Republic of the Philippines
Department of Energy

Final Report
on
the Data Collection Survey
on
Utilization of Clean Alternative Energy
in the Republic of the Philippines

March 2012

JAPAN INTERNATIONAL COOPERATION AGENCY

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BatMan 1 Proposed Pipeline and Facilities Overview

Photos of Project Sites

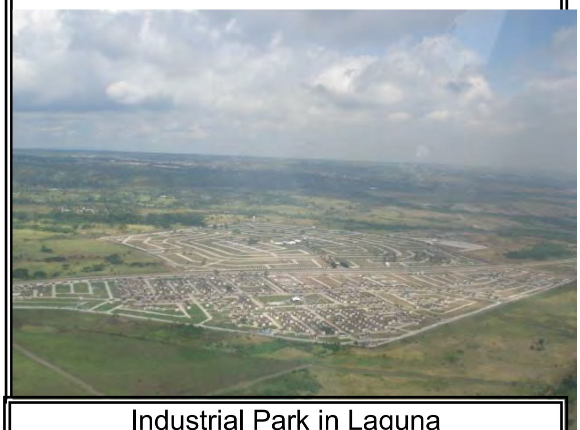
IRIJAN natural gas fired power plant
Existing Malampaya OGP Facility

Gas Pipeline Route Section 1

Gas Pipeline Route Section 2

Gas Pipeline Route Section 3

LNG Terminal Candidate Site



Industrial Park in Laguna

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List of Abbreviated Terms

(Alphabetical Order)

ADB	Asian Development Bank
BOG	boil-off gas
BIR	Bureau of Internal Revenue
BOI	Board of Investment
BOT	Build Operate Transfer
CAPEX	Capital Expenditure
CBR	Cost Benefit Ratio
CCGT	Combined Cycle Gas Turbine
CD	Cathodic Protection
CNC	Certificate of Non-Coverage(CNC)
CNG	Compressed Natural Gas
CPC	China Petroleum Corporation
DAR	Department of Agrarian Reform
DCF	Discounted Cash Flow
DCS	Distributed Control System
DENR	Department of Environment and Natural Resources
DILG	Department of the Interior and Local Government
DMS	Dimethyl Sulphide
DO	Department Order
DOE	Department of Energy
DOF	Department of Finance
DPWH	Department of Public Works and Highways
DSCR	Debt Service Coverage Ratio
ECA	Environmentally Critical Area
ECC	Environmental Compliance certificate
ECP	Environmentally Critical Project
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EIS	Environmental Impact Statement
EMB	Environmental Management Bureau
EPC	Engineering, Procurement and Construction
EPRMP	Environmental Performance Report and Management Plan
ERA	Energy Reform Agenda
ERC	Energy Regulatory Commission
ESD	Emergency Shut Down system
F&G	Fire and Gas System
FERC	US Federal Energy Regulatory Commission
FIRR	Financial Internal Rate of Return
FPIC	Free Prior Informed Consent
FS	Feasibility Study
FSRU	Floating Storage and Regasification Unit
FSU	Floating Storage Unit
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Gas insulation switch gear
GOP	The Government of the Philippines
GPS	Global Positioning System
GSPL	Gujarat State Petronet Ltd
HUDCC	Housing and Urban Development Coordinating Council
ICCs	indigenous cultural communities
IEEC	IEE Checklist
IEER	Initial Environmental Examination Report
IO	Implementing Office
IPAP	Indigenous Peoples Action Plan

IPs	indigenous peoples
IROW	Infrastructure Right of Way
IRR	Internal Rate of Return
JICA	Japan International Cooperation Agency
JV	Joint Venture
LAPRAP	Land Acquisition Plan and Resettlement Action Plan
LNG	Liquefied Natural Gas
MMS	Marine Monitoring System
MOA	Memorandum of Agreement
M/P	Master Plan Study
MS	Metering Station
NAPOCOR	National Power Corporation
NCIP	National Commission on Indigenous Peoples
NECA	Non-Environmentally Critical Area
NEDA	National Economic Development Authority
NGVPPT	Natural Gas Vehicle Program for Public Transport
NHA	National Housing Authority
NIA	National Irrigation Administration
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operating Expenditure
ORV	Open Rack Vaporizer
PDP	Power Development Plan
PDR	Project Description Report
PEIS	Programmatic Environmental Impact Statement
PEISS	Philippines Environmental Impact Statement System
PEP	Philippine Energy Plan
PEZA	Philippine Economic Zone Authority
PIP	Public Investment Program
PFD	Process Flow Diagram
PIMS	Plant Information Management System
PL	Pipeline
PMS	Unloading arm Position Monitoring System
PNCC	Philippine National Construction Corporation
PNOC	Philippine National Oil Company
PNOC-EC	Philippine National Oil Company Exploration Corporation
PQ	Prequalification
PPP	Public-Private Partnership
PS	Percellary Survey
RAP	Resettlement Action Plan
ROI	Return on Investment
ROW	Right of Way
SCV	Submerged Combustion Vaporizer
SCADA	Supervisory Control And Data Acquisition
SCF	Standard Conversion Factor
SLEX	The South Luzon Expressway
SPS	Safeguard Policy Statement
STAR	South Tagalog Arterial Road
STEP	Special Terms for Economic Partnership
STV	Shell & Tube Vaporizer
TBM	tertiaty butyl mercaptan
TRANSCO	Transmission Corporation
USD	United States Dollars
VS	Valve station
WACC	Weighted Average Cost of Capital

Units

Category	Abbreviation		Unit	Remarks
Natural Gas	scf	:	standard cubic feet	1 scf = 0.0268 normal cubic meters
	ton	:	tonnes	1,000 tonnes = 48,700 cuf = 51,750 million Btu = 0.05458 PJ
	Btu	:	British thermal unit	1 Btu = 1,055.056 joules
	PJ	:	peta joule	1 PJ = 23.9 toe
	toe	:	tonne oil equivalent	1 toe = 41.8 GJ
	BCF	:	billion cubic feet	
	MMscf/d	:	million standard cubic feet per day	
	MMscf/h	:	million standard cubic feet per hour	
	Nm^3	:	normal cubic meter	
	$MMNm^3/h$	:	million Normal cubic per hour	
Distance	ft.	:	feet	1 feet = 12 inch = 0.303 meter
	m.	:	meter	1 meter = 100 cm = 0.001 km
Area	m^2	:	square meters	1.0 m * 1.0 m
	km^2	:	square kilometers	1.0 km* 1.0 km
	Ha	:	hectare	1 ha = 10,000 m^2
	acre	:	acre	1 acre = 4,046.86 m^2
Currency	JPY	:	Japanese Yen	
	USD	:	United States Dollars	1 USD = 85 JPY **
	PHP	:	Philippines Pesos	1 USD = 43 PHP ** (**as of 2010, at the time of project cost estimation)
Power	kV	:	kilo volts	
	kW	:	kilo watts	1 kW = 1,000 W
	MW	:	mega watts	1 MW = 1,000 kW
	Wh	:	watt-hours	
	kWh	:	kilo watt-hours	1 kWh = 1,000 Wh
	MWh	:	mega watt-hours	1 MWh = 1,000 kWh
	GWh	:	giga watt-hours	1 GWh = 1,000 MWh

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Chapter 1 Introduction

1.1 Background

According to the Medium-Term Philippine Development Plan (2011-2016) of the Philippine government, for the purpose of reducing the traditional dependency on oil, increase of utilization of alternative energy is set out as one of the key policies in the energy field. Because natural gas is considered as environmentally friendly among alternative energy source, increase of utilization of natural gas in the industrial and commercial sectors is positioned as a priority issue. Specifically, for both domestic natural gas development and increase of utilization and import of LNG, the government demonstrated policies to promote development of gas pipeline network, gas conversion of the existing thermal plants and increase of utilization of natural gas in transport sector (e.g., introduction of CNG vehicles).

Natural gas utilization in the Philippines has been widespread since the start of commercial operation of Camago-Malampaya gas field in 2002. The gas is transported by offshore pipelines (maximum capacity: 650MMcf/d) and supplied to three power plants (Ilijan, Santa Rita and San Lorenzo. Total: 2,700 MW).

The master plan including a construction project of natural gas pipeline network-related facilities was developed based on the master plan study on the development of the natural gas industry in the Republic of the Philippines by JICA (2002 : hereinafter called JICA M/P (2002)). Although the Philippines government has promoted policies including the increase of utilization of domestic natural gas based on the JICA M/P (2002), encouraging entry of private sector, some projects including construction of related facilities were not materialized for such reasons as undeveloped investment environment. However, under the Aquino administration established in June 2010, infrastructure development by public-private partnership (PPP) have been put up as a top priority issue and improvement of PPP promotion- related systems and policies and specific project formation have been promoted.

1.2 Objective

Following the previously-conducted study, Department of Energy (DOE), with utilization of PPP in mind, is now engaged in the development of natural gas-related infrastructure facilities. They are planning a Batangas-Manila pipeline project as a top-priority project. In the project, to construct about 100km pipeline from Batangas to Sucat, Metro Manila and to supply gas to the power plant in Sucat in which conversion to gas-fired power generation is planned and the surrounding area. In addition, the possibility of its extension to Quirino Highway has also been considered in view of demand in the transportation sector. The project is positioned as one of high-priority projects of natural gas-related facilities in the future. In prospect of gas depletion in Camago-Malampaya gas field and the possibility of import LNG supply to three power plants in Batangas, the necessity of LNG plants in Batangas has also been put under review.

Based on the above-mentioned projects since the conduct of JICA M/P (2002) and in view of the current status, the Study will be conducted for the purposes of collecting information required for the realization of future natural gas projects in a manner that would contribute policy promotion of the Philippine government.

1.3 Study Area

The study covers all the areas of the Philippines. (The BatMan 1 and LNG terminal projects are located at the Luzon island.)

1.4 Scope of the Study

(1) To review the precondition at the time of conducting JICA M/P(2002)

(a)To compare the energy policy at the time of conducting JICA M/P(2002) and the current energy policy
(b)To position increase of utilization of natural gas
(c)To identify focused investigation items

(2) To verify the current status of potential natural gas demand

(a)To investigate natural gas demand in Luzon
(b)To investigate natural gas demand in Visayas and Mindanao

(3) To review the validity of natural gas-related facilities projects proposed in JICA M/P (2002)

(a)To review the validity of pipeline planning
(b)To verify the current status of other projects

(4) To collect information on natural gas-related facilities projects since the conduct of JICA M/P(2002)

(5) To evaluate priorities of natural gas-related facilities projects

(6) To collect information on regulations and systems regarding environmental and social considerations associated with construction of natural gas-related facilities

(a)To verify the status of environmental permit approval for pipeline planning
(b)To collect information on environmental permit required for construction of LNG plant.

(7) To consider construction and business schemes for promotion of natural gas-related facilities projects

(a)To consider business schemes regarding pipeline projects
(b)To consider business schemes regarding LNG plant

(8)To verify the current status of bidding system of natural gas-related projects

(a)To verify the current status of bidding system for private enterprises and assignment of roles between the private and public sectors
(b)To verify items such as TOR of expected consultants

(9)To prepare a draft of proposal on improvement of policies and systems in natural gas sector

(a)To prepare a draft of proposal on pipeline projects
(b)To prepare a draft of proposal on LNG plant projects
(c)To prepare a draft of proposal on other natural gas-related projects

(10)To report to the Philippines government on contents of the study

1.5 Main Findings

1.5.1 BatMan 1

The Study confirmed that the BatMan 1 project would be feasible from the viewpoints of land acquisition, technical and environmental aspects for the segment from Batangas to Sucat.

The financial analysis showed that the private sector development would have a financial challenge compared with the development by public sector due to the gas supply shortage during the first few years after the commissioning. The analysis also confirmed that so-called ownership-operation separation model, where the asset-holding and asset-operation are managed by two separate entities, could be effectively applicable for the project. The Study therefore proposed the PPP development, in which the infrastructure development and the facility operation would be conducted by the public sector and the private sector, respectively.

1.5.2 LNG Terminal

The Study found the possibilities of the LNG terminal development in several potential sites around the Batangas area while the additional examinations would be required for the environmental and social considerations as well as the land acquisition. Since the LNG terminal would expect the solid revenue basis from the beginning of the operation, the facility could be developed and operated by the private sector with the appropriate tariff setting of the gas wheeling charge. Thus the Study proposed to conduct the feasibility study with the idea of the development by the private sector. In addition, the task and schedule for the action plans were suggested to the Department of Energy in order to expedite the project development.

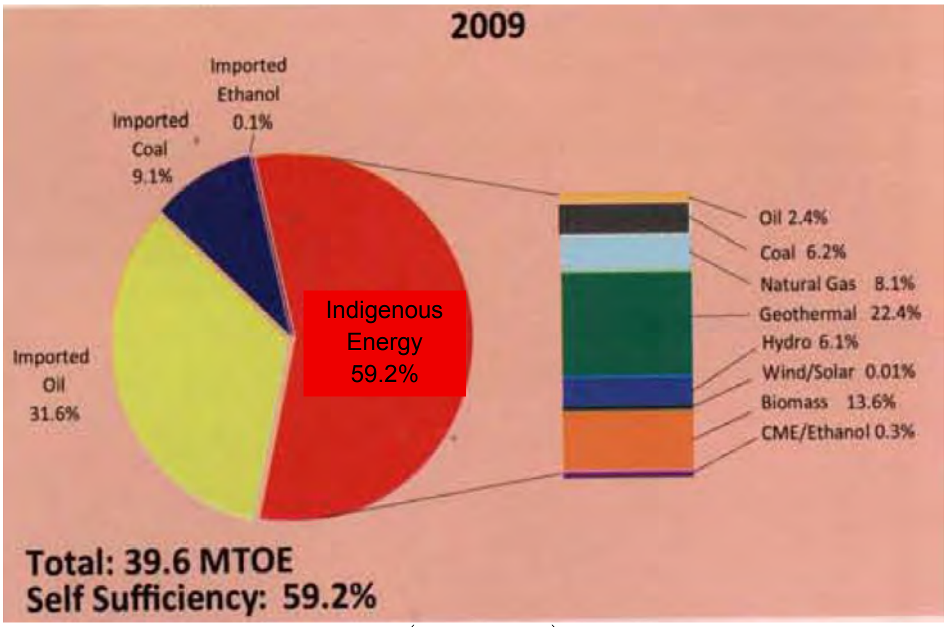
Chapter 2 Natural Gas Utilization Policy and Regulatory Framework

2.1 Current Situation of Natural Gas Production and Consumption

2.1.1 Primary Energy Composition and Position of Natural Gas

In the Philippines, the large part of the primary energy is imported. Improvement of the self-sufficiency ratio of energy has been put at the core of energy policy since the former Arroyo administration. Total primary energy supply in 2009 was 39.5 MTOE and its self-sufficiency ratio was 59.2%. The share of natural gas in the total primary energy was 7.8% (2008), which is the lowest level in the ASEAN countries except for Laos. Natural gas is an important energy resource in the sense that its utilization is required to be promoted early toward the realization of low carbon society. It is expected that natural gas utilization will be promoted actively in the future.

The website of DOE positions natural gas as below.
"Natural gas will provide for the structural change in the country's energy mix and strengthen our fuel diversification program. It will also add to our energy security position and sustainable development as we move away from oil. As a fuel of the future, natural gas will lead to the development of the natural gas industry in the country with attendant transfer of technology, job creation and pouring in of local and foreign investments in the country." In view of the above, it is assumed that Philippines positions natural gas as strategic energy in the future.



Source : "Philippine Energy Situationer" (DOE webpage)

Figure 2.1-1 Primary Energy Supply (As of 2009)

Table 2.1-1 Primary Energy Balance and the Position of Philippines(as of 2008)

	ASEAN	Brunei	Cambodia	Indonesia	Malaysia	Myanmar	Philippines	Singapore	Thailand	VietNam
Coal and Peat	15.5%	0.0%	9.2%	18.7%	13.1%	0.9%	16.4%	0.0%	14.4%	19.8%
Crude	37.7%	22.9%	55.7%	24.4%	40.9%	5.9%	22.7%	276.7%	51.9%	1.2%
Oil	-5.0%	-1.0%	-13.2%	6.5%	-5.7%	3.5%	10.0%	-214.5%	-13.6%	22.5%
Gas	22.7%	78.2%	21.1%	16.1%	46.8%	20.7%	7.8%	37.7%	27.9%	10.5%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	1.1%	0.0%	13.0%	0.5%	0.9%	2.2%	2.1%	0.0%	0.6%	3.8%
Geothermal	4.5%	0.0%	0.0%	7.2%	0.0%	0.0%	22.5%	0.0%	0.0%	0.0%
Combustible	23.5%	0.0%	14.7%	26.7%	4.1%	66.8%	18.6%	0.0%	18.7%	41.8%
Electricity	0.1%	0.0%	-0.4%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.1%	0.5%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note:There is no data on Laos
Source:IEA

2.1.2 Natural Gas Production and Consumption

Natural gas production and consumption in the Philippines are shown in Table 2.1-2. As for natural gas production, the total amount is produced by the Malampaya gas field which started production in 2001. The gas production as of 2010 is 130 BCF.
Natural gas consumption as of 2010 is 120 BCF, and nearly 100% of it is consumed by the power plants in Ilijan, Sta.Rita and San Lorenzo which are located in Batangas area. At present, some of the amount is used for the Shell Refinery, while a small portion of the demand is used for CNG buses plying the routes in Manila-Batangas- Calamba-.

Because the Philippines intend to enhance energy security, the promotion of development and utilization of domestic energy resources is regarded as an important position in the energy policy. In the past performance, the self-sufficiency ratio increased after Malampaya gas field had started its production in 2001(Figure 2.1-2).

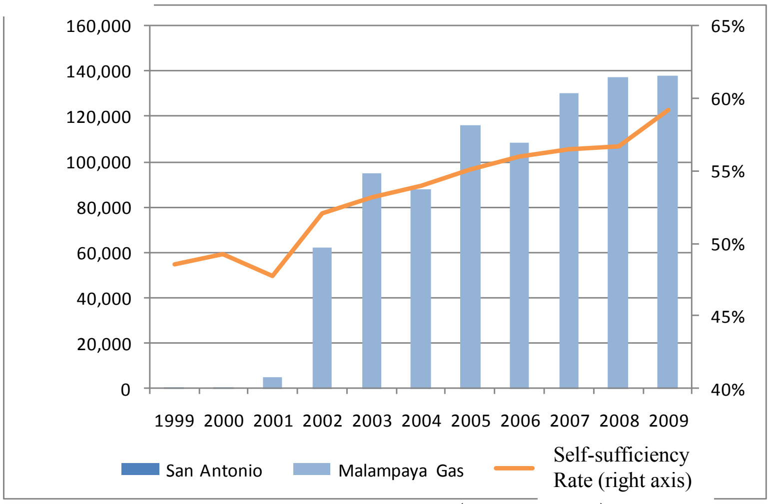
Table 2.1-2 Natural Gas Production and Consumption

(unit:MMscf)

Year	Production			Consumption							
	San Antonio	Malampaya	TOTAL	POWER							
				San Antonio	Ilijian	Sta. Rita	San Lorenzo	TOTAL	INDUSTRY	TRANSPORT	TOTAL
1994	194.78	0.00	194.78	194.78	0.00	0.00	0.00	194.78	0.00	0.00	194.78
1995	188.42	0.00	188.42	188.42	0.00	0.00	0.00	188.42	0.00	0.00	188.42
1996	317.88	0.00	317.88	317.88	0.00	0.00	0.00	317.88	0.00	0.00	317.88
1997	193.41	0.00	193.41	193.41	0.00	0.00	0.00	193.41	0.00	0.00	193.41
1998	329.02	0.00	329.02	329.02	0.00	0.00	0.00	329.02	0.00	0.00	329.02
1999	253.25	0.00	253.25	253.25	0.00	0.00	0.00	253.25	0.00	0.00	253.25
2000	375.90	0.00	375.90	375.90	0.00	0.00	0.00	375.90	0.00	0.00	375.90
2001	111.59	4,839.68	4,951.27	111.59	245.29	4,594.39	0.00	4,951.27	0.00	0.00	4,951.27
2002	82.68	62,122.29	62,204.97	82.68	17,196.29	29,772.42	7,360.13	54,411.52	0.00	0.00	54,411.52
2003	276.54	94,530.28	94,806.82	276.54	26,862.99	37,989.60	19,388.38	84,517.51	0.00	0.00	84,517.51
2004	285.08	87,272.17	87,557.25	285.08	25,953.99	38,005.68	17,137.58	81,382.33	0.00	0.00	81,382.33
2005	93.64	115,872.60	115,966.24	93.64	39,957.30	44,777.06	22,262.52	107,090.52	252.00	0.00	107,342.52
2006	327.69	108,278.78	108,606.47	327.69	34,216.28	43,428.96	21,553.89	99,526.82	2,192.50	0.00	101,719.32
2007	324.80	129,886.04	130,210.84	324.80	47,193.94	47,199.99	23,397.78	118,116.51	3,315.66	0.00	121,432.17
2008	186.63	136,885.87	137,072.50	186.63	48,704.25	50,004.63	24,895.34	123,790.85	2,931.66	14.59	126,737.10
2009	0.00	138,029.81	138,029.81	0.00	51,853.76	48,758.35	24,445.65	125,057.76	3,019.13	18.08	128,094.97
2010	0.00	130,008.00	130,008.00	0.00	47,377.92	46,672.11	22,758.89	116,808.92	3,044.00	16.00	119,868.92
TOTAL	3,541.31	1,007,725.52	1,011,266.83	3,541.31	339,562.01	391,203.19	183,200.16	917,506.67	14,754.95	48.67	932,310.29

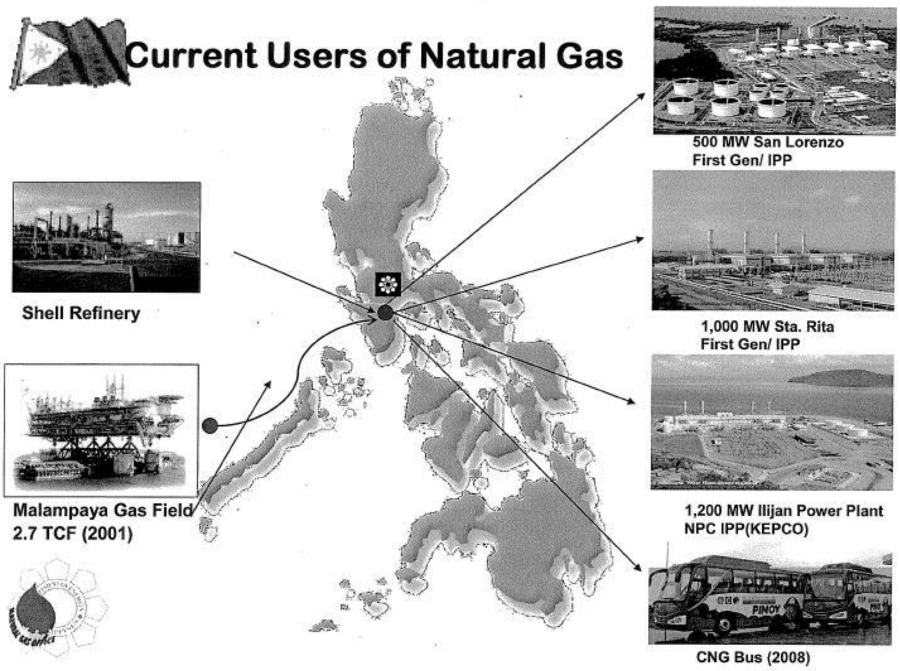
Source:DOE

Amount of gas production
(MMSCF)



Source：“KEY ENERGY STATISTICS 2009” (DOE webpage)

Figure 2.1-2 Production of Natural Gas and Self-sufficiency Rate



Source:DOE

Figure 2.1-3 Current Users of Natural Gas

Table 2.1-3 Project Information of Gas Plants

ITEMS	ILIJAN COMBINED CYCLE PLANT	STA. RITA COMBINED CYCLE PLANT	SAN LORENZO COMBINED CYCLE PLANT
			
Project Name	KEPCO Ilijan Combined Cycle Plant	First Gen Sta. Rita Combined Cycle Plant	First Gen Sta. Lorenzo Combined Cycle Plant
Project Owner	♦ Korea Electric Corporation ♦ TeaM Diamond Holding Corporation ♦ Kyuden Ilijan Holding Corporation	♦ First Gas Power Corporation ♦ British Gas Corporation (might transfer to Korea Electric Corporation)	♦ First Gas Power Corporation ♦ British Gas Corporation (might transfer to Korea Electric Corporation)
Project Cost	US$ 710 Million	US$ 680 Million	US$ 375 Million
Electricity Off-taker	Thru National Power Corporation	MERALCO	MERALCO
Power Purchase Agreement Duration	20 years	25 years	25 years
Plant Output	1,200 MW	1,000 MW	500 MW
Plant Configuration	2 x 600MW (2-on-1 train)	2 x 500MW (2-on-1 train)	1 x 500MW (2-on-1 train)
Gas Turbine Type	MHI 501G	Siemens V84.3A	Siemens V84.3A
Type of Fuel Used	Primary – Natural Gas Secondary – Distillate	Primary – Natural Gas Secondary - Distillate	Primary – Natural Gas Secondary - Distillate
Natural Gas Source	Shell Malampaya Gas Refinery Plant		
Quantity Consumed (2010 figure)	47,377.92MMscf (natural gas base)	46,672.11MMscf (natural gas base)	22,758.89MMscf (natural gas base)
Year of Operation	June 2002	January 2002	October 2002

Source:JICA Study team

2.2 Outline of the Current Energy Policy

2.2.1 PEP 2009-2030 and Energy Policy of the Aquino Administration

The Philippine Energy Plan (PEP) announced by DOE each year focuses on plans and programs in energy sector. The future of energy development, which is an important issue for the prosperity of the Philippines, is a major consideration for the PEP. The latest PEP, "the PEP 2009-2030" was announced in April 2010 (before the start of the Aquino administration).

