?

BSA's approach toward determining the value of the Malampaya/Camago gas is rooted in the economic theory of opportunity cost, i.e., the economic value of the gas is determined by the value of the next best alternative energy source. Consequently, the heart of the contract negotiation strategy for the DOE is to ascertain the full extent

of the costs and benefits from the perspective of each of the parties, the Philippine economy and government on one hand, and Shell/Oxy on the other. This understanding must then be translated into a rational strategy for negotiations in a way that will obtain for each party the best price within a fair range, and one which the nation can afford.

In our effort to determine the highest value use of the Malampaya/Camago gas, BSA undertook the approach diagrammed in Figure 1, including completion of the following tasks:

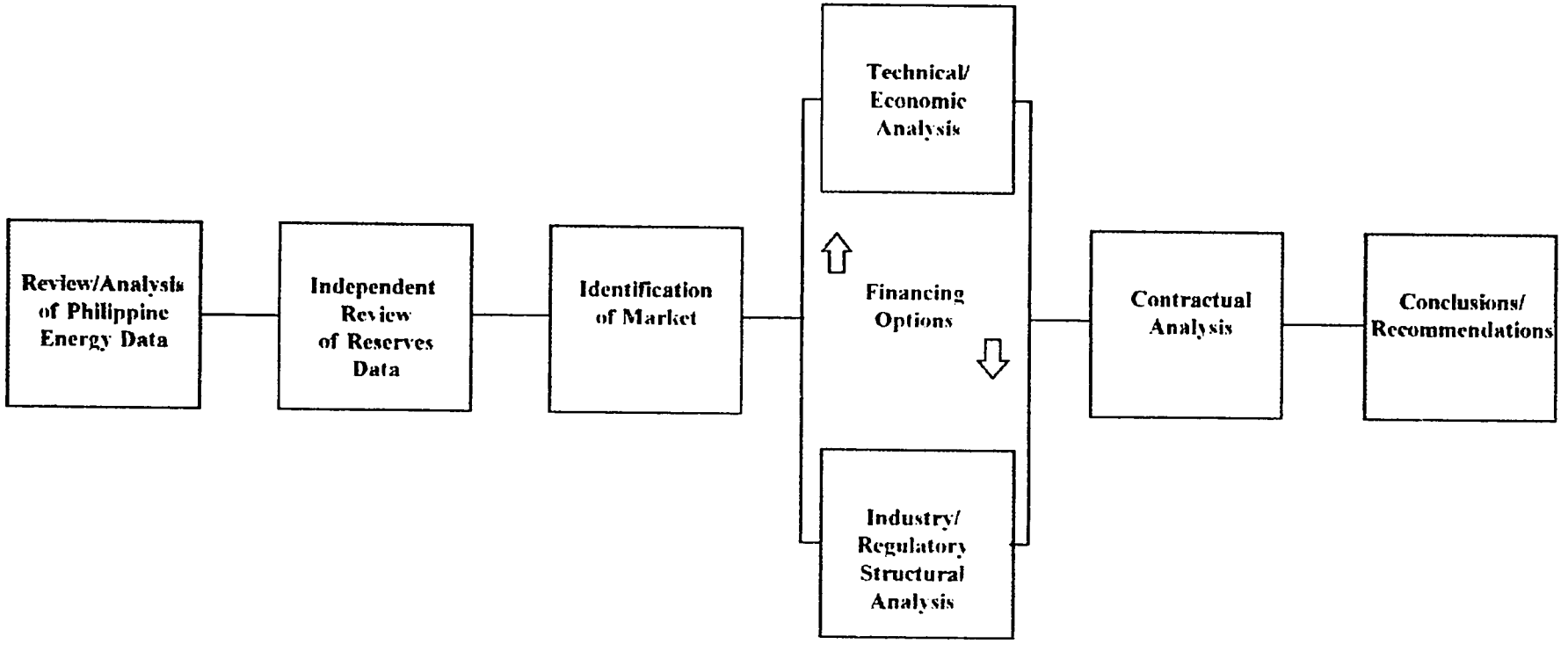
- Review and analysis of Philippine energy sector data and information provided by the DOE, NAPOCOR, and others
- Independent review of the Malampaya reserve estimates based on well completion reports provided by Shell/Oxy
- Identification and analysis of the customer base for Malampaya/Camago gas in Bataan, Batangas, and Metro Manila
- Cost-of-service analysis of three basic options for the delivery of Malampaya/Camago gas, including:
  - Undersea/land gas pipeline in several configurations
  - Liquefied natural gas (LNG)
  - 500 kV cable.
- Development of an organizational structure for the Philippine natural gas industry, including regulatory and institutional aspects
- Analysis of key provisions in gas supply and transportation contracts, and a review of basic negotiating techniques.

In its review and analysis, BSA has reached the following conclusions and recommendations:

Overall - Development of the Malampaya/Camago gas reserves can provide the Philippines with a reliable, economical source of domestic energy. If deployed properly, Malampaya/Camago gas represents the foundation for the development of a modern, domestic natural gas industry for the Philippines that will spur growth in the overall economy and provide the nation with a degree of energy independence from imported fuel sources. Our analysis of the cost of developing, producing, and delivering Malampaya/Camago gas to the Central Luzon markets of Bataan, Batangas, and Metro Manila indicates that the all-in delivered to burner-tip levelized nominal

Figure 1

SUMMARY OF BSA'S APPROACH



cost of about $2.76 to $3.34 per million British thermal units (MMBtus) will be competitive with the price of alternate fuels currently in the market when the complete fuel cycle costs of burning one fuel versus another are factored in, e.g., capital cost of power plant construction (see below).

COMPARISON OF DELIVERED FUEL COSTS
($ per MMBtu)

Market Area	*Natural Gas*	*Diesel*	*Bunker C*	*Coal*
Central Luzon	$2.76 - $3.34	$4.41	$2.78	$2.12

Notes: The range of natural gas costs reflects differing financing assumptions, delivered to large volume customers in Central Luzon. The above comparison excludes such factors as capital costs of power plants, annual operation and maintenance costs, plant reliability, efficiency, and compliance costs with relevant emission control laws.

In addition, the environmental benefits to using clean burning natural gas will contribute to the fuel's marketability. A cost analysis of three delivery options for the gas strongly favors the construction of a natural gas pipeline over either LNG or a 500 kV transmission cable.

Overview (Chapter 1) - This chapter briefly reviews the history of the Malampaya/ Camago project prior to this study. The discussion clarifies BSA's role as an advisor to the Committee in preparation for the upcoming negotiations, rather than as a direct participant in the negotiations.

Goals and Approach (Chapter 2) - The primary goals of this study are to determine the value of the Malampaya/Camago gas to the Philippine economy and then, knowing the value of the gas, determine the best way to exploit that value to serve the interests of the Philippine economy. BSA took the following approach to determine the economic value of the Malampaya/Camago gas at the burner-tip relative to other fuel sources:

- Identified the potential customer base. The Malampaya/Camago gas has a relative value dependent on how it is being used and where it is being used

- Determined of the cost of fuel oil and coal to the identified customer base.

After determining the value of the Malampaya/Camago gas, our next step was to structure the future Philippine gas industry in a manner that maximizes the benefits of the gas. The gas industry structure we developed in this study involves competitive gas production and end-use sectors, with regulated private industry participants providing gas transmission and distribution services on an open access basis. In our assessment, Philippine gas companies act within a market environment in order to promote and develop gas energy as a viable domestic industry in an economically efficient way.

Reserve Analysis (Chapter 3) - BSA determined the most likely recoverable reserve base of the Malampaya reservoir to be 3.0 Tcf through independent review of the Malampaya-1 and 2 well reports by Advanced Resources International, Inc. (ARI). Shell's estimates were judged to be very reasonable, and well supported by the data they provided. The Camago formation, which Shell/Oxy estimates to contain reserves of about 1 Tcf, was not included in our review. No substantial additional gas reserves have thus far been discovered in the offshore region surrounding Malampaya/Camago, however, a number of companies are exploring for oil and gas in the region.

Customer Base (Chapter 4) - BSA identified and assessed potential gas requirements in both the power generation and industrial sectors as they might exist in the 1998-2000 time frame. From available information, we concluded there will be more than sufficient potential demand for the Malampaya/Camago gas in the Central Luzon market areas of Bataan, Batangas, and Metro Manila. Indeed, enough base load power plant demand for the Malampaya/Camago gas production will exist among combined cycle plants alone. Furthermore, the Philippines has an increasingly well developed and diverse industrial sector capable of providing an interruptible load for the gas.

CUSTOMER BASE SUMMARY

Market Area	*Share of Identified Base Load*	*Additional Factors*
Bataan	63 %	Repowered Bataan nuclear plant as anchor load, possible petrochemical facility
Batangas	15 %	Closest in proximity to the Malampaya/Camago reserves, large industrial base
Metro Manila	22 %	Existing network of gas distribution pipes, numerous industrial facilities

The Bataan area represents the single greatest potential future market for the Malampaya/Camago gas with over 63 percent of the identified combined-cycle power plant demand. Nearly half of the Bataan area demand and 31 percent of the overall projected demand is represented by repowering of the Bataan nuclear plant with natural gas. Assuming a creditworthy buyer, this one facility with its estimated gas consumption of 263 MMcf/d is ideally situated to be the anchor load for the entire Malampaya/Camago gas pipeline project. The planned development of a domestic petrochemical industry that could utilize natural gas as a feedstock also contributes to Bataan as the single most attractive market for the gas.

Small-scale residential and commercial gas uses are typically more costly on a per unit basis to serve than are large-volume customers such as power and industrial plants. However, the existing pipeline assets and customer base of Manila Gas Corporation (MGC) may make it an excellent potential customer for Malampaya/Camago gas.

In summary, the substantial capital investment required for development and production of Malampaya/Camago strongly favors a customer base consisting of a small number of large creditworthy parties. Of the identified customers, the substantial fuel requirements of the Bataan nuclear plant, repowered with combined-cycle gas turbines, make it a potentially ideal anchor load for the project.

Delivery Options (Chapter 5) - BSA evaluated three delivery options for the Malampaya/Camago project: undersea/land pipeline configurations, LNG, and transmission of electricity via a 500 kV cable. The project cost of building a gas pipeline consisting of a 500 km undersea line from SC 38 to Central Luzon as well as necessary onshore pipeline and distribution networks is significantly less costly than

either an LNG or 500 kV project. The Base Case Pipeline Configuration (see Figure 2) consists of:

- Undersea pipeline from SC 38 to Batangas (24-inch, 450 MMcf/d)
- Onshore pipeline from Batangas to Manila (24-inch, 400 MMcf/d)
- Onshore/under Manila Bay pipeline from Manila to Bataan (20-inch, 300 MMcf/d)
- Construction of distribution networks in Batangas and Bataan, and refurbishment of a portion of MGC's existing distribution network in Manila.

Note BSA recommends initial construction of 30-inch diameter pipeline facilities wherever Shell/Oxy has recommended 24-inch line, i.e., oversized to accommodate the future growth in gas supply.

The following is a comparison of the estimated capital construction cost of the Base Case Pipeline Configuration with both the liquefaction, shipping, and regasification of Malampaya/Camago natural gas to Bataan (the Base Case LNG Option) and the transmission of 3,000 MWs of electricity to Luzon generated with Malampaya/Camago gas in a power plant on Palawan (the 500 kV Cable), including our estimate of production costs which Shell/Oxy will likely have to incur:

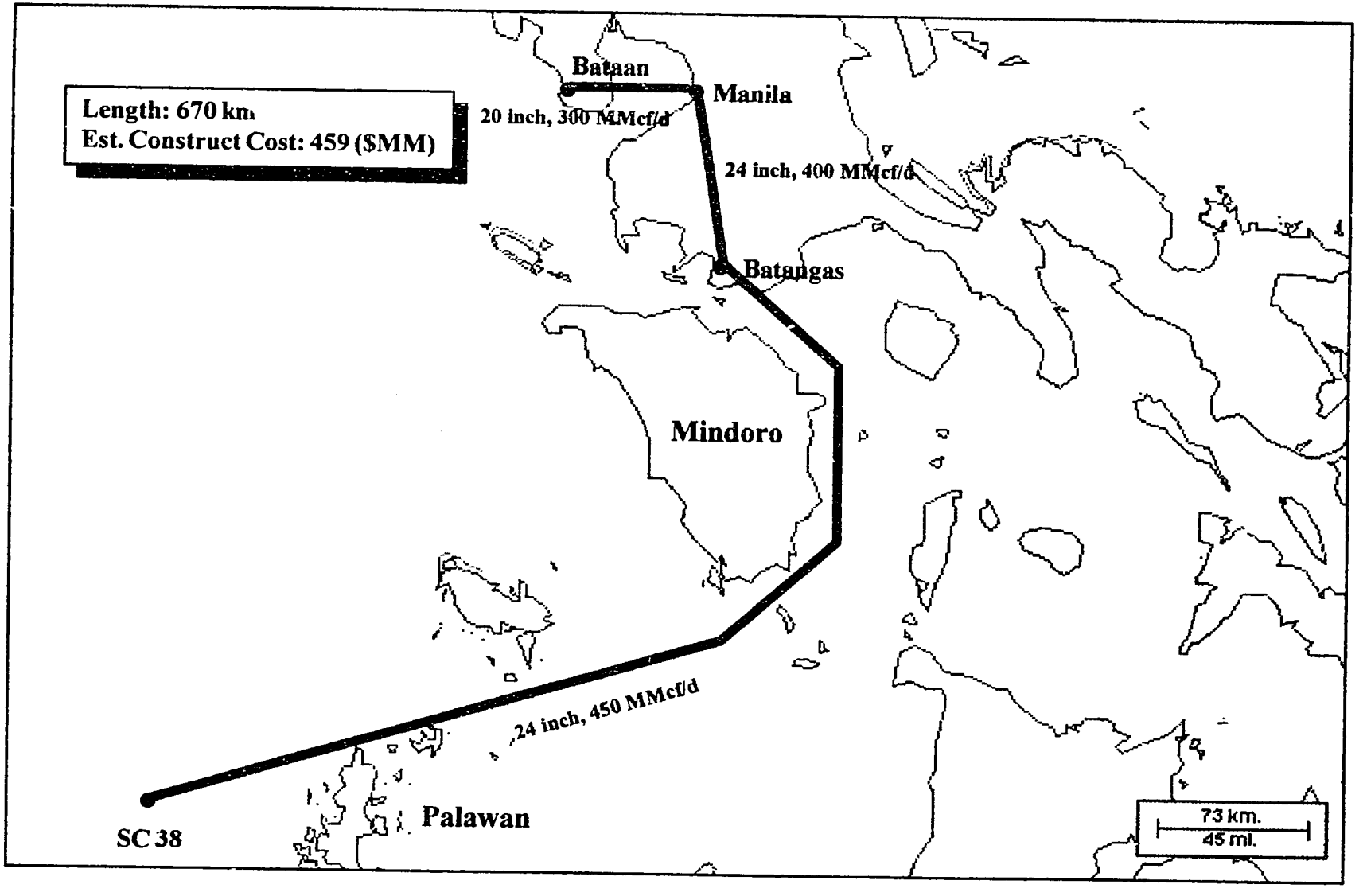
COST COMPARISON OF DELIVERY OPTIONS

Delivery Option	*Capital Cost (94$MM)*	*Annual Cost (Levelized $MM)*
Base Case Pipeline Configuration	1,838	448
Base Case LNG Option	4,065	787
500 kV Cable	4,433	817

The Base Case Pipeline Configuration, i.e., constructing a non-telescoping pipeline through Central Luzon, provides efficient delivery of the Malampaya/Camago

Figure 2

BASE CASE CONFIGURATION



gas to the identified customer bases in Bataan, Batangas, and Metro Manila at competitive prices while establishing a foundation for the future growth and development of a diverse Philippine gas industry. The potential for strong future market growth exists along the recommended pipeline route.

The following is a breakdown of the estimated incremental delivered cost of gas in each market via the Base Case Pipeline Configuration:

BREAKDOWN OF DELIVERED GAS COST (BASE CASE)
($ per MMBtu, to Large Volume Customers)

Cost Component	*Bataan*	*Batangas*	*Metro Manila*
Production Cost	$2.48	$2.48	$2.48
Royalty Add-on	$0.54	$0.54	$0.54
Mainline to Batangas	$0.18	$0.18	$0.18
Manila Lateral	$0.03	N/A	$0.03
Manila/Bataan Ext.	$0.03	N/A	N/A
Distribution Network	$0.02	$0.09	$0.02
Total Delivered Cost	$3.28	$3.29	$3.25

The model used to calculate the cost-of-service of each of the three delivery options provides the flexibility to assess the sensitivity of each option to a number of inputs. The following table shows the sensitivity of the Base Case Configuration to changes in the diameter of the Mainline undersea pipeline segment, and the addition of onshore storage facilities:

SENSITIVITY ANALYSIS OF FACILITIES (BASE CASE)

Sensitivity	*Delivered Gas Price - Manila $/MMBtu*	*Capital Cost 1994$MM*
Base Case	$3.25	1,838
Mainline diameter increased from 24-inch to 30-inch	$3.27	1,870
Mainline diameter increased from 24-inch to 36-inch	$3.28	1,903
Storage facilities added at terminus of Mainline (100 MMcf)	$3.27	1,878

Note: Assumes constant volumes.

We conducted other sensitivity analyses of the Base Case Pipeline Configuration to assess the impact of different financing opportunities on the project economics. These various financial opportunities may be available to the project based on the ownership of the facilities and the ability of the project to qualify for assistance in the form of developmental financing. The following table summarizes a number of possible financing scenarios ranging from commercial financing to low cost developmental financing:

SENSITIVITY ANALYSIS OF FINANCING (BASE CASE)

Financing Variable	*Developmental Financing*	*Base Case Financing*	*Commercial Financing*
Production Gross ROR (20 years)	15%	20%	20%
Pipeline Financing:			
- Interest rate	3.5%	6.5%	8.0%
- Grace period	5 years	2 years	none
Annual Cost in Levelized $MM	377	448	460
Rolled-in $/MMBtu	$2.76	$3.27	$3.34

Structure (Chapter 6) - BSA's assessment of the Philippine natural gas industry sectors suggests that it is feasible to adopt a long-term vision of a Philippine natural gas industry characterized by private firms operating within competitive production and end use sectors and non-competitive transmission and distribution sectors.

In the short term, however, we recognize that the Philippine production and end use sectors will be insufficiently competitive to establish an industry structure premised on workable competition. Consequently, we recommend an interim structure that will promote the immediate objectives of developing the identified indigenous resource base and ensuring its best use largely for power generation. In the short-term, NAPOCOR or PNOC represent appropriate creditworthy buyers of Malampaya/Camago gas, assuming contracts provide for assignment to ultimate gas end-users in a privatization context. We also recommend establishing an independent Philippine Gas Pipeline Company (PGPC) to transport gas to users onshore, again to be set within a privatization context, e.g., construction on a build-own-operate basis.

Finally we establish a framework for securing the longer-term objectives of private investment in a Philippine natural gas infrastructure to accommodate the development of future resources and end use markets and promote the evolution of competitive markets. Figure 3 depicts our recommendation for structuring the Philippine gas industry in both a transitional and permanent form.

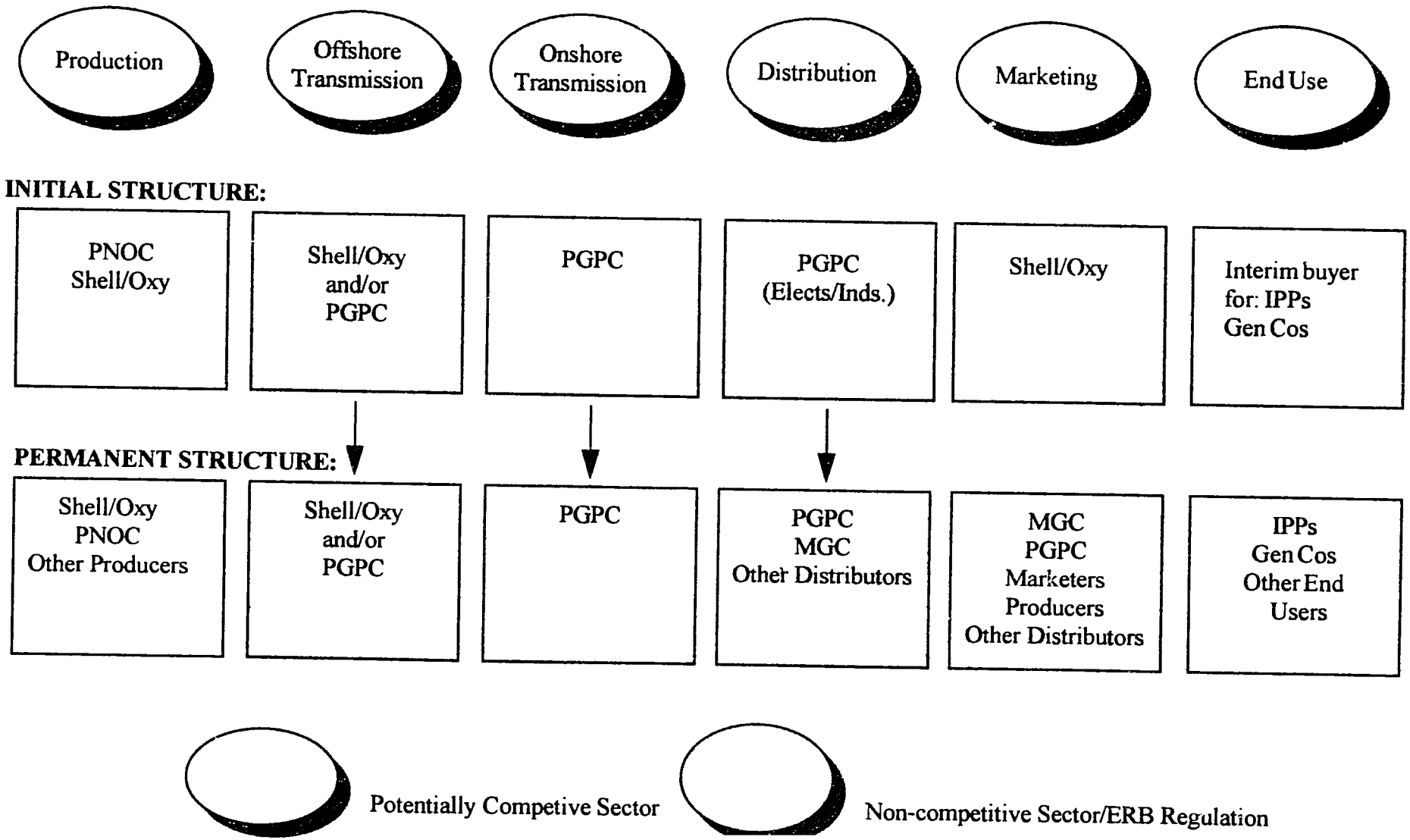
Contractual Issues (Chapter 7) - The results of the foregoing price and structural analysis must be effectively embodied in gas sales and transportation contracts that will ultimately bind together the various parties to the Malampaya/Camago in a long-term relationship. Because of the substantial capital investment required, it is essential that the parties involved achieve a high level of comfort in each others' abilities to perform. Each piece of the project must be developed and promoted concurrently by parties with the ability and financial strength to guarantee performance.

Conclusions, Recommendations, and Next Steps (Chapter 8) - In this chapter, we review key findings of the study, and we identify a number of areas that demand future analysis.

The following chapters of this study contain BSA's analysis in reaching the above conclusions and recommendations. The next chapter contains a brief overview of the Malampaya/Camago project and a discussion of BSA's role in this project.

Figure 3

STRUCTURING THE PHILIPPINE NATURAL GAS INDUSTRY



CHAPTER 1
OVERVIEW OF MALAMPAYA/CAMAGO PROJECT

In October 1989, Oxy discovered the Camago natural gas reservoir located in offshore block SC 38 in the South China Sea about 400 km southwest of Manila and about 75 km off the northern tip of Palawan Island. Shell obtained a 50 percent stake in the block in mid-1990 and soon located the adjacent Malampaya reservoir. Shell/Oxy estimates the combined recoverable gas reserves of the Malampaya/Camago reservoir at between 2 and 4 Tcf with gas production estimated at 450 million cubic feet per day (MMcf/d).

The Malampaya/Camago gas reserves potentially represent the Philippines' largest indigenous source of fossil fuel. Current energy consumption is largely met with imported oil and a blend of low grade domestic and high grade imported coal. The Philippines currently has no natural gas industry. Shell/Oxy has undertaken an appraisal program to better determine the reserve base. The final test well, Malampaya 4, was completed in September 1994.

Shell/Oxy has presented the DOE with a plan for the development of the Malampaya/Camago gas reservoir targeting an in-service production date of 1998. Shell/Oxy has proposed a base case development plan estimated to require a capital expenditure of US$2.1 billion and annual operation expenditures of US$90 million, consisting of (see Figure 4):

- Offshore production facilities including an integrated oil and gas tension leg platform (TLP) and possible floating storage unit (FSU) to store and evacuate oil/condensate

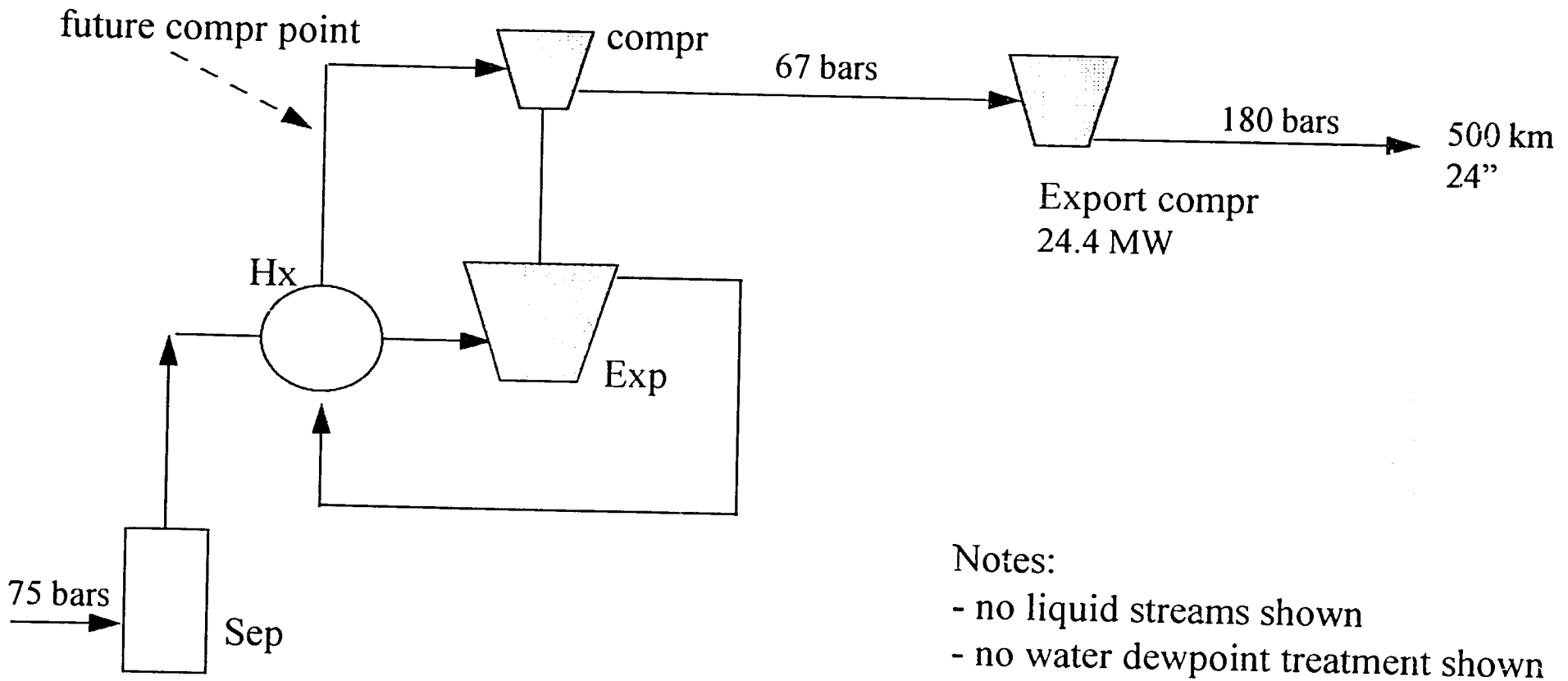
- Offshore gas separation/treatment processing facilities including compression necessary to bring the gas pressure to 180 bar before entering an undersea pipeline

- A 24-inch diameter, 500 km undersea pipeline from the offshore production area to Batangas on Luzon Island.

Several meetings have taken place involving Shell/Oxy and the Committee formed by the DOE to lead the effort of ensuring that development and ultimate production of the Malampaya/Camago reserves proceeds in a manner that best serves the interests of the Philippine people. These preliminary meetings have been primarily aimed at exchanging information and analysis. At these meetings, Shell/Oxy has

Figure 4

MALAMPAYA TLP GAS PROCESS DIAGRAM



Notes:
- no liquid streams shown
- no water dewpoint treatment shown
- two 60% trains planned

Source: Shell/Oxy

expressed a strong desire to enter into a gas sales agreement with a creditworthy party, e.g., the Philippine government. Shell/Oxy is currently seeking to enter into a "heads of agreement" by year end 1994.

At this point BSA was asked by RCG to assist the DOE in the preparation of a contract negotiating strategy for the Malampaya/Camago gas. BSA was not asked to participate directly in the negotiations, but rather, to provide assistance to the Committee in preparation for the upcoming negotiations by conducting an analysis of the value and best utilization of the Malampaya/Camago gas to the Philippine economy. BSA was also asked to advise the Committee on basic contractual and negotiating principles in the field of natural gas procurement.

The following chapter is a discussion of the goals of this study as well as a description of the tasks BSA has undertaken to accomplish these goals.

CHAPTER 2
GOALS AND APPROACH OF STUDY

The primary goals of this study are to determine the value of the Malampaya/Camago gas to the Philippine economy and then, knowing the value of the gas, determine the best way to exploit that value to best serve the interests of the Philippine economy.

Determination of value is complex and dependent on numerous tangible and intangible factors. The concept of value is often mistakenly used interchangeably with the term cost, e.g., water costs relatively little, however, it is extremely valuable given that life itself depends on it. As long as the value of a good is the same or more than its cost, then consumers will be willing to pay that cost or price (assuming cost-based pricing). Cost is kept in check by free market forces, primarily competition among suppliers.

One method of determining the economic value of a good is by determining the opportunity cost of buying that good. The opportunity cost of buying a good is determined by looking at the price of using close substitutes for that good, in the case of natural gas, alternate fuels such as fuel oil, coal, etc. For example, the value of natural gas at a power plant in Bataan is in its use as a fuel source to generate electricity. In the simplest terms, the value of the natural gas is only equivalent to its heat content, i.e., the number of MMBtus that are captured for use when the gas is burned. However, natural gas is only one fuel among many alternatives. Bunker C, diesel, and coal are fuels that can also be burned to generate electricity. *All other things equal, the price of natural gas at the burner-tip must be competitive with the price of these alternate fuels, or natural gas cannot economically be utilized as a fuel source.*

BSA took the following steps to determine the economic value of the Malampaya/Camago gas at the burner-tip relative to other fuel sources:

- Identified the potential customer base. The Malampaya/Camago gas has a relative value dependent on how it is being used and where it is being used

- Determined the cost of fuel oil and coal to the identified customer base.

However, a simple cost comparison of fuels at the burner-tip understates the value of the Malampaya/Camago gas reserves because of several tangible and

intangible factors each of which contribute to the premium that natural gas commands on an all-in-cost-basis versus other competing fuels. For example, one tangible factor from an operations perspective, is that the use of natural gas in a combustion turbine results in longer turbine life and lower operation and maintenance (O&M) costs than the use of fuel oil. The added costs of using fuel oil, over and above the delivered cost of the fuel oil itself, may contribute to a price premium for natural gas. Other factors that may contribute to the price premium for natural gas include:

- Environmental impact. For example, the use of coal without extensive emission controls results in the release of significant amounts of pollutants into the environment. These pollutants result in an external cost that is forced upon everyone living in the surrounding area in terms of lower air quality, human health risks, reduced agricultural productivity, etc. If the polluter is made to internalize these costs through regulatory initiatives such as setting a limit on the level of pollutants that can legally be released into the environment, the price premium for clean burning natural gas increases to reflect the cost of emission controls for coal

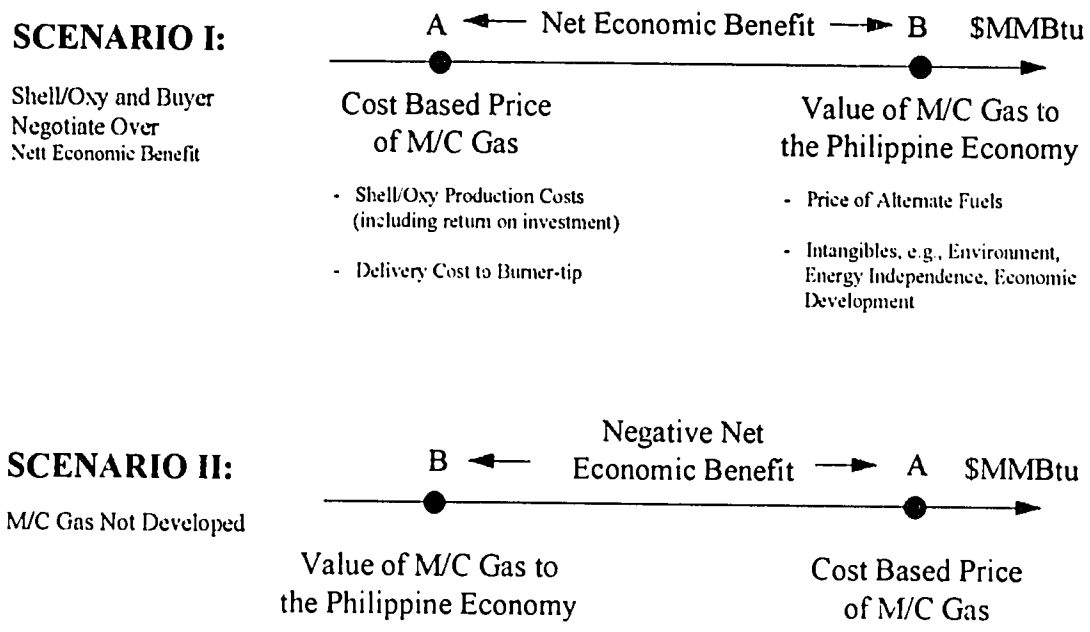
- Energy independence. Malampaya/Camago represents a degree of energy independence for the Philippines. Even if the cost of producing and delivering the Malampaya/Camago gas to the burner-tip proves to be uncompetitive relative to the delivered price of alternate fuels, there is a certain intangible value associated with diversification and security that is associated with the production of domestic energy sources, e.g., avoided costs of strategic petroleum storage. Domestic energy production will also provide a degree of price insulation to the economy from fluctuations in the price of imported fuels

- Economic development. New capital investment, taxes, jobs in the gas industry. In addition, the potential expansion and improvement in electricity service as a result of new gas-fired electricity generation can facilitate expansion of the Philippine economy.

In summary, the value of the Malampaya/Camago gas to the Philippine economy is the sum of the price of alternate fuels at the burner-tip and other tangible and intangible factors such as environmental impact and energy independence that contribute to a premium for natural gas over the price of the other fuels. This value is represented by Point B in the figure below.

Figure 5

PRICING THEORY



The value of the Malampaya/Camago gas represents the most that the economy should be willing to pay for the gas. Assuming that the cost of producing and delivering the gas is less than the value of the gas (represented by Scenario I in Figure 5), the economy will benefit through the development of the Malampaya/Camago reserves. Point A in Figure 5 represents the cost of producing and delivering the gas. At any price below this point Shell/Oxy would logically be unwilling to develop and sell the Malampaya/Camago gas. In an effort to estimate what these production and delivery costs are, i.e., where Point A is, BSA undertook the following steps:

- Independently reviewed the Malampaya/Camago reserve base to verify the total volume of producible reserves. This initial step is critical because the size of the reserve base is a threshold factor as to the economic feasibility of the different delivery options considered

- Reviewed the cost estimate for production of the Malampaya/Camago reservoir

Developed cost estimates for natural gas delivered to the identified customer base via several delivery options, including:

- Undersea/land gas pipeline configurations
- LNG
- 500 kV cable.

The difference between the value of the gas to the Philippine economy (Point B) and the cost of producing and delivering the gas (Point A) represents the excess economic benefit over its cost that is accrued through development of the Malampaya/Camago reservoir. How this economic benefit is allocated is one of the issues that must be decided in negotiations between the Committee and Shell/Oxy. The Philippine economy will benefit as long the price does not exceed Point B. Shell/Oxy will likely be willing to develop Malampaya/Camago as long as they secure an agreement which includes a price greater than or equal to Point A.

In Scenario II in Figure 5 the cost of producing and delivering the Malampaya/Camago gas reserves (Point A) exceeds the value of those reserves (Point B). In this scenario there is no economic benefit to the Philippine economy in developing the Malampaya/Camago reservoir and, therefore, it should not be developed.

After determining the value of the Malampaya/Camago gas, the next step is to structure the future Philippine gas industry in a manner that maximizes the benefits of the gas. The structure developed in this study embodies our overriding belief that private firms operating in a free market will generally best serve the long-term interests of the industry and the economy as a whole. The potential role of the Philippine government in promoting and facilitating the initial development of the gas industry is discussed as is the need for government's long-term involvement as a regulator of private firms. To accomplish these overall goals, BSA has developed a structure that:

- Promotes private sector development of identified domestic natural gas resources

- Promotes the "best use" of domestic natural gas resources in the short-term for power generation

- Utilizes the gas-fired electric generation markets to spur private investment in a natural gas infrastructure that will accommodate the development of future natural gas resources and market growth

- Promotes development of a competitive natural gas industry where feasible

Promotes public investment in the industry and regulation of private firms only to the extent necessary to promote private capital investment and ensure competition in the industry.

The last step in our analysis is a discussion of how the preferred price and structural paths developed in this study can be embodied contractually. The analysis discusses what types of contracts are necessary, who the contracting parties are, and key provisions these contracts should contain.

The next chapter is a summary of the results and conclusions of the independent review of gas reserves conducted on the Malampaya gas reserves.

CHAPTER 3
SUMMARY OF INDEPENDENT REVIEW OF GAS RESERVES DATA

Shell/Oxy's current estimate of the total producible gas reserves contained in the Malampaya/Camago reservoir is 2 to 4 Tcf. This estimate was determined based upon the results of an appraisal program that included the drilling of three test wells: Camago-1, Malampaya-1, and Malampaya-2. This year Shell/Oxy drilled two additional wells, Malampaya-3 and Malampaya-4. The data collected while drilling these two wells has not yet been incorporated into Shell/Oxy's reserve estimate. Shell/Oxy plans to release a revised estimate of the Malampaya/Camago gas reserves in late 1994 that will incorporate the additional data collected from Malampaya-3 and 4.

Reliability of the 2 to 4 Tcf estimate, even within the established range, is critical to determination of the economic viability of pursuing the gas delivery options. If reserves prove to be only 2 Tcf, for example, the economic viability of the entire project may be diminished. Production of 450 MMcf/d from a 2 Tcf reserve base would result in depletion of the Malampaya/Camago reservoir in about 12 years. Because of the large capital investment of at least about US$2 billion, a gas reserve base of only 2 Tcf is likely to be incapable of sustaining any delivery option economically. A total reserve base of 4 Tcf is regarded as the minimum volume needed to support an LNG delivery option.

BSA retained the firm of ARI, which provides technical advisory services relating to oil and gas resource extraction, to undertake an independent review of the Malampaya/Camago reserve base data provided to the DOE by Shell/Oxy. ARI concluded from its review that the Shell/Oxy estimate is "very reasonable, and is well supported by the data provided." The most likely recoverable reserve base of the Malampaya reservoir was determined to be 3.0 Tcf (see the ARI report contained in Appendix A).

ARI's estimate of the size of the Malampaya reserve base was determined by reviewing the Malampaya-1 and 2 well reports. The Camago-1 well report, and therefore, the Camago formation, was not available for review by ARI. Shell/Oxy estimates that the Camago formation contains reserves of about 1 Tcf.

No additional gas reserves of any real significance have been proved in the offshore region surrounding Malampaya/Camago, however, a number of companies are currently continuing to explore for oil and gas in the area. For example, in

December 1994 Oxy plans to drill its first well (Bantac-1) in the West Culion field, located offshore of Palawan along the same reefal trend as Malampaya/Camago in block SC 65. Preliminary unproved reserve estimates indicate that the prospect could contain 2 Tcf of gas.

BSA concludes that there are most likely at least 4 Tcf of gas reserves behind the initial pipeline project. In particular, we note the results of the ARI review (i.e., a best estimate of 3 Tcf for Malampaya), together with 1 Tcf for Camago and prospects elsewhere.

