Table 5-4-59 Main facilities and equipment (1)

Case	High Case / Area L-3			Area C-M and D	Remarks
Nominal LNG handling weight	1.6 million t/year	3 million t/year	5 million t/year	1 million t/year	
Facility name	Specifications in 2009	Specifications in 2017	Specifications in 2025	Specifications in 2019	
Unloading arm	Arms for LNG: 3 lines Arms for return gas: 1 line 16B×60Ft	→ → →	→ → →	Arms for LNG: 3 lines Arms for return gas: 1 line 16B×60Ft	130,000kL tanker receiving for 12 hours
Disaster prevention Facilities at jetty site	(1) Dry chemicals (2) Water curtain equipment (3) Low foaming equipment (4) Others Hydrants, Gas detectors, Fire alarms, Siren, Speaker, Communication system	→ → → → →	→ → → → →	→ → → → →	
Sampling facility for LNG receiving	Sampling vaporizer 20m³/h, Sampling holder, Gas compressor, Gas density meter, Gas chromatograph 1 unit	→	→	→	
Return gas blower	Centrifugal 27000Nm³/h×2 units (stand-by 1unit) 4100mmAq, 250kW	→	→	Centrifugal 27,000Nm³/h×2units (stand-by 1unit) 4,100mmAq, 250kw	
LNG storage tank	Above ground type PC tank Capacity 140,000kL×2 units 1600mmAq, Inner tank 9%Ni	Above ground type PC tank Capacity 140,000kL×3 units 1600mmAq, Inner tank 9%Ni	Above ground type PC tank Capacity 140,000kL×4 units 1,600mmAq, Inner tank 9%Ni	Above ground type PC tank Capacity 170,000kL×2 units 1,600mmAq, Inner tank 9%Ni	
LNG pump	(1) Primary pump Capacity 170t/h×4 units, Intank pump 10kg/cm², 220kW (2) Secondary pump Capacity 150t/h×4 units, Submerged pump 75kg/cm², 1450kW (3) Transfer pump Capacity 170t/h×3 units, Intank pump 10kg/cm², 330kW	(1) Primary pump Capacity 170t/h×6 units, Intank pump 10kg/cm², 220kW (2) Secondary pump Capacity 150t/h×6 units, Submerged pump 75kg/cm², 1450kW (3) Transfer pump Capacity 170t/h×3 units, Intank pump 10kg/cm², 330kW	(1) Primary pump Capacity 170t/h×8units, Intank pump 10kg/cm², 220kW (2) Secondary pump Capacity 150t/h×8units, Submerged pump 75kg/cm², 1450kW (3) Transfer pump Capacity 300t/h×3 units, Intank pump 10kg/cm², 330kW	(1) Primary pump Capacity 85t/h×4 units, Intank pump 10kg/cm², 220kW (2) Secondary pump Capacity 65t/h×4units, Submerged pump 75kg/cm², 1450kW (3) Transfer Capacity 85t/h×3 units, Intank pump 10kg/cm², 330kW	Including 2 stand-by Including 2 stand-by Including 1 stand-by
Disaster prevention facility	(1) Pond (2) Cooling and water drench system (3) Dry chemical extinguishing system (4) High expansion foam equipment (5) Water curtain system (6) Other disaster prevention equipment Gas leak detector, Low temperature line sensor, Low temperature detector, Flame detector, Flange cover, ITV, Paging system, Telephone for emergency, Fire alarm system, Fire extinguisher, Hydrant	(1) Pond (2) Cooling and water drenching system (3) Dry chemical-extinguishing system (4) High expansion foam equipment (5) Water curtain system (6) Other disaster prevention equipment Gas leak detector, Low-temperature line sensor, Low-temperature detector, Flame detector, Flange cover, ITV, Paging system, Telephone for emergency, Fire alarm system, Fire extinguisher, Hydrant	(1) Pond (2) Cooling and water drenching system (3) Dry chemical-extinguishing system (4) High expansion foam equipment (5) Water curtain system (6) Other disaster prevention equipment Gas leak detector, Low-temperature line sensor, Low-temperature detector, Flame detector, Flange cover, ITV, Paging system, Telephone for emergency, Fire alarm system, Fire extinguisher, Hydrant	(1) Pond (2) Cooling and water drenching system (3) Dry chemical-extinguishing system (4) High expansion foam equipment (5) Water curtain system (6) Other disaster prevention equipment Gas leak detector, Low-temperature line sensor, Low-temperature detector, Flame detector, Flange cover, ITV, Paging system, Telephone for emergency, Fire alarm system, Fire extinguisher, Hydrant	
Flare stack	60t/h× 1 unit	→	→	60t/h×1 unit	
BOG compressors	Reciprocating type 15t/h×5 units 0→8kg/cm², 1100kW	→	→	Reciprocating type 15t/h×5units 0→8kg/cm², 1100kW	Including one backup

Table 5-4-59 Main facilities and equipment (2)

Case	High Case / Area L-3			Area C-M and D	Remarks
Nominal LNG handling weight	1.6 million t/year	3 million t/year	5 million t/year	1 million t/year	
Facility	Specifications in 2006	Specifications in 2017	Specifications in 2025	Specifications in 2019	
BOG booster	Reciprocating type 15t/h×4 units 8→70kg/cm², 2,800kW	→	→	Reciprocating type 15t/h×4 units 8→70kg/cm², 2,800kW	Including 1 back-up
BOG reliquefaction facility	BOG reliquefaction 40.6t/h	→	→	BOG reliquefaction capacity 4.8 t/h	
LNG vaporizer	Open rack 150t/h×3 units Sea water 5,250m³/hunit(10℃) Design pressure 70kg/cm²	Open rack 150t/h×5 units Sea water 5,250m³/hunit(10℃) Design pressure 70kg/cm²	Open rack 150t/h×7 units Sea water 5,250m³/hunit(10℃) Design pressure 70kg/cm²	Open rack 150t/h×3 units Sea water 5,250m³/hunit(10℃) Design pressure 70kg/cm²	Including 1 backups
Sea water pump for vaporizers	Capacity 7,000m³/h×4units 30m, 780kW	Capacity 7,000m³/h×6 units 30m, 780kW	Capacity 7,000m³/h×7 units 30m, 780kW	Capacity 2,200m³/h×4 units 30m, 780kW	Including 2 back-ups
Sea water pump for Hydrant	Capacity 3,000m³/h×3 units 80m, 1,200kW	→	→	Capacity 3000m³/h×3 units 80m, 1200kW	Including 1 back-up
Chlorinator equipment	100kg/h×2 units, 320kW	→	→	20kg/h×2 units, 60kW	Including 1 back-up
Odorization system	Tank capacity 3m³×1 unit, Design pressure70kg/cm² Pump 6l/h×4units, 80kg/cm² Blower, Deodorant	Tank capacity 3m³×2 units, Design pressure70kg/cm² Pump 6l/h×4units, 80kg/cm² Blower, Deodorant	Tank capacity 3m³×2 units, Design pressure70kg/cm² Pump 6l/h×4units, 80kg/cm² Blower, Deodorant	Tank capacity 2m³×2 units, Design pressure70kg/cm² Pump 2l/h×2 units, 80kg/cm² Blower, Deodorant	Odorant concentration 10mg/Nm³
Metering system	One unit	→	→	→	
Vent stack	500A×60m×1 unit	→	→	500A×60m×1 unit	
Utility Facility	(1) Cooling water facility Cooling water tower 300m³/h×3 units Cooling water pump 300m³/h×3 units, 50m (2) Instrument air compressors Reciprocating type 1,000m³/h×3 units, 7kg/cm² Dryer 2 units, Tank 15m³×2 units (3) Nitrogen facility L-N2 tank 20m³×2 units HP N2 vaporizer 100m³/h×1 unit LP N2 vaporizer 100m³/h×2 units (4) Portable water facilities Tank 500m³, Pump 30m³/h×2units,45m (5) Seawage treatment facilities Activated sewage treatment 20m³/D	→ → → → → →	→ → → → → →	(1) Cooling water facility Cooling water tower 300m³/h×3 units Cooling water pump 300m³/h×3 units, 50m (2) Instrument air compressors Reciprocating type 1,000m³/h×3 units, 7kg/cm² Dryer 2units, Tank 15m³×2 units (3) Nitrogen facility L-N2 tank 20m³×2 units HP N2 vaporizer 100m³/h×1 unit LP N2 vaporizer 100m³/h×2 units (4) Portable water facilities Tank 500m³, Pump 30m³/h×2 units,45m (5) Seawage treatment facilities Activated sewage treatment 20m³/D	Including 1 back-up Including 1 back-up Including 1 back-up
Sea water intake facility	Main intake mouth 31,700m³/h 8mΦ×2 lines Intake pipeline 47,500m³/h 2.7mΦ×2 lines	→ → → →	→ → → →	Main intake mouth 4,230m³/h 2.8mΦ×2 lines Intake pipeline 4,230m³/h 0.9mΦ×2 lines	Including 1 back-up line Including 1 back-up line
Draining facility	40,080m³/h	→	→	12,630m³/h	
Analyzers	1 unit	→	→	→	

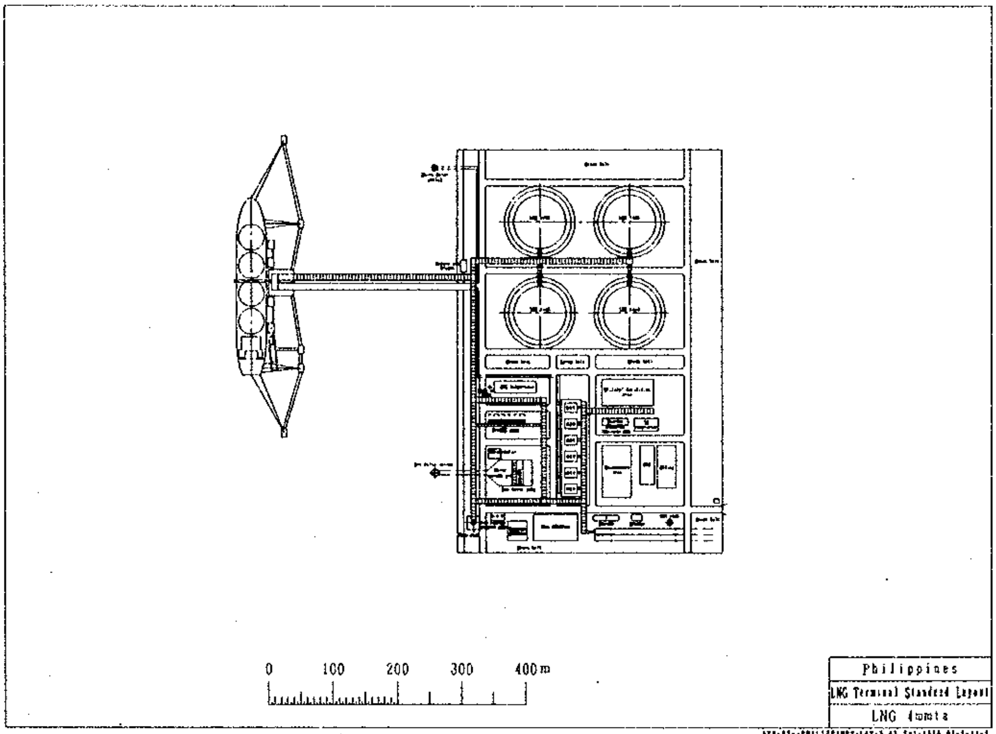

Figure 5-4-1 Layout of LNG Receiving Terminal (4 million t/y)

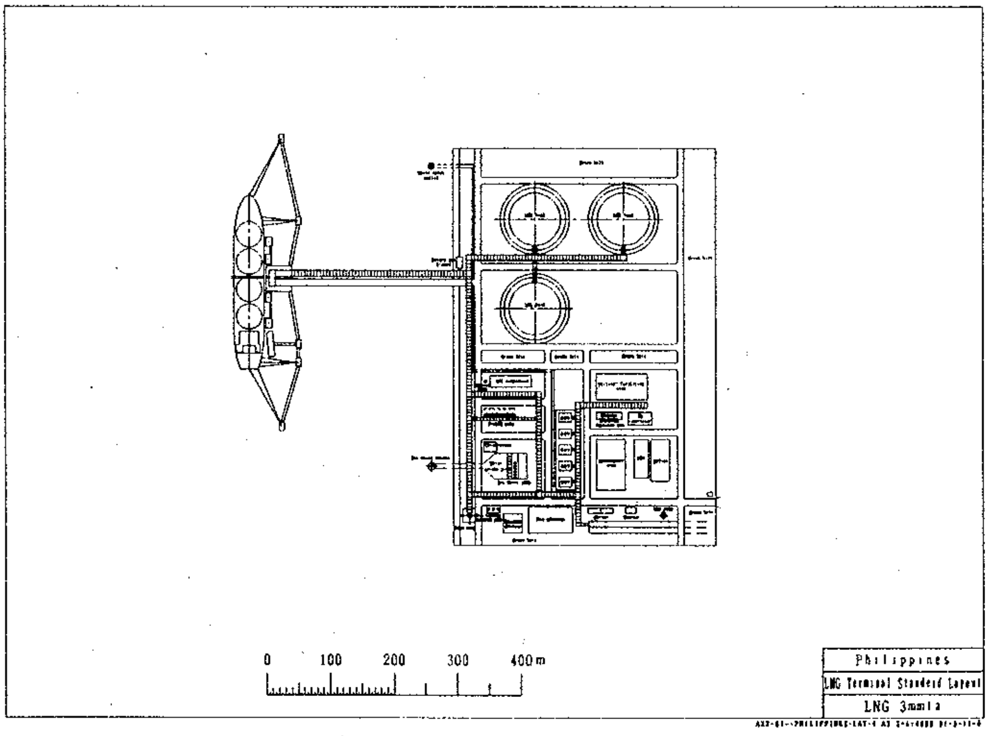

Figure 5-4-2 Layout of LNG Receiving Terminal (3 million t/y)

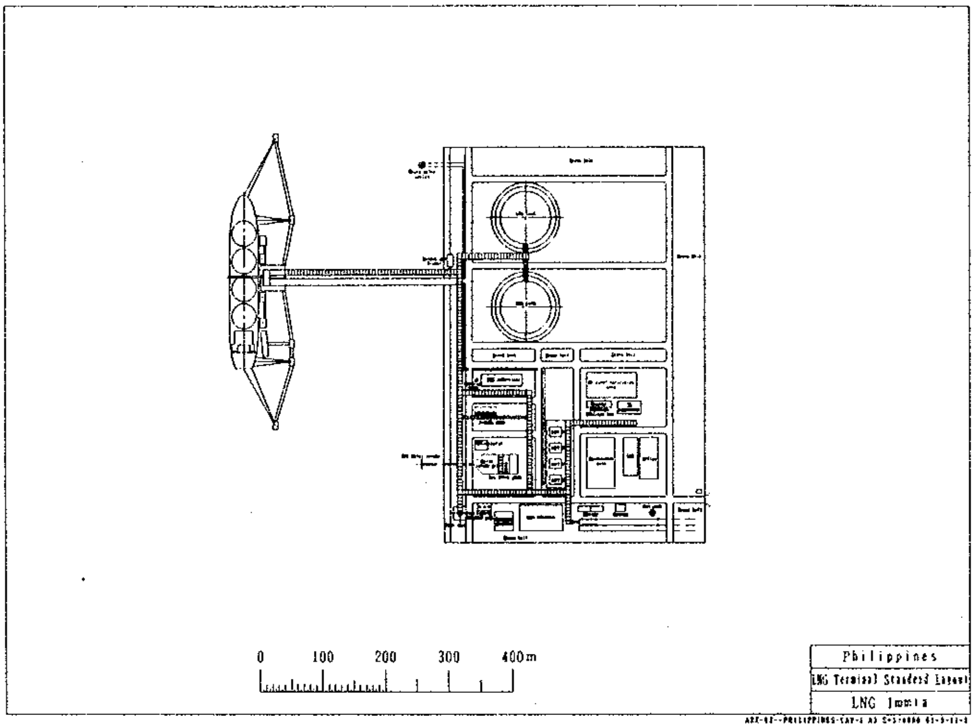

Figure 5-4-3 Layout of LNG Receiving Terminal (1 million t/y)

5-4-13 Estimation of terminal costs

(1) Terminal Cost

Total terminal cost is shown in Table 5-4-60

Table 5-4-60 LNG terminal cost

(Million US$)

Nominal annual LNG quantity (million t/year)	1	3	6	9
Jetty and Unloading facilities	19	19	19	44
LNG storage tanks	153	194	258	322
BOG treatment facilities	33	35	37	54
Pumps, Vaporizers, Seawater facilities	25	54	94	125
Pipe and auxiliary facilities	41	61	67	106
Electrical/Instrumentation	22	29	36	47
Civil and Buildings	19	23	24	24
Total	312	413	535	722

(2) Simplified Estimation Method

Usually, the cost of an LNG unloading and filling terminal is estimated on the basis of facilities specifications, taking into account volume handled and other conditions. A significant amount of labor would be required to study individual cases in this manner. We, therefore, came up with a method with which to make a simplified estimation on the basis of basic conditions.

The LNG tanks account for the greatest portion of the cost of an LNG receiving terminal; usually from 45% to 70% of the total facilities cost. As mentioned earlier, the capacity of a tank is determined according to the storage capacity required for emergencies, seasonal demand fluctuations, and the capacity of an LNG tanker.

With LNG 12, the ratio of the cost of each piece of equipment to that of all equipment in a typical case (below) is shown.

Volume of LNG handled: 4 million t/y

LNG tank: 90,000 kl/unit × 3 units

Table 5-4-61 Cost Breakdowns

Facilities	Cost ratio (%)
Jetty	10
LNG storage tanks	45
Vaporizers/Untaken Outfall	13
BOG compressors	6
Electrical/Instrumentation	15
Utilities/Misc	11
Total	100

In the above case, the capacity of a tank to handle a volume of one million t/y is 67,500 kl/(1 million t/y).

If we assume the following for a case with greater values than the above, the capacity of a tank to handle one million t/y would be 180,000 kl/(one million t/y).

Volume of LNG handled	three million t/y
LNG storage	14 days-portion
Seasonal differential	none
LNG vessel capacity	130,000 kl
For unloading operations	26 kl
LNG storage required	510,000 kl
LNG tank	180,000 kl x 3 units

Adjusting the above on the assumption that tank cost is in proportion to a capacity rise of 0.8 power, tank cost vis-à-vis cost of the entire terminal would be 64.2%.

Using the same calculations for the following case, tank cost versus cost of the entire terminal would be 77.3%. The relationship is shown in Figure 5-4-4.

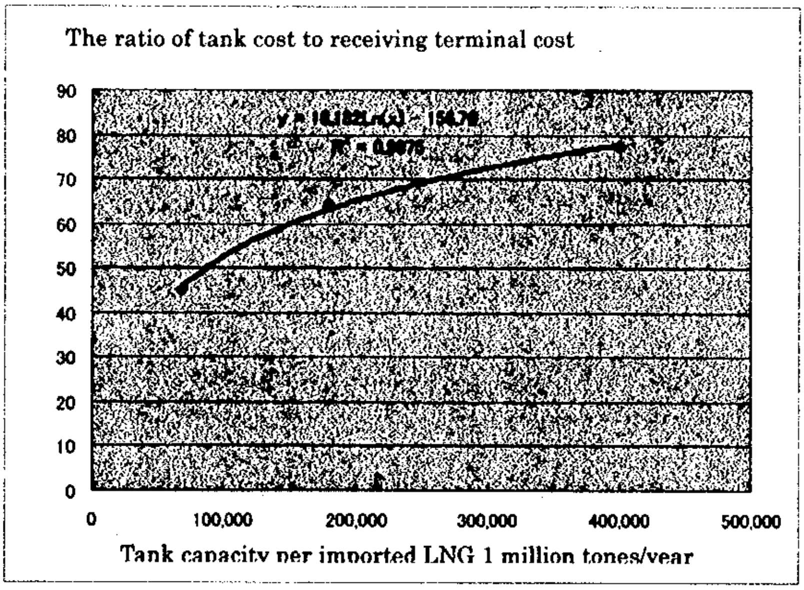

Figure 5-4-4 Cost Ratios vs. Capacity Ratios

As demonstrated above, if we know the tank capacity vis-à-vis the volume of LNG handled, the percentage of tank costs of the entire terminal costs can be determined. If the cost of the tanks can be estimated, that of the entire terminal may be estimated using the formula above.