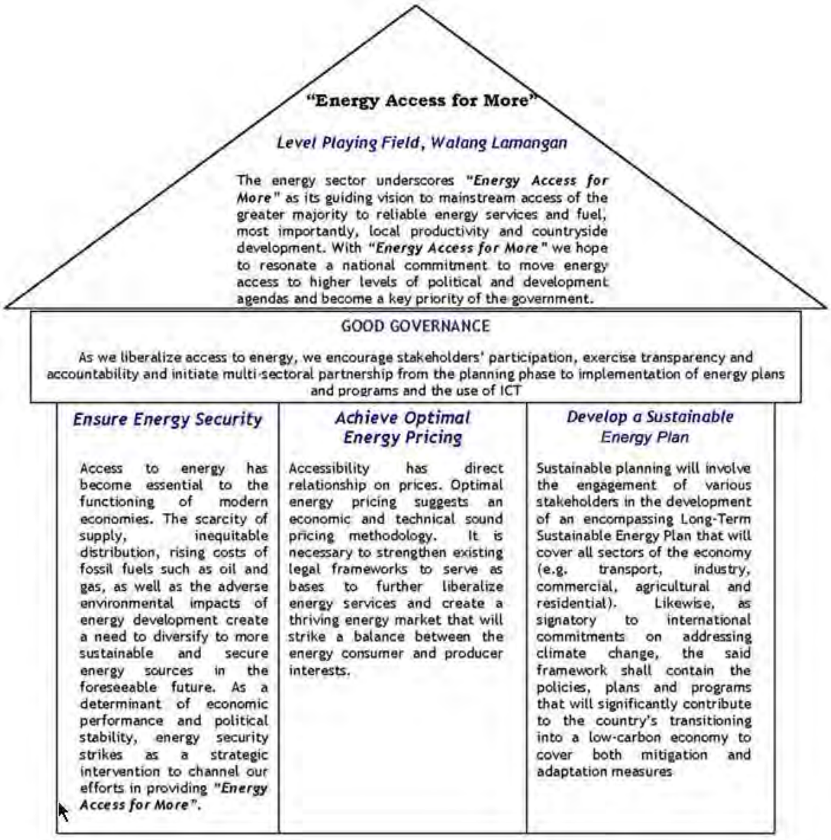
The comprehensive goal of the PEP 2009-2030 is "Ensuring the best energy choices for a better quality of life". The PEP indicates the changes required for the current energy sector for the future energy outlook. The PEP 2009-2030 is based on the following three policies;

- Ensure energy security
- Pursue effective implementation of energy sector reforms
- Implement social mobilization and cross-sector monitoring mechanisms

The Aquino administration, inaugurated in July 2010, is following the energy policy of the former administration basically. The PEP of 2010 version is being formulated and has not been published though it would have been completed at the end of 2011. According to the interview with DOE, there is unlikely much difference between the 2009 version and the 2010 version. Natural gas related measures in the 2009 PEP are shown in the next page.

The energy policies of the Aquino administration are presented in the Energy Reform Agenda (ERA) which includes its goals for the next 6 years. The ERA states that energy is a measure for poverty reduction and also it is a social infrastructure as it serves as an enabling factor to promote grassroots development with the delivery of public services to marginalized and disadvantaged sectors of the society. Along these lines, the ERA emphasizes its guiding vision to mainstream access of the larger populace to reliable and affordable energy services to fuel by "Energy Access for more". It also states that local productivity and countryside development are the most important.

The Aquino administration outlined the following three major pillars of energy sector. The first pillar is "Ensure energy security" which is the same as the former administration. The second and the third pillars are "Achieve optimal energy pricing" and "Develop a sustainable energy plan". The programs that will lead to the attainment of the pillars have been phased into short-(2010-2011), medium-(2011-2013) and long-term (2013-2016) timelines (Figure 2.2-1).



Source : DOE webpage

Figure 2.2-1 Energy Reform Agenda

2.2.2 PEP and Natural Gas-related Measures

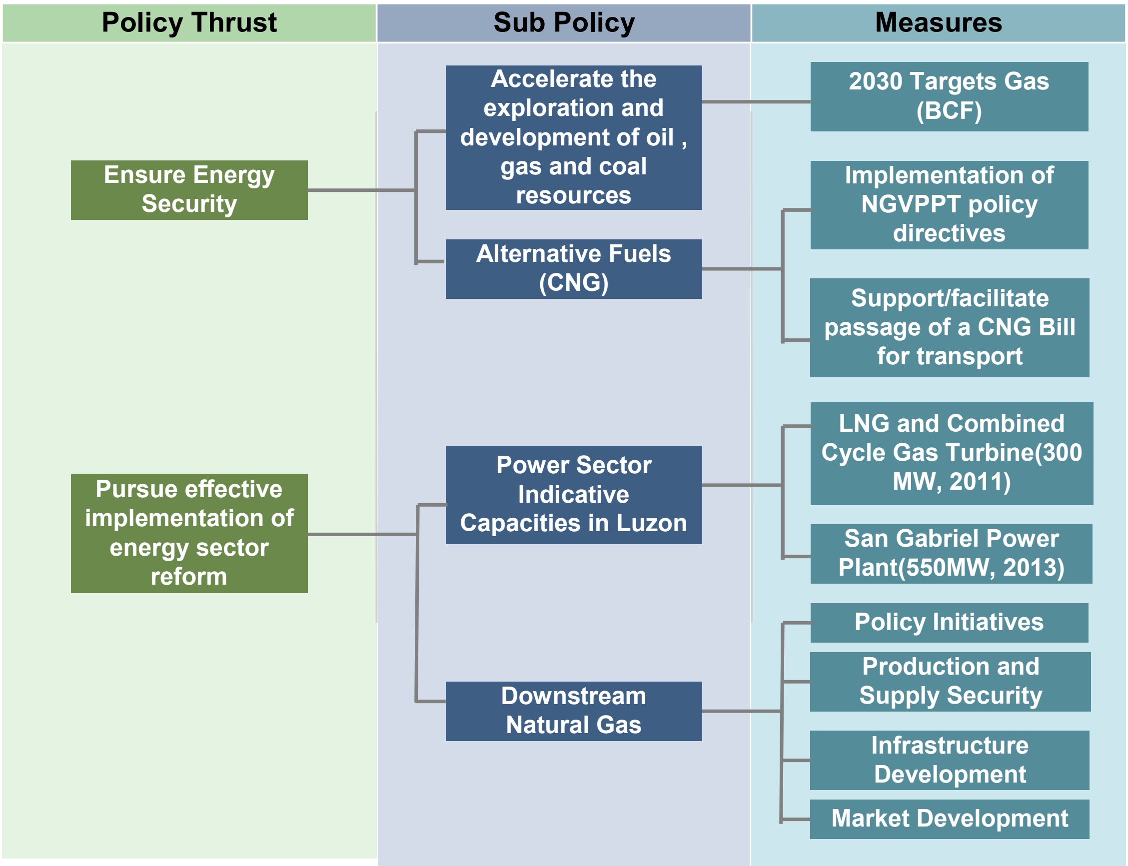
PEP presents specific programs to carry out the basic policies. Among these, natural gas-related measures are shown in Table 2.2-2.

As for upstream, especially natural gas development, it is emphasized that the exploration in South China Sea area should be promoted. However, as the targets toward 2030 show, it is assumed Malampaya gas field will continuously play a major role in natural gas production.

As for CNG as alternative energy, it aims at encouraging diffusion in transportation sector (CNG bus). According to the DOE, the target for CNG bus numbers are 2,500 in 2020 (of which 1,884 in Luzon), 10,000 in 2030 (of which 7,535 in Luzon)(Table 2.2-1). However, when it is converted to natural gas demand, it will be 0.006BCF in 2020 (of which 0.0046BCF in Luzon) and 0.24 BCF in 2030 (of which 0.18 BCF in Luzon) which are small quantity.

In electricity sector, the plan of natural gas-fired thermal plant should be noted. The PEP refers to Combined Cycle Gas Turbine (300MW, 2011) and San Gabriel Power Plant (550MW, 2013). The electric power development plans including Combined Cycle Gas Turbine and San Gabriel Power Plant are shown in (4).

In natural gas downstream sector, several measures are being planned. Especially with regard to infrastructure development, to formulate a master plan of natural gas which is currently implemented by JICA is positioned as the highest-priority measure. In addition, to conduct FS of LNG terminals and to develop natural gas infrastructure in Visayas and Mindanao are also included in the PEP According to hearing from DOE, in Visayas, Cebu Island is a candidate for LNG terminal.



Source:PEP2009-2030

Figure 2.2-2 Policy Thrust of the PEP and Natural Gas Related Measures

Table 2.2-1 NGVPPT Measurable Targets

Year	Number of CNG Buses(Target)				Diesel Liter Equivalent (In million liters)
	Luzon	Visayas	Mindanao	Total	
2011	100			100	7.95(0.007KTOE)
2015	1,000			1,000	79.502(0.067KTOE)
2020	1,884	288	328	2,500	198.755(0.168KTOE)
2025	3,768	575	657	5,000	397.510(0.337KTOE)
2030	7,535	1,151	1,314	10,000	795.020(0.674KTOE)

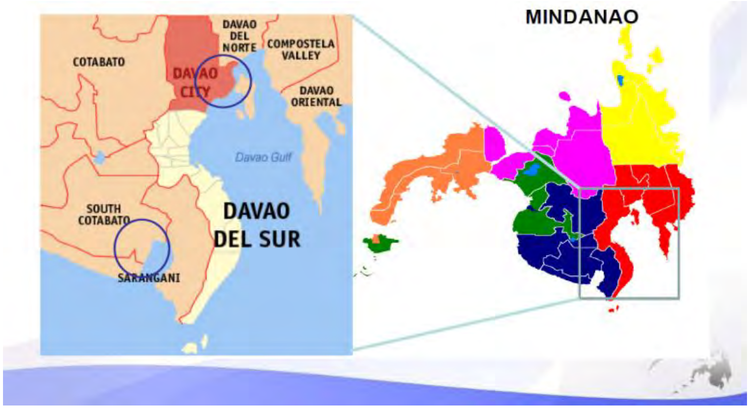
Note : Diesel liter Equivalent is based n 254 liters/day at 313 days per annum
Source: DOE

Table 2.2-2 Natural Gas Related Measures

Policy Thrusts	Sub Policy	Measures
Ensure Energy Security	Accelerate the exploration and development of oil, gas and coal resources	2030 Targets Gas(BCF) - Malampaya 2,628.00 - San Martin 51.72 - Sultan sa Barongis 10.92 - Libertad 3.52
	Alternative Fuels (CNG)	✓Implementation of NGVPPT policy directives ✓Support/facilitate passage of a CNG Bill for transport ✓Enhancement of policy directives and program incentives (supply and price mechanisms) ✓Ensure gas supply for the commercial phase ✓"Measurable Targets" is shown in Table X
Pursue effective implementation of energy sector reforms	Power Sector Indicative Capacities in Luzon	LNG and Combined Cycle Gas Turbine (300MW,2011) San Gabriel Power Plant (550MW,2013)
	Downstream Natural Gas	Policy Initiatives ✓Natural Gas Bill ✓Implementing Rules and Regulations, Transmission Code, Distribution Code and Supply Code ✓Incentives for natural gas in the Investment Priorities Plan Production and Supply Security ✓Exploration and development of natural gas supply base ✓Inventory of other potential sources of natural gas and its application ✓Promote the establishment of LNG import terminal hub in the country ✓Monitoring and evaluation of natural gas supply developments in ASEAN, Middle East and APEC member countries Infrastructure Development ✓Review and update of the country's Master Plan Study for the Development of the Natural Gas Industry ✓Conduct of FS for LNG terminal to supply natural gas requirements in Visayas and Mindanao ✓Implement Infrastructure Development Plan for Visayas and Mindanao by 2021-2030 Market Development ✓Review the gas pricing formula ✓Recommend standard/base price structure ✓Review and integrate incentive package for natural gas infrastructure ✓Conduct study for the use of natural gas from other potential sources ✓Evaluation of techno-economic aspects of related technologies for fuel shift to natural gas

		✓Promotion of on-site or small-scale power generation using marginal gas fields ✓Conduct profiling of potential gas markets ✓"Infrastructure development" is shown in Table 2.2-3

Source: Philippine Energy Plan 2009-2030



Source：“Investment Opportunities in the Philippines ENERGY SECTOR”（DOE, 2011）

Figure 2.2-3 Planned LNG Terminal in Mindanao

2.2.3 Natural Gas-related Infrastructure Projects

Specific infrastructure development projects are shown in Table 2.2-3. According to DOE, BatMan 1 pipeline from Batangas to Manila is positioned as the highest-priority project. DOE gives higher priority to LNG terminal in Batangas area than LNG terminal in Bataan Peninsular. The reasons might be as follows; 1) Although the Malampaya gas field is expected to be a source for BatMan 1 pipeline, there is a concern about depletion of the Malampaya gas field in the future and a new LNG terminal is expected to serve alternative function of natural gas supply. 2) As the price of natural gas of Malampaya gas field(retail price of natural gas based on the price formula of Malampaya gas field) is relatively higher, natural gas price decline is expected by competition between LNG as a new supply source with Malampaya gas field.

Regarding natural gas demand along BatMan1, DOE expects not only electricity demand, but also industrial, commercial (communal central air-conditioning) and residential demand.
For electricity demand, the exisiting Sucat power(850MW) plant is expected to be converted to gas-fired plant. However, if the conversion of Sucat power plant is difficult, it is expected to build new natural gas-fired power plants along the pipeline.
BatMan1 pipeline are divided into the following three zones;

- Zone1:Batangas-Binan
- Zone2:Binan-Rosario/Robin
- Zone3:Binan-Sucat

Philippine National Oil Company (PNOC) positioned Zone 1 as the 1st stage.

The role of PNOC in BatMan 1 is to prepare sufficient budget. However, DOE sees that PNOC will not able to secure sufficient budget and they will have to seek partners. Engineering, procurement and construction (EPC) and operation and management (O&M) of the pipeline will be left to the judgment of the pipeline company which will be established in the future. PNOC will grant a franchise to PNOCEC.

According to DOE, DOE considers it is needed to introduce new technologies for natural gas transportation as well as realization of infrastructure programs such as pipeline and LNG. For example, LNG transportation cars and LNG tankers are being discussed as natural gas transportation means, considering economic efficiency and early feasibility

Table 2.2-3 Infrastructure Development

Critical Gas Infrastructure Project	Target Year
Batangas-Manila (BatMan 1) pipeline	
Zone 1: Batangas-Binan	2013
Zone 2: Binan-Rosario/Robin	2014
Zone 3: Bian-Sucat	2015
CNG Refilling Stations in Metro Manila	2010-2015
Bataan-Manila (BatMan 2) Pipeline	2016
LNG Hub Terminal in Pagbilao Quezon	2013
LNG Terminal in Bataan	2015
Pipelines to Subic and Clark	2017
Sucat-Fort Bonifacio Pipeline	2017
Bataan-Cavite (BatCave) Pipeline	2020
Metro Manila Gas Loop/EDSA-Taft Loop	2020

Note:
PNOC to undertake front-end engineering and design(feed), engineering procurement and construction (epc) and permitting.
Funding will be handled by the private sector while the gas supply will be shared between PNOC and private sector
Source: Philippine Energy Plan 2009-2030

Source:"Investment Opportunities in the Philippines ENERGY SECTOR"(DOE, 2011)

Figure 2.2-4 Planned Natural Gas Infrastructure in Luzon

2.2.4 Power Development Plan2010-2030

Electricity demand is viewed as a key to forecast natural gas demand. As of 2010, 97% of natural gas consumption is consumed by natural gas-fired power plants. (They are Ilijan combined cycle plant, Sta.Rita combined cycle plant and San Lorenzo combined cycle plant in Batangas area using natural gas from Malampaya gas field). In the future, it is expected that new construction of natural gas-fired power plants and fuel conversion along the BatMan 1 pipeline and around the LNG bases. The trends of power development make an impact on FS of BatMan 1 pipeline and LNG bases. Hereinafter, future prospects of power development based on "Power Development Plan 2010-2030" will be described.

Electricity installed capacity in the Philippines as of 2010 is shown in Figure 2.2-5. The total installed capacity is 16,359 MW and the share of natural gas-fired power generation is 17.49%. The gross generation is 67,743 GWh. The share of natural gas-fired power generation with high generating efficiency accounts for 28.81% of the total, which is higher than that of installed capacity. By region, installed capacity in Luzon is 11,981 MW which accounts for the 73.24% of the total.

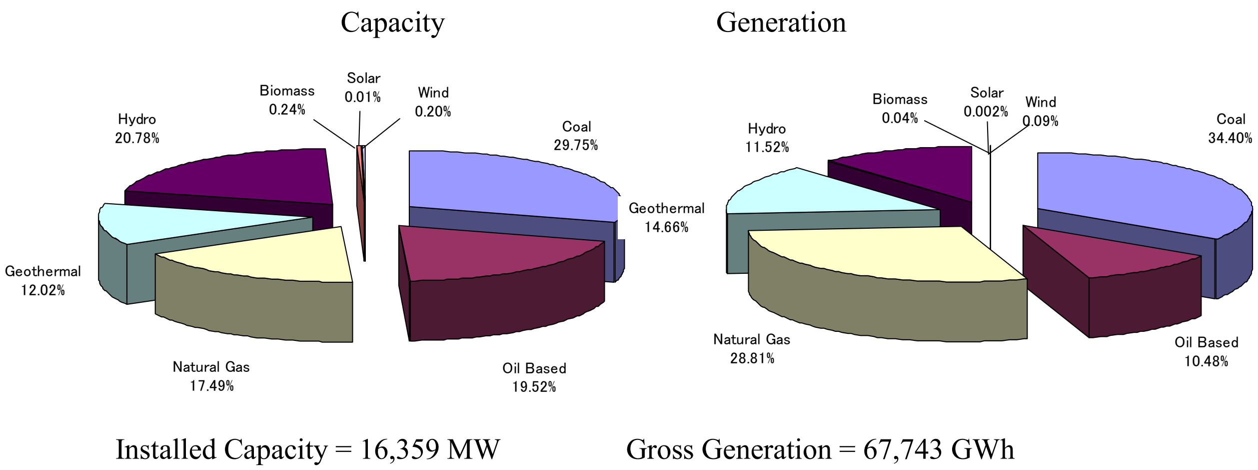


Figure 2.2-5 Capacity and Gross Power Generation (2010)

Table 2.2-4 Capacity by Region

GRID	Capacity(MW)		Percent Share (%)		2010 Peak
	Installed	Dependable	Installed	Dependable	Demand(MW)
LUZON	11,981	10,498	73.24	75.52	7,656
VISAYAS	2,407	1,745	14.71	12.55	1,431
MINDANAO	1,971	1,658	12.05	11.93	1,288
TOTAL	**16.359**	**13,902**			**10,231**

Source: Power Development Plan2010-2030

According to "Luzon Power Supply Demand Outlook to 2030", the required additional capacity is 300 MW in 2014 and the total required additional capacity from 2014 to 2020 for 7 years is 3,400 MW. And new construction and expansion of power plants with 12,300 MW is needed for 17 years to 2030. In Luzon, there is a great need for new construction and expansion of power plants, so new construction and expansion of natural gas-fired power plants along BatMan1 pipeline is also expected.

Along the BatMan 1 pipeline, First Gen San Gabriel (550 MW, 2013)1 which is planned to be built in Batangas area should be noted. Natural gas produced in Malampaya gas field is supplied to three power plants in Batangas area. It is an important point whether required natural gas will be supplied to BatMan 1 as a result of new demand of natural gas created by the construction of First Gen San Gabriel.

In Luzon there are 23 new power plants projects conducted by private companies, as shown in table 2.2-5. If these new power plants are constructed as scheduled, the total capacity in 2020 will increase by 5208.3MW compared to the capacity in 2010. Table 2.2-6 shows the forecast for power supply and demand in case the new combined cycle power plants are constructed.

Table 2.2-5 New power plants projects conducted by private companies in Luzon

Committed / Indicative	Name of the Project	Location	Rated Capacity (MW)
	COAL		**3,635.00**
Committed	**2 X 300 MW Coal-Fired Power Plant**	**Mariveles, Bataan**	**600**
Indicative	Puting Bato Coal Fired Power Plant	Brgy. Puting Bato West, Calaca, Batangas	135
Indicative	2 X 300 MW Coal-Fired Power Plant	Sitio Naglatore, Cawag, Subic	600
Indicative	Quezon Power Expansion Project	Mauban, Quezon	500
Indicative	SLPGC Coal-Fired Power Plant	Brgy. San Rafael, Calaca, Batangas	1200
Indicative	2 X 300 Masinloc Expansion	Zambales	600
	DIESEL		**171.00**
Committed	**CIP 2 Bunker Fired Power Plant**	**Bacnotan, La Union**	**21**
Indicative	Aero Derivative Combined Cycle Power Plant	Calamba, Laguna	150
	NATURAL GAS		**850.00**
Indicative	2 X 100 MW Gas Turbine Power Project 2 X 50 MW Steam Turbine Power Project	Brgy. Ibabang Polo, Grande Island, Pagbilao, Quezon	300
Indicative	San Gabriel Power Plant	San Gabriel, Batangas	550
	GEOTHERMAL		**140.00**
Committed	**Maibarara Geothermal Power Project**	**Sto. Tomas, Batangas**	**20**
Indicative	Tanawon Geothermal Project	Bacman Geothermal Field, Sorsogon	40
Indicative	Rangas Geothermal Project	Bacman Geothermal Field, Sorsogon	40
Indicative	Manito-Kayabon Geothermal Project	Bacman Geothermal Field, Sorsogon	40
	HYDROPOWER		**150.00**
Indicative	Kanan Hydro Power Project	Gen. Nakar, Quezon Province	150
	WIND		**206.00**
Indicative	Burgos Wind Power Project	Nagsurot-Saoit, Burgos, Ilocos Norte	86
Indicative	Pasuquin East Wind Energy Project Phase One	Pasuquin, Ilocos Norte	45
Indicative	Pasuquin East Wind Energy Project Phase Two	Pasuquin, Ilocos Norte	75
	BIOMASS		**56.30**
Committed	Green Future Biomass Project	Isabela	13
Indicative	Unisan Biogas Project	Quezon Province	11.2
Indicative	Lucky PPH Biomass project	Isabela	3.6
Indicative	17.5 MW Nueva Ecija Biomass Power Project	Brgy. Tambo-Tabuating, San Leonardo, Nueva Ecija	17.5
Indicative	San Jose City I Power Corporations' Biomass Project	Nueva Ecija	11
		total	**5,208.30**

[1] It is in the F/S stage.

Table 2.2-6 Forecast for Power Supply and Demand in Luzon

(MW)

	① Required additional capacity	② Committed capacity	③ Existing capacity	④ Required reserve margin	⑤Peak demand	⑥ Required capacity	⑦non-committee project	⑧Existing capacity (in case if non-committee projects are completed as scheduled)	⑨Required additional capacity (in case if non-committee projects are completed as scheduled)
2010			10,197	1,825	7,799	9,624		10197	
2011		75	10,272	1,847	7,895	9,742		10272	
2012		34	10,347	1,932	8,257	10,190		10347	
2013	276	620	10,381	2,021	8,636	10,657	295.8	10,381	276
2014	145		11,001	2,114	9,033	11,146	238.5	11,297	-150
2015	657		11,001	2,211	9,447	11,658	980	11,535	123
2016	1,192		11,001	2,312	9,881	12,193	1050	12,515	-322
2017	1,752		11,001	2,418	10,335	12,753	1240	13,565	-812
2018	2,337		11,001	2,529	10,809	13,338	600	14,805	-1,467
2019	2,949		11,001	2,645	11,305	13,950	0	15,405	-1,455
2020	3,590		11,001	2,767	11,824	14,591	150	15,405	-815
2021	4,260		11,001	2,894	12,367	15,261	700	15,555	-295
2022	4,960		11,001	3,027	12,934	15,961	0	16,255	-294
2023	5,693		11,001	3,166	13,528	16,694	0	16,255	438
2024	6,459		11,001	3,311	14,149	17,460	700	16,255	1,205
2025	7,260		11,001	3,463	14,798	18,261	0	16,955	1,306
2026	8,098		11,001	3,622	15,478	19,099	0	16,955	2,144
2027	8,975		11,001	3,788	16,188	19,976	0	16,955	3,021
2028	9,892		11,001	3,962	16,931	20,893	0	16,955	3,938
2029	10,851		11,001	4,144	17,708	21,852	0	16,955	4,897
2030	11,854		11,001	4,334	18,521	22,855	0	16,955	5,900

↑
shortfall : in black
(surplus : in red)

note) ⑨Required additional capacity is calculated by the following method.
⑨=(⑥in the reference year(=④+⑤) - ⑧in the reference year (=⑦+⑧in the previous fiscal year)

source) modified by MRI using 2010-2030PDP
(growth rate : 4.59%
reserve margin(23.4%) is the same condition as PDP)

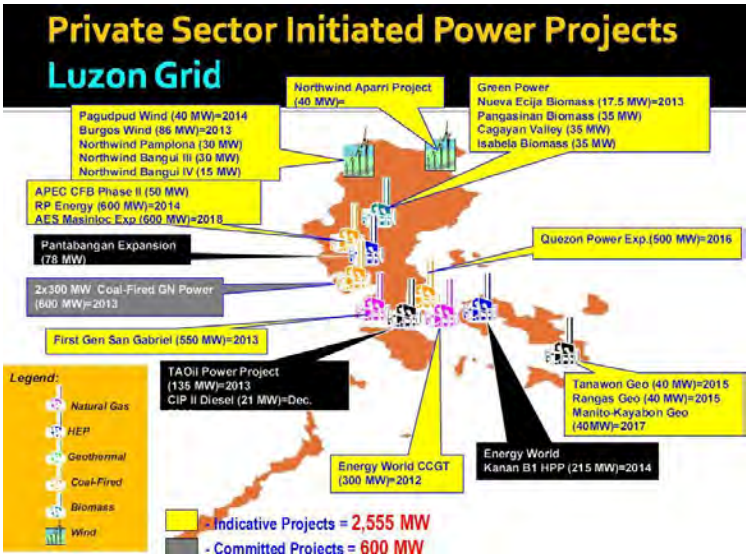


Figure 2.2-6 Private Sector Initiated Power Projects(Luzon Grid)

2.2.5 Current Trend of Other Donors (World Bank)

As for natural gas sector in the Philippines, the current trend of World Bank is worthy of note.