In the following chapter the potential customer base for Malampaya/Camago gas in Bataan, Batangas, and Metro Manila is identified and analyzed.

CHAPTER 4
IDENTIFICATION AND ANALYSIS OF CUSTOMER BASE

In this chapter BSA discusses the high degree of comfort that the contracting parties must gain in each others' abilities to perform and how this requirement translates to the targeting of a customer base for the Malampaya/Camago project.

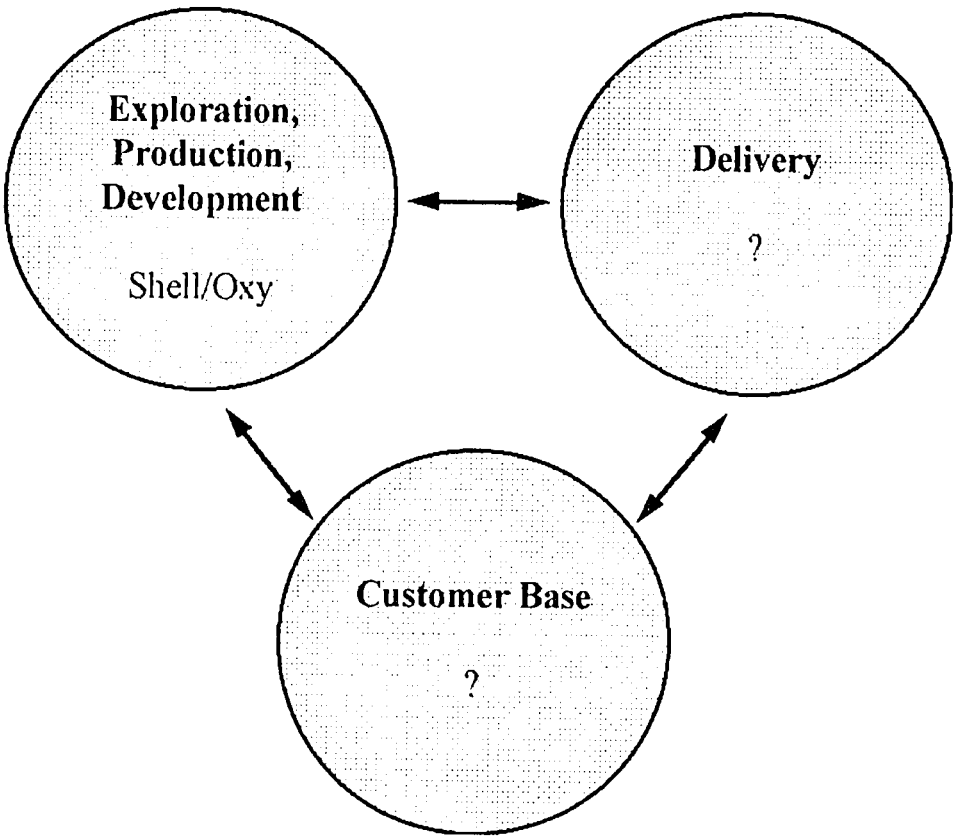
4.1 GUARANTEES OF PERFORMANCE

Development of Malampaya/Camago represents the beginning of the Philippine natural gas industry. Major "green field" projects, such as development of Malampaya/Camago gas, require substantial capital investment, with returns on investment often deferred over a lengthy period of time. Furthermore, investors in developing countries such as the Philippines typically demand a higher rate of return on their investment than they would in a developed country because of increased risk associated with potential political instability, less predictability in the outcome of litigation, etc. Consequently, greenfield projects in developing countries typically face somewhat of a "chicken or egg" dilemma: none of the parties involved want to be the first to invest in a project of this magnitude without substantial assurances, or ideally a guarantee, that the project will indeed be developed and yield a return on investment. Because of this dilemma, it is essential that the parties involved in a transaction of this magnitude achieve a high level of comfort in each others' abilities to perform. All of the various pieces of a project of this size have to be developed and promoted concurrently by parties with the ability and financial strength to guarantee performance.

Development of the Malampaya/Camago gas reserves can be broken into three basic pieces.

Figure 6

MALAMPAYA/CAMAGO PROJECT



1. The first piece or link in the chain is the exploration, development, and production of the gas. Shell/Oxy is undoubtedly a world leader in this area with the capability and financial strength to guarantee production of the reserves

2. The second link is delivery of the gas to the market

3. The third link is a market or customer base to purchase and consume the gas. Shell/Oxy will be unwilling, justifiably so, to develop the Malampaya/Camago reserves without assurance that facilities to deliver the gas to the market will be constructed and that a sufficient customer base will be in place to purchase the gas.

In order to facilitate the development of the Malampaya/Camago project, Shell/Oxy has prepared a plan which involves the construction of a pipeline by Shell/Oxy to Batangas, one potential market for the gas. From Shell/Oxy's perspective, construction and ownership of the means of delivery minimizes risk of nonperformance or delay by another developing party and makes it more likely the Malampaya/Camago gas that Shell/Oxy produces will reach the targeted market. The economics of this delivery option will be evaluated along with other delivery options in the following chapter. The cost and benefits of the various ways to structure the Philippine gas industry will also be reviewed below, i.e., whether it is beneficial to the Philippine economy (and to Shell/Oxy) for Shell/Oxy to construct and own the means of delivering the gas to the market.

The third link, customer base, is a more difficult area in which to achieve comfort simply because the projected volume of 450 MMcf/d of gas to be produced and delivered is far greater than the needs of any one single existing or potential end-use facility (customer). From a contractual perspective, ideally Shell/Oxy would prefer an arrangement with one customer or purchaser with the financial strength to guarantee payment for all of the gas, i.e., one customer to sign a "take-or-pay" contract under which that customer must pay for the volume of gas contracted whether the customer physically takes the gas or not (for more detail on contracting terms and provisions see Chapter 7: Contractual Issues). Dealing with multiple customers is more difficult because Shell/Oxy must, of necessity, achieve comfort as to each individual customer's ability to perform and pay. For this reason, for example, Shell/Oxy may seek a government guarantee of payment for the gas. A government guarantee would place ultimate responsibility of marketing the gas onto the Philippine government, most likely through NAPOCOR or the Philippine National Oil Company (PNOC). The cost and benefits to the Philippine economy of providing such a guarantee will be discussed below. However, whether Shell/Oxy or the Philippine government is ultimately at risk for nonperformance by individual customers, the following analysis and conclusions advocating a core customer base consisting of a handful of large base load facilities remains true.

4.2 OVERVIEW OF CUSTOMER BASE

As discussed, from a contractual perspective, one creditworthy buyer for all of the gas would be ideal. This also holds true from an operations perspective; one large customer consuming 450 MMcf/d would be the ideal. Usually, the large buyer and large consumer of the gas are the same entity. Only in situations where the creditworthiness of the consumer is insufficient is it necessary to have a guarantor of payment, i.e., the Philippine government, standing behind the consumer as the ultimate buyer. If a single creditworthy customer consuming all of the gas is unavailable, the next best alternative is a single large creditworthy customer consuming a significant

portion of the gas. We refer to this customer as the "anchor load" for the project. The presence of an anchor load has often been essential toward facilitating the development of major pipeline projects because of the uncertainties and inefficiencies involved in achieving comfort with multiple, small customers.

The power generation sector and the industrial sector of the economy are comprised of large energy intensive customers and therefore are the likely sectors to include an anchor load. This is in contrast to the residential and commercial sectors which are comprised of numerous small customers. Without an existing infrastructure to serve commercial and residential customers, it is generally not cost effective to target these sectors in the early phases of the development of a gas industry. Because of the necessary comfort level that must be achieved among parties and the practical difficulties associated with contracting with numerous customers discussed above, residential and commercial load can only be served with the aid of government, e.g., the Philippine government could decide that it is in the best interests of the economy to develop these sectors and undertake the construction of necessary infrastructure and potentially legislate necessary subsidization of the customer base to make gas service to the residential and commercial sectors a reality.

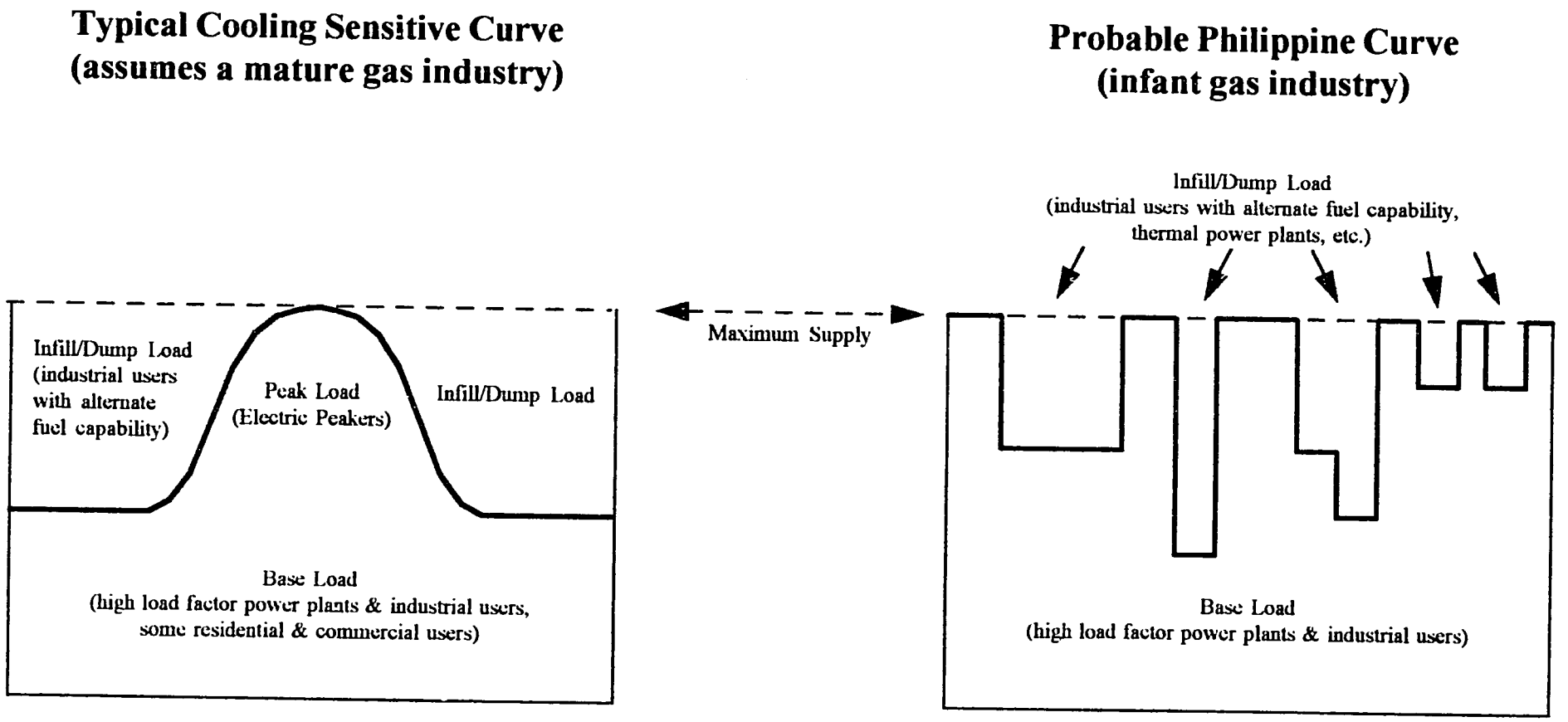
This analysis does not explore the possibility of gas service to the residential and commercial sectors. No infrastructure currently exists for the distribution of natural gas with the exception of a fairly extensive existing network of gas pipelines in Metro Manila that was used by MGC to deliver manufactured gas to industrial, commercial, and residential customers until MGC discontinued using the system in 1991. Refurbishment of the MGC system would likely result in significant cost savings over the construction of a completely new gas distribution system, e.g., in Batangas. However, refurbishment of MGC beyond what is necessary to serve contracted industrial customers is unlikely to be supported by the economics of the Malampaya/Camago project because the volume of gas delivered and sold to these smaller customers is likely to be insufficient to support the relatively large capital investment in piping and metering facilities required to serve them. Once a Philippine natural gas industry has been established through the initial development of the Malampaya/Camago reserves for power generation and industrial use, future phases of development targeting residential and commercial customers should be explored.[1]

Figure 7 contrasts the load curve of the typical cooling sensitive customer base of a mature gas industry with that of an infant Philippine gas industry. In the mature

[1] Providing gas service to the islands of Palawan and/or Mindoro, while attractive from a service perspective, is unlikely to be economical in the initial stage of development of the Malampaya/Camago project for the same reason that service to smaller customers on Luzon is not initially feasible, i.e., without a concentrated base of large gas consumers and/or an existing gas pipeline infrastructure, the high capital cost of constructing the necessary facilities required to serve small users makes natural gas prohibitively expensive relative to other fuels.

Figure 7

ILLUSTRATIVE ANNUAL LOAD DURATION CURVES



industry the supply of natural gas in the market exceeds the demand represented by base load customers, i.e., high load factor power plants and industrial users as well as gas utilities serving non-cooling residential and commercial uses. The excess gas supply in the market is consumed by either peak load users, e.g., peaking power plants serving increased air conditioning loads during the hottest periods of the year, or by infill/dump load users that are willing and able to consume gas on an interruptible as-available basis ("interruptibles"). *We emphasize that the role of the interruptible customers on the gas delivery system can be quite important in maintaining a constant flow of gas at the point of production and through the pipeline, as well as in promoting future gas market expansion.*

In contrast, in the infant Philippine gas industry, the initial supply of gas in the market will match the use of base load customers. As discussed above, this is necessary because Shell/Oxy will be unwilling to develop the Malampaya/Camago reserves unless a customer base of creditworthy users is clearly defined and contracted. These customers will be high load factor base load users that are willing to guarantee to Shell/Oxy that they will take substantially all of the gas they have contracted for on a regular basis or pay for what they fail to take, i.e., take-or-pay for the contract volume. The other users of gas in the infant market will be the interruptibles that, as discussed above, utilize the gas when the base load users are inoperable, e.g., during scheduled maintenance outages, etc. The interruptible users may perform the function of balancing load swings that may occur thus ensuring that there is always a market for all of the gas produced. Beside serving an operations function, gas use by interruptibles is likely to promote the ultimate introduction of new industries utilizing natural gas into the economy. For example, the development of a petrochemical industry in the Philippines is likely to be facilitated by the availability of natural gas as a feedstock. Figure 8 shows the broad range of industries utilizing natural gas in a mature gas market.

4.3 SELECTION OF CUSTOMER BASE

The majority of potential power plant and industrial demand for natural gas is located on the island of Luzon extending from Batangas through Metro Manila and over to Bataan (see Figure 9). These three markets in Central Luzon provide more than ample opportunity for natural gas use making this area the target market for the Malampaya/Camago gas. The remainder of this chapter is devoted to determining a specific list of customers in each region to meet the base load and infill/dump load requirements of the Malampaya/Camago gas.

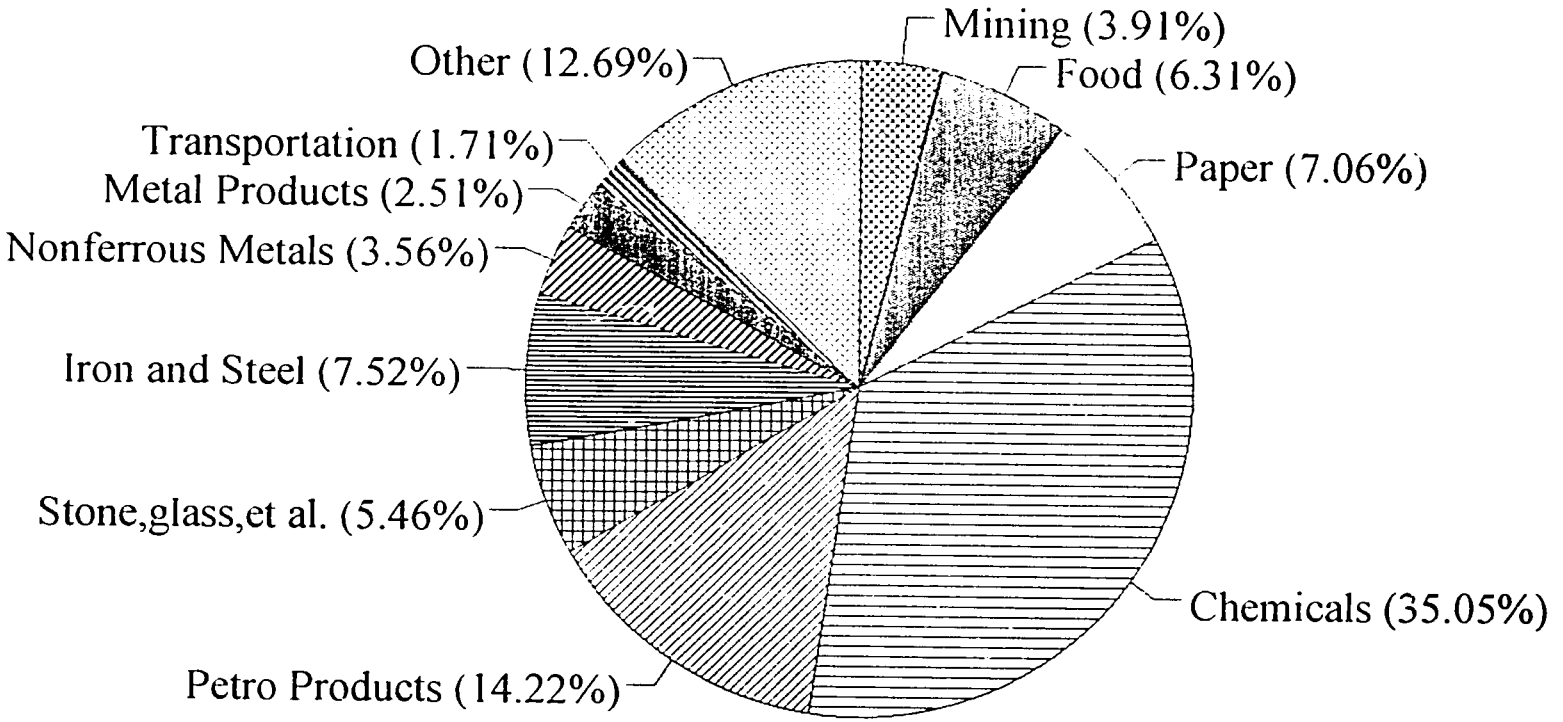
4.3.1 Power Generation Sector (Base Load)

A significant number of studies have been completed on power generation in the Philippines including: "Opportunities for Consumption of Natural Gas in Power

Figure 8

GAS CONSUMPTION BY INDUSTRIAL USERS

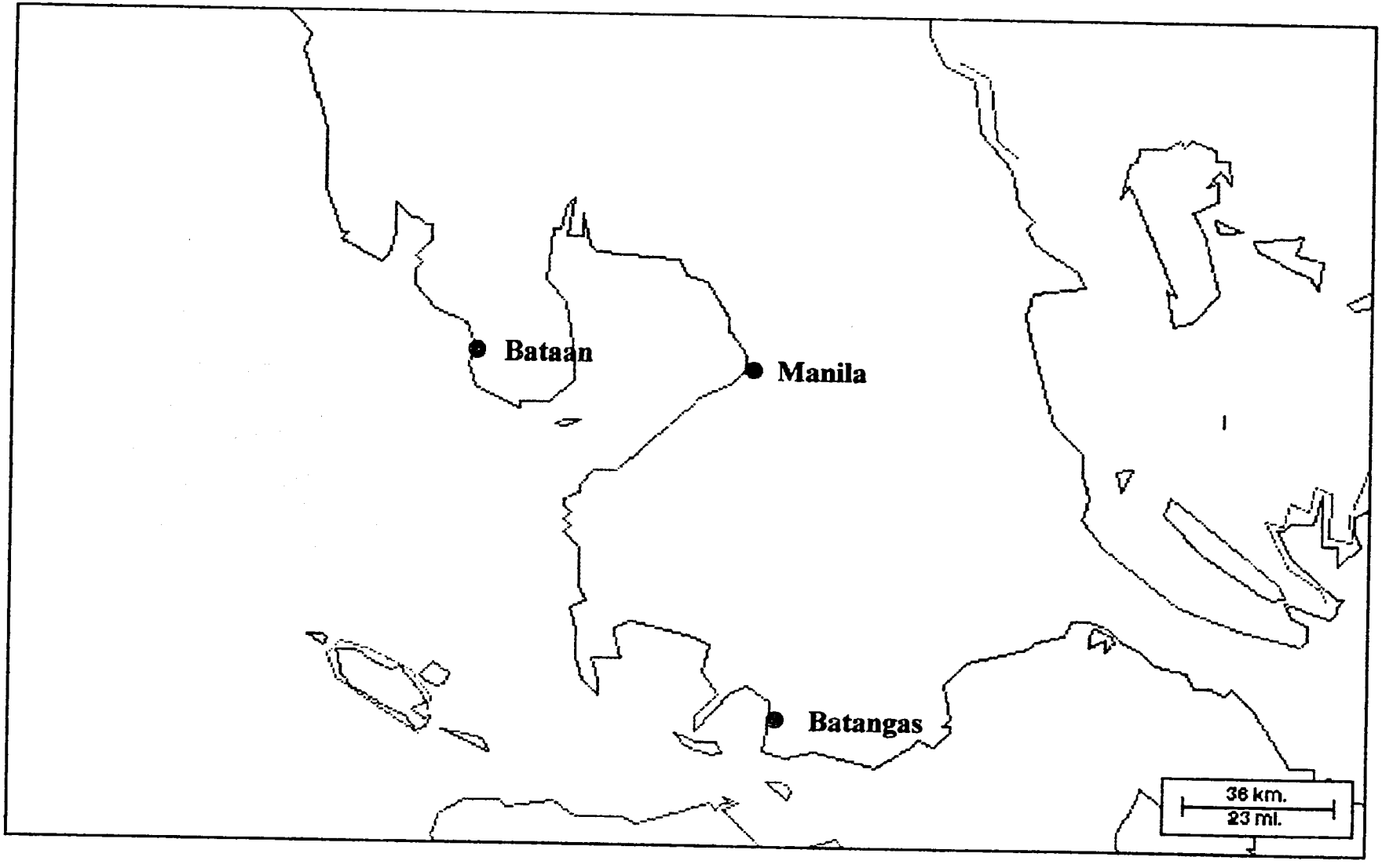
1992 U.S. Industrial Consumption Data



Source: American Gas Association - Gas Requirements Committee, 1992.

Figure 9

CENTRAL LUZON MARKET AREA



Generation in the Philippines - A Scouting Study" by Shell in August 1993, and "Natural Gas For Power Generation in the Philippines, Part I. Identification of Main Planning Issues" jointly by Shell/Oxy and NAPOCOR in June 1994. An Asian Development Bank (ADB) study on long-term power generation in the Philippines is currently ongoing and should be complete in September 1994. BSA has reviewed these studies as well as additional materials provided by NAPOCOR, DOE, ADB, RCG, etc. (see list of sources reviewed by BSA in attached "List of Sources").

A majority of the studies and reports completed on the Philippine power sector point to continued growth within the power sector as the demand for electricity rises driven by an expanding Philippine economy. For example, the National Economic Development Authority (NEDA) forecasts that the growth in power demand will average 11.3 percent over the period 1994 through 2005. This growth rate assumes an average annual increase in Gross Domestic Product (GDP) of 8.1 percent and a power demand elasticity of 1.4 for all of the Philippines and 1.2 for the Island of Luzon. NAPOCOR bases its power demand forecasts on the GDP growth figures published by NEDA and is, therefore, similarly aggressive in its outlook on continued growth in the demand for electricity. In contrast, preliminary results of the ADB long-term power generation study project a surplus of about 1,000 MW by the year 1999 based upon NAPOCOR's currently planned power plant additions.[2] If ADB's assumptions prove to be correct, large capacity additions to the Philippine power sector beyond the year 2000 will not be required for several years.

Regardless of whether the demand for power in the Philippines continues to grow rapidly or stagnates at the turn of the century because of overcapacity, it is clear that a number of new power plants will be constructed between now and the year 2000, which generally coincides with the introduction of Malampaya/Camago gas in the Philippine economy. These power plants are in various stages of the planning process, and some will be combined-cycle facilities. It is essential for the development of the Malampaya/Camago reserves that a number of these new plants be targeted to utilize natural gas. Utilization of natural gas in newly constructed combined-cycle plants maximizes the value of burning natural gas for power generation by utilizing the fuel more efficiently than older less efficient technologies.

Natural gas could be used to replace fuel oil in existing Luzon thermal generating units, however, the large capital expenditures required to rehabilitate many of these older plants that are plagued by poor reliability generally makes this alternative less favorable than using the gas in new more efficient plants. A number of these thermal plants are scheduled for shutdown by NAPOCOR between now and 2005. Repowering these units with combined-cycle gas turbines is another viable option to considered, however, repowering is generally not as cost effective as the use

Conversation with Mr. Jeffrey Wilson, Financial Analyst of the ADB on July 5, 1994.

of gas in new plants. While not the ideal base load customers, the thermal plants do provide an excellent interruptible, i.e., infill/dump load (to be discussed below).

One strong candidate for repowering is the Bataan nuclear plant. A number of studies have assessed the feasibility of repowering the Bataan nuclear plant with combined-cycle technology. The most recent of these, issued in June 1994 by the West Japan Engineering Consultants, Inc. (WestJec), recommends repowering the Bataan nuclear plant with combined-cycle gas fired turbines to produce 1,500 MW. A repowered Bataan nuclear plant run as a base load facility would require approximately 263 MMcf/d, or approximately 58 percent of the projected daily Malampaya/Camago gas production of 450 MMcf.[3] *The consumption requirements of a repowered Bataan nuclear plant makes it a potentially ideal anchor load for the Malampaya/Camago gas pipeline facilities, assuming the existence of a creditworthy buyer.*

BSA reviewed available data on proposed and existing power plants in Bataan, Batangas, and Metro Manila.[4] Plants falling into the following categories were selected:

- New combined-cycle gas turbine facilities
- Combined-cycle facilities that can be switched from fuel oil to natural gas
- Single-cycle facilities that can be converted to combined-cycle and powered by natural gas
- Existing facilities able to be economically repowered with combined-cycle gas turbines.

[3] Consumption of 263 MMcf/d is based upon the estimated fuel requirements of modern combined-cycle gas turbines being approximately 175 Mcf/d per MW.

[4] Data sources include materials provided by DOE, NAPOCOR, RCG, and Shell/Oxy.

The following is a list of power plants that could be possible base load customers of the Malampaya/Camago gas:

BATAAN POWER PLANTS

Plant Name	*Assumed Load Factor*	*MW w/ Gas*	*MMcf/d @ 100% LF*	*MMcf/d @ LF*	*Comments*
New CCGT	80%	600	105	84	New Facility
Bataan CC - Block A	80%	300	53	42	Fuel switch from fuel oil to natural gas
Bataan CC - Block B	80%	300	53	42	Fuel switch from fuel oil to natural gas
Bataan GT	80%	180	32	25	Conversion to CC, fuel switch from oil to natural gas
Bataan Nuclear Plant	80%	1,500	263	210	Repower with CCGT
Bataan II	80%	150	26	21	Repower with CCGT
TOTAL BATAAN:		**3,030**	**530**	**424**	

BATANGAS POWER PLANTS

Plant Name	*Assumed Load Factor*	*MW w/ Gas*	*MMcf/d @ 100% LF*	*MMcf/d @ LF*	*Comments*
New CCGT	80%	600	105	84	New Facility
Enron I	80%	105	18	15	Conversion to CC, fuel switch from diesel to natural gas
TOTAL BATANGAS:		**705**	**123**	**99**	

METRO MANILA POWER PLANTS

Plant Name	*Assumed Load Factor*	*MW w/ Gas*	*MMcf/d @ 100% LF*	*MMcf/d @ LF*	*Comments*
New CCGT	80%	600	105	84	New Facility
Navotas (Hopewell)	80%	465	81	65	Conversion to CC, fuel switch from oil to natural gas
TOTAL METRO MANILA:		**1,065**	**186**	**149**	

From the above tables, it can be seen that 3,030 MWs of possible base load gas fired power production is located in Bataan. Furthermore, the Bataan nuclear plant, which represents the best possible anchor load, is also located in Bataan. An additional 705 MW of possible base load gas fired power production is located in Batangas; 1,065 MWs are located in Metro Manila. The number of MWs shown represents the number of MWs that can be produced when the plant is run on natural gas in combined-cycle mode. Gas consumption is shown for both a load factor of 100 percent as well as the projected operating load factor, e.g., 80 percent.

Note that although the above identification of base load customers is focused on power generation, a number of large industrial users with constant gas requirements also fall into the base load category. One excellent example is PNOC's planned petrochemical complex in Bataan that could utilize natural gas as a feedstock in the production of ethylene and propylene instead of the originally conceptualized use of naphtha. Likewise, as noted, some power plants make ideal interruptible customers, e.g., older less efficient thermal plants.

4.3.2 Industrial Sector (Interruptible Load)

As discussed above, the Central Luzon area is heavily industrialized. There are hundreds of industrial facilities in the region representing numerous possible infill/dump load customers to compliment the base load power plant consumption demonstrated above. These industrial customers currently use either Bunker C heavy fuel oil, diesel fuel, coal, or in some cases, liquefied petroleum gas (LPG). The following tables list some of the major industrial customers in Bataan, Batangas, and Metro Manila in those industries that are known for using natural gas:

BATAAN INDUSTRIALS

Company Name	*Type of Industry*	*Location*
BPPMI (Bataan Pulp and Paper Mills, Inc.)	Paper	Samal, Bataan
CCP (Columbian Carbon Philippines, Inc., a chemical company)	Chemicals	Lamao, Limay, Bataan
Planters Products	Fertilizer	Limay, Bataan

In addition to the above industrial customers, note that the PNOC through the Petrochemical Development Corporation is planning to construct a petrochemical complex in Bataan that will include an upstream facility capable of processing natural gas into basic raw materials that can be used by downstream manufacturing plants. The project will be built in three phases, with the first phase to be completed in 1997 and the second in the year 2000.

BATANGAS INDUSTRIALS

Company Name	*Type of Industry*	*Location*
Fortune Cement Corp.	Cement	Napulo, Tayson Batangas
Pilipinas Shell Petroleum Corp.	Refinery	Batangas City
Caltec Philippines	Refinery	San Pascual, Batangas
Chemphil-LMG, Inc.	Chemicals	San Pascual, Batangas
Phil-Asia Food Industries, Corp.	Food	Batangas City

METRO MANILA INDUSTRIALS

Company Name	*Type of Industry*	*Location*
San Miguel Corporation - Carton Plant	Packaging	Binondo, Manila
EEI, Engineering Equipment, Inc.	Metal Casting	Mandaluyong, Metro Manila
Benguet - Foundry Division	Steel/Iron Casting	Metro Manila
Capital Steel Corp.	Steel	Metro Manila
Goodyear Steel Pipe Corp.	Steel	Metro Manila

The following is a list of the nine largest industrial customers supplied with LPG by MGC. Some of these facilities may be connected to MGC's piped gas network.

MANILA GAS LPG CUSTOMERS

Company Name	*Type of Industry*	*LPG Consumption (MT/Month)*
Lin Fong Industrial	Ceramic	113
Yon Hoo Phils.	Transportation	31
Resins	Chemicals	14
La Perla	Food	7
Kuntray	Packaging	6.6
Jonis	Food	6.2
Chow King	Food	6.2
Galactica	Food	6.0
Sea Champ	Food	5.5

4.4 CONCLUSIONS AND NEXT STEPS

In summary, the above analysis demonstrates that there is more than sufficient base load power plant demand for the Malampaya/Camago gas among combined-cycle plants alone. Furthermore, there is a well developed and diverse industrial sector capable of providing an interruptible load for the gas.

CUSTOMER BASE SUMMARY

Market Area	*Share of Identified Base Load*	*Additional Factors*
Bataan	63 %	Bataan nuclear plant as anchor load, possible petrochemical facility
Batangas	15 %	Closest in proximity to the Malampaya/Camago reserves, large industrial base
Metro Manila	22 %	Existing network of gas distribution pipes, numerous industrial facilities

The Bataan area represents the single greatest potential market for the Malampaya/Camago gas with over 63 percent of the identified combined-cycle power plant demand. Nearly half of the Bataan area demand and 31 percent of the overall demand is represented by repowering of the Bataan nuclear plant. Assuming a creditworthy buyer, this one facility, as discussed above, is ideally situated to be the anchor load for the entire Malampaya/Camago gas pipeline project, with its estimated consumption of 263 MMcf/d. The potential for development of a domestic petrochemical industry that utilizes natural gas as a feedstock also contributes to Bataan as the single most attractive market for the gas.

Batangas has the smallest amount of identified power plant demand with only 15 percent of the total. However, there are numerous industrial facilities located in Batangas and, because of its geographical location, a pipeline route from Malampaya/Camago to either Bataan or Metro Manila must necessarily pass by or through Batangas.

Identified combined-cycle power plant load in Metro Manila represents about 22 percent of the overall demand. Advantages to serving Metro Manila include its substantial industrial base as well as MGC's existing piped gas network that could significantly reduce the cost of constructing a distribution network to serve area industrial customers, and provide the springboard for future service to a broad base of residential and commercial customers.

A significant amount of work remains to be done in the area of identifying the specific customers for the Malampaya/Camago gas, including:

- Feasibility studies for each individual power plant that will utilize natural gas detailing the cost of conversion/repowering, if necessary
- A dispatch analysis of the Luzon power grid to determine the load factor of all gas fired power plants
- A detailed analysis of the surrounding industrial base in order to select industrial users that will complement the projected load factor of the base load power plants and are in close proximity to the power plants, thus minimizing the initial investment in piping
- Assessment of the economic feasibility of constructing a distribution network to provide service to existing and/or future "industrial zones" such as Subic
- Feasibility studies for each individual industrial customer selected
- Configuration of a gas distribution network to link the customer base within each market area.

The following is a discussion of the relative economics of three options for delivering gas from Malampaya/Camago to the above identified customers. This chapter concludes with estimated costs for the delivery of gas to Bataan, Batangas, and Metro Manila. These delivered gas prices are then compared to the existing prices for alternate fuels in those markets.

CHAPTER 5
ANALYSIS OF DELIVERY OPTIONS

The Malampaya/Camago reservoir is located in the South China Sea off the northwest coast of Palawan Island about 400 km southwest of Central Luzon, the identified market for the gas. Three possible delivery options for linking the production area to the market area were reviewed, including:

- Undersea/land gas pipeline configurations
- LNG
- 500 kV cable.

5.1 SUMMARY OF ANALYSIS

Cost-of-service analysis indicates that the least cost delivery option for the Malampaya/Camago gas is the construction of an undersea pipeline from SC 38 to Luzon. The selected Base Case Pipeline Configuration (see Figure 10) consists of:[1]

- Undersea pipeline from SC 38 to Batangas (24-inch, 450 MMcf/d)

- Onshore pipeline from Batangas to Manila (24-inch, 400 MMcf/d)

- Onshore/under Manila Bay pipeline from Manila to Bataan (20-inch, 300 MMcf/d)

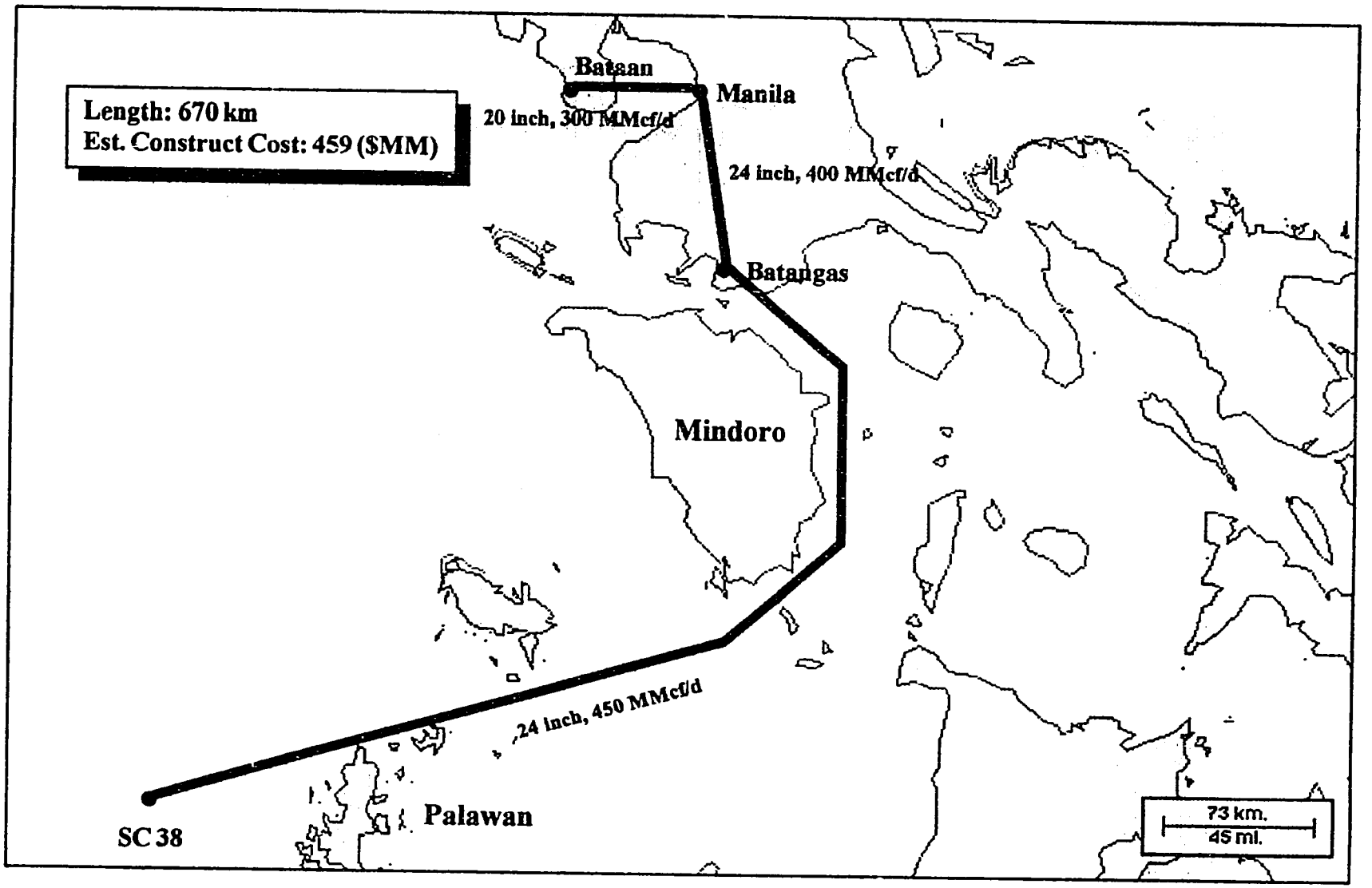
- Construction of distribution networks in Batangas and Bataan, and refurbishment of a portion of MGC's existing distribution network in Manila.

The following is a comparison of the estimated capital construction costs of the Base Case Pipeline Configuration with both the liquefaction, shipping, and regasification of Malampaya/Camago natural gas to Bataan (the Base Case LNG Option) and the transmission of 3,000 MWs of electricity to Luzon generated with Malampaya/Camago gas in a power plant on Palawan (the 500 kV Cable), including our estimate of production costs which Shell/Oxy will likely have to incur:

[1] Note BSA recommends initial construction of 30-inch diameter pipeline facilities wherever Shell/Oxy has recommended 24-inch line, i.e., oversized to accomodate the future growth in gas supply.

Figure 10

BASE CASE CONFIGURATION



COST COMPARISON OF DELIVERY OPTIONS

Delivery Option	*Capital Cost (94$MM)*	*Annual Cost (Levelized $MM)*
Base Case Pipeline Configuration	1,838	448
Base Case LNG Option	4,065	787
500 kV Cable	4,433	817

The Base Case Pipeline Configuration provides efficient delivery of the Malampaya/Camago gas to the identified customer bases in Bataan, Batangas, and Metro Manila at competitive prices while establishing a foundation for the future growth and development of the Philippine gas industry. The potential for strong future market growth exists along the pipeline route. On a per MMBtu basis the delivered cost of gas delivered via the Base Case Pipeline Configuration compares favorably with the price of alternate fuels currently in the market when the complete fuel cycle costs of burning one fuel versus another are factored in, e.g., capital cost of power plant construction (see below).