Results of a comparison between cost calculated using this method and an assumed LNG tank cost of US$492/kl and the cost of (1) are given in Table 5-4-62.

Table 5-4-62 Comparison of Investment Costs for LNG Receiving Terminals

Nominal Annual LNG Quantity (Million t/year) (a)	1	3	6	9
Capacity of LNG storage tanks (kl) (b)	340,000	420,000	560,000	700,000
(b)/(a) (kl・year/million t)	340,000	140,000	93,333	77,778
Cost ratio of tanks versus terminal (%)	74.8	58.7	51.3	48.0
Cost of LNG storage tanks (million dollars)	167	207	276	344
Terminal cost (million dollars)	223	352	537	717
Terminal cost in (1) (million dollars)	312	413	535	722

This table shows that the cost estimates by simple calculations well coincide with those by the bottom-up method when the LNG quantity is more than 6 million t/y, but that there are certain gaps in the estimates , 29% for 1 million t/y and 15% for 3 million t/y, in case of smaller scale LNG terminals.

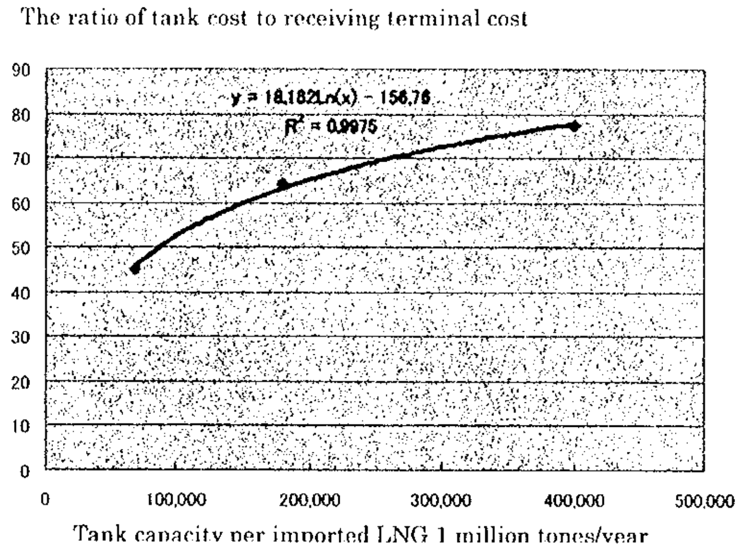

Figure 5-4-4　Cost Ratios vs. Capacity Ratios

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(3) Equipment Cost for Each Case

Shown below is the equipment cost for each case. The construction period is three years, regardless of whether or not it is newly constructed or expanded.

Table 5-4-63 Investment cost in each case

(Million US$)

Year		2009	2013	2017	2019	2020	2021	2022	2024	2025
High Case	L-2		312			101			78	
	L-3	312		101				78		21
	C-M/D				312					
Low Case	L-2			312			101			
	L-3		312		101				78	
	C-M/D					312				

5-4-14 Operating Organization and Maintenance and Operating Costs

(1) Operating Organization

Table 5-4-40 shows the operating and maintenance manpower needed for terminal at the three different levels of three million t/y, six million t/y, and nine million t/y, based on data for LNG terminals in Japan.

Table5-4-64 Operation and maintenance manpower

Nominal annual LNG quantity (Million t/year)		~2	3	4	5
Operation	Shift chief	1	1	1	1
	Foreman	1	1	1	1
	Operators in each shift	2	2	3	3
	Patrollers in each shift	1	2	2	3
	Sub-total in each shift	5	6	7	8
	Staff	23	26	29	32
	Total	48	56	64	72
Maintenance	Mechanical	15	18	21	24
	Electrical/Instrument	23	25	27	29
	Sub-total	38	43	48	53
Guards for disaster prevention and security		14	21	31	41
Total		100	120	143	166

(2) Operating and Maintenance Costs

Operating cost (excluding labor) and maintenance cost was calculated referring to actual data in Japan. These are:

Annual maintenance cost required: One percent of capital expenditures

Annual running cost: US$1.8 /t – LNG

5-5 Response to Possible Additional Indigenous Gas Finds

The Philippines has additional prospective gas fields with sizable potential reserves waiting for development next to the Camago/Malampaya fields. We hereby consider how to handle the plans in this study if additional sizable gas reserves get proven in the near future. We will especially focus on the effect of additional proven gas reserves of one (1) to five (5) TCF on the LNG import policies stated in this study.

Assuming the production period for a gas field is normally set as 20 years, additional gas find of one (1) TCF is interpreted into a production of about 140 mmscfd. While the current capacity of the Camago/Malampaya project we understand is 500 mmscfd, the size of the 504 km submarine pipeline has a potential of 650 mmscfd and additional gas find of, e.g., 1 TCF and resultant expanded production will be absorbed in the existing pipeline by installing additional compressors on the platform.

The expansion of the production by more than 1 TCF of added reserves will require additional installations to the gas fields as well as development and investment for extra pipelines, taking certain years from proving the gas finds to operation.

A period of 20 years is a short period to be completed in view of long term national plans and a part of additional gas reserves will better be reserved for future generations considering sustainable development depending on the size of potential reserve addition and certainty of the potential reserve estimates. It will be also considered that slower rate of production may increase the rate of gas recovery from a gas field rather than rapid production which may decrease the recoverable quantity.

Base on the above considerations, we will assume that the gas from a next gas field will be produced for 30 years instead of normal 20 years. For other assumptions and calculations procedures, please see Table 5-5-3 at the end of this section.

Table 5-5-1 demonstrates how additional proven gas reserves of one to five TCF are interpreted into the size of production and consumption based on the above assumptions.

This table says that, if the additionally found gas is used for residential purposes, a gas find of, say, 3 TCF, will accommodate 12.4 million households, comparable to most of the Philippine population of 70 million, for 30 years assuming that a household may use the gas at a rate of 18 Nm³/month. While this is a demonstration of a measure of household use, commercial and NGV's gas uses are further in potential prospect in the civil gas use sector. If future society considerably changes, it may be an option to plan geographically wider gas distribution after re-examination of feasibility, but current economic assessment at this stage might prohibit it.

Table 5-5-1 Impacts of Additional Reserves on the Size of Consumption

Reserve Size	Pipe capacity required (mmscfd)	If used for power generation: (MW)	If fuel oil is converted: (bblfoe/d)	If gas distributed to residences: (x1000 customers)
TCF	(Average)			
1	91	695	15,123	4,133
2	183	1,390	30,246	8,266
3	274	2,086	45,369	12,398
4	365	2,781	60,492	16,531
5	457	3,476	75,614	20,664

The same 3 TCF of gas reserves will be accommodating 2,086 MW of gas power generation, if the gas is solely used for power, assuming an average generation efficiency as 40% (gross thermal value based) since existing power converted into gas may not be necessarily combined cycle gas turbines. Table 5-5-2 shows that the overall generation capacity of the most of existing coal, fuel oil and diesel oil power generations in NCR, Region III and Region IV in Luzon amounts to approximately 2,800 MW as of 2001, which size is approximately comparable to the potential capacity that 3 TCF of gas can accommodate. Most of them are strategically located on the transmission network near Manila, to be greatly benefited by gas conversion. (We may have to be careful that the list of power generations in the table includes some planned to be abolished in several years.)

In the upstream, an extra gas reserve expansion of more than one (1) TCF may require development and installation of new facilities as stated before, taking considerable time. How to make the development smoothly meet the rate of power demand growth will be an issue. Beside the upstream facilities, gas transmission capacities after the Batangas (possibly) landfall also has limitation, and new additional transmission facilities will have to be installed for the demand in NCR or more northern demand areas. The new facilities may be a loop, another line along Laguna province or further another route on the western coast (submarine); in the latter case the Bataan

Peninsula or the Cavite area will be a serious candidate for landfall for the Manila demand area.

The plan of future LNG import depends on how indigenous gas development will meet the growing demand of gas power generation (assuming gas will be preferred by future power generations). Energy security improvement by diversified ways is important at the same time.

Along the growth of gas market, the need of improved energy security and, as a directly relevant issue, the size of gas storage in the nation will become important. Although current gas related plans do not include any gas storage consideration, the need for storage will inevitably become far more important than now, and LNG will be a serious part of a solution. Under the circumstances, the plan of certain LNG facilities in the Bataan Peninsula, means that the LNG terminal will facilitate either option: the continued LNG import expansion or taking in piped gas from expanded Camago/Malampaya reserves to meet the future gas demand growth and security.

Table 5-5-2 Power Generations in the NCR Area

Planned or with Potential Conversion into Gas

Potential Natural Gas Conversion of Power Plants near NCR

Near NCR and Batangas

Gas quality: 9780 kcal/m3 at 0 dC, sm3/t=

Plant Name	Conv'n Priority	Owner	Contract	Location	Political Region	Comm'ning	Current Fuel	Plant Size	units	Installed Capacity	Assumed load %	Assumed Eff'cy %	Gas Use
								MW		MW	%	Gross %	mmscfd
Existing/ Planned Gas Power Generations:													
Santa Rita		First Gas	Meralco PPA	Santa Rita, Batangas	Region IV	2000	Gas	250	4	1000	75	45	131.4
Ilijan		KEPCO/NPC	NPC PPA	Ilijan, Batangas	Region IV	2002	Gas			1200	75	45	157.6
San Lorenzo		First Gas	Meralco PPA	S. Lorenzo, Batangas	Region IV	2002	Gas			500	75	45	65.7
	Eisting Contract Sub-Total									2700			354.7
San Pascual Cogen			NPC PPA	Batangas	Region IV	2004	Gas			430	75	45	56.5
Bataan		JV	Meralco PPA	Limay or Mariveles	Region III	2006	NG planne	600	2	1200	75	45	157.6
Sucat Thermal		NPC to sell 2001/E		Sucat, Paranaque	NCR	2008	Bunker C			700	75	45	92.0
	Existing/ Planned Total									7730			1015.4
Potential Conversion of Existing Generations:													
Calaca Coal I	High	NPC		Calaca, Batangas	Region IV	1984	Coal	300	1	300	70	40	41.4
Calaca Coal II	High	NPC		Calaca, Batangas	Region IV	1995	Coal	300	1	300	70	40	41.4
Malaya GT	High	NPC		Pilila, Rizal	NCR	1989	Diesel	30	3	90	70	40	12.4
Bataan GT		NPC		Limay, Bataan	Region III	1989	Diesel	30	4	120	70	40	16.6
Manila Thermal 1&2	High	NPC		Isla de Provisor	Ermita, NCR	1965&66	Bunker C	100	2	200	70	40	27.6
Bataan Thermal 1		NPC		Limay, Bataan	Region III	1972	Bunker C	75	1	75	70	40	10.3
Malaya 1	High	NPC/IPP	ROM	Pilila, Rizal	NCR	1975	Bunker C	300	1	300	70	40	41.4
Malaya 2	High	NPC/IPP	ROM	Pilila, Rizal	NCR	1979	Bunker C	350	1	350	70	40	48.3
Bataan CC "A"		NPC/IPP	BTO	Limay, Bataan	Region III	1993	Bunker C	70	6	420	70	40	57.9
Bataan CC "B"		NPC/IPP	BTO	Limay, Bataan	Region III	1994	Bunker C	100	2	200	70	40	27.6
Subic Enron 2		BOT	BOT	Olongapo, Zambales	Region III	1994	Bunker C		8	108	70	40	14.9
Edison Global			PPA	Mariveles, Bataan	Region III	1994&5	Bunker C			58	70	40	8.0
Magelan Cogen			PPA	Rosario, Cavite	Region IV	1995	Bunker C			46	70	40	6.6
Hopewell GT 1-3	High	BOT		Navotas, Metro M	NCR	1990&91	Diesel			210	70	40	29.0
Hopewell GT 4	High	BOT		Navotas, Metro M	NCR	1993	Diesel			100	70	40	13.8
	Potential Total									2,879			397.1
	Grand Total									10,609			1412.5
						Of which high priority potential:				1,850			255.2
										MW	%	%	mmscfd

Note) ROM: Rehabilitate-Operate-Maintain; PPA: Power Purchase Agreement

Potential "High priority": designated by DOE

Table 5-5-3 Impacts of Additional Proven Gas Reserves – Trial Calculation

Assumptions:

How Camago-Malampaya Expansion Relates to Production and Use

Gas Reserves, Production and Power Generation, Gas Distribution

Reseves	3	TCF		Generation Efficiency	45%	Per-meter	18	Nm3/month
Operation years	30	yrs		Average Load	75%			per residence
Thermal value	9780	kcal/Nm3=	1039	Btu/scf				
Ave. Production Rate:	273.97	mmscfd =	2.83	sbcmy =, if for power	2,086	MW		
		equal to:	2.678	Nbcmy=, if distributed	2678.034	Nmmcm for		
Standard FO API 15.5:	6.2763	Btu/bl, then	45,369	bblfoe/d.	12,398	X 1000 residential gas customers		

Operation years: 30 years, considering future generations

Results of Calculation:

Sensitivity of Size of Additional Reserves

Reserve Size TCF	Pipe capa. mmscfd	If for Power MW	Fuel oil saved bblfoe/d	If distributed x1000 customers
	273.9726027	2,086	45,369	12,398
1	91	695	15,123	4,133
2	183	1,391	30,246	8,266
3	274	2,086	45,369	12,398
4	365	2,782	60,492	16,531
5	457	3,477	75,614	20,664

Chapter 6 Selection of Optimum Supply / Demand Scenario

We select the optimum gas supply and demand scenario (more specifically, the optimum supply option) in each Case in 6-1 and 6-2, according to the gas distribution plan determined in Chapter 5. Table 6-0-1 shows "actual" gas demand estimated based upon the distribution plan, which is used for the evaluation of the scenarios in 6-2 (For more details on "Others" in the table, refer to Table 5-3-11 to 5-3-18 in Chapter 5).

Gas demand in the target areas on Luzon Island is estimated to increase from 363 mmscfd in 2006 to 1,533 mmscfd in 2025. Demand in the power sector will account for the predominant share, which is at least around 90% of the total for the whole period from 2006 to 2025. We can see a similar picture in Areas C-M and D, where the power sector will also account for the predominant share of total gas demand. However, the financial analysis shows that gas-related businesses are estimated to be unfeasible, assuming gas demand estimated for the areas. Accordingly, there will actually be no gas demand by 2025 in both areas.

Thus, future actual gas demand depends upon that for power generation, but almost all gas demand for power is not used for determining the gas distribution plan, because we assume that power plants, except for two plants on Luzon Island, will be supplied gas through designated pipelines.

Table 6-0-1(1) Estimated actual gas demand in Area L (High Case)

(mmscfd)

	2006	2010	2015	2020	2025
Power (a)	362	597	791	1,036	1,371
Others	1	10	39	90	162
Total (b)	363	606	830	1,126	1,533
a / b	1.00	0.98	0.95	0.92	0.89

Table 6-0-1(2) Estimated actual gas demand in Area L (Low Case)

(mmscfd)

	2006	2010	2015	2020	2025
Power (a)	362	386	646	997	1,268
Others	1	3	10	23	47
Total (b)	363	388	656	1,020	1,316
a / b	1.00	0.99	0.98	0.98	0.96

6-1 Selection of Natural Gas Supply System

In this section, an optimum supply model is built, based on future potential demand for natural gas estimated in Chapter 4, as well as pipeline routes and their construction costs in natural gas distribution plans considered in Chapter 5. We examine areas where natural gas can be supplied through pipelines using the model. The optimum supply model focuses on gas pipeline networks, which distribute gas to non-power users. Therefore, natural gas demand in the model does not include that in power plants, which are located in Batangas and Limay areas, and designated pipelines are laid. However, only Sucat power plant and a small power plant for an industrial park in Santo Tomas are targeted by the model, because it gas is supplied to the above two power plants by the pipeline networks.

6-1-1 Optimum Supply Model

An optimum supply model is built on Microsoft Excel and seeks an optimal solution using Large-scale LP Solver in Add-in Software There are 494 variables in this model. The model can examine natural gas supply in 19 areas from 2000 to 2025. The objective function of the model is the maximum profit for a gas distribution company. Constraints are "amount of gas supply is less than demand" and "amount of gas supply is less than pipeline capacity."

Figure 6-1-1 shows the model flow. The annual pipeline investment is calculated as the amount of principal and interest, which will be equally repaid for 20 years at the interest rate of 7%. Contents of the investments are pipeline materials and labor cost for construction. Other annual costs are that of operation and maintenance (OM). OM cost depends on the length of high-pressure pipeline (km) and the distribution area (km^2). These costs are fixed. Another variable cost is the wholesale price of natural gas multiplied by volume of gas supplied. The model seeks a gas supply area where supply costs do not exceed sales. Therefore, in the model, gas is not supplied to areas where costs exceed sales. In our study plan, however, natural gas will be supplied to NCR from 2006.

Σ (Annual sales - Annual cost) = Maximum profit

Gas wholesale price and gas sales price in the model are assumed based on the prices of other fuels that compete with natural gas. This pricing mechanism is described in 6-2 this chapter in detail.