The World Bank proposed solutions for the Philippines and Vietnam utilizing mid-scale LNG. In the Philippines, the construction of onshore and offshore LNG terminals in Limay in Bataan Peninsular is under consideration. The World Bank pointed out that the development of smaller LNG carriers is needed for mid-scale market such as the Philippines and FSRU/FSU has drawn more attention with the intention of accelerating the realization of projects. As for the natural gas by LNG terminal in Limay proposed by the World Bank, it is assumed to be consumed in a natural gas power plant which is expected to be constructed in neighboring area.

As the World Bank assumed a LNG terminal in Bataan Peninsular, it needs to be taken into account when formulating natural gas master plan for all over the Philippines or Luzon Island. However, we believe that the basic design of BatMan 1 pipeline and others in this study does not require consideration of its direct effect

2.3 Outline of the Existing Regulatory Framework

2.3.1 Legislation and Existing Laws including Presidential Decree

Natural gas utilization in the Philippines has started in the twenty-first century and gas regulatory framework has not been fully institutionalized yet. The existing gas related regulations are included in the following oil related laws. However, regarding Natural Gas Act intended for national control of gas development and quantitative expansion, its deliberation in Congress has been held up for many years.

Table 2.3-1 Legislation and Existing Laws at the Same Level as Presidential Decrees

1)Commonwealth Act No.146(CA146) of 1936
2)Petroleum Act of 1949(Republic Act 387, June 18, 1949)as amended
3)RA 6173 Oil Industry Commission Act, April 30, 1971)
4)Presidential Decrees(PD)87, Dec.31, 1972
5)PD 1206, Creating the Department of Energy, October 6, 1977
6)PD 1700, Regulating Pipeline Concessionaires, July 10, 1980
7)The new constitution (1987)
8)Executive Order 172 of 1987
9)Act of Creating the Department of Energy (Republic Act 7638, December 9, 1992)
10)Downstream Oil Industry Deregulation Act of1998(Republic Act no.8479, July 28, 1997)
11)Tax Reform Act of 1997 and National Internal Revenue Code
12)Philippine Air Clean Act of 1999
13)PD No.314 of November 2000
14)An Act to grant First Gas Holdings franchise to construct, install, own, operate and maintain a natural gas pipeline for the transportation and distribution of natural gas to different areas in the Island Luzon(Republic Act No. 8997)
15) An Act Ordaining Reforms in the Electric Power Industry(RA No. 9136, June 8 2001)

2.3.2 Gas Related Regulations

The following ministerial ordinances, guidelines, official views and regulations are important.

Table 2.3-2 Natural Gas Related Regulations

1) Constituting an Inter-Agency Committee on Natural Gas Development.(Department Adm.Order No.193 (22 August 1990)
2) An Act Creating the Department of Energy, Rationalizing the Organization and Functions of Government Agencies Related to Energy, and for Other Purposes (Republic Act no. 7638 (9 December 1992)
3)Rules and Regulations Implementing Section 5 of DOE Act of 1992 or RA 7638((Energy Regulation ER 1-94.May,24,1994)
4)Policy Guidelines on the Overall Development and Utilization of Natural Gas in the Philippines(DOE Circular No.95-06-006.June,15,1995)
5)Creating the Philippine Gas Project Task Force (Executive Order No.254(30, June 1995)
6)Department of Justice Opinion No.95,S.1988 (May,11,1988)
7) Department Circular No.2000-03-003 (March,17,2000)
8)Department Circular No.2000-06-010 and other several circulars in 2000
9)Department of Justice Opinion No.95,S.2000 (June,6,2000)
10)Designating the Department of Energy as the Lead Agency in Developing the Philippine Natural Gas Industry(18 January 2001)
11)Rules of Practice and Procedure Before the Department of Energy (DOE Circular No.2992-07-004(31 July 2002)
12)DOE Reorganization (Administrative Order No.38 (23 August 2002)
13)Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas(DOE Circular No.2002-08-005(27 August 2002)
14) Assignment of Personnel at the Natural Gas Office (DOE Special Order No.2002-12-050 (3 December 2002)
15) Implementing the Natural Gas Vehicle Program for Public Transport(Executive Order No.290 24 February 2004)
16) Guidelines on the Issuance of Certificate of Accreditation and Certificate of Authority to import under the Natural Gas Vehicle Program for Public Transport(NGVPPT)(DOE Circular No.2004-04-004(2 April 2004)
17) Enhanced Implementation of the NGVPPT and the Development of Compressed Natural Gas (CNG) Supply and Infrastructure (DOE Circular No. 2005-07-006 (5 July 2005)

Circular No.2002-08-005 (hereinafter called "Circular") provides the basis for natural gas transportation, distribution, supply related businesses.

The Circular is applied to a) The transmission and distribution of Natural Gas, whether indigenous or imported, for own use, b) The Supply of Natural Gas, whether indigenous or imported, to Customers; c) The responsibilities of the DOE and its relation with other government agencies, and the role and responsibilities of such private participants in the Natural Gas industry. Its basic policies are promotion of natural gas utilization by the establishment of natural gas industry, facilitation of the participation of the private sector in the natural gas industry, promotion of competition by liberalizing entry into the industry and compliance with international safety standards. The Circular provides the guidelines on structure and operation of natural gas industry and others. The natural gas industry is divided into three sectors, namely: transmission distribution and supply of natural gas.
The main characteristics of the circular are as follows;

Transmission, distribution and natural gas supply sectors' entities are subject to the permitting authority of the DOE.

The operation of Gas Transmission and Distribution Systems is recognized to be public utility operations requiring a Franchise. For these operations, the Philippine ownership is required.

Third Party Access obligations shall apply to the Gas Transmission Systems and Gas Distribution Systems.

No Person shall undertake the construction, operation and maintenance, expansion, extension or modification of a Gas Transmission System and Gas Distribution System or a Transmission– and/or Distribution-related Facility unless a Permit has been issued by the DOE

DOE may recommend the bidding out of a Gas Infrastructure Project subject to existing laws and regulations.

All Pipelines shall be constructed following a route that will provide the greatest benefit to Customers that can be identified at the time the application is submitted. Before issuing a Pipeline Permit, the DOE may require an applicant to submit the results of studies undertaken on alternative routes and options for expansion along these proposed routes.

No Pipeline or Transmission- and/or Distribution-related Facilities for which a Permit has been issued shall be abandoned or withdrawn from service by the grantee of the Permit without obtaining prior written authorization from the DOE.

A Permit shall be valid for twenty five years extendible for up to an additional twenty five years. The construction and operation of Pipelines and Transmission- and/or Distribution-related Facilities shall be in accordance with relevant standards promulgated by the International Standards Organization (ISO). The design standard for Pipelines shall comply with the requirements of ISO 13623

All Permit holders shall conduct their activities and operations consistent with all environmental laws of the Philippines.

All matters related to fixing and regulating the rate or schedule of prices of piped gas shall remain the responsibility of ERC consistent with the ERB Charter

The other items in each section of Circular are shown in the Table 2.3-3.

Table 2.3-3 Brief Description of DOE Circular No.2002-08-005

Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas

PART/Rule	Title	Contents	Note
PART Ⅰ	General Provisions		
Rule 1	Scope	Transmission/Distribution of NG, whether indigenous/imported, for own-use/ by virtue of a Franchise/as a Pipeline Concession Supply of NG	
Rule 2	Declaration of Policy	Promote natural Gas Facilitate the participation of the private sector in the Natural Gas industry Promote competition Ensure compliance	
Rule 3	Responsibilities of the DOE	Policy making body for the energy sector Supervising and regulating the development and operation of the Natural Gas industry	
Rule 4	Measurement of Natural Gas	The volume of natural gas : SCM The energy of Natural Gas : Joules Standard conditions: Natural Gas at a temperature of 15.5 degrees Celsius and an absolute pressure of 0.101325 Mpa	
Rule 5	Definition of Terms	(To be left out)	
PART Ⅱ	Structure and Operation of the Natural Gas Industry		
Rule 6	Transmission Sector	The Transmission of NG by Gas Transmission Utilities is subject to the permitting authority of the DOE.	
Rule 7	Distribution Sector	The Distribution of NG by Gas Distribution Utilities to Customers is subject to the permitting authority of the DOE and the rate-making powers of the ERC. Pipeline Networks Universal Service Obligations of Gas Distribution Utilities.	
Rule 8	Transmission-and/or Distribution-related Facilities	Facilities are subject only to the permitting authority of the DOE. a) Natural Gas Processing plants b) Facilities for interconnecting Pipelines c) Pipeline metering stations d) LNG terminals and degasification facilities e) Storage Facilities f) CNG-refilling stations Authorization to Operate Transmission- and/or Distribution- related Facilities	
Rule 9	Supply Sector	The supply of NG to Customers is subject to the permitting authority of the DOE. Authorization to Supply NG to Customers Affiliated Suppliers	
Rule 10	Regulation of Transmission, Distribution, and Supply of Natural Gas	The Transmission, Distribution, and supply of NG are businesses affected with public interest and the regulation. Franchising Requirement in the Transmission and Distribution of NG Pipelines and Related Facilities Under Service Contracts Philippine Ownership requirement Cross-ownership	
Rule 11	Third Party Access	Third Party Access Obligation Available Capacity Deferment of Third Party Access Obligation Approved Access Conditions for Gas Transmission Utilities and Gas Distribution Utilities	Gas Transmission Systems and Gas Distribution Systems shall be available for non-discriminatory access by third party users.
Rule 12	Permits	Requirement for a Permit Gas Infrastructure Projects Pipeline Route Conditions of the Permit	No Person shall undertake the construction, operation and

		Petroleum Operations Own-use Permits Fees Abandonment of Pipeline and Transmission- and Distribution- related Facilities Duration of Permit	maintenance, expansion, extension or modification of a Gas Transmission System and Gas Distribution System or a Transmission- and/or Distribution-related Facility unless a permit has been issued by the DOE.
Rule 13	Application for Permits	Application Required Contents of the Application Application Fee Confidential Information Decision to Issue a Permit	
Rule 14	Standards for Construction, Operation and Safety	Conduct of Operations Impact on Public Infrastructure Pipeline Design Standard Pipeline Testing Signs Discontinuation of Operations Discharge of Substances from Pipelines Onshore Pipeline Abandonment Submarine Pipeline Abandonment Compliance with Environmental and Other Laws and Regulations	The construction and operation of pipelines shall be in accordance with ISO. The design standard for Pipelines shall comply with the requirements of ISO 13623. All permit holders conduct their activities and operations with all environmental and other laws of the Philippines.
PARTⅢ	Natural Gas Pricing		
Rule 15	Natural Gas Pricing	Determination of Rates and Price Schedules Guiding Principles for Pricing Just and Reasonable Standard Unbundled Service	All matters related to fixing and regulating the rate or schedule of prices of piped gas shall remain the responsibility of ERC.
Rule 16	Promotion of Competition	Promotion of Competition Take-or-Pay Obligations	
PARTⅣ	Transitory Provisions		
Rule 17	Existing Systems	Permits Application	
Rule 18	Pending Applications		
PARTⅣ	Final Provisions		
Rule 19	Reportorial Requirements	The pertinent reportorial requirements are provided in Annex.3	
Rule 20	Offenses and Penalties	Offenses Enforcement of Rules Penalties Cancellation of Permit	
Rule 21	Separability Clause		
Rule 22	Amendment of		

	Rules		
Rule 23	Effectivity		
Annex 1	Documents to Accompany Application for Pipeline Permit		
Annex 2	Access Conditions for Pipelines		
Annex 3	Reporting and Documentation		

2.3.3 Considerations on Circular No.2002-08-005

Circular No.2002-08-005 (hereinafter called “Circular”) provides the basis for natural gas sector. However, the situation surrounding natural gas sector is different than before and DOE recognized the need to revise Circular.

DOE understands that specific projects will not be advanced unless Circular is revised because Circular provides the basis for approval of pipeline projects.

The deliberation of Natural Gas Act in parliament has been held up for many years. DOE see that it takes at least three years to enact the legislation. At present, Circular is the only rule for natural gas sector. If the deliberation of Natural Gas Act is restarted, Circular is more likely to be the basis of Natural Gas Act.

The points of Circular are shown in Table 2.3-3. As described below, JICA Team makes a proposal on perspectives for the revision of Circular based on comparison of the Circular with natural gas-related laws of Japan and others.

(1) The position of Circular in pipeline related laws and regulations and its confines.

In general, the main laws related to natural gas pipeline business are divided into the following five categories. The related laws are shown in Table 2.3-4.

1) Business related laws (project implementing players, contents of business and fees, etc.)
2) Public Facility Administration related laws(occupancy and drilling of national property including roads and rivers)
3) Land expropriation and land use related laws (land use, land expropriation, etc.)
4) Security related laws (Technical standards for work of construction and operation and maintenance)
5) Environment related law (environmental regulation for work of construction and operation and maintenance)

In the Philippines, Circular No.2002-08-005 is positioned as the main regulation for business related activities specifically focused on pipeline operations and supply of natural gas..

Table 2.3-4 Regulations and Laws Related to Natural Gas Pipeline Business in Japan

Type of laws	Japan	Philippine
Business related laws	Mining Act Article 21(to create mining rights) Article 63 (Operation Plan) Gas Business Act Article 3-Article15 (Business License) Article 16-Article 25-4 (Services) Petroleum Pipeline Business Act Article 5-Article 14 (Business License) Electricity Business Act Article 3-Article 17(Business License) Article 18-Article 33 (Services) High Pressure Gas Safety Act Article 5- Article 25(Services)	Circular No. 2002-08-005 PART Ⅰ(General Provisions) ✧ Rule 1-5 PART Ⅱ(Structure and Operation of the Natural Gas Industry) ✧ Rule 6-14 PART Ⅲ(Natural Gas Industry Pricing) ✧ Rule 15-16
Public Facility Administration related laws	Road Act Article 32 – Article 41 (occupancy of roads) Act on Special Measures concerning Preparation, etc. for Common-Use Tunnel Article 12-Article 19 (Occupancy of Common-Use Tunnel) Road Traffic Act Article 77 (Permission of road- use) Coast Act Article 7 (Occupancy of Coastal Protection Area) Ports and Harbors Act Article 37 (Permission of Construction Works in Port Area) Sewerage Service Act Article 24 (Constraint of Activity) Urban Park Act Article 6 (Permission of Occupancy of Urban Park) Natural Parks Act Article 17 (Special Area) City Planning Act Article 65 (Restriction of construction, etc.) Forest Act Article 10-2 (Permission of development action)	
Land expropriation and land use related laws	Compulsory Purchase of Land Act Article 3(Services authorized to land expropriation and land use) Article 16-Article30-2(Authorization of Service) City Planning Act Article 11 (City Facility) Article 69-73(land expropriation and land use for city planning business	

	Mining Act Article 101-108(Use and Expropriation of Land) Civil Code Article 206(meaning and contents of ownership Article 207(limit of land ownership) Article 265-269 (Superficies) Basic Act for Land Article 2 (Precedence of public welfare with regard to land)	
Security related laws	Mine Safety Act Article 4-Arcicle 31-3 Gas Business Act Article 28-36 Petroleum Pipeline Business Act Article 24-31 Electricity Business Act Article 42-46 High Pressure Gas Security Act Article 29-39	Circular No. 2002-08-005 ✧ Rule 14(Standards for Construction, Operation and Safety)
Environment related Laws	Noise Regulation Act Article 14 Vibration Regulation Act Article 14 Environment impact assessment ordinance or guidelines by local governments	Circular No. 2002-08-005 ✧ Rule 14(Standards for Construction, Operation and Safety) - Compliance with Environmental and Other Laws and Regulations

(2) Response to introduction of LNG and CNG

It appears that DOE recognized the need to revise related laws including Circular along with the introduction of new technologies such as LNG terminals and CNG refueling stations. The key points will be whether to define association with LNG terminal and CNG refueling stations in the case of pipeline, and if so, how to define it.

(3) Other Considerations

Other considerations include response to notable new technologies and the need of provisions concerning operation and maintenance. New technologies include the followings;

high-strength materials : strength of material is one of basic characteristics required for pipeline. Response to advent of X100 and X120.

Introduction of weld and inspection technologies : Welding and inspection, as well as its efficiency and rationalization, carry the considerable weight in quality improvement and safety. Automatic welding and automatic ultrasonic inspection, etc.

Pipeline monitoring control system : leak testing system, etc. Corrosion inspection technology and figure inspection technology: There is no regulation legally required to conduct inspections. Those technologies are controlled on pipeline owners' responsibility. In Japan, there are growing concerns about aging pipelines, inspection by an intelligent pig is mainstream. In the future, facility planning, conservation and maintenance plan will be formulated considering life cycle maintenance.

Provisions concerning operation and maintenance. Both Mine Safety Act and Gas Business Act have only a few provisions concerning maintenance. In actual operation, maintenance is performed based on self-imposed rule. From the perspective of continuity, there is a possibility to establish a provision concerning maintenance.

Meanwhile, in Japan, to reduce costs including pipeline development cost, there is a sign of deregulation by depth of burial. In the Philippines, Rule 14 of Circular requires that the construction and operation of Pipelines shall be in accordance with relevant standards promulgated by ISO. In particular the design, construction, operation and maintenance of pipelines should comply with the requirements of ISO13623 issued in 2000. Therefore, it is needed to examine ISO 13623 closely and consider technical standards which should be added and amended.

2.4 Review of JICA M/P (2002) and Necessity of Development of Natural Gas Infrastructure

2.4.1 Review of JICA M/P(2002)

JICA conducted “A Master Plan Study on the Development of the Natural Gas Industry in the Republic of Philippines” in 2002(hereinafter called “JICA M/P (2002)”). In this section, we summarize and review JICA M/P (2002) based on the development and utilization of natural gas and the development of natural gas infrastructure since 2002.

(1) Summary of JICA M/P（2002）

JICA M/P (2002) was conducted to prepare a comprehensive medium and long-term master plan for promoting natural gas utilization in the Philippines and to engage in technology transfer, so that the Philippine counterpart can evolve the master plan and continue its effective use by making necessary reviews and modifications themselves. The study consists of “ Gas Demand and Supply Scenarios”(Phase 1) and “a Master Plan for Promoting Natural Gas Use”(Phase 2). The major study items of each phase are summarized in the following table.

Table 2.4-1 Study items of JICA M/P(2002) (Phase 1)

Step	Study items	Remarks
Step 1	Demand survey/ utilization plan	Three target areas The electric power sector, the industrial sector, the commercial and residential sector and the transportation sector
	Supply system study	Domestic natural gas, imported LNG and Trans-ASEAN pipeline gas
	Policy study	Various policy measures and institutions involved in the promotion of natural gas use
Step 2	Macro-economy assumptions and energy demand forecast	Three target areas Economic forecast → Energy demand forecast
	Supply option study	Natural gas supply facilities(pipelines, storage facilities, LNG receiving terminals, etc.) distribution systems, supply cost
Step 3	Natural gas demand forecast	Gas demand for the three target areas "Gas use scenario" and "Gas promotion scenario"
	Supply system formation	B1（domestic gas supply alone） B2（combination of domestic gas and imported LNG） B3（a triple combination of domestic gas, imported LNG, and Tran-ASEAN pipeline gas）
Step 4	Supply system selection	To evaluate two supply cases, focusing on pipelines, using the results of the financial analysis and others
	GDS scenario setting	To select an optimal supply scenario for each demand scenario

Table 2.4-2 Study items of JICA M/P(2002) (Phase 2)

Step	Study items	Remarks
Step 5	To select an optimal "GDS Scenario"	Economic evaluation of the project Effects on macro-economy (to compare effects of individual scenarios on the Philippine economy, in such points as GDP growth, income levels, and government budget balance) Environment and safety (to compare negative impacts and/or favorable effects of individual scenarios on local and global environment) Comparison of gas supply and demand features(to compare the contribution of individual scenarios to the stable supply of gas) Comparison of other socio-economic impacts of effects
Step 6	Master plan for promoting gas use	GDS Scenario Action Plans ・fund raising method ・how to establish policy measures and institutions/organizations ・how to develop manpower A proposal for specific gas-related projects (for the first 10 years it is prepared in the form of yearly programs）

The major findings on gas demand, gas supply, policy measures and priority projects are summarized in the following table. These findings are divided into High Case and Low case on the basis of gas demand forecast.

Table 2.4-3 The Major Findings of JICA M/P(2002)

Study items	High Case	Low Case
Gas demand	2010 Power generation 522 MMscfd Except for power generation 27.6MMscfd Total 549.6 MMscfd 2025 Power generation 1,395 MMscfd Except for powergeneration 176.37MMscfd Total 1,571.37 MMscfd	2010 Power generation 382 MMscfd Except for power generation 7.68MMscfd Total 389.68MMscfd 2025 Power generation 1,261 MMscfd Except for power generation 51.71 MMscfd Total 1,312.71 MMscfd
Gas supply	LNG terminals are constructed in both Batangas area and Bataan Peninsula. LNG is supplied to the area beyond NCR by onshore pipeline and offshore pipeline.	LNG terminals are constructed in both Batangas area and Bataan Peninsula. LNG is supplied to the area beyond NCR by onshore pipeline and offshore pipeline.
Policy measures	a)10-year tax holiday for corporate tax for the pipeline sector. b)Tax exemption of LNG import duty for the LNG sector (since 2006) c)Tax exemption for machine/materials for the pipeline sector(since 2005) d)Applying low interest rates from international development financial institutions e)A discount for natural gas price and investment tax credit for gas filling stations to promote gas use for NGV f)10% investment tax credits for gas cogeneration and gas air conditioning	The government needs to take no supportive measures for the businesses. The only one exception is gas use for NGV.
Priority projects	1)Construction of gas pipeline from Tabangao to Sucat. 2)Construction of a LNG terminal in Limay/Mriveles area in Bataan Peninsula 3)Construction of gas filling stations for NGV in NCR. 4)Construction of LNG terminals in Batangas area. 5)Construction of an offshore pipeline from LNG terminal in Bataan Peninsula to NCR.	1)Construction of gas pipeline from Tabangao to Sucat. 2) Construction of a LNG terminal in Limay/Mriveles area in Bataan Peninsula 3)Construction of gas filling stations for NGV in NCR. 4)Construction of LNG terminals in Batangas area.

(2) Review of JICA M/P(2002)

JICA Study Team conducted reviews of each major study item. The results are described below.

1) Gas Demand

It is possible to compare the predicted value for year 2010 in JICA M/P(2002)with the actual measured value.

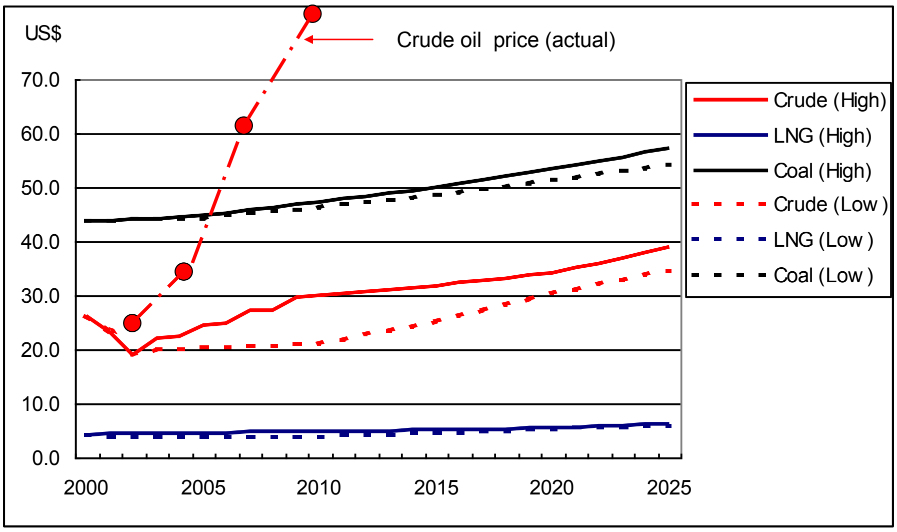
The predicted value for year 2010 in JICA M/P(2002) is 550MMscfd in High Case and 390MMscfd in Low Case. However the actual measured value is 279 MMscfd, which is substantially below the predicted value.