COMPARISON OF DELIVERED FUEL COSTS
($ per MMBtu)

Market Area	*Natural Gas*	*Diesel*	*Bunker C*	*Coal*
Central Luzon	$2.76 - $3.34	$4.41	$2.78	$2.12

5.2 OVERVIEW OF METHODOLOGY EMPLOYED

BSA arrived at the above results by completing a cost-of-service analysis to determine the estimated cost of pursuing each delivery option. The following is a review of the methodology used to calculate the estimated cost of each option. It is important to recognize that the following analysis is intended only to provide a cost estimate for each delivery option so that the costs and benefits of one option can be compared relative to another. More exact estimates of the cost of each option require

project specific preliminary engineering studies. BSA recommends that a more detailed analysis of project specific costs be conducted on the selected delivery option.

BSA developed an interactive computer model to determine the estimated cost of each delivery option. The model was designed to provide the flexibility to reconfigure each option by changing a number of predefined input variables and assess the impact and sensitivity of cost-of-service to different variables. For example, the cost of a 24-inch diameter pipeline can be easily compared with the cost of a 30-inch diameter pipeline. A print-out of the model and a detailed summary of the quantitative assumptions used in the model are contained in Appendix B.

5.2.1 Financial Assumptions

Unless otherwise noted, the following financial assumptions constitute the "Base Case Financing Option" used to develop cost estimates for the undersea/land pipeline configurations, LNG, and the 500 kV cable delivery options to be discussed below:

- A 20 percent rate of return on Shell/Oxy's production related expenditures over a 20-year payback period
- A 6.5 percent, 20-year loan for all pipeline and distribution facilities with a 2-year grace period
- Philippine Government royalty share of 18 percent
- A US$ inflation rate of 4 percent per year
- O&M escalation rate equal to inflation.

The above financial assumptions are inputs to the BSA interactive computer model and may be changed to assess the sensitivity of the model to various financing options. A detailed assessment of financing arrangements should be pursued.

5.3 PRODUCTION COSTS

The estimated cost of production is assumed to be the same for each delivery option. The production costs used in the model are based on the estimates provided by Shell/Oxy to the DOE. These estimates were reviewed by BSA in discussion with ARI and determined to be reasonable. Further analysis of these costs is not possible without more detailed project specific data.

5.4 UNDERSEA/LAND PIPELINE CONFIGURATIONS

One option to deliver Malampaya/Camago gas to the market area in Central Luzon is to construct a natural gas pipeline from Shell/Oxy's offshore production platform on SC 38 to Central Luzon. The gas pipeline option consists of an undersea mainline plus a number of possible laterals depending on the market area served, i.e., Bataan, Batangas, Metro Manila, or a combination of the three markets. The gas pipeline option was broken into the following segments (see Figures 11 through 14):

- Mainline to Batangas (500 km undersea pipeline from SC 38 to Batangas)[2]
- Manila Lateral (90 km onshore pipeline from Batangas to Manila)
- Bataan Lateral (180 km undersea pipeline from Batangas to Bataan)
- Manila/Bataan Extension (80 km -- 38 km onshore, 42 km under Manila Bay -- pipeline connecting Manila and Bataan).

In addition to the pipeline serving each market area, distribution lines within each market area must be constructed to link the individual customers. The model assumes that 80 km of 8-inch diameter distribution line is constructed in each market area served.

Additional facilities that may be required include:

- Onshore compression
- Onshore storage facilities for load balancing
- Additional gas treatment facilities.

The cost-of-service of constructing each of the above pipeline segments was estimated using the methodology discussed in the following two sections.

[2] The routing for the undersea pipeline from SC 38 to Batangas shown in Figure 11 has been presented by Shell/Oxy to be the most cost effective technically feasible pipeline route. Routing the pipeline around the west coast of Mindoro is apparently not as favorable a route for the pipeline because of several deep underwater trenches that would have to be traversed. Bringing the pipeline onshore at the southern tip of Mindoro and constructing an approximately 150 km onshore pipeline to the northern tip of the island is also apparently not as favorable as the planned offshore pipeline because of the island's mountainous terrain.

Figure 11

MAINLINE TO BATANGAS

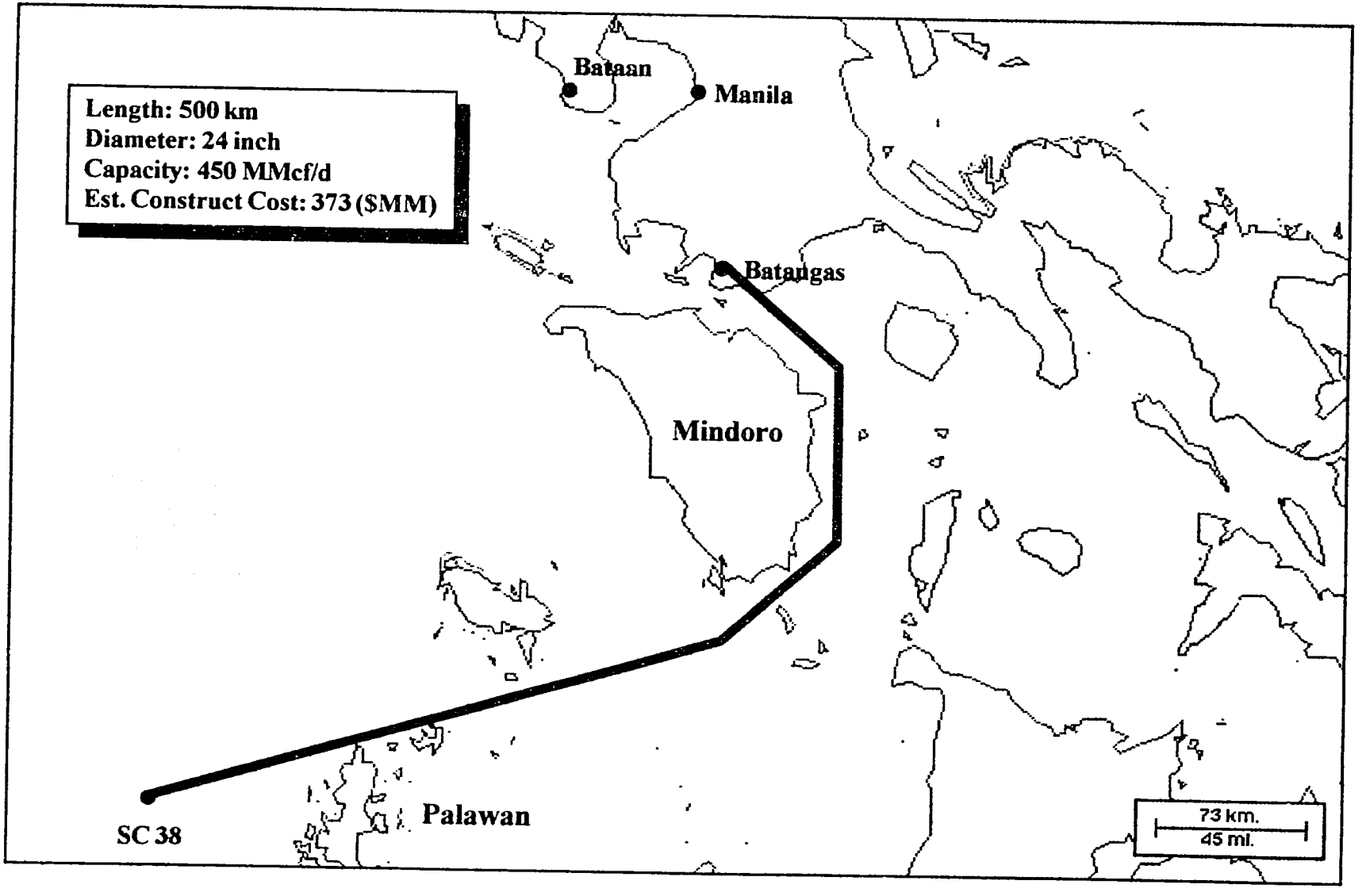


Figure 12

MANILA LATERAL

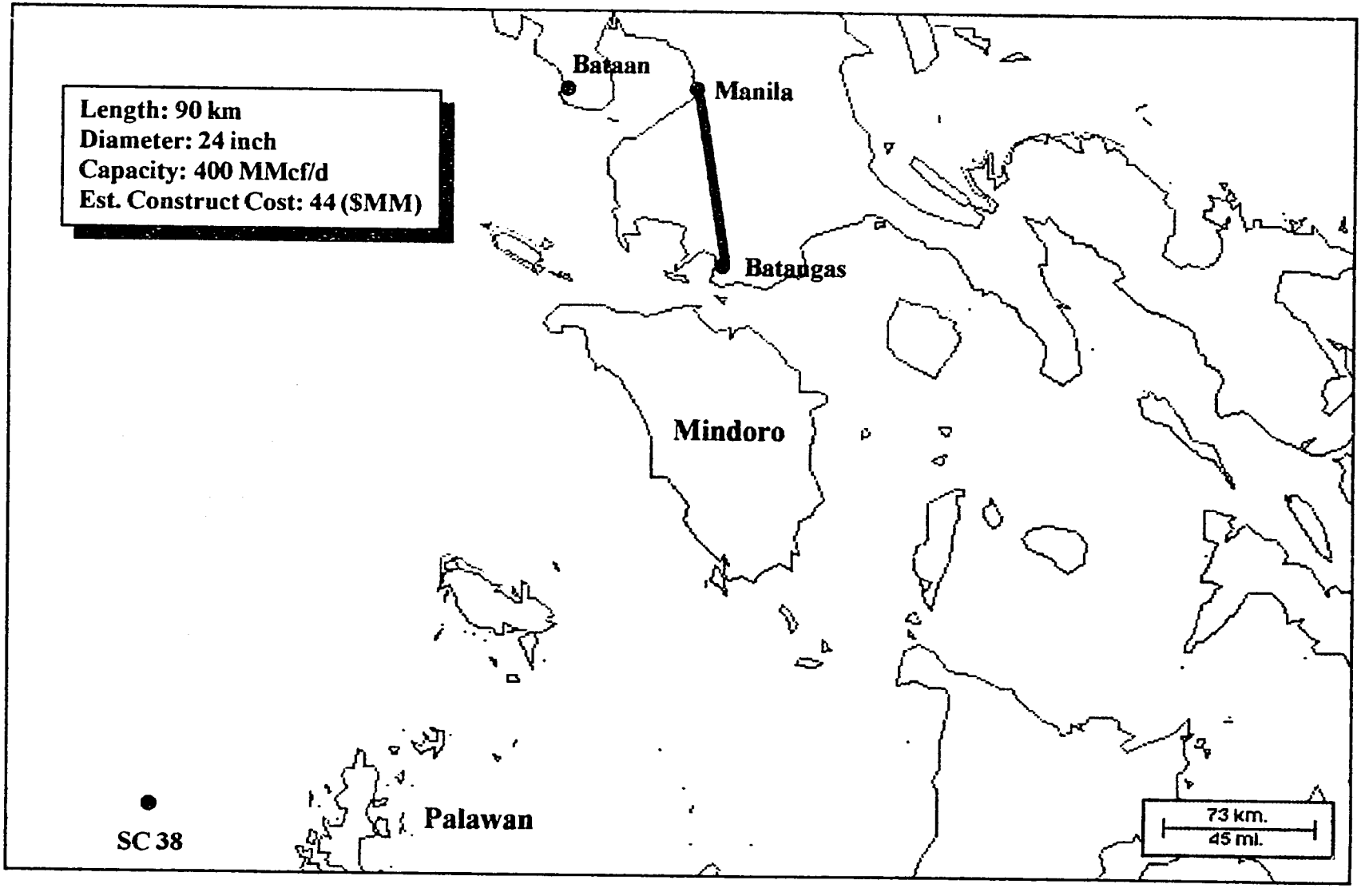


Figure 13

BATAAN LATERAL

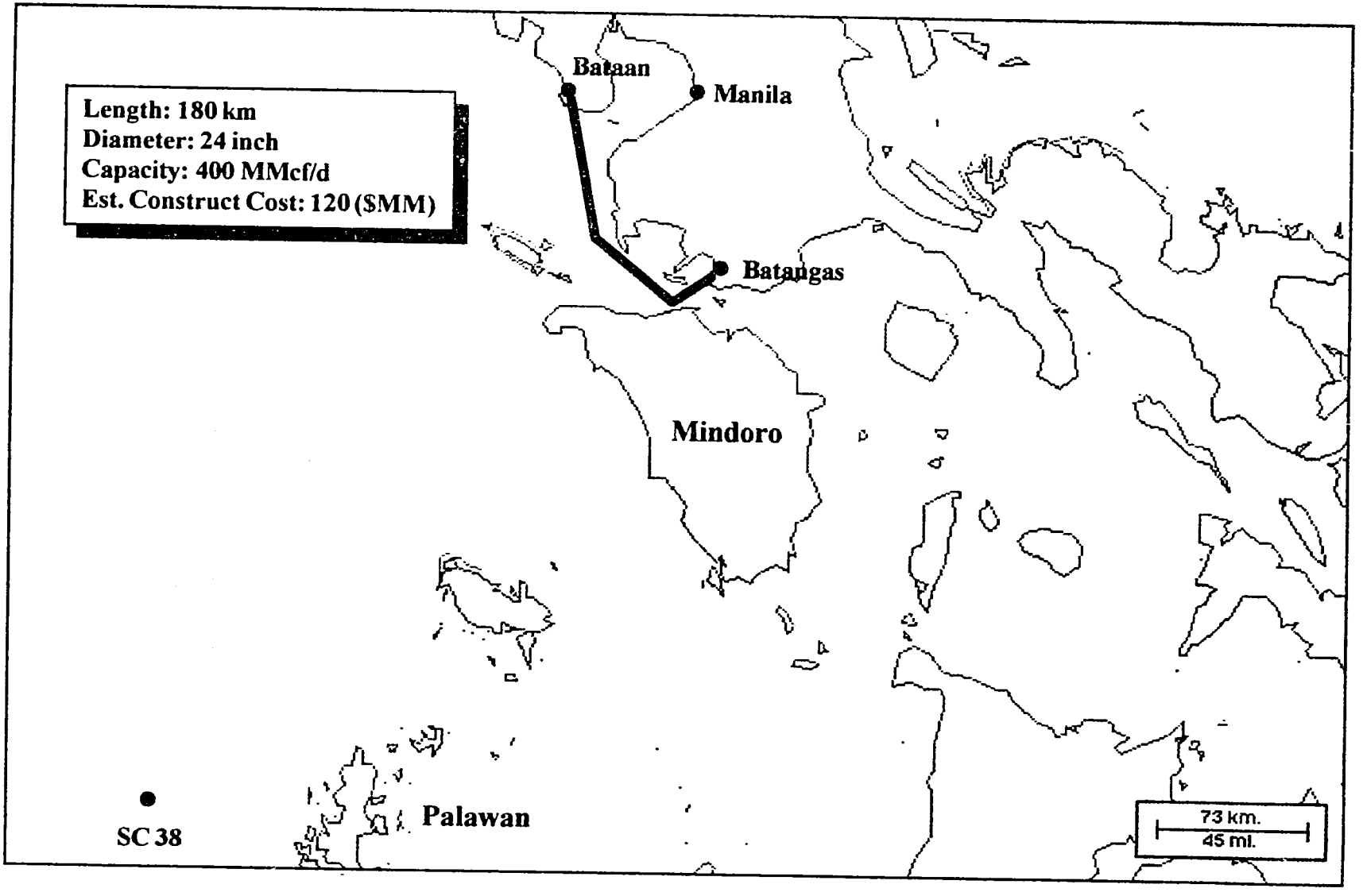
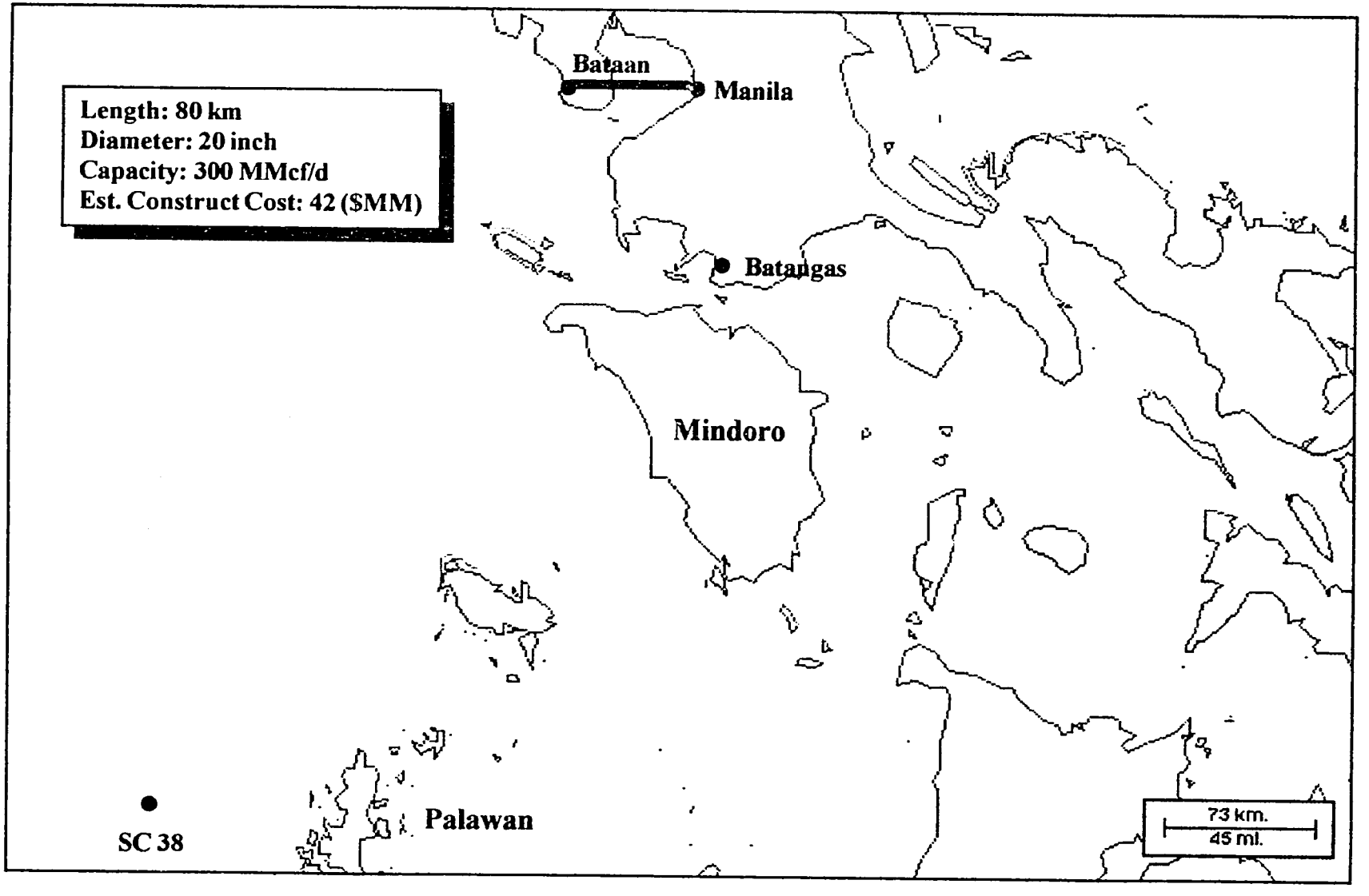


Figure 14

MANILA/BATAAN EXTENSION



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5.4.1 Onshore Pipeline Construction

BSA reviewed data on over 200 onshore natural gas pipelines constructed in the U.S. between 1991 and 1993 ranging in diameter from 8 inches to 36 inches.[3] The total cost of each pipeline is broken into the following categories:

- Materials
- Labor
- Right of way (ROW) and damages
- Miscellaneous expenses.

Regression analysis resulted in good correlations between pipeline diameter and the following construction cost components (see Appendix B):

- Average cost of pipeline (R-squared = .98)
- Materials cost (R-squared = .94)
- Labor cost (R-squared = .87)
- Miscellaneous cost (R-squared = .92).

An average cost per diameter inch per km of onshore pipeline constructed was computed from the fitted regression lines.

No correlation was found between diameter and ROW costs, as expected, given that ROW costs vary widely from project to project based on the value of the land traversed. The ROW cost estimates used in the model are based on estimates provided by NAPOCOR. The estimated cost of ROW was added to the above computed costs. Adjustment factors for the differential between Philippine construction costs and U.S. construction costs were included.

The cost of each of the above onshore pipeline segments as well as distribution lines within each market area was modeled by varying the following input variables:

- Length of pipeline (km)
- Diameter of pipeline (inches)
- Daily volume (MMcf/d).

O&M costs were estimated to be 1 percent per year of total capital costs based on analysis of O&M costs on new pipeline construction in the U.S.

Oil & Gas Journal's annual Special Issue on Pipeline Economics, November 22, 1993.

Compression can also be added to each onshore pipeline segment, if necessary, at US$1,200 per horsepower installed.[4] O&M costs for compression are estimated to be 4 percent of the capital cost of compression.

5.4.2 Offshore Pipeline Construction

BSA reviewed available cost data on a number of offshore pipeline projects in southeast Asia and around the world in an effort to develop correlations between diameter, materials cost, etc. similar to those found for onshore pipeline construction. Projects reviewed include:

- Arco's Yacheng 13 gas pipeline project in China
- East Java Gas Pipeline Co.'s offshore Pagerungan Beasar to Porong line in Indonesia
- Petroleum Authority of Thailand's Erawan-Mab Ta Pud project in Thailand.

Available data proved to be insufficient to draw any statistically significant conclusions that would enable us to extrapolate undersea pipeline construction costs from the foregoing. Offshore pipelines are difficult to generalize because construction costs are sensitive to a number of project specific variables including the depth of the water (which impacts the necessary wall thickness of the pipe) and the gradient of the seabed terrain. Route selection is a key first step in offshore pipeline construction in order to minimize the cost of ocean floor spanning, etc.

Without the benefit of detailed project specific data, BSA developed a cost estimate for the undersea portions of the pipeline option based on conversations with Bechtel International, Inc. (Bechtel) project engineers currently developing the 425 km 36-inch diameter Erawan-Mab Ta Pud offshore pipeline project in Thailand.

Bechtel provided cost estimates for:

- Materials cost
- Anticorrosion and cement coating
- Installation
- Compression.

Cost of compression based on estimate used by Bechtel International, Inc. on Erawan-Mab Ta Pud pipeline in Thailand as well as cost estimate provided by ANR Pipeline Co.

Bechtel's estimates were confirmed, where possible, based on information provided by materials suppliers.

The cost of offshore pipeline construction is substantially independent of the country in which the pipeline is being constructed. Because of the high level of expertise and necessary technology to lay offshore pipelines, there are a limited number of companies worldwide capable of constructing offshore pipelines. Cost is dependent, in part, on the relative demand for the services of these companies. It is interesting to note that Filipinos makeup a large percentage of the crews employed by offshore pipeline laying barges worldwide.

O&M costs on new offshore pipelines are essentially zero (however, the compressors require O&M estimated to cost approximately 4 percent per year of the total capital cost of compression).

The above estimates were used to develop a construction cost per diameter inch per km for the undersea portions of the pipeline option. The cost of each undersea pipeline segment was modeled by varying the following input variables:

- Length of pipeline (km)
- Diameter of pipeline (inches)
- Daily volume (MMcf/d).

5.4.3 Discussion of Selected Pipeline Configurations

After developing basic cost estimates for the onshore and offshore segments of the pipeline option, the next step is to choose the pipeline configuration that best serves the needs of the Philippine economy by delivering the Malampaya/Camago gas by the most economical route while serving the needs of the customer bases in Bataan, Batangas, and Metro Manila. The selection of the pipeline configuration necessarily draws upon our analysis of the customer base discussed in the previous chapter. Once a pipeline configuration is selected the delivered cost of gas can be determined in each market.

The four pipeline segments discussed above are:

- Mainline to Batangas (SC 38 to Batangas)
- Manila Lateral (Batangas to Manila)
- Bataan Lateral (Batangas to Bataan)
- Manila/Bataan Extension (Manila to Bataan).

Three pipeline configurations were selected by linking together combinations of the above segments (see Figures 15 - 17)[5]

Base Case Configuration:

- Mainline to Batangas (24-inch, 450 MMcf/d)
- Manila Lateral (24-inch, 400 MMcf/d)
- Manila/Bataan Extension (20-inch, 300 MMcf/d).

First Alternate Configuration:

- Mainline to Batangas (24-inch, 450 MMcf/d)
- Bataan Lateral (24-inch, 400 MMcf/d).

Second Alternate Configuration:

- Mainline to Batangas (24-inch, 450 MMcf/d)
- Bataan Lateral (20-inch, 300 MMcf/d)
- Manila Lateral (20-inch, 100 MMcf/d).

The advantage of selecting one pipeline configuration over another are summarized below:

[5] Note that the pipeline configurations are single pipe configurations. The construction of a double pipeline (i.e., side-by-side pipes) is not cost effective given the high reliability of gas pipeline transmission both on- and offshore.

Figure 15

BASE CASE CONFIGURATION

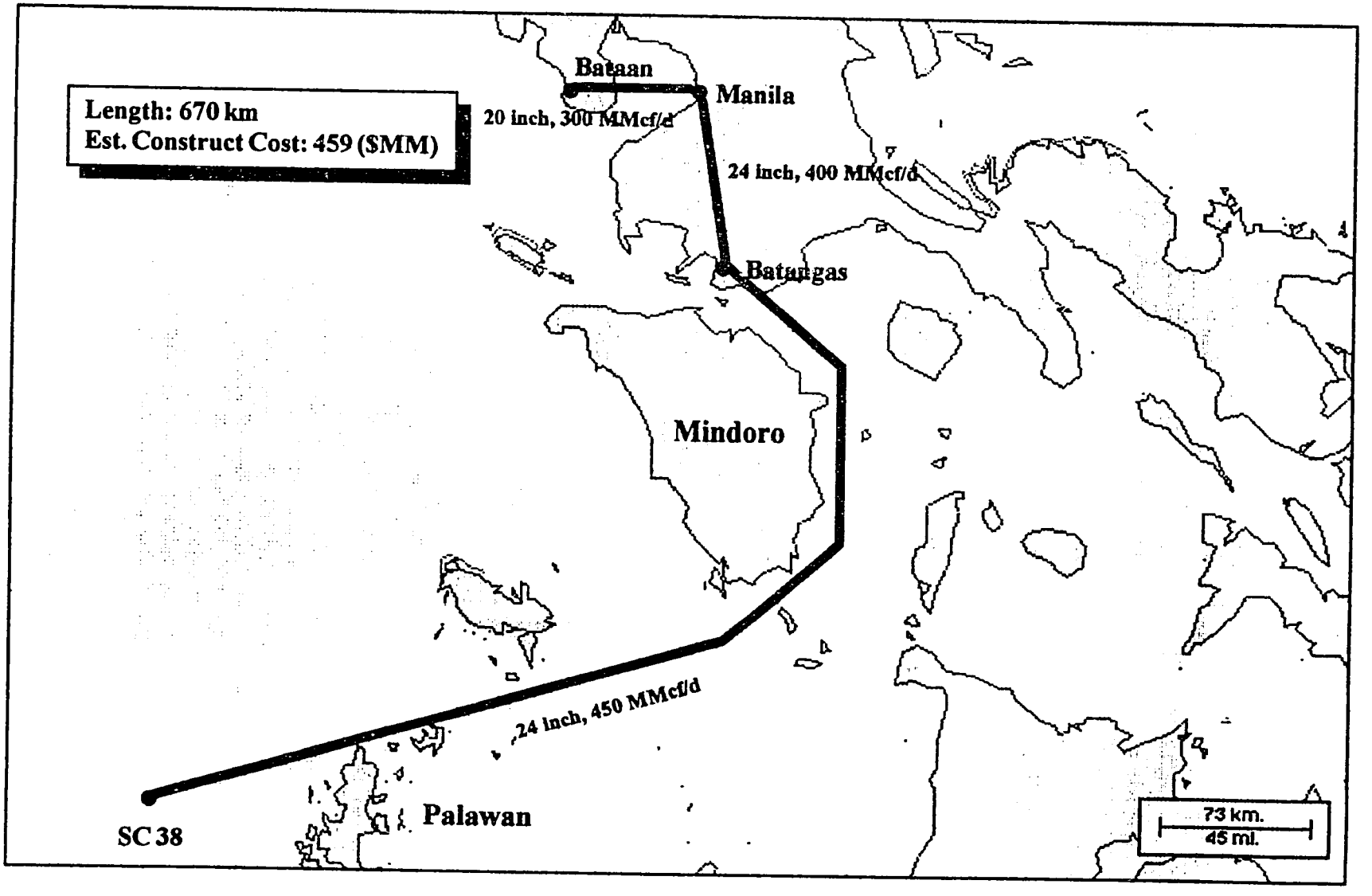

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Figure 16

FIRST ALTERNATE CONFIGURATION

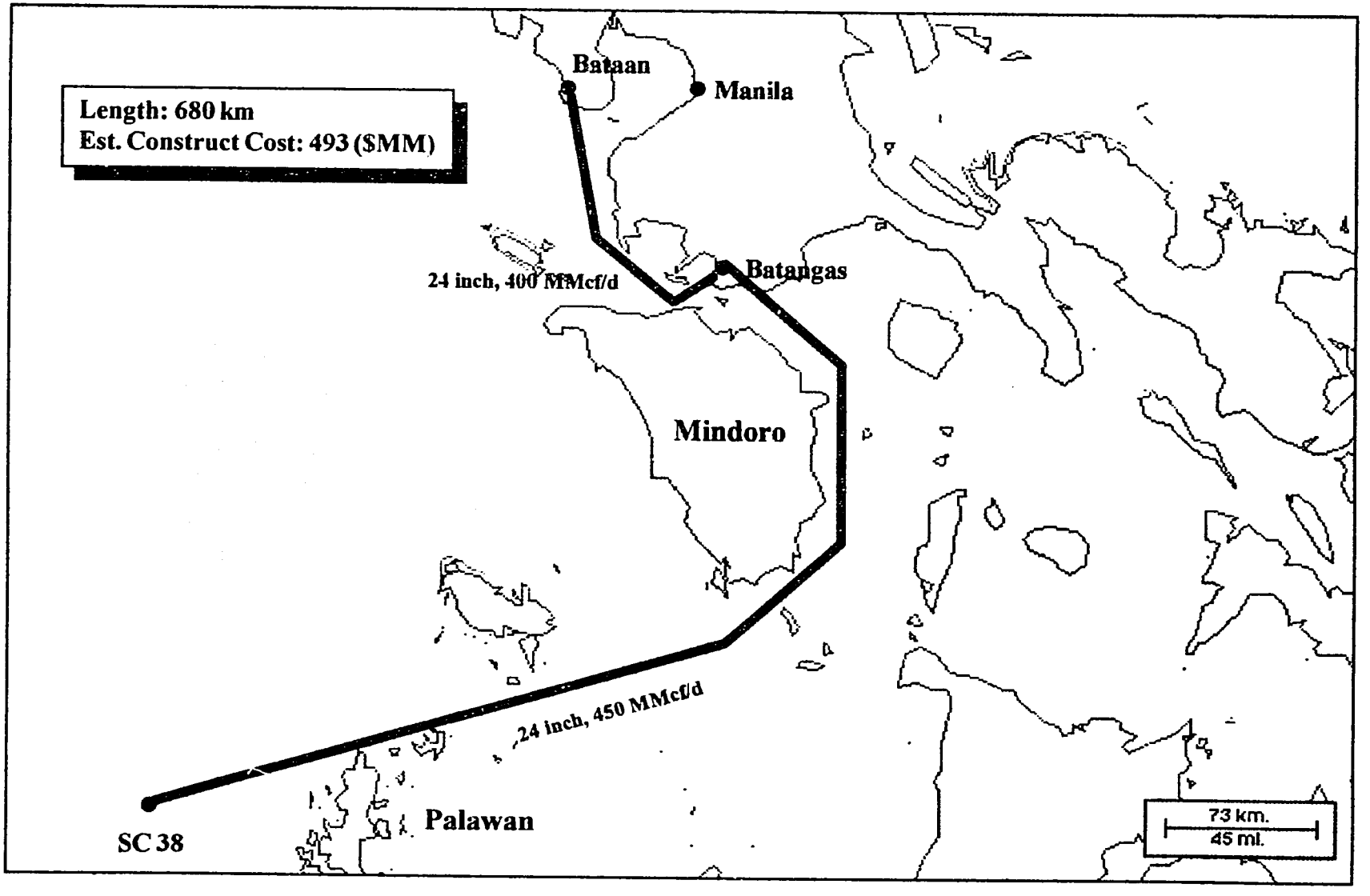
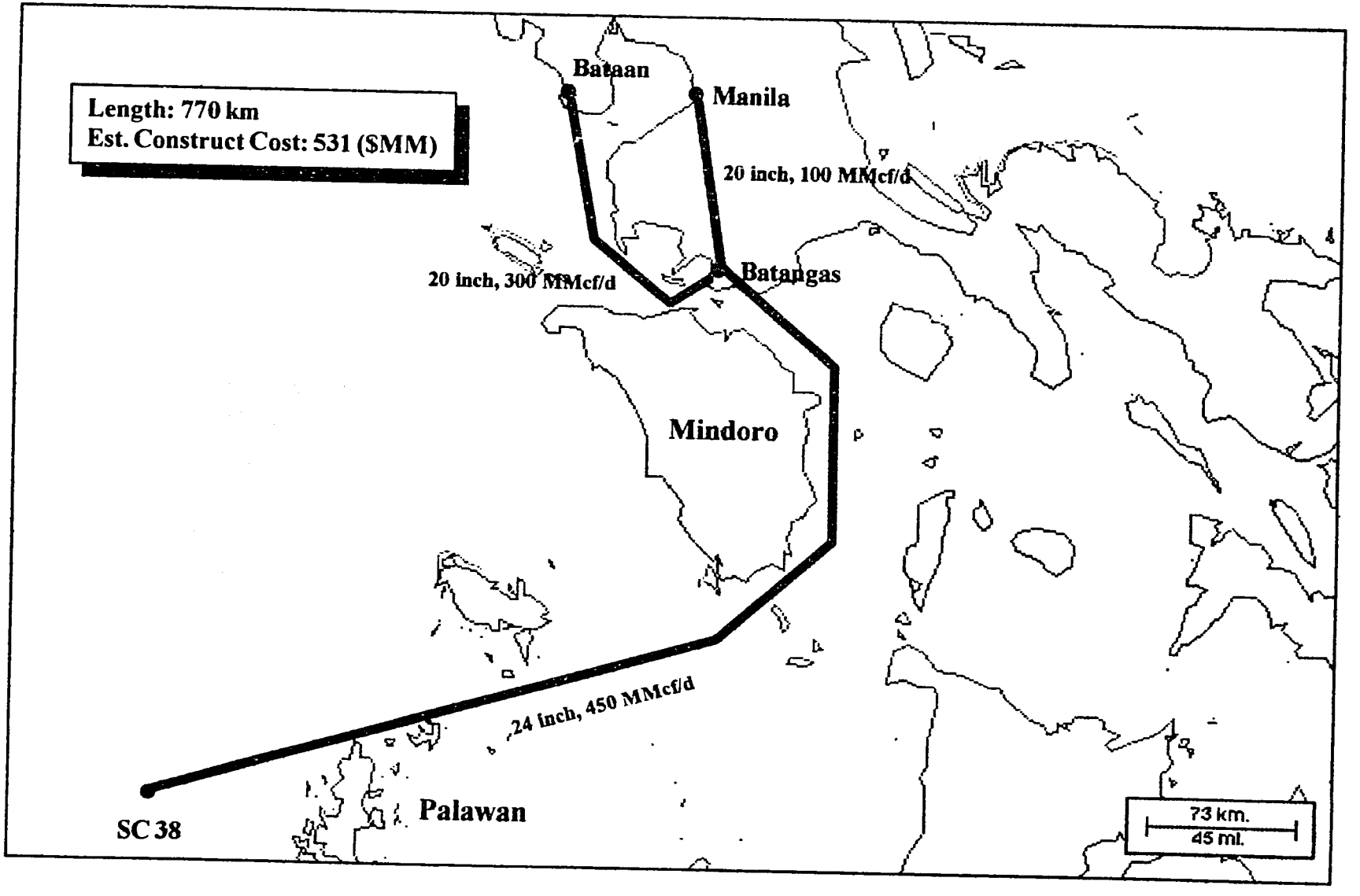


Figure 17

SECOND ALTERNATE CONFIGURATION



EVALUATION OF PIPELINE CONFIGURATIONS

Advantage	*Base Case*	*First Alternate*	*Second Alternate*
Use of Bataan nuclear repowering load to anchor the overall project	Yes	Yes	
Service to Metro Manila	Yes		Yes
Pipeline route accessible to the greatest number of potential customers	Yes		Yes
Reduced potential for ROW and land ownership disputes		Yes	
Minimization of more expensive undersea pipeline routing	Yes		

Use of Bataan nuclear repowering load to anchor the overall project. - From our analysis of the customer base in Bataan, Batangas, and Metro Manila it is apparent that the primary market for Malampaya/Camago gas will be the Bataan area, which we estimate will contain approximately 63 percent of the total identified base load demand. Furthermore, the potential anchor load (the Bataan nuclear plant) is located in Bataan. BSA's analysis and past experience strongly suggests that the selected pipeline configuration serve the Bataan market as directly as possible, with as few lateral lines as possible. The Second Alternate Configuration provides mainline service to several load centers, which, we feel, partly explains its relatively higher cost.

In summary, constructing a non-telescoping pipeline through Central Luzon, i.e., the Base Case, provides a workable foundation for future growth of the Philippine gas industry. This configuration (as well as the First Alternate) also has the feature of conservatism, as follows: A possible future "Phase II" project could involve construction of an LNG terminal in Bataan which would backfeed the Base Case Configuration, i.e., provide Central Luzon with two supply sources feeding the pipeline grid at opposite ends. Such an option would have to be explored in the context of developing a depletion scenario, i.e., the Project is developed, but no economical volumes of gas are subsequently found. Preliminary analysis indicate that construction of a regasification terminal in Bataan with a sendout capacity of 225 MMcf/d and 20 days of on-site storage would cost approximately 94US$160 million.

Service to Metro Manila. - The Metro Manila area contains numerous industrial customers as well as 22 percent of the identified base load power plant demand. Metro Manila is also the only market area with an existing network of gas distribution lines. Once a pipeline to Manila is constructed, the refurbishment of portions of the MGC's piped gas system versus new pipeline construction is likely to result in significant reductions in construction costs as well as fewer ROW and land ownership disputes. The Manila Gas distribution network also provides an excellent springboard for a future Phase II expansion of the customer base beyond power plants and industrials and into the residential and commercial sectors.

In addition to the identified market potential in Metro Manila, environmental and political factors also encourage service to the Philippine capital. Manila's severe air pollution can be reduced through the substitution of natural gas for coal and fuel oil in stationary sources. A program encouraging the use of compressed natural gas (CNG) in place of diesel fuel and gasoline in vehicles, particularly buses, will also be possible.

Both the Base Case and Second Alternate Configurations provide service to Manila. The Bataan/Manila Extension could be added to the First Alternate Configuration to serve Manila, however, given that the identified demand for natural gas in the Bataan area is more than sufficient to utilize all 450 MMcf/d of the Malampaya/Camago gas and the expense of crossing under Manila Bay, it is unlikely that the extension would be constructed as part of a Phase I gas pipeline construction program. A more likely scenario, if more pipe were to be built, would be construction of the Manila Lateral, i.e., the Second Alternate Configuration.

Pipeline route accessible to the greatest number of potential customs. - The Base Case Configuration results in a natural gas pipeline being constructed right through the most heavily populated and industrialized region of the Philippines. The present and future market potential for natural gas in this region is virtually limitless. The selected pipeline configuration should be constructed to tap this market potential thus laying the foundation for future growth in the use of natural gas.

The First and Second Alternate Configurations result in a significant amount of pipeline being constructed offshore (the Bataan Lateral), with no future growth potential. Although these configurations guarantee service to Bataan prior to the other markets, an advantage discussed above, they do so by sacrificing market potential.

Reduced potential for ROW and land ownership disputes. - The Base Case Configuration provides access to the greatest number of customers, but because it directly serves customers throughput the Manila region, will be the most difficult pipeline configuration to site. One possibility that may reduce ROW and land ownership disputes is to site the Manila Lateral connecting Batangas to Manila along

the existing pipeline ROW used by Shell's LPG line linking Shell's refinery in Batangas to Metro Manila. Sharing this ROW, if possible, should greatly facilitate construction to Manila

The First Alternate (and the Second Alternate, to a lesser degree) reduce the potential for ROW and land ownership disputes by placing a significant portion of the pipeline underwater. While the actual construction cost of an offshore pipeline is significantly higher than an onshore pipeline, this construction cost differential may be reduced significantly by the additional ROW related costs of siting an onshore pipeline through a populated area. Our analysis of pipeline construction costs includes an ROW allowance of $75,340 per km for all onshore pipeline construction. This estimate is based on data provided by NAPOCOR. However, in addition to the added expense of procuring onshore ROW, and potentially of more significance to the success of the project, ROW and ownership disputes may lead to lengthy delays in the construction of an onshore pipeline. Legal challenges could delay or even halt construction. Offshore pipeline construction removes this obstacle and ensures that the pipeline is likely to be completed on schedule.