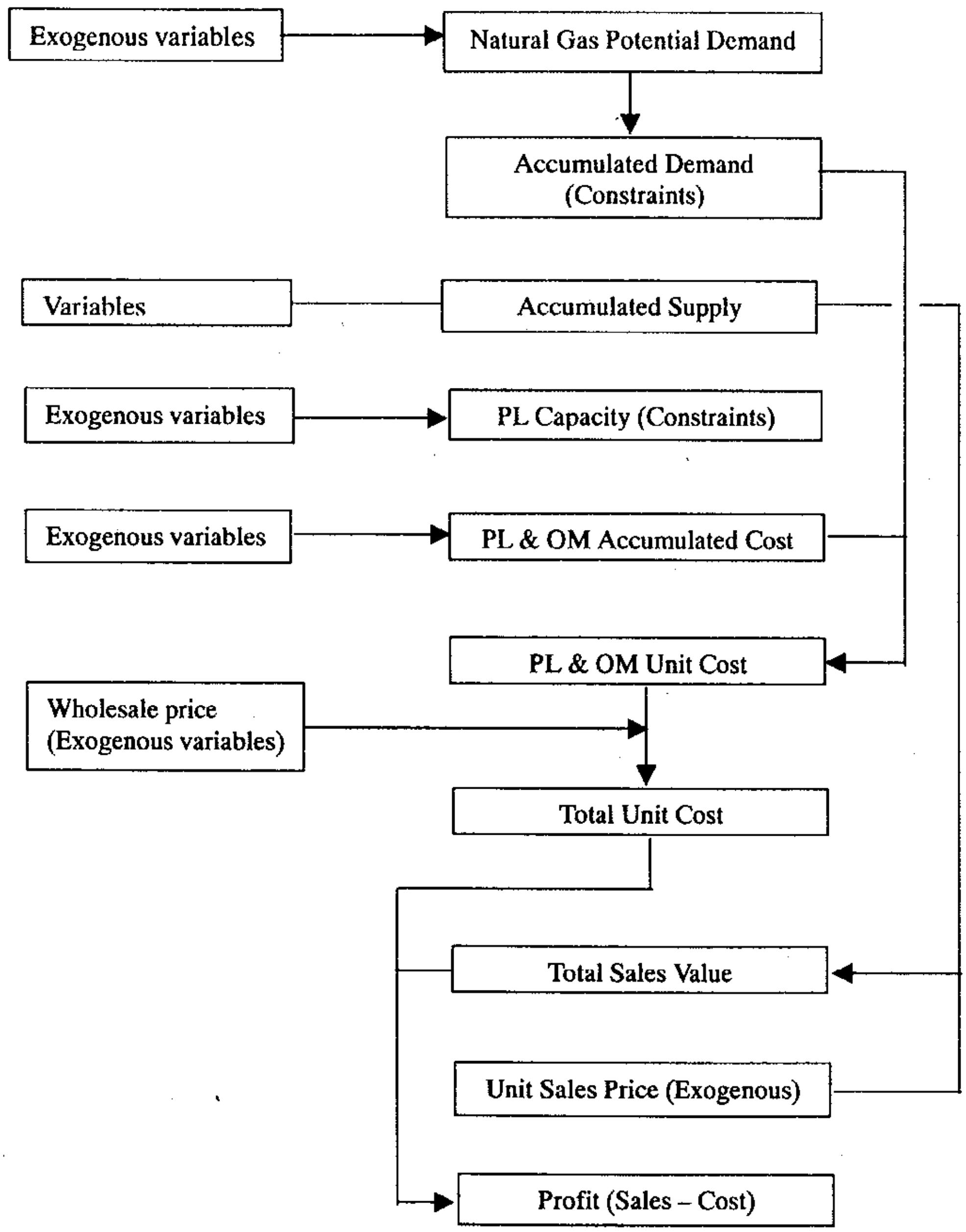

Figure 6-1-1 Flow Chart of Model Sheet

6-1-2 Input Data

(1) Natural Gas Demand

Natural gas potential demand in the future is shown in Table 6-1-1. Natural gas will be consumed in the industry, commercial, transport, and residential sectors in each area shown in the table. However, "Sucat" and "Santo Tomas" include natural gas demand for power plants. We assume that a power plant in Sucat and Santo Tomas will start firing gas in 2008 in the the High Case. In the the Low Case, power plant in Santo Tomas will start in 2008 and Sucat will start in 2012. Natural gas demand will be concentrated in the National Capital Region (NCR) with 90% of total demand.

Table 6-1-1 Potential Gas Demand in each Target Area

(Unit: mmscfd)

	2000	2005	2010	2015	2020	2025
High Case						
Santo Tomas	0.25	0.18	4.67	8.67	10.30	12.03
Cabuyao	0.23	0.16	0.84	2.02	3.53	5.15
Palapala (Cavite)	0.25	0.18	0.91	2.21	3.86	5.62
Alabang (South NCR)	0.74	0.48	2.71	6.72	11.88	17.45
Sucat	0.22	0.16	71.52	72.67	74.13	75.69
Pasay (Central NCR)	2.21	1.45	8.15	20.20	35.68	52.44
North NCR	2.65	1.74	9.74	24.16	42.67	62.70
Santa Rita	0.17	0.13	0.66	1.61	2.83	4.14
San Fernando	0.11	0.08	0.44	1.07	1.88	2.76
Clark	0.00	0.00	0.02	0.04	0.07	0.10
Subic	0.00	0.00	0.01	0.02	0.04	0.05
Limay	0.04	0.03	0.14	0.34	0.60	0.88
Total	6.88	4.60	99.82	139.75	187.47	239.01
Low Case						
Santo Tomas	0.25	0.13	3.76	7.01	7.41	8.13
Cabuyao	0.23	0.12	0.24	0.49	0.86	1.53
Palapala (Cavite)	0.25	0.13	0.26	0.53	0.94	1.67
Alabang (South NCR)	0.74	0.36	0.75	1.57	2.83	5.10
Sucat	0.22	0.12	0.23	71.18	71.55	72.19
Pasay (Central NCR)	2.21	1.08	2.25	4.71	8.49	15.32
North NCR	2.65	1.29	2.69	5.63	10.15	18.31
Santa Rita	0.17	0.10	0.19	0.39	0.70	1.24
San Fernando	0.11	0.06	0.13	0.26	0.46	0.82
Clark	0.00	0.00	0.00	0.01	0.02	0.03
Subic	0.00	0.00	0.00	0.00	0.01	0.02
Limay	0.04	0.02	0.04	0.08	0.15	0.26
Total	6.88	3.42	10.55	91.86	103.56	124.61

(2) Cost Data

In this study, we assume two pipeline routes (refer to Figure 6-1-2 to 6-1-3). Option 1 is the route that will have two LNG terminals in Batangas and Limay areas, and will not cross Manila bay. Option 2 is also the route that will have two LNG terminals in Batangas and Limay areas, and does cross Manila bay.

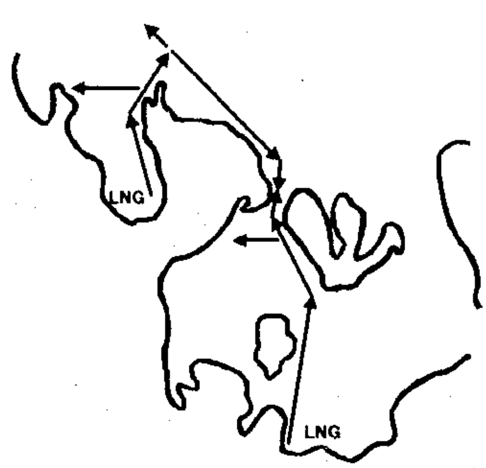

Figure 6-1-2 Supply route Option 1

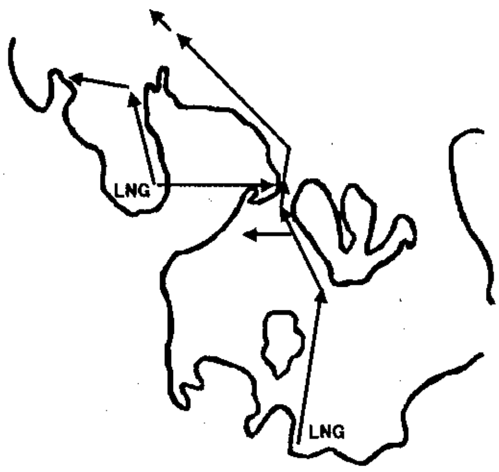

Figure 6-1-3 Supply route Option 2

Table 6-1-2 Investment and OM costs for each route

(Unit: Million US$)

	High-pressure line investment cost	Low- & medium-pressure line investment cost	High-pressure line OM cost	Low- & medium-pressure line OM cost
High Case/Option 1	136.0	500.3	11.3	22.2
High Case/Option 2	120.9	550.3	11.4	22.2
Low Case/Option 1	124.4	161.4	11.3	6.37
Low Case/Option 2	98.3	161.4	11.4	6.53

Table 6-1-2 above shows the cost for each route. As for investment costs of low- and medium-pressure pipelines, the High Case is bigger than the Low Case, because the total distribution area of the High Case is bigger than that of the Low Case. OM cost depends on the pipeline length and the distribution area. Annual OM cost of high-pressure pipeline is assumed to be US$35,000/km, and that of low- and medium-pressure pipeline is US$30,000/km^2. These costs are estimated from experience of gas distribution companies in Japan.

Investment cost of high-pressure pipeline depends on the caliber and the length of the pipeline. Option 1 has two LNG terminals located in Batangas and Limay. The LNG terminal in Limay area would supply gas to NCR along Manila bay. Therefore, it is necessary to construct a large caliber pipeline network to supply gas to NCR. Also, Option 2 has two LNG terminals, as in Option 1. However, Option 2 has a submarine pipeline crossing Manila bay for supplying gas to NCR from Limay area. Option 2 needs investment costs for the submarine pipeline, but a small-size pipeline is sufficient for areas with small demand such as Subic, Clark, and San Fernando. Thus, the investments of Option 1 are higher than Option 2.

6-1-3 Result of the Model Simulation

The optimum supply model simulates conditions in two Cases and two Options. In all Cases and Options, natural gas cannot be supplied anywhere until a power plant in Sucat and Santo Tomas will start firing gas, because of small demand. When a gas-fired power plant in Santo Tomas and Sucat commissions, gas can be supplied with the gas distribution company generating profits. The simulation result of each Case and each Option is explained as follows.

(1) The High Case / Option 1

In the High Case Option 1, supplying gas from Batangas area to Sucat generates the maximum profit from 2009 to 2013. The profit is maximized when gas is supplied to Pasay from 2014 to 2017. After 2018, the gas distribution company can supply gas to North NCR, generating profits. In Option 1, two routes are needed to supply gas to NCR. One is the route from Limay area to NCR along Manila bay. The other is the route from the Batangas area to NCR. Namely, to supply gas to NCR, it is necessary to construct a pipeline from Limay area to NCR along Manila bay, in addition to the pipeline from Batangas to NCR, because it is not enough to meet the demand from only one route, due to the small pipeline capacity (Refer to Table 6-1-4 and Figure 6-1-5). The gas distribution company cannot supply gas along dotted lines such as Clark and Subic shown in Figure 6-1-5, because of small demand.

Figure 6-1-4 shows the NPV of profits from 2007 to 2025 at the discount rate of 7% in each area. The profit from supplying gas to North NCR is the largest.

(2) The High Case / Option 2

To meet demand in NCR, gas is directly supplied by a submarine pipeline from the

Limay area to NCR, in addition to a pipeline from Batangas area to NCR. In The High Case Option 2, supplying gas to Sucat will also be economical from 2009, as in Option 1. According to the increase in gas demand, the gas distribution company can supply gas to Pasay in 2014, North NCR in 2016, Santa Rita in 2020, and San Fernando in 2025 (Refer to Table 6-1-5 and Figure 6-1-7).

Figure 6-1-6 shows the NPV of profits from 2007 to 2025 at the discount rate of 7% in each area. The profit from supplying gas to North NCR is the largest. If gas is supplied to an area beyond North NCR, the profits fall.

(3) The Low Case / Option 1

In the Low Case / Option 1, gas is supplied to Santo Tomas from 2011, Sucat from 2012, Pasay from 2017, and North NCR from 2023. In the Low Case, gas supply will delay compared with the High Case, because operation of Sucat power plant also delays due to small electricity demand (Refer to Table 6-1-6 and Figure 6-1-9).

Figure 6-1-8 shows the Net Present Value (NPV) of profits from 2007 to 2025 at the discount rate of 7% in each area.

(4) The Low Case / Option 2

It is economical to supply gas to Santo Tomas from 2011 in the Low Case Option 2, as in Option 1. After that, gas will be supplied to Sucat from 2012, Pasay from 2017, North NCR from 2020, and Santa Rita from 2025 (Refer to Table 6-1-7 and Figure 6-1-11).

Figure 6-1-10 shows the Net Present Value (NPV) of profits from 2007 to 2025 at the discount rate of 7% in each area.

6-1-4 Evaluation of Model Result

In all Cases and Options, the gas supply route to NCR is economical because NCR has a large demand. In areas beyond NCR, gas demand is very small and the distribution costs exceed the sales.

Table 6-1-3 shows a summary of supply starting year for the maximum profit, each net present value, and cost-benefit ratio. The most profitable is the High Case / Option 2, following by the High Case / Option 1, the Low Case / Option 2, and the Low Case /

Option 1.

However, we cannot judge the economic case by from profit alone because cost of each option is different. Thus, we analyzed the cost-benefit ratio. The result of the cost-benefit analysis is that the High Case / Option 2 is the highest at 1.133, following by 1.091 for the High Case / Option 1. This result is same as the profit comparison.

Considering economic aspects, we can recommend Option 2.

Table 6-1-3 Result of Evaluations

Case/Option	Economically supplied area	NPV of profit (2007-2025) (Million US$)	Cost-benefit ratio (Benefit/Cost)
High Case Option 1	Sucat (2009) – Pasay (2015) - North NCR (2018)	364	1.091
High Case Option 2	Sucat (2009) – Pasay (2014) - North NCR (2016) - Snta Rita (2020) – San Fernando (2025)	514	1.133
Low Case Option 1	Santo Tomas (2011) – Sucat (2012) – Pasay (2018) - North NCR (2024)	160	1.066
Low Case Option 2	Santo Tomas (2011) – Sucat (2012) – Pasay (2018) - North NCR (2021)	167	1.073

Table 6-1-4 Change of Profit by region in the High Case / Option 1

(Million US$)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	NPV
Sucat	0.0	0.0	[redacted]						20.9	23.8	26.9	30.1	33.5	37.0	41.4	46.0	51.0	56.2	61.6	202.4
Bacoor	0.0	0.0	3.4	5.4	7.5	12.8	15.1	17.5	20.0	22.9	26.0	29.2	32.5	36.1	40.5	45.1	50.1	55.3	60.7	194.5
Pasay	0.0	0.0	0.0	0.0	0.0	6.9	12.2	17.7	[redacted]			44.8	52.7	60.9	70.7	81.2	92.2	104.0	116.2	279.2
North NCR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	19.9	32.3	[redacted]								304.2

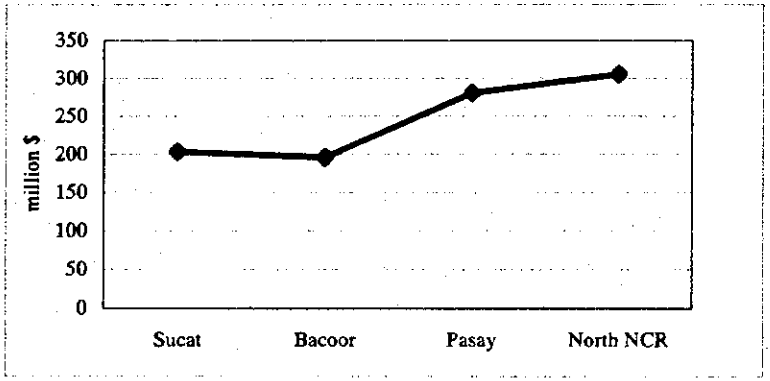

Figure 6-1-4 NPV of Profit by each region in The High Case

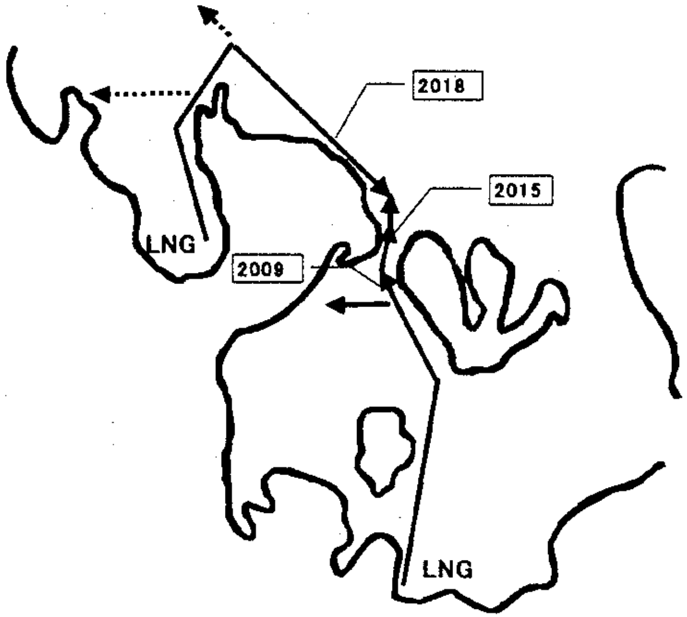

Figure 6-1-5 Supply Area and Year in the High Case / Option 1

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4.9	6.2	8.4	13.7	16.0	23.4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	23.6	30.3	37.4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	45.4	59.3	75.7	93.7	108.7	127.3	148.3	165.7

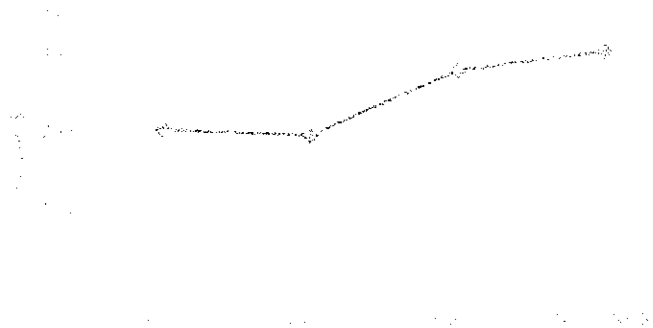

Table 6-1-5 Change of Profit by region in the High Case / Option 2

(Million US$)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	NPV
Sucat	0.0	0.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	28.4	31.3	34.6	38.0	41.7	45.5	49.5	54.5	59.8	65.4	71.4	77.6	294.5
Bacoor	0.0	0.0	11.7	14.0	16.3	22.2	24.8	27.5	30.4	33.7	37.1	40.8	44.6	48.5	53.6	58.9	64.5	70.5	76.7	286.7
Pasay	0.0	0.0	0.0	3.5	8.8	17.7	23.6	[redacted]	[redacted]	43.7	51.6	59.8	68.5	77.7	88.6	100.3	112.6	125.7	139.4	381.8
North NCR	0.0	0.0	0.0	0.0	0.0	1.8	11.6	21.8	32.6	[redacted]	[redacted]	[redacted]	[redacted]	102.0	120.0	139.2	159.5	181.2	203.9	448.1
Santa Rita	0.0	0.0	0.0	0.0	0.0	0.0	9.4	19.9	31.0	43.8	57.3	71.5	86.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	206.7	444.9
San Fernando	0.0	0.0	0.0	0.0	0.0	0.0	6.3	17.0	28.3	41.3	55.0	69.4	84.7	100.7	119.5	139.5	160.7	183.3	[redacted]	434.2
Clark	0.0	0.0	0.0	0.0	0.0	0.0	2.5	13.2	24.5	37.5	51.2	65.7	80.9	97.0	115.8	135.8	157.0	179.6	203.3	413.3

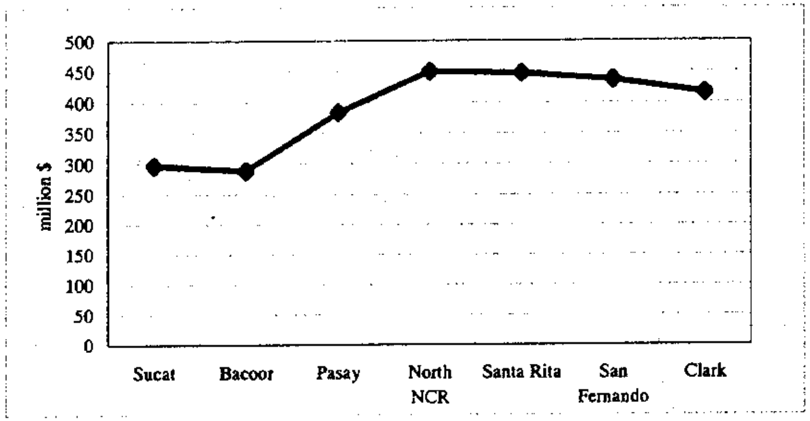

Figure 6-1-6 NPV of Profit by each region in The High Case

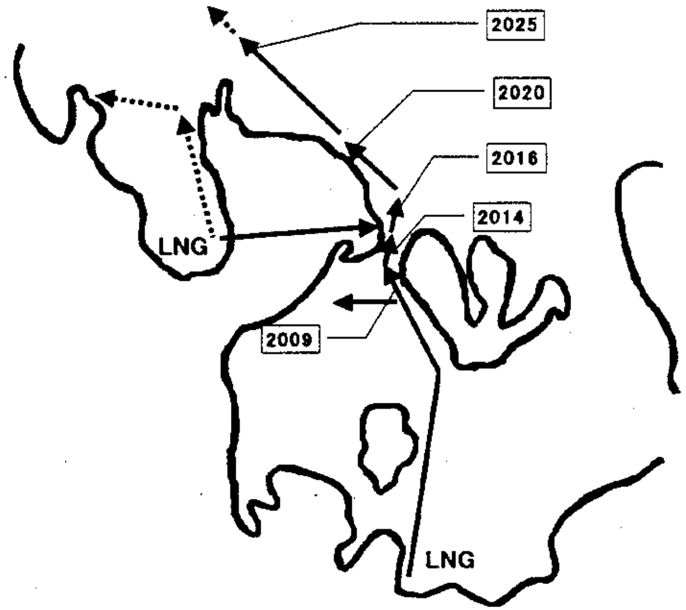

Figure 6-1-7 Supply Area and Year in the High Case / Option 2

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	12.5	14.9	17.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	29.3	36.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	45.1	58.2	72.1	86.6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	102.2	120.7	140.4	161.3	183.5	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	206.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