Most of the actual measured value of demand is consumed in three power plants around Batangas. One of the reasons for the relatively low gas demand is a delay in the development of new power plants due to the limited supply capacity of Malampaya gas field. In addition, as there has not been much progress in the development of natural gas transport infrastructure including BatMan 1 pipeline, the power generation demand in the area other than Batangas and gas demand for industrial and business use have not become apparent.

In the JICA M/P(2002) , the future energy price was predicted as shown in Figure 2.4-6. At that time, the predicted crude oil price in 2010 was USD 30/bbl and predicted LNG price in 2010 was USD 5.MMBtu. However, the actual prices are triple what was expected. The rise of energy price is one of the reasons for the slower growth of energy demand.

As for the price in 2025, in the JICA M/P(2002) it was predicted 1,571 MMscfd in High Case and 1,313 MMscfd in Low Case. Meanwhile, in this study the gas demand prediction in the whole Philippines is not conducted. However, the gas demand in Luzon only is predicted to reach 576 MMscfd and the gas demand in the whole Philippines is predicted to be the same or more than that of JICA M/P(2002).

To make the predicted demand apparent in the future, it is needed to develop BatMan 1 pipeline and LNG terminals in Batangas area and others steadily and organize natural gas supply and transmission system.



note : Crude Oil: US$/bbl, LNG: US$/MMBtu, Coal: US$/ton
Source : A Master Plan Study on The Development of the Natural Gas Industry in The Philippines, 2002

Figure 2.4-1 Energy Price Prediction as of 2002

2) Gas Supply

JICA M/P(2002) states that LNG terminals are constructed in both Batangas area and Bataan Peninsula and LNG is supplied to the area beyond NCR by onshore pipeline and offshore pipeline. However, at present these infrastructures have not been developed yet.

As for Bataan Peninsular, the World Bank has proposed onshore or offshore LNG terminals project to the Philippine government.

LNG terminals in Batangas area and onshore pipeline from Batangas area to NCR are covered in this study.

3) Policy measures

As of 1999, the accelerated development of indigenous energy is one of the most important energy policy directions in the Philippine, mainly because it was importing nearly 60% of primary energy consumption from foreign countries. Thus, it was expected that natural gas, commercial reserves of which have been proved in the sea off the Palawan Island, would be one of promising energy sources for solving the problem of developing indigenous energy, and it would open the door for a large scale utilization of natural gas.

According to "Philippine Energy Plan 2000-2009", the share of natural gas in primary energy consumption would increase from only 0.01% in 2000 to 5.97% in 2004 and 5.72% in 2009. In addition, increased oil production from oil fields around Palawan Island and others is also forecast. Such increases in oil and gas production would reduce the dependency of the Philippines on imported energy to 49.9% in 2004, although dependency would increase again to 52.7% in 2009.

The actual measured share of natural gas in primary energy consumption was increase to 5.1% in 2004 and 8.1% in 2009. In addition, the dependency on the Philippines on imported energy reduced to 45.8% in 2004 and 40.5% in 2009 exceeded the planned value. The Philippines still positions natural gas as an important factor for energy diversification and the change of energy supply structures. The basic policy of natural gas has not changed.

As for policy measures, the JICA M/P(2002) proposed the creation of new systems including 10-year tax holiday for corporate tax for the pipeline sector and tax exemption of LNG import duty for the LNG sector (since 2006). However, these systems have not been created yet due to the delay in development of pipeline projects and natural gas infrastructures of LNG terminals.

In 2002, Circular No. 2002-08-005 which is the only rules and regulations for natural gas sector was established. It serves as a basis for all activities on natural gas. However, the necessity of revision of the Circular is pointed out because of the natural gas-related technology development of recent years. It is pointed out

4) Priority Projects

JICA M/P(2002) proposed the following five priority projects.

1)Construction of a gas pipeline from Tabangao to Sucat
2)Construction of a LNG terminal in Limay/Mariveles area on Bataan Peninsula
3)Construction of a gas filling station for NGV in NCR
4)Construction of a LNG terminal in the Batangas area
5)Construction of an offshore pipeline from a LNG terminal in Bataan Peninsula to NCR

The current situation of each project is as follows;

(a) Construction of a gas pipeline from Tabangao to Sucat

There has been a delay in the construction due to the gas supply constraints of Malampaya gas field.

One of the reasons for the delay is that application procedure for permit approval by the government is not well organized.

However, according to DOE, it is the highest priority project at present.

(b) Construction of a LNG terminal in Limay/Mariveles area on Bataan Peninsula

According to DOE, the priority of this project is lower than that of Construction of a LNG terminal in the Batangas area.

At present, the World Bank has proposed onshore or offshore LNG terminals project to the Philippine government.

According to DOE, it is scheduled for completion in 2016. However, there is a possibility that the time of completion may change depending on the JICA study's results including future pipeline constructions. LNG terminal

(c) Construction of a gas filling station for NGV in NCR

According to Alternative Fuel and Energy Technology Division (AFETD), there are two gas filling stations in operation; the gas filling station in Malampaya can serve 200 cars per day and the other one in Laguna can serve 50 cars per day.

However, the construction of a gas filling station for NGV in NCR has not progressed because BatMan 1 pipeline has not been developed yet.

The number of NGV which are scheduled for introduction in the Philippines are; 250 in year 2012, 1000 in 2015, 2500 in 2020 and 10,000 in 2030.

(d) Construction of a LNG terminal in the Batangas area

There has been no progress since 2002.

According to DOE, the priority of this project is higher than that of the construction of a LNG terminal in Limay/Mariveles area on Bataan Peninsula.

Due to the future supply constraints of Malaympaya gas field, it is expected to hasten construction of a LNG terminal in the Batangas area as an important natural gas supply source for BatMan 1 pipeline.

(e) Construction of an offshore pipeline from a LNG terminal in Bataan Peninsula to NCR

There has been no progress in this project. It is the lowest priority project among the five projects.

This project is expected to be realized after the LNG terminal in Limay/Mariveles area on Bataan Peninsula is constructed.

2.4.2 Necessity of Development of Natural Gas Infrastructure

In the Philippines, it is expected to promote natural gas utilization actively. For this end, development of several pipelines, LNG terminals and CNG refueling stations are being planned. Among them, DOE positioned BatMan 1 pipeline from Batangas to NCR and LNG terminal which is scheduled to be constructed around Batangas as the highest-priority projects.

Response to environmental issues is an important issue of energy policy in the Philippines. To promote natural gas shift toward the realization of a low-carbon society, it is important to promote the introduction of fuel conversion, cogeneration and communal central air-conditioning in industrial and business sectors, as well as development of natural gas fired power plants and acceleration of fuel conversion of the existing power plants in electricity sector. In addition, it is also important to promote the introduction of CNG bus by developing pipelines and CNG refilling station to connect pipelines.

A common way to promote natural gas shift in industrial and business sectors is to develop pipelines passing through industry and business accumulation areas and supply natural gas by pipelines. BatMan 1 passes through areas with the most accumulated industry and business and it is the most effective infrastructure. Natural gas supply by pipeline has advantages including realization of large-scale transportation, ensuring of security, environmental load reduction at the time of transportation and response to future hydrogen society as compared to other transportation means such as container lorry transportation.

Table 2.4-4 Effects of Natural Gas Pipeline

Effects	Contents
Effect in environmental aspect by realization of fuel conversion	Significant CO_2 reduction can be expected if fuel conversion from other fossil fuel to natural gas is promoted by the development of natural gas supply infrastructure.
Effect by price reduction	In general, those who get supply of piped gas can purchase gas at lower price than those who don't get supply of piped gas. (see the cases in Japan)
Economic Ripple Effect	There will be an economic ripple effect of production inducement and job creation associated with pipeline construction work in the region. In addition, expansion of related equipment market by the progress of fuel conversion, price reduction of equipment by introduction of industrial furnace and cogeneration and further high-efficiency by technology competition can be expected.

In the Philippines there is a Malampaya gas field. As it is pointed out the supply capacity of Malampaya gas field is limited, it is indispensable to import LNG in order to accelerate the shift to natural gas. LNG terminals are positioned as import infrastructure for that purpose. The development of LNG terminals in Luzon, especially in Batangas area is high-priority issue. It is for this reason that LNG terminals are positioned as important infrastructure. From Batangas to Manila, BatMan1 pipeline project is being planned. If Malampaya gas field is depleted in the future, it becomes possible to supply imported natural gas from LNG terminals to pipelines. Although it is pointed out that the current price formula of Malampaya gas field is advantageous to producers (Shell, Chevron), for the Philippines as consumer, price reduction due to competition between imported LNG and domestic gas in Malampaya can be expected.

Regarding the formation of pipelines in Europe and the United States and East Asian countries including Japan, Korea and Taiwan, it takes on different forms depending on energy resources and situations of each country.

In Europe, pipeline network for domestic distribution of gas has been developed mainly by national companies in a well-planned manner by public fund injection. In recent years, international pipelines for imported gas have been developed, which is supported by EU policy. In the United States, natural gas pipelines have been developed mainly by private companies. In Japan, LNG terminals have been set up in urban neighborhood. And along with the LNG terminals, pipelines for transportation and distribution have been developed. In Korea and Taiwan, LNG has been introduced later than Japan and natural gas pipelines have been developed mainly by national companies in a relatively short period of time in a well-planned manner.

In the Philippines there is a domestic gas field (Malampaya gas field). BatMan 1 pipeline connecting the domestic gas field with metropolitan area is similar to the European pipelines from the perspective of pipeline formation process. In addition, LNG terminals are scheduled to be constructed based on an assumed depletion of Malampaya gas field. So in the future, the Philippines are likely to follow the situations in East Asian countries such as Japan, Korea and Taiwan.

With regard to implementing bodies, the Philippines has large expectations for private companies and PPP. However, the demand has not sufficiently manifested and it is uncertain how soon it will be manifested. With this in mind, JICA Team conducts careful consideration on implementing bodies in this study.

Chapter 3 Confirmation of Basic Information on Regulation and System for Environmental and Social Considerations

3.1 Regulations and System For Environmental and Social Considerations relevant to This Project

3.1.1 Environment Impact Assessment (EIA)

(1) Outline

In the Philippines, all projects are required to submit necessary documents and acquire Environmental Compliance Certificate (ECC) or Certificate of Non-Coverage (CNC) from the final approver (Chief of Environmental Management Bureau etc.). By Philippines Environmental Impact Statement System (PEISS) ,projects are categorized into 5 groups as described in Table 3.1-1.

In the Revised Procedural Manual（RPM） for DENR Administrative Order No. 30 series of 2003 (DAO 03-30)of Department of Environment and Natural Resources(DENR), Pipeline business is defined as Non-Environmentally Critical Projects(NECP) and belongs to Group Ⅱ or Ⅲ. As for the project in the study, the rules of Group Ⅱ is applied, because the project area includes Environmental Critical Area(ECA).With regard to the LNG terminal construction project, although its impact on the environment is not expected to be as serious as that of the oil refinery or petrochemical industry since it belongs to the sector of natural gas storage, the rules of Group Ⅱ should be applicable to it just like the case of pipeline project since the project site is likely to be close to an environmentally critical area.

In the case of a project of pipeline exceeding 25 km, or of LNG terminal with a storage capacity exceeding 5,000KL, it is required to submit Environmental Impact Statement(EIS) and acquire ECC . It should be approved by the director of Local EMB. The pipeline in the projects covered by the study is required to submit EIS and acquire ECC because it is more than 25 km in length.

In the case of a project of pipeline less than 25 km in length, or of LNG terminal with a storage capacity less than 5,000KL, it is required to submit Initial Environmental Examination(IEE) Report（IEER） and acquire ECC[2]. It should be approved by the director of Local office of EMB[3].

Table 3.1-1 Category Classification by Philippines Environmental Impact Statement System

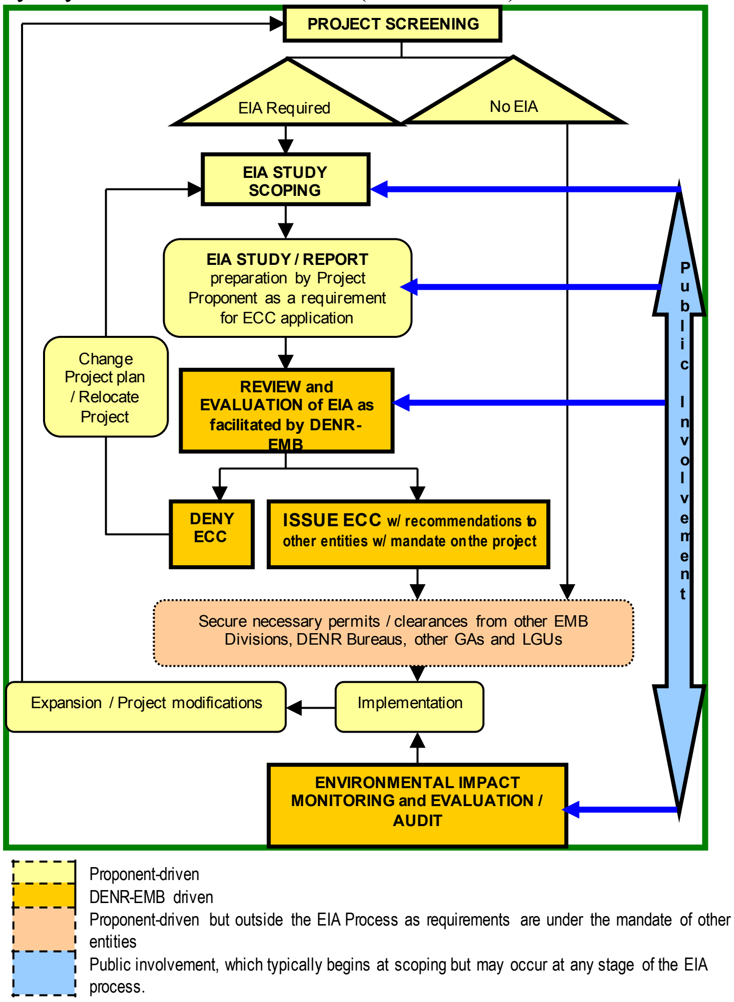
Group	Kinds of businesses and location implemented
I	All Environmentally Critical Projects (ECP)（regardless of locations implemented）
II	Non-Environmentally Critical Projects (NECP) in Environmentally Critical Areas (ECA)
III	NECP in Non-Environmentally Critical Areas (NECA）
IV	Co-located Projects (Several business operators implement and manage business in a contiguous area. Economic zone and industrial park etc are included.）
V	Other projects not listed in any of groups

Source：Revised Procedural Manual for DAO 2003-30（2008）

(2) Flowchart of EIA Process

[2] Revised Procedural Manual for DENR Administrative Order No.30 Series of 2003 (DAO 03-30) ANNEX 2-1b
[3] The pipeline in the projects covered by the study is under the jurisdiction of Region4A.

Summary flowchart of EIA process is shown in the Figure 3.1-1. Previously, the term for gaining approval after submission of EIS was 60 business days. However, it was shortened to 20 business days by Memorandum Circular(Jan.29 2010) of DENR.



Source: Revised Procedural Manual for DENR Administrative Order No. 30 Series of 2003 (2008)

Figure 3.1-1 Summary Flowchart of EIA Process

(3) ECC Acquisition Procedure

ECC acquisition procedure after the EIS submission is outlined below. According to DOE, after the selection of project proponents, the proponents conduct EIA.

1) Scoping

The project proponents conduct consideration of stakeholders and Public Scoping. the proponents submit five copies of the followings to the local EMB; 1)Letter of Request for Scoping 2) Pro-forma Project description for Scoping 3) Map &Description of Preliminary Impact Areas 4) Stakeholder ID Form 5)Summary IEC documentation 6)Scoping /procedural Screening Checklist)SPSC). Within five working days from receipt of letter –request, EMB forms Environmental Impact Assessment Review Committee(EIARC)[4]. The proponents are required to conduct project briefing with EIARC, public scoping in the area and technical scoping with EIARC as needed in the region of project location.

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4 It consist of technical staff (EMB Case Handler)of Environmental Impact Assessment Management Division of EMB, the third-party organization ,experts and others.

2) Preparation of EIS

In cases where the local EMB approves the SPSC and determines the TOR of the EIA Study, the projects proponent conducts EIA Study based on the TOR and prepares the EIS. The proponent submits one copy of EIS and the SPSC to the local EMB. Within three days from receipt of the EIS, EMB checks the validity of the EIS. If conforming, the proponent is instructed to pay the filing fee.

3) Evaluation of EIS

After the receipt of the filling fee by the proponent, EIARC and the resource person through a contract reviews the EIS. They submit the additional information(AI) Request to the proponent before or during the 1st Review Team Meeting. It is also required to hold Site Visit or Public Hearing(organized by EMB) . If the most of opponents are absent from the Public Hearing or if there is any request from stakeholders, it is required to hold Public Consultation.

The proponents are required to give the response to the AI by the 1st Review Team meeting or Public Hearing or Public Consultation within 15 working days. The proponents are required to explain about unresolved additional information at the 2nd or 3rd EIA Review Team Meeting which is held if necessary. After that EIARC prepares the report (within 15 working days after the latest EIA Review Team Meeting) and submit it to EMB. EMB official Review Process Report(RPR) and Recommendation Document to EIA and Management Division. EMB issues ECC after it is approved by EIA and Management Division.

4) Outline for EIS

The outline for EIS is shown in Table 3.1-2. It consists of the chapters including Project Description, Analysis of key Environmental Impacts, Environmental Ecological Risk Assessment and Impact Management Plan.

Table 3.1-2 Outline for EIS, IEER and IEEC

<table>
<tr><th>Chapter</th><th colspan="2">Section/Contents</th></tr>
<tr><td>I. Project Description</td><td colspan="2">1.1 Project Location and Area
1.2 Project Retionale
1.3 Project Alternatives
1.4 Project Components
1.5 Process/ Technology Options
1.6 Project Size
1.7 Development Plan, Description of Project Phase and Corresponding Timeframes
1.8 Manpower</td></tr>
<tr><td rowspan="4">II. Analysis of Key Environmental Impacts</td><td>2.1 Land</td><td>2.1.1 Land Use and Classification
2.1.2 Geology/ Geomorphology
2.1.3 Pedology
2.1.4 Terrestrial Biology</td></tr>
<tr><td>2.2 Water</td><td>2.3.1 Hydrology/Hydrogeology
2.3.2 Oceanography
2.3.3 Water Quality
2.3.4 Freshwater or Marine Ecology</td></tr>
<tr><td>2.3 Air</td><td>2.3.1 Meteorology/Climatology
2.3.2 Air Quality (& Noise)</td></tr>
<tr><td>2.4 People</td><td>2.4.1 Identify settlers that will be displaced from among the existing settlers
2.4.2 Discuss the immigration patterns impact as a result of project implementation
2.4.3 Discuss the impacts on IPs and Culture/lifestyle (if any)
2.4.4 Discuss the project implementation's threat to public health vis-a-vis the baseline health conditions in the area
2.4.5 Discuss local benefits expected from project implementation
2.4.6 Discuss how the project would affect the delivery of basic services and resource competition in the area
2.4.7 Discuss how the project would affect traffic situation in the area
2.4.8 Identify entity to be accountable for environmental management in the area
2.4.9 Discuss how the project would affect existing properties in the area in terms of relocation and devaluation
2.4.1 0 Identify affected properties</td></tr>
<tr><td colspan="2">III. Environmental Ecological Risk Assessment</td><td>Identify and provide management measures for:
• Chronic Risks
• Acute Risks / Worst Case Scenario</td></tr>
<tr><td colspan="3">IV. Impact Management Plan</td></tr>
<tr><td colspan="3">V. Social Development Framework (Social Development Program) and IEC Framework</td></tr>
<tr><td colspan="3">VI. Environmental Compliance Monitoring</td></tr>
<tr><td colspan="3">VII. Emergency Response Policy and Generic Guidelines</td></tr>
<tr><td colspan="3">VIII. Abandonment/ Decommissioning/ Rehabilitation Policies and Generic Guidelines</td></tr>
<tr><td colspan="3">IX. Institutional Plan for EMP Implementation</td></tr>
</table>

Source: Memorandum Circular No.2010-04 (2010)

(4) Comparison of JICA Guidelines for Environmental and Social Considerations and the Philippine EIA Related Laws

The comparison of JICA Guidelines for Environmental and Social Considerations (April, 2010) and the Philippine EIA related laws is shown in the Table 3.1-3. There is not much difference in the legally system.

Table 3.1-3 Comparison of JICA Guidelines for Environmental and Social Considerations and EIA Related Laws of the Philippines

Policies including JICA Guidelines for Environmental and Social Considerations and the World Bank's Safeguard Policies	**EIA related laws of the Philippines**	**Major Differences**
JICA confirms that projects comply with the laws or standards related to the environment and local communities in the central and local governments of host countries; it also confirms that projects conform to those governments' policies and plans on the environment and local communities. JICA confirms that projects do not deviate significantly from the World Bank's Safeguard Policies	EIA System is established by	N/A
EIA report(the name is different depending on the system) should be written in an official or widely used language in the country where the project is conducted. When explaining the contents of the report, it should be prepared in a language and in a form that are understandable by local people.	EIS, IEE report etc. is written in English which is the official language. When explaining to local residents, Tagalog and other language in the region are used. Cartoons and illustrations are also used as needed.	N.A
In principle, the host countries etc. disclose information about the environmental and social considerations of their projects. JICA encourages the host countries, etc. to disclose and present information about environmental and social considerations to local stakeholders.	Project proponents are required to conduct IEC in the Scoping. In the Scoping, they conduct public scoping for disclosing the contents of the project. .○ In the Public Hearing/Public Consultation during examination period of EIA report should be disclosed in advance.	N/A
EIA report is disclosed for the people including local residents in the country where the project is conducted. It is required to be available for inspection and to get a copy by stakeholders including local residents and	EIA report etc. used in issuing ECC is available for inspection and it can be copied requested by documents.	N/A

Policies including JICA Guidelines for Environmental and Social Considerations and the World Bank's Safeguard Policies	EIA related laws of the Philippines	Major Differences
In principle, the host countries etc. conduct consultation with local stakeholders voluntarily within reasonable range and JICA supports the host countries etc. as needed. In the case of Category A projects, JICA encourages the host countries etc. to consult with local stakeholders about their understanding of development needs, the likely adverse impacts on the environment and society, and the analysis of alternatives at an early stage of the project, and assists project proponents as needed.	Local residents can participate in the phase of Scoping and during the examination period of EIA report. As for all new ECPs, it is required to consider stakeholders in the Scoping and consult with stakeholders including local residents. During the examination period of EIA report Public Hearings are required. DENR/EMB consults with local residents as needed. As for the project requiring IEE, Public Hearings/Consultations with local residents are held as needed.	N/A
JICA confirms with the host countries etc. the results of monitoring the items that have significant environmental impacts. This is done in order to confirm that the host countries etc. are undertaking environmental and social considerations The information necessary for monitoring confirmation by JICA must be supplied by the host countries etc. by appropriate means, including in writing. When necessary, JICA discloses the results of monitoring conducted by project proponents etc. on its website to the extent that they are made public in the host countries etc.	The Proponents issued ECCs are required to submit two kinds of monitoring reports, the ECC Compliance Monitoring Report (CMR) on semi-annual frequency and the Self-Monitoring Report (SMR) on a quarterly basis to the concerned EMB RO. All monitoring reports are to be disclosed.	N/A

Source: Profile of Environmental and Social Considerations of the Philippines (September 2011, JICA)

3.1.2 Land Acquisition and Resettlement

(1) Outline

An Act to Facilitate the Acquisition of Right-of-Way or Repubic Act (RA)No.8974(2000) provides the legal basis for land acquisition and resettlement.

The Act is to facilitate land acquisition in taking private properties for public use. In regard to legitimate land acquisition from land owners, it is specified that private property shall be taken for public use with compensation. In regard to squatter relocation, it is specified that the National Housing Authority, in coordination with the Local Government Unit(LGU) , housing and Urban Development Coordinating Council and other governmental agencies concerned, shall provide squatter relocation sites. In the same year, administrative instructions were defined (Revised edition of Executive Order No. 1035 (1985): guidelines for procedures for acquisition of property)

In the Philippines each project implementing agency conducts independently land acquisition and resettlement, because there is no governmental agency specializing in land acquisition and resettlement. In addition to Department of Public Works and Highways (DPWH), the main agencies conducting land acquisition are as follows. DPWH is the only organization that specified the procedures for land acquisition and resettlement. The agencies except for DPWH conduct land acquisition and resettlement in accordance with the procedures of DPWH and guidelines of financing institutions.