A detailed assessment should be made of the likely difficulty that ROW and land ownership disputes may have on the cost and timing of an onshore pipeline project.

Minimization of more expensive undersea pipeline routing. - As discussed above, while the First and Second Alternate Configurations reduce the likelihood of delays caused by ROW and land ownership challenges, building offshore is expensive. The additional expense of offshore construction needs to be weighed against the probable cost and delay of ROW and land ownership challenges.

The Base Case Configuration was selected over the First and Second Alternate Configurations because it provides efficient delivery of the Malampaya/Camago gas to the identified customer bases in Bataan, Batangas, and Metro Manila at competitive prices while establishing a foundation for the future growth and development of the Philippine gas industry. The potential for strong future market growth exists along the pipeline route. A Phase II LNG regasification terminal in Bataan providing another source of supply to the region will adapt well to the Base Case Configuration.

5.4.4 Undersea/land Pipeline Results

The following is a summary of the construction cost for each pipeline segment used in the above three pipeline configurations in millions of 1994 U.S. dollars:

CONSTRUCTION COST OF EACH PIPELINE SEGMENT
(1994$MM)

Pipeline Segment	*Capital Cost*
Mainline - All configurations (24-inch)	372.9
Manila Lateral - Base Case (24-inch)	44.2
Manila Lateral - Second Alternate (20-inch)	37.8
Bataan Lateral - First Alternate (24-inch)	120.1
Bataan Lateral - Second Alternate (20-inch)	112.3
Manila/Bataan Ext. - Base Case (20-inch)	42.2

The all-inclusive delivered cost of gas to the burner-tip in Bataan, Batangas, and Manila was computed for the Base Case, First Alternate, and Second Alternate pipeline Configurations. The following table shows the per MMBtu cost of natural gas on a 20-year levelized basis in each market area based on an incremental pipeline rate structure, i.e., the price of gas in each market is reflective of the proportional share of expenses required to produce and deliver gas to that market. A rolled-in rate for all markets is also shown. Under a rolled-in rate structure, the price of gas is the same in all markets.

SUMMARY OF PIPELINE OPTION DELIVERED GAS COSTS
($ per MMBtu)

Market Area	*Base Case*	*First Alternate*	*Second Alternate*
Bataan	$3.28	$3.29	$3.32
Batangas	$3.29	$3.29	$3.29
Metro Manila	$3.25	N/A	$3.32
Rolled-in Rate	$3.27	$3.29	$3.31
Capital Cost in 1994$MM	1,838	1,865	1,902

The following is a breakdown of the delivered cost of gas in each market via the Base Case Pipeline Configuration:

BREAKDOWN OF DELIVERED GAS COST (BASE CASE)
($ per MMBtu, to Large Volume Customers)

Cost Component	*Bataan*	*Batangas*	*Metro Manila*
Production Cost	$2.48	$2.48	$2.48
Royalty Add-on	$0.54	$0.54	$0.54
Mainline to Batangas	$0.18	$0.18	$0.18
Manila Lateral	$0.03	N/A	$0.03
Manila/Bataan Ext.	$0.03	N/A	N/A
Distribution Network	$0.02	$0.09	$0.02
Total Delivered Cost	$3.28	$3.29	$3.25

Note from the above table the advantage of concentrating the consumption of the gas in as small an area as possible among a relatively small group of large users. The Base Case Pipeline Configuration assumes that a distribution network of 80 km of 8-inch pipe is constructed (refurbished in the case of Manila because of MGC's existing system) in each market area, however, the volume consumed in each market varies widely from 50 MMcf/d in Batangas to 300 MMcf/d in Bataan. The result is significantly higher incremental distribution costs in Batangas ($0.09 per MMBtu) versus in Bataan ($0.02 per MMBtu).

5.4.5 Sensitivity Analysis of Base Case Pipeline Configuration

As discussed, the model used to calculate the cost-of-service of each of the three delivery options provides the flexibility to assess the sensitivity of each option to a number of inputs. The following table illustrates this capability showing the sensitivity of the Base Case Configuration to changes in the diameter of the Mainline undersea pipeline segment, and the addition of onshore storage facilities:

SENSITIVITY ANALYSIS OF FACILITIES (BASE CASE)

Sensitivity	*Delivered Gas Price - Manila $/MMBtu*	*Capital Cost 1994$MM*
Base Case	$3.25	1,838
Mainline diameter increased from 24-inch to 30-inch	$3.27	1,870
Mainline diameter increased from 24-inch to 36-inch	$3.28	1,903
Storage facilities added at terminus of Mainline (100 MMcf)	$3.27	1,878

Note: Assumes constant volumes.

A sensitivity analysis was also conducted on the Base Case Pipeline Configuration to assess the impact of different financing opportunities on the project economics. These various financial opportunities may be available to the project based on the ownership of the facilities and the ability of the project to qualify for assistance in the form of developmental financing. The following table summarizes a number of possible financing scenarios ranging from commercial financing to low cost developmental financing:

SENSITIVITY ANALYSIS OF FINANCING (BASE CASE)

Financing Variable	*Developmental Financing*	*Base Case Financing*	*Commercial Financing*
Production Gross ROR (20 years)	15%	20%	20%
Pipeline Financing:			
- Interest rate	3.5%	6.5%	8.0%
- Grace period	5 years	2 years	none
Annual Cost in Levelized $MM (Rolled-in $/MMBtu)	377 ($2.76)	448 ($3.27)	460 ($3.34)

5.5 LIQUEFIED NATURAL GAS

LNG projects are very capital intensive. Because of the large capital investment required, there are significant returns to scale that favor a substantial reserve base and an established market for the gas. An LNG project developed for the Malampaya/Camago reserve base of 4 Tcf would be atypical. LNG projects usually have proven reserve bases much greater than 4 Tcf, which is considered to be the absolute minimum reserve base necessary to support an LNG project.

An LNG project developed around the Malampaya/Camago gas reserves with capability to supply 450 MMcf/d or 160 billion cubic feet per year (Bcf/year) to serve the domestic Philippine markets identified above, i.e., Bataan, Batangas, and/or Metro Manila would consist of the following components (see Figure 18):

- Production
- Pipeline transport to Palawan Island
- Liquefaction
- Shipping to Bataan
- Regasification
- Market area pipeline distribution.

5.5.1 LNG Methodology

BSA conducted an analysis of each of the above components and developed a cost-of-service estimate for LNG in each of the three market areas discussed above. The following is a summary of the methodology used to develop cost estimates for each component of the LNG project. These estimates were incorporated into the interactive computer model. Appendix B contains a more detailed summary of the quantitative assumptions used in the LNG portion of the model.

Production.

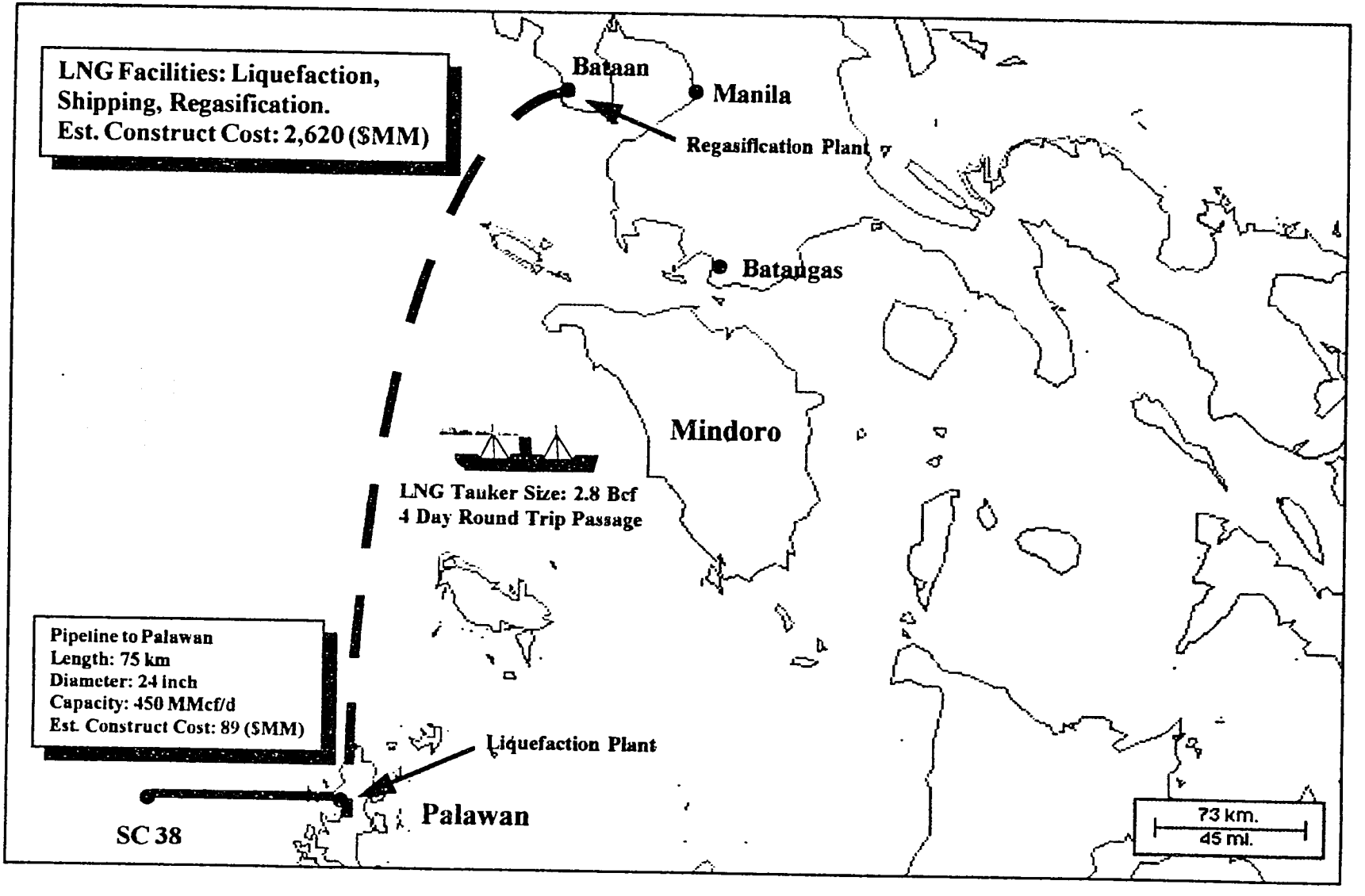
Production costs for the Malampaya/Camago reserves are based on the estimates provided by Shell/Oxy. As detailed in our discussion of the pipeline option, these costs were reviewed and found to be reasonable. The estimated cost of production is assumed to be the same for each delivery option.

Pipeline Transport to Palawan Island.

A 75 km 24-inch undersea pipeline will link the Malampaya/Camago production area to a liquefaction plant on Palawan. The cost of constructing and

Figure 18

LNG TO BATAAN



operating this pipeline was determined based upon the same methodology outlined above for offshore pipelines.

Liquefaction.

Liquefaction plants are constructed in block format, i.e., with the formation of trains. This modular construction allows for future expansion of the facility through the addition of more trains. To determine the cost of building a liquefaction plant capable of producing 160 Bcf/year, BSA reviewed cost data on a number of projects currently being developed around the world including:

- Christopher Colon in Venezuela - 235 Bcf/year
- Santos-Northwest Shelf in Australia - 95 Bcf/year
- Trinidad and Tobago - 180 Bcf/yr.

BSA reviewed data for these projects and data from other sources to develop an estimate of 1994$2.0 billion for the cost of constructing a liquefaction plant on Palawan.

Self consumption, i.e., the gas consumed by the liquefaction plant in the process of liquefying the natural gas into LNG is estimated to be 12 percent. O&M costs of a facility of this size were assumed to be $80 million per year.

Shipping to Bataan.

LNG tankers come in two basic sizes:

- Large tankers with a capacity of 135,000 cubic meters (the equivalent of 2.8 Bcf of regasified natural gas) with a current purchase price of about $250 million per tanker

- Small tankers with a capacity of 85,000 cubic meters with a current price of about $200 million per tanker.

Based on a speed of approximately 400 nautical miles per day and 12 hours for loading or unloading; one tanker with a capacity of 135,000 cubic meters can easily make the 500 nautical mile round trip between Palawan and Central Luzon every 4 days including loading/unloading. One tanker is estimated to be more than sufficient to serve the project.

The addition of another tanker adds substantially to the cost of the project, but would enhance the reliability of delivery. An alternative way to enhance reliability of

supply and at the same time eliminate whatever impact inclement weather, etc. may have on shipping is through the construction of more storage capacity in Bataan.

Regasification.

Based on our analysis and identification of the customer bases, the best location for a regasification plant is near the anchor load, Bataan nuclear plant. As with the liquefaction plant, a cost estimate for the regasification plant and necessary storage facilities was determined primarily through the review of cost data for a number of projects in various stages of development worldwide.

The cost of constructing storage represents about 50 percent of the capital cost of constructing a regasification facility. A review of data on a number of projects revealed no statistically significant direct correlation between sendout capacity and cost. The lack of any correlation is most likely attributable to the different storage requirements necessary to serve different markets. An estimate of 1994$320 million was developed for a gasification facility in Bataan with 20 days of storage capacity and a sendout capacity of 450 MMcf/d.

Market Area Pipeline Distribution.

Once the LNG has been regasified in Bataan, the cost estimates for distribution of the gas within the Bataan market area and possible transport of the gas to Metro Manila and Batangas are borrowed from our cost analysis of the construction of onshore pipeline and distribution lines.

5.5.2 Discussion of LNG Configurations and Results

The following is a summary of the all-inclusive delivered cost of gas at the burner-tip in Bataan, Batangas, and Metro Manila. These delivered cost estimates use the same financial assumptions discussed for the pipeline option and are based on the following configurations:

LNG Base Case:

- LNG supply to Bataan market (450 MMcf/d)

LNG First Alternate (service to Bataan and Manila):

- LNG supply to Bataan market (350 MMcf/d)
- Manila/Bataan Extension (20-inch, 100 MMcf/d) - service to Manila

LNG Second Alternate (service to Bataan, Manila, and Batangas):

- LNG supply to Bataan market (300 MMcf/d)
- Manila/Bataan Extension (20-inch, 150 MMcf/d) - service to Manila
- Manila Lateral (18-inch, 50 MMcf/d) - service to Batangas

SUMMARY OF LNG OPTION DELIVERED GAS COSTS
($ per MMBtu)

Market Area	*LNG Base Case*	*LNG First Alternate*	*LNG Second Alternate*
Bataan	$5.43	$5.43	$5.43
Batangas	N/A	N/A	$5.75
Metro Manila	N/A	$5.53	$5.50
Rolled-in Rate	$5.43	$5.45	$5.48
Capital Cost in 1994$MM	4,065	4,113	4,165

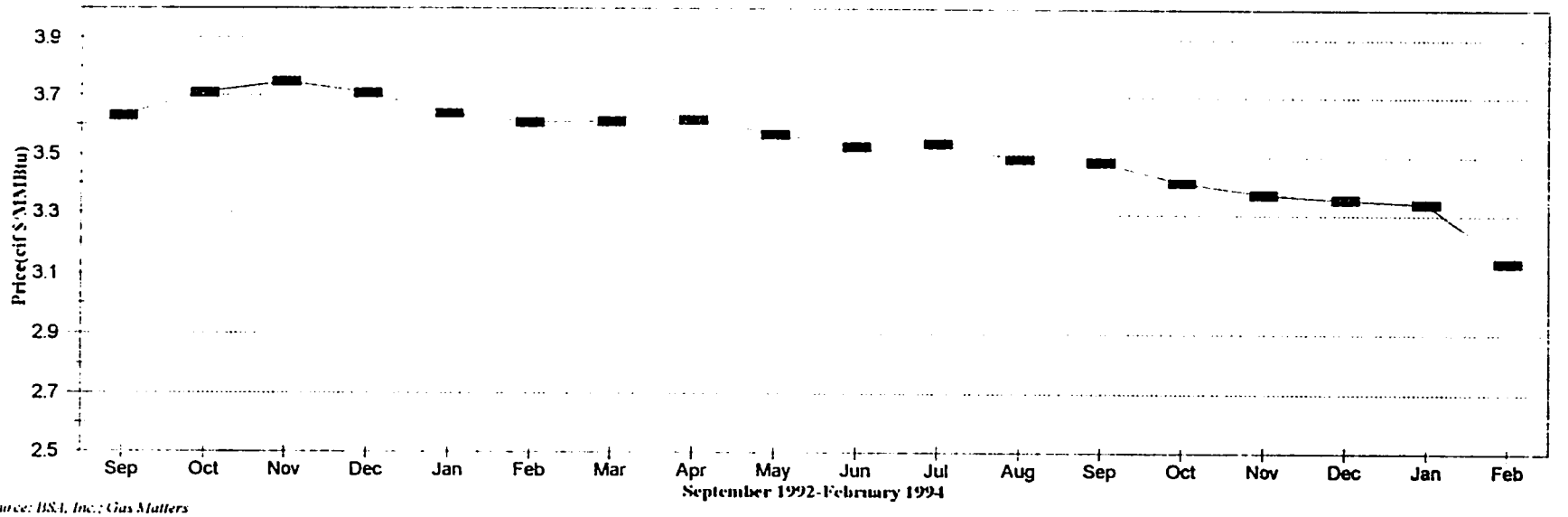
5.5.3 Imported LNG

Another LNG option considered was the cost of imported LNG, most likely from a neighboring country such as Indonesia or Malaysia. The downstream or market infrastructure required for this imported LNG option would be identical to that necessary for the above domestic LNG option; the difference in the two options being that LNG imports could substitute altogether for the development of the Malampaya/Camago reserves.

Projections on the future price of LNG are difficult to assess. The world LNG market is currently plagued with overcapacity because of Japan's recent cutback in consumption. LNG prices have fallen steadily over the past few years (see Figure 19). Furthermore, most LNG prices are currently linked to the cost of crude oil. Current low crude oil prices have also depressed the cost of LNG. However, current LNG prices have little bearing on future LNG prices because LNG projects are developed and priced to serve a pre-contracted customer base. In summary, we believe that the cost-of-service of a new LNG project, such as the estimate for the

Figure 19

JAPAN'S LNG PRICES (cif $/MMBtu)



Source: BSA, Inc.; Gas Matters

	1992				1993												1994	
	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB
Malaysia	$3.38	$3.49	$3.62	$3.69	$3.68	$3.66		$3.54	$3.43	$3.36	$3.33	$3.38	$3.43	$3.40	$3.34		$3.14	$3.15
Brunei	$3.32	$3.45	$3.57	$3.62	$3.61	$3.59		$3.59	$3.49	$3.42	$3.40	$3.44	$3.49	$3.47	$3.39		$3.22	$3.21
Indonesia	$3.91	$3.85	$3.85	$3.75	$3.60	$3.57		$3.71	$3.75	$3.74	$3.73	$3.56	$3.51	$3.38	$3.39		$3.04	$3.07
Abu Dhabi	$3.38	$3.48	$3.61	$3.70	$3.74	$3.73		$3.64		$3.42	$3.38	$3.39	$3.44	$3.45	$3.42		$3.24	$3.19
USA	$3.30	$3.39	$3.55	$3.59	$3.57	$3.54		$3.48	$3.35	$3.28	$3.24	$3.26	$3.29	$3.30	$3.20		$3.06	$3.00
Australia	$3.60	$3.80	$3.83	$3.78	$3.75	$3.76		$3.53	$3.40	$3.41	$3.49	$3.53	$3.54	$3.46	$3.31		$3.21	$3.23
Average	3.63	3.71	3.75	3.71	3.64	3.61		3.62	3.57	3.53	3.54	3.49	3.48	3.41	3.37		3.34	3.14

Malampaya/Camago LNG project developed above, is likely to be a better predictor of future LNG prices than a review of current prices.

While it might be possible in the current climate for the Philippines to construct an LNG receiving terminal at Bataan, and seek to contract with an existing LNG buyer (or buyers) to take over an existing supply chain on a permanent basis, long-term supply release opportunities that would result in LNG pricing for a new customer at currently depressed levels are currently unavailable. In fact, the outlook for future growth in LNG demand remains bullish. Many area nations, e.g., South Korea, are expected to increase their demand for LNG dramatically in the next several years. Increased demand should soak up any currently existing excess supply, while at the same time encourage capacity additions by exporting nations such as Indonesia, which plans to increase its LNG exports from the current level of 26 million tons per year to 28 million tons per year by 1998.[6]

As a footnote, LNG sellers are attempting to de-link the price of LNG and crude oil and market LNG as a premium environmentally friendly fuel. Many forecasters predict substantial increases in LNG demand of 200 to 300 percent over the next twenty years. Cedigaz News Report projects an LNG price in the range of $4.40 per MMBtu in 2000 and $5.00 per MMBtu in 2010.[7]

5.6 500 kV CABLE

BSA considered another delivery option for the Malampaya/Camago gas that does not involve the transportation of gas to Central Luzon at all. Instead a large power plant, approximately 3,000 MW in size, located on Palawan, would produce electricity that would be transmitted via a 500 kV undersea/overland cable to Central Luzon (see Figure 20). The 500 kV cable routing consists of:

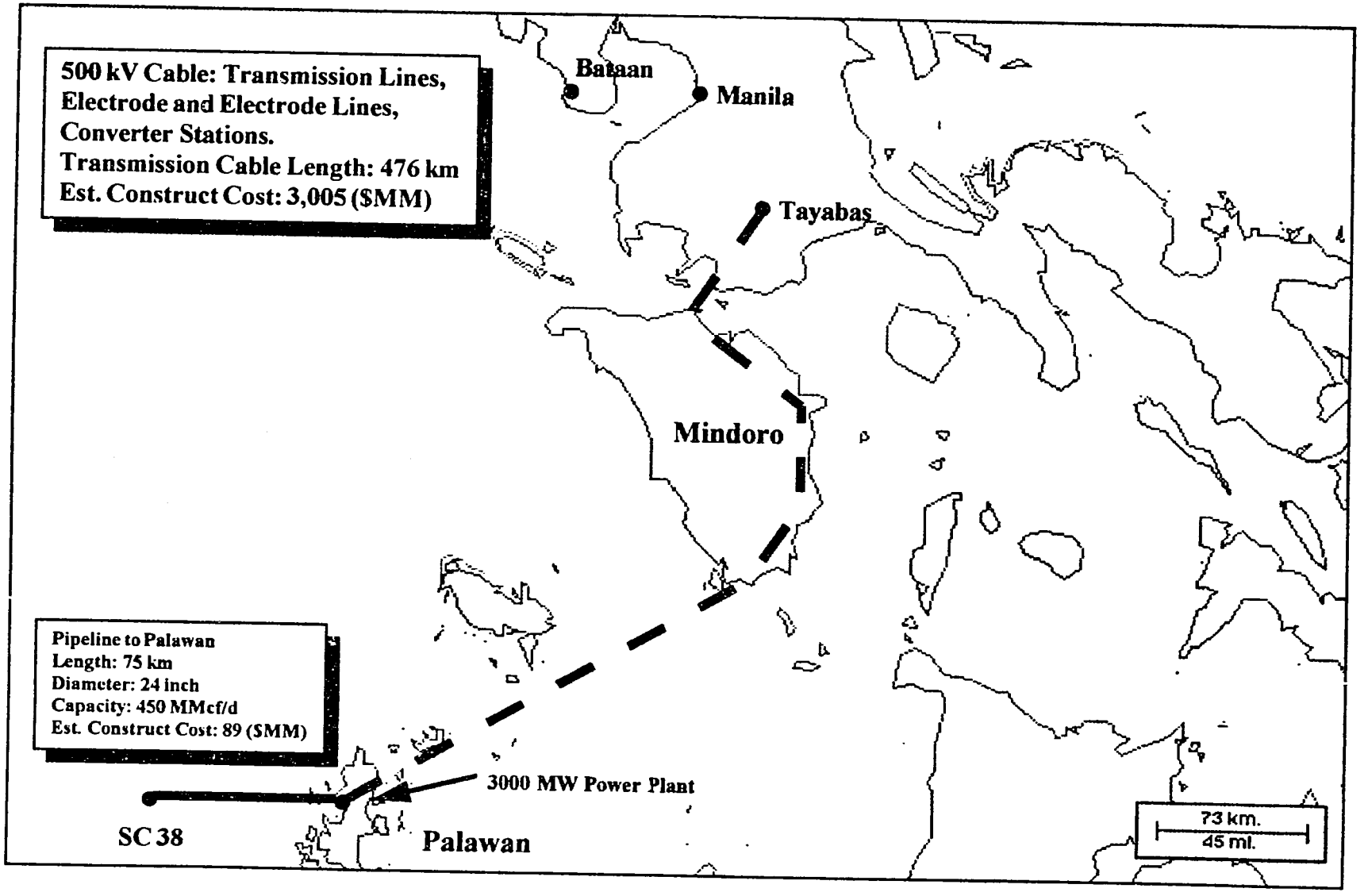
- 227 km of undersea cable from Palawan to Mindoro
- 150 km of overland cable across Mindoro
- 24 km of undersea cable from Mindoro to Batangas
- 65 km of overland cable to Tayabas.

The above cable routing was selected by NAPOCOR because it minimizes the expense of undersea cable by traversing Mindoro. An all undersea cable routing that would remain offshore of Mindoro, following a similar route to that of the undersea gas pipeline, is substantially more expensive than the above route. The technology for undersea transmission of large quantities of electricity is relatively new and it is very expensive. The average cost of the undersea portions of the above cable configuration

6 Natural Gas Week International, July 4, 1994.
7 Cedigaz News Report, September 10, 1993.

Figure 20

500 kV CABLE



are US$8.8 million per km whereas the cost of the overland portions are US$294 thousand per km.[8]

BSA developed cost estimates for the following components of the 500 kV option including:

- Production of the gas
- Pipeline transport of the gas to Palawan Island
- Transmission of electricity via a 500 kV cable to Central Luzon.

BSA did not review the cost of constructing a 3,000 MW power plant on Palawan; to do so would not provide for a relevant cost comparison between this option and the above pipeline and LNG options. Nonetheless, it is important to note that the construction of a power plant on Palawan may prove to be more expensive than in Luzon because of the island's lack of infrastructure such as roads, port facilities, etc.

The production costs of the Malampaya/Camago gas and the pipeline transportation costs via a 24-inch 450 MMcf/d pipeline to Palawan are identical to those developed for the LNG option above. The cost of transmission from Palawan to Luzon is based on independent analysis as well as an estimate provided by NAPOCOR (see Appendix B for a more detailed cost estimate).

In addition to this option's high cost of over 1994$3.0 billion for transmission of electricity alone, transmission of electricity and not gas to Luzon would foreclose the development of a gas industry in the Philippines and with it the associated benefits of the use of gas, i.e., the promotion of new industries, the environmental benefits of a clean burning fuel source, etc.

5.7 CONCLUSIONS

The above analysis clearly demonstrates that the least cost delivery option for the Malampaya/Camago gas is the construction of an undersea pipeline from SC 38 to Luzon as well as necessary onshore pipeline and distribution lines to transport the gas to the market areas of Batangas, Metro Manila, and Bataan. The construction of the Base Case Pipeline Configuration is significantly less costly than either the LNG Option or the 500 kV Cable:

[8] Note that although the cost savings of routing the transmission cable over Mindoro are substantial, this overland route greatly increases the opportunity for sabotage of the transmission cable. An all undersea cable, though significantly more costly, would not be an easy target for sabotage.

COST COMPARISON OF DELIVERY OPTIONS

Delivery Option	*Capital Cost (94$MM)*	*Annual Cost (Levelized $MM)*
Base Case Pipeline Configuration	1,838	448
Base Case LNG Option	4,065	787
500 kV Cable	4,433	817

The table below demonstrates that the cost of natural gas delivered to each of the three markets via the Base Case Pipeline Configuration is competitive with the current and forecasted price of alternate fuel[9] (see alternate fuel price forecast in Figure 21).

COMPARISON OF FUELS
($ per MMBtu)

Market Area	*Natural Gas*	*Diesel*	*Bunker C*	*Coal*
Bataan	$3.28	$4.41	$2.78	$2.12
Batangas	$3.29	$4.41	$2.78	$2.12
Metro Manila	$3.25	$4.41	$2.78	$2.12

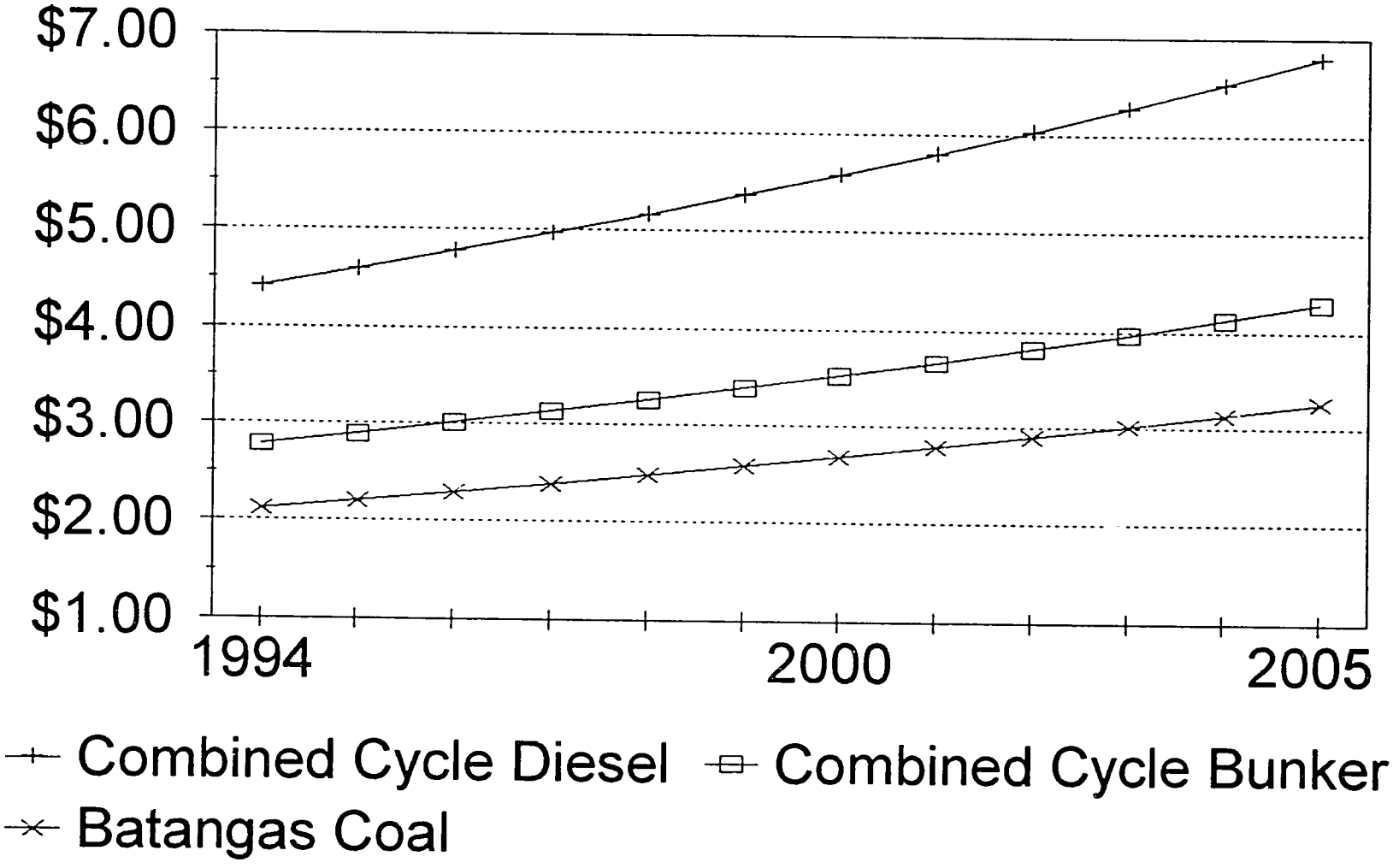
The above comparison of delivered fuel prices appears to indicate that coal would be significantly less costly than either natural gas, diesel, or bunker C for use in power generation. While it is true that coal commands a substantial price advantage in a simple comparison of delivered fuel costs, this comparison is not indicative of the total fuel cycle cost of using each fuel type. To make a worthwhile comparison of fuel types, additional factors such as the capital cost of the power plant itself, annual operation and maintenance costs, plant reliability, efficiency, compliance costs with

Source: NAPOCOR

Figure 21

ALTERNATE FUEL COSTS

($/MMBtu)



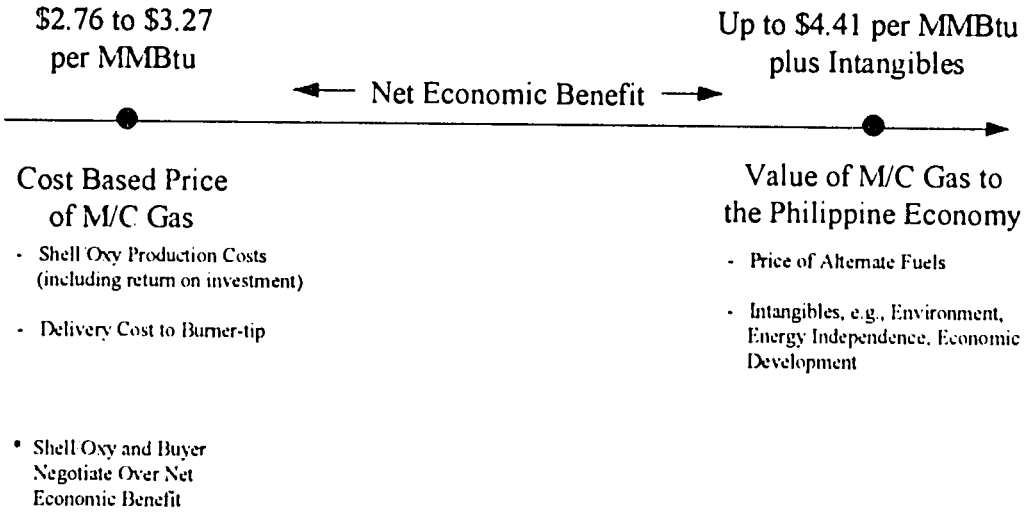
relevant emission control laws, etc. must all be considered in arriving at an all-in $ per kWh of electricity generated cost comparison.

A detailed comparison of fuels on a per kWh basis is well outside the scope of this study. However, some work has been done in this area by SRC International. Preliminary results of SRC International's "Long-term Power Planning Study" presented on August 15, 1994 indicate that coal is less costly than gas on an annual total cost per kW basis in plants with a greater than 50 percent load factor. The SRC presentation materials that BSA reviewed were not sufficient to allow a substantive evaluation of SRC's results or methodology. However, it is worthwhile to note that the gas price forecast contained in the SRC materials is significantly higher than the approximately $2.76 to $3.34 per MMBtu levelized delivered cost developed in this study for Malampaya/Camago gas. Furthermore, the SRC coal price forecast appears to be lower than the current price of $2.12 per MMBtu. Given the likely high degree of sensitivity of the SRC results to the delivered price of fuel, substitution of the SRC forecasts with the above delivered fuel prices may significantly alter the results. Finally, NAPOCOR estimates of the substantially greater capital expense of constructing, operating, and maintaining a coal plant versus a gas-fired plant do not appear to support the SRC results. In any case, comparison of fuels on a per kWh basis is certainly an area demanding further study. We recommend that more detailed analyses be conducted on this issue (see Chapter 8).

Having completed our analysis of delivery options we return to our diagram of "Pricing Theory" and fill in values for Points A and B, the endpoints for the negotiated price (see below).

Figure 22

PRICING THEORY



The next chapter discusses the structuring of the Philippine natural gas industry and examines ways in which structure can be organized to promote the goals of the Malampaya/Camago project.

CHAPTER 6
STRUCTURING THE PHILIPPINE NATURAL GAS INDUSTRY

The following structural analysis defines a set of strategic objectives, examines the component sectors of the natural gas industry, and then structures these sectors in a manner that is best suited to achieving the stated objectives.

6.1 STRATEGIC OBJECTIVES

BSA's identification of an appropriate structure for the Philippine natural gas industry proceeds from a definition of a set of objectives to guide our strategic assessment of alternate industry structures. We have formed the following set of strategic objectives for structuring the Philippine natural gas industry based in part on our discussions with Philippine government and energy industry representatives, USAID officials and RCG consultants, and in part on our experience in evaluating the conditions that are most likely to yield durable natural gas industry commercial arrangements.

1. The industry structure should promote the private sector development of the Philippines' identified domestic natural gas resources. In the immediate time frame, this objective focuses on Shell/Oxy's production and marketing of its offshore Palawan reserves in a commercially acceptable manner. In a longer time frame, the industry structure should provide mechanisms and facilities that will promote the private sector development of incremental reserves in an economic fashion.

2. The industry structure should promote the short-term "best use" of the domestic natural gas resources for power generation, industrial and other markets, as identified in Chapter 5 of this report.

3. While promoting the short-term "best use" of the domestic resource, the industry structure should promote private sector investment in a natural gas infrastructure in order to guide most economically the development of future natural gas resources and market growth.

4. The industry structure should promote the development of competitive natural gas markets where feasible. We assess the likelihood of competitive markets evolving in each gas industry sector and discuss the mechanisms that can be employed to promote the evolution of potentially competitive industry sectors by judging the degree to which

an industry sector satisfies the following set of conditions necessary for competitive markets:

- Multiple independent sellers and buyers of a product
- Ease of entry and exit from a market
- Readily available information
- Price transparency.

5. The industry structure should provide for public investment in the industry and regulation of private firms only to the extent necessary to promote private capital investment and competition in the industry. Except where there is a clearly defined strategic need for public investments (see below), government ownership of industry facilities should be prohibited so as to reduce the need for public sector capital investments in the industry, to minimize ongoing economic risks to the public (taxpayers), and to permit private firms to respond flexibly to financial incentives. In situations where it is clear that private capital is unavailable for necessary infrastructure investments either because the magnitude of the capital requirement relative to the potential market for services yields an inadequate return to private investors or there exist significant institutional/legal risks to private investment, the industry structure should strategically focus public investments toward the development of the necessary infrastructure that will in turn promote the long-term economic development of future gas resources and end use markets by private firms. Finally, the industry structure should provide for a regulatory authority charged with creating publicly-accountable mechanisms that foster the above objectives and promote the establishment of an environment conducive to the development of stable long-term commercial arrangements between private parties.

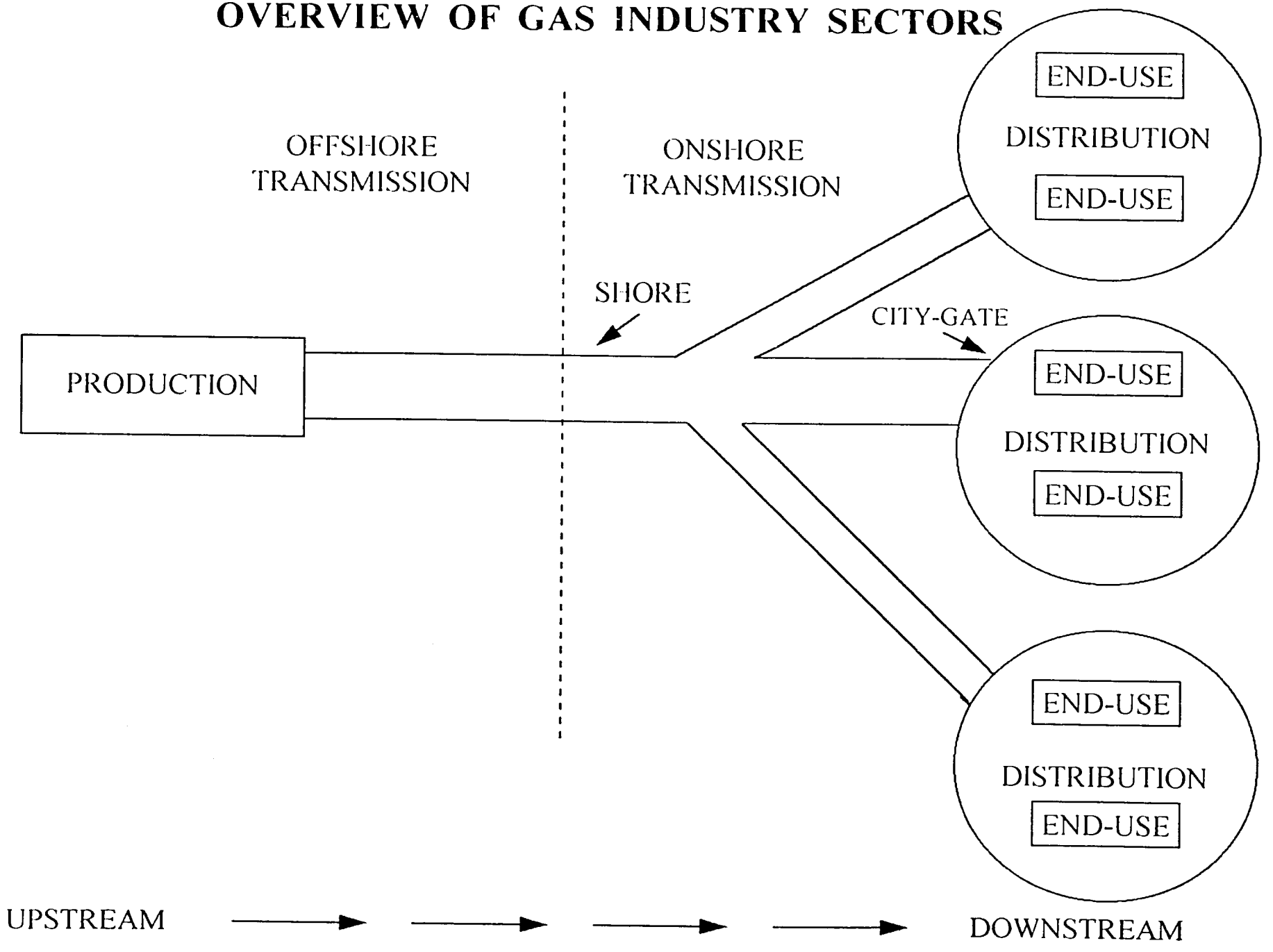
6.2 DEFINITION OF INDUSTRY SECTORS

The following is a breakdown of the gas industry into component sectors based on the service provided. We begin at the wellhead with "production" and move downstream, i.e., with the flow of gas, to "end use" (see Figure 23).