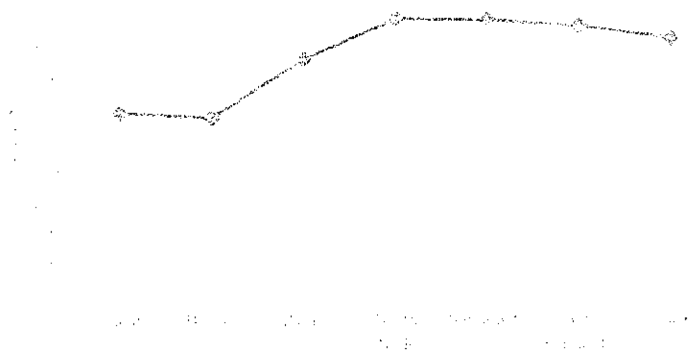

Figure 6.1-6 NPV of Profit by each Region in the High Case

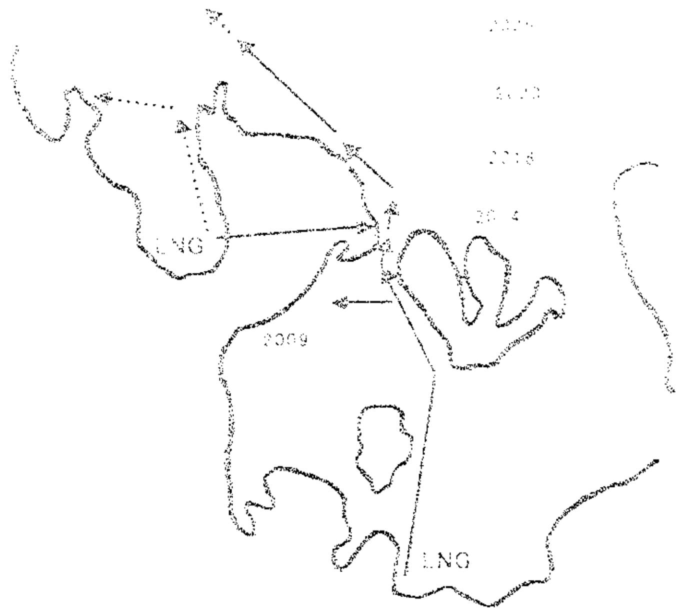

Figure 6.1-7 Supply Area and Year in the High Case (Option 2)

Table 6-1-6 Change of Profit by region in the Low Case / Option 1

(Million US$)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	NPV
Santo Tomas	0.0	0.0	0.0	0.0	[redacted]	2.8	3.1	3.3	3.6	3.9	4.2	4.6	4.9	5.3	5.7	6.0	6.4	6.9	7.3	29.8
Sucat	0.0	0.0	0.0	0.0	0.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	20.8	22.3	24.0	25.9	27.7	29.7	31.8	34.1	36.5	138.9
Bacoor	0.0	0.0	0.0	0.0	0.0	13.7	14.8	15.9	17.1	18.4	19.9	21.5	23.2	25.1	26.9	28.8	30.9	33.2	35.6	133.5
Pasay	0.0	0.0	0.0	0.0	0.0	10.2	11.9	13.7	15.6	17.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	40.9	45.5	50.5	146.1
North NCR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	3.5	7.2	11.3	15.9	21.2	27.1	33.5	[redacted]	[redacted]	[redacted]	89.1

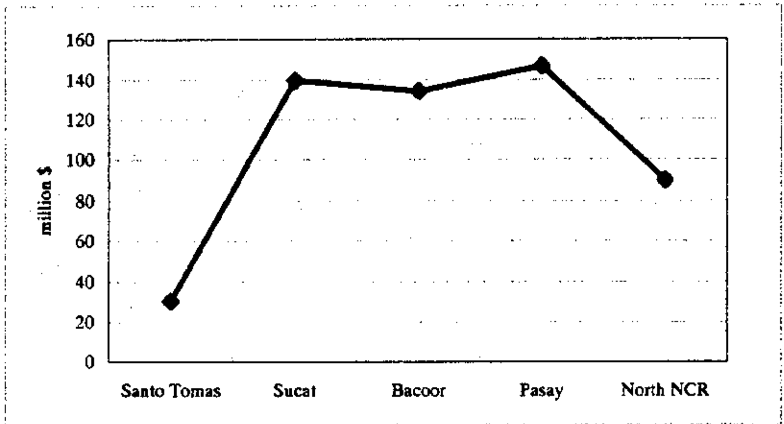

Figure 6-1-8 NPV of Profit by each region in The Low Case Option 1

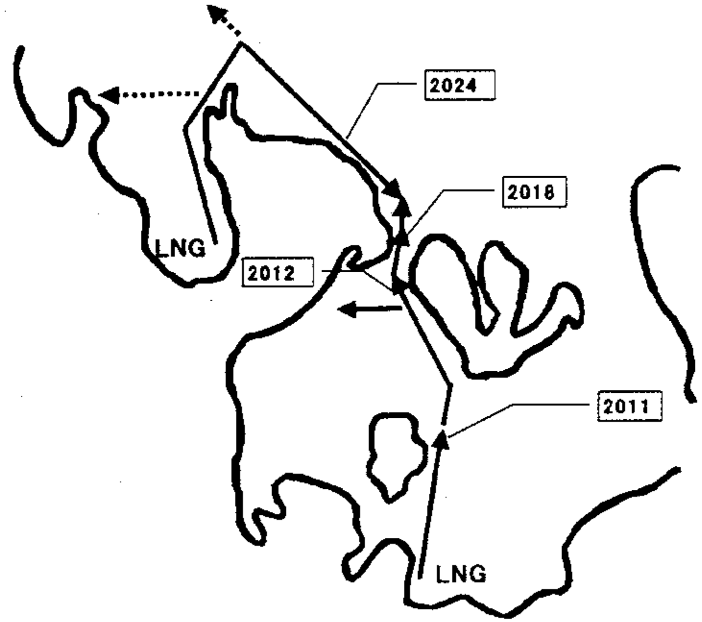

Figure 6-1-9 Supply Area and Year in the Low Case / Option 1

[illegible]	2.6														
[illegible]		14.6	15.6	16.7	17.9	19.3									
[illegible]															
[illegible]							20.0	22.9	25.8	29.3	32.7	36.6			
[illegible]													40.3	48.[illegible]	56.8

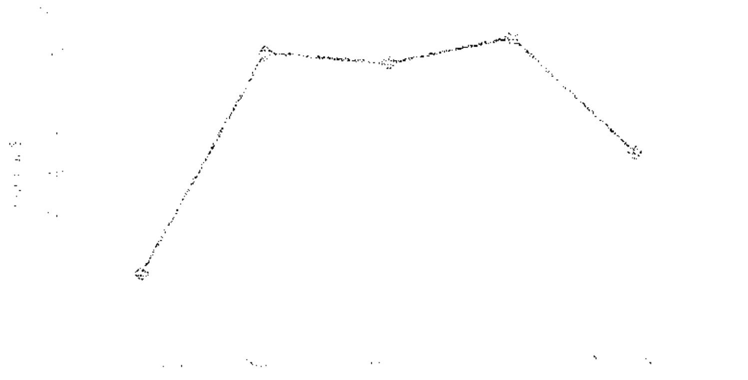

Table 6-1-7 Change of Profit by region in the Low Case / Option 2

(Million US$)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	NPV
Santo Tomas	0.0	0.0	0.0	0.0	[redacted]	2.8	3.1	3.3	3.6	3.9	4.2	4.6	4.9	5.3	5.7	6.0	6.4	6.9	7.3	29.8
Sucat	0.0	0.0	0.0	0.0	0.0	[redacted]						22.4	24.1	26.0	27.8	29.7	31.8	34.1	36.5	139.1
Bacoor	0.0	0.0	0.0	0.0	0.0	13.7	14.8	15.9	17.1	18.5	19.9	21.5	23.2	25.1	26.9	28.9	31.0	33.2	35.6	133.7
Pasay	0.0	0.0	0.0	0.0	0.0	10.3	11.9	13.7	15.6	17.8	20.3	[redacted]			32.8	36.6	40.9	45.5	50.5	146.3
North NCR	0.0	0.0	0.0	0.0	0.0	0.1	2.5	5.0	7.8	11.1	14.7	18.6	23.1	28.2	[redacted]					124.1
Santa Rita	0.0	0.0	0.0	0.0	0.0	0.0	1.0	3.7	6.5	9.9	13.5	17.5	22.1	27.3	33.1	39.4	46.4	54.0	62.3	118.5
San Fernando	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	4.8	8.2	11.9	16.0	20.6	25.9	31.8	38.2	45.3	53.1	61.5	110.8
Clark	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	3.0	6.4	10.1	14.2	18.8	24.1	30.0	36.4	43.5	51.3	59.7	101.8

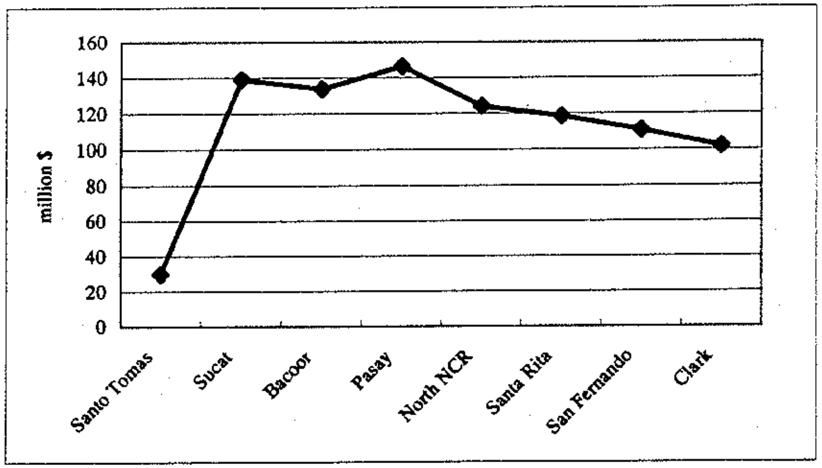

Figure 6-1-10 NPV of Profit by each region in The Low Case

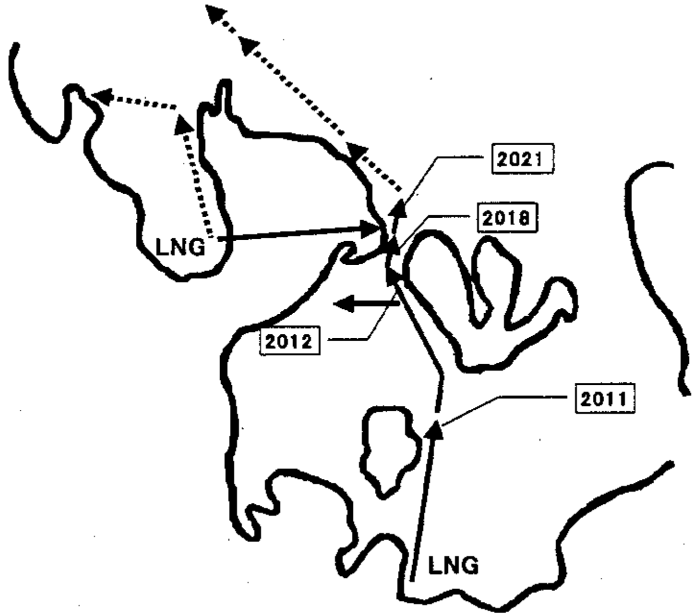

Figure 6-1-11 Supply Area and Year in the Low Case / Option 2

Table 6-1-7 Change of Profit by region in the Low Case Option 2

(Million US$)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2012	[illegible]	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2.6	2.8	[illegible]	3.3	3.6	3.9	4.2	[illegible]	[illegible]	5.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	14.6	15.6	16.8	17.9	19.3	20.8	22.4	24.1	[illegible]	[illegible]	29.7	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.0	13.7	14.8	15.9	17.1	18.5	19.9	21.5	23.2	[illegible]	[illegible]	28.9	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.0	[illegible]	[illegible]	[illegible]	15.6	[illegible]	20.3	22.9	25.9	29.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.0	[illegible]	[illegible]	[illegible]	[illegible]	11.1	14.7	18.6	[illegible]	28.2	33.8	40.0	46.8	54.2	62.3	[illegible]
[illegible]	[illegible]	0.0	0.0	0.0	0.0	0.0	1.0	3.7	6.5	9.9	13.5	17.5	22.1	27.3	[illegible]	39.4	46.4	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	0.0	0.0	0.0	0.0	0.0	0.0	1.7	4.8	8.2	11.9	16.0	20.6	[illegible]	[illegible]	38.2	45.3	[illegible]	[illegible]	[illegible]
Clark	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	3.0	6.4	10.1	14.2	18.8	24.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

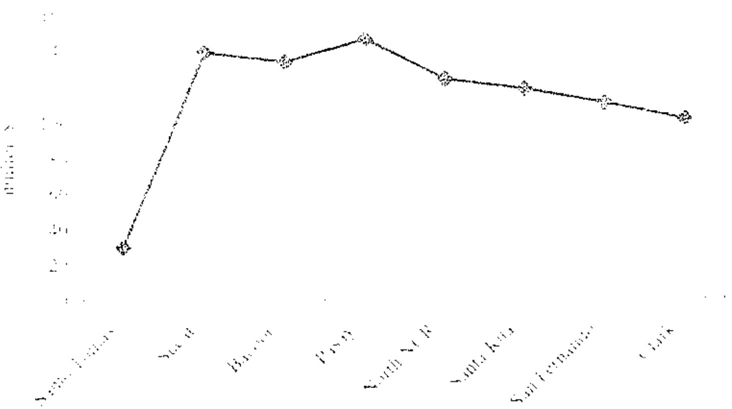

Figure 6-1-10 NPV of Profit by each region in The Low Case

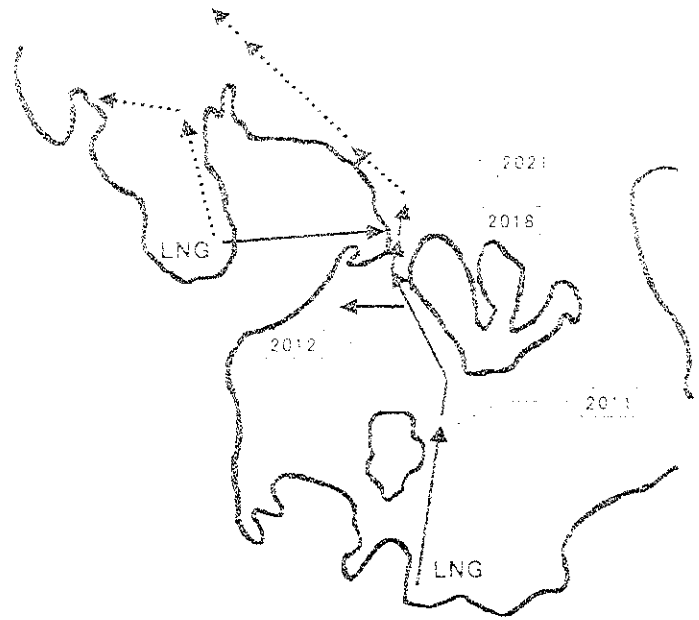

Figure 6-1-11 Supply Area and Year in the Low Case Option 2

6-2 Economic / financial Analyses and the Effects of Gas Related Projects on the Philippine Economy

6-2-1 Preconditions of the Economic/financial Analyses

(1) Target Sectors

The purposes of the project determine investments and schedules for building pipelines in the study area. Then target sectors in the economic/financial analysis of the project are LNG supply, gas pipeline, and gas-fired power generation. We set the three sectors, and prepared financial statements and some policy variables, which are shown in the following table. The policy variables are set in the model for directing the control of gas flows, which starts with natural gas production and/or importation, is followed by gas transportation by pipeline, and finally ends with natural gas consumption in the power generation sector and non-power users, which belong to the industry, commercial, transportation, or residential sectors.

Table 6-2-1 Setting policy variables for the sectors

Sectors	Contents
LNG sector	1) This sector re-gasifies imported LNG and sells the natural gas to pipeline and gas-fired power sectors. 2) We defined that Camago/Malampaya natural gas price is given for the sectors and LNG price imported can be change politically as exogenous variables. 3) It is considered that LNG plants are located in Batangas area and/or Bataan peninsula. The LNG plants are assumed to belong to a LNG sector in the model.
Pipeline sector	1) This sector transports the natural gas using a pipeline from Batangas area to the northern area of Manila via NCR. The gas is consumed in power stations and non-power sectors (Industry, commercial and residential users). 2) Non-power sector cannot use natural gas without a pipeline. Installation of the pipeline, as well as decision on the natural gas price for users are political variables in the model.
Power sector	1) In the Philippines, gas-fired power generation started in 2001. However, the model targets the gas-fired power generation to start beyond the year of 2006. It means the power plants that started from 2001 to 2005 are not included in the model. 2) It is defined that the power generated in the gas-fired power plants is sold to power distribution companies. Then it is the power sales price from the generation sector to distribution companies.

(Note 1) Camago/Malampaya natural gas price is calculated in line with the natural gas price agreement of the related companies outside the model.

(Note 2) Power sector in the model has a power transmission block to calculate the transmission cost.

(2) Currency and Inflation rate

We define that the model uses US$, not the Philippine Peso, for the calculation, because the US$ has been comparatively stable in recent years and is usually used for economic / financial analyses in projects other than natural gas in the Philippines. And inflation rates in the analysis are represented by Consumer price index (CPI) and Industrial products price index (IPI) of USA. The future inflation rates are in the following table.

Table 6-2-2 Setting the increase rate of CPI and IPI of USA

	High		Low	
Indicators	Consumer Price Index	Industrial Products price Index	Consumer Price Index	Industrial Products price Index
2001-2005	1.0%	0.6%	0.5%	0.3%
2005-2015	2.5%	1.5%	2.0%	1.2%
2015-2025	3.0%	1.8%	2.5%	1.5%

The elastic value on IPI to CPI is 0.6.

(3) Project Life and Base Year

We set the year at 2001, when domestic natural gas is to be supplied from Camago/ Malampaya, as the starting year of gas-related projects. The year (2001) is also set to be the base year for the present value method, and the final year of the project is 2025. Therefore, the project calculation term is from 2001 to 2025.

The first investment for constructing pipelines will be made in 2006. Accordingly, the project life is around 20 years (from 2006 to 2025). We target all investments in the analysis, which will be made from 2001 and 2025, although we do not target additional investments beyond 2026, because the effects of the investments will not appear within the project life.

Table 6-2-3 Base year and project life

Items	Year	Term
Base year	2001 (Present value)	
Calculation term	2001 -- 2025	25 years
Project life	Starting year -- 2025	20 years

(4) Depreciation

Depreciation for the sectors is calculated by the straight-line depreciation method, and the residual values (scrap value) of installed machines and equipment in all sectors are determined to be 10% of acquisition value. The depreciation term is 20 years for each sector.

a. LNG sector

We define that the depreciation term of LNG related facilities is 20 years, although concrete houses and buildings are usually depreciated over 20 to 30 years. The fact that re-gasification plants and gas storage tanks are depreciated for 10 to 20 years is one of the main reasons.