- National Housing Authority (NHA)
- National Power Corporation (NAPOCOR)
- Transmission Corporation (TRANSCO)
- National Irrigation Administration(NIA)
- Department of Agrarian Reform (DAR)

(2) Details of Major Laws Relevant to Land Acquisition and Involuntary Resettlement
Some of the details of major laws relevant to land acquisition and involuntary resettlement are summarized as follows:

1) "An Act to Facilitate the Acquisition of Right-of-Way, 2000"
The policy and measures to facilitate the acquisition of right-of-way for public purpose are stipulated in the document of "An Act to Facilitate the Acquisition of Right-of-Way, 2000" as explained below:

- Project operator should first of all confirm with the land owner regarding his (her) intention of whether to convey the land or not.

- On the occasion that the land owner refuse to convey the land, the project operator should offer the amount of compensation worked out based on the Zonal Value [5]decided by the Bureau of Internal Revenue (BIR) so as to start negotiation with the land owner.

- If the land owner refuse to accept the offer based on BIR terms, the project operator should negotiate with the land owner by offering the amount of compensation based on the price not higher than the appropriate market rate. The project operator can ask a government or private financial institution to figure out the appropriate market rate. The period of negotiation can be possibly prolonged to a maximum extent of 15 days.

- If the land owner still does not agree with the amount offered, the project operator should apply to the Court for arbitrament. The Court should work out the amount of compensation within 60 days for the project operator to pay the land owner so as to settle the deal.

2) "Infrastructure Right-of-Way (IROW) Procedural Manual (2003)"
The IROW Procedural Manual formulated by DPWH in 2003 consists of the following items regarding the procedure of land acquisition for public purpose:

- Implementation of the Percellary Survey and Formulation of the Report

- Preparation of Land Acquisition Plan and Resettlement Action Plan (LAPRAP)

- IROW Acquisition Through Purchase

- Expropriation Proceedings

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[5]Zonal Value is calculated based on the past record of land selling prices, which is different from the meaning of Replacement Cost defined by the World Bank in its OP4.12.

3) Laws Relevant to the Issue of Resettlement of Squatters

The treatment regarding squatters is required to follow the stipulations by Act No. 7279, which forbids the practice of forcing the deforciants to resettle without providing them alternative place for resettlement. The provision of alternative place of resettlement should mainly be the responsibility of local governments, while the government institutions of National Housing Authority (NHA) and Housing and Urban Development Coordinating Council (HUDCC) should give them support.

4) Title Holders of Compensation

Under the IROW Procedural Manual (2003), the determination of the title holders of compensation, that is Project Affected Persons (PAPs), and improvements shall be based on the cutoff date, which is the start of the census of PAPs and tagging for improvements.

As for squatter, the person who meets the following conditions are subject to relocation (as beneficiaries of the RA 7279).

a. Filipino citizen
b. The person whose income or combined household income falls within the poverty threshold
c. The person who do not own housing facilities
   The person who are not the professional squatter and/or the member of the squatter syndicate

3.1.3 Indigenous peoples

(1) Definition of Indigenous People and Its Distribution in the Philippines

The Philippines is said to be the only country in Asia which clearly recognizes the existence of "indigenous people"[6]. In the Philippines, "The Indigenous Peoples Rights Act of 1997" specifies indigenous peoples(IPs) and indigenous cultural communities(ICCs) as follows (Article 3-h in Section 2 in Chapter 2) .

Indigenous Cultural Communities/Indigenous Peoples - refer to a group of people or homogenous societies identified by self-ascription and ascription by other, who have continuously lived as organized community on communally bounded and defined territory, and who have, under claims of ownership since time immemorial, occupied, possessed customs, tradition and other distinctive cultural traits, or who have, through resistance to political, social and cultural inroads of colonization, non-indigenous religions and culture, became historically differentiated from the majority of Filipinos.

There is no exact statistics of population distribution of IPs. National Commision on Indigenous Peoples (NCIP) estimates the IPs population as 14,183,809. 62.6% lives in Mindanao, 35.9% lives in Luzon and 1.4% lives in Visayas(see table 3.1-4. It is calculated by NCIP based on an unofficial statistics and IPs account for more than 20 % of the entire population.

6 Raja Devasish Roy of Minority Rights Group International (MRG), "Traditional Customary Laws and Indigenous Peoples in Asia" (2005)

Table 3.1-4 Population of Indigenous Peoples by Region(as of March 2011)

region		IPs	Percentage of the total IPs(%)
Luzon		5,094,220	35.9
	CAR	1,470,700	10.4
	R-1	1,206,798	8.5
	R-2	1,030,179	7.3
	R-3	236,487	1.7
	R-4	936,745	6.6
	R-5	213,311	1.5
Visayas		203,912	1.4
	R-6	168,145	1.2
	R-7	35,767	0.3
Mindanao		8,885,677	62.6
	R-9	1,203,598	8.5
	R-10	1,801,739	12.7
	R-11	2,289,268	16.1
	R-12	1,856,268	13.1
	R-13	1,004,750	7.1
	ARMM	730,054	5.1
total		14,183,809	100.0

Source : Office on Policy, Planning and Research, National Commission on Indigenous Peoples(NCIP)(March 2011)

As shown in Table 3.1-5, there are 110 tribes of indigenous peoples living in different regions in the Philippines.

Table 3.1-5 110 Tribes of Indigenous Peoples in the Philippines (as of March 2011)

1	Abelling/Aborlin	38	Dumagat	75	Mabaca
2	Abiyan	39	Eskaya	76	Malaueg
3	Adesen	40	Gaddang	77	Magahat/Corolanos
4	Aeta	41	Giangan	78	Manobo
5	Agta	42	Gubang	79	Manobo-Blit
6	Agta-Cimaron	43	Gubanon (Mangyan)	80	Mangguangan
7	Agta-Tabangnon	44	Guiangan-Clata	81	Mamanwa
8	Agutayon	45	Hanunuo (Mangyan)	82	Mansaka
9	Alangan (Mangyan)	46	Hanglulo	83	Matisalog
10	Applai	47	Higaonon	84	Mandaya
11	ata-Matisalog	48	Itneg	85	Molbog
12	Ati	49	Inlaud	86	Pullon
13	Arumanen	50	Inbaloi	87	Palawanon
14	Ayangan	51	Ibanag	88	Remontado
15	Binongan	52	Itwanes	89	Ratagnon (Mangyan)
16	Bago	53	Ikalahan	90	Sulod
17	Bangon (Mangyan)	54	Ilianen	91	Sama (Badjao)
18	Bontok	55	Isinai	92	Sama/Samal
19	Balatoc	56	Isneg/Apayao	93	Sama/Kalibugan
20	Baliwen	57	Iwak	94	Subanen
21	Bulaga	58	Iraya (Mangyan)	95	Sangil
22	Batak	59	Itnom	96	Tadyawan (Mangyan)
23	Batangan/Tao Buid	60	Ilongot/Bungkalot	97	Tagabawa
24	Buhid (mangyan)	61	Ivatan	98	Tagbanwa
25	Balangao	62	Kirintenken	99	Tagakaolo
26	Bantoanon	63	Kalinga	100	Talaandig
27	Bukidnon	64	Kankanaey	101	Talaingod
28	Badjao	65	Kalanguya	102	T'Boli
29	Banac	66	Kalibugan	103	Tao't Bato
30	B'laan	67	Kabihug	104	Tasaday
31	Bagobo	68	Kalagan	105	Tigwayanon
32	Bunwaon	69	Karao	106	Tingguian
33	Calinga	70	Kaylawan	107	Tiruray/Tenduray
34	Camiguin	71	Kongking	108	Tuwali
35	Coyonon	72	Langilan	109	Ubo
36	Danao	73	Masadiit	110	Umayamnon
37	Dibabawon	74	Maeng		

Source：Office on Policy, Planning and Research, National Commission on Indigenous Peoples(NCIP)(March 2011)

(2) Considerations for Indigenous People in Issues of Land Acquisition and Resettlement

With respect to its relations with this project, the issue of indigenous people consideration in terms of land acquisition and involuntary resettlement mentioned above is of particular importance. In this regard, the "Land Acquisition, Resettlement, Recovery and Indigenous People Policy"（LARRIP Policy; 3rd edition, 2007） gives explanation of the required procedures regarding projects having potential impact on indigenous people. Here, it is made a prerequisite during the stage of project formulation to go all out to prevent the project from impacting the indigenous people especially in the case where there is the possibility of involuntary resettlement. Regarding those projects with evidently negative impact on indigenous people as identified by social assessment, the preparation of an Indigenous Peoples Action Plan (IPAP) is compulsory.

a) Land acquisition inside Ancestral Domain

In the event land (including structures, improvements, crops, trees, and perennials) is to be acquired inside an ancestral domain, the DPWH and its agents shall obtain the Free and Prior Informed Consent (FPIC) [7]of the affected ICC/IPs.

- Land Acquisition without Resettlement
  If passage through, and hence damage to and/or partial or total relocation of religious and cultural properties is unavoidable, this should be presented to the ICC/IPs in the Consultative Community Assembly (CCA) or First Meeting whichever is applicable and obtained the FPIC of the affected ICC/IPs. The restriction involved by the project and its mitigation measures will also be disclosed by the project proponent to the affected ICC/IPs and include as part of the Memorandum of Agreement (MOA). The MOA with the additions written above shall serve as the Indigenous Peoples' Action Plan (IPAP).

- Land Acquisition with Removal and Resettlement
  Following their customary law, the ICCs/IPs will be consulted regarding the resettlement site. The project affected families will be resettled as much as possible within their ancestral domain. When the resettlement site is outside the affected ancestral domain, the IPs will be consulted regarding the choice of resettlement site. The project proponent in cooperation with the relevant government agencies shall ensure that the resettlement site is of equivalent productive potential and spatial advantages, e.g. providing the same degree of access to resources and to public and privately provided services and protection. Barring this, the Resettlement Action Plan (RAP) as well as MOA should include measures to mitigate the lack of access to natural resources, basic services, and to cultural and religious sites. The MOA with additions written above shall served as the Indigenous Peoples' Action Plan (IPAP)

b) Land Acquisition Affected IPs Outside Ancestral Domain

FPIC procedure is not required if the affected ICCs/IPs are outside of Ancestral Domain. However regardless of the impact, the project proponent will conduct a separate, meeting with the ICCs/IPs to disclose the project contents and adverse impact and to obtain their broad support for the project. If the project requires resettlement and the affected IPs were migrants in the place and would have to be resettled, the project proponent can represent the option of returning to their place origin. If this option were chosen, the project proponent with the NCIP will prepare the hosting community. If the place of origin and re-settlement of the affected ICCs/IPs were an ancestral domain or an area with a pending application to be declared such, the FPIC of the receiving ICCs/IPs would be obtained first following the FPIC Guidelines of 2006.

[7] NCIP Administrative Order No,1, series of 2006

3.2 Environmental and Social Considerations Regarding the Pipeline Project

3.2.1 Current State of EIS Preparation and ECC Acquisition

So far, EIS regarding this project has not been prepared, and ECC has not been acquired. As the tasks of the next step, it is necessary to organize the basic data needed for the drafting of EIS, followed by the formulation of EIS and the acquisition of ECC. Moreover, completion of the Environment Checklist required by JICA and the Scoping required by the Philippines government before the fulfillment of EIS formulation and ECC acquisition is also necessary. With respect to the pipeline project, the relevant JICA Environment Checklist and the document of Scoping are to be prepared as follows.

(1) Environmental Checklist in JICA Guidelines for Environmental and Social Considerations

In the JICA JICA Guidelines for Environmental and Social Considerations pipeline is distributed into Category A. When utilizing yen loans in pipeline projects, it is required to receive advice on support and confirmation of environmental and social considerations from Advisory Council of Environmental and Social Considerations.

Environmental checklist of pipeline projects is shown in Table 3.2-1. The checklist consists of the following items; permits and explanations, pollution control, natural environment, social environment and others.

(2) Draft of the Scoping Document

The draft of scoping is shown in the table 3.2-2. It is needed to consider measures for pollution control under construction and impact on the social environment.

Table 3.2-1 Checklist in JICA Guidelines for Environmental and Social Considerations

Category	Environmental Item	Main Check Items	Yes: Y No: N	Confirmation of Environmental Considerations (Reasons, Mitigation Measures)
1 Permits and Explanation	(1) EIA and Environmental Permits	(a) Have EIA reports been already prepared in official process? (b) Have EIA reports been approved by authorities of the host country's government? (c) Have EIA reports been unconditionally approved? If conditions are imposed on the approval of EIA reports, are the conditions satisfied? (d) In addition to the above approvals, have other required environmental permits been obtained from the appropriate regulatory authorities of the host country's government?	(a) (b) (c) (d)	(a) (b) (c) (d)
	(2) Explanation to the Local Stakeholders	(a) Have contents of the project and the potential impacts been adequately explained to the Local stakeholders based on appropriate procedures, including information disclosure? Is understanding obtained from the Local stakeholders? (b) Have the comment from the stakeholders (such as local residents) been reflected to the project design?	(a) (b)	(a) (b)
	(3) Examination of Alternatives	(a) Have alternative plans of the project been examined with social and environmental considerations?	(a)	(a)
2 Pollution Control	(1) Air Quality	(a) Do air pollutants, (such as sulfur oxides (SOx), nitrogen oxides (NOx), and soot and dust) emitted from the proposed infrastructure facilities and ancillary facilities comply with the country's emission standards and ambient air quality standards? Are any mitigating measures taken? (b) Are electric and heat source at accommodation used fuel which emission factor is low?	(a) (b)	(a) (b)
	(2) Water Quality	(a) Do effluents or leachates from various facilities, such as infrastructure facilities and the ancillary facilities comply with the country's effluent standards and ambient water quality standards?	(a)	(a)
	(3) Wastes	(a) Are wastes from the infrastructure facilities and ancillary facilities properly treated and disposed of in accordance with the country's regulations?	(a)	(a)
	(4) Soil Contamination	(a) Are adequate measures taken to prevent contamination of soil and groundwater by the effluents or leachates from the infrastructure facilities and the ancillary facilities?	(a)	(a)
	(5) Noise and Vibration	(a) Do noise and vibrations comply with the country's standards?	(a)	(a)
	(6) Subsidence	(a) In the case of extraction of a large volume of groundwater, is there a possibility that the extraction of groundwater will cause subsidence?	(a)	(a)
	(7) Odor	(a) Are there any odor sources? Are adequate odor control measures taken?	(a)	(a)
3 Natural Environment	(1) Protected Areas	(a) Is the project site or discharge area located in protected areas designated by the country's laws or international treaties and conventions? Is there a possibility that the project will affect the protected areas?	(a)	(a)
	(2) Ecosystem	(a) Does the project site encompass primeval forests, tropical rain forests, ecologically valuable habitats (e.g., coral reefs, mangroves, or tidal flats)? (b) Does the project site encompass the protected habitats of endangered species designated by the country's laws or international treaties and conventions? (c) Is there a possibility that changes in localized micro-meteorological conditions, such as solar radiation, temperature, and humidity due to a large-scale timber harvesting will affect the surrounding vegetation? (d) Is there a possibility that the amount of water (e.g., surface water, groundwater) used by the project will adversely affect aquatic environments, such as rivers? Are adequate measures taken to reduce the impacts on aquatic environments, such as aquatic organisms?	(a) (b) (c) (d)	(a) (b) (c) (d)
	(3) Hydrology	(a) Is there a possibility that hydrologic changes due to the project will adversely affect surface water and groundwater flows?	(a)	(a)
	(4) Topography and Geology	(a) Is there a possibility the project will cause large-scale alteration of the topographic features and geologic structures in the project site and surrounding areas?	(a)	(a)
4 Social Environment	(1) Resettlement	(a) Is involuntary resettlement caused by project implementation? If involuntary resettlement is caused, are efforts made to minimize the impacts caused by the resettlement? (b) Is adequate explanation on compensation and resettlement assistance given to affected people prior to resettlement? (c) Is the resettlement plan, including compensation with full replacement costs, restoration of livelihoods and living standards developed based on socioeconomic studies on resettlement? (d) Is the compensations going to be paid prior to the resettlement? (e) Is the compensation policies prepared in document? (f) Does the resettlement plan pay particular attention to vulnerable groups or people, including women, children, the elderly, people below the poverty line, ethnic minorities, and indigenous peoples? (g) Are agreements with the affected people obtained prior to resettlement? (h) Is the organizational framework established to properly implement resettlement? Are the capacity and budget secured to implement the plan? (i) Are any plans developed to monitor the impacts of resettlement? (j) Is the grievance redress mechanism established?	(a) (b) (c) (d) (e) (f) (g) (h) (i) (j)	(a) (b) (c) (d) (e) (f) (g) (h) (i) (j)
4 Social Environment	(2) Living and Livelihood	(a) Is there a possibility that the project will adversely affect the living conditions of inhabitants? Are adequate measures considered to reduce the impacts, if necessary?	(a)	(a)
	(3) Heritage	(a) Is there a possibility that the project will damage the local archeological, historical, cultural, and religious heritage? Are adequate measures considered to protect these sites in accordance with the country's laws?	(a)	(a)
	(4) Landscape	(a) Is there a possibility that the project will adversely affect the local landscape? Are necessary measures taken? (b) Is there a possibility that landscape is spoiled by construction of high-rise buildings such as huge hotels?	(a) (b)	(a) (b)
	(5) Ethnic Minorities and Indigenous Peoples	(a) Are considerations given to reduce impacts on the culture and lifestyle of ethnic minorities and indigenous peoples? (b) Are all of the rights of ethnic minorities and indigenous peoples in relation to land and resources respected?	(a) (b)	(a) (b)
	(6) Working Conditions	(a) Is the project proponent not violating any laws and ordinances associated with the working conditions of the country which the project proponent should observe in the project? (b) Are tangible safety considerations in place for individuals involved in the project, such as the installation of safety equipment which prevents industrial accidents, and management of hazardous materials? (c) Are intangible measures being planned and implemented for individuals involved in the project, such as the establishment of a safety and health program, and safety training (including traffic safety and public health) for workers etc.? (d) Are appropriate measures taken to ensure that security guards involved in the project not to violate safety of other individuals involved, or local residents?	(a) (b) (c) (d)	(a) (b) (c) (d)
5 Others	(1) Impacts during Construction	(a) Are adequate measures considered to reduce impacts during construction (e.g., noise, vibrations, turbid water, dust, exhaust gases, and wastes)? (b) If construction activities adversely affect the natural environment (ecosystem), are adequate measures considered to reduce impacts? (c) If construction activities adversely affect the social environment, are adequate measures considered to reduce impacts?	(a) (b) (c)	(a) (b) (c)
	(2) Monitoring	(a) Does the proponent develop and implement monitoring program for the environmental items that are considered to have potential impacts? (b) What are the items, methods and frequencies of the monitoring program? (c) Does the proponent establish an adequate monitoring framework (organization, personnel, equipment, and adequate budget to sustain the monitoring framework)? (d) Are any regulatory requirements pertaining to the monitoring report system identified, such as the format and frequency of reports from the proponent to the regulatory authorities?	(a) (b) (c) (d)	(a) (b) (c) (d)
6 Note	Reference to Checklist of Other Sectors	(a) Where necessary, pertinent items described in the Roads, Railways and Bridges checklist should also be checked (e.g., projects including access roads to the infrastructure facilities). (b) For projects, such as installation of telecommunication cables, power line towers, and submarine cables, where necessary, pertinent items described in the Power Transmission and Distribution Lines checklists should also be checked.	(a) (b)	(a) (b)
	Note on Using Environmental Checklist	(a) If necessary, the impacts to transboundary or global issues should be confirmed (e.g., the project includes factors that may cause problems, such as transboundary waste treatment, acid rain, destruction of the ozone layer, or global warming).	(a)	(a)

1) Regarding the term "Country's Standards" mentioned in the above table, in the event that environmental standards in the country where the project is located diverge significantly from international standards, appropriate environmental considerations are required to be made.
In cases where local environmental regulations are yet to be established in some areas, considerations should be made based on comparisons with appropriate standards of other countries (including Japan's experience).
2) Environmental checklist provides general environmental items to be checked. It may be necessary to add or delete an item taking into account the characteristics of the project and the particular circumstances of the country and locality in which the project is located.

Source : JICA Guidelines for Environmental and Social Considerations

Table 3.2-2 Draft of Scoping

Category	No.	Environmental item	evaluation		Reason of evaluation
			Before and during construction	In service	
pollution control	1	Air Quality	B-	D	During construction : On a temporary basis, worsened air quality is expected due to operation of construction equipment In service : No impact on air quality is expected
	2	Water Quality	B-	D	During construction : Possibility of water contamination due to sewer water from construction site, heavy equipment, cars and lodgment for construction workers. In service : No impact on water quality is expected.
	3	Wastes	B-	D	During construction : Construction waste soil and scrap wood generation are expected. In service :Waste generation affecting environment is not expected.
	4	Soil Contamination	B-	D	During construction : Possibility of soil pollution by spill of oil for construction and others In service : No impact of soil pollution is expected.
	5	Noise and Vibration	B-	D	During construction : Noise by operation of construction machine and cars is expected. In service : No impact of noise and vibration is expected.
	6	Subsidence	D	D	Any work causing subsidence is not expected
	7	Odor	D	D	Any work causing odor is not expected.
	8	Bottom Sediment	D	D	Any work causing bottom sediment is not expected.
Natural Environ ment	9	Protected Areas	D	D	There is neither national park nor protected regions in the project site and the surrounding area.
	10	Ecosystem	D	D	The project has little impact on ecosystem because it will use the existing road shoulder and land for PNR rails.
	11	Hydrology	D	D	During construction : Any work causing the change of water flow of rivers and river bed is not projected In service : No impact on hydrology is expected.
	12	Topography and Geology	D	D	Any impact on topography and geology is not projected because large-scale cut earth and earth fill is not planned.
Social Environ ment	13	Resettlement	B-	D	Before construction：There is a possibility of small-scale involuntary resettlement due to land acquisition to ensure the ROW
	14	Poverty Group	C	D	Before construction：There is a possibility that the poor people are included in the people who should be resettled such as illegal occupants.
	15	Ethnic Minorities and Indigenous People	D	D	There is no ethnic minority or indigenous people in the project site and the surrounding area.

	16	Regional Economy including employment and livelihood	B+	B+	Job creation by the project and its impact on regional economy is expected
	17	Land Use and Local Resources	D	D	The project has little impact on regional economy because it will use the existing road shoulder and land for PNR rails.
	18	Water Use	C	C	During construction：Muddy water caused by construction is expected. In service：No impact on water use is expected.
	19	Existing Social Infrastructure and Social Service	B-	C	During construction：Traffic jam during construction is expected. In service：No impact expected
	20	Social Organizations including society related resource and regional Decision-making Body	B+	B+	The construction of pipelines by the project has impact on society related resource and regional decision making body.
	21	Maldistribution of damage and benefit	D	D	The project causes little damage and benefit on the surrounding area.
	22	Conflicts of interest in the region	D	D	The project causes no conflicts of interest in the region
	23	Cultural Heritage	D	D	There is no cultural heritage in the project site and the surrounding area.
	24	Landscape	D	D	There is little landscape impact because pipeline will be buried.
	25	Gender	D	D	The project has no particular negative effect on gender.
	26	Children's Rights	D	D	The project has no particular negative effect on Children's rights.
	27	Infection including HIV/AIDS and others	B-	D	During construction：There is a possibility of spread of infection due to the inflow of construction workers
	28	Labor Environment(including work safety)	B-	D	During construction：Attention to labor environment of construction workers is needed In service： There is no work which causes negative effect on construction workers in service
	29	Accidents	B-	B-	During construction：Attention to accidents during construction is needed In service：No particular negative effect is expected.
Others	30	Impact of Crossing the border and Climate Change	D	B+	The project has no impact on crossing the border. It has positive impact concerning climate change because of CO_2 emissions reduction by conversion of oil to natural gas.

A+/-: Significant positive/negative impact is expected.

B+/-: Positive/negative impact is expected to some extent.

C+/-: Extent of positive/negative impact is unknown. (A further examination is needed, and the impact could be clarified as the study progresses)

D: No impact is expected.

3.2.2 Current Status of ROW and Land Acquisition

(1) Provision on ROW

ROW is for 5 m from the middle of the pipeline to right and left (10m in width) based on the Philippine legal provision.