Production. - Exploration, development and production of the natural gas resource at a production platform or well for consumption in the field or shipment to markets. For purposes of this analysis we assume that producers process the raw gas to strip away impurities and liquid hydrocarbons, although processing can be a separate industry sector

Figure 23

OVERVIEW OF GAS INDUSTRY SECTORS



- Transmission.- Receipt of the commodity from the producer and bulk shipment to markets in the form of either LNG or high-pressure pipeline transmission. For offshore resources, we differentiate between offshore transmission from the production platform to land and onshore transmission from the shore to the interconnect with a distributor (the "city gate")

- Distribution. - Receipt of the commodity from the transporter at the city gate, vaporization and decompression as required, and shipment to multiple end users for ultimate consumption (the "burner tip")

- End use. - Consumption of the commodity at the burner tip. Typical end use markets are residential (space/water heating, cooking), commercial (space heating/cooling, cooking), industrial (process use, boiler use, space heating/cooling), and power generation

- Marketing. - Arranging the sale of the commodity and related value-added services at any point along the chain from production to end use.

6.3 COMPETITIVE ASSESSMENT OF NATURAL GAS INDUSTRY SECTORS

The following is an assessment of the competitiveness of each industry sector defined above.

Production.

The structure of the world natural gas industry suggests gas production is a potentially competitive sector depending on the size of the resource base and definition of ownership rights. Factors contributing to competitiveness are the magnitude of the capital investment required to produce the resource in a given area and legal access to production rights. Given the extent of the currently-identified resource base and the limited number of companies actively developing natural gas in the Philippines at this time, the Philippine production sector cannot currently be viewed as competitive. However, the government's promotion of private exploration and development activity and the large number of firms leasing resource exploration rights suggests that the Philippine production sector could evolve into a competitive sector assuming the identification of a resource base significant enough to justify capital investment by more than a single production entity.

Transmission.

Gas transmission is characterized by high initial capital costs and low operating costs leading to significant economic returns to scale. Hence, in most markets gas transmission is structured as a monopoly or at best an oligopoly.

Distribution.

Gas distribution also features high initial entry costs and relatively low operating costs, yielding significant returns to scale. In most gas markets, therefore, gas distribution is structured as a monopoly. Currently, there exists only one gas distribution network in the Philippines, owned by MGC. MGC has an exclusive franchise through 2012 to serve the Metro Manila area with piped gas service. From 1912 through 1991, MGC sold low-Btu gas that it manufactured at its central Manila (Paco) plant using as feedstock first coal (1912-1940), then bunker fuel oil (1940-1976) and finally naphtha/LPGs (1976 -1991). MGC distributed the manufactured gas to as many as 17,000 customers through a pipeline network comprised of 24 km of high pressure pipeline of up to 16 inches in diameter and 312 km of low pressure distribution pipeline. MGC discontinued use of its pipeline network in October 1991 and currently provides gas service solely as a wholesale and retail distributor of LPG, with sales of 4,000 to 5,000 metric tons of LPG/month, approximately 10% of the total Philippine LPG market. MGC's current customer base has fallen to approximately 8,000 LPG accounts, which is comprised of approximately 40% residential and the remainder commercial/industrial users. The National Development Corporation, a government entity, is currently seeking buyers for its 91.7% ownership share of MGC and plans to complete the privatization by the first quarter of 1995.

End use.

The degree of competition in end use markets typically reflects the degree of competition in the economy as a whole. In some industries, e.g., Indonesia, the government owns or controls many end use gas applications. In such an economic structure, the end use sector is in effect comprised of a single large consumer, i.e., a monopsony. In other industries, e.g., the U.S., numerous independent private firms control the end use applications, thereby yielding a competitive end use sector structure. Due to Shell/Oxy's need to target a large volume, high load factor end use to justify the high capital costs of developing the initial indigenous resource and because there is no existing natural gas requirements due to a lack of gas availability, we envision the Philippine end use sector for natural gas initially to be either one government consumer (NAPOCOR/PNOC) or a limited number of private sector power generation customers. Hence the initial Philippine natural gas end use sector cannot currently be viewed as competitive. However, as discussed above in Chapter 5. "Identification and Analysis of the Customer Base," of this report, there are numerous

private industrial, electric generation, and other facilities that can easily be converted to burn natural gas in existing applications. This suggests that the Philippine end use sector could rather quickly evolve into a competitive sector given the development of an onshore gas delivery infrastructure and, possibly, government policy (including financial incentives to private industry) to convert existing oil-fired applications to dual oil/natural gas capability.

Marketing.

We use the term gas marketing to refer generically to two distinct services. Brokering refers to a commercial transaction where the broker matches buyers and sellers but does not actually take title to the product, e.g., natural gas, and may have no permanent role in an ensuing commercial relationship. Marketing refers to any transaction where the marketer takes title to the product and bears the price risk between the purchase and sale of the product for the duration of the transaction. Brokering in particular poses few entry hurdles in the form of high initial capital investments, specialized expertise or technology. As such, gas marketing can be viewed as a potentially competitive industry sector, although legal restrictions on entry or pricing can diminish or eliminate competitive market forces.

6.4 NATURAL GAS INDUSTRY SERVICES AND IMPLICATIONS FOR COMPETITIVE MARKETS

The natural gas industry provides two products, the gas commodity and the delivery (transportation) of the commodity to the consumer. For each product, sellers provide either firm (guaranteed) or interruptible (as available) service. Moreover, sellers market the services either on an unbundled (stand-alone) basis, where the consumer separately purchases the gas commodity and the transportation services, or on a bundled basis where the seller combines sale of the commodity and transportation services to the consumer.

This characterization of natural gas industry services yields several key structural considerations. First is the role played by the transportation service provider (transporter) controlling scarce transportation capacity on a sole provider (monopoly) basis. When providing unbundled transportation service, the transporter does not take title to the commodity and hence bears no commodity price risk. When providing bundled sales service, however, it takes title to the commodity and bears attendant commodity price risk. As such, its relative financial exposure may affect its willingness and preference for providing bundled sales versus unbundled transportation service. Since the monopolist transporter can sell either service using the same transportation capacity, it is able to control the market's access to the scarce transportation capacity and the quantity of bundled sales versus unbundled transportation services the market purchases in the following ways:

- The monopolist can price bundled sales and unbundled transportation services in a way that favors the market's purchase of the service that is most profitable to the monopolist

- The monopolist can condition access to the scarce transportation capacity so that those customers purchasing the preferred service are favored, e.g., it may offer unbundled transportation service only on an inferior interruptible basis while offering the favored bundled sales service in both firm and interruptible flavors.

A second structural consideration is that both end user and producer preference for firm versus interruptible services varies widely depending upon the use of the service and the availability of service alternatives. For example, an electric generation facility may easily be able to switch its gas consumption to an alternate fuel while a residential consumer may have no immediate alternate means of satisfying its energy requirements. Alternatively, one producer may have an alternate transportation path for its commodity or it may be able to shut-in production for the duration of a transportation service curtailment without undue economic harm, while a second producer may lack alternate transportation paths and may have to maintain maximum throughput to protect its significant investment production facility. Because it controls access to scarce transportation capacity, the monopolist transporter is in a position to discriminate amongst the consumers of the transportation service and charge a higher price for the same product based on each consumer's market situation. Alternatively, the monopolist may alter its provision of bundled sales versus unbundled transportation services depending upon its ability to exert market power and increase profits for one service versus the other.

Common tools that policy makers employ to curb a monopolist's ability and incentive to control markets include:

- Restrict or prohibit a monopolist from participation in upstream and downstream markets

- Regulate a monopolist to restrict its ability to price and service discriminate in its markets by:

    1. Unbundling services, i.e., requiring the monopolist to separate the sale of the commodity and transportation services and identify the cost of each,

2. Requiring the monopolist to provide unbundled services on a non-discriminatory basis, i.e., provide open access to the scarce transportation capacity,

3. Designing rates and establishing conditions for service on a comparable basis, i.e., the cost of unbundled transportation service equals the cost of bundled sales service less the monopolist's cost to purchase gas and related sales expenses.

6.4.1 Implications

In considering an appropriate structure for the Philippine natural gas industry, it is essential to assess the competitive structure of each sector to understand the ability and incentive of firms operating in noncompetitive sectors to exert market power in competitive upstream or downstream sectors. If the government regulates a firm in one market/sector because that firm provides a monopoly service and controls access to that service, and that same firm also operates in the second, unregulated market/sector, that firm has both the ability and financial incentive to discriminate in the provision of the regulated service so that it favors its service in the unregulated market. For example, a gas distributor controls all access to end use markets in its franchised service area at a regulated price. If it also owns an affiliated producer operating in a competitive production sector on an unregulated basis, it can condition end user access to the production sector such that the end user must buy gas from the affiliated producer, thereby increasing profits to the production affiliate.

A competitive market assessment also is necessary to determine what form of regulation is likely to enhance competitive market conditions. In situations where a monopolist controls access to upstream and downstream markets, but those markets are themselves non-competitive, service unbundling and rate design comparability in the monopolistic sector are irrelevant in addressing the lack of competition in the upstream and downstream sectors. For example, if there exists a sole gas producer and multiple end users, forcing a monopolist transporter to provide unbundled transportation service permits the sole producer to project its market power downstream of the monopolist transporter by discriminating in serving the individual end use customers. The opposite situation could arise in a scenario when a sole end user, e.g., the government, uses unbundled transportation service to exert market power in a competitive production sector Similar problems can arise when regulators permit monopolists to discriminate in the provision of unbundled services. For example, a monopolist transporter may provide both bundled sales and unbundled transportation services, but the regulator may permit a higher return on the sales service. Unless the regulator requires the monopolist transporter to provide the unbundled services on an open access (non-discriminatory) basis, the transporter will

have a strong incentive to condition access to its services so as to promote sales in favor of transportation.

6.5 PROPOSED INDUSTRY STRUCTURE

The above assessment suggests that it is feasible to adopt a long-term vision of a Philippine natural gas industry characterized by potentially competitive production and end use sectors and with non-competitive transmission and distribution sectors. In the immediate picture, however, we recognize that the Philippine production and end use sectors are insufficiently competitive to establish an industry structure premised on workable competition therein from the start. The strategic challenge, therefore, is to design an industry structure that accommodates both short-term market realities and long-term market potential.

In this section we outline such a structure. We envision that the Philippine gas industry will transition through an initial phase designed primarily to promote the marketing of the Shell/Oxy gas reserves for electricity generation, to a permanent structure designed to suit a mature set of markets and regulatory institutions. In developing the structural recommendations that follow, we are guided by our set of strategic recommendations and by the competitive market assessment developed earlier in this Chapter. At the same time, however, our recommendations acknowledge the practical reality that the Philippine government and Shell/Oxy are currently negotiating a set of long-term agreements that will identify the price, risks, and appropriate commercial parties governing the development of the Malampaya gas. In particular, the parties plan to enter into a "heads of agreement" in the near future that will commit them to conclude binding, long-term gas sales and delivery agreements in time to permit the gas to flow to markets before the end of this decade. In this report we point to the lack of currently-identified creditworthy parties to assume the responsibility for delivery and purchase of the Shell/Oxy supplies as the single most significant obstacle to the successful negotiation of such preliminary agreements. In this context, therefore, our proposed industry structure departs in some respects from a straight application of our strategic objectives. More specifically, since we believe that a purely strategic approach to industry structuring is unlikely to lead to the formation of creditworthy gas transportation and purchasing entities on a timely and practical basis to support the current negotiations, thereby jeopardizing the development of a Philippine gas industry, we seek not to undermine the negotiation process. Rather, our two-phased structure, while falling somewhat short of full consistency with our strategic goals in the initial phase, maps out a transition process to overcome those initial phase steps designed primarily to support the current commercial negotiations.

6.5.1 Initial Phase

1. We recommend that Shell/Oxy build and own offshore private pipeline facilities permitting them to deliver gas from their production facilities to the shore. At that location, independent onshore pipeline facilities will connect the offshore facilities to onshore markets. Shell/Oxy will sell the gas at the interconnect of their offshore pipeline and the independent onshore pipeline and the sales customers will contract with the onshore pipeline to transport the gas to the burner tip. This recommendation recognizes the intent of the parties to the Service Contract and Memorandum of Clarification, both documents executed on December 11, 1990, that Shell/Oxy is the responsible party for constructing and operating pipeline facilities that will permit it to bring its resource to shore in a technically appropriate and economically efficient manner (see Appendix C).

   Our conception of Shell/Oxy's gas sales customer(s) is driven by our understanding of the proposed restructuring of the Philippine electric industry as recommended by RCG in its June 27, 1994 report to DOE. Based on RCG's proposed electric industry restructuring plan, we assume that within the next five years, NAPOCOR's fossil fuel generation facilities on Luzon will be privatized into two or three independent companies during Phases 1 and 2 of the electric industry restructuring plan and that NAPOCOR will withdraw from the fuel supply business. In addition, we assume that NAPOCOR's Bataan Nuclear Power Plant (BNPP) will ultimately be privatized as a gas-fired combined cycle generating facility. This restructuring of the existing electric generation sector suggests that Shell/Oxy ultimately will contract to sell gas to a handful of Luzon electric generation companies, i.e., the two or three privatized companies owning NAPOCOR's fossil fuel generation facilities, the privatized BNPP converted to a gas-fired facility, plus the IPP GenCos that will no longer be buying fuel from NAPOCOR.

   To implement this recommendation in the context of negotiating a gas sales contract with Shell/Oxy, we recognize that an interim buyer may have to negotiate in place of the private generators and other industrial gas buyers because the negotiations are on track to conclude prior to the time that NAPOCOR's generation facilities are privatized, i.e., there is a practical need for a creditworthy buyer to negotiate with Shell/Oxy prior to the time that the private generators exist. We therefore recommend the following:

- NAPOCOR, as the current owner and/or fuel buyer for the generation facilities that ultimately will use most of the gas and as an existing creditworthy public agency, would appear to be an appropriate party to act as interim gas buyer in this context. PNOC, in its role as the Philippine energy development company and also an existing creditworthy public agency, would be another reasonable choice for interim gas buyer. Clearly, however, NAPOCOR and PNOC are not the only possible entities that can assume the role of interim gas buyer. Other possibilities include existing private entities owning gas-fired electric generation facilities, e.g., the current IPPs and/or Meralco. However, from the practical perspective of accommodating the current contract negotiations, we believe that designating NAPOCOR or PNOC as the interim gas buyer is best because NAPOCOR and PNOC are established creditworthy entities that can contract for all the gas Shell/Oxy seek to market, e.g., relative to the other choices, there are fewer legal, institutional, and marketing hurdles to overcome in having NAPOCOR or PNOC assume the role of interim gas buyer. Moreover, since NAPOCOR itself will be privatizing the generation facilities (or the fuel procurement function for the generation facilities) that will consume most of the gas, it should be well positioned to manage the process of assigning its gas purchase contract to the future private buyers.

- All parties to the negotiations must recognize the planned transition from the interim buyer to the permanent gas buyer(s) as the relevant generation facilities are privatized and structure the gas sale agreement so as to accommodate this transition. Specifically, the contract must provide for transfer or assignment of the interim buyer's purchase and performance obligations under the gas sales contract to creditworthy private parties that will actually be consuming this gas.

- Shell/Oxy must be comfortable with the ability of the as-yet unidentified private buyers to perform under the disaggregated gas sales contracts that will replace Shell/Oxy's single original gas sales contract with the interim buyer. This implies the potential need for the interim buyer to provide a continuing performance guarantee to Shell/Oxy that will permit the producers to agree, in the original sales contract with the interim buyer, to a future assignment to as-yet unspecified private buyers. For example, it may be appropriate to give Shell/Oxy the

right to reasonably reject contract assignment to parties not meeting specified qualifications.

In conclusion, we recognize that our recommendation regarding the appropriate gas buyer would temporarily violate our strategic objective of limiting the government's role in the industry. Nonetheless, as we emphasized previously in this report, the commercial negotiations have reached a critical stage wherein it is imperative for Shell/Oxy to identify one or, at worst, a small handful of creditworthy buyers for the Malampaya gas and to conclude an initial binding sales commitment in the near future. As the predecessor organization for the future private GenCos, NAPOCOR would appear to be an appropriate interim gas buyer for the Shell/Oxy gas. Alternatively, as a public agency acting broadly to develop the energy sector of the Philippine economy, PNOC would also appear to be an appropriate interim gas buyer. In any event, we recommend that either party, NAPOCOR or PNOC, assign its role as buyer to the ultimate gas users, i.e., the creditworthy private power generation and industrial users, soon after the private firms become established in a creditworthy form, e.g., within six months of the date that each private buyer is established as a legal entity.

2. We recommend that Shell/Oxy be required to size its private offshore pipeline so that it is readily expandable to accommodate substantial potential future offshore resource development in the vicinity of the pipeline route and that Shell/Oxy be compensated for assuming this obligation. Specifically, prior to permitting Shell/Oxy to interconnect its pipeline facilities with onshore pipeline facilities, the government should require Shell/Oxy to file a facilities design application with the Energy Regulatory Board (ERB). ERB will be responsible for approving the pipeline design based on the ability of the facilities to accommodate future capacity expansion requirements and for identifying the incremental cost to Shell/Oxy of specific design features required solely to accommodate the government's desire for future expandability beyond the capacity specifically required by Shell/Oxy to market the Malampaya gas. The government should compensate Shell/Oxy for reasonable costs incurred to accommodate future capacity expansion, as approved by ERB, such compensation taking the form of a higher purchase price for gas or other direct compensation from the government. For example, construction of a 30" offshore pipeline, rather than a 24" offshore pipeline, increasing capacity by more than 50%, would add approximately $.02/MMBtu to the delivered cost of gas according to BSA's preliminary analysis in Chapter 5 of this report.

We believe that ERB is the appropriate body to assume responsibility for regulating gas companies in the Philippines as it has been granted legal authority to regulate the facilities, operations and pricing of firms operating in the energy sector of the Philippine economy. President Aquino created ERB in Executive Order 172 issued on May 8, 1987. Pursuant to its authority, ERB: "fixes and regulates the rate schedule or prices of piped gas to be charged by duly franchised gas companies which distribute gas by means of underground pipe systems;"... "fixes and regulates the rates of pipeline concessionaires under the provisions of Republic Act No. 387, as amended, otherwise known as the "Petroleum Act of 1949," as amended by Presidential Decree 1700;"... "imposes administrative penalties or sanctions for violations of price and rate orders and of ERB rules and regulations;".[1]

Our scope of work in this assignment has not permitted us to conduct an institutional assessment of the adequacy of ERB's current resources to assume the wide range of regulatory responsibilities that we recommend in our proposed industry structure. Such responsibilities will include approving the design, routing and cost of new natural gas facilities in certificate applications, establishing prices for unbundled gas, transportation, and distribution services, and designing and enforcing tariff conditions providing open access transportation service by monopoly service providers. Given ERB's crucial role in ensuring the competitiveness of production and end use markets in our proposed industry structure, we recommend that an institutional assessment geared towards identifying the appropriate resources necessary for ERB to assume its various gas industry responsibilities must be an essential first step in the implementation of our proposed industry structure.

3. In order to secure its capacity expansion option, we recommend that ERB condition approval of Shell/Oxy's pipeline on the pipeline operator providing open access transportation service on a non-discriminatory basis to any creditworthy customer that requests service on the offshore facilities. This responsibility must include the operator's obligation to construct facilities as necessary to accommodate such requests, provided that the operator be permitted to charge a transportation rate to third party users of the expanded pipeline capacity that compensates the operator for its incremental capital and operating costs associated with providing the incremental transportation service. ERB will be responsible for authorizing the reasonableness of such rates, after review of an application from the operator.

Source: "Primer on the Energy Regulatory Board", ERB Information and Production Unit.

4. We recommend that Shell/Oxy not be permitted to sell gas nor contract for transportation services downstream of their offshore pipeline facilities so that they will not be in a position to control scarce transmission capacity and exert their production sector market power all the way to the burner tip. However, the onshore pipeline facilities must provide open access transportation service on a cost-of-service basis to ensure that, at the interconnection of the offshore and onshore pipeline systems, Shell/Oxy will have access to their onshore sales customers for the duration of their sales contracts.

5. We recommend that an independent entity, which we refer to conceptually in this report as PGPC, construct and own the onshore pipeline facilities. This recommendation rests upon the following considerations:

- To the extent PGPC is a public entity, it may be eligible for low cost financing, thereby reducing the cost of the onshore facilities to the benefit of all parties Note: this argument justifies PGPC also constructing and owning the offshore pipeline, a development Shell/Oxy may favor assuming they share in attendant economic benefits.

- If Shell/Oxy were to own the onshore facilities, it is possible that they might not elect to construct BSA's recommended base case delivery option given their fundamental desire to market the Malampaya gas directly to the identified anchor load, i.e., the Bataan power generation market As an independent entity, PGPC can control the initial design and routing of the onshore facilities from the perspective of accommodating potential future gas markets in line with BSA's recommended base case delivery option.

- As discussed previously in this Chapter, we believe it would be inconsistent with the development of competitive market conditions to give the sole initial gas supplier (Shell/Oxy) or the sole interim gas buyer (NAPOCOR or PNOC) the responsibility for controlling the monopoly onshore gas transmission capacity. Rather, we believe this responsibility appropriately belongs with an independently-structured PGPC,

- We believe that long-term objective of developing a Philippine natural gas industry can best be served by ensuring that the

expertise necessary to operate a gas pipeline system and market gas services is developed domestically, rather than contracted out to a foreign entity.

In identifying the appropriate entity to form PGPC, we note again the practical necessity for a creditworthy entity to be present at the negotiating table with Shell/Oxy and the gas buyer(s) in a form that gives all parties to the negotiations the commercial assurance that the onshore gas delivery mechanism will be in place on a timely basis. Possible parties to form PGPC include:

- **Shell/Oxy**. Assuming the producers are agreeable to forming PGPC, this option minimizes the risk of delay in the current contract negotiations. However, giving Shell/Oxy control over the monopoly transmission facilities introduces a potentially serious threat to the long-term development of competitive markets (see above) and would require the early deployment of strong regulatory policies to combat such threats. Moreover, this option may not be eligible to take advantage of low cost public sector financing.

- **Philippine or Foreign Private Energy Company**. This option satisfies our preference for private sector investment as the best way to ensure that the Philippine natural gas industry develops in an economically efficient way. However, it is apparent that no private Philippine company currently exists with the necessary combination of expertise and resources to manage the construction and operation of the onshore pipeline. While numerous foreign companies clearly are capable of forming PGPC, we anticipate that it would take some time to bring them into the current negotiations process in a commercially acceptable fashion. In addition, this option also may not be eligible to take advantage of low cost public sector financing. Finally, to the extent the private sector firm that forms PGPC is also a gas buyer, this option suffers from the same threat to the long-term development of competitive markets as having Shell/Oxy form PGPC.

- **Philippine Public Energy Entity (NAPOCOR or PNOC)**. This may be the only option that is eligible for low cost public sector financing, based on our preliminary research. However, reliance on a public entity would violate our strategic objective of limiting the government's role in the industry. In addition,

this option suffers the same weakness as the previous option in that no existing Philippine public entity appears to have the expertise to manage the construction and operation of a gas pipeline. Finally, to the extent the public sector entity that forms PGPC is also the interim gas buyer, this option suffers from the same threat to the long-term development of competitive markets as having Shell/Oxy form PGPC.

At this time, the above assessment leaves us with no clear winner. The key strategic decision appears to rest on: (i) whether the benefits of low cost financing are strong enough to justify delaying privatization and (ii) which of the above options best leads to the formation of a creditworthy PGPC that helps to move the gas negotiations to a successful conclusion, i e , what legal/institutional steps are necessary before each of the above entities can form PGPC in a way that provides the other parties to the negotiations a sufficient degree of commercial assurance, e.g., corporate chartering, management, credit quality, etc.? Although we suspect that all parties to the negotiations would favor structuring PGPC to take advantage of low cost financing, our scope of work in this assignment has not permitted us to research the possible forms of PGPC that qualify for such benefits nor the nature of the benefits. To the extent that the benefits of low cost financing drive the decision toward structuring PGPC as a public sector entity, it may make the most sense for PGPC to be formed as a subsidiary of PNOC, with the goal of privatizing the subsidiary in a manner consistent with financing restrictions (see recommendation 9 below). However, our preference would be to have a private firm form PGPC and we believe that a foreign company could be active in the negotiations process within 6-12 months

6. We recommend that ERB require PGPC to initially size its facilities to satisfy the requirements of its initial shipper(s), the interim buyer on behalf of the handful of power generators that will buy the Shell/Oxy gas at the interconnect of the offshore and onshore pipeline facilities. In this way, the initial size of the onshore pipeline will be sufficient for the volume Shell/Oxy is obligated to sell to the interim gas buyer. In addition, the PGPC must be obligated to complete the onshore facilities on a schedule that accommodates the initial in-service date of Shell/Oxy's offshore facilities. In this way, the initial shipper(s) will be assured of paying for no more onshore capacity than they require and Shell/Oxy will be assured that the necessary onshore facilities will be ready when its delivery obligation begins. However, we recommend that ERB require PGPC to design and route the onshore facilities with a

view to serve potential future markets (see Chapter 5 of this report) inexpensively through capacity expansion.

7. We recommend that ERB require PGPC to interconnect its onshore transmission facilities with MGC's piped gas distribution network at the southernmost possible connection point. We also recommend that the government delay its planned first quarter of 1995 privatization of MGC until the status of Malampaya gas availability to MGC becomes clear. As the government proceeds to privatize MGC, the promise of this interconnect, along with expectations for PGPC's cost-based, open access transportation service, will provide a crucial link permitting potential investors in MGC to consider a variety of contractual arrangements with other private firms for the purchase and delivery of natural gas to the MGC city gate. We believe interconnecting MGC's and PGPC's pipeline systems will enhance the financial attractiveness of MGC to private sector investors and can promote the growth of end use gas markets by increasing the utilization of MGC's existing gas distribution infrastructure, provided engineering analysis confirms that MGC can convert its existing pipeline facilities to a natural gas distribution network.

8. We recommend that ERB regulate PGPC as an open access transporter. PGPC will provide only transportation service to all credit-worthy customers on a non-discriminatory basis at rates that recover its costs to construct and operate its facilities, including a reasonable return on investment, i.e., rates designed on a cost-of-service basis. The transportation rates should provide PGPC with a financial incentive to expand its capacity and service to satisfy incremental market demand, i.e., earn a return on throughput and capacity.

9. If PGPC is initially created as a public sector entity (see recommendation 5), we recommend privatizing PGPC as soon as the pipeline facilities are constructed and financing restrictions permit. The government should retain no ownership interest in PGPC, but ERB should continue to regulate the company as a public utility, i.e., PGPC must continue to provide open access transportation on a cost-of-service basis.

We believe that this initial phase structure best satisfies our strategic objectives as follows:

- Since Shell/Oxy's potential Luzon gas-fired electric generation customers, or the interim gas buyer contracting on their behalf, will be

able to contract with PGPC for long-term, cost-based, firm transportation service onshore, Shell/Oxy can be assured of long-term direct access to its markets. In this way, the parties will be able to structure long-term gas sales contracts that manage commercial risk in an acceptable manner without concern for intermediary party control of the gas.

- New resources developed in the vicinity of the currently-identified offshore resources can be developed and brought to market in an economic manner by means of Shell/Oxy's obligation to expand the capacity of its offshore pipeline and provide open access transportation service thereon on a reasonable cost-of-service basis.

- The ERB will ensure that the initial offshore pipeline facilities are designed to be economically expandable to accommodate potential new offshore gas resource development.

- Since ERB will ensure that PGPC's onshore pipeline facilities will be sized to match the requirements of Shell/Oxy's initial sales customer(s), the shipper(s) will be guaranteed of paying no more than a reasonable cost for the transportation service.

- The ERB will approve the routing and design of PGPC's onshore pipeline facilities from the long-term perspective of developing a natural gas industry infrastructure. In particular, ERB will require PGPC to interconnect with MGC's gas distribution network, thereby enhancing the future privatization and growth of MGC's existing distribution facilities.

- If the government elects to make a strategic public investment in the initial formation of PGPC, our initial phase structure provides for the government to recover its capital investment and promote further private investment in the industry by privatizing PGPC as soon as the pipeline facilities are constructed and financing restrictions permit.

- Through its approval of certificate applications for gas pipeline and distribution facilities, its rate setting jurisdiction, and its authority to establish tariff conditions for regulated firms, ERB will be able to restrict the ability of monopoly gas transportation and distribution service providers from exerting market power in the potentially-competitive production and end use sectors of the industry.

6.5.2 Permanent Structure

Initially, PGPC will offer only transportation service and will operate as the monopoly service provider in both the onshore transmission and distribution sectors. After Shell/Oxy completes its offshore pipeline facilities, gas flows to power generation markets under initial long-term firm sales contract(s), and, if necessary, PGPC is privatized, we recommend the following enhancements to the nascent Philippine natural gas industry to promote the penetration of gas in potential end use markets and increase the competitiveness of production and end use sectors:

1. We recommend that PGPC be allowed to provide bundled gas sales service as well as transportation service so as to offer a variety of service options for potential customers and expand the end use gas market. However, ERB must design PGPC's bundled sales and unbundled transportation rates on a comparable basis so as to ensure a level playing field between the two competing services that utilize PGPC's common capacity. ERB's objective must be to prevent PGPC from exerting its transmission and distribution sector market power to control access to both end use and production sectors. We recommend that ERB continue to give PGPC a financial incentive in its rate design to expand capacity on a nondiscriminatory basis so as to promote the development of any new indigenous supplies and end use markets.

2. We recommend that PGPC be permitted to construct and own offshore pipeline facilities connecting new resources to its onshore facilities, provided that it must offer producers open access transportation service on a cost-of-service basis.

3. We recommend that ERB regulate the privatized MGC's natural gas distribution operations and require it to offer both bundled sales and unbundled transportation service to all customers on an open access basis, conditioned only on the availability of sufficient capacity (and gas supply for bundled sales service). We recommend that ERB be responsible for approving MGC's sales and transportation rates on a cost of service/comparability basis and the rates should provide MGC with a financial incentive to expand end use markets.

4. We recommend that the government encourage the formation of other private distribution companies in other geographic areas of potential natural gas demand. Independent, private distribution companies may be better positioned than PGPC to market gas sales and transportation

services to smaller loads by assuming the role of gas aggregator, negotiating with producers, and managing transportation through PGPC.

Figure 24 depicts our recommended structure for the Philippine natural gas industry in both its initial phase and its permanent structure. Figure 25 outlines the range of various services that may be available in both the Initial Phase and Permanent Structure of our proposed Philippine natural gas industry.

Figure 24

STRUCTURING THE PHILIPPINE NATURAL GAS INDUSTRY

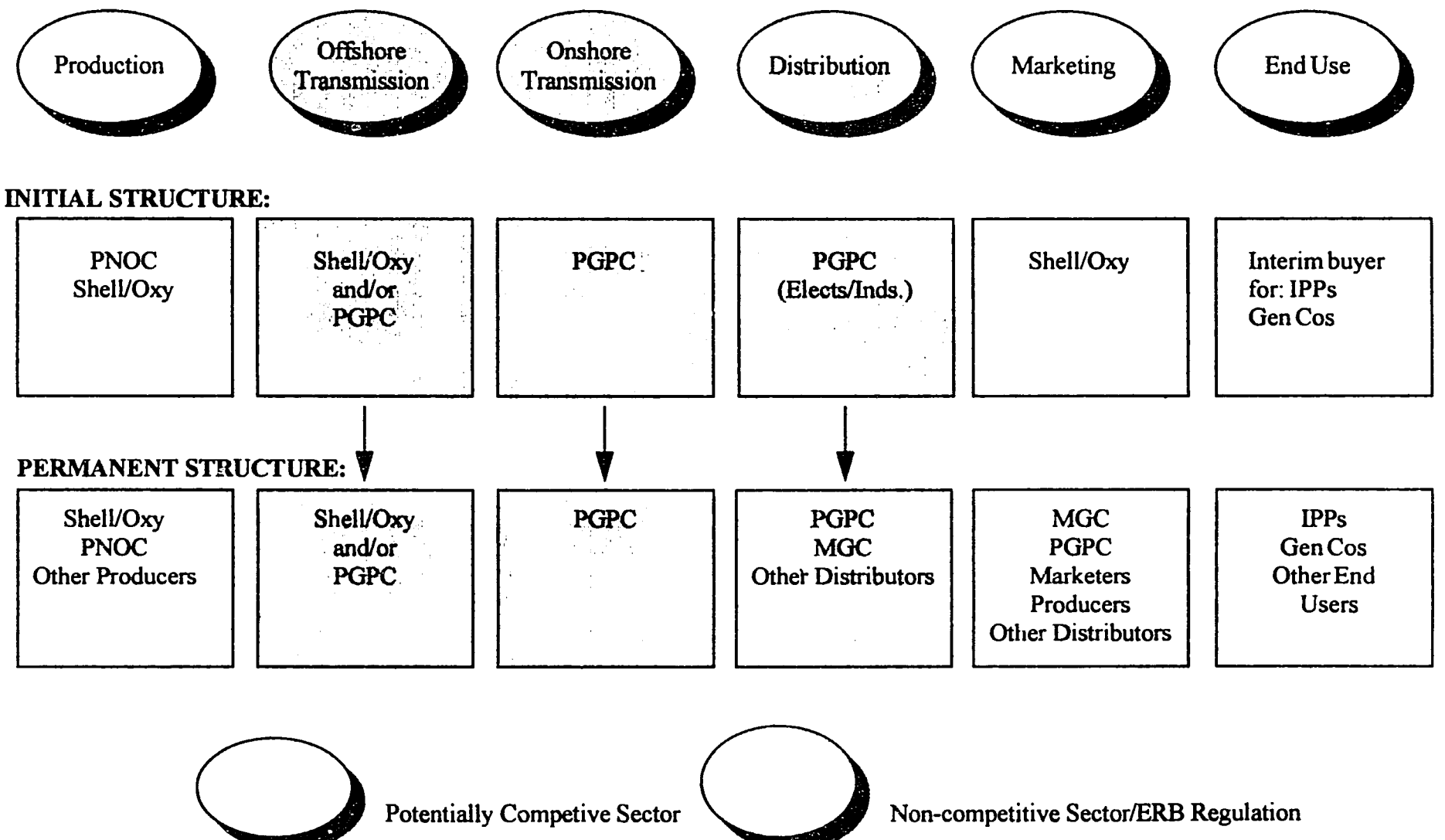


Figure 25

STRUCTURING THE PHILIPPINE NATURAL GAS INDUSTRY

	SERVICES
INITIAL PHASE	Shell/Oxy sells gas to handful of electric generators at shore or interim gas buyer. PGPC provides onshore transportation service to burnertip.
PERMANENT STRUCTURE	Initial Phase agreements remain in effect (interim buyer assigns contracts to private electric generators and industrials). Ending the restrictions on PGPC constructing offshore facilities, allowing PGPC to sell bundled sales in addition to transportation service, and the potential entry of new producers, distributors, and end users in the industry vastly expands the range of commercial transactions, as follows: 1). Producer sells gas to PGPC at shore or at platform (if PGPC elects to enter offshore transmission sector), PGPC sells bundled sales service to MGC, Other Distributors, Marketers, or End-Users at citygate or purchases transportation service from MGC or Other Distributors and sells bundled sales service to End Users at burnertip. 2). MGC or other Distributor buys gas from Producer at platform or shore, buys PGPC transportation service from platform or shore to citygate, and sells bundled sale service to End Users at burnertip. 3). Marketers buys gas from Producer at platform or shore, buys PGPC transportation service from the platform or shore to the citygate, buys transportation service from MGC or Other Distributors from citygate to burnertip, and sells bundled sales service to End Users at burnertip. 4). End User buys gas from Producer at platform or shore, buys PGPC transportation service from platform or shore to citygate, and buys transportation service from MGC or Other Distributors to deliver gas to its burnertip.

CHAPTER 7
CONTRACTUAL ISSUES

In this chapter we describe the key features of the contractual arrangements that will provide for the sale and transportation of the gas commodity as described in previous chapters of this report. Rather than presenting a comprehensive handbook on how to structure natural gas contracts, we intend that this chapter provide a basic understanding of how these key provisions provide for:

- A sharing of risk between the parties, and
- An identification of the key operational parameters that govern the commercial transaction.

In the context of this report, the "Seller" is Shell/Oxy, the "Buyer" is the one or more creditworthy entities with whom Shell/Oxy will negotiate to sell the gas commodity, the "Shipper" is the purchaser of gas transportation service and can be either the Seller or Buyer, and the "Transporter" is the entity owning the transmission or distribution facilities and offering gas transportation services. Appendices D and E contains examples from our files of an actual firm gas sales contract and an actual firm gas transportation contract in which we have deleted references to specific parties and key commercial details.

7.1 OVERVIEW OF KEY TERMS AND PROVISIONS OF GAS SALES CONTRACTS

In this section, we briefly describe the key terms in a firm gas sales contract. Non-firm or interruptible sales contracts contain similar provisions, except that the Buyer and Seller are not obligated to purchase or sell the commodity. Hence, interruptible contracts contain no minimum take or supply warranty provisions, nor do they contain a demand or reservation charge in the price structure.

Quantity.

A firm gas sales contract typically includes a section devoted to the rights and obligations of each party regarding the quantity of gas under the contract. This section specifies a maximum quantity that the Buyer has a right to receive, and the Seller an obligation to deliver, in any given period of time, usually a 24-hour day. In addition, many firm gas sales contracts contain minimum take provisions that obligate the Buyer to purchase and take delivery of a minimum quantity of gas in a given time period,

e.g., a calendar month or year, or to pay for the minimum quantity if not taken. These provisions are known as "take-and-pay" or "take-or-pay" provisions, respectively. The contract typically spells out any restrictions on the ability of the Buyer to resell gas purchased under the contract (usually done to limit the ability of the Buyer to arbitrage the Seller if the commodity is being priced at some formula other than the short-term market price) and on the ability of the Seller to sell gas not taken by the Buyer (usually to reduce the Buyer's risk that the Seller will sell the reserves supporting a long-term firm contract in the short-term, thereby undermining the security of the Seller's obligation to deliver gas pursuant to the Buyer's nominations in the long-term). Finally, the contract specifies nomination provisions pursuant to which the Buyer provides notice to the Seller of the volume of gas to deliver at a specific location on a given day.

Supply Warranty.

A firm sales contract includes a provision that binds the Seller to its delivery obligation. The supply warranty typically takes one of two forms. In a reserves-backed warranty, the Seller dedicates specific reserves (defined wells, pools, acreage) to the contract and may not sell the dedicated reserves to any other market without breaching the contract and assuming the risk of being held liable for damages as specified in the contract. In contrast, a corporate warranty contract does not dedicate specific reserves, but the Seller pledges the full faith and credit of its firm to back its obligation to deliver gas. If the corporate warranty Seller fails to deliver gas as nominated by the Buyer pursuant to the contract, the Seller is liable for specific damages under the contract, typically to make the Buyer whole for its costs to secure an alternate gas or fuel supply.

Price.