Additional investments are often made in the sector, and many assets remain un-depreciated at the end of the term if the depreciation term is as long as 20 years. This is another reason we set the term to be 20 years.

b. Pipeline sector

We define that the term for the pipeline sector is 20 years. Usually, the depreciation term is from 20 to 25 years for the pipeline sector. By defining the term to be 20 years, the end of the depreciation term is in agreement with the end of the calculation term of the model, because we assume investments on pipelines will start five years after the base year.

c. Power generation sector

We define the depreciation term for the power sector to be 20 years. The breakdown of investments in the power sector is not available for the analysis, while the depreciation term for machines and equipment except housing and civil works for the sector is usually 10 to 20 years.

d. Amortization term of L.T. L. interest in pre-operation term

We define that the amortization term for pre-operation assets is 10 years. The amortization term is applied to all target sectors. Usually, the term actually applied is five years in corporate financial statements. In the analysis, however, the term of 10 years is adopted, because the sectors have a huge amount of pre-operation assets (accordingly, a large amount of interest), therefore, they cannot enjoy a very high profit.

Table 6-2-4 Depreciation and amortization term

Items	Sectors & assets	Term
Depreciation Term	LNG	20
	Pipeline	20
	Power	20
Amortization Term	Pre-operation assets	10

(5) Short-Term Loan

When a project needs working capital and/ or others, short-term loans (S.T.L.) can be supplied by domestic banks. We set the interest rate of S.T. L. at 7%, referring to the rates shown in the following table, in addition to actual interest rates recorded in Meralco's accounting report.

Bank average lending rates (Interest rates of S.T. L) in the Philippines shown in the above table are from "The Philippine Statistical Yearbook." Inflation rates of the Philippines are shown in the second column from the right. Using these two data, we can calculate the effective interest rate of S.T.L., which are shown in the far right column titled "Bank average lending rates - Inflation rate."

The estimated nominal rate of S.T.L. is 15%, and the effective interest rate of S.T.L. is 7.0%, as shown in the table. This means that the project has to pay an interest rate of 15% to domestic banks for a short-term loan on a Peso basis. However, the project will have to pay an interest rate of around 7% (effective interest rate) for loans from U.S. banks.

Table 6-2-5 Interest rates of short-term loans in the Philippines

	Manila Reference rates (Deposit rate)	Bank Average Lending Rates (A) (Int. rate of S.T.L)	CPI For the whole Country (B)	Effective interest rate of S.T.L. (A)-(B)
1994	11.6	15.0	8.3	6.7
1995	10.0	14.6	8.0	6.6
1996	11.7	14.8	9.0	5.8
1997	13.1	16.2	5.9	10.3
1998	15.4	16.0	9.8	6.2
1999	15.4	16.0	6.7	9.3
Average	12.9	15.4	7.9	7.5
Estimated value	12.0	15.0 (Nominal rate)	8.0	7.0 (Effective rate)

(Note) Manila Reference rates: Promissory notes and time deposit transactions

(Sources) Philippine Statistical Year Book

(6) Long-term Loan

a. Financing by long-term loans

We assume that 75% of the required capital will be financed by long-term loans and that all of the loans will come from foreign countries. As a result, a withholding tax of 10% on the interest of L.T.L. will be levied for the long-term loans, except international development bank loans.

b. Repayment term of L.T.L.

The repayment terms and grace periods of the international development agencies are shown in the following table. Referring to these, we assume that the repayment term of long-term loans is 10–30 years. However, the 10 years, the period in which the principal of a long-term loan need not be paid ("grace period"), is exclusive of the repayment term.

Table 6-2-6 Repayment term and grace period

International Development Agencies	Repayment term	Grace period
World Bank	15 - 20	5
International Finance Corporation	3 - 13	Max 8
Asia Development Bank	10 - 30	3 – 7
Japan Bank for International Cooperation	10 - 30	Case by case
(Foreign commercial bank)	(5-10)	(Case by case)

(Sources) Referred to the homepage of each facility

c. Interest rate of long-term loan

According to "The Philippine Statistical Yearbook 2000", the interest rate of long-term loan is 18%(The term of a long-term loan is usually one year in the Philippines), which is shown in the following table. This means that the rate of domestic L.T.L. is " Interest rate of short-term loan + 3%(spread)."

Table 6-2-7 Long-term loans in the Philippines

Long-term loan	Items	Contents
Long-term loan in local banks	Repayment term for Local L.T.L.	1 year
	Nominal Interest rate of Local L.T.L.	18.0%

It is difficult for a project to have long-term loans with a repayment term of more than one year from domestic banks in the Philippines. In this case, the project needs to have long-term loans from foreign or international development facilities.

The interest rates of international development facilities are shown in the following table. Project finance is usually a combination of financing from several banking institutions, including commercial banks and international development facilities. Therefore, the interest rate of long-term loans can be calculated as their average.

Table 6-2-8 Long-term loans in International Development Facilities

Agencies	Interest rate	As of
World Bank	6.4%	Jan-Jun 98
International Finance Corporation	Market rate	
Asia Development Bank	6.0 - 6.8%	As of April 98
Japan Bank for International Cooperation	1.3 - 2.0%	As of June 200 1
(Foreign commercial bank)	(7 %)	

(Sources) Referred to the homepage of each facility

The interest rates of L.T.L. in the following table are set in the model. It is assumed that the project takes out long-term loans from foreign commercial banks, International Development Facilities A (IDF-A), and International Development Facilities B (IDF-B).

Table 6-2-9 Shares of L.T.L. and interest rates in the model

Agencies	Shares of loan	Interest rate	Repayment term	Grace
Foreign bank	25%	7.7%	10 years	Nothing
IDF-A	25%	2.0%	20 years	10 years
IDF-B	25%	7.0%	20 years	10 years

(Note 1) The remain (25% fund) comes from own capital.
(Note 2) The average interest rate of L.T.L. is 4.5%

(7) Labor Cost

There are several kinds of labor cost for building and maintaining the project. Table 6-2-9 below shows the income statistics of the Philippines.

a. Labor cost of operators

Operators work, for instance, to construct gas refining plants and pipelines, as well as maintain gas-fired power plants and LNG terminals. They are required to have the capabilities and the technologies necessary for the operation, which are equivalent to high-school graduate level.

Labor cost of an operator is estimated to be Ps100,000 / year (US$2000) in 2001. They also need employee benefits and welfare facilities. It is considered that labor cost including employee benefits and welfare facility cost is Ps120,000 (US$2,400).

b. Salaries of administrators and engineers

Administrators and engineers work for gas production facilities and in corporate administrations. They are required to have capabilities equivalent to a college and university graduate level. Salaries of administrators and engineers are estimated to be Ps300,000 / year (US$6,000) in 2001.

The wages of the engineers are included in construction cost (that is investment cost), and that of the administrators are included in sales and administration cost in our economic/financial model.

Table 6-2-10 Household income in urban areas in 1997

Income class	Number of families (1,000 households)	Average (Ps / year)
Under 10,000	8.1	7,612
10,000 – 19,999	82.9	15,971
20,000 – 29,999	181.3	25,578
30,000 – 39,999	297.1	35,099
40,000 – 49,999	367.3	45,024
50,000 – 59,999	372.9	54,921
60,000 – 79,999	816.4	70,039
80,000 – 99,999	715.3	89,772
100,000 – 149,000	1348.8	122,950
150,000 – 249,000	1391.2	192,049
250,000 – 499,000	870.7	332,043
500,000 – over	298.7	1,022,447

(Sources) Philippine Statistical Yearbook

(8) Maintenance, Sales, and Factory Expenses and Others

Maintenance cost (factory expenses, spare parts, and utilities) is defined to be 2% to 5% of investment value. The costs of utilities, which LNG and pipeline related facilities use, are included in the maintenance costs. Sales and administration costs are assumed to be 5% of sales value in the LNG, pipeline and power sectors, respectively. We assume that the insurance cost of each sector is 1% of acquisition value of fixed assets.

Table 6-2-11 Maintenance, sales, administration, and insurance costs

Fixed cost items	%	Multiplicand
Maintenance cost: LNG	2.0	% of acquisition value of assets
Pipeline	4.0	Same as above
Power	5.0	Same as above
Sales cost, administration cost	5.0	% of sales value
Insurance cost	1.0	% of acquisition value of assets

(9) Tax rate

We can account taxes such as VAT tax, real property tax, business tax, corporate tax, withholding tax and customs duties related to the LNG, pipeline, and power sectors. The tax rates are in the following table.

The above taxes are cost items in the financial analysis, however, in the economic analysis, the tax values are dealt with as income items for the Philippine government.

Table 6-2-12 Tax rates related to the project

Tax items	%	Multiplicand
VAT tax	10.0	% of "sales value – variable cost"
Real property tax	2.0 1.0	% of assessment value in NCR % of assessment value in Provinces
Business tax (Local tax)	0.5	% of sales value
Corporate tax	32.0	% of before tax profit
Customs tax	3.0 3.0 3.0	% of crude oil % of imported petroleum products price % of LNG (from 2003)
Import duty(LNG)	3%	% of Imported LNG beyond the year of 2006
Import duty(Materials)	5%	% of Import values (5% is the average import tax rate)
Withholding tax	10.0	% of interest rate

(Sources) The Tax reform act of 1997 in Philippines

(10) Dividend Rate

Dividend rate is 15% of capital equity, however, when the current profit is lower than dividend value, the profit is not delivered. And, although there exists an accumulative deficit in the current financial statements, current profit more than dividend value is delivered to shareholders.

Table 6-2-13 Dividend Rate and Dividend value

Items	Dividend distribution conditions
Distribute Dividend	Current profit > Investment *0.15, then current profit is distributed. Dividend value is determined by "Investment *0.15", the undistributed profit become internal reserves.
Not distribute Dividend	Current profit < Investment *0.15, then current profit is not distributed.

(11) Exchange Rate

The exchange rate is forecasted in the macro-economic model in Chapter 4. In the model, basically, the exchange rate between the Pesos and US$ is determined by the Philippine foreign trade balance. (Explanation variables are Import value / Export value).

Shadow exchange rates are used in the economic analysis. In the Philippines, the difference between shadow exchange rates and market exchange rates of Pesos and US$ was within 1% from 1995 to 1999. This means that the Philippine Pesos' shadow exchange rates almost equal to the market exchange rates. Therefore, the market exchange rate is used in the model.

Table 6-2-14 Shadow exchange rate of the Philippine Pesos

Items		Unit	1995	1996	1997	1998	1999	Average
Market exchange rate		Peso/US$	25.7	26.2	29.5	40.9	39.1	32.3
Export	Exports in total	Billion peso	448.4	538.2	744.2	1,206.4	1,369.9	861.4
	Electric equipment	Billion peso	190.5	261.9	384.3	700.9	827.6	473.1
	Machinery & transportation	Billion peso	19.0	33.9	79.2	135.6	193.5	92.3
	Textile & garment	Billion peso	78.2	76.9	88.3	119.3	106.0	93.7
	Bananas, Mangoes, Coffee & Fish	Billion peso	22.3	18.9	19.9	28.8	26.8	23.4
	Total	Billion peso	310.1	391.7	571.7	984.7	1,154.0	682.4
Export subsidry rate (Tax reduction)	Electric equipment	%	3.0	3.0	3.0	3.0	3.0	3.0
	Machinery & transportation	%	3.0	3.0	3.0	3.0	3.0	3.0
	Textile & garment	%	3.0	3.0	3.0	3.0	3.0	3.0
	Bananas, Mangoes, Coffee & Fish	%	3.0	3.0	3.0	3.0	3.0	3.0
	Average	%	0.0	0.0	0.0	0.0	0.0	0.0
Export subsidy	Electric equipment	Billion peso	5.7	7.9	11.5	21.0	24.8	14.2
	Machinery & transportation	Billion peso	0.6	1.0	2.4	4.1	5.8	2.8
	Textile & garment	Billion peso	2.3	2.3	2.6	3.6	3.2	2.8
	Bananas, Mangoes, Coffee & Fish	Billion peso	0.7	0.6	0.6	0.9	0.8	0.7
	Total of subsidary	Billion peso	9.3	11.7	17.2	29.5	34.6	20.5
Import(FOB)	Imports in total	Billion peso	682.0	849.6	1,060.0	1,213.1	1,202.0	1,001.3
	Electrical machines	Billion peso	97.7	128.4	200.6	294.5	281.5	200.5
	Machines	Billion peso	113.1	157.2	162.3	175.9	152.5	152.2
	Base metal	Billion peso	25.7	36.7	41.3	46.2	55.6	41.1
	Mineral fuels	Billion peso	64.3	78.6	88.5	90.0	97.8	83.8
	Total	Billion peso	300.7	400.9	492.7	606.5	587.4	477.6
Import tax rate	Electrical machines	%	5.7	5.7	5.7	5.7	5.7	5.7
	Machines	%	5.8	5.8	5.8	5.8	5.8	5.8
	Base metal	%	8.0	8.0	8.0	8.0	8.0	8.0
	Mineral fuels	%	5.4	5.4	5.4	5.4	5.4	5.4
	Average	%						
Import tax	F	Million peso	5.5	7.3	11.4	16.7	15.9	11.4
	G	Million peso	6.6	9.1	9.4	10.2	8.9	8.8
	H	Million peso	2.0	2.9	3.3	3.7	4.4	3.3
	I	Million peso	3.5	4.2	4.8	4.8	5.3	4.5
	Total	Million peso	17.6	23.5	28.8	35.4	34.5	28.0
Shadow Exchange Coefficient			1.0	1.0	1.0	1.0	1.0	1.0
Shadow Exchange Rate		Peso/US$	25.9	26.4	29.7	41.0	39.1	32.4

(12) Natural Gas Price

Basically, the price of natural gas delivered to industrial users and households, for instance, through pipelines, is defined to be "Gas purchased cost + pipeline cost +profit". But, when the price is higher than the prices of petroleum products such as LPG, kerosene and diesel fuel oil, or electricity, customers will not use natural gas. Accordingly, the price of natural gas should be set in keeping with its competitiveness to petroleum products or electricity.

Pricing of Camago/Malampaya natural gas has been agreed between the gas supply company (Shell) and its users (NPC: National Petroleum Company and FGH: First Gas Holdings). Prices agreed are important indicators for forecasting the prices of domestic natural gas delivered to other users.

The following table shows the components of Camago/Malampaya natural gas prices we have estimated for our study.

Camago/Malampaya natural gas price formula for NPC

Base price *(0.53*US-CPI increase rate

+0.075* Singapore marin bunker spot price

+0.075*Singapore products spot price

+0.075*Dubai crude oil spot price

+0.075*Oman crude oil spot price

+0.17)

Camago/Malampaya natural gas price formula for FGH

Base price *(0.43*US-CPI increase rate

+0.15* Singapore marine bunker spot price

+0.10* Singapore oil products spot price

+0.075*Dubai crude oil spot price

+0.075*Oman crude oil spot price

+0.17)

Table 6-2-15 Camago/Malampaya gas prices estimated

Types	Data	Comments	UNit	2001	2002	2003	2004	2005	2010	2015
Values in 1995	USCPI	1985=100	1985=100	141.6	141.6	141.6	141.6	141.6	141.6	141.6
	MSFO	Marin bunker spo	$/MT	103.97	103.97	103.97	103.97	103.97	103.97	103.97
	Gasoil	Oil products spot	$/bbl	21.60	21.60	21.60	21.60	21.60	21.60	21.60
	Dubai oil	Crude oil spot pri	$/bbl	16.10	16.10	16.10	16.10	16.10	16.10	16.10
	Oman oil	Crude oil spot pri	$/bbl	16.10	16.10	16.10	16.10	16.10	16.10	16.10
	NCV	MJ/kg	MJ/kg	45.70	45.70	45.70	45.70	45.70	45.70	45.70
	GCV	MJ/kg	MJ/kg	50.64	50.64	50.64	50.64	50.64	50.64	50.64
	USCPI	1985=100	1985=100	159.2	160.8	162.4	164.0	165.6	187.4	212.0
	MSFO	Marin bunker spo	$/MT	148.47	123.20	143.09	143.67	157.37	193.54	204.79
	Gasoil	Oilproducts spot	$/bbl	24.73	20.52	23.83	23.93	26.21	32.24	34.11
	Dubai oil	Crude oil spot pri	$/bbl	22.85	18.96	22.02	22.11	24.22	29.78	31.51
	Oman oil	Crude oil spot pri	$/bbl	22.85	18.96	22.02	22.11	24.22	29.78	31.51
	NCV	MJ/kg	MJ/kg	45.70	45.70	46.70	46.70	45.70	45.70	45.70
	GCV	MJ/kg	MJ/kg	50.64	50.64	50.64	50.64	50.64	50.64	50.64
NPC formula	Base price		$/GJ	4.029	4.029	4.029	4.029	3.934	3.744	3.555
	Base price	Net calory value	$/MMBtu	4.251	4.251	4.251	4.251	4.150	3.950	3.751
	GJ / mmBtu		1.055							
	NPC-NG prices		$/MMBtu	4.979	4.711	4.968	5.000	5.063	5.531	5.713
	NCV mmBtu / 1000scf		1.010							
	NPC-NG prices		$/1000scf	5.029	4.758	5.017	5.050	5.114	5.586	5.770
FGH formula	Base price		$/GJ	4.076	4.076	4.076	4.076	3.981	3.791	3.602
	Base price	Net calory value	$/MMBtu	4.300	4.300	4.300	4.300	4.200	4.000	3.800
	GJ / mmBtu		1.055							
	FGH-NG prices		$/MMBtu	5.138	4.762	5.095	5.126	5.237	5.779	5.931
	NCV mmBtu / 1000scf		1.010							
	FGH-NG prices		$/1000scf	5.189	4.810	5.146	5.177	5.289	5.837	5.990

Regarding imported LNG price, we estimated the LNG cif price at the Philippines referring to Australia LNG export price. The future LNG cif price is forecasted in the macro-economic forecasting model.

(13) Working Capital

We assume that working capital is an amount equal to three-twelfths of the difference between annual sales value and variable costs. Stock costs of raw materials and products are included in the working capital. Working capital is assumed to be funded by short-term loans from the domestic monetary market.

The short-term loans are not repaid until the end of the project life. When FIRR and EIRR are calculated, working capital is returned in the income category of FIRR and EIRR tables at the end of the project life.

Table 6-2-16 Example for Working Capital (W/C) calculation

(US$1,000)

Year	2006	2007	2008	2009	2010	2011	2012
Sales	1000	1200	1300	1500	1600	1700	2000
W/C (Additional)	250	50	25	50	25	25	75
W/C (Accumulative)	250	300	325	375	400	425	500

W/C (Additional)=(Current sales – Previous sales)*(3 months /12months)

(14) Procedures for Booked Assets beyond the Project Life

When FIRR and EIRR are calculated, booked assets that are un-depreciated at the end of the project life are returned in the income category of FIRR and EIRR tables.

Table 6-2-17 Example for returning booked value beyond calculation term

(US$1,000)

Year	2019	2020	2021	2022	2023	2024	2025
Acquisition value	1000	1000	1000	1000	1000	1000	1000
Depreciation value	90	90	90	90	90	90	90
Booked value	910	820	730	640	550	460	370

The value of 370 in 2025 is booked value beyond the calculation term. The value is added to "Return" at the time of calculating FIRR and EIRR.

(15) Summary of Preconditions for the Economic / financial Analyses

The preconditions of the economic and financial analyses are summarized in the following tables.