(2) Acquirer of ROW

The project proponent is required to acquire

(3) Current status of ROW and land acquisition

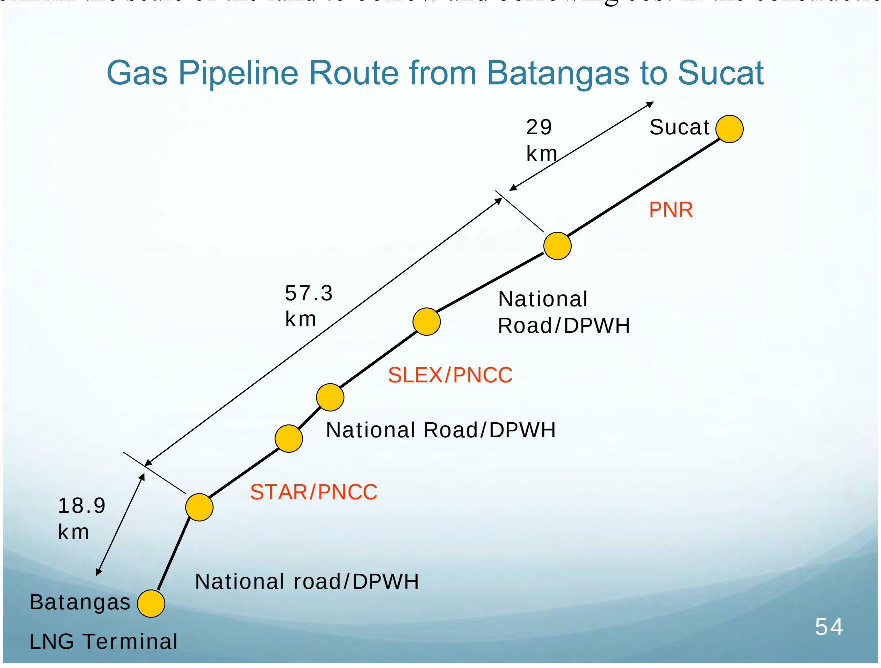
As shown in the Figure 3.2-1, ROW is distributed into the categories of National Road(under the jurisdiction of DPWH), STAR SLEX(under the jurisdiction of PNCC) and PNG(under the jurisdiction of PNC). Land acquisition and involuntary resettlement are not required(Table 3.2-3).

As for National Road, it is needed to make adjustments with DPWH. As for 42 km part of STAR, STAR acquired a permit from Philippine National Construction Corporation(PNCC). However, the range of tranverse direction has not been defined. SLEX needs to make adjustments with PNCC. As for PNR, the ROW is 30m and it is possible to apply to site for pipeline. As for ROW lease, it is needed to negotiate with each regulatory authority, respectively.

The related Municipalities and Barangays on the pipeline route are shown in Table 3.2-4. There are 13 Municipalities and 82 Barangays in total on the pipeline route. It is needed to make adjustments with them and get their approvals.

Consequently, the ROW acquisition has not been completed. The future issues include the followings.

- To confirm tasks and schedule of ROW acquisition (including ROW lease)
- To consider the handling of pipeline site
- To confirm the scale of the land to borrow and borrowing cost in the construction phase



Source: JICA Study Team

Figure 3.2-1 Pipeline Route

Table 3.2-3 ROW, Land Acquisition, Involuntary Resettlement

Route		ROW	Land Acquisition	Involuntary Resettlement
Sucat	PNR	Negotiate with PNR	Not required	Need to move illegal people in PNR railway No Involuntary Resettlement In other area
	National Road	Negotiate with DPWH		
	SLEX	Negotiate with PNCC		
	National Road	Negotiate with DPWH		
	STAR	Granted to STAR by PNCC		
	National Road	Negotiate with DPWH		

Source : JICA Study Team

Table 3.2-4 The Number of Municipality and Barangay on the Pipeline Route

Route		Number of Municipality	Number of Barangay
Sucat	PNR	4	29
	National road (DPWH)		
	SLEX	8	39
	STAR Tollway		
Batangas(LNG Terminal)	National Road(DPWH)	1	14
Total		13.	82

Source: JICA Study Team

3.2.3 The Scale and Compensations of Resettlement

The table 3.2-5 shows the required land for Case 4. Section 1 is in Batangas city and there is no need for land acquisition and resettlement because pipeline will be constructed along the roads. However it is required to pay the ROW lease. The lease amount is 200-500 PHP/m^2 in residential area, 4,000-12,000 PHP/m^2 in commercial area and 1,500-7,000 PHP/m^2 in industrial area.

Section 2 is located along the expressway and there is no need for land acquisition and resettlement. However it is required to pay the ROW lease. The lease amount is 250-3,000 PHP/m^2 in residential area and 1,000-11,000 PHP/m^2 in commercial area.

Section 3 is located along PNR. There is a need for land acquisition and resettlement for a part of it(30-meter-wide and 5-kilometer-long). The cost is currently under investigation. In addition, it is required to pay the ROW lease to PNR. The lease amount is 1,600-38,500 PHP/m^2 in residential area and 1,565-5,300 PHP/m^2 in commercial area.

There is squatter in the land for PNR. According to the interviews with PNR, it is possible to relocate the habitants because compensations have been already paid. The current status of ROW, land acquisition and involuntary resettlement is shown in the Table 3.2-6

Table 3.2-5 Required Land for Case 4

Section 1 / 11.5km: Public road in Batangas city
Permanent occupation area

	Width (m)	Length (m)	Area (m^2)	Remarks
24" Pipeline	0.61	11,400	6,954	Buried in the public roads in Batangas city.

Section 2 / 57.3km: ROW along the existing highway
Permanent occupation area

	Width (m)	Length (m)	Area (m^2)	Remarks
24" Pipeline	2.0	52,000	104,000	Buried in the ROW
16"	2.0	3,700	7,400	Buried in the ROW
16" Pipeline	0.61	1,600	976	Buried in the public road at the end of Sec.2.
Service track	4.0	55,700	222,800	For O&M
		Total	335,176	(a)
Temporary land allocation area for construction				
	Width (m)	**Length (m)**	**Area (m^2)**	**Remarks**
24"&16" Pipeline	25.0	55,700	1,392,500	(b)
		Total	1,057,324	(b)-(a)

Section 3 / 29.0km: Buried along PNR
Permanent occupation area

	Width (m)	Length (m)	Area (m^2)	Remarks
16" Pipeline	2.0	26,800	53,600	Buried along PNR
16" Pipeline	0.61	1,900	1,159	Buried in the public road at front/rear end of
Service track	4.0	26,800	107,200	For O&M excluded 300m in Sucat P/S
		Total	161,959	(a)
Temporary land allocation area for construction				
	Width (m)	**Length (m)**	**Area (m^2)**	**Remarks**
16" Pipeline	30.0	28,700	861,000	(b)
		Total	699,041	(b)-(a)

Valve / Metering stations
Permanent occupation area

	Width (m)	Length (m)	Qty	Area (m^2)	Remarks
Section 1	30.0	30.0	1	900	
Section 2	30.0	30.0	3	2,700	
Section 3	30.0	30.0	3	2,700	
			Total	6,300	(a)
Temporary land allocation area for construction					
	Width (m)	**Length (m)**	**Qty**	**Area (m^2)**	**Remarks**
Section 1	100.0	100.0	1	10,000	
Section 2	100.0	100.0	3	30,000	
Section 3	100.0	100.0	3	30,000	
			Subtotal	70,000	(b)
			Total	63,700	(b)-(a)

Table 3.2-6 The Number of Municipality and Barangay on the Pipeline Route

Route		ROW	Land Acquisition	Involuntary Resettlement
Sucat	PNR	Not acquired ROW lease payment	N/A	N/A
	National road(DPWH)	Not acquired ROW lease payment	N/A	N/A
	National road(DPWH)	Not acquired ROW lease payment	N/A	N/A
	SLEX(PNCC)	Not acquired ROW lease payment	N/A	N/A
	STAR Tollway (PNCC)	Partly acquired(42km) ROW lease payment	N/A	N/A
Batangas	National Road(DPWH)	Not acquired ROW lease payment	N/A	N/A
Total		-		

Source: JICA Study Team

3.2.4 Indigenous Peoples

There is not any need to take measures for indigenous peoples concerning pipeline construction.

3.3 Environmental and Social Considerations Regarding LNG Terminal Construction

3.3.1 Selection of Candidate LNG Terminal Sites

(1) The Process of Candidate LNG Terminal Site Selection

The Study Team has so far made four trips to the Batangas Province to look for suitable LNG terminal sites. Based on information obtained from these field trips and result of comparison among all the candidate sites visited, the site of Batangas Baseport in Batangas City is considered as the most suitable site for LNG terminal construction. Meanwhile, the site in Barangay Simlong of the same Batangas City and the site of an energy supply base owned by PNOC in Bauan Municipality are regarded as comparatively suitable sites for the project. The process of selection regarding these candidate sites is summed up as follows.

1) Summary of the 1st Site Visit

The 1st site visit was conducted on July 19th of 2011 (Tuesday), when the team member in charge of environmental and social considerations, together with DOE officials, visited two sites in Calaca Municipality, one in Barangay Qizumbing and the other in Barangay Sinisian, as well as one site in Barangay Ilihan of Batangas City. The following are an overview of these three sites

Table 3.3-1 Overview of Candidate Sites Visited during the 1st Site Visit

Site	Location	Status Quo	Surrounding Circumstances	Depth of the Sea
1	Barangay Qizumbing, Calaca Municipality	A sugarcane field of 80ha, predetermined as an industrial area.	100 households currently residing on the seashore area; a storage of chemical materials and a coal power plant nearby.	Unclear, but a jetty for chemical material discharge existing nearby
2	Bsrangay Sinisian, Calaca Municipality	A publicly owned grass of 8ha, predetermined as an industrial area.	Neither residents nor infrastructure facilities existing nearby.	Unclear
N3	Barangay Ilihan, Batangas City	A long and narrow vacant lot of 300m×30m on the sea shore.	Facilities of KEPCO next to the vacant lot.	Unclear, but a jetty of KEPCO existing nearby.

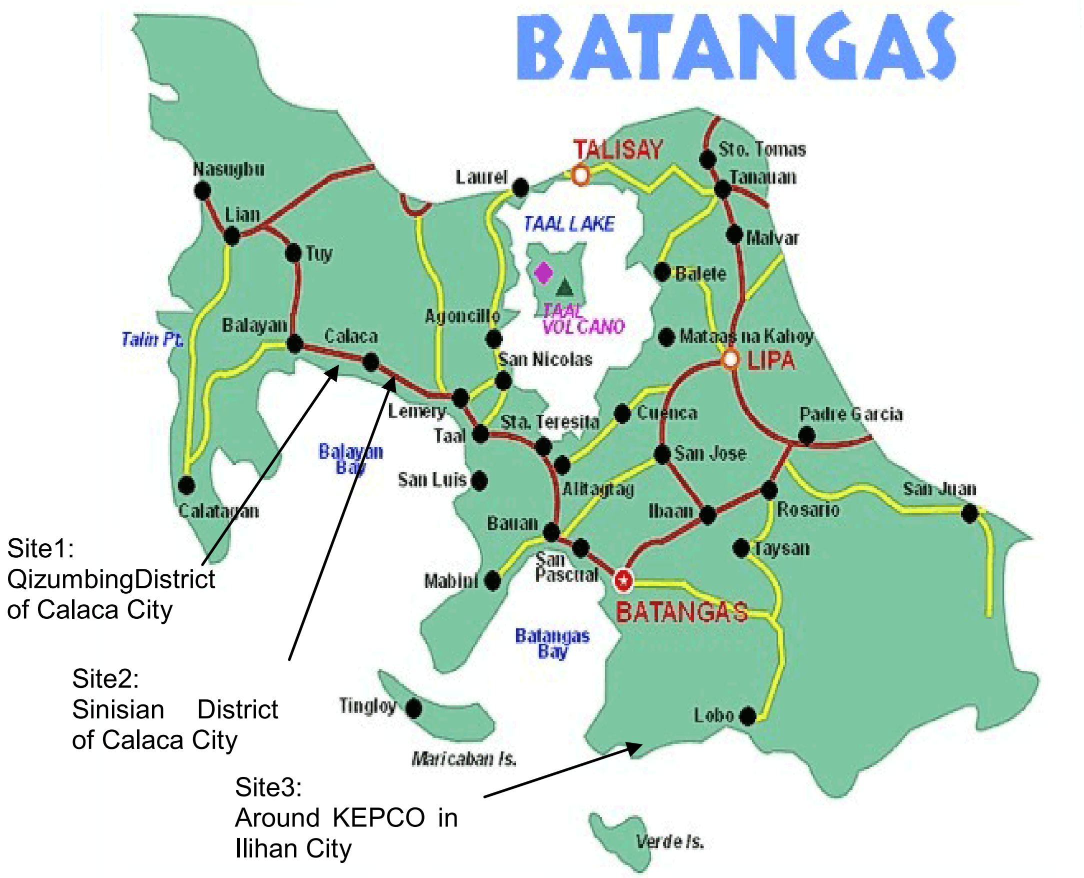
Source: JICA Study Team

The above-mentioned Site 1 is currently a sugarcane field of 80ha in area. As the area has been predetermined as an industrial area, there will not be any legal problem once it is decided on as the site of LNG terminal, except for the necessity of paying a certain amount of compensation. Besides, as currently there are 100 households residing on the seashore area between the sugarcane field and the coastal line, resettlement of these households will be unavoidable. According to the officials of the municipal government, it is possible for the municipal government to handle issues like persuading the local residents to cooperate, but the key point will be the money for compensation.

Site 2, owned by the municipal government, is currently a grass without any crop on it. As there is no need to resettle any residents, compensation payment will be unnecessary in the case that it is adopted as the site of the LNG terminal. But the problem is that the site is not more than 8ha in area, insufficient for the construction of the proposed LNG terminal.

As for Site 3. it is a long and narrow vacant lot on the sea shore just in front of the KEPCO power plant. As it is not more than 1ha in area, virtually far from enough for the construction of the LNG terminal.

The locations of the above-mentioned 3 sites are illustrated in the map below.



Source: http://www.islandsproperties.com/maps/batangas.htm

Figure 3.3-1 Candidate Sites of LNG Terminal Visited during the 1st Site Visit

2) Summary of the 2nd Site Visit

The 2nd site visit was conducted on September 28th of 2011 (Wednesday), when a group of 10 persons including members of the study team, JICA official, DOE officials and local consultants, visited seven sites in the Mabini Municipality, Bauan Municipality, San Pascual Municipality and Batangas City (with regard to a few of them, acquisition of relevant data from the city hall was made instead of site visit). Among the seven sites, four are considered evidently unsuitable for the LNG terminal construction purpose and thus excluded, and the remaining 3 sites are regarded as relevant, of which the overview and the locations are indicated in Table 3.3.2 and Figure 3.3-2.

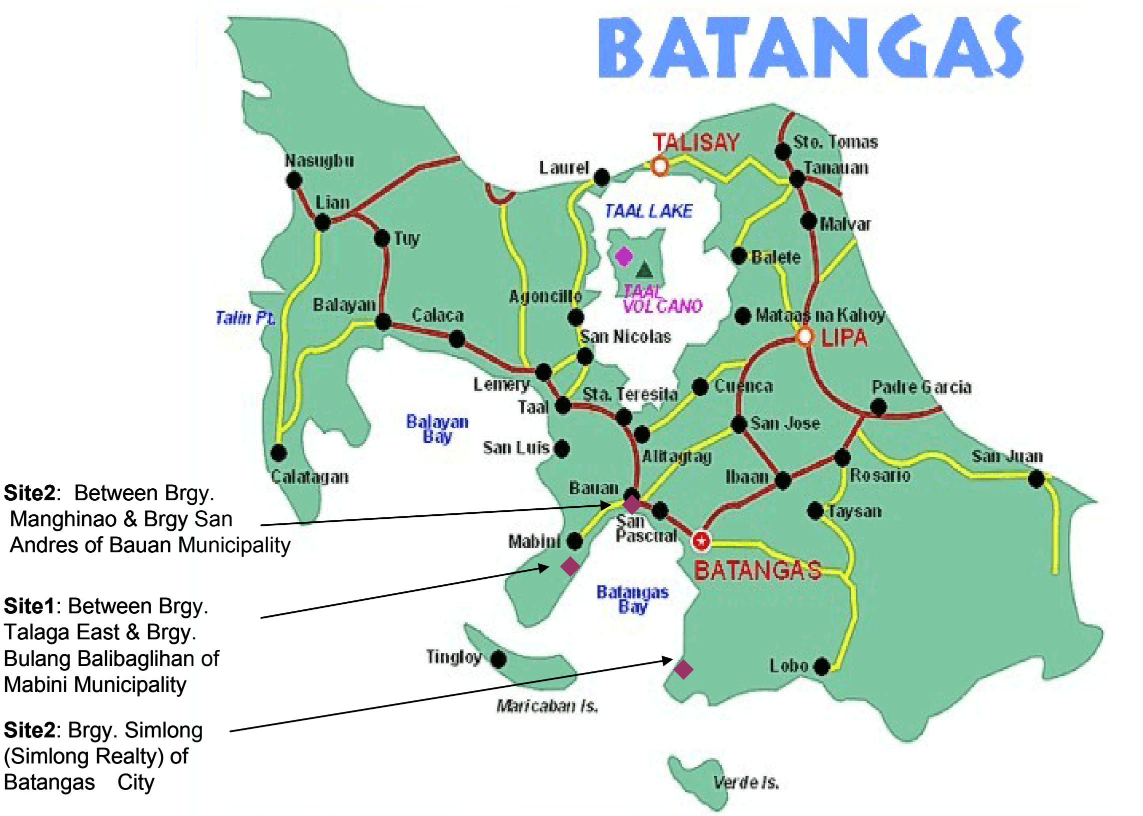
Site 1 of Mabini Municipality, located between Barangay Talaga East and Barangay Bulang Balibaglihan, used to be a site for the cement production and storage facilities of Lucky Cement, a Philippino company, but was sold to a Mexican company and a French company after being closed 8 years ago, and has actually not been in use so far. Although it looks spacious enough for the construction of LNG terminal, the cost of dismantling the existing construction and its vicinity to the residential area would be a vital demerit.

Site 2 situated between the Barangay Manghinao and Barangay San Andres of Bauan Municipality is owned by a Japanese-Philippino joint venture known as Republic Asahi. The site has been developed and is more than 40ha in area, the depth of the sea is estimated to be 15 to 20m at the location approximately 400m away from the shoreline, and the municipal government is very positive and supportive to the LNG terminal project. However, there is the problem that the part of the area alongside the shoreline is too narrow to be of use while expanding it to the neighboring residential area will entail involuntary resettlement, and additionally, construction of luxury housing in the surrounding area is now under contemplation.

Table 3.3-2 Overview of Candidate Sites Visited during the 2nd Site Visit

Site	Location	Status Quo	Surrounding Circumstances	Depth of the Sea
1	Between Brgy. Talaga East and Brgy. Bulang Balibaglihan of Mabini Municipality	A land spacious enough for a LNG terminal, with existing cement related facilities on it.	Densely populated residential area existing nearby	Unclear, but a jetty for cement products & material discharge existing nearby
2	Between Brgy. Manghinao and Brgy. San Andre of Bauan Municipality	A land of over 40ha, but the part near the shoreline too narrow, while expansion entailing resettlement	Luxury housing construction in the surrounding area under contemplation.	15 to 20m at the location around 400m from the shoreline
3	Simlong Realty of Brgy. Simlong in Batangas City	A hilly land with an altitude of 10 to 140m high; over 45ha in area plus 10ha of foreshore right, predetermined as industrial area	Petrochemical plant of JG Summit 1km away; Ilihan power plant 5km away; vicinity to Tigerland oil storage	165m at the location around 5 to 15m from the shoreline

Source: JICA Study Team



Source: http://www.islandsproperties.com/maps/batangas.htm

Figure 3.3-2 Candidate Sites of LNG Terminal Visited during the 2nd Site Visit

Site 3 in Barangay Simlong of Batangas City is owned by the Simlong Realty. In addition to an area as large as 45ha, it also includes a foreshore right close to 10ha. There are the petrochemical plant of JG Summit Company, the oil storage of Tigerland Company and the facilities of Ilihan power plant in the surrounding area, and this site has been predetermined as an industrial area. Although there is the disadvantage that the site is basically a hilly land with an altitude of 10 to 140m high, as seen from the current state of development in the neighboring facilities of JG Summit and Tigerland, the development of hilly land of this kind will not be a serious problem.. Moreover, as the depth of the sea is exceptionally good in that it is 165m at the location around 5 to 15m away from the shoreline, the cost of jetty construction is expected to be reduced greatly. Furthermore, there is also the advantage that the land owner is very positive about the idea of selling, or leasing out the site, or developing it through joint-venture.

3) Summary of the 3rd Site Visit

The 3rd site visit was conducted on October 13th of 2011 (Thursday) by the local consultant Philkairos, who visited the site in Barangay Simlong of Batangas City that the study team would had visited during the 2nd site visit but had failed to owing to the lack of time, as well as the site in Barangai Balibago of Lobo Municipality as recommended by DOE. The locations of the two sites are indicated in Figure 3.3-3, and the related information of the latter is summed up below.

The site in in Barangai Balibago of Lobo Municipality is basically a hilly land of 45~100ha in area. There is a sea port nearby, and the depth of the sea is 46m at a location of 18m away from the shoreline. The problem of this site is that it has been predetermined as an agricultural land, the indigenous species of flora and fauna are very rich, and the local government is negative about the idea of constructing an LNG terminal on this site. Therefore, the suitability for this site to be adopted for LNG terminal construction is regarded very low.

Source: http://www.islandsproperties.com/maps/batangas.htm

Figure 3.3-3 Candidate Sites of LNG Terminal Visited during the 3rd Site Visit

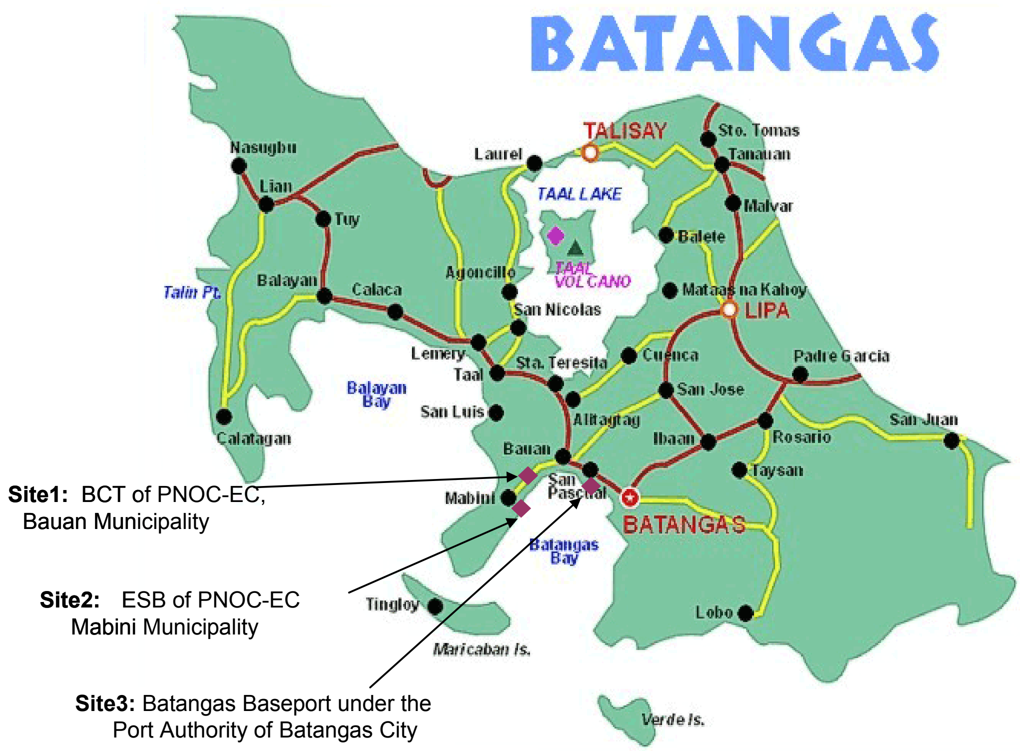
4) Summary of the 4th Site Visit

The 4th site visit was conducted on November 25th of 2011 (Friday) by members of the study team. In addition to the site owned by Republic Asahi which had been visited during the 2nd site visit and Simlong Realty visited during the 3rd site visit, the team also visited two sites owned by the PNOV group, i.e. a vacant lot next to the PNOC coal terminal and another vacant lot adjacent to the PNOC energy supply base, as well as the site of the Batangas Baseport under the jurisdiction of the Port Authority of Batangas City; altogether five sites were visited. Among them, there are three sites that the team visited for the first time, and their overviews are summarized as follows.

Table 3.3-3 Overview of Candidate Sites visited during the 4th Site Visit

Site	Location	Status Quo	Surrounding Circumstances	Depth of the Sea
1	Batangas Coal Terminal (BCT) of PNOC-EC in Bauan Municipality	5.3ha in area plus a beachfront of 100m in width, possible for reclamation	A coal terminal existing nearby	Not more than 3.5m; needed to build a long jetty.
2	Energy supply base (ESB) of PNOC-EC in Mabini Municipality	14ha in area, possible to expand to 20ha.	An energy supply base existing nearby	Over 13m at the location around 200m from the shoreline.
3	Batangas Baseport under the Port Authority of Batangas City	49ha in area,; bidding for lease from the end of 2011; lease contract to be renewed every 7 years.	Adjacent to the Santa Rita CCGT power plant	Over 13m at the location around 200m from the shoreline.

Source: JICA Study Team



Source: http://www.islandsproperties.com/maps/batangas.htm

Figure 3.3-4 Candidate Sites of LNG Terminal Visited during the 4th Site Visit

5) Evaluation and Comparison among the Candidate LNG Terminal Sites

Based on the information acquired from the above-mentioned four site visits, ten candidate sites were selected. By comparing and evaluating their respective advantages and disadvantages as indicated in the following table, the Batangas Baseport under the jurisdiction of Batangas Port Authority is chosen as the most promising candidate site, and the next step of the study will be focused on collecting information of further detail regarding this site. Meanwhile, the energy supply base (ESB) of PNOC-EC in Mabini Municipality and the site of Simlong Realty in Batangas City are reserved as the relatively promising candidate sites.