The firm sales contract specifies a price or a pricing formula applicable for the duration of the firm sales contract. The price can be fixed and knowable at the start of the contract, or it can be determined periodically throughout the contract term by means of a formula, usually with reference to a gas market price index. The contract price may be a two part demand/commodity structure, with the demand charge payable on the maximum delivery quantity specified in the contract and the commodity charge payable on the volume of commodity delivered during a billing period.

Delivery Point.

A firm sales contract specifies the primary point(s) for delivery of the commodity. Typically, this is the location where control of the transportation service changes hands from the Seller to the Buyer and can be anywhere from the wellhead (or offshore platform) to the burner tip. Gas sales contracts also specify technical

parameters governing delivery conditions, including the minimum and maximum acceptable pressure and quality of the gas.

Term.

A firm sales contract specifies the starting date when the Buyer may first nominate gas and a term during which the Seller and Buyer are committed to performing under the contract. The contract will often specify rollover or renewal rights at the option of one or both parties.

7.2 OVERVIEW OF KEY TERMS AND PROVISIONS OF GAS TRANSPORTATION CONTRACTS

In this section, we briefly describe the key terms in a firm gas transportation (FT) contract. Non-firm or interruptible transportation (IT) contracts contain similar provisions, except that the Shipper and Transporter are not obligated to deliver gas. Hence, (IT) contracts contain no minimum take or supply warranty provisions, nor do they contain a demand or reservation charge in the rate structure.

Quantity.

An FT contract includes a section devoted to the rights and obligations of each party regarding the quantity of gas under the contract. This section specifies a maximum quantity that the Shipper has a right to deliver to the Transporter at the designated receipt point(s) and receive from the Transporter at other designated delivery point(s), in any given period of time, usually a 24-hour day. In contrast to firm sales contracts, FT contracts do not contain "take-and-pay" or "take-or-pay" provisions obligating the Shipper to ship a minimum quantity of gas in a given time period or to pay for the minimum quantity if not taken. Instead, FT service typically is priced with a significant, or total fixed charge price structure so that the Transporter is largely indifferent to whether the Shipper actually transports gas and the Shipper has an economic incentive to utilize the capacity for which it pays irrespective of use. The FT contract typically spells out any restrictions on the ability of the Shipper to resell the capacity reserved for its use (usually done to limit the ability of the Shipper to arbitrage the Transporter since the price of the capacity generally does not reflect its short-term market value) and on the ability of the Transporter to resell the capacity not utilized by the Shipper (usually to protect the FT Shipper's guaranteed use of the capacity). Finally, the contract specifies nomination provisions pursuant to which the Shipper gives notice to the Transporter of how much gas to receive and deliver for its account on a given day at specific locations.

Price.

As explained above, FT rates typically recover a substantial portion of the cost to construct and operate the capacity in the form of a fixed monthly demand or reservation charge. Differing rate designs allocate more or less of the system's costs to the fixed demand charge versus a variable or commodity charge. IT service typically is provided on a 100 percent variable charge basis (pay only for volumes shipped) because IT Shippers have no claim on the capacity. Transportation service rates are typically established by regulation on a cost of service basis.

Receipt/Delivery Point.

Both FT and IT contracts specify one or more primary delivery point(s) where the Shipper may nominate to deliver gas to the Transporter and a set of primary delivery point(s) where the Shipper may nominate to receive the gas delivered to the Transporter. A Transporter may permit shippers to elect different receipt and delivery points than those specified in the contract, provided the Transporter may honor the request without curtailing service to other FT Shippers at their primary point(s). Transportation contracts typically provide that either party may refuse receipt of gas that fails to meet the Transporter's pressure and quality standards.

Term.

FT and IT contracts specify a starting date when the Shipper may first nominate gas and a term during which the Transporter and Shipper are committed to performing under the contract. The contract will often specify rollover or renewal rights at the option of one or both parties.

CHAPTER 8
CONCLUSIONS, RECOMMENDATIONS, AND NEXT STEPS

The discussion and analysis in this report focuses on determining:

- What is the value of the Malampaya/Camago gas to the Philippine economy?

- What is the best way to exploit that value to serve the interests of the Philippine economy?

The results of our analysis indicate that development of Malampaya/Camago will provide the Philippines with a reliable, economical, domestic source of energy for a cost of about $2.76 to $3.34 per MMBtu. The most cost effective way to exploit this resource is the construction of an undersea/land pipeline from the Malampaya/Camago reservoir in the South China Sea to the Central Luzon market areas of Bataan, Batangas, and Manila to serve power generation and industrial sector demand. Additionally, the development of Malampaya/Camago will form the foundation for a domestic natural gas industry that will both spur economic growth in the overall economy and provide the Philippines with a degree of energy independence from imported fuel sources.

In the long-term, it is likely that the Philippine natural gas industry will be characterized by potentially competitive production and end use sectors and with non-competitive transmission and distribution sectors. Nonetheless, recognizing that the Philippine production and end use sectors will be insufficiently competitive in the short-term to establish an industry structure premised on workable competition, this report contains recommendations for both interim and permanent industry structures to promote the immediate objectives of developing the identified indigenous resource base and ensuring its best use for power generation while establishing a framework for securing the longer-term objectives of private investment in a Philippine natural gas infrastructure to accommodate the development of future resources and end use markets and promote the evolution of competitive markets.

The above cost analysis and industry structure must be effectively embodied in gas sales and transportation contracts that will ultimately bind together the various parties to the Malampaya/Camago in a long-term relationship. Because of the substantial capital investment required, it is essential that the parties involved achieve a high level of comfort in each others' abilities to perform. All of the various pieces of the project must be developed and promoted concurrently by parties with the ability

and financial strength to guarantee performance. Of the three basic pieces of the project, i.e.,

- Exploration, production, development
- Delivery
- Customer base,

a significant amount of work remains to be done in both the delivery and customer base areas.

The selected Base Case Pipeline Configuration delivery option needs to be better defined through the identification of the specific customers for the Malampaya/Camago gas; the result being a concrete and detailed plan for the construction of the pipeline. Furthermore, additional analysis must be conducted to progress the above proposed structural and regulatory framework from the conceptual stage to implementation. The following is a list of tasks that need to be completed to further the various pieces of analysis begun in this study:

- Feasibility studies for each individual power plant that will utilize natural gas detailing the cost of construction, conversion, or repowering

- A more pointed comparison of the all-in cost of power generation on a per kWh basis using natural gas, fuel oil, and coal

- A dispatch analysis of the Luzon power grid to determine the load factor of those power plants that will utilize natural gas

- A customer specific analysis of the surrounding industrial base in order to select industrial users that will complement the projected load factor of the base load power plants and are in close proximity to the power plants, thus minimizing the initial investment in piping

- Configuration of a gas distribution network to link the customer base within each market area, and feasibility studies for each individual industrial customer selected

- An analysis of the financing options and advantages of different pipeline ownership configurations, based on specific developmental financing opportunities through the Asian Development Bank, Japan, the United States, and other potential sources

- Legal and institutional analysis, and specification of the role and parameters of the ERB, of PGPC, and of other key entities for the

development of Malampaya/Camago gas in order to confirm the practical/political/economic acceptability of the initial and permanent industry structures proposed in this report

- Assessment of the condition of MGC's existing piped gas system including estimates of the cost of refurbishment

- An assessment of local potential right-of-way issues, i.e., cost and more importantly the potential for delay, in development of the Base Case Pipeline Configuration, particularly in the Metro Manila area

- An environmental assessment to determine what steps can be taken to minimize the impact of the Malampaya/Camago project on both the onshore and offshore environments.

APPENDIX A
ARI REPORT - REVIEW OF GAS RESERVES DATA

ADVANCED RESOURCES INTERNATIONAL

August 5, 1994

Mr. Benjamin Schlesinger, Ph. D.
Benjamin Schlesinger and Associates
7201 Wisconsin Avenue, Suite 740
Bethesda, Maryland 20814

RE: MALAMPAYA 1 AND 2 WELL REPORTS
SENT BY: FAX (301) 951-3381

Dear Ben:

Pursuant to your request, I have reviewed the captioned well reports. The results of the reviews of these two wells are being communicated together in a single letter, because the information from both well reports was needed to properly assess the estimated reserves. Based on the information contained in the reports, the estimate of 1 to 4 Tcf of gas you mentioned is very reasonable, and is well supported by the data provided.

The well reports document many results learned from the drilling of the two wells. The most important of these is the presence of oil and gas and the good producibility of the reservoirs. The entire Nido limestone section was productive in both wells, down to a free water level (FWL) at 3495 m depth in the Malampaya-1 and 3410 m in the Malampaya-1. The Malampaya-1 tested 7023 bopd from the oil zone at 3411-3440 m, 4970 bopd from the oil zone at 3378-3392 m, and 28.8 MMcfd from the gas zone at 3126-3153 m. Oil was produced at a rate of 4300 bopd from 3376-3387 m in the Malampaya-2, but the gas zone was not tested there. The thick gas and oil columns and the high test rates confirm a major oil and gas accumulation is present at Malampaya Field.

The major risk item affecting the level of reserves at Malampaya Field is the volume of hydrocarbons in place, since the production tests conclusively demonstrated the presence of good permeability and producibility. The volume of hydrocarbons in place is dependent on the areal

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extent and net pay distribution in the reservoir, the porosity, the hydrocarbon saturation, and the location of fluid contacts. Each of these items, along with the implications of potential errors in measurement, is discussed below.

The areal extent and pay distribution in the reservoir are considered the variables most likely to be subject to error. A volumetric analysis consists of calculating the volume of hydrocarbons present from the areal and vertical extent of the reservoir, along with the porosity, the fluid saturations, and the formation volume factor to convert from reservoir conditions to standard pressure and temperature. The volumetric properties of the Nido formation at the two test wells are summarized in Table I. The recoverable gas in place in the Malampaya-1 is estimated to be 1.2 Tcf per square mile, and 0.18 Tcf per square mile under the Malampaya-2. The recoverable hydrocarbon liquids (condensate and oil) underlying the wells is estimated at approximately 85 million barrels per square mile under the Malampaya-1, and 23 million barrels per square mile under the Malampaya-2.

The overall volumes recoverable from the field will be a directly proportional to how much of the field is similar to the Malampaya-1, and how much is similar to the Malampaya-2. Unfortunately, the predicted thicknesses from the seismic interpretations did not tie in very well with the actual observed pay thickness in the wells, indicating some difficulties with the seismic interpretations. To assess the potential impact of different possible pay distributions across the structure, three different volumetric calculations were prepared, as shown on Table II. The potential reserves were first computed per square mile, and various areal and volumetric assumptions were made to bracket the likely range of reserves. The computed oil in place of 76 MMbbl per square mile under the Malampaya-2 well would correspond to 41 MMbbl in the area covered by Shell's simulation of Malampaya-2 performance, which had an estimated oil in place of 45 MMbbl (Figure 7-17 of the Malampaya-2 well report).

Minimum recoverable hydrocarbon volumes are estimated to be 1.0 Tcf and 88 MMbbl, if half the structure is unproductive for some (as yet unknown) reason. It should be emphasized

that no such reason has been identified or suspected, and that this calculation was made simply to bracket the range of what is considered possible. The most likely recoverable hydrocarbon volumes are estimated to be 3.0 Tcf and 270 MMbbl, based on applying the pyramidal rule for calculating reservoir volumes. This method assumes the Malampaya-2 net pay thickness, porosity, etc. are about the minimum that will be observed, with properties improving toward the Malampaya-1 at the upper extent of the field. For this calculation, the net recoverable hydrocarbon feet in the field would be like a pyramid shape, with Malampaya-1 properties at the top and Malampaya-2 properties around the edges. The maximum recoverable hydrocarbon volumes were estimated using the trapezoidal method, which assumes a linear gradation in reservoir properties from the Malampaya-2 to the Malampaya-1, so that any cross-section through the reservoir parallel to a line passing through those wells would look like a trapezoid. This method led to recoverable volume estimates of 3.6 Tcf gas and 290 MMbbl oil and condensate. The calculations presented here bracket the Shell estimates, indicating the general reasonableness of those estimates. Shell apparently used a Monte Carlo analysis, along with more detailed information regarding the seismic interpretations, to prepare their estimates.

The porosity and hydrocarbon saturations have been determined from well log interpretations, calibrated with the core analysis. The actual logs were not contained in the report, so we could not independently verify those interpretations. However, we see no apparent errors or omissions in the description of the log and core analysis procedures or results contained in the reports. The location of the fluid contacts affects whether a particular depth in each well has gas, oil, or water. In the Malampaya-2 report (p. 30), Shell estimated that the uncertainty in the equivalent hydrocarbon content from all of these factors to be from -19% to +22%. The equivalent hydrocarbon content is the main component in the calculated hydrocarbons in place per unit area. Since this degree of variation is so much less than the potential range due to possible areal or vertical variations in the net pay, and because it is as likely to be positive as negative, the uncertainty in these factors will not materially affect the overall range of the estimates.

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In summary, the Shell estimates appear reasonable, based on the information provided. These estimates are only as good as the information available, and additional wells and improved seismic interpretations will be needed to reduce the uncertainties. Because of the inherent limitations of the data and the limited amount of information provided, Advanced Resources International provides no warranty or guarantee regarding these interpretations, and any persons or parties making use of or relying on the material contained herein assume all risks and liability arising from such use or reliance.

After you have had a chance to review this letter, please give me a call if you have any questions or need further clarification.

Sincerely,

ADVANCED RESOURCES INTERNATIONAL, INC.

Dave O. Cox, Senior Project Manager

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TABLE I: SUMMARY RESULTS FROM MALAMPAYA 1 AND 2

	Malampaya 1	Malampaya 2	Comments
Gross Gas Zone Thickness, m	394	76	From Well Reports
Net Gas Zone Thickness, m	394	62	From Well Reports
Average Porosity	20%	19%	From Well Reports
Average Hydrocarbon Saturation	85%	85%	From Well Reports
Initial Pressure, psia	4730	4730	From M-1 Well Report
Temperature, °F	235	235	Computed From M-2 Well Report
Non-ideal Gas Z-Factor	0.97	0.97	GPSA Data Book
Gas Formation Volume Factor, scf/rcf	248	248	Calculated
Gas in Place, Bcf/mi²	1,519	227	Calculated
Recovery Factor	78%	78%	To assumed 1000 psia abandonment pressure
Recoverable Gas in Place, Bcf/mi²	**1,185**	**177**	Calculated
Condensate Ratio, bbl/MMcf	57	57	From M-1 Well Report
Condensate in Place, MMbbl/mi²	87	13	Calculated
Condensate Recovery Factor	50%	50%	Assumed, if some condensation occurs
Recoverable Condensate in Place, MMbbl/mi²	**43**	**6**	Calculated
Gross Oil Zone Thickness, m	106	65	From Well Reports
Net Oil Zone Thickness, m	106	65	From Well Reports
Average Porosity	23%	18%	From Well Reports
Average Hydrocarbon Saturation	71%	58%	From Well Reports
Oil Formation Volume Factor, rbbl/stb	1.46	1.46	From Well Reports
Oil in Place, MMbbl/mi²	193	76	Calculated
Recovery Factor	22%	22%	From M-2 Well Report
Oil in Place, MMbbl/mi²	**42**	**17**	Calculated

TABLE II: VOLUMETRIC CALCULATION OF RESERVES

A range of potential reserves has been computed for the area outlined in the Depth Map (Figure 1.1 of Malampaya-2 Well Report). The area underlain by oil and gas on that figure was determined by planimetering to be 5.3 mi^2 within the Malampaya Core Area. Minimum, probable and maximum reserves were computed volumetrically, as follows:

Minimum Reserves: If the reservoir properties observed at the Malampaya-1 are applicable to 0.5 mi^2, and those observed at Malampaya-2 apply to 2 mi^2, with the remainder being unproductive for unknown reasons, the reserves would be:

Gas:	1185 Bcf/mi^2 x 0.5 mi^2 + 177 Bcf/mi^2 x 2.0 mi^2 = **1.0 Tcf**
Condensate:	43 Bcf/mi^2 x 0.5 mi^2 + 6 Bcf/mi^2 x 2.0 mi^2 = **33 MMbbl**
Oil:	42 Bcf/mi^2 x 0.5 mi^2 + 17 Bcf/mi^2 x 2.0 mi^2 = **55 MMbbl**

Most Likely Reserves: If the reservoir properties observed at the Malampaya-1 are the best in the reservoir, and those observed at Malampaya-2 are approximately the lower end, the reserves computed from the pyramidal rule for the 5.3 mi^2 area would be:

Gas:	(1185 Bcf/mi^2 / 3 + 177 Bcf/mi^2) x 5.3 mi^2 = **3.0 Tcf**
Condensate:	(43 Bcf/mi^2 / 3 + 6 Bcf/mi^2) x 5.3 mi^2 = **108 MMbbl**
Oil:	(42 Bcf/mi^2 / 3 + 17 Bcf/mi^2) x 5.3 mi^2 = **164 MMbbl**

Maximum Reserves: If the reservoir properties observed at the Malampaya-1 are the best in the reservoir, and those observed at Malampaya-2 are approximately the lower end, the reserves computed from the trapezoidal rule for the 5.3 mi^2 area would be:

Gas:	(1185 Bcf/mi^2 + 177 Bcf/mi^2) / 2 x 5.3 mi^2 = **3.6 Tcf**
Condensate:	(43 Bcf/mi^2 + 6 Bcf/mi^2) / 2 x 5.3 mi^2 = **130 MMbbl**
Oil:	(42 Bcf/mi^2 + 17 Bcf/mi^2) / 2 x 5.3 mi^2 = **156 MMbbl**

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APPENDIX B
METHODOLOGY FOR THE INTERACTIVE PHILIPPINE GAS MODEL

APPENDIX B
METHODOLOGY FOR INTERACTIVE PHILIPPINE GAS MODEL

B.1 ONSHORE PIPELINE CALCULATIONS

BSA calculated the cost of onshore pipeline construction using economic data from the November 22, 1993 issue of Oil & Gas Journal. This issue contains:

- Information on over 200 U.S. pipeline construction projects built between 1991 and 1993 including economic data on:

  - Materials cost
  - Labor cost
  - R.O.W. cost
  - Miscellaneous cost
  - Total average cost.

  The data is provided in the form of dollars per mile.

- Data within each cost category is broken up according to the diameter of the pipe. 8-inch, 12-inch, 16-inch, 20-inch, 24-inch, and 30-inch pipe were included.

All costs were converted into 1994 dollars, and averaged for the years 1991 to 1993 within each category.

BSA then regressed the data for each category. For the regressions, the pipeline diameter is the independent variable and the average cost is the dependent variable.

The linear regression equations for each category are as follows:

1. Total Average Cost: Cost = 28,283.86*Diameter + 27,046.93
   R squared = 0.982189

2. Materials Cost: Cost = 13,104.51*Diameter - 89,957.7
   R squared = 0.938278

3. Labor Cost — Cost = 8,419.863*Diameter - 86,061.27
R squared = 0.86686

4. R.O.W. Cost — Cost = -13.947*Diameter + 40,460.46
R squared = 0.000121

5. Misc. Cost — Cost = 6,862.436*Diameter - 11,958.3
R squared = 0.919524

The accompanying graphs show the costs of constructing the pipeline within each category. The points on the graphs are the actual average cost for each category over the past three years. The solid lines are the regressions.

PIPELINE CONSTRUCTION COSTS
(THOUSANDS OF 1994$/MILE)

DIAMETER (inches)	AVERAGE COST 1991-1993	FORECASTED COST y= 28283.86x + 27046.93	MATERIALS COST 1991-1993	FORECASTED COST y= 13104.51x - 89957.7
8	$245	$253	$53	$15
12	$414	$366	$81	$67
16	$445	$480	$103	$120
20	$621	$593	$138	$172
24	$644	$706	$178	$225
30	$888	$876	$313	$303
36	$1,062	$1,045	$418	$382

AVERAGE COST
1991-1993 Regression Output:

Constant		27046.93
Std Err of Y Est		41403.57
R Squared		0.982189
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	28283.86	
Std Err of Coef.	1703.321	

MATERIALS COST
1991-1993 Regression Output:

Constant		-89957.72
Std Err of Y Est		36536.99
R Squared		0.938278
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	13104.51	
Std Err of Coef.	1503.113	

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PIPELINE CONSTRUCTION COSTS
(THOUSANDS OF 1994$/MILE)

DIAMETER (inches)	LABOR COST 1991-1993	FORECASTED COST y= 8419.863x + 86061.27	R.O.W. COST 1991-1993	FORECASTED COST y= -13.9474x + 40460.46
8	$101	$153	24	$40
12	$207	$187	53	$40
16	$226	$221	39	$40
20	$287	$254	60	$40
24	$319	$288	29	$40
30	$338	$339	37	$40
36	$354	$389	39	$40

LABOR COST
1991-1993 Regression Output:

Constant		86061.27
Std Err of Y Est		35870.86
R Squared		0.86686
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	8419.863	
Std Err of Coef.	1475.708	

R.O.W. COST
1991-1993 Regression Output:

Constant		40460.46
Std Err of Y Est		13787.68
R Squared		0.000121
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	-13.94741	
Std Err of Coef.	567.2178	

PIPELINE CONSTRUCTION COSTS
(THOUSANDS OF 1994$/MILE)

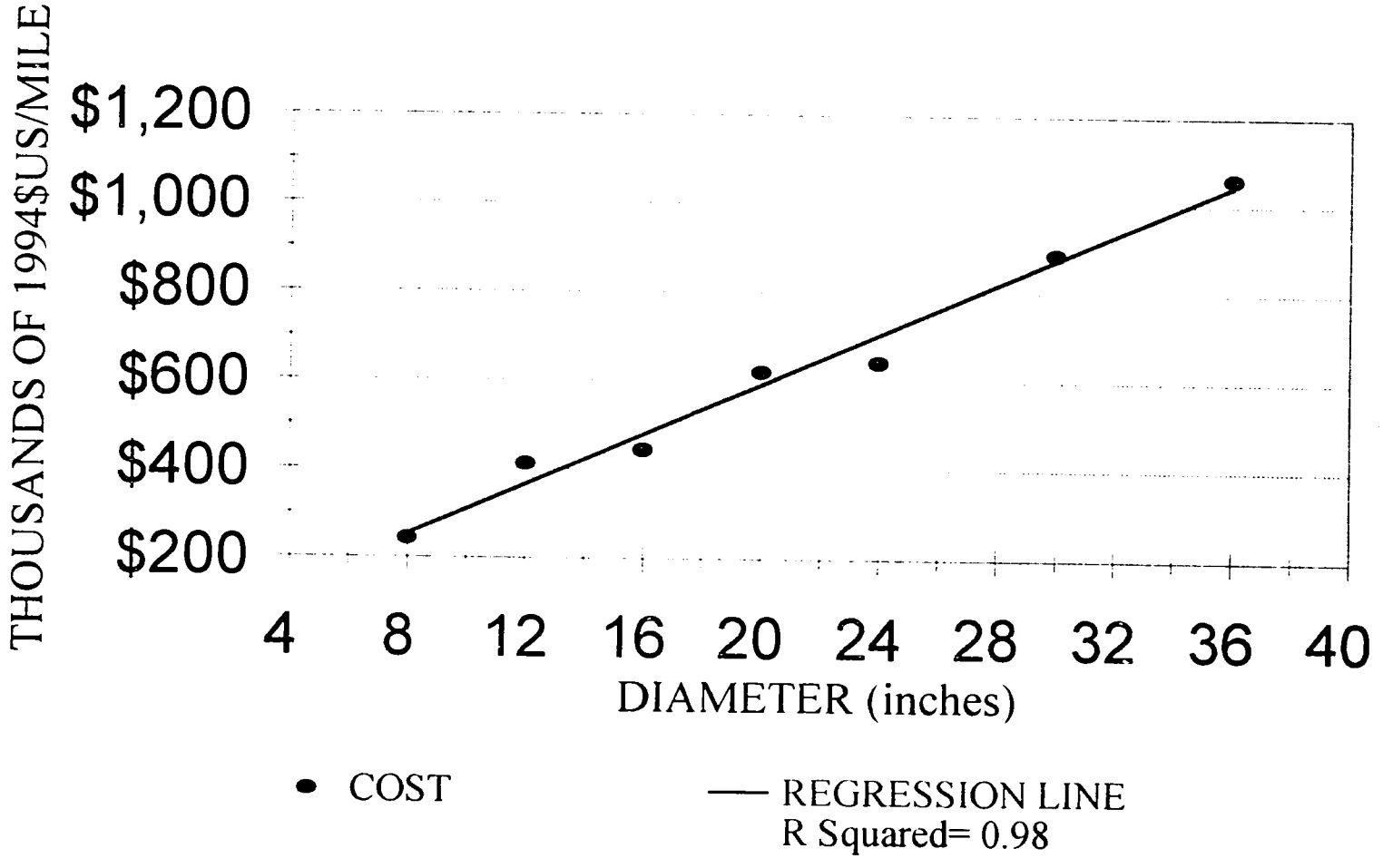
DIAMETER (inches)	MISC. COST 1991-1993	FORECASTED COST y= 6862.436x - 11958..
8	$63	$43
12	$73	$70
16	$77	$98
20	$137	$125
24	$118	$153
30	$200	$194
36	$251	$235

MISC. COST
1991-1993 Regression Output:

Constant		-11958.3
Std Err of Y Est		22069.13
R Squared		0.919524
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	6862.436	
Std Err of Coef.	907.9122	

AVERAGE COST

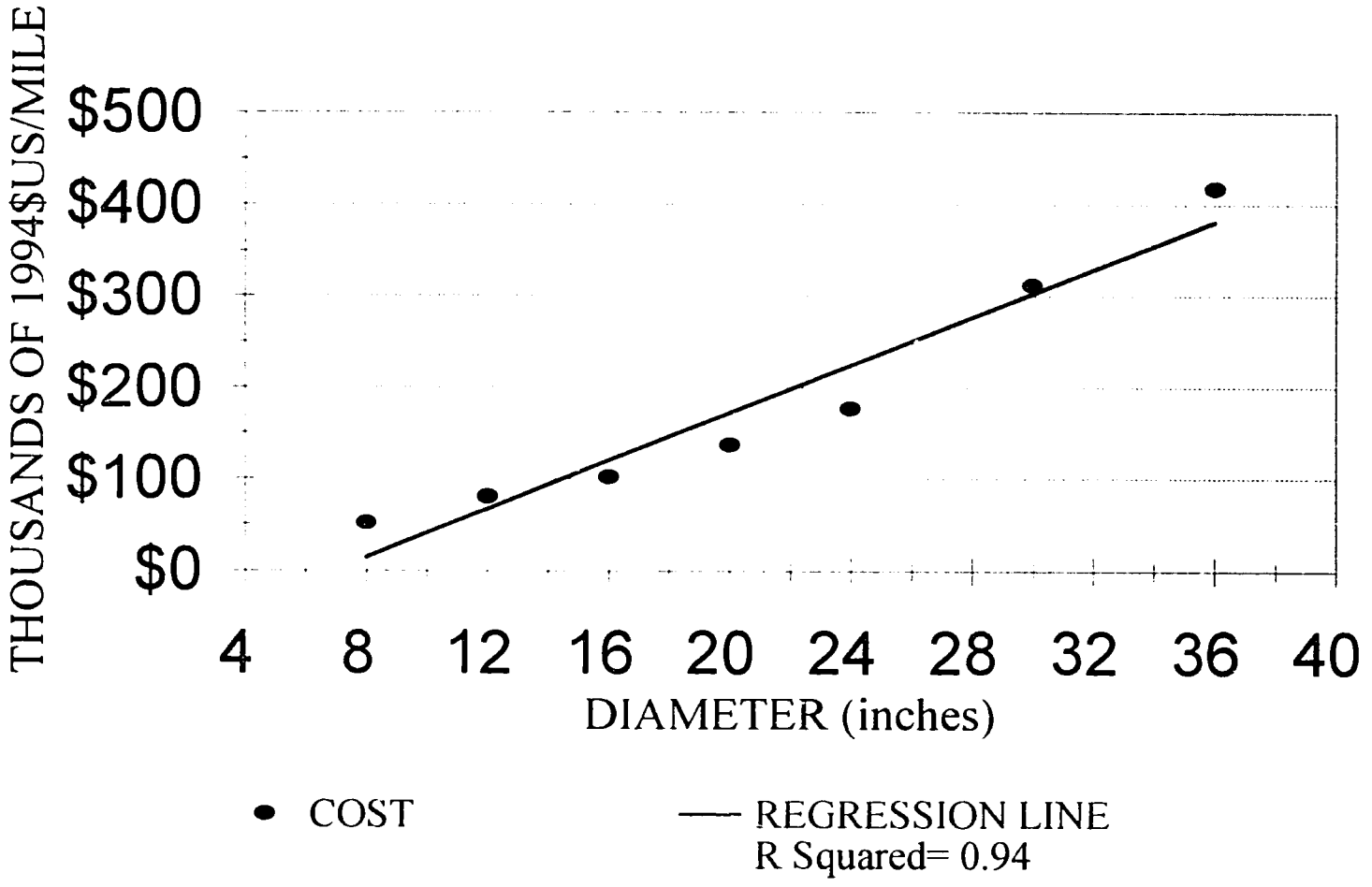
AVERAGE OF 1991 - 1993 DATA



Source: BSA, Inc.; Oil & Gas Journal

MATERIALS COST

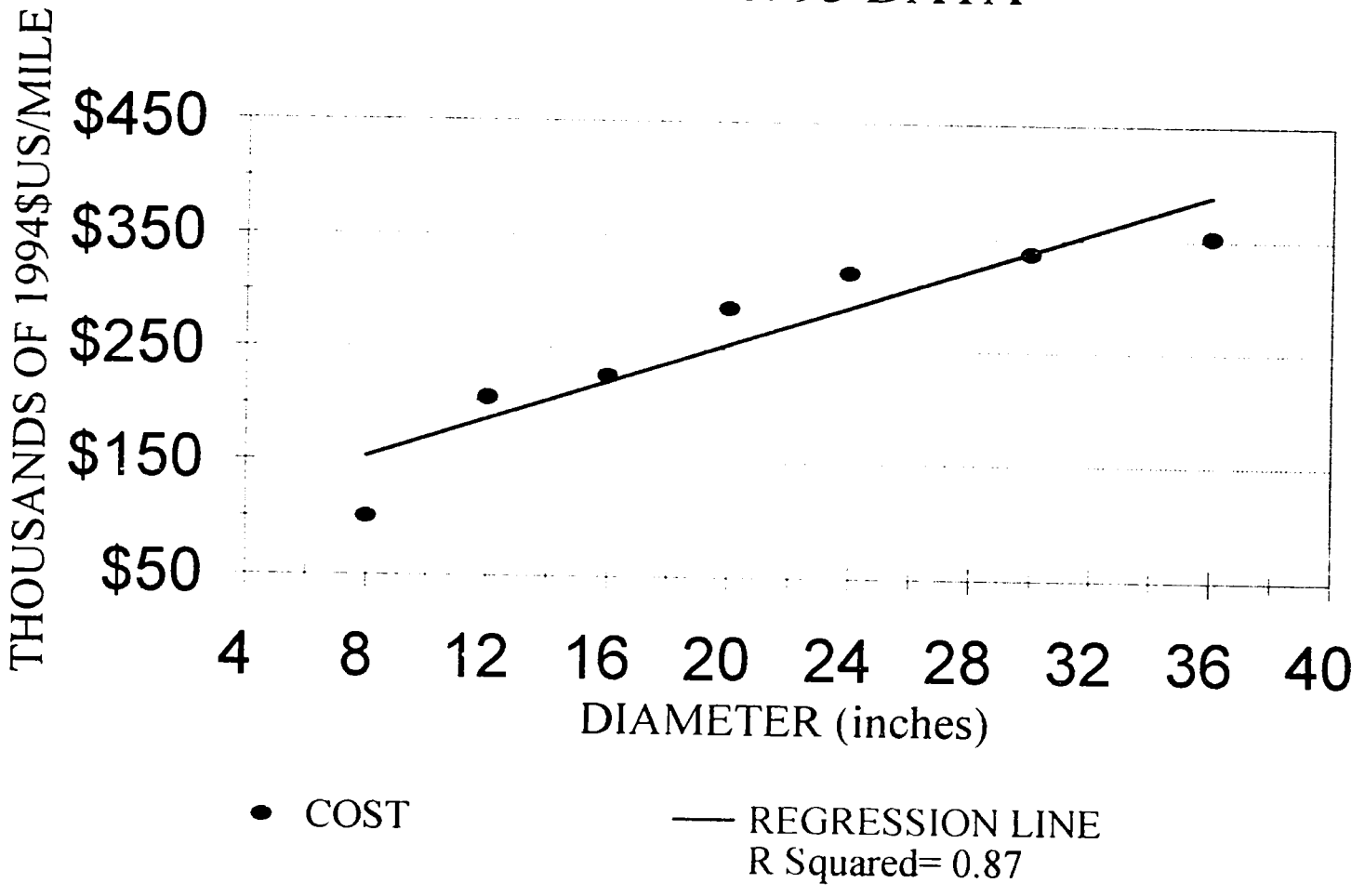
AVERAGE OF 1991 - 1993 DATA



Source: BSA, Inc.; Oil & Gas Journal

LABOR COST

AVERAGE OF 1991 - 1993 DATA



Source: BSA, Inc.; Oil & Gas Journal

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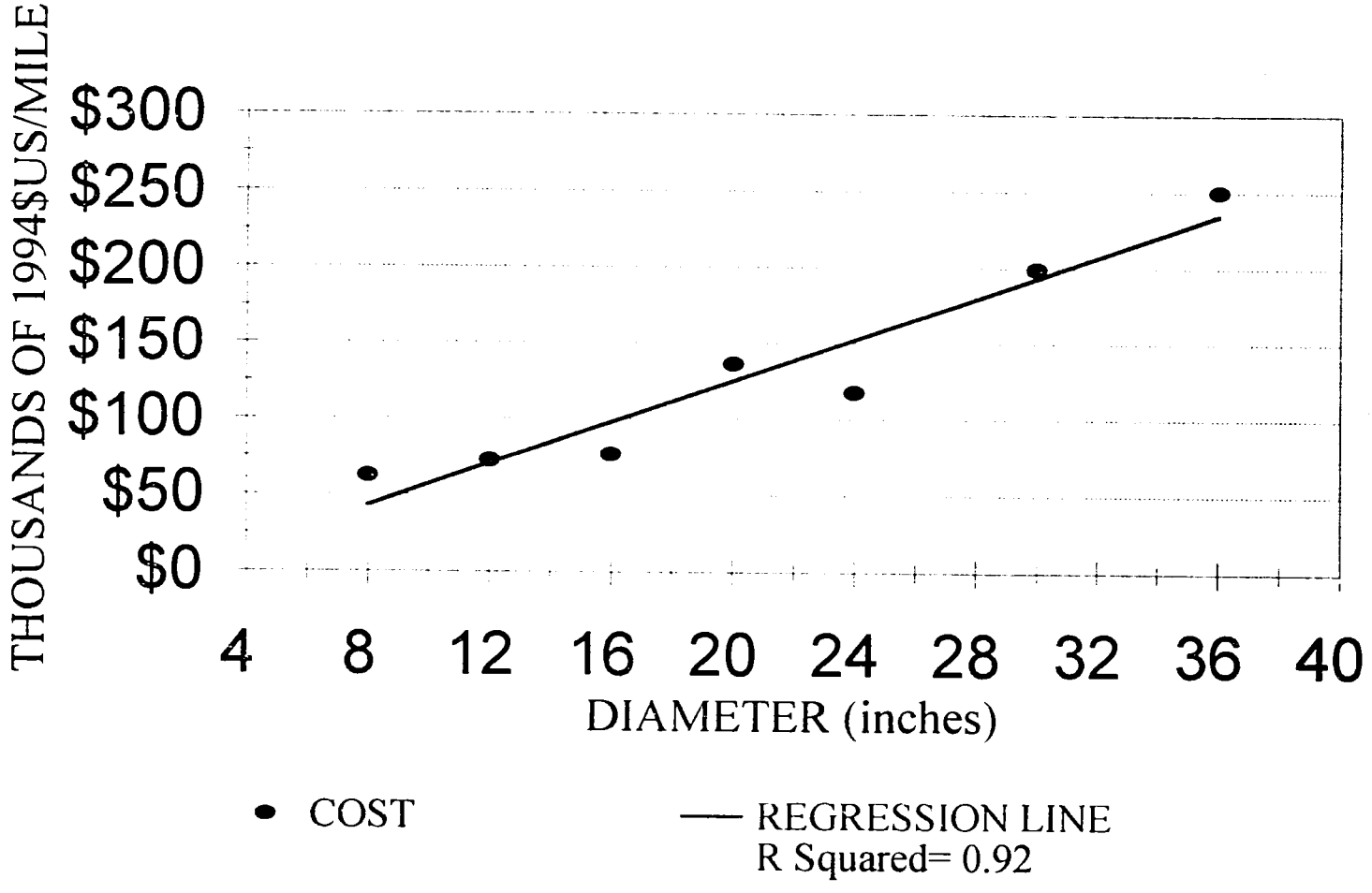
MISC. COST

AVERAGE OF 1991 - 1993 DATA



Source: BSA, Inc.; Oil & Gas Journal

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REGRESSION EQUATIONS

AVERAGE COST	$y = 28283.86x + 27046.93$ R Squared = 0.982189
MATERIALS COST	$y = 13104.51x - 89957.7$ R Squared = 0.938278
LABOR COST	$y = 8419.863x + 86061.27$ R Squared = 0.86686
R.O.W. COST	$y = -13.9474x + 40460.46$ R Squared = 0.000121
MISC. COST	$y = 6862.436x - 11958.3$ R Squared = 0.919524

B.2 OFFSHORE PIPELINE CALCULATIONS

There are four primary cost factors for offshore pipelines: pipe coating, installation, material cost, and the cost of a compression, if applicable. BSA estimates the costs as follows:

Pipe coating	$150,000/km
Installation	$250,000/km
Material Cost	$900/ton
Compressor	$1,200/horsepower

For the material costs, we assumed a wall thickness of 0.75 inches. The equation used to calculate the amount of material necessary is as follows:

[(Outside Diameter-thickness of pipe)*10.68]*thickness of pipe.

This equation was obtained through an engineer from a manufacturer of undersea pipe and it is in lbs/square foot. The diameter input parameter in the Model is assumed to be the inside diameter.

Although the above figures were not obtained specifically for a Philippine project, offshore pipe laying labor costs are highly consistent all over the world because of the high level of technology and expertise required.

In the model, the mainline pipeline also has a storage facility parameter. A high pressure storage facility costs approximately $400,000 per MMcf when the range is within an order of magnitude of 100 MMcf. The operations and management costs of a storage tank are approximately $100,000 a year per 100 MMcf of storage for the gas engine drive.[1]

The operations and management costs of an undersea pipeline are very low. Only the compressor has significant operations and management costs which BSA estimates at 4% of the capital costs.

BSA assumes the operations and management costs escalate at the same rate as inflation.

[1] Source: *High Pressure Holders*, by B.C. White, 1965 and *U.S. Department of Labor Bureau of Labor Statistics*, CPI.

B.3 LNG CALCULATIONS

For the LNG option, the breakdown of the costs falls easily into six parts: the capital and operating costs, for the liquefaction plant, the LNG tankers, and the regasification plant.

Liquefaction Plant.

Since it is so site dependent, the liquefaction plant is the only major segment of our estimate for which there is no quantifiable analysis. It is also the most important part. We based our estimate on comparisons to similar sized projects, consultation with experts in the LNG field, and rules of thumb. Considered strongly in our estimate is the fact the Philippine project is a greenfield project, and that the island of Palawan does not have a well developed infrastructure. We looked at comparable projects in Santos, Australia, Trinidad and Tobago, Venezuela, and other places around the world. The following chart is a breakdown from a liquefaction facility with the flow of 330 Bcf/year (about twice the size as the Philippines project) in a typical developing country[2]:

	$(1993 millions)	%
Liquefaction Plant:		
Gas Pretreatment	70	3
Liquefaction	420	20
Utilities	373	18
Auxiliary Services	105	5
Storage	105	5
Loading Facilities	70	3
Marine Facilities	70	3
Indirect Costs:		
Construction	339	16
Engineering	85	4
Contingencies	245	12
Owners Costs, Fuels Project	187	9
Land	12	0.5
Start-up Costs	35	1.5
Total	2,053	10

Source: *Gas Energy Review, October 1992.*

Operation and Management Costs of the Liquefaction Plant.

The main cost of the liquefaction plant is its self consumption, up to 12% for smaller plants. There are technologies that can bring the self consumption down to 6% but they are very expensive and not worthwhile for a small project. The estimate of the operations and management costs did not include self consumption; self consumption was taken into account when figuring per MMBtu cost. The operations and management of the liquefaction was loosely estimated at 4% of the capital costs based on consultation with various engineers working in the LNG field. BSA assumes operations and management costs escalate at the same rate as inflation.

LNG Tanker.