Table 6-2-18 Pre-conditions for economy and tax rates

Currency	Used US$ Used US-CPI as the inflation rate in the analyses. Plant construction inflation rate has the elastic value of 0.6 to US-CPI (For deleting the effects of movements of Peso's exchange rate)
Interest rate	Interest rate of L.T.L in commercial bank is 7.7%; Interest rate of L.T.L in International development A is 2.0%; Interest rate of L.T.L in International development B is 7.0%; Interest rate of S.T.L.: 7.0% (Interest rate from U.S. banks to Meralco is 6.96-7.13%)
Discount rate	12% (The same rate as that for other projects in the Philippines)
VAT rate	10% of sales value (Refer to Table 6-2-9)
Real estate property tax rate	1% of acquisition value of assets (2% in NCR, 1% in other areas)
Business tax	0.5% of sales values (Refer to Table 6-2-9)
Corporate tax	32% of profit (32% beyond 2000, 35% before 1999)
Import duty	3% of the imported LNG (beyond the year of 2003) 5% of the imported machines / materials (Assuming that 60% of investment values is imported ones)

Table 6-2-19 Pre-conditions of investment and annual expense

Labor cost	US$2,400/person,
Required man-power	LNG maintenance : High Option1 : 309, Option2 : 309, C-M, Davao : 100 Low Option1 : 240, Option2 : 240, C-M, Davao : 100 Pipeline maintenance: High Option1 : 606, Option2 : 606, C-M, Davao : 40 Low Option1 : 289, Option2 : 289, C-M, Davao : 40 Power maintenance High Option1 : 7050, Option2 : 7050, C-M, Davao : 385 Low Option1 : 5895, Option2 : 5895, C-M, Davao : 385 (Estimated by the JICA Study Team)
Maintenance cost	LNG: 2% of acquisition value Pipeline: 4% of acquisition value Power: 5% of acquisition value (Estimated by the JICA Study Team)
Sales and administration costs	5% of sales values (Estimated by the JICA Study Team)
Insurance fee	1% of acquisition values (Estimated by the JICA Study Team)
Investment	LNG is estimated by the Study Team Pipeline is estimated by the Study Team Gas combined cycle defined by US$600/kW (Refer to investment cost of Ilijan power plant)
Investment schedule	Initial investment: Made one year before commissioning the plant. Additional investment: Made one year before commissioning additional capacities. (We assume that the investments are carried out with a one-time payment, although actually they are made in annual payment.)

Table 6-2-20 Pre-conditions of depreciation and capital fund

Depreciation term	LNG: 20 years, Pipeline: 20 years, Power: 20 years (Most of the assets are depreciated from 2006 to 2025.)
Residual value rate of depreciation	10% of acquisition value of assets (The equipment in plants are re-usable)
Depreciation method	Straight line method (The method is widely used in the Philippines)
Capital ratio	Own capital fund: 25% of the total funds L.T.L. from commercial bank: 25% of the total funds. L.T.L. from JBIC: 25% of the total funds. L.T.L. from ADB: 25% of the total funds. (Same as other projects in the Philippines)
Repayment term of L.T.L	10 years for commercial bank 20 years for International development A including 10 years grace 20 years for International development B including 10 years grace (10 years is the maximum repayment term of L.T.L.)

Table 6-2-21 Pre-conditions of prices and conversion factors

Batangas natural gas price	High US$5.23/MMBtu in 2006, Low US$4.77/MMBtu in 2006 (The average price of NPC and FGH natural gas price)
LNG cif price	High US$4.63/MMBtu in 2006, Low US$3.80/MMBtu in 2006 (Estimated based upon Australia actual values)
LNG sales price	The sales price is set for LNG sector to be able to get 12% of FIRR.
Power prices	Power tariffs from IPPs to distribution companies is ¢ 8/kWh (Actual buying value of NPC in Nov. 2000)
Pipeline gas sales prices	High Industry use : US$7.25 /MMBtu in 2006 Commercial use : US$8.48 /MMBtu in 2006 Residential use : US$9.42 /MMBtu in 2006 Transportation use : US$7.82 /MMBtu in 2006 Power use : US$7.06 /MMBtu in 2006 Low Industry use : US$6.15 /MMBtu in 2006 Commercial use : US$7.19 /MMBtu in 2006 Residential use : US$7.98 /MMBtu in 2006 Transportation use : US$6.63 /MMBtu in 2006 Power use : US$5.99 /MMBtu in 2006 (Natural gas has competitiveness to LPG in this price)
Natural gas calories	LHC= 9,495Kcal/kg, HHC=13,122Kcal/kg
Natural gas density	0.806kg/Nm3

Table 6-2-22 Pre-conditions of calculation methods

Un-depreciated assets	Returned to income category in 2025 (In FIRR theory, they are returned at the end of project life.)
Working capital	Returned to income category in 2025 (In FIRR theory, it is returned at the end of the project life.)
Pre-operation interest	It is depreciated over 10 years after starting operation (Only interest in pre-operation is set as pre-operation assets)

6-2-2 Algorithm for Economic and Financial Analyses

(1) The Calculation Procedures for Financial Statements

In this model, the financial statements are prepared by the following procedures.

Table 6-2-23 Calculation procedures for economic financial analysis

Model blocks	Calculation items
Energy balance	Demand and supply balance for NG & LNG
Economic and financial statements for LNG sector, Pipeline sector, Power sector, and Total sectors	Investment and capital fund plan Operating cost calculation Depreciation cost Interest payable and pre-operation interest Income statements Cash flow table FIRR calculation DCR calculation EIRR calculation
Changes in macro-economy between with-project and without-project	Changes in GDE Changes in Government revenues Changes in Unemployment rates

(Note1) The above financial statements are prepared for LNG, pipeline, and Power sectors
(Note2) GDE: Gross domestic expenditure

Energy demand supply balance table describes domestic natural gas and LNG demand by utilization, and it use the sales value calculation for LNG and pipeline sectors.

The financial statements of each sector are the main outputs in the analysis, current profit, FIRR, DCR, and EIRR in the statements are important appraisal indicators.

Regarding the analysis of the Philippine macro-economy, changes of GDP, government tax revenues, and un-employment rate between with-projects of LNG, pipeline and gas-fired power generation sectors and without-projects are calculated.

(2) Investment and Capital Fund Plan

By inputting investment scheduling and its amount in the model, investment value from 2001, which has been escalated by U.S. inflation rates, are calculated. It is assumed that 75% of the investment comes from long-term loans and the remaining (25%) is from own capital. Long-term loans from commercial banks are repaid over 10 years and those from international development facilities are repaid over 20 years including 10 years grace periods.

(3) Operating Cost Calculation

Operating costs included property tax, insurance fee, maintenance cost, and labor cost are calculated with input data. These cost items are used in income statements with depreciation, interest payable, administration cost, and head office cost.

(4) Depreciation Cost

Capital investments are depreciated for a prepared depreciation term by the straight-line method. The residual value (scrap value) is defined to be 10% of the acquisition value. The starting year of depreciation is one year after investment.

(5) Interest Payable and Pre-operation Interest

At the same time as long-term loan interests are calculated, pre-operation interest is calculated, and depreciated over 10 years. In the Philippines, a withholding tax of 10% is levied on capital loans from foreign countries. In the model, it is assumed that all long-term loans come from foreign countries. Therefore, the withholding tax is levied on long-term loans of foreign commercial banks in the model.

(6) Income Statement

In the following formula, income statements of LNG sector, pipeline sector, power sector, and the project total are calculated.

Sales value of LNG sector includes that to the both power and non-power sectors (Industry, commercial, transportation, and residential). Sales value of pipeline sector is that to non-power sectors and Sucat power generation plant. Sales value to the power sector is calculated by the wholesale power price from generation companies to power distribution companies. As mentioned already, we assume that the price is 84% of the average power tariff NPC sells to final users.

Variable costs include import LNG cost in LNG sector, natural gas cost (it is supplied from the both of Camago/Malampaya gas fields and LNG plants) in pipeline sector and natural gas cost (It is supplied from the three routes of Camago/Malampaya gas fields, LNG plants directly, and through pipeline) in gas-fired power sector.

Production fixed costs include depreciation cost, property tax, insurance cost, maintenance cost, and labor cost. Among non-operating expenses, we can also account for sales cost, administration cost, business tax, value added tax, long-term and short-term loans, and pre-operation amortization.

Current profit after tax is delivered to shareholders with a dividend rate of 15% when the profit is greater than the total dividend value. Although an accumulative deficit remained in the current year, the dividend is delivered under previous conditions.

Sales prices and unit costs of the each sector in the targeted years are calculated in the income statement. The average sales price and the average unit cost in all years are also calculated by present value method.

Table 6-2-24 Income statement table

Sales	LNG sales value	1000US$
	(Sales volume)	mmcf
	(Sales price)	$/1000scf
Variable cost	LNG import cost	1000US$
Fixed cost	Depreciation	1000US$
	Assets tax	1000US$
	Insurance	1000US$
	Maintenance cost	1000US$
	Wages	1000US$
	Total	1000US$
Supply cost	Direct supply cost	1000US$
	Gross profit on sales	1000US$
Non-operating expenses	Sales cost & administration	1000US$
	Business tax	1000US$
	Value added tax	1000US$
	Interest of L.T.L	1000US$
	Interest of S.T.L	1000US$
	Amortization	
	Total	1000US$
Profit before tax	Full cost	1000US$
	(Unit cost)	$/1000scf
	Profit before tax	1000US$
Profit after tax	Corporate tax	1000US$
	Profit after tax	1000US$
	Dividend	1000US$
	Retained earnings	1000US$
	(Accumulatice)	1000US$
price & cost	Sales price	$/1000scf
	Full cost	$/1000scf
	Re-gasfication cost	$/1000scf
ROA	Cash on hand	1000US$
	Acc. Receivable	1000US$
	Booked value of the assets	1000US$
	total	1000US$
	ROA	%

(7) Cash Flow Table

In the following formula, the cash flow tables of LNG sector, pipeline sector, power sector, and all sectors are calculated.

The summation of long-term loans and equity equals capital investments for the each sector.

In the model, short-term loans are assumed to be made only for working capital. When there is a capital shortage in the cash flow, the shortfall is fulfilled by short-term loans from banks. But this is not the case in the model. Thus, interest payable for the short-term loans needed by the capital shortage is not taken into account in the model.

Table 6-2-25 Cash flow table

Sources	Cash in total	1000 US$
	(+) LNG sales value	1000 US$
	(+) Equipty	1000 US$
	(+) Long Term Loan	1000 US$
	(+) Short term loan for W/C	1000 US$
Application	Investment	1000 US$
	Working capital	1000 US$
	(Accumulatice W/C)	1000 US$
	Direct operating cost	1000 US$
	(+) Fuel cost	1000 US$
	(+) Assets tax	1000 US$
	(+) Insurance	1000 US$
	(+) Maintenance cost	1000 US$
	(+) Wages	1000 US$
	Indirect operating cost	1000 US$
	(+) Sales cost & administrat	1000 US$
	(+) Business tax	1000 US$
	(+)Value added tax	1000 US$
	(+) Coporate tax	1000 US$
	(+) Interest of L.T.L.	1000 US$
	(+) Interest of S.T.L.	1000 US$
	(+) Repayment of L.T.L.	1000 US$
	(+) Dividend	1000 US$
	Cash out total	1000 US$
Cash surplus	Cash surplus a year	1000 US$
	Accumulative	1000 US$

(8) FIRR Calculation

FIRR (Financial internal rate of return) is calculated by the method shown in the following table.

Investment and working capital fund are summed up as Capex (Capital cost accounts). All working capital is returned to the income category at the end of calculation term.

As Opex (Operation cost accounts), LNG import costs are summed up for the LNG sector, domestic natural gas and LNG purchasing costs for the pipeline sector, and domestic natural gas purchasing costs and import natural gas cost for the power sector, respectively. In addition, other costs for all sectors, including property tax, insurance fee, maintenance cost, labor cost, sales and administration cost, business tax, value added tax, and corporate tax are summed up.

Sales revenues are LNG sector's natural gas sales to pipeline and power sectors, pipeline sector's natural gas sales to power and non-power sector, and power sector's power sales to industry and end-users.

Benefit of the sectors is expressed as "Sales revenue – Capex – Opex".

FIRR is calculated by "=IRR(Xm : Xn、0)" in EXCEL functions.

Xm: the starting year of the cash flow, Xn : the final year of the cash flow

Table 6-2-26 FIRR calculation table

Capex	Investment	1000 US$
	Working capital for gas users	1000 US$
	Total	1000 US$
Opex	LNG import cost	1000 US$
	Assets tax	1000 US$
	Insurance	1000 US$
	Maintenance cost	1000 US$
	Wages	1000 US$
	Sales cost & administration	1000 US$
	Business tax	1000 US$
	Value added tax	1000 US$
	Coporate tax	1000 US$
	Total	1000 US$
Income	LNG sales amount	1000 US$
Benefit	Cash flow	1000 US$
	FIRR	%

(9) DCR Calculation

DCR (Debt coverage ratio) is calculated as shown in the following Table6-2-23. The total principal loan contains long-term and short-term loans.

The capability of repayment is shown by the summation of capital surplus, interest payable, and repayment of long-term loans.

DCR means the present value of repayment capability divided by the present value of total principal loans.

Table 6-2-27 Debt Coverage Ratio(DCR) table

DCR	Income	Sales	1000 US$
		Equity	1000 US$
		Long term loan	1000 US$
		Short term loan for W/C	1000 US$
		Total	1000 US$
	Expenditure	Opex	1000 US$
		Interest	1000 US$
		Equipment	1000 US$
		Working capital	
		Repayment	1000 US$
		Total	1000 US$
	Capital surplus		1000 US$
	Capability of repayment	Capital surplus(PV)	1000 US$
		Interest(PV)	1000 US$
		Repayment(PV)	1000 US$
		Total(PV)	1000 US$
	Principal loan(PV)		1000 US$
	DCR		

(10) EIRR Calculation

EIRR (economic internal rate of return) is calculated as shown in the following Table 6-2-24.

Capex in EIRR is the same value as that in FIRR. It is assumed that 60% of the investment is for importing machines and materials, on which are levied 5% customs. In the EIRR analysis, all taxes and customs are treated as income to the government. Therefore, 5% customs on imported machines and materials should be eliminated from the cost items of the sectors.

Investment (FIRR)= Equipment investment (FIRR)+ Working capital(FIRR)
Investment (EIRR)= Equipment investment (FIRR)*(0.6*0.95+0.4)
+ Working capital(FIRR)

0.6: 60% of equipment investment is levied by customs tax
0.95: Decreased by 5% customs tax rate
0.4: 40% of equipment investment are procured in domestic markets.

In the same way, the withholding tax of 10% for foreign loan is eliminated from the cost items of the sectors.

Opex in EIRR is defined as Opex in FIRR from which property tax, business tax, withholding tax, value added tax, and corporate tax are subtracted.

Table 6-2-28 Example of EIRR

EIRR	Capex	Investment	1000 US$
		- Customs tax to 60% of investment	1000 US$
		Working capital for gas users	1000 US$
		Total	1000 US$
	Opex	Opex	1000 US$
		- LNG costums	1000 US$
		- Asset tax	1000 US$
		- Business tax	1000 US$
		- Value added tax	1000 US$
		- Corporate tax	1000 US$
		Total	1000 US$
	Income	LNG sales value	1000 US$
		- Others	1000 US$
		Total	1000 US$
	Benefit	Cash flow	1000 US$
		EIRR	%

Income (Sales revenues) are LNG sales value for the LNG sector, gas sales value for the pipeline sector, and power sales value for the power sector, respectively.

Benefit of the sectors is expressed as "Income – Capex – Opex".

EIRR is calculated by "=IRR（Xm : Xn、0）" in EXCEL functions.

Xm: the starting year of the cash flow, Xn: the ending year of the cash flow

(11) Effects on GDP and Other Macro-Economic Indicators

In the analysis, effects on the Philippine economy are compared for "GDP with-the project (LNG, pipeline and power sectors)" and "GDP without-project.

Table 6-2-29 Effects on GDP

GDP	Without	Private consumption		Billion pesos
		Government consumption		Billion pesos
		Gross fixed formation		Billion pesos
		Exports		Billion pesos
		Imports		Billion pesos
		Stock		Billion pesos
		GDP		Billion pesos
	With	Value added	+GDP	
			+Sales Value	Billion pesos
			-LNG Imported	Billion pesos
			Net	Billion pesos
	Changes	PV without		Billion pesos
		PV with		Billion pesos
		With / Without		%

It is considered that nominal GDP is changed by the productivity of the project.

GDP without-project

GDP forecast in Macro-economic model

GDP with-project

GDP + The total sales value of the projects − Import value of LNG

The increase of GDP with-project accounts for only the additional value added in business as usual of each sector. Strictly it has happened that some types of energy are not consumed due to the use of natural gas in residential and industry sectors. But, in the study, it is assumed that the un-used energies are consumed in new sectors or it is not imported.

(12) Effects on Government Revenues

The utilization of natural gas will bring tax income to the government budgets. The government revenue will increase in the following ways:

Government revenue without- project

Government revenue forecasted in the macro-economic model

Government revenue with- project

Government revenue + Tax revenue from project sectors

(Custom tax, property tax, corporate tax, business tax and VAT)

In the above expressions, royalty revenues from Camago/Malampaya natural gas project are excluded.

(13) Effects on un-employment rate

The Philippine GDP will be increased by introducing natural gas. When the labor productivity is constant, the number of employees will increase. As a result, the un-employment rate will decrease. Then, the following expressions are considered.

Un-employment rate without-project

Forecast in the macro-economic model

Un-employment rate with-project

Additional employee =additional VAT / labor productivity

1- (Number of employee + Additional employee) / number of labor forces

Table 6-2-30 Example of effects on government revenues and un-employment rate

Government finance	Without	Government revenue		Billion pesos
	With	Government revenue		Billion pesos
	Changes	PV without		Billion pesos
		PV with		Billion pesos
		With/Without		%
Employment	Without	Labor productivity		Million Peso/p
		Number of Labor Force		Million person
		Employees		Million person
		Unemployment rate		%
	With	Labor productivity		Million Peso/p
		Number of Labor Force		Milion person
		Employees		Million person
		Unemployment rate		%
	Changes	With - without on unemployment		%

6-2-3 Results of Economic and Financial Analyses

In this chapter, we offer economic and financial analyses of the project. In the first half, the financial analyses are discussed; in the second, economic analyses and effects on the Philippine economy are discussed. For the analyses, we prepared the following cases (The High Case, The Low Case) to examine the effects of crude oil prices and options (Option 1, Option 2) for studying effects of constructing pipeline routes.

Table 6-2-31 Case setting for economic and financial analyses

Area	Cases	Cases	Comments
Luzon	High crude oil price case	Option1	Refer to below
		Option 2	Refer to below
	Low crude oil price case	Option1	Refer to below
		Option 2	Refer to below
C-M	High crude oil price case		
(Cebu/Mactan)	Low crude oil price case		
Davao	High crude oil price case		
	Low crude oil price case		

Option1: The pipelines will be built from Batangas to NCR and from Bataan to NCR (Northern area). Besides, LNG plants are intentionally allocated in Batangas and Bataan. By doing so, natural gas from LNG has two logistic routes. Therefore, stability of the natural gas supply is higher than with a route.

Option2: The pipelines will be built from Batangas to NCR and also from Bataan to NCR, as well as Option 1. But, the pipeline from Bataan to NCR is built over the shortest distance in Manila bay. Besides, LNG plants are intentionally allocated in Batangas and Bataan. By doing so, natural gas from LNG has two logistic routes.

(1) **Financial analysis for the High Case / Option 1 in Luzon area**

a. The gas supply system (High / Option 1 in Luzon)

The following figure shows the LNG facilities and the gas pipeline construction plan. Natural gas will be distributed from the Batangas area to NCR and from the Bataan area to NCR through the northern side of NCR.