Table 3.3-4 Comparison and Evaluation of the Candidate Sites for LNG Terminal

Site	Location	Advantage	Disadvantage	Result
1	Brgy. Qizumbing, Calaca Municipality	・A spacious area of 80ha ・An industrial area ・Local government support ・Sufficient depth of the sea	・A sugarcane field requiring compensation ・Resettlement needed for 100 households	C
2	Brgy. Sinisian, Calaca Municipality	・A government owned land ・Local government support ・No existing facilities	・An area of 8ha, too small	D
3	Brgy, Ilihan, Batangas City	・No existing facilities ・Vicinity to a power plant ・Sufficient depth of the sea	・An area less than 1ha, far from enough	D
4	Brgy. Talaga East and Brgy. Bulang Balibaglihan, Mabini Municipality	・An area large enough ・Sufficient depth of the sea	・Existing construction needed to be destroyed ・Vicinity to a residential area	C
5	Brgy. Manghinao and Brgy. San Andres, Bauan Municipality	・A spacious area of over 40ha ・Local government support	・The part of the land near the shoreline too small; expansion entailing resettlement ・Luxury housing construction nearby under contemplation	C
6	Simlong Realty in Brgy. Simlong, Batangas City	・A spacious area of 45ha ・Excellent depth of the sea ・An industrial area ・Supportive land owner	・A hilly land of 10 to140m high entailing considerable cost of development	B
7	Brgy. Balibago, Lobo City	・An area of 45 to 100ha ・Excellent depth of the sea	・An agricultural area ・Environmentally critical area ・Negative local government	D
8	BCT of PNOC-EC, Bauan City	・The land owned by PNOC ・An industrial area	・An area too small that reclamation needed. ・In sufficient depth of the sea	C
9	ESB of PNOC-EC, Mabini Municipality	・The land owned by PNOC ・An industrial area ・Sufficient depth of the sea	・An area too small that reclamation needed	B
10	Batangas Baseport under Batangas Port Authority	・A spacious area of 49ha ・Sufficient depth of the sea ・Vicinity to CCGT power plant	・Bidding for lease starting from the end of 2011 ・Lease contract to be renewed every 7 years	B+

Source: JICA Study Team

(2) Environmental Conditions of the Site of Batangas Baseport and the Surrounding Area

1) Size of the Area and Location

The total area of Batangas Baseport is 150ha, out of which, a land of 49ha is to be leased out though bidding and the Port Authority is now soliciting leaseholders. This site is located 110km from Metro Manila, Latitude 13^0 45.2' N, longitude 121^0 06.6' E on the northeast section of Batangas Bay along the southwestern part of Luzon. The port is in Barangay Sta. Clara, Batangas City, about 2 kilometers from the city proper

2) Access from Outside Area

Besides the national road passing through Batangas City proper, the Southern Tagalog Arterial Road (also known as Star Tollway, or Calabarzon Expressway) connects Batangas City with South Luzon Expressway (SLEX), which directly leads to Manila.

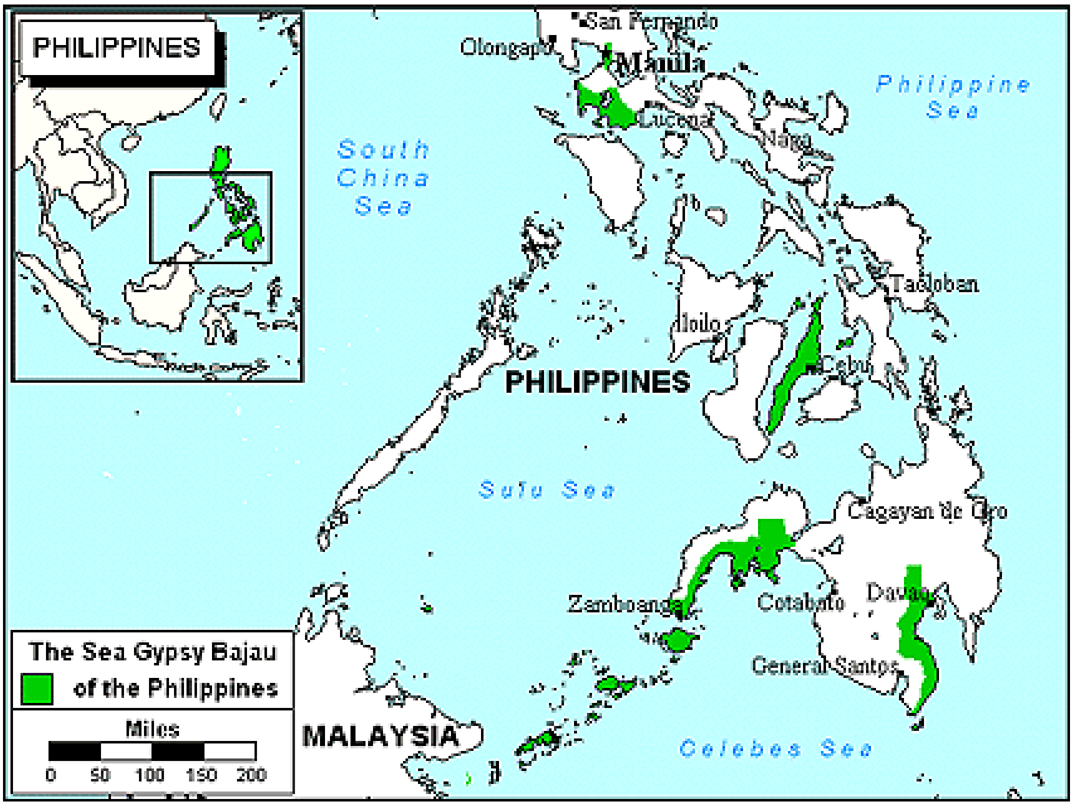
3) Climate Conditions

The climate of Batangas is marine tropical, characterized by gentle winds, moderate cloudiness, high temperature and a relatively high humidity. The wet season of Batangas is from the beginning of May until the end of December with June, July and August as the wettest months. This is the period when the southwest monsoon blows.

4) Natural Reserve

In light of the vicinity of Batangas Baseport to the Santa Rita power plant, it can be imagined that there would not be any area which needs special protection like natural reserve near the proposed candidate site of LNG terminal. However, the Batangas Bay is said to be a marine area with high degree of biodiversity, abounding with coral reef, mangrove and fish. Therefore, it would be necessary to make sure whether the construction of LNG terminal will make an impact on the ecosystem of Batangas Bay or not.

5) Indigenous People



Source: http://www.prayway.com/unreached/peoplegroups4/1104.html

Figure 3.3-5 Distribution of the Indigenous Ethnic Group Bajau People in the Philippines

There are indigenous communities known as Bajau living along the coastal line of Batangas Bay. These communities are the subgroup of indigenous people now scattering throughout the Southeast Asian countries like Indonesia, Malaysia, Myanmar and so on. In Sulawesi and East Kalimantan of Indonesia, for example, there exists the subgroup known as Bajo. As these people have traditionally lived on fishing and have been boat-dwelling and nomadic on the sea, they are usually called “Sea Nomad”, “Sea People”, or “Sea Gypsies”. As illustrated by the map below, the Bajau people in the Philippines mainly exist in Mindanao, Cebu and South Luzon including Batangas. The list of 110 indigenous ethnic groups in the Philippines issued by the Office on Policy, Planning and Research (OPPR) of National Commission on Indigenous People (NCIP) in March, 2011 also includes the ethnic group of Bajau.

As the Bajau people basically do not possess any inherent land ownership owing to their traditional boat-dwelling lifestyle, there is no worry about the possible violation of their interest on shore by the implementation of this project. Nevertheless, it needs to be clarified whether the marine component of the LNG terminal, i.e. the jetty and the ship berth and so on, will overlap with the area where the Bajau people have their fishing ground, and whether the project will have negative effect on their livelihood or not.

3.3.2 Current State of EIS Preparation and ECC Acquisition

Just like the component of Pipeline, EIS regarding the LNG component has not been prepared, and ECC has not been acquired up to now. As the tasks of the next step, it is necessary to organize the basic data needed for the drafting of EIS, followed by the formulation of EIS and the acquisition of ECC. Moreover, completion of the Environment Checklist required by JICA and the Scoping required by the Philippines government before the fulfillment of EIS formulation and ECC acquisition is also necessary. The JICA Environment Checklist relevant to the LNG component and the scoping document are indicated below.

(1) Environmental Checklist in JICA Guidelines for Environmental and Social Considerations

Focusing on the afore-mentioned Batangas Baseport as the most promising candidate site for LNG terminal construction, verification based on JICA’s Environmental Checklist was conducted. The results are summed up as follows:

1) Permits and Explanation

Currently, activities relevant to the items of EIA and Environmental Permits, and explanation to the local people around the project site are not yet started, but the 1st seminar on information disclosure of the project was held on Dec. 1, 2011, targeting business circle of gas pipeline, energy and power generation, government officials and mass media people. After the designation of the implementation agency in the near future, with the help of the consultant, the implementation agency will hold the responsibility of preparing the EIA report, conducting information disclosure seminar targeting the local stakeholders especially the affected people, and applying for necessary permits from the Environment Management Bureau (EMB) under Department of Environment and Natural Resources (DENR) or its regional office.

2) Pollution Control

With respect to pollution control covering the seven items of air quality, water quality, wastes, noise and vibration, subsidence, odor and sediment, the design and construction work will be conducted by complying with the emission standards and environmental standards of the Philippines. The specific measures will be decided through the study of the next phase.

3) Natural Environment

It is sure that, Batangas Baseport, currently considered the most promising candidate site for LNG terminal construction, is not located in any protected area designated by the country's laws or international treaties and conventions. Nevertheless, the possibility of mangroves and coral reefs existing in the surrounding marine areas and the possibility for them to be impacted by the implementation of this project need to be verified in the study of the next phase.

4) Social Environment

Although involuntary resettlement will not happen regarding the LNG terminal construction component itself on the site of Batangas Baseport, clarification is needed to make sure whether it will happen or not when the construction work start to connect the LNG terminal to the gas pipeline. In the case that such possibility be identified, it would be necessary to take proper measures according to the country's laws and regulations relevant to land acquisition and resettlement.

In addition, it is also needed to verify in detail whether or not the implementation of this project will have any negative impact on the local people's living and livelihood or the landscape. When problems are identified, necessary mitigation measures will be taken. Moreover, the possibility of adverse effects on the Bajau people's culture and lifestyle requires verification, and proper steps should be considered in the case that these effects are anticipated. With regard to the labor conditions, installation of safety equipment and implementation of safety training for workers are indispensable measures. Furthermore, appropriate measures needs to be taken to ensure that security guards involved in the project not to violate safety of other individuals involved, or local residents; specifically, this item should be clearly stated in the document of employment conditions.

5) Others

Regarding the items of impacts during construction and monitoring, compliance with the relevant laws of the Philippines should be the first concern in contemplating the necessary steps to take.

6) Note

In the study of the next phase, it is needed to clarify the issue of possible impact of the jetty construction and other related works on the groundwater system and work out proper solutions in the case that problems are identified. When necessary, the impacts of the project on transboundary or global issues might also need to be confirmed.

Table 3.3-5 Results of Verification by JICA's Environmental Checklist

Category	Environmental Item	Main Check Items	Confirmation of Environmental Considerations
Permits and Explanation	EIA and Environmental Permits	(a)Have EIA reports been already prepared in official process?	Activities relevant to the all the items on the left column have not yet started.
		(b)Have EIA reports been approved by authorities of the host country's government?	
		(c)Have EIA reports been unconditionally approved? If conditions are imposed on the approval of EIA reports, are the conditions satisfied?	
		(d)In addition to the above approvals, have other required environmental permits been obtained from the appropriate regulatory authorities of the host country's government?	
	Explanation to the Local Stakeholders	(a)Have contents of the project and the potential impacts been adequately explained to the Local stakeholders based on appropriate procedures, including information disclosure? Is	The 1st seminar on information disclosure of the project was held on Dec. 1, 2011, targeting business circle of gas pipeline, energy and power generation, government officials and mass media people, but not

Category	Environmental Item	Main Check Items	Confirmation of Environmental Considerations
		understanding obtained from the Local stakeholders?	including local residents.
		(b)Have the comment from the stakeholders (such as local residents) been reflected to the project design?	
	Examination of Alternatives	(a)Have alternative plans of the project been examined with social and environmental considerations?	The most promising candidate site and two standby candidate sites are decided.
Pollution Control	Air Quality	(a) Do air pollutants, such as sulfur oxides (SOx), nitrogen oxides (NOx), and soot and dust emitted from ships, vehicles and project equipments comply with the country's emission standards? Are any mitigating measures taken?	Yes. The specific measures will be considered in the study of the next phase.
	Water Quality	a) Do effluents from the project facilities comply with the country's effluent and environmental standards?	Yes.
		(b) Do effluents from the ships and other project equipments comply with the country's effluent and environmental standards?	Yes.
		(c) Does the project prepare any measures to prevent leakages of oils and toxicants?	The specific measures will be considered in the study of the next phase.
		(d) Does the project cause any alterations in coastal lines and disappearance/appearance of surface water to change water temperature or quality by decrease of water exchange or changes in flow regimes?	This issue is to be verified in the study of the next phase.
		(e) Does the project prepare any measures to prevent polluting surface, sea or underground water by the penetration from reclaimed lands?	The specific measures will be considered in the study of the next phase.
	Wastes	(a) Are wastes generated from the ships and other project facilities properly treated and disposed of in accordance with the country's regulations?	Yes.
		(b) Is offshore dumping of dredged soil properly disposed in accordance with the country's regulations?	Yes.
		(c) Does the project prepare any measures to avoid dumping or discharge toxicants?	The specific measures will be considered in the study of the next phase.
	Noise and Vibration	(a) Do noise and vibrations from the vehicle and train traffic comply with the country's standards?	Yes.
	Subsidence	(a) In the case of extraction of a large volume of groundwater, is there a possibility that the extraction of groundwater will cause subsidence?	This issue is to be verified in the study of the next phase.
	Odor	(a) Are there any odor sources? Are adequate odor control measures taken?	This issue is to be verified in the study of the next phase.
	Sediment	(a) Are adequate measures taken to prevent contamination of sediments by discharges or dumping of hazardous materials from the ships and related facilities?	The specific measures will be considered in the study of the next phase.
Natural Environment	Protected Areas	(a) Is the project site located in protected areas designated by the country's laws	The project site will not be located in any protected area designated by the country's

Category	Environmental Item	Main Check Items	Confirmation of Environmental Considerations
		or international treaties and conventions? Is there a possibility that the project will affect the protected areas?	laws or international treaties and conventions
	Ecosystem	a) Does the project site encompass primeval forests, tropical rain forests, ecologically valuable habitats (e.g., coral reefs, mangroves, or tidal flats)?	The project site on shore will not encompass any primeval forests, tropical rain forests, and other ecologically valuable habitats. As for the possibility of existence of mangrove or coral reef in the surrounding marine area, it needs to be verified in the study of the next phase.
		(b) Does the project site encompass the protected habitats of endangered species designated by the country's laws or international treaties and conventions?	No.
		(c) If significant ecological impacts are anticipated, are adequate protection measures taken to reduce the impacts on the ecosystem?	Mitigation measures will be taken in the case that such impacts are anticipated.
		(d) Is there a possibility that the project will adversely affect aquatic organisms? Are adequate measures taken to reduce negative impacts on aquatic organisms?	This issue is to be verified in the study of the next phase.
		(e) Is there a possibility that the project will adversely affect vegetation or wildlife of coastal zones? If any negative impacts are anticipated, are adequate measures taken to reduce the impacts on vegetation and wildlife?	This issue is to be verified in the study of the next phase.
	Hydrology	(a) Do the project facilities affect adversely flow regimes, waves, tides, currents of rivers and etc if the project facilities are constructed on/by the seas?	This issue is to be verified in the study of the next phase.
	Topography and Geology	(a) Does the project require any large scale changes of topographic/ geographic features or cause disappearance of the natural seashore?	This issue is to be verified in the study of the next phase.
Social Environment	Resettlement	(a) Is involuntary resettlement caused by project implementation? If involuntary resettlement is caused, are efforts made to minimize the impacts caused by the resettlement?	Involuntary resettlement will not happen in the case of LNG terminal construction on the site of Batangas Baseport, which is chosen as the most promising candidate site. However, with regard to the construction work needed to connect the terminal to the gas pipeline, the possibility of involuntary resettlement needs to be verified. In the case that such possibility be identified, the following measures will be taken: - Conduct consultation meeting with affected people. - Formulate resettlement plan including compensation with full replacement costs in market price and restoration of livelihoods and living standards. - Prepare the compensation policies in document. - Pay particular attention to vulnerable groups or people in the resettlement plan formulation. -Obtain agreements with the affected
		(b) Is adequate explanation on compensation and resettlement assistance given to affected people prior to resettlement?	
		(c) Is the resettlement plan, including compensation with full replacement costs, restoration of livelihoods and living standards developed based on socioeconomic studies on resettlement?	
		(d) Are the compensations going to be paid prior to the resettlement?	
		(e) Are the compensation policies prepared in document?	
		(f) Does the resettlement plan pay particular attention to vulnerable groups or people, including women, children, the elderly, people below the	

Category	Environmental Item	Main Check Items	Confirmation of Environmental Considerations
		poverty line, ethnic minorities, and indigenous peoples?	people prior to resettlement. - Pay the compensations prior to the resettlement. - Establish a highly capable organization to properly implement the resettlement. - Develop plan to monitor the impacts of resettlement. - Establish grievance redress mechanism
		(g) Are agreements with the affected people obtained prior to resettlement?	
		(h) Is the organizational framework established to properly implement resettlement? Are the capacity and budget secured to implement the plan?	
		(i) Are any plans developed to monitor the impacts of resettlement?	
		(j) Is the grievance redress mechanism established?	
	Living and Livelihood	(a) Is there a possibility that the project will adversely affect the living conditions of inhabitants? Are adequate measures considered to reduce the impacts, if necessary?	This issue is to be verified in the study of the next phase.
		(b) Is there a possibility that changes in water uses (including fisheries and recreational uses) in the surrounding areas due to project will adversely affect the livelihoods of inhabitants?	This issue is to be verified in the study of the next phase.
		(c) Is there a possibility that port and harbor facilities will adversely affect the existing water traffic and road traffic in the surrounding areas?	This issue is to be verified in the study of the next phase.
		(d) Is there a possibility that diseases, including infectious diseases, such as HIV will be brought due to immigration of workers associated with the project? Are considerations given to public health, if necessary?	There is no possibility for this kind of effect to happen as a result of the implementation of this project.
	Heritage	(a) Is there a possibility that the project will damage the local archeological, historical, cultural, and religious heritage? Are adequate measures considered to protect these sites in accordance with the country's laws?	There is no heritage of any kind existing in Batangas Baseport, the most promising candidate site for this project.
	Landscape	(a) Is there a possibility that the project will adversely affect the local landscape? Are necessary measures taken?	This issue is to be verified in the study of the next phase, and mitigation measures will be taken in the case that such effect are anticipated
	Ethnic Minorities and Indigenous Peoples	(a) Are considerations given to reduce impacts on the culture and lifestyle of ethnic minorities and indigenous peoples?	This issue of whether the implementation of this project will have impacts on the culture and lifestyle of Bajau people is to be verified in the study of the next phase, and mitigation measures will be taken in the case that such impacts are anticipated.
		(b) Are all of the rights of ethnic minorities and indigenous peoples in relation to land and resources respected?	
	Working Conditions	(a) Is the project proponent not violating any laws and ordinances associated with the working conditions of the country which the project proponent should observe in the project?	The Labor Code of the Philippines (Presidential Decree No.442)will be followed.
		(b) Are tangible safety considerations in place for individuals involved in the project, such as the installation of safety equipment which prevents industrial accidents, and management of hazardous materials?	Safety measures for individuals involved in the project will be taken.

Category	Environmental Item	Main Check Items	Confirmation of Environmental Considerations
		(c) Are intangible measures being planned and implemented for individuals involved in the project, such as the establishment of a safety and health program, and safety training (including traffic safety and public health) for workers etc.?	Measures including formulating a safety and health program, and conducting safety training for workers will be taken.
		(d) Are appropriate measures taken to ensure that security guards involved in the project not to violate safety of other individuals involved, or local residents?	Appropriate measures should be taken to ensure that security guards involved in the project not to violate safety of other individuals involved, or local residents. Specifically, this item should be stipulated in the document of employment conditions.
Others	Impacts during Construction	(a) Are adequate measures considered to reduce impacts during construction (e.g., noise, vibrations, turbid water, dust, exhaust gases, and wastes)?	Impacts during construction such as pollution, adverse effect on natural environment and social environment are foreseeable, and mitigation measures will be taken by complying with the laws and regulations of the Philippines.
		(b) If construction activities adversely affect the natural environment (ecosystem), are adequate measures considered to reduce impacts?	
		(c) If construction activities adversely affect the social environment, are adequate measures considered to reduce impacts?	
	Monitoring	(a) Does the proponent develop and implement monitoring program for the environmental items that are considered to have potential impacts?	Monitoring program for the environmental items that are considered to have potential impacts will be developed and implemented according to the EIA system of the Philippines.
		(b) Are the items, methods and frequencies of the monitoring program regarded appropriate?	The items, methods and frequencies of the monitoring program, the monitoring framework, and the monitoring report system will be decided according to the stipulation of EIA regulations of the Philippines.
		(c) Does the proponent establish an adequate monitoring framework (organization, personnel, equipment, and adequate budget to sustain the monitoring framework)?	
		(d) Are any regulatory requirements pertaining to the monitoring report system identified, such as the format and frequency of reports from the proponent to the regulatory authorities?	
Note	Note on Using Environmental Checklist	(a) Where necessary, impacts on groundwater hydrology (groundwater level drawdown and salinization) that may be caused by alteration of topography, such as land reclamation and canal excavation should be considered, and impacts, such as land subsidence that may be caused by groundwater uses should be considered. If significant impacts are anticipated, adequate mitigation measures should be taken.	Regarding the site of Batangas Baseport, reclamation is unnecessary thanks to the spacious available land, but the construction of a jetty is needed. Therefore, the possible impacts of the construction work of the jetty on the groundwater hydrology will need to be verified in the study of the next phase.
		(b) If necessary, the impacts on transboundary or global issues should be confirmed (e.g., the project includes factors that may cause problems, such as transboundary waste treatment, acid rain, destruction of the ozone layer, or global warming).	Yes.

Source: JICA Study Team

(2) Draft of the Scoping Document

The Scoping document is to be prepared as indicated previously in Table 3.2-2, whereby a total of thirty items in the four categories of pollution control, natural environment, social environment and others are to be evaluated with the grades from A to D. The specific work of Scoping with regard to the LNG component will be conducted in the study of the next stage.

3.3.3 Current Status of ROW and Land Acquisition

The site of LNG terminal is envisioned as the public land under the jurisdiction of the Batangas Port Authority. So long as the land can be acquired through open bidding, it is possible to use it for a long time by way of leasing, though the leasing contract will need to be renewed every seven years. Accordingly, efforts in obtaining additional ROW and land are unnecessary.

3.3.4 Scale and Compensations of Resettlement

The LNG terminal component is not expected to cause any involuntary resettlement, but it needs to make sure whether resettlement will happen or not when the installation work is required to connect the LNG terminal with the pipeline afterwards.

3.3.5 Indigenous Peoples

As was mentioned in (2) of 3.3.1, there are tribes of indigenous people known as Bajau living in the coastal areas of the Batangas Bay, and though it is almost impossible for the implementation of this project to violate their interest on shore, it still needs to be clarified whether the marine component of the LNG terminal, i.e. the jetty and the ship berth and so on, will overlap with the area where the Bajau people have their fishing ground, and whether the project will have negative effect on their livelihood or not.

3.4 CO_2 Emission Reduction Effect Expected to Be Brought by the Proposed Project

It can be expected that part of the environmental improvement effect to be brought by the implementation of this project will be reflected in the effect of CO_2 emission reduction. In this section, the CO_2 emission reduction effect to be brought by the implementation of this project are estimated focusing on the electric power sector and industrial sector of Luzon Region which is assumed to be the area to benefit from this project . The estimation covers the period from the year of 2017 when the pipeline installation work is to be completed to the year of 2030 which is the final year of demand forecast conducted in this study. The result estimation shows that the total CO_2 emission reduction including both the electric power sector and the industrial sector is expected to attain 14.5Mt. The specific way of estimation regarding the two sectors and their respective results are as follows.

3.4.1 CO_2 Emission Reduction Effect on the Electric Power Sector

(1) CO_2 Emission from the Power Sector in Luzon Area with the Implementation of This Project

According to the result of projection for future natural gas demand in Chapter 4, the amount of annual natural gas consumption relevant to the additional installation of electric power sector in Luzon Region by 2030 will be 697 $MMNm^3$ starting from 2022 and 1,395 $MMNm^3$ from2025. Moreover, during the 4 year's period from 2017 to 2020, which is envisioned as the period begun with the completion of the pipeline installation work and lasting through to the year when the LNG terminal start operation, a limited amount of natural gas envisioned as around 123 million Nm^3 per annum will be provided to a power generation station of 100 MW in capacity from the Camago-Malampaya gas field through pipelines. Accordingly, CO_2 emission resulted from the natural gas consumption by the electric power sector in Luzon area with regard to this project during the period from 2017 to 2030 can be divided into three time frames, i.e. the time frames of 2017-2021, 2022-2024 and 2025-2030. As seen from Table 3.4-1, the total amount of CO_2 emission resulted from the natural gas consumption is estimated as 25.2Mt.