The range on the cost of a brand new 2.8 Bcf LNG tanker is between 230 and 300 million dollars. The price has increased rapidly in the past few years[3], and since there are only thirteen companies in the world that have ever made an LNG tankers[4], the price is highly negotiable. Japanese companies only keep their tankers for twenty years and some in the business think that tankers can last longer. So it is possible to buy a old second-hand tanker. For a new 2.8 Bcf tanker, 300 million dollars is a conservative estimate. For a 1.8 Bcf tanker, based on past prices BSA estimates the cost at 200 million dollars. The size of the tanker needed depends on how many days it takes to make the journey and how much volume is required in a year. The equation BSA uses in the Interactive Model worked as follows:

If there is more than 550 MMcfd throughput or if a round trip takes more than three days then a 2.8 Bcf tanker is used, otherwise a 1.8 Bcf tanker is used. These numbers are based on the fact that a typical year for a tanker is 330 days[5] and the following calculations:

550 MMcf/d*365 days = c. 200 Bcf/year
200 Bcf/1.8 Bcf = c. 110 trips * 3 days a trip = 330 days

At 4 days a trip, a volume less than 400 MMcfd is necessary for a 1.8 Bcf tanker, so the assumption is that at four days a trip a bigger tanker is necessary.

The length of the trip was derived in the following manner:

3 Source: *Cedigaz World LNG Trade*, 1991.
4 Source: *Asian Oil and Gas*, May 1992.
5 Source: *Gas Energy Review*, October 1992

Using the chart below, BSA derived the velocity of a 2.8 Bcf tanker and its self consumption[6]:

Destination/origin nautical miles(nm)	*Round Trip Distance nautical miles(nm)*	*Days per round trip*	*Gas Losses(%)*	*Margina nm/da*	*Margina % ga loss/da*
Georgia/Venezuela	3530	10.7	2.4	458.0	0.
Maryland/Venezuela	3988	11.7	2.6	410.0	0.2
Everett/Venezuela	4152	12.1	2.7	442.2	0.1
Louisiana/Venezuela	4550	13	2.8	456.8	0.1
Everett/Algeria	6606	17.5	3.6	466.6	0.1
Maryland/Algeria	7446	19.3	3.9	436.0	0.
Georgia/Algeria	7882	20.3	4.1	453.7	0.1
Louisiana/Algeria	9924	24.8	4.8	N	N
Everett/Nigeria	9950	24.8	4.8	416.6	0.1
Georgia/Nigeria	10200	25.4	4.9	458.2	0.1
Louisiana/Nigeria	12262	29.9	5.7	410.1	0.1
			Average=	400.7	0.1
Palawan/Bataan	500	1.1			0.

At 400 nm a day, with a round trip of about 500 nm, BSA estimates the travel time at about one day each way added to a one day to load and unload and one day of port time to equal about four days of travel. This parameter is flexible.

Shipping costs.

There are two methods of determining the cost of shipping in the Interactive Model. With the utilized method, we estimate a fixed cost at $0.05/MMBtu for a trip and $0.02/MMBtu for every day of the trip. The second method, which usually comes out to around the same price as the first method, is to multiply $50,000/d by the number of days and this total is divided by the quantity of the size of the tanker minus its self consumption parameter.

Source: *Potential for Long-Term LNG Supply*, ADL/GRI, August 1991

The Regasification Plant.

The storage costs consist of about half the total capital costs of an LNG regasification plant. The needed capacity for storage depends on the capacity and fluctuation of the load. Based on the relatively stable climate the storage capacity flexible parameter was set at 20 days. The estimated price for one 2.4 Bcf tank is 40 million dollars. So the calculation for the cost of the regasification plant in the Interactive model is as follows:

{The integer amount of [(# days*volume/day)/(2.4 Bcf)]}*2*40 million dollars.

When figuring the per MMBtu cost, the model takes the above amount and divides it by the quantity of the volume per year in MMBtu units minus the regasification plant's self consumption.

Based on consultation with various people in the LNG field, the operations and management costs of the regasification plant are estimated at 15 million dollars. BSA assumes the operations and management costs escalate at the same rate as inflation.

Sources Reviewed for the LNG Option

Potential for Long-Term LNG Supply, ADL/GRI, August 1991.
Asian Oil and Gas, May 1992.
Cedigaz News Report, Various recent issues.
Cedigaz World LNG Trade, 1991.
Gas Energy Review, Various recent issues.
Gas Matters, Various recent issues.
International Gas Report, 6/24/94.
Natural Gas Week International, Various recent issues.
Oil and Gas Journal, Various recent issues.
The Status of Liquefied Natural Gas Worldwide, 1990. The World Bank Industry and Energy Department, PRE.
Trunkline LNG Company. Brochure.
U S. Department of Labor Bureau of Labor Statistics, CPI.
Interviews with senior officials and engineers at the following companies:

ADL
Cabot
Distrigas
Trunkline LNG Company
The World Bank.

B.4 Undersea 500 kV Cable Calculations.

With undersea cable, the material cost is the main capital cost. The insulation, to protect the cable from corrosion, ship anchors, etc., is an order of magnitude more expensive than overhead insulation. Another price concern is the undersea terrain. If the sea bottom has ridges, cable suspension and bridging may be necessary.

For the capital cost estimation, BSA uses an estimate from NAPOCOR. BSA compared this estimate with our own research and found the numbers to be consistent.

There are significant operations and management costs for the terminals and the transmission line; after phone conversations with experts at the World Bank, BSA estimates operation and management costs at 4% of the capital costs.

BSA assumes operations and management costs escalate at the same rate as inflation.

NOTEBOOK A

PHILIPPINE GAS MODEL - OUTPUT TABLES

Configuration Setup

Delivery Option	*Volume(MMcfd)*	*Diameter(in)*
Via Pipeline		
Mainline to Batangas	450	24
Bataan Lateral	0	24
Manila Lateral	400	24
Extension (Manila/Bataan)	300	20
Via Bataan Regasification Terminal		
Volume of Imported LNG	0	N/A
Via LNG		
LNG to Bataan	450	N/A
Extension (Manila/Bataan)	0	20
Manila Lateral	0	18
Via 500 kV Cable ?		yes

Comparison of Costs ($MM)

Delivery Option	*Market Served*	*Total Cost ($94MM)*	*Capital Cost ($94MM)*	*Annual Cost($nom.)*	*$/MMBtu Cost*
Pipeline	Batangas	$410	$207	$50	$3.29
Pipeline	Manila	$801	$398	$99	$3.25
Pipeline	Bataan	$2,446	$1,233	$300	$3.28
Pipeline	**Rolled-in**	**$3,858**	**$1,838**	**$448**	**$3.27**
Imported LNG (*) Regas. Cynon	Bataan	$0	$0	$0	$0.00
Domestic LNG	Bataan	$8,081	$4,065	$787	$5.43
Domestic LNG	Manila	$0	$0	$0	$0.00
Domestic LNG	Batangas	$0	$0	$0	$0.00
Domestic LNG	**Rolled-in**	**$8,081**	**$4,065**	**$787**	**$5.43**
Electric Cable	Central Luzon	$8,469	$4,433	$817	N/A

Summary of Costs

Total Onshore Pipeline Cost

	(94MM)
Materials	$18.72
Labor	$22.25
R.O.W	$9.63
Misc	$11.57
	($MM)
Total Capital Cost($94)	$60.17
Total O&M Cost($94)	$12.03
Total Cost($94)	$72.21
Annual Capital Cost(nominal)	$4.77
Annual O&M Cost(nominal)	$0.89
Annual Total Cost(nominal)	$5.66
Levelized $/MMBtu Cost	$0.04

Total Offshore Pipeline Cost

	(94MM)
Materials	$224.37
Installation	$135.50
Compressor	$39.27
Annual O&M Cost	$0.00
	($MM)
Total Capital Cost($94)	$399.13
Total O&M Cost($94)	$0.00
Total Cost($94)	$399.13
Annual Capital Cost(nominal)	$31.67
Annual O&M Cost(nominal)	$0.00
Annual Total Cost(nominal)	$31.67
Levelized $/MMBtu Cost	$0.20

Total Distribution Costs

	(94MM)
Materials	$1.86
Labor	$19.18
R.O.W	$12.10
Misc	$6.44
Total Capital Cost ($/km)	$0.29
Annual O&M Cost	$0.40
	($MM)
Total Capital Cost($94)	$39.58
Total O&M Cost($94)	$7.92
Total Cost($94)	$47.50
Annual Capital Cost(nominal)	$3.14
Annual O&M Cost(nominal)	$0.58
Annual Total Cost(nominal)	$3.72
Levelized $/MMBtu Cost	$0.12

LNG (not including production)

	(94MM)
Pipe to Palawan Capital	$89.31
Pipe to Palawan Variable	$0.00
Liquefaction Plant	$2,000.00
Liquefaction Plant O&M	$117.73
Tanker	$300.00
Shipping Costs	$21.02
Regasification Plant	$320.00
Regasification Plant O&M	$24.05
	($MM)
Total Capital Cost($94)	$2,709.31
Total O&M Cost($94)	$2,212.46
Total Cost($94)	$4,921.78
Annual Capital Cost(nominal)	$214.96
Annual O&M Cost(nominal)	$162.80
Annual Total Cost(nominal)	$377.76
Levelized $/MMBtu Cost	$2.39

Electric Cable (not including production)

	(94MM)
Pipe to Palawan Capital	$89.31
Pipe to Palawan Variable	$0.00
Transmission Lines	2274.94
Converter Stations	520.8
Annual O&M Cost	$111.82
	($MM)
Total Capital Cost($94)	$3,094.00
Total O&M Cost($94)	$2,236.43
Total Cost($94)	$5,330.44
Annual Capital Cost(nominal)	$252.57
Annual O&M(nominal)	$164.56
Annual Total Cost(nominal)	$417.13

*PRODUCTION COSTS**

	(94MM)
Platform -Top Sides	$550.00
-Substructure	$88.00
Shore Facilities, Jetty	$152.00
MA Wells	$255.00
CA Satellite Well	$104.00
Subsea Manifold	$90.00
Flowline & Umbilicals to Manifold	$120.00
Additional Expenses	$0.00
Annual O&M Cost	$90.00
Total Capital Cost($94)	$1,339.00
Total O&M Cost($94)	$1,800.00
Total Cost($94)	$3,139.00
	($MM)
Annual Capital Cost(nominal)	$274.97
Annual O&M Cost(nominal)	$132.45
Annual Total Cost (nominal)	$407.42
Levelized $/MMBtu (pre-royalty)	$2.48
Royalty $/MMBtu	$0.54
Levelized $/MMBtu Cost	$3.02

*Based on [illegible] (pre-royalty) [illegible]

NOTEBOOK B

PHILIPPINE GAS MODEL - INPUT TABLES

Pipeline Configuration Inputs

Mainline (Wellhead to Batangas)

Length of Segment(km)	500
Storage(MMcf)	0
Compressor(MW)*	24.4

Extension (Manila to Bataan)

Length of Segment(km)	80
Onshore	38
Offshore	42
Compressor (MW)	0

Bataan Distribution

Length of Pipe(km)	80
Diameter of Pipe(in)	8

Philippine Adjustment Factors

Materials Differential	1
Labor Differential	1
R.O.W. Differential	3
Misc. Differential	1
O & M Escalator	1

Manila Lateral

Length of Segment(km)	90
Compressor (MW)	0

Manila Distribution

Length of Pipe(km)	80
Diameter of Pipe(in)	8
R.O.W Factor	0
Material Factor	0.5
Labor Factor	0.5

Heat Content of Gas per MMcf	1000

Bataan Lateral

Length of Segment(km)	180
Compressor(MW)	0

Batangas Distribution

Length of Pipe(km)	80
Diameter of Pipe(in)	8

Imported LNG Regasification Option

Imported LNG (pre-regas) $/MMBtu	$4.00
Storage days	20
Regasification Self Consumption	2.5%

LNG Configurations

Liquefaction and Regasification

Liquefaction Variables	
Self Consumption	12%
Tanker Variables	
Days Travel	4
Volume(MMcf/day)	450
Regasification Variables	
Volume(MMcf/day)	450
Storage days	20
Self Consumption	2.5%
Shipping Variables	
$/day	50000
Days Travel	4
Capital O&M($/MMBtu)	0.05
Variable O&M($/MMBtu)	0.02
Method 1	yes
Self consumption/day	0.2%

Pipeline to Palawan

Length of Segment(km)	75
Diameter of Pipeline(in)	24
Volume(MMcf/day)	450
Compressor(MW)	24.4

Transmission Cable Configurations

Pipeline to Palawan

Length of Segment(km)	75
Diameter of Pipeline(in)	24
Volume(MMcf/day)	450
Compressor(MW)	24.4

Financial Configurations

O&M Escalator/Inflation		4%
Transmission	Years Payment of Loan	20
	Grace Period	2
	Base Interest	6.5%
Production	Years Payment of Loan	20
	Rate of Return	20.0%
Government Royalty		18.00%

NOTEBOOK C

PHILIPPINE GAS MODEL - COST OF PIPELINE CONSTRUCTION

Mainline (Wellhead to Batangas)

Offshore	
	(94$MM)
Pipe Coating	$75 00
Installation	$125 00
Compressor	$39 27
Material Cost	$133 66
Storage Cost	$0 00
Annual O&M Cost (*)	$0 00
	($MM)
Total Capital Cost($94)	$372 92
Total O&M Cost($94)	$0 00
Total Cost($94)	$372 92
Annual Capital Cost(nominal)	$29 59
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$29 59
$/MMBtu Cost	$0 18

Batangas Distribution

	($94/km)
Materials	$9 299
Labor	$95 888
R O W	$75 654
Misc	$26 838
Total Capital Cost	$0 21
	(94$MM)
Materials	$0 74
Labor	$7 67
R O W	$6 05
Misc	$2 15
Annual O&M Cost	$0 17
	($MM)
Total Capital Cost($94)	$16 61
Total O&M Cost($94)	$3 32
Total Cost($94)	$19 94
Annual Capital Cost(nominal)	$1 32
Annual O&M Cost(nominal)	$0 24
Total Annual Cost(nominal)	$1 56
Levelized $/MMBtu	$0 09

Conditional Statements

Mainline	1
Extension	1
Bataan Undersea	0
Manila Lateral	1
Regasification Option	0

Offshore Pipelines

	(94$MM)
Pipe Coating	$81 30
Installation	$135 50
Compressor	$39 27
Material Cost	$143 07
Annual O&M Cost	$0 00
	($MM)
Total Capital Cost($94)	$399 13
Total O&M Cost($94)	$0 00
Total Cost($94)	$399 13
Annual Capital Cost(nominal)	$31 67
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$31 67
Levelized $/MMBtu Cost	$0 20

Extension (Manila to Bataan)

Onshore Segment	
	($94/km)
Materials	$107 583
Labor	$159 037
R O W	$75 340
Misc	$78 307
Total Capital Cost	$420 266
	(94$MM)
Materials	$4 09
Labor	$6 04
R O W	$2 86
Misc	$2 98
Annual O&M Cost	$0 16
	($MM)
Total Capital Cost($94)	$15 97
Total O&M Cost($94)	$3 19
Total Cost($94)	$19 16
Annual Capital Cost(nominal)	$1 27
Annual O&M Cost(nominal)	$0 24
Total Annual Cost(nominal)	$1 50
Levelized $/MMBtu	$0 014

Extension (Manila to Bataan)

Offshore Segment	
	(94$MM)
Pipe Coating	$6 30
Installation	$10 50
Compressor	$0 00
Material Cost	$9 41
O & M Charges per year	$0 00
	($MM)
Total Capital Cost($94)	$26 21
Total O&M Cost($94)	$0 00
Total Cost($94)	$26 21
Annual Capital Cost(nominal)	$2 08
Annual O&M cost(nominal)	$0 00
Total Annual Cost(nominal)	$2 08
Levelized $/MMBtu Cost	$0 019

Bataan Distribution

	(94$/km)
Materials	$9 299
Labor	$95 888
R O W	$75 654
Misc	$26 838
Total Capital Cost	$207 679
	(94$MM)
Materials	$0 74
Labor	$7 67
R O W	$6 05
Misc	$2 15
Annual O&M Cost	$0 17
	($MM)
Total Capital Cost($94)	$16 61
Total O&M Cost($94)	$3 32
Total Cost($94)	$19 94
Annual Capital Cost(nominal)	$1 32
Annual O&M Cost(nominal)	$0 24
Total Annual Cost(nominal)	$1 56
Levelized $/MMBtu	$0 014

Bataan Lateral (Batangas to Bataan)

Offshore	
	(94$MM)
Pipe Coating	$27 00
Installation	$45 00
Compressor	$0 00
Material Cost	$48 12
Annual O&M Cost	$0 00
	($MM)
Total Capital Cost($94)	$0 00
Total O&M Cost($94)	$0 00
Total Cost($94)	$0 00
Annual Capital Cost(nominal)	$0 00
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu Cost	$0 000

NOTEBOOK C CONTINUED

Manila Lateral (Batangas to Manila)

Onshore	
	(94$/km)
Materials	$140 344
Labor	$180 086
R O W	$75 236
Misc	$95 463
Compressor	$0
Total Capital Cost	$491 129
	(94$MM)
Materials	$12 83
Labor	$16 21
R O W	$6 77
Misc	$8 59
Compressor	$0 00
Annual O&M Cost	$0 44
	($MM)
Total Capital Cost($94)	$44 20
Total O&M Cost($94)	$8 84
Total Cost($94)	$53 04
Annual Capital Cost(nominal)	$3 51
Annual O&M Cost(nominal)	$0 65
Total Annual Cost(nominal)	$4 16
Levelized $/MMBtu	$0 028

Pipeline to Palawan - LNG

Offshore	
	(94$MM)
Pipe Coating	$11 25
Installation	$18 75
Compressor	$39 27
Material Cost	$20 05
Annual O&M Cost (*)	$0 00
	($MM)
Total Capital Cost($94)	$89 31
Total O&M Cost($94)	$0 00
Total Cost($94)	$89 31
Annual Capital Cost(nominal)	$7 09
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$7 09
Levelized $/MMBtu Cost	$0 043

Pipeline to Palawan - 500kV

Offshore	
	(94$MM)
Pipe Coating	$11 25
Installation	$18 75
Compressor	$39 27
Material Cost	$20 05
Annual O&M Cost (*)	$0 00
	($MM)
Total Capital Cost($94)	$89 31
Total O&M Cost($94)	$0 00
Total Cost($94)	$89 31
Annual Capital Cost(nominal)	$7 09
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$7 09

Manila Distribution

	(94$/km)
Materials	$4 649
Labor	$47 944
R O W	$0
Misc	$26 838
Total Capital Cost	$79 432
	(94$MM)
Materials	$0 37
Labor	$3 84
R O W	$0 00
Misc	$2 15
Annual O&M Cost	$0 06
	($MM)
Total Capital Cost($94)	$6 35
Total O&M Cost($94)	$1 27
Total Cost($94)	$7 63
Annual Capital Cost(nominal)	$0 50
Annual O&M Cost(nominal)	$0 09
Total Annual Cost(nominal)	$0 60
Levelized $/MMBtu	$0 018

NOTEBOOK C CONTINUED

Onshore Pipelines

	(94$MM)
Materials	$16 72
Labor	$22 25
R O W	$9 83
Misc	$11 57
Annual O&M Cost	$0 80
	(:$MM)
Total Capital Cost($94)	$60 17
Total O&M Cost($94)	$12 03
Total Cost($94)	$72 21
Annual Capital Cost(nominal)	$4 77
Annual O&M Cost(nominal)	$0 89
Total Annual Cost(nominal)	$5 66
Total Cost in $/MMBtu Cost	$0 04

Distribution Networks

	(94$MM)
Materials	$1 88
Labor	$19 18
R O W	$12 10
Misc	$6 44
Total Capital Cost (:$/km)	$0 29
Annual O&M Cost	$0 40
	(:$MM)
Total Capital Cost($94)	$39 58
Total O&M Cost($94)	$7 92
Total Cost($94)	$47 50
Annual Capital Cost(nominal)	$3 14
Annual O&M Cost(nominal)	$0 58
Total Annual Cost(nominal)	$3 72
Levelized $/MMBtu	$0 12

Imported LNG Regasification Option

Number of Tanks	1
	(:$MM)
Capital Cost($94)	$0 00
Annual O&M Cost($94)	$0 00
Total O&M Cost(s($94)	$0 00
Total Cost($94)	$0 00
Annual Capital Cost(nominal)	$0 00
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$0 00
Imported LNG Cost (pre-regas)	
$ per MMBtu	$0 00
Regasification Cost per MMBtu	$0 00
Bataan Distribution Cost	$0 00
Total per MMBtu Cost	$0 00

NOTEBOOK D

PHILIPPINE GAS MODEL - COST OF LNG

OUTPUT VARIABLES

Description of Cost Item	*Secondary Variables*	*Capital Cost(1994) (94$MM)*	*$/MMBtu*	*(94$MM)/ year*	*Nominal ($MM)/year*
Fixed					
Liquefaction Plant		$2 000	$1 10	$159	$159
Tanker		$300	$0 14	$24	$24
Tanker Size(Bcf)	2 8				
True Tanker Capacity(Bcf)	2 8				
Regasification plant		$320	$0 18	$25	$25
Variable					
Liquefaction Plant(per year)			$0 72	$80	$118
Shipping costs					
First method			$0 08	$14	$21
Fixed O&M(per MMBtu)	0 05				
Variable O&M(per MMBtu)	0 02				
#days	4				
Tanker capacity(Bcf)	2 8				
Second Method			$0 00	$0	
$/day	50000				
#days	4				
Fixed O&M(per MMBtu)	0 05				
Self consumption	0 008				
Regasification			$0 15	$18	$24
Total		$2,620	$2.35	$318	$371

	(94$MM)
Annual O&M Cost($94)	$119 82
Total Capital Cost($94)	**********
Total Variable Cost($94)	**********
Total Cost($94)	**********
	($MM)
Annual Capital Cost(nominal)	$207 87
Annual Variable Cost(nominal)	$162 80
Total Annual Cost(nominal)	$370 67
Levelized $/MMBtu - self cons	$2 26
Levelized per MMBtu Cost	$2 35
$/MMBtu plus Palawan pipe	$2 39

INPUT VARIABLES

Financial Variables	amounts
Interest	4 9%
Years financing	20
Liquefaction Variables	
Self Consumption	12%
Tanker Variables	
Days Travel	4
Volume(MMcf/day)	450
Regasification Variables	
Volume(MMcf/day)	450
Storage days	20
Self Consumption	2 5%
Shipping Variables	
$/day	50000
Days Travel	4
Fixed O&M	$0 05
Variable O&M	$0 02
Self consumption/day	0 2%

SECONDARY INPUT VARIABL

Tanker Size(Bcf)	2 8
True Tanker Size(Bcf	2 8
#Storage Tanks	4
Shipping Self Consumption	0 8%
Conditional	1

NOTEBOOK E

PHILIPPINE GAS MODEL - COST OF ELECTRIC TRANSMISSION LINE

Costs

	($94MM)
Capital Costs	
Transmission Lines	
Palawan C/S - Palawan CTS	2.94
Palawan CTS - Burunoan CTS	1997.6
Burunoan CTS - Calapan CTS	44.09
Calapan CTS - Soloc CTS	211.2
Soloc CTS - Tayabas C/S	19.11
Sub-Total	2274.94
Electrode and Electrode Lines	
Palawan Side	0.25
Luzon Side	0.83
Sub-Total	1.08
Converter Stations	
Palawan C/S	260.3
Tayabas C/S	260.3
Sub-Total	520.6
Total Direct Cost	2796.62
Engineering	$68
Physical Contingency	139.83
Total Capital Cost	$3.005
Annual O&M Cost of Transmission	$91
Annual O&M Cost of Converter Stations	$21
Total Annual O&M Cost	$112

Summary	($MM)
Total Capital Cost($94)	$3.005
Total O&M Cost($94)	$2.236
Total Cost($94)	$5.241
Annual Capital Cost(nominal)	$238
Annual O&M Cost(nominal)	$165
Total Annual Cost(nominal)	$403

Assumptions

Distance(km)	476
Capacity(MW)	3000
Voltage(V)	500
Years of loan	20
Interest	4.9%
# of pairs of cables	3
Condition	1

N.B. Step-up transformers at Palawan are assumed to be part of the power plant cost while no step-down transformers are needed at Tayabas being a 500 kV substation.

NOTEBOOK F

PHILIPPINE GAS MODEL - SECONDARY VARIABLES

Real Interest	4.87%

Volume Bataan Distribution(MMcf/d)	300
Volume Manila Distribution(MMcf/d)	100
Volume Batangas Distribution(MMcf/d)	50

Final Cost in Millions

Total cost of prod + mainline+regas	$3,511.92
Total cost to Batangas (P/M/D)	$410.15
Total Manila 1	$801.31
Total Manila 2	$833.43
Total Bataan 1	$2,381.22
Total Bataan 2	$2,446.38
Total Conditional Manila Cost	$801.31
Total Conditional Bataan Cost	$2,446.38

Market Share of Mainline	
Manila	22.22%
Bataan	66.67%
Batangas	11.11%

Market Share of Laterals	
MM of ML	25.00%
MM of BL	0.00%
B of BL	0.00%
B of ML	75.00%

Capital cost of prod + mainline+regas	$1,711.92
Capital cost to Batangas (P/M/D)	$209.83
Capital Manila 1	$397.83
Capital Manila 2	$428.96
Capital Bataan 1	$1,157.90
Capital Bataan 2	$1,233.23
Capital Conditional Manila Cost	$397.83
Capital Conditional Bataan Cost	$1,233.23

Annual cost of prod + mainline+regas	$437.01
Annual Manila 1	$98.75
Annual Manila 2	$101.29
Annual Bataan 1	$294.66
Annual Bataan 2	$299.80
Annual Batangas Cost	$50.12
Conditional Annual Manila Cost	598.75
Conditional Annual Bataan Cost	$269.60

NOTEBOOK G

PHILIPPINE GAS MODEL - LNG PIPELINE CONFIGURATIONS

Extension (Bataan to Manila)

Onshore Segment	
	(94$/km)
Materials	$107 583
Labor	$150.037
R O W	$75 340
Misc	$78.307
Total Capital Costs	$420,268
	(94$MM)
Materials	$4 09
Labor	$6 04
R O W	$2 86
Misc	$2 98
Annual O&M Cost	$0 00
	($MM)
Total Capital Cost($94)	$0 00
Total O&M Cost($94)	$0 00
Total Cost($94)	$0 00
Annal Capital Cost(nominal)	$0 00
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu	$0 000

Manila Lateral (Bataan to Manila)

Onshore	
	(94$/km)
Materials	$91 202
Labor	$148 512
R O W	$75 393
Misc	$69.728
Total Capital Cost	$384 835
	(94$MM)
Materials	$6 21
Labor	$13 37
R O W	$6 79
Misc	$6 28
Annual O&M Cost	$0 00
	($MM)
Total Capital Cost($94)	$0 00
Total O&M Cost($94)	$0 00
Total Cost($94)	$0 00
Annual Capital Cost(nominal)	$0 00
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu Cost	$0 000

Bataan Distribution

	($MM)
Volume	450
Capital Cost($94)	$16 61
Total Cost($94)	$19 94
Total Annual Cost(nominal)	$1 56
Levelized $/MMBtu	$0 01

Manila Distribution

	($MM)
Volume	0
Capital Cost($94)	$0 00
Total Cost($94)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu	$0 000

Batangas Distribution

	($MM)
Volume	0
Capital Cost ($94)	$0 00
Total Cost($94)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu	$0 000

Extension (Bataan to Manila)

Offshore Segment	
	(94$MM)
Pipe Coating	$6 30
Installation	$10 50
Compressor	$0 00
Material Cost	$9 41
Annual O&M Cost	$0 00
	($MM)
Total Capital Cost($94)	$0 00
Total O&M Cost($94)	$0 00
Total Cost($94)	$0 00
Annual Capital Cost(nominal)	$0 00
Annual O&M Cost(nominal)	$0 00
Total Annual Cost(nominal)	$0 00
Levelized $/MMBtu Cost	$0 000

Conditionals

Bataan to Manila	0
Manila to Batangas	0

LNG Cost Calculator

	Total	Capital	Annual	$/MMBtu
Base	$8 081	$4 048	$785	
To Bataan	$8 081	$4 065	$787	$5 43
To Manila	$0	$0	$0	$0 00
To Batang	$0	$0	$0	$0 00
Total	$8 081	$4.065	$787	$5 43

	LNG	Extension
Bataan Market %	100 00%	n/a
Manila Market %	0 00%	0 00%
Batangas Market %	0 00%	0 00%

APPENDIX C
SHELL/OXY SERVICE CONTRACT PROVISIONS RELATING TO NATURAL GAS PIPELINE

SHELL/OXY SERVICE CONTRACT
PROVISIONS RELATING TO NATURAL GAS PIPELINE

Shell Exploration B.V. and Occidental Philippines, Inc. (the "Contractor") entered into a Service Contract and a Memorandum of Clarification[1] with the Government of the Republic of the Philippines on December 11, 1990. The provisions of these agreements indicate that the Contractor has an obligation to construct a natural gas pipeline from the Contractor's offshore wellheads to the final delivery point to the buyer. The Contractor will own the pipeline and is entitled to the recovery of the cost of the pipeline as an Operating Expense. Specifically, the pertinent provisions of the Service Contract and Memorandum of Clarification are as follows:

- The Memorandum of Clarification expands the definition of "Petroleum Operations" found in the Service Contract to include both "transportation of Natural Gas by pipeline up to final delivery point to the buyer or buyers thereof and facilities upstream of the sales point for extraction of liquid hydrocarbons from Natural Gas."

- Section 6.1 of the Service Contract states that "Contractor shall have the following obligations: (a) perform all Petroleum Operations . . .."[2]

- Section 7.1 of the Service Agreement provides for the Contractor's recovery of all "Operating Expenses" which are defined in section 2.19 to include "the total expenditures incurred by the Operator within and without the Philippines in Petroleum Operations." The second sentence in section 2.19 expressly includes the "construction of . . . pipelines . . . and the cost of operating and maintaining all such facilities" in the definition of Operating Expenses.[3]

- According to section 11.2 the natural gas pipeline would remain the property of the Contractor until the Contractor had fully recovered its investment at which time the Contractor will transfer ownership to the Philippine government, but only after the Contractor has concluded its use of the pipeline.

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1 The Memorandum of Clarification is a separate agreement between the parties that was executed concurrently with the Service Contract.

2 Note that the Contractor has an obligation and not a right (Contractor's rights are defined in Section 6.2) to perform all Petroleum Operations. The legal distinction between the terms obligation and right may very well determine whether or not the Contractor may choose to press ahead with the construction, ownership, and operation of a natural gas pipeline without the Philippine government's cooperation.

3 The Natural Gas pipeline would likely be classified as a Tangible Investment as defined in Annex B section 13A.

APPENDIX D
MODEL GAS SALES AND PURCHASE AGREEMENT

GAS SALES AND PURCHASE AGREEMENT

between

[NAME OF SELLER]

and

[NAME OF BUYER]

Dated as of:

[DATE]

(ABRIDGED FOR TRANSLATION -- NOT FOR LEGAL PURPOSES)

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NOTE: Portions of the following material have been adapted, or taken verbatim in cases, from existing gas transportation and supply contracts offered by major U.S. pipeline and producing companies.

GAS SALES AND PURCHASE AGREEMENT

This Gas Sales and Purchase Agreement is entered into as of [DATE] between [NAME OF BUYER] ("Buyer") located at [ADDRESS] and [NAME OF SELLER] ("Seller"), a corporation organized and validly existing under the laws of [STATE], having an office for the transaction of business at [ADDRESS].

INTRODUCTION

WHEREAS, Seller has Gas supplies available to it in various locations reasonably accessible to the transportation facilities of [NAME OF PIPELINES] ("Transporting Pipelines"), which are and will be available for sale from time to time;

WHEREAS, Buyer has firm transportation rights and is seeking to purchase Gas supplies on a Firm Basis; and

WHEREAS, Seller and Buyer desire to enter into a Gas Purchase Agreement relating to the sale and purchase of such available Gas supplies;

NOW, THEREFORE, in consideration of the mutual promises and agreements in this Gas Purchase Agreement, Seller and Buyer today agree to bind themselves as follows:

ARTICLE I - DEFINITIONS

1.1 The term "Commodity Charge" shall mean the fee which Buyer shall pay Seller for each cubic meter of Gas that Seller delivers to the Delivery Point for Buyer's account.

1.2 The term "Cubic Meter" or "m^3" shall mean that volume of Gas which occupies one cubic meter when such Gas is at a temperature of fifteen degrees Celsius (15°C) and at a pressure of one hundred-and-one and three hundred-and-twenty-five thousandths (101.325) kiloPascals ("kPa") absolute.

1.3 The term "Day" shall mean a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

1.4 The term "Firm Basis" shall mean that Gas will be available for delivery and sale by Seller to Buyer without interruption unless such sale or delivery interruption is excused by, or authorized by, other provisions of this Gas Purchase Agreement.

1.5 The term "Gas" shall mean the methane, ethane and heavier hydrocarbons remaining in the vapor phase of gas-well Gas, oil-well Gas, or the combination of both delivered at the Delivery Point.

1.6 The term "Gas Purchase Agreement" shall mean this Gas Sales and Purchase Agreement.

1.7 The term "Month" shall mean a calendar month.

1.8 The term "Parties" shall refer to the Seller and the Buyer.

1.9 The term "Reservation Charge" shall mean the monthly fee as described in Article VII of this Gas Purchase Agreement which Buyer has agreed to pay to Seller for the right to call upon a certain volume of Gas on a Firm Basis.

1.10 The term "1,000 Cubic Meters" or "10^3m^3" shall mean one thousand (1,000) cubic meters.

ARTICLE II - QUANTITY

2.1 Buyer and Seller agree that Buyer will have the right to call upon Seller to deliver and sell up to [QUANTITY] 10^3m^3 ("Maximum Daily Quantity") on a Firm Basis and that Buyer shall exercise its rights by making a monthly nomination in accordance with the procedure for nominations provided in Article IV of this Gas Purchase Agreement.

2.2 Subject to the terms and conditions hereof, Seller agrees to sell and deliver or have delivered on a Firm Basis that volume of Gas which may be nominated each Month by Buyer, and Buyer agrees to purchase such nominated volumes, such volume not to exceed the Maximum Daily Quantity.

2.3 Seller reserves unto itself the sole and exclusive right to manage its Gas supply available to Buyer without interference of Buyer or third parties.

2.4 On a rolling twelve-Month basis, Buyer shall provide Seller with a list of projected volumes that may be nominated by Buyer for each of the next twelve Months. Such list of projected volumes shall be used for supply management purposes by Seller and is non-binding upon the Buyer.

2.5 All quantities of Gas sold pursuant to this Gas Purchase Agreement shall be delivered within the constraints of the Transporting Pipelines' nomination and dispatch requirements. Delivery obligations pursuant to this Gas Purchase Agreement shall be adjusted by and constrained by such pipeline requirements. Seller and Buyer shall take reasonable steps to properly arrange for the nomination, dispatch, and delivery of Gas, and to arrange for required transportation in order to carry out the intent of and obligations of this Gas Purchase Agreement.

ARTICLE III - DELIVERY POINT

3.1 Seller shall arrange and be responsible for the delivery of the volumes purchased herein to the Delivery Point [TO BE SPECIFIED IN A SEPARATE EXHIBIT] at which all of Seller's Gas is to be delivered to Buyer.

3.2 Over time, one of the Parties may desire to change the Delivery Point on Transporting Pipelines' system. Upon receipt of written notice of such proposed Delivery Point changes, the Parties will use all reasonable efforts to obtain authorization from the Transporting Pipelines for the use of such points for deliveries, subject to applicable transportation contracts and tariffs. Once authority for Delivery Point changes has been obtained from the Transporting Pipelines, the Parties agree that such new or changed Delivery Point shall constitute an amendment to the Gas Supply Agreement and shall thereafter be used for the delivery of Gas hereunder, subject to the terms of this Gas Purchase Agreement and the terms and conditions of the applicable transportation contracts and tariffs.

3.3 Title to all Gas delivered hereunder shall pass to Buyer at the Delivery Point.

ARTICLE IV - NOMINATIONS

4.1 For each Month, Buyer will nominate the average daily volumes Buyer intends to purchase the following Month. Such nominations must be submitted to Seller in writing by telefax transmission no later than five (5) business Days preceding the date nominations are due to the Transporting Pipeline. Buyer has a right to nominate up to the Maximum Daily Quantity and Seller shall have no obligation to deliver a volume in excess of this amount. Any volumes within this entitlement not nominated by Buyer in accordance with the above time schedule shall be deemed released that Month by Buyer, and Seller may dispose of such volumes at its sole discretion.

4.2 Seller shall confirm such nomination from Buyer in writing by submitting to Buyer the volume of Gas to be delivered at the designated Delivery Point. Buyer and Seller shall communicate these nominations as appropriate to the Transporting Pipeline within scheduling deadlines. Such written confirmation may be made by telefax or other electronic media communication.

4.3 Seller shall make arrangements to tender Buyer's nominated volumes at the agreed upon Delivery Point.

ARTICLE V - TRANSPORTATION

5.1 Buyer and Seller agree and understand that transportation of all volumes sold and delivered hereunder shall be provided by third parties, primarily Transporting Pipelines. Buyer represents and warrants that it has firm transportation rights necessary to satisfy its obligations under this Gas Purchase Agreement. Buyer shall be responsible for transportation of volumes from the Delivery Point to Buyer's markets. Seller shall be responsible for transportation from the production area to the Delivery Point. Buyer and Seller shall maintain appropriate contracts with Transporting Pipelines so that each can receive and deliver volumes pursuant to this Gas

Purchase Agreement; however, neither Party shall be obligated to accept terms or conditions which would adversely affect its ability to perform under this Gas Purchase Agreement. If either Party determines the such terms or conditions are unreasonable, such Party shall so inform the other. Within thirty (30) Days after nomination, the Parties shall either modify this Gas Purchase Agreement to reflect the revised responsibility for such terms which have been deemed unreasonable, or modify this Gas Purchase Agreement to reflect the appropriate reduction in the Maximum Daily Quantity listed herein which is affected by such changes in terms or conditions.

5.2 Seller shall hold Buyer harmless for all costs and penalties which may be assessed by a Transporting Pipeline against Seller prior to the Delivery Point as a result of over or under delivery of Gas. Buyer shall hold Seller harmless for all costs and penalties which may be assessed by a Transporting Pipeline against Buyer at or after the Delivery Point. If any such costs or penalties become likely, the Party becoming aware that such costs may be assessed shall inform the other Party in writing as soon as Party becomes aware. Each Party shall immediately work with the other Party to minimize or eliminate, if possible, such costs or penalties. The Parties shall work with each other and with the Transporting Pipelines to verify delivery and receipt of nominated volumes on a timely basis.

5.3 Notwithstanding anything to the contrary in this Article, in the event a Transporting Pipeline substantially changes its rates which results in higher transportation charges to Seller, the Parties agree to meet promptly to renegotiate this Article. Within thirty (30) Days after notification of such change in transportation costs, the Parties shall modify this Gas Purchase Agreement to reflect any revisions or additions necessary to accommodate these changes and determine the appropriate cost apportionment. If the Parties are unable to reach agreement within such time period, either Party may refer the matter to arbitration as described in Article XVII. Any modifications to this Gas Purchase Agreement, determination of

cost apportionment, or other provision determined in arbitration, shall be effective on the first Day of the Month following the arbitrators' decision.

ARTICLE VI - BILLING AND PAYMENT

6.1 On or about the fifteenth (15th) Day of the Month following deliveries hereunder, Seller shall render to Buyer an invoice showing the Gas volume delivered during the previous Month and the Reservation Charge payable for the following Month. Adjustments, when required, shall be made in Seller's succeeding Month's statement to the fullest extent practical.

6.2 Buyer shall pay Seller within fifteen (15) Days of receipt of an invoice in accordance with Seller's statement or invoice by electronic funds transfer to Seller's account as specified in Article XX. If Buyer does not pay Seller within such time, Seller, in addition to other options which may be available, may stop deliveries hereunder. Interest shall accrue on any late payment by Buyer, except for bona fide disputes of invoiced amounts, at the [PREVAILING, AUTHORIZED RATE OF INTEREST].

6.3 Each Party hereto shall have the right at all reasonable times to examine the books and records of the other Party to the extent necessary to verify the accuracy of any statement, charge, computation, invoice or demand made pursuant to this Gas Purchase Agreement. Any payment shall be final as to both Parties unless questioned within two (2) calendar years from the date of such payment.

6.4 If during the term of this Gas Purchase Agreement, Seller determines that the financial viability of Buyer has become impaired or unsatisfactory, advance cash payment prior to delivery of Gas or other satisfactory security acceptable by Seller shall be given by Buyer upon demand by Seller and delivery of Gas may be withheld until such advance payment or other security is received. If such payment or assurance is not received within thirty (30) Days of demand, Seller may terminate this Gas Purchase Agreement at any time thereafter upon notice to

Buyer. If there are instituted by or against Buyer proceedings in bankruptcy or under any insolvency law, Seller may terminate this Gas Purchase Agreement at any time.