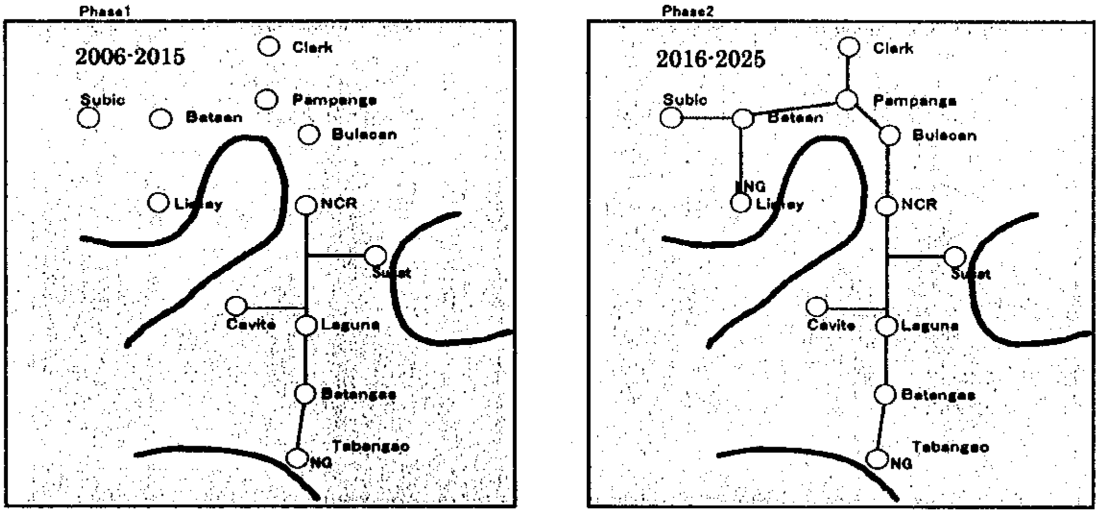

Figure 6-2-1 Gas distribution plan of Option 1

① The planned LNG facilities are installed in the Batangas and Bataan area in Option 1, increasing the stability of the gas supply.

② LNG facilities are to be installed in the Bataan area in 2008, and natural gas is to be suppied to the Bataan area. LNG facilities are also to be installed in Batangas in 2013. After that, investments on increase of capacity of the LNG sector are to be continued.

③ In parallel, investments for gas pipelines from Batangas to NCR will be made in 2005. Natural gas will be supplied in 2006. Gas from LNG will be supplied to NCR through a pipeline after 2011. Natural gas from the Bataan area will be also supplied to Clark and Subic through the northern area in 2016.

④ Investments for the power sector will continue from 2005 to 2025. The incremental capacity of power generation will be 9,155MW.

b. Financial statements (The High Case/Option 1 in Luzon)

The financial statements are shown in the following table.

Table 6-2-32 Economic / financial analyses (High / Option 1 in Luzon)

	LNG sector	Pipeline sector	Power sector	Project total
Investment	US$1,180 Millions	US$794 Millions	US$7,991 Millions	US$9,965 Millions
FIRR	12.0%	10.3%	12.5%	14..0%
DCR	0.9	0.9	1.0	1.9
EIRR	19.6%	15.7%	21.9%	23.3%

(Note 1) Investment values include inflation.
(Note 2) Natural gas price of LNG is set to maintain a FIRR of 12% for LNG.
(Note 3) FIRR of the project total is higher than those of each sector, because the working capital of the project total is smaller than the total working capital of each sector.

Table 6-2-33 Gas sales prices in each sector (High / Option 1 in Luzon)

Item	Unit	2006	2007	2008	2009	2010	2015	2020	2025
1) NG cost at Batangas	$/1000scf	5.280	5.545	5.498	5.766	5.714	5.881	6.146	6.992
2) LNG import cost	$/1000scf	5.357	5.417	5.478	5.539	5.602	5.924	6.335	7.258
3) LNG price to power and pipeline	$/1000scf	7.231	7.313	7.395	7.478	7.562	7.998	8.552	9.798
(LNG cost)					9.843	9.858	7.564	7.697	8.564
4) Power price to power distributors	$/kWh	0.079	0.080	0.080	0.081	0.082	0.087	0.093	0.106
(Power cost)		0.058	0.064	0.071	0.073	0.072	0.076	0.080	0.092
5) Pipeline gas price to Sucat	$/1000scf	7.947	8.037	8.127	8.218	8.311	8.789	9.399	10.768
				7.843	7.716	7.792	8.265	8.807	9.986
6) Pipeline gas price to non power users	$/1000scf	10.232	10.344	10.458	10.574	10.690	11.286	12.049	13.779
(Pipeline cost)		59.293	39.568	8.189	7.700	7.753	8.949	9.852	11.203

Table 6-2-34 Process cost (High / Option 1 in Luzon)

Cost items	Unit	2009	2010	2015	2020	2025
LNG re-gasification cost	US$/1000scf	4.304	4.257	1.640	1.362	1.306
Pipeline transmission cost	US$/1000scf	0.238	0.229	0.267	0.255	0.187
Pipeline distribution cost	US$/1000scf	0.536	0.600	0.825	0.844	0.737
Pipeline transportation cost	US$/1000scf	0.774	0.829	1.092	1.099	0.924
Power fixed cost	US$ / kWh	0.025	0.027	0.026	0.027	0.031
Inflation index	2001=100	115	118	133	154	179

c. Financial evaluation (High / Option 1 in Luzon)

① The gas sales price from LNG is set to maintain a FIRR of 12%. The investment values are US$1180 million for LNG, US$794 million for pipeline, and US$7991 million for power sector. In the above table, re-gasification costs in the LNG sector in 2009 and 2010 are extremely high, because LNG plant operation load during the terms is at a low level.

② LNG sales prices in the above table are US$7.56/1,000scf in 2010 and US$8.00/1,000scf in 2015. The prices are 32% higher in 2010 and 36% higher in 2015 compared to Camago/Malampaya natural gas prices.

③The FIRR of the pipeline sector is 10.3% in Option 1. We consider that the profitability of the pipeline sector under our forecast is not more than a FIRR of 12% .

④The FIRR of the power sector is 12.5%. We can say that the power sector maintains profitability in Option 1.

d. Cost analysis (High /Option 1 in Luzon)

①Re-gasification costs of LNG sector in 2009 and 2010 are extremely high due to its low operation load. However, it is US$1.3-1.6/1000scf beyond 2011.

② Transmission cost for a high-pressure pipeline can be estimated at US$0.5-0.8/1000scf beyond 2009.

③Distribution cost by a low-and medium-pressure pipeline can be estimated at US$0.5-0.8 /1000scf beyond 2009.

④The process cost (fixed cost) of gas-fired power generation can be estimated at US$0.03/kWh beyond 2009.

(2) Financial analysis for the High Case / Option 2 in Luzon area

a. The gas supply system (High / Option 2 in Luzon)

The following figures show the LNG facilities and gas pipeline construction plan for the High Case / Option 2 in Luzon. After constructing a pipeline from the Batangas area to NCR, LNG terminals will be built in both the Bataan and Batangas areas, and natural gas will be supplied to NCR through a submarine pipeline from the Bataan area.

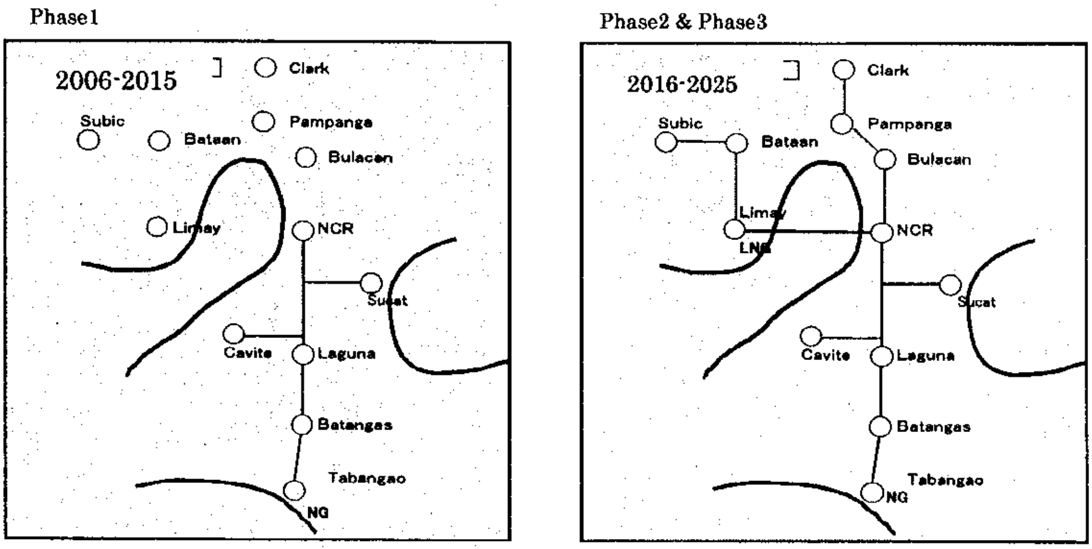

Figure 6-2-2 Gas distribution plan of Option 2

① In Option 2, LNG plants are built in the Bataan area at the same time as the pipeline is constructed from Batangas to NCR. After that, natural gas in Bataan is supplied to NCR through an offshore pipeline and a new LNG plant is built in the Batanga area.

② The pipeline is built from Bataan to Subic and Clark. The differences between Option1 and Option 2 are the offshore pipeline construction and gas pipeline network. In particularly, Option 1 has a high cost due to the construction of a 16-inch pipeline in the northern area.

③ High-pressure pipelines will be constructed in 2005 and 2015. Meanwhile, the low- and medium-pressure pipelines will be constructed stepwise from 2005 to 2025.

④ Investments for the power sector will continue from 2005 to 2025. The additional power generation capacity will be 9,155MW.

b. Financial statements (High / Option 2 in Luzon)

The results of the economic and financial analyses in Option 2 are shown in the following table.

Table 6-2-35 Economic / financial analyses (High / Option 2 in Luzon)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$1,180 Million	US$788 Million	US$7,991 Million	US$9,958 Million
FIRR	12.0%	10.9%	12.5%	14.1%
DCR	0.9	1.0	1.0	2.1
EIRR	19.7%	16.5%	21.9%	23.5%

(Note 1) Investment values include inflation

(Note 2) Natural gas price of LNG is set to maintain a FIRR of 12%.

(Note 3) FIRR of the total project is higher than that of each sector, because the working capital of the total project is smaller than the total working capital of each sector.

Table 6-2-36 Gas sales prices of each sector (High / Option 2 in Luzon)

Item	Unit	2006	2007	2008	2009	2010	2015	2020	2025
1) NG cost at Batangas	$/1000scf	5.280	5.545	5.498	5.766	5.714	5.881	6.146	6.992
2) LNG import cost	$/1000scf	5.357	5.417	5.478	5.539	5.602	5.924	6.335	7.258
3) LNG price to power and pipeline	$/1000scf	7.242	7.324	7.406	7.489	7.574	8.009	8.565	9.813
(LNG cost)					9.789	9.805	7.566	7.704	8.566
4) Power price to power distributors	$/kWh	0.079	0.080	0.080	0.081	0.082	0.087	0.093	0.106
(Power cost)		0.058	0.064	0.071	0.073	0.072	0.076	0.080	0.093
5) Pipeline gas price to Sucat	$/1000scf	7.947	8.037	8.127	8.218	8.311	8.789	9.399	10.768
				7.854	7.727	7.803	8.180	8.722	9.981
6) Pipeline gas price to non power users	$/1000scf	10.232	10.344	10.458	10.574	10.690	11.286	12.049	13.779
(Pipeline cost)		59.293	39.568	8.189	7.700	7.753	8.784	9.636	11.202

Table 6-2-37 Process cost (High / Option 2 in Luzon)

Cost items	Unit	2009	2010	2015	2020	2025
LNG re-gasification cost	US$/1000scf	4.250	4.203	1.642	1.369	1.308
Pipeline transmission cost	US$/1000scf	0.238	0.229	0.171	0.158	0.168
Pipeline distribution cost	US$/1000scf	0.536	0.600	0.820	0.782	0.733
Pipeline transportation cost	US$/1000scf	0.744	0.829	0.911	0.939	0.901
Power fixed cost	US$ / kWh	0.025	0.027	0.026	0.027	0.031
Inflation index	2001=100	115	118	133	154	179

c. Financial evaluation (High / Option 2 in Luzon)

① The gas sales price from LNG is set to maintain a FIRR of 12%. The investment values are US $1180 million for LNG (the same value as in Option1), US$787 million for pipeline (US$794 million in Option 1) and US$7,991 million for power sector (the same value as in Option 1).

② The LNG sales prices in the above table are US$7.57/1,000scf in 2010(US$7.56/1000scf in Option 1), US$8.00/1,000scf in 2015 (the same price as in Option 1). The prices are 32% higher in 2010 and 36% higher in 2015 compared to Camago/Malampaya natural gas prices.

③DCR value of LNG is 0.9. This means that the LNG sector does not have sufficient loan repayment ability during the period of the calculation, because the sector has a high investment in the latter half of the period of the calculation.

④The FIRR of the pipeline sector is 10.9% in Option 2. We consider that the profitability of the pipeline sector is not maintained under our forecast or a FIRR of more than12%.

⑤The FIRR for the power sector is 12.5%. We can say that the power sector maintains profitability in Option 2.

d. Cost analysis (High/Option 2 in Luzon)

①Re-gasification costs of LNG sector in 2009 are extremely high (US$4.25/1000scf) due to its low operation load. However, it is US$1.3-1.6/1000scf beyond 2011.

②Transmission cost using high-pressure pipeline can be estimated at US$0.15-0.24 /1000scf beyond 2009.

③ Distribution cost by low and medium-pressure pipeline can be estimated at US$0.6-0.8 /1000scf beyond 2010.

④The process cost (fixed cost) of gas-fired power generation can be estimated at US$0.03/kWh beyond 2009.

(3) Financial analysis for the Low Case / Option 1 in Luzon area

a. The gas supply system (Low / Option 1 in Luzon)

The gas supply system for the Low Case / Option 1 in Luzon is shown in Figure 6-2-1.

① The LNG investment starts in 2012 and gas is supplied in 2013.

② The high- pressure pipeline receives investment in 2005 and 2010.

③ Investments for the power sector continue from 2005 to 2025.

b. Financial statements (Low / Option 1 in Luzon)

The results of the financial statements are shown in the following table.

Table 6-2-38 Economic/financial analyses (Low / Option1 in Luzon)

	LNG sector	Pipeline sector	Power sector	Project total
Investment	US$1049 MillionUS$	US$311 MillionUS$	US$6,230 MillionUS$	US$7,590 MillionUS$
FIRR	12.0%	11.0%	19.5%	18.6%
DCR	0.8	1.0	1.7	3.0
EIRR	20.6%	16.4%	32.7%	30.3%

(Note 1) Investment values include inflation.

(Note 2) Natural gas price of LNG is set to maintaina FIRR of 12%.

(Note 3) FIRR of the project total is higher than that of each sector, because the working capital of the total project is smaller than the tota working capital of each sector.

Table 6-2-39 Gas sales prices in each sector (Low / Option 1 in Luzon)

Item	2013	2014	2015	2020	2025
1) NG cost at Batangas	5.046	5.030	5.148	5.574	6.242
2) LNG import cost	4.944	5.079	5.218	6.072	6.765
3) LNG price to power and pipeline	6.873	7.060	7.252	8.440	9.403
(LNG cost)	8.812	8.676	7.359	7.531	8.141
4) Power price to power distributors	0.085	0.087	0.090	0.105	0.117
(Power cost)	0.069	0.068	0.070	0.080	0.091
5) Pipeline gas price to Sucat	7.569	7.775	7.987	9.296	10.356
	7.321	7.501	7.685	8.820	9.718
6) Pipeline gas price to non power users	9.726	9.988	10.257	11.917	13.251
(Pipeline cost)	6.844	6.926	7.134	8.097	9.292

Table 6-2-40 Process cost (Low / Option 1 in Luzon)

Cost items	Unit	2013	2014	2015	2020	2025
LNG re-gasification cost	US$/1000scf	3.867	3.597	2.142	1.458	1.376
Pipeline transmission cost	US$/1000scf	0.448	0.441	0.432	0.380	0.315
Pipeline distribution cost	US$/1000scf	0.292	0.323	0.351	0.412	0.398
Pipeline transportation cost	US$/1000scf	0.740	0.764	0.783	0.792	0.713
Power fixed cost	US$ / kWh	0.026	0.026	0.026	0.028	0.032
Inflation index	2001=100	115	118	133	154	179

c. Financial evaluation (Low / Option 1 in Luzon)

①The investment values are US$1049 million for LNG, US$311 million for pipeline, and US$6,230 million for power sector. The investment ratios comparing High / Option 1 are 89% in the LNG sector, 39% in the pipeline sector, and 78% in the power sector.

②The gas sales price of the LNG sector is set to maintain a FIRR of 12%. The DCR value of LNG is then0.8. This means that the LNG sector does not have sufficient loan repayment ability during the periods of calculation. Because the LNG sector has heavy investments in the latter half of the periods of the calculation term, if the investments are suspended, the LNG sector can reach a sufficient DCR value (>1.0)

③ Gas sales prices of the LNG sector in the table above are US$7.25/1,000scf in 2015 and US$8.44/1,000scf in 2020. The prices are 41% higher in 2015 and 51% higher in 2020 than to Camago/Malampaya natural gas prices.

④The FIRR of the pipeline sector is 11.0% in Low/Option 1. We consider that the profitability of the pipeline sector is not maintained under our forecast for a of FIRR of 12%

⑤The FIRR of the power sector is 19.5%. We can say that the power sector maintains profitability in Low/Option 1.

d. Cost analysis (Low / Option 1 in Luzon)

①Re-gasification costs of LNG sector are US$1.3-2.1/1000scf beyond 2015.

②Transmission cost using a high-pressure pipeline can be estimated at US$0.30-0.42 /1000scf beyond 2013.

③Distribution cost by low and medium-pressure pipeline can be estimated at US$0.3-0.4 /1000scf beyond 2013.

④The process cost (fixed cost) of gas-fired power generation can be estimated at 0.026-0.032$/kWh beyond 2013.

(4) Financial analysis for the Low Case / Option 2 in Luzon area

a. The gas supply system (Low / Option 2 in Luzon)

The gas supply system for the Low Case / Option 2 in Luzon is shown in Figure 6-2-2.

① The LNG investment starts in 2012 and gas is supplied in 2013.

② The high-pressure pipeline receives investment in 2005 and 2011, and the low-and -medium pressure pipeline for gas distribution receives investment from 2005 to 2025.

③ Investments for the power sector will continue from 2005 to 2025.

b. Financial statements (Low / Option 2 in Luzon)

The results of the economic and financial analyses in Option 2 are shown in the following table.

Table 6-2-41 Economic / financial analyses (Low / Option2 in Luzon)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$1,049 Million	US$289 Million	US$6,231 Million	US$7,569 Million
FIRR	12.0%	12.7%	19.5%	19.0%
DCR	0.8	1.3	1.7	3.1
EIRR	20.6%	18.5%	32.7%	30.9%

(Note 1) Investment values include inflation

(Note 2) Natural gas price of LNG is set to maintain a FIRR of 12%.

(Note 3) FIRR of the total project is higher than that of each sector, because the working capital of the total project is smaller than the totalized working capital of each sector.