ARTICLE VII - RESERVATION CHARGE

7.1 Buyer shall pay Seller in accordance with Article VI each month a Reservation Charge equal to the product of the Reservation Rate of [RATE] per 10^3m^3 and the Maximum Daily Quantity.

7.2 The Reservation Charge may be renegotiated pursuant to the provisions of Article XVII.

ARTICLE VIII - COMMODITY CHARGE

8.1 For each 10^3m^3 of Gas delivered to Buyer by Seller at the mutually agreed upon Delivery Point, Buyer shall pay Seller a Commodity Charge which will be equal to the price specified in the [REFERENCE PUBLICATION TABLE] published in the first issue of each Month by [REFERENCE PUBLICATION]. In the event the [REFERENCE PUBLICATION TABLE] ceases to be published by [REFERENCE PUBLICATION], the categories change, or the index is not representative of the market price of the Gas delivered, then the Parties shall mutually agree on a substitute index or pricing mechanism upon which to base the Commodity Charge. If Buyer and Seller are unable to agree upon an alternate index or pricing mechanism, either Party may initiate arbitration solely to determine the Commodity Charge in a manner similar to that described in Article XVII. The Commodity Charge resulting from arbitration shall become effective on the first Day of the Month following the arbitrators' decision and shall remain in effect until renegotiated by the Parties pursuant to Article XVII.

8.2 In addition to any of the changes necessitated by Paragraph 8.1, the Commodity Charge may be renegotiated pursuant to the provisions of Article XVII.

ARTICLE IX - WARRANTY

If either Party is unable, in whole or in part, to perform its obligation under this Gas Purchase Agreement for any reason, such Party shall curtail the other Party on a pro-rata basis with its other comparable Firm Basis contract commitments involving transportation on facilities operated by Transporting Pipelines, recognizing that such contractual agreements have a higher priority for performance than interruptible or best-efforts agreements. For purposes thereof, comparable Firm Basis contract commitments shall mean those having an initial term in excess of one (1) year. In the event either Party fails to perform its obligations under this Gas Purchase Agreement for any reason, then the other Party shall use its best efforts, in a commercially reasonable manner, to mitigate the efforts of such failure. Seller hereby warrants that it will make the Maximum Daily Quantity available to Buyer on a Firm Basis, if nominated by Buyer, subject to all of the terms and conditions of this Gas Purchase Agreement. Seller's obligation to make volumes available shall be excused during events of force majeure, and for other reasons described in other pertinent provisions of this Gas Purchase Agreement. In the event that Seller is unable or fails to make volumes available to Buyer in accordance with this Gas Purchase Agreement, Seller shall not charge Buyer for that portion of the Reservation Charge applicable to the Days and the volumes during which Seller did not perform or shall reimburse Buyer if such amount has already been paid. In the event that Seller's deliveries to Buyer consistently or repeatedly fall materially below Buyer's nominations, then Buyer may cancel this Gas Purchase Agreement upon thirty (30) Days written notice.

ARTICLE X - FORCE MAJEURE

10.1 The term force majeure shall mean acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, storms, floods, washouts, arrests, the order of any court or governmental

authority having jurisdiction prohibiting service or performance, while the same is in force and effect, civil disturbances, explosions, breakage, accident to machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, not including shortages of gas supply or curtailment therefore, inability to obtain or unavoidable delay in obtaining material, equipment, easements, franchises, permits, or authorization and any other causes whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension and which by the exercise of due diligence such Party is unable to prevent or overcome.

10.2 The loss of markets to other gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure.

10.3 In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Gas Purchase Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax or telegraph to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

ARTICLE XI - MEASUREMENT AND TESTING

11.1 Volumes delivered to the Delivery Point hereunder shall be measured and tested according to generally accepted industry standards and measurement and testing provisions contained in the general terms and conditions of the Transporting Pipeline's effective tariff.

11.2 The total amount of Gas delivered and purchased herein shall be determined by multiplying the measured volumes in 10^3m^3 by the heat content of such Gas expressed on a dry basis.

ARTICLE XII - QUALITY

It is understood by the Parties that delivery of the volumes hereunder shall be of the pressure and quality existing in the Transporting Pipeline into which, and at time or times when, delivery is made. Either Party may at any time and from time to time, upon written notice to the other, elect to cease deliveries or takes of any or all volumes that do not meet the required quality specifications of any Transporting Pipeline required to deliver such volumes until such time as quality of said delivery or deliveries again meets the Transporting Pipeline's requirement specifications. If this provision is invoked by Seller and such event is not covered by force majeure, then Seller's obligations as expressly stated in Article IX shall apply.

ARTICLE XIII - TITLE

Seller warrants that it has good and lawful authority to sell the volumes delivered, and that such volumes are free from all liens and adverse claims of any kind or character. Seller agrees to indemnify and hold Buyer harmless from all claims, suits, actions, debts, accounts, damages, costs, losses and expenses of every kind and character arising out of any adverse claim to or against title to such Gas.

ARTICLE XIV - ASSIGNMENT

14.1 This Gas Purchase Agreement shall inure to the benefit and be binding upon the successors and assigns of the Parties; provided, that neither Party shall assign this Gas Purchase Agreement and the rights without first having obtained the written approval of the other Party.

14.2 No conveyance or transfer of any interest in this Gas Purchase Agreement by either Party shall be binding upon the other Party, unless and until such other Party has been furnished

with written notice and, in the event of a conveyance or transfer of an interest in real estate, a recorded copy of the instrument of assignment.

ARTICLE XV - LIABILITY

15.1 Each Party shall assume full responsibility and liability for the maintenance and operation of its properties and shall indemnify and hold harmless the other Party from all liability and expense on account of any and all damages, claims or actions, including injury to and death of persons, arising from any act or accident in connection with the installation, maintenance and/or operation of the property and equipment of the indemnifying Party, its agents or employees.

15.2 Seller shall be deemed to be in control and in possession of the volumes and responsible, as between the Parties, for any damage, injury, or penalty caused or associated with such volumes until such volumes shall have been delivered to the Delivery Point, and Seller shall indemnify and hold Buyer harmless for any and all claims, losses, damages and costs, including reasonable fees of attorneys, arising from such actions.

ARTICLE XVI - TERM

This Gas Purchase Agreement will become effective on the date of execution and shall continue in effect for [NUMBER OF YEARS] years following the initial delivery date subject to and conditioned upon pertinent provisions as more specifically set forth herein. This Gas Purchase Agreement may be extended year to year thereafter upon mutual agreement of the Parties.

ARTICLE XVII - RENEGOTIATION AND ARBITRATION

17.1 On or before [DATE] of each second year thereafter, or as otherwise described in this Gas Purchase Agreement, either Party may request renegotiation of the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligations, and/or other cost sharing provisions of the Gas

Purchase Agreement. The Parties shall meet and attempt to agree on such renegotiated provisions, and any modifications to this Gas Purchase Agreement resulting from such renegotiations shall become effective on [DATE] of the applicable year. If nether Party requests renegotiation of the applicable terms by [DATE] of the applicable year, then the terms and conditions that exist on [DATE] of the applicable year shall continue in full force and effect.

17.2 In the event Buyer and Seller cannot agree on the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligations, and/or other cost sharing provisions, then either Party may submit such matter to arbitration in accordance with this and the following Paragraphs, it being understood that only the issue of determining the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligation, and/or other cost sharing provisions shall be subject to arbitration. While these matters are subject to arbitration, the terms and conditions which existed on [DATE] of that year shall continue in full force and effect. The charges and other provisions determined through arbitration will become effective the Day following the arbitrator's decision and will remain in effect until renegotiated as specified herein.

17.3 Either Party may initiate arbitration by written notice to the other Party within sixty (60) Days after the applicable date when renegotiated provisions for Commodity Charge, Reservation Charge, transportation provisions, and/or other cost sharing provisions were to become effective pursuant to Paragraph 17.1.

(a) Arbitration will be deemed to be initiated when timely written notice, properly addressed and stamped, is sent by ordinary mail. The Party initiating arbitration shall nominate one (1) arbitrator at the same time it initiates arbitration. The other Party shall nominate one (1) arbitrator within ten (10) Days of receiving the notice or arbitration, failing which

the initiating Party shall nominate a second arbitrator. The two arbitrators shall appoint a third, neutral arbitrator. The third, neutral arbitrator shall be competent and experienced in matters involving the natural gas business, and shall be unaffiliated and without prior financial alliances with either Party, or either of the other arbitrators.

(b) If the two arbitrators are unable to agree on a third arbitrator within sixty (60) Days from initiation of arbitration, then a third arbitrator shall be selected by [AN INDEPENDENT PARTY] with due regard given to the selection criteria above and input from the Parties and other arbitrators. Parties shall undertake to request [AN INDEPENDENT PARTY] to complete selection of the third arbitrator no later than ninety (90) Days from initiation of arbitration. Costs charged by [AN INDEPENDENT PARTY] for this service shall be borne equally by Buyer and Seller.

(c) If [AN INDEPENDENT PARTY] fails to select the third arbitrator within ninety (90) Days from initiation of arbitration, then either Party may petition a court of competent jurisdiction to select the third arbitrator. Due regard shall be given to the selection criteria above and input from the Parties and other arbitrators.

17.4 Once the third arbitrator is appointed, the Parties shall seek to cause the arbitrators to promptly hear and determine (after due notice of hearing and giving the Parties a reasonable opportunity to be heard) the matter of reviewing and determining the Commodity Charge, Reservation Charge, transportation provisions, and/or other cost sharing provisions subject to the following:

(a) In determining the Reservation Charge, the arbitrators shall consider the costs associated with the acquisition of and the value of maintaining Gas supply in accordance with this Gas Purchase Agreement and

other reservation charges or compensation paid by Buyer for similar services. However, in no event shall the Reservation Charge (at a 100 percent load factor) be less than [AGREED-UPON FIXED PERCENTAGE] of the applicable Commodity Charge escalated at [APPLICABLE INFLATION RATE] per year.

(b) The Commodity Charge shall be established in a manner similar to the initial indexed pricing, shall reflect the market prices for comparable Gas supplies, and shall be no less than the prices paid on Transporting Pipelines' system for similar Gas purchases from similar supply sources.

(c) In establishing the provisions for transportation, Buyer shall pay for all of the costs of transportation including any applicable third-party transportation costs.

17.5 The Parties anticipate that the arbitrators will permit liberal discovery between the Parties, and will issue whatever subpoenas are considered necessary, consistent with applicable law, in order to review and determine these charges and provisions in a fair manner.

17.6 The written decision rendered by the arbitrators, or a majority of the arbitrators, shall be final and binding upon the Parties. The expenses of arbitration shall be borne equally by the Parties, except that each Party shall bear the compensation and expenses of its own counsel, witnesses and employees; provided further, that any costs incurred by a Party in seeking judicial enforcement of any written decision rendered by the arbitrators, or a majority of the arbitrators, shall be chargeable to and borne exclusively by the Party against whom such court order is obtained.

ARTICLE XVIII - REGULATIONS AND LAWS

18.1 In selling and delivering the Gas hereunder, Seller is doing so as a private company and not as a public utility. Seller does not dedicate its production or any of its facilities

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to public use. Seller does not sell or deliver Gas to the public. If any regulatory agency, at any time, shall attempt to assert public utility jurisdiction over Seller by reason of this Gas Purchase Agreement, Seller may, at its sole option, cancel and terminate this Gas Purchase Agreement, notwithstanding anything to the contrary in any other provision of this Gas Purchase Agreement.

18.2 The sale and delivery of the Gas by Seller and the purchase and receipt thereof by Buyer are subject to all valid legislation with respect to the subject matter hereof and to all valid present and future orders, rules and regulations of duly constituted authorities having jurisdiction.

18.3 If all or any portion of the Gas sold and delivered hereunder is conditioned upon or affected by regulatory or governmental approvals, terms, conditions or restrictions during the effectiveness of this Gas Purchase Agreement, the Party so affected may notify the other Party as to said regulatory or governmental approval, term, condition or restriction and may reduce its obligation hereunder for either the sale or purchase, as appropriate, of the volume of Gas affected provided that such Party shall curtail the other Party on a pro-rata basis based upon other Firm Basis contract commitments, recognizing that Firm Basis agreements shall have a higher priority for performance than interruptible or best-efforts agreements.

18.4 This Gas Purchase Agreement shall be governed and construed in accordance with the laws of [STATE], excluding any conflicts of law, rule, or other principle which might refer such construction to the laws of another state.

18.5 If any provisions of this Gas Purchase Agreement shall be held invalid or unenforceable to any extent and for any reason by a court of competent jurisdiction, the remainder of this Gas Purchase Agreement shall not be affected thereby and shall be enforceable to the full extent permitted by law.

ARTICLE XIX - TAXES

19.1 Seller agrees to bear and pay, or cause to be paid, all gross production, severance, and other taxes now and hereafter required by law to be paid to governmental authorities with respect to the production of Gas prior to the Delivery Point. Buyer shall pay, or cause to be paid, all taxes which may be imposed on or with respect to the Gas at or after its delivery at the Delivery Point.

19.2 Buyer agrees that the sales price provided for hereunder excludes any state or local sales or use taxes required to be paid in connection with the sale of Gas pursuant to this Gas Purchase Agreement. Notwithstanding any provision contained under this Gas Supply Agreement to the contrary, all sales or use taxes imposed by law in connection with the sale of Gas under this Gas Purchase Agreement may be collected from Buyer and remitted by Seller to the appropriate taxing jurisdictions, unless Buyer issues Seller a valid sales and use tax exemption certificate for the state in which the sale of Gas took place.

ARTICLE XX - MISCELLANEOUS

20.1 Any notice, request, statement, bill or payment provided in this Gas Purchase Agreement between Buyer and Seller shall be in writing. Such notice may be transmitted via ordinary mail, telefax or acceptable means of electronic transfer; however, telefaxed notices shall be followed up by ordinary mail as soon as possible.

20.2 Any notice shall be considered as duly delivered as of the earlier of the receipt date indicated on the telefax, date of acceptable electronic transmission or the postmark date when mailed by ordinary mail to the other Party at the following address:

(a)	Notice to Seller:	[SELLER'S ADDRESS]
(b)	Payment to Seller:	[SELLER'S ADDRESS AND WIRE TRANSFER ACCOUNT NUMBER]
(c)	Notice to Buyer:	[BUYER'S ADDRESS]

(d) Statement to Buyer: [BUYER'S ADDRESS]

20.3 Either Buyer or Seller may change its address under this Article by giving written notice to the other Party.

20.4 This written Gas Purchase Agreement contains the entire Gas Purchase Agreement between the Parties, and there are no other understandings or representations between the Parties hereto. This Gas Purchase Agreement may not be amended except by an instrument in writing signed by a duly authorized representative or each Party.

20.5 The failure of either Party at any time to exercise any right or to require performance by the other Party of any provision herein shall in no way affect the right of such Party thereafter to enforce the same, nor shall the waiver by either Party hereto of any breach of any provision herein by the other Party be a waiver of any other breach of such provision, or as a waiver of the provision itself.

20.6 The title headings are for identification and reference only and shall not be used in interpreting any part of this Gas Purchase Agreement.

IN WITNESS WHEREOF, the Parties have duly executed this Gas Purchase Agreement by their proper officers or representatives:

SELLER	BUYER
_____	_____
Name	Name
_____	_____
Title	Title
_____	_____
Date	Date

APPENDIX E
MODEL GAS TRANSPORTATION AGREEMENT

GAS TRANSPORTATION AGREEMENT

between

[NAME OF TRANSPORTER]

and

[NAME OF SHIPPER]

Dated as of:

[DATE]

(ABRIDGED FOR TRANSLATION -- NOT FOR LEGAL PURPOSES)

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NOTE: Portions of the following material have been adapted, or taken verbatim in cases, from existing gas transportation and supply contracts offered by major U.S. pipeline and producing companies.

GAS TRANSPORTATION AGREEMENT

This Gas Transportation Agreement is entered into as of [DATE] between [NAME OF SHIPPER] ("Shipper") located at [ADDRESS] and [NAME OF TRANSPORTER] ("Transporter"), a corporation organized and validly existing under the laws of [STATE], having an office for the transaction of business at [ADDRESS].

INTRODUCTION

WHEREAS, Transporter owns and operates a high-pressure natural gas pipeline located in close proximity to Shipper's facilities;

WHEREAS, Shipper requires transportation and delivery of [QUANTITY] thousand cubic meters ("10^3m^3") per day of natural gas on Transporter's gas pipeline system on a firm basis, subject to the terms and conditions of this Transportation Agreement;

WHEREAS, Transporter will construct, install and operate facilities, as required, and provide firm transportation for Shipper on its gas pipeline system from the Point of Receipt to the Point of Delivery; and

WHEREAS, Shipper will construct, at its sole cost and expense, and to Transporter's construction standards and practices, a gas service lateral to be used to transport the Shipper's Gas between Shipper's facilities and Transporter's nearby pipeline;

NOW, THEREFORE, in consideration of the mutual promises and agreements in this Transportation Agreement, Shipper and Transporter today agree to bind themselves as follows:

ARTICLE I - DEFINITIONS

1.1 The term "Contract Year" shall refer to the annual period from April 1 of any calendar year to March 31 of the next succeeding calendar year.

1.2 The term "Cubic Meter" shall mean that volume of gas which occupies one cubic meter, when such gas is at a temperature of fifteen degrees Celsius (15°C) and at a pressure of one

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hundred-and-one and three hundred-and-twenty-five thousandths (101.325) kiloPascals ("KPa") absolute.

1.3 The term "Day" shall mean a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

1.4 The term "Maximum Daily Quantity" ("MDQ") shall mean the maximum volume of gas that Shipper can nominate in one day, which is [QUANTITY] 10^3m^3 per day in this Agreement.

1.5 The term "Parties" shall refer to the Transporter and the Shipper.

1.6 The term "Point of Delivery" shall refer to the point at which all of Shipper's Gas transported by Transporter is delivered to Shipper. Such point shall be the outlet of the Transporter's meter located at the Shipper's facility [TO BE SPECIFIED IN A SEPARATE EXHIBIT].

1.7 The term "Point of Receipt" shall refer to the point at which all of Shipper's Gas is tendered by Shipper to Transporter for transportation [TO BE SPECIFIED IN A SEPARATE EXHIBIT].

1.8 The term "Shipper's Gas" shall include all gas belonging to Shipper and transported by Transporter.

1.9 The term "Transporter Standard Tariff Rate" shall refer to the lowest rate per 10^3m^3 (at a 100 percent load factor) for gas transportation service under Transporter's approved Schedule for Gas Service in effect on that day, or, if that tariff rate is eliminated, such other rate that Shipper would have been eligible for if it had not entered into this Transportation Agreement.

ARTICLE II - SCOPE OF TRANSPORTATION SERVICE

Transporter agrees to transport on a firm basis, from the Point of Receipt to the Point of Delivery, for the Shipper's benefit, such quantities of gas as Shipper may from time to time tender to Transporter for transportation.

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ARTICLE III - REPRESENTATIONS AND WARRANTIES

3.1 Shipper makes the following representations and warranties at this time:

(a) Shipper is a corporation duly organized, validly existing and qualified to do business under the laws of [STATE], and is duly authorized to execute this Transportation Agreement and consummate the transactions herein contemplated.

(b) This Transportation Agreement is the legal, valid and binding obligation of Shipper enforceable in accordance with its terms.

3.2 Transporter makes the following representations and warranties at this time:

(a) Transporter is a corporation duly organized, validly existing and qualified to do business under the laws of [STATE], and is duly authorized to execute and deliver this Transportation Agreement and consummate the transactions herein contemplated.

(b) This Transportation Agreement is the legal, valid and binding obligation of Transporter enforceable in accordance with its terms.

ARTICLE IV - TERM OF TRANSPORTATION AGREEMENT

4.1 The term of this Transportation Agreement shall commence on [DATE], and shall continue until [DATE].

4.2 This Transportation Agreement is subject to approval by the [RELEVANT AUTHORITY]. After this Transportation Agreement has been fully executed, Transporter shall promptly file the Transportation Agreement with the [RELEVANT AUTHORITY] for its approval. If the [RELEVANT AUTHORITY] requires a change in this Transportation Agreement, or imposes any other material condition to its approval, or otherwise takes action with respect to this Transportation Agreement that is unacceptable to either Party, the Parties shall, within the next thirty (30) Day period, use their best efforts in good faith to agree upon a mutually satisfactory amendment to this Transportation Agreement, and to

resubmit this Transportation Agreement, as so amended, for any necessary further approval by the [RELEVANT AUTHORITY].

4.3 Firm transportation service shall commence as soon as possible after all necessary facilities have been constructed and placed in operation, and all necessary regulatory authorizations have been received and accepted.

ARTICLE V - TRANSPORTER'S OBLIGATIONS

5.1 The maximum amount of Shipper's Gas that Transporter shall be required to accept at the Point of Receipt for transportation on behalf of Shipper to the Point of Delivery on any Day shall be the MDQ.

5.2 Transportation of Shipper's Gas under this Transportation Agreement shall be on a firm basis, and shall not be subject to interruption or curtailment except as caused by force majeure conditions beyond Transporter's or Shipper's control.

ARTICLE VI - PRESSURE AND QUALITY

6.1 All gas delivered by Shipper to Transporter at the Point of Receipt shall be at such delivery pressures as are required from time to time by Transporter, up to a maximum of [MAXIMUM RECEIPT PRESSURE]. All of Shipper's Gas delivered by Transporter to Shipper at the Point of Delivery shall be at such delivery pressures as are available from time to time to Transporter at such point, up to a maximum of [MAXIMUM DELIVERY PRESSURE] but not lower than [MINIMUM DELIVERY PRESSURE].

6.2 The Parties recognize that the natural gas delivered by Shipper for transportation at the Point of Receipt will necessarily be mixed in Transporter's gas pipeline system with gas received from other sources, and that the specific gas delivered to Transporter cannot be redelivered for Shipper's account. It is further agreed that the natural gas delivered to and by Transporter shall be merchantable natural gas.

6.3 All gas tendered by Shipper for transportation under this Transportation Agreement shall, have a total heating value

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of not less than [MINIMUM ENERGY CONTENT] and not more than [MAXIMUM ENERGY CONTENT]. The natural gas received by Transporter and delivered for the account of Shipper:

(a) Shall be free from objectionable odors, dust, gums or gum-forming constituents, or other solid or liquid matter which might interfere with its salability, or injure or interfere with proper operation of the lines, regulators, meters or other appliances through which it flows;

(b) Shall contain no more than 20 parts per million of total sulphur by weight of gas, nor more than 10 parts per million of hydrogen sulfide by weight of gas volume when tested in accordance with the following procedure: A strip of white filter paper previously moistened with fresh 5 percent lead acetate solution shall be exposed to the gas for one and one-half minutes in a previously purged apparatus through which the test gas is flowing at a rate of approximately 0.15 cubic meters per hour; the gas jet shall not directly impinge upon the test strip during the test. At the end of the stated time, the test paper thus exposed shall be compared with a second test strip similarly prepared but not exposed to the test gas. If the exposed strip is not noticeably darker than the comparison strip, the gas under the test shall be considered acceptable. If the exposed strip is noticeably darker than the comparison strip, the gas shall be tested quantitatively for hydrogen sulfide by the Tutweiler or other approved method;

(c) Shall be odorized, except when the transportation and delivery by Transporter of gas that is not odorized is permitted under safety regulations, and Shipper requests and Transporter agrees that gas delivered for the account of Shipper shall not be odorized, and Shipper in writing agrees to perform necessary odorization prior to final consumption;

(d) Shall not at any time have an uncombined oxygen content in excess of 1 percent by volume, and the Parties shall make every reasonable effort to keep the gas free from oxygen;

(e) Shall not at any time have a carbon dioxide and nitrogen content in excess of 4 percent by volume, and carbon dioxide content shall not at any time exceed 3 percent by volume.

(f) Shall not be delivered at a temperature of more than 49 degrees Celsius (49°C);

(g) Shall not contain more than 65 milligrams of water vapor per cubic meter.

6.4 If the natural gas offered to Transporter for transportation shall fail at any time to conform to the pressure or quality specifications set forth in this Article, then Transporter may refuse to accept delivery. Likewise, if the natural gas offered by Transporter for delivery for the account of Shipper fails at any time to conform to any of the specifications set forth in this Article, then Shipper may refuse to accept delivery pending correction by Transporter. Upon the failure of either Party promptly to remedy any deficiency in quality or pressure, then the other may make changes as may be necessary to bring such gas into conformity with such quality and pressure specifications.

ARTICLE VII - MEASURING AND METERING EQUIPMENT

7.1 The volume and the total heating value of the transportation gas received and delivered shall be determined as follows:

(a) The measurement unit of natural gas transported shall be one (1) cubic meter measured according to Boyle's Law for the measurement of gas under varying pressures with deviations therefrom as provided below, on the measurement basis hereinafter specified.

(b) The unit of volume for purposes of measurement of gas transported for the purposes of determination of

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equivalent volumes shall be one (1) cubic meter of natural gas as defined in Article I.

(c) The total heating value of the gas received at the Point of Receipt and delivered at the Point of Delivery, per cubic meter, shall be determined from a continuous sampling device, by chromatographic analysis, by periodically running a spot sample on a recording calorimeter, or by such other equipment or method as may be mutually agreed upon. The total heating value of the gas shall be determined by Transporter at each such point at least monthly or at other intervals of time as deemed necessary by either Party from a continuous sampling device or other methods mutually agreed upon. The total heating value of the gas so determined at each such point shall be deemed to remain constant until the next determination.

(d) For purposes of computing gas volumes, the temperature of the gas passing through the meters shall be determined for any Day by the continuous use of a recording thermometer so installed that it may properly record the temperature of the gas flowing through the meters.

(e) The specific gravity of the gas passing through each meter utilized shall be determined by the use of a recording gravitometer, from a continuous sample device, or by chromatographic analysis of approved type which shall be checked at least once each month by the use of any other approved method mutually agreed upon. The specific gravity of the gas so determined shall be deemed to remain constant until the next determination.

7.2 Orifice meters installed in measuring stations used in the measurement of the transportation gas to be received or delivered shall be operated in accordance with Specifications of the American Petroleum Institute ("API") Publication Number 2530

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as amended from time to time, including the API Publication for Determination of Supercompressibility Factor of Natural Gas or AGA Committee Report No. 8, titled "Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases." Turbine meters installed in measuring stations used in the measurement of the transportation gas to be received or redelivered shall be operated in accordance with specifications of the American Gas Association ("AGA") Committee Report #7 which is titled "Measurement of Gas by Turbine Meters." Any modification and amendment thereof as agreed upon by the Parties shall include the use of straightening vanes and pulsation and dampening equipment where necessary.

7.3 Shipper acting jointly with Transporter may install, maintain and operate, at its own expense, such check measuring equipment as desired, provided that such equipment shall be installed so as not to interfere with the operations of Transporter's measuring equipment.

7.4 All installations of measurement equipment applying to or affecting deliveries shall be made in such manner as to permit an accurate determination of the volume and total heating value of natural gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by Shipper in the installation, maintenance and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the quantity of gas delivered.

7.5 The characteristics of the measuring equipment will be as follows:

(a) The accuracy of the measuring equipment shall be verified at reasonable intervals and, if so requested, in the presence of representatives of both Parties, but neither Party shall be required to verify the accuracy of such equipment more frequently than once in any 30-Day period. In the event either Party shall notify the other Party that it desires a special test of any measuring equipment, the Parties shall cooperate to secure a prompt verification of the

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accuracy of such equipment. The expense of any such special test, if requested, shall be borne by the Party requesting the test if the measuring equipment tested is found to be in error by not more than two (2) percent.

(b) If upon test, any measuring equipment, including auxiliary instruments, is found to be in error in the aggregate by not more than 2 percent, previous recordings of such equipment shall be considered accurate in computing deliveries of gas, but such equipment shall be adjusted at once to record accurately.

(c) If upon test, any measuring equipment shall be found in the aggregate to be inaccurate by an amount exceeding 2 percent since the last preceding test, such equipment shall be adjusted at once to record accurately, and any previous recordings of such equipment shall be corrected to zero error for any period which is known definitely, but in case the period is not known or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test, but not exceeding a correction period of sixteen (16) Days.

7.6 In the event a meter is out of service or registering inaccurately, the quantities of gas received or redelivered during such period shall be determined as follows:

(a) By using the registration of any check meter or meters, if installed and accurately registering; or in the absence of subsection (a),

(b) By correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or in the absence of both subsections (a) and (b), then,

(c) By estimating the quantity received or redelivered by receipts or deliveries during periods under similar conditions when the meter was registering accurately.

7.7 Each Party shall preserve or cause to be preserved for mutual use all test data, charts, or other similar records in accordance with the applicable rules and regulations of the [RELEVANT AUTHORITY] with respect to the retention of such records.

ARTICLE VIII - RATE

8.1 On and after the date transportation service begins, Shipper shall pay to Transporter each month the following charges:

(a) A Monthly Demand Charge equal to the product of the monthly Demand Rate defined in Paragraph 9.2 of this Article and the Maximum Daily Quantity defined in Article I of this Agreement;

(b) A Commodity Charge equal to the product of the volume actually received by Transporter during the month at the Point of Receipt and the Commodity Rate defined in Paragraph 9.2 of this Article.

8.2 Nomination Schedule and Rates:

Delivery Point(s)	Annual Quantity Nominated (10^3m^3)	Rate (Lev/10^3m^3) Demand Rate	Commodity Rate
[TO BE SUPPLIED]	[TO BE SUPPLIED]	[TO BE SUPPLIED]	

8.3 Transporter shall not be liable for any gas gathering, occupation or production, severance or sales tax, or taxes of similar nature or equivalent in effect which are now or hereafter validly imposed by any lawful authority on the gas transported pursuant to this agreement or on the production thereof. Shipper shall reimburse Transporter the amount of any future tax or other governmental exaction validly laid on and paid by Transporter for, in respect of, or on account of the receipt, transportation or delivery by Transporter of the gas provided for in this

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Transportation Agreement; provided, however, that such reimbursement shall not include income, excess profits, capital stock, or general property taxes.

8.4 Transporter shall have the right, from time to time, through filings with the [RELEVANT AUTHORITY] to seek to increase or decrease the rates, and to change the other terms and conditions of this Transportation Agreement, without limitation or reservation; provided, however, that (a) the character of firm service, (b) the term, (c) the quantities, (d) the Points of Receipt and Delivery, and (e) the receipt and delivery pressures shall not be subject to change. Shipper shall have the right to oppose any of the foregoing and to seek a reduction in rates or other changes to the terms and conditions of this Transportation Agreement to the extent that Shipper is legally permitted to do so under applicable provision(s) of law.

ARTICLE IX - OPERATING PROCEDURES AND BALANCING

9.1 Throughout the term of this Transportation Agreement, Shipper shall provide to Transporter by the fifteenth (15th) Day of every calendar month an estimated transportation nomination schedule ("Nomination Schedule") indicating the daily quantity of gas Shipper reasonably anticipates it will require to be transported each Day during the next month, which schedule shall be subject to change on verbal notice as provided for in Paragraph 10.2 of this Agreement.

9.2 Shipper shall have the right to change the Nomination Schedule, but Shipper must notify Transporter verbally of any such changes at least eight (8) hours in advance of the Day on which the change in deliveries will commence, and Shipper shall use its best efforts to do so at least twenty-four (24) hours in advance of any such change. Requested changes to the Nomination Schedule shall be kept to the minimum permitted by operating conditions. Shipper shall deliver or cause to be delivered to Transporter, and Shipper shall receive from Transporter the scheduled daily quantity as nearly as possible at uniform hourly rates.

9.3 It is the intention of the Parties that the total heating value of daily deliveries of Shipper's Gas to Transporter at the Point of Receipt for transportation for Shipper's account shall equal the total heating value of Shipper's Gas that Transporter shall deliver at the Point of Delivery. However, it is recognized that due to operating conditions, the total heating value of gas deliveries into and from Transporter's facilities may not balance on a daily or other short-term basis. The Parties therefore agree to abide by the following balancing procedures:

(a) The quantity of gas delivered or caused to be delivered by Shipper to Transporter at the Point of Receipt for transportation on any Day (less any quantity retained by Transporter for compressor fuel and line loss makeup) shall be redelivered by Transporter for the account of Shipper, balanced on the basis of total heating value.

(b) If the quantity of gas which Shipper schedules to receive from Transporter on any Day is not taken by Shipper during each Day, Shipper shall pay Transporter a scheduling penalty equal to the Commodity Charge applicable under Transporter's Standard Tariff Rate, multiplied by the amount by which the quantity scheduled for delivery to Transporter exceeds the quantity actually delivered, minus 4 percent.

(c) Any monthly imbalance between Shipper's deliveries of gas for transportation and Transporter's redeliveries shall be kept to minimum. At the end of each calendar month, Transporter shall determine the net amount of surplus or deficiency in the total heating value of Transporter's deliveries of Shipper's Gas to the Point of Delivery, above or below the total heating value of Shipper's Gas delivered to Transporter at the Point of Receipt. Transporter shall adjust any net surplus or deficiency of such gas delivered by Transporter by adjusting the quantity of Shipper's Gas dispatched by

Transporter at the Point of Delivery in the next succeeding calendar month. If Shipper does not within 45 Days immediately following notice by Transporter's dispatcher balance out any monthly imbalance between Shipper's deliveries of gas for transportation and Transporter's redeliveries then:

(i) Shipper shall pay Transporter a penalty equal to two times the Commodity Charge applicable under the Transporter's Standard Tariff Rate, multiplied by any excess quantity received by Shipper; or

(ii) Transporter shall retain at no cost any excess deliveries by Shipper, free and clear of any claims to title.

(d) If an imbalance exists between receipts and deliveries upon termination of this Transportation Agreement or when quantities cease to be delivered to Transporter for transportation, as a result of the depletion of supplies or a termination of deliveries from Shipper's suppliers, such that the quantities delivered by Transporter to Shipper or for the account of Shipper exceed the quantities delivered to Transporter (less the quantities retained for compressor fuel and line loss make-up), Shipper shall immediately take whatever action is required to acquire the quantities necessary to eliminate such imbalance. If such imbalance is not eliminated within a period of sixty (60) Days after written notification to Shipper by Transporter, Shipper shall pay Transporter a penalty equal to two times the Commodity Charge applicable under the Transporter's Standard Tariff Rate, multiplied by such imbalance quantity.

(e) If Transporter determines that, because of operational constraints or other reasons, it cannot reasonably apply any or all the provisions set forth in Sections (a)-(d) above, it may, at its discretion, waive any or

all of such provisions; provided, however, that any such waiver shall be made on a nondiscriminatory basis.

(f) The penalty provisions set forth in Sections (a)-(d) above shall not apply if the excess deliveries or excess takes are caused by Transporter's actions or events of force majeure as such term is defined in Article XIII of this Transportation Agreement.

ARTICLE X - BILLING AND PAYMENT

10.1 Transporter shall render its bill on or before the last Day of each month for the Demand Charges due for service rendered during the preceding calendar month. On or before the 10th Day of each month, Transporter shall render its bill for the Commodity Charge payable for gas services rendered during the preceding calendar month.

10.2 Each Party shall, upon request of the other, mail or deliver for checking and calculation any available documentation that was used in either the measuring of gas and calculation of volumes or billing within twenty (20) Days after the date on which Transporter renders its billing statement for such month for all charges other than demand charges. All records and charts, together with calculations for inspection and verification, are subject to return within ten (10) Days after receipt thereof.

10.3 Shipper, except as otherwise provided in this Agreement, shall pay to Transporter at its designated office: (a) on or before the 10th Day of each month for the Demand Charges due for service rendered by Transporter during the preceding month and billed by Transporter in the statement for such month, and (b) on or before the 20th Day of each month for the remainder of the charges for service which are due.

10.4 If Shipper fails to pay all of the amount of any bill to Transporter when such amount is due, interest on the unpaid portion of such amount shall accrue at [PREVAILING, AUTHORIZED RATE OF INTEREST]. If such failure to pay continues for 30 Days

after payment is due, Transporter, in addition to any other remedy it may have, may suspend further transportation of natural gas until such amount is paid; provided, however, that if Shipper in good faith shall dispute the amount of any such bill or any part thereof, and shall pay to Transporter such amount as it concedes to be correct, and at any time thereafter within 30 Days of a demand made by Transporter, shall furnish good and sufficient surety bond, guaranteeing payment to Transporter of the amount ultimately found to be due under such bill after a final determination, which may be reached either by agreement between the Parties, arbitration or judgment of a court, then Transporter shall not be entitled to suspend further delivery of natural gas unless and until default be made in the conditions of such bond.

10.5 If within 12 months of the date of payment, it shall be found that Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof, and Shipper shall have actually paid the bills containing such overcharge or undercharge, then within 30 Days after the final determination thereof, Transporter shall refund the amount of any such overcharge with interest at the rate of [PREVAILING, AUTHORIZED RATE OF INTEREST], calculated from the time such overcharge was paid to the date of refund.

ARTICLE XI - ASSUMPTION OF RISK

Shipper shall be deemed to be in control and possession of the gas to be transported until the gas has been delivered to Transporter at the Point of Receipt, and Shipper shall be deemed to be in control and possession of the gas after delivery for Shipper's account at the Point of Delivery. Transporter shall be deemed to be in control and possession of Shipper's Gas after the gas is delivered to Transporter at the Point of Receipt and before the gas is delivered for Shipper's account at the Point of Delivery.

ARTICLE XII - WARRANTIES

Shipper warrants for itself, and for its successors and assigns, that it will at the time of delivery to Transporter for transportation have good and merchantable title to all gas.

ARTICLE XIII - FORCE MAJEURE

13.1 The term force majeure shall mean acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, storms, floods, washouts, arrests, the order of any court or governmental authority having jurisdiction prohibiting service or performance, while the same is in force and effect, civil disturbances, explosions, breakage, accident to machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, not including shortages of gas supply or curtailment therefore, inability to obtain or unavoidable delay in obtaining material, equipment, easements, franchises, permits, or authorization and any other causes whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension and which by the exercise of due diligence such Party is unable to prevent or overcome.

13.2 The loss of markets to other gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure.

13.3 In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Transportation Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax or telegraph to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as

they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

ARTICLE XIV - NOTICES

14.1 Any notice, request, demand, statement or bill provided for herein, or any notice which either Transporter or Shipper may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail addressed to said Party at its last known post office address, or at such other address as any Party may be designate in writing. Routine communications, including monthly statement and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

(a) If to Shipper: [ADDRESS]

(b) If to Transporter: [ADDRESS]

ARTICLE XV - EVENTS OF DEFAULT

15.1 Any one or more of the following events shall constitute an Event of Default under this Transportation Agreement:

(a) Failure by either Party to pay any amount due and payable by it pursuant to this Transportation Agreement for fifteen (15) Days after the same shall have become due;

(b) Failure of either Party to perform any material part of this Transportation Agreement, other than in an event of force majeure, and continuance of such failure for a period of thirty (30) Days after written notice to the defaulting Party specifying the nature of such Default and requesting that it be remedied;

(c) Bankruptcy of either Party; or,

(d) If any material representation or warranty made herein shall prove to have been false or incorrect in any material respect at the time made.

ARTICLE XVI - TERMINATION

16.1 Subject to Paragraph 16.2 below, whenever any Event of Default shall have occurred and be continuing, the non-defaulting Party, to the extent permitted by law, may, upon sixty (60) Days prior written notice to the defaulting Party, terminate this Transportation Agreement. In such event, this Transportation Agreement shall terminate unless within such sixty (60) Day period prior to such termination all Events of Default that were the subject of such notice shall have been fully cured, or the defaulting Party has instituted and is diligently pursuing corrective action sufficient to cure such Default.

16.2 No termination of this Transportation Agreement shall relieve the defaulting Party of its liability and obligations.

ARTICLE XVII - ASSIGNMENT OR TRANSFER

Except for assignment in connection with any financing, the Parties agree not to assign or transfer their interest in this Transportation Agreement without the prior written consent of the other Party, which consent shall neither be unreasonably withheld nor delayed. If this Transportation Agreement is assigned without the written consent of the non-assigning Party, the non-assigning Party may terminate this Transportation Agreement on thirty (30) Days written notice to the assigning Party.

ARTICLE XVIII - AMENDMENTS

This Transportation Agreement, or any extension or renewal hereof, may not be amended, changed, modified or altered unless such amendment, change, modification or alteration shall be in writing and signed by the Parties hereto, or by such successor in interest.

IN WITNESS WHEREOF, the Parties have duly executed this Transportation Agreement by their proper officers or representatives:

SHIPPER	TRANSPORTER
_____	Name _____
Name	
_____	Title _____
Title	
_____	Date _____
Date	

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LIST OF SOURCES

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LIST OF SOURCES

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