Table 6-2-42 Gas sales prices of each sector (Low / Option 2 in Luzon)

Item	2013	2014	2015	2020	2025
1) NG cost at Batangas	5.046	5.030	5.148	5.574	6.242
2) LNG import cost	4.944	5.079	5.218	6.072	6.765
3) LNG price to power and pipeline	6.873	7.060	7.252	8.440	9.403
(LNG cost)	8.812	8.716	7.371	7.532	8.141
4) Power price to power distributors	0.085	0.087	0.090	0.105	0.117
(Power cost)	0.069	0.068	0.070	0.080	0.091
5) Pipeline gas price to Sucat	7.569	7.775	7.987	9.296	10.356
	7.145	7.328	7.516	8.710	9.657
6) Pipeline gas price to non power users	9.726	9.988	10.257	11.917	13.251
(Pipeline cost)	6.575	6.645	6.853	7.910	9.249

Table 6-2-43 Process cost (Low / Option 2 in Luzon)

Cost items	Unit	2013	2014	2015	2020	2025
LNG re-gasification cost	US$/1000scf	3.867	3.637	2.154	1.460	1.376
Pipeline transmission cost	US$/1000scf	0.273	0.268	0.264	0.269	0.254
Pipeline distribution cost	US$/1000scf	0.266	0.291	0.314	0.372	0.399
Pipeline transportation cost	US$/1000scf	0.539	0.559	0.578	0.641	0.653
Power fixed cost	US$ / kWh	0.026	0.026	0.026	0.028	0.032
Inflation index	2001=100	115	118	133	154	179

c. Financial evaluation (Low / Option 2 in Luzon)

①The investment values are US$1,049 million for LNG, US$289 million for pipeline and US$6,231 million for power sector. The investment ratios comparing High/Option 2 are 89% in the LNG sector, 37% in the pipeline sector, and 78% in the power sector.

②The gas sales price of the LNG sector is set to maintain a FIRR of 12%. Then the DCR value of LNG is 0.8. This means that the LNG sector does not have sufficient loan repayment ability during the period of the calculation. It is because the LNG sector has investments in the latter half of the period of the calculation. If the investments are suspended, the LNG sector can reach a sufficient DCR value (>1.0)

③ Gas sales prices of the LNG sector in the above table are US$7.25/1,000scf in 2015 and US$8.44/1,000scf in 2020. The prices are 41% higher in 2015 and 51% higher in 2020 than Camago/Malampaya natural gas prices.

④The FIRR of the pipeline sector is 12.7% in Low / Option2. We consider that the profitability of the pipeline sector is maintained under our forecast.

⑤The FIRR of the power sector is 19.5%. We can say that the power sector maintains profitability in Option 1.

d. Cost analysis (Low / Option 2 in Luzon)

①Re-gasification costs of LNG sector are US$1.4-2.2/1000scf beyond 2015.

②Transmission cost using a high-pressure pipeline can be estimated at US$0.25-0.27 /1000scf beyond 2015.

③Distribution cost using a low-and medium-pressure pipeline can be estimated at US$0.3-0.4 /1000scf beyond 2015.

④The process cost (fixed cost) of gas-fired power generation can be estimated at US$0.03/kWh beyond 2015.

(5) Financial analysis for Cebu / Mactan in the High and Low Cases

a. The gas supply system in Area C-M

Investment on the C-M natural gas project will start in 2018. We decided to use the present value for investment and other cost items in the economic financial analyses. LNG prices and domestic natural gas prices are the same values as in other cases. Usually, investment value and labor cost are affected by the inflationary environment. However, the items are assumed not to be affected by an inflation factor in C-M case.

The calculation term of the C-M case is from 2001 to 2035, and the project life is from 2018 to 2035. The project life is 17 years. Natural gas demand beyond 2026 is the same as in 2025.

When there is a long period between the base year and the project starting year, big differences arise between cost items that are affected by inflation and those with no relation to inflation. Therefore, the results of the financial analysis under the above conditions have a distortion. We studied the C-M case for reference purposes.

b. Financial statements (High and Low Cases in Area C-M)

The results of the economic and financial analyses in Area C-M case are shown in the following table.

Table 6-2-44 Economic/financial analyses (High Case in Area C-M)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$392 Million	US$60 Million	US$397 Million	US$849 Million
FIRR	12.0%	Infeasible	Infeasible	6.3%
DCR	1.5	Infeasible	Infeasible	0.6
EIRR	18.2%	Infeasible	Infeasible	10.7%

(Note 1) Natural gas price of LNG is set to maintain a FIRR of 12% in the LNG sector.

(Note 2) Infeasible in the table means profitability is very low.

Table 6-2-45 Economic/financial analyses (Low Case in Area C-M)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$372 Million	US$58 Million	US$376 Million	US$847 Million
FIRR	12.0%	Infeasible	Infeasible	3.9%
DCR	1.5	Infeasible	Infeasible	0.1
EIRR	17.9%	Infeasible	Infeasible	15.4%

(Note 1) Natural gas price of LNG is set for keeping FIRR 12% in the LNG.

(Note 2) Infeasible in the table means profitability is very low.

Table 6-2-46 Gas sales prices of each sector (High Case in Area C-M)

Item	Unit	2020	2021	2022	2023	2024	2025	2030	2035
1) LNG import cost	$/1000scf	6.335	6.510	6.689	6.874	7.063	7.258	7.258	7.258
2) LNG price to power and pipeline	$/1000scf	12.632	12.980	13.338	13.706	14.084	14.473	14.473	14.473
(LNG cost)		12.630	12.803	12.846	12.971	10.769	10.959	10.687	10.446
3) Power price to power distributors	$/kWh	0.093	0.095	0.098	0.100	0.103	0.106	0.106	0.106
(Power cost)		0.106	0.109	0.112	0.123	0.119	0.122	0.120	0.119
4) Pipeline gas price to non power users	$/1000scf	12.049	12.376	12.713	13.059	13.414	13.779	13.779	13.779
(Pipeline cost)		17.093	17.103	17.026	17.218	17.392	17.604	17.385	17.377

Table 6-2-47 Gas sales prices of each sector (Low Case in Area C-M)

Comments	UNit	2020	2021	2022	2023	2024	2025	2030	2035
1) LNG import cost	$/1000scf	6.072	6.205	6.340	6.479	6.620	6.765	6.765	6.765
2) LNG price to power and pipeline	$/1000scf	12.448	12.720	12.998	13.281	13.571	13.868	13.868	13.868
(LNG cost)		11.729	11.907	12.064	12.168	10.094	10.275	10.023	9.799
3) Power price to power distributors	$/kWh	0.105	0.107	0.109	0.112	0.114	0.117	0.117	0.117
(Power cost)		0.105	0.107	0.110	0.120	0.116	0.118	0.117	0.116
4) Pipeline gas price to non power users	$/1000scf	11.917	12.173	12.434	12.701	12.973	13.251	13.251	13.251
(Pipeline cost)		16.716	16.660	16.518	16.629	16.719	16.843	16.629	16.618

Table 6-2-48 Process cost (High Case in Area C-M)

Cost items	Unit	2020	2025	2030	2035
LNG re-gasification cost	US$/1000scf	6.295	3.701	3.429	3.188
Pipeline transmission cost	US$/1000scf	0.000	0.000	0.000	0.000
Pipeline distribution cost	US$/1000scf	2.346	1.753	1.764	1.771
Pipeline transportation cost	US$/1000scf	2.346	1.753	1.764	1.771
Power fixed cost	US$ / kWh	0.026	0.029	0.028	0.026
Inflation index	2001=100	154	179	179	179

Table 6-2-49 Process cost (Low Case in Area C-M)

Cost items	Unit	2020	2025	2030	2035
LNG re-gasification cost	US$/1000scf	5.657	3.511	3.258	3.034
Pipeline transmission cost	US$/1000scf	0.000	0.000	0.000	0.000
Pipeline distribution cost	US$/1000scf	2.227	1.656	1.661	1.665
Pipeline transportation cost	US$/1000scf	2.227	1.656	1.661	1.665
Power fixed cost	US$ / kWh	0.025	0.030	0.029	0.027
Inflation index	2001=100	154	179	179	179

c. Financial evaluation (High and Low in Area C-M)

①The FIRR of the total project is 3.9%. Therefore, the C-M case is not profitable.

②The LNG sales price in the above table is set to maintain a FIRR of 12% in the LNG sector. The LNG sales price is US$11.0/1000scf in 2025, which is expensive.

③Gas sales price in pipeline sector US$13.8/1000scf in the High Case in 2025. The natural gas cost in the pipeline sector was US$17.6/1000scf at the time. The cost is higher than the sales price.

④The re-gasification costs of LNG sector beyond 2021 are US$3.0-3.5/1000scf. The re-gasification cost is about double those in Luzon area.

⑤Distribution cost by high-pressure, medium-pressure, and low-pressure pipeline can be estimated at US$1.6-1.7 /1000scf beyond 2020.

⑥ The process cost (fixed cost) of gas-fired power generation can be estimated at US$0.03/1000scf.

(6) Financial Analysis for Area D in the High and Low Cases

a. The gas supply system (High and Low Cases in Area D)

Investments for the Davao natural gas project will start in 2018. We decided to use present value for investment and other cost items in the economic financial analyses. LNG prices and domestic natural gas prices are the same as those of other calculations. Usually, investment values and labor costs are affected by the inflation environment. However, items beyond 2025 are assumed not to be affected by inflation in the High and Low Cases for Area D.

The calculation term of the High and Low of Area D is from 2001 to 2035, and the project life is from 2018 to 2035. The project life is 17 years. Natural gas demand beyond 2026 is the same as 2025 demand.

When there is a long period between the base year and the project starting year, big differences occur between cost items affected by inflation and those with no relation to inflation. Therefore, the results of the financial analysis in the above conditions have a distortion. We studied the Davao case for reference.

The results of the economic and financial analyses in the Davao case are shown in the following table.

Table 6-2-50 Economic/financial analyses (High Case in Area D)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$392 Million	US$102 Million	US$397 Million	US$891 Million
FIRR	12.0%	Infeasible	Infeasible	5.9%
DCR	1.5	Infeasible	Infeasible	0.4
EIRR	18.1%	Infeasible	Infeasible	10.0%

(Note 1) Natural gas price of LNG is set to maintain a FIRR of 12%.

(Note 2) Infeasible in the table means the profitability is very low.

Table 6-2-51 Economic/financial analyses (Low Case in Area D)

	LNG sector	Pipeline sector	Power sector	The total
Investment	US$373 Million	US$9 6 Million	US$376 Million	US$845 Million
FIRR	12.0%	Infeasible	Infeasible	9.2%
DCR	1.5	Infeasible	Infeasible	1.3
EIRR	17.9%	Infeasible	Infeasible	14.6%

(Note 1) Natural gas price of LNG is set to maintain a FIRR of 12% in the LNG.

(Note 2) Infeasible in the table means the profitability is very low.

Table 6-2-52 Gas sales prices of each sector (High Case in Area D)

Item	Unit	2020	2021	2022	2023	2024	2025	2030	2035
1) LNG import cost	$/1000scf	6.335	6.510	6.689	6.874	7.063	7.258	7.258	7.258
2) LNG price to power and pipeline	$/1000scf	12.765	13.117	13.479	13.850	14.232	14.625	14.625	14.625
(LNG cost)		12.922	13.168	13.272	13.372	10.888	11.073	10.756	10.514
3) Power price to power distributors	$/kWh	0.093	0.095	0.098	0.100	0.103	0.106	0.106	0.106
(Power cost)		0.107	0.110	0.113	0.124	0.120	0.123	0.121	0.121
4) Pipeline gas price to non power users	$/1000scf	12.049	12.376	12.713	13.059	13.414	13.779	13.779	13.779
(Pipeline cost)		23.480	23.112	22.484	21.882	21.513	21.308	19.481	19.076

Table 6-2-53 Gas sales prices of each sector (Low Case in Area D)

Comments	UNit	2020	2021	2022	2023	2024	2025	2030	2035
1) LNG import cost	$/1000scf	6.072	6.205	6.340	6.479	6.620	6.765	6.765	6.765
2) LNG price to power and pipeline	$/1000scf	12.569	12.844	13.124	13.411	13.704	14.003	14.003	14.003
(LNG cost)		11.970	12.210	12.438	12.524	10.199	10.379	10.085	9.861
3) Power price to power distributors	$/kWh	0.105	0.107	0.109	0.112	0.114	0.117	0.117	0.117
(Power cost)		0.106	0.108	0.111	0.121	0.117	0.119	0.118	0.117
4) Pipeline gas price to non power users	$/1000scf	11.917	12.173	12.434	12.701	12.973	13.251	13.251	13.251
(Pipeline cost)		22.766	22.345	21.676	21.030	20.601	20.324	18.593	18.206

Table 6-2-54 Process cost (High Case in Area D)

Cost items	Unit	2020	2025	2030	2035
LNG re-gasification cost	US$/1000scf	6.587	3.815	3.498	3.256
Pipeline transmission cost	US$/1000scf	3.029	1.435	0.800	0.647
Pipeline distribution cost	US$/1000scf	3.040	2.535	1.996	1.908
Pipeline transportation cost	US$/1000scf	6.069	3.970	2.796	2.554
Power fixed cost	US$ / kWh	0.026	0.030	0.028	0.027
Inflation index	2001=100	154	179	179	179

Table 6-2-55 Process cost (Low Case in Area D)

Cost items	Unit	2020	2025	2030	2035
LNG re-gasification cost	US$/1000scf	5.898	3.614	3.321	3.096
Pipeline transmission cost	US$/1000scf	2.871	1.353	0.753	0.608
Pipeline distribution cost	US$/1000scf	2.882	2.391	1.878	1.793
Pipeline transportation cost	US$/1000scf	5.753	3.744	2.632	2.401
Power fixed cost	US$ / kWh	0.026	0.030	0.029	0.027
Inflation index	2001=100	154	179	179	179

c. Financial evaluation (High and Low Cases in Area D)

① The FIRR of the total project is 9%. Therefore, the Davao case is not profitable.

② The LNG sales price in the above table is set to maintain a FIRR of 12% in the LNG sector. The LNG sales price is US$11.1/1000scf in 2025, which is expensive.

③ Gas sales price in the pipeline sector is US$13.8/1000scf in 2025. The natural gas cost in the pipeline sector was US$21.3/1000scf at the time. The cost is higher than the sales price.

④ Re-gasification costs of the LNG sector beyond 2025 are US$3.1-3.6/1000scf. The re-gasification costs are about double those in the Luzon area.

⑤ The high-pressure pipeline costs for gas transmission are US$0.60-1.4/1000scf in the High Case of Davao. Distribution costs using low-and medium-pressure pipeline can be estimated at US$1.9-2.5 /1000scf beyond 2025.

⑥ The process cost (fixed cost) of gas-fired power generation can be estimated at US$0.03/1000scf.

(7) Evaluation of the Economic / Financial Analyses and Policy Measures

a. Four policy measures

As mentioned above, the profitability of High/ Option 1, High/Option 2 and Low/Option 1 are not high. If we want to make profitability reasonably high, we will have to consider some policy measures to be taken for gas-related projects. We select the following policy measures, including a tax holiday for corporate tax, exemption of LNG import customs, and machines/materials import duty, all of which we consider in Chapter 3, to assess their effects on profitability. More specifically, "the four policy measures" are as follows:

①10-year tax holiday for corporate tax (32% of profit) for the pipeline sector

The current tax credit system for gas-related business gives permission of a six-year corporate tax holiday. Then LNG and pipeline sectors before tax holiday have a six-year corporate tax holiday. As the first policy measure, a ten-year corporate tax holiday is applied only to the pipeline sector.

②Tax exemption of LNG import duty (5% of import value) for the LNG sector

LNG imported tax will change from 10% to 3% beyond 2006. When the import tax is completely lifted beyond 2006, we can consider that the FIRR of the LNG sector will increase. Then, by reducing the gas sales price of the LNG sector, the additional profit of the LNG sector moves to the pipeline and power generation sectors. This is the second policy measure for the pipeline sector.

③Tax exemption of machine/materials (5% of import value) for the pipeline sector.

We assume that many machine/materials for constructing LNG, pipeline, and power generation sectors will be imported. Then it is assumed that 60% of the equipment investment of each sector has a machine/material import tax(5%) levied before policy measures. As the third policy measure, we consider that the import tax or machine/materials is not levied only in the pipeline sector.

④ Applying low-interest rate from international development facilities

Before instituting policy measures, capital funds for the projects are financed 25% from own capital, 25% from commercial banks, 25% from international development bank A (interest rate: 2%), and 25% from international development bank B (interest rate: 7%). As the fourth policy measure, the pipeline sector can use 75% of the low interest rate (2%) from international development facility A, with the remainder (25%) financed by own capital. Through this fourth policy measure, we can consider that the pipeline sector will take advantage of the low interest rate with less interest payable, than it will without the policy measure.

Table 6-2-56 Contents of the four policy measures for the sectors

Credit scenario		LNG	Pipeline	Power
1. Corporate tax credit	No policy With policy	6 years 6 years	6 years 10 years	0 0
2. LNG import tax	No policy With policy	3% 0%		
3. Machine/Materials import tax	No policy With policy	5 % 5 %	5 % 0 %	5 % 5 %
4. Financed by low interest rate	No policy	OCP 25% CMB 25% ID-A 25% ID-B 25%	OCP 25% CMB 25% ID-A 25% ID-B 25%	OCP. 25% CMB 25% ID-A 25% ID-B 25%
	With policy	Same as Above	OCP. 25% ID-A 25%	Same as above

OCD: Own capital; CMB: commercial Bank; ID-A: International Development Facility A

b. FIRR evaluation after the four policy measures

The FIRRs affected by the four policy measures are shown in the following table.

Table 6-2-57 FIRR of pipeline sector after the four policy measures

Tax and finance credit policies	High Option1	High Option2	Low Option1	Low Option2
(0) Non-credit policy	10.3	10.9	11.0	12.7
(1) 10-year corporate tax holiday	10.8	11.5	11.9	13.9
(2) Except LNG import duty	10.6	11.3	11.2	12.9
(3) Except machine/materials import duty	10.7	11.3	11.4	13.1
(4) Low interest rate from IDF	10.0	10.7	10.9	12.7
(1)+(2)	11.1	11.8	12.0	14.0
(1)+(2)+(3)	11.6	12.2	12.3	14.4
(1)+(2)+(3)+(4)	11.4	12.1	12.2	14.3

The profitability of the cases are changed by the four policy measures as follows:

① The FIRR of the High Case / Option 1 does not exceed the critical level of 12% even after a 10-year corporate tax, holiday, exception of LNG import tax, exception of machine/materials import tax and introduction of low interest rate from international development banks.

② The FIRR of the High Case / Option 2 exceeds the critical level of 12% after applying the three policy measures including 10-year corporate tax holiday, exception of LNG import tax, and exception of machine/materials import tax.

③ The FIRR of the Low Case / Option 1 exceeds the critical level with 12% after applying the two policy measures including 10-year corporate tax holiday and exception of LNG import tax.

④ The FIRR of the Low Case / Option 2 can exceed the critical level without any policy measures.

c Sales price evaluation after the four policy measures

The changes of gas sales prices and demand after the four policy measures are shown in the following table. The four policy measures include (1) 10-year corporate tax holiday, (2) Exemption from LNG import tax, (3) Exemption from machine/materials import tax and (4) finance at low-interest rate from international development facility.

Table 6-2-58a Changes of gas sales prices and gas demand between with the four policy measures and without the measures (High Case) (%)

Case	Policy	User sectors	2010	2015	2020	2025
High	Without policy	Industry	7.58	8.02	8.58	9.83
		Commercial	8.87	9.38	10.03	11.49
		Residential	9.85	10.42	11.14	12.76
		Transportation	8.18	8.65	9.25	10.59
		Prices for power	7.39	7.81	8.35	9.57
High Option 1	With Policy	Industry Commercial Residential Transportation Prices for power	Same Above	Same Above	Same Above	Same Above
High Option 2	With Policy	Industry	7.58	8.01	8.57	9.81
		Commercial	8.85	9.36	10.01	11.47
		Residential	9.84	10.40	11.13	12.75
		Transportation	8.17	8.64	9.23	10.58
		Prices for power	7.38	7.80	8.34	9.56