(2) Energy Consumption by Fuel Type Relevant to Generation in the Case without This Project

Meanwhile, assume that in the case of without this project, the generation mix in 2013 envisioned by DOE will remain the same up to 2030, and the generating efficiency of coal and oil/natural gas will be 40% and 55% respectively, the annual energy consumption by fuel type based on the above-mentioned generation mix expressed in heat value to be replaced by utilizing natural gas with this project can be worked out and displayed in the afore-mentioned three time frames as follows:

- 2017-2021: Coal 329,286Gcal Oil 100,122Gcal Natural gas 230,010Gcal
- 2022-2024: Coal 1,865,956Gcal Oil 567,358Gcal Natural gas 1,303,390Gcal
- 2025-2030: Coal 3,734,589Gcal Oil 1,135,530Gcal Natural gas 2,608,650Gcal

(3) CO_2 Emission Reduction with the Implementation of This Project

The annual CO_2 emission by fuel type can be worked out by multiplying the heat values of respective fuel types with CO_2 conversion factors. In order to estimate the CO_2 emission reduction effect, it is necessary to compare the afore-mentioned CO_2 emission value with the implementation of this project with the values of CO_2 emission by coal and oil consumption in the case without this project. The results of CO_2 emission reduction in the three time frames are worked out as follows:

- 2017-2021: 84.7kt
- 2022-2024: 480kt
- 2025-2030: 960.7kt

Accordingly, the total amount of CO_2 emission in the power sector of Luzon area from 2017 to 2030 is expected to be reduced by 7.6Mt with the introduction of natural gas.

Table 3.4-1 CO_2 Reduction Effect on the Electric Power Sector of Luzon Region with the Implementation of This Project

Item		Unit	Total	Coal	Oil	NG	Others
Pre-conditions	Generation mix	%	100.0	17.7	7.4	17.0	57.9
	Generating efficiency	%	-	40	55	55	-
Demand of NG and expected CO_2 emission (2017-2030)	Annual demand for NG(2017-21)	$MMNm^3$	123				
	Annual demand for NG(2022-24)	$MMNm^3$	697	-	-	-	-
	Annual demand for NG(2025-30)	$MMNm^3$	1395	-	-	-	-
	Heat value per unit volume of NG	$kcal/m^3$	11,000	-	-	-	-
	Annual heat value of NG(2017-21)	Gcal	1,353,000	-	-	-	-
	Annual heat value of NG(2022-24)	Gcal	7,667,000	-	-	-	-
	Annual heat value of NG(2025-30)	Gcal	15,345,000	-	-	-	-
	Conversion factor for NG to CO_2	$t\text{-}CO_2$/Gcal	0.20675	-	-	-	-
	Annual emission of CO_2 by NG (2017-21)	$t\text{-}CO_2$	279,733	-	-	-	-
	Annual emission of CO_2 by NG (2022-24)	$t\text{-}CO_2$	1,585,152	-	-	-	-
	Annual emission of CO_2 by NG (2025-30)	$t\text{-}CO_2$	3,172,579	-	-	-	-
	Total emission of CO_2 by NG (2017-30)	$t\text{-}CO_2$	25,189,593	-	-	-	-
Total CO_2 reduction with LNG (2017-2030)	Annual heat value of fuels to be replaced by LNG (2017-21)	Gcal	-	329,286	100,122	230,010	-
	Annual heat value of fuels to be replaced by LNG (2022-24)	Gcal	-	1,865,956	567,358	1,303,390	-
	Annual heat value of fuels to be replaced by LNG (2025-30)	Gcal	-	3,734,589	1,135,530	2,608,650	-
	CO_2 conversion factor by fuel type	$t\text{-}CO_2$/Gcal	-	0.37927	0.29992	0.20675	-
	Annual CO_2 emission by fuel type (2017-21)	$t\text{-}CO_2$	-	124,888	30,029	47,555	-
	Annual CO_2 emission by fuel type (2022-24)	$t\text{-}CO_2$	-	707,701	170,162	269,476	-
	Annual CO_2 emission by fuel type (2025-30)	$t\text{-}CO_2$	-	1,416,418	340,568	539,338	-
	Annual CO_2 reduction with LNG (2017-21)	$t\text{-}CO_2$	84,704	-	-	-	-
	Annual CO_2 reduction with LNG (2022-24)	$t\text{-}CO_2$	479,990	-	-	-	-
	Annual CO_2 reduction with LNG (2025-30)	$t\text{-}CO_2$	960,669	-	-	-	-
	Total CO_2 reduction with LNG (2017-30)	$t\text{-}CO_2$	7,627,502	-	-	-	-

Source : 1. Generation mix: DOE "Power Development Program (2004-2013)" (projected value for 2013)
2. Heat value per unit volume of natural gas: Heat value per unit volume of imported LNG
3. Heat value per unit volume of coal: Heat value per unit volume of imported fuel coal
4. Conversion factors for natural gas to CO_2 and for coal to CO_2:
"The Energy Data and Modeling Center, IEEJ, "Handbook of Energy & Economic Statistics in Japan 2011"

3.4.2 CO_2 Emission Reduction Effect on the Industrial Sector

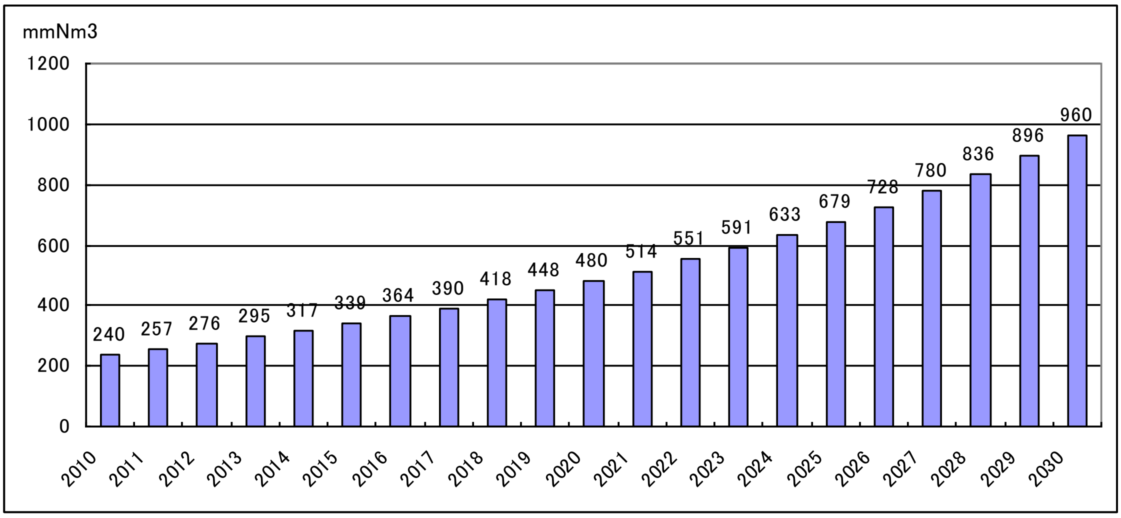
The estimation of CO_2 emission reduction effect on the industrial sector was conducted through the following steps:

(1) Calculation of the Share of Existing Energy Consumption by Fuel Type

Based on the current status of energy consumption by fuel type observed from 73 sampling factories situated in the industrial parks along the gas pipeline under planning in this project, the share of existing energy consumption by fuel type was estimated through converting the data to heat values. The results show that the shares of light diesel oil, kerosene, heavy oil and LPG are 28.1%, 0.1%、67.8%、4% respectively.

(2) Calculation of CO_2 Emission Resulted from the Consumption of Natural Gas in 2030

As indicated in Chapter 4, the potential need for natural gas by the industrial sector along the pipeline in 2010 is thought to be 240MMNm^3, and it is expected to increase to register a four-fold growth to reach 960MMNm^3. Thus, the annual growth rate of demand for natural gas (7.2%) and the amount of annual consumption can be worked out as illustrated by Figure 3.4-6. Based on this, the total demand for natural gas during the 10 years beginning from 2021 when the LNG terminal start operation to the year of 2030 can be estimated as 7,168 MMNm^{3,} which can be converted into 16.3Mt of CO_2 emission associated with natural gas consumption via conversion to heat value.



Source: JICA Study Team

Figure 3.4-1 Forecast of Natural Gas Demand in the Industrial Sector along the Pipeline (by 2030)

(3) Calculation of CO_2 Emission Reduction Resulted from the Introduction of LNG

By utilizing the values of share of energy consumption by fuel type estimated in the afore-mentioned (1), the values of total energy consumption from 2021 to 2030 regarding various types of fuel to be replaced by LNG in terms of heat value can be calculated. Based on these data and values of CO_2 conversion factor by fuel type, the amount of CO_2 emission in the case of “without-LNG” is worked out as 23.2Mt, and the amount of CO_2 emission reduction as a result of LNG introduction will be 6.9Mt.

Table 3.4-2 CO_2 Reduction Effect on the Industrial Sector of Luzon Region in 2030 with the Implementation of This Project

Item		Unit	Total	Light Oil	Kerosene	Heavy Oil	LPG
Share of existing energy consumption by fuel type	Annual energy consumption	-	-	(ℓ)	(ℓ)	(ℓ)	(kg)
				536,023	1,871	1,162,588	57,269
	Heat value per unit volume	kcal/ℓ(kg)	-	9,006	8,767	10,009	12,136
	Total annual heat value	Gcal	17,175	4,827	16	11,636	695
	Energy mix	%	100.0	28.1	0.1	67.8	4.0
CO_2 emission resulted from the consumption of natural gas in 2030	NG demand in 2010	$MMNm^3$	240	–	–	–	–
	NG demand in 2030	$MMNm^3$	960	–	–	–	–
	Annual growth rate of NG (2010-30)	%	7.2	–	–	–	–
	Total NG demand (2021-30)	$MMNm^3$	7,168	–	–	–	–
	Heat value per unit volume of NG	kcal/m^3	11,000	–	–	–	–
	Total heat value of NG (2021-30)	Gcal	78,848,000	–	–	–	–
	Conversion factor for NG to CO_2	t-CO_2/Gcal	0.20675	–	–	–	–
	Total CO_2 emission (2021-30) (A)	t-CO_2	16,301,824	–	–	–	–
CO_2 emission to be reduced by using LNG in 2030	Heat value of fuels to be replaced by NG (2021-30)	Gcal	78,848,000	22,161,778	75,303	53,420,230	3,190,688
	CO_2 conversion factor by fuel type	t-CO_2/Gcal	–	0.28748	0.28411	0.29992	0.24758
	Total CO_2 emission (2021-30) (B)	t-CO_2	23,204,208	6,371,068	21,394	16,021,795	789,951
	Total CO_2 emission reduction (B-A)	t-CO_2	6,902,384	–	–	–	–

Source: 1. Heat value per unit volume of natural gas: Heat value per unit volume of imported LNG

2. Conversion factors for natural gas to CO_2, heat value per unit volume and CO_2 conversion factor of the other fuel types:

"The Energy Data and Modeling Center, IEEJ, "Handbook of Energy & Economic Statistics in Japan 2011"

Chapter 4　Natural Gas Demand

4.1　Review of JICA M/P(2002)

4.1.1　Energy Policy

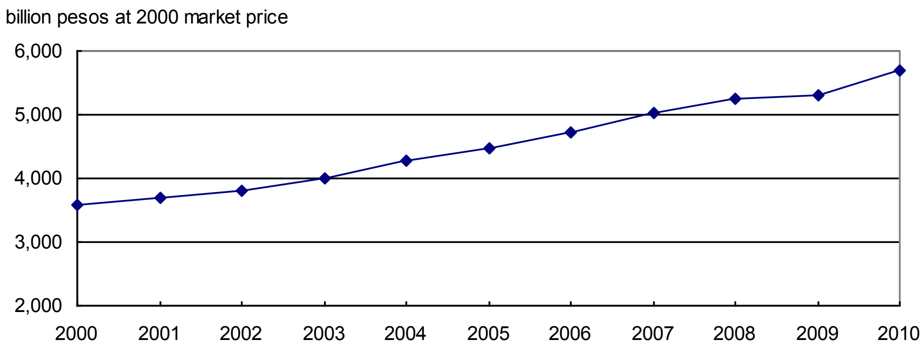
The accelerated development of indigenous energy was one of the most important energy policy directions in the Philippines, mainly because it was importing nearly 60% of primary energy consumption from foreign countries in1999. Thus, it was expected that natural gas, commercial reserves of which have been proved in the sea off the Palawan Island, would be one of promising energy sources for solving the problem of developing indigenous energy, and it would open the door for a large scale utilization of natural gas.

According to "Philippine Energy Plan 2000-2009," which was prepared by the Department of Energy, the share of natural gas in primary energy consumption expected to increase from only 0.01% in 1999 to 5.97% in 2004 and 5.72% in 2009. In addition, increased oil production from oil fields around Palawan Island and others was also forecasted. Such increases in oil and gas production were foreseen to reduce the dependency of the imported energy to 45.8% in 2004 and 52.7% in 2009, although dependency would increase again during the period from 2004 to 2009.

The share of natural gas supply to total primary energy supply, however, increased to 5.1% in 2004 and 8.1% in 2009. The dependency of the imported energy reduced to 45.8% in 2004 and 40.5% in 2009. Natural gas will provide for the structural change in the country's energy mix and strengthen the fuel diversification program. It will also add to energy security position and sustainable development. Philippines still considers natural gas as important fuel. Policy on natural gas is not changed.

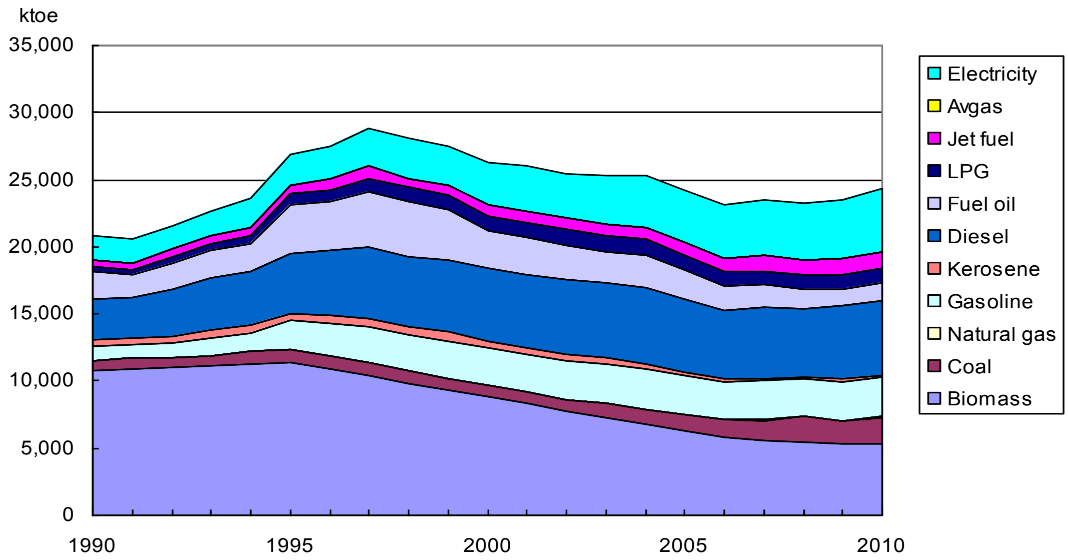
4.1.2　Energy Demand

In the master plan in 2002, it was forecasted that the annual growth rate of energy demand would increase at around 5% based on the past trend. However, actual energy demand from 2000 to 2010 decreased even though the average GDP growth rate increased at 4.8%. The share of natural gas supply to total primary energy supply, however, increased to 5.1% in 2004 and 8.1% in 2009. The dependency of the imported energy reduced to 45.8 in 2004 and 40.5% in 2009. The cause is that biomass rapidly decreased in this period. The growth rate of energy excluding biomass remains at 0.5%. Looking at energy demand by sector, annual growth rate of residential sector was minus 5% and other sectors were flat. It is considered that industry structure changed from heavy industry to light industry.



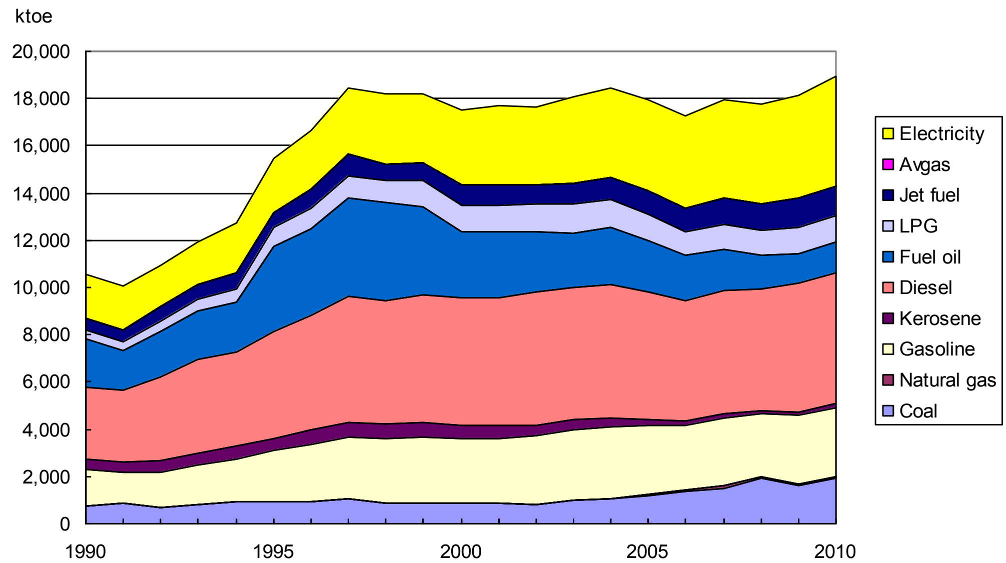
Source: ADB

Figure 4.1-1 Trend of GDP in the Philippines



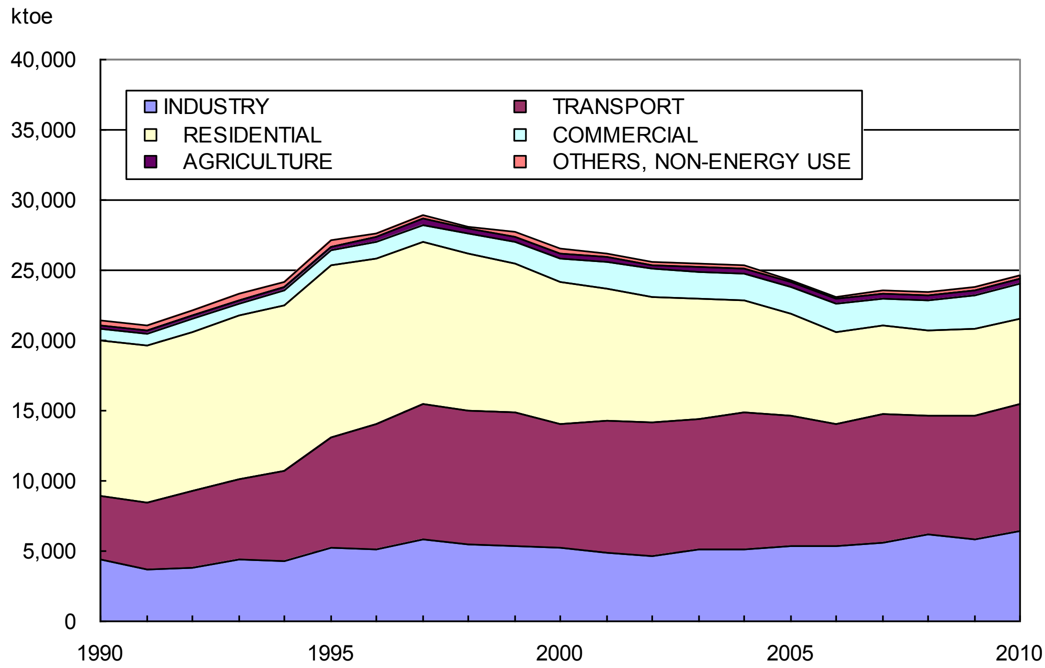
Source: Energy Balance Table, DOE

Figure 4.1-2 Trend of Final Energy Consumption in the Philippines



Source: Energy Balance Table, DOE

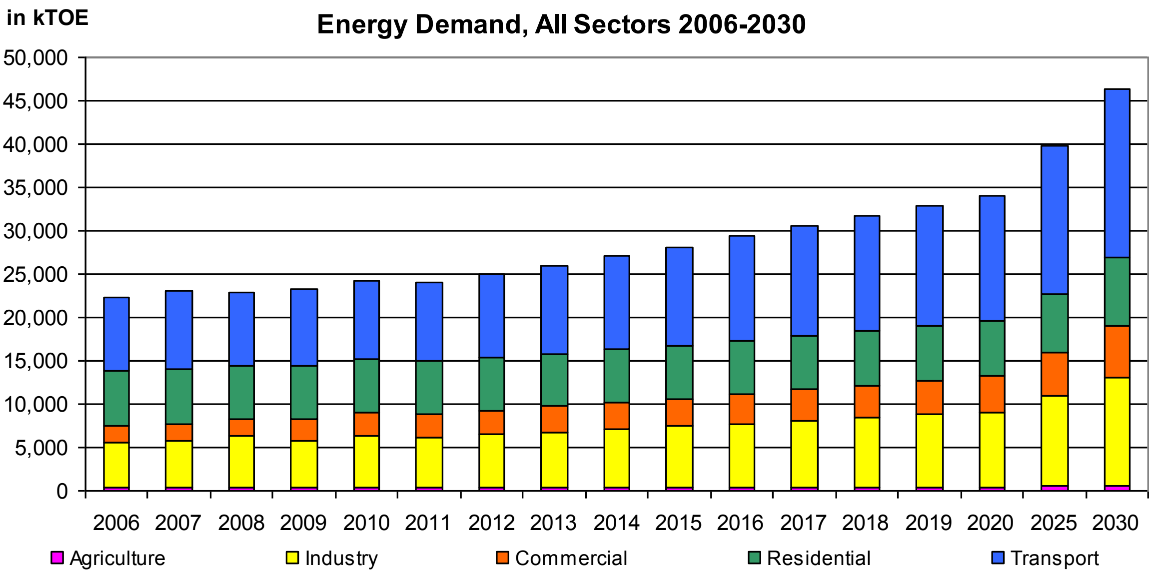
Figure 4.1-3 Trend of Final Energy Consumption excluding Biomass



Source: Energy Balance Table, DOE

Figure 4.1-4 Trend of Final Energy Consumption by Sector

Figure 4.1-5 shows the final energy consumption by sector up to 2030 forecasted by DOE. Average growth rate of total energy is forecasted at 3.3%, agriculture of 1.8%, industry of 3.8%, commercial of 4.1%, residential of 1.2%, and transport of 3.9%.

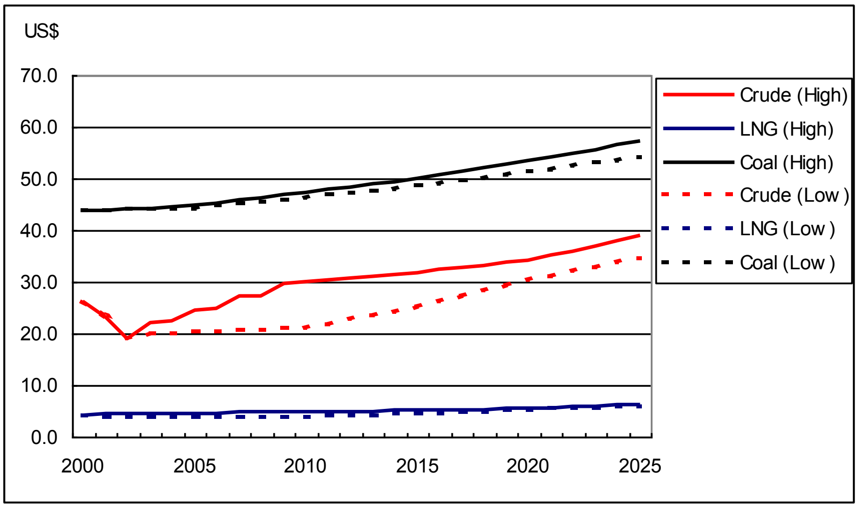


Source: DOE

Figure 4.1-5 Forecast of Final Energy Consumption by Sector

4.1.3 Energy Prices

Figure 4.1-6 shows energy price assumption as of 2002. At the time, it was assumed that crude oil price in 2010 is US$30/bbl and LNG price is US$5/MMBtu. However, actually, both fuel prices became three times compared with past assumption. It is also indicated that price gap between petroleum products and LNG becomes three times. This shows that LNG becomes more competitive than petroleum products.



Note: Crude Oil: US$/bbl, LNG: US$/MMBtu, Coal: US$/ton
Source: : A Master Plan Study on The Development of the Natural Gas Industry in The Philippines, 2002

Figure 4.1-6 Energy Price Assumption as of 2002

4.2 Current Situation of Gas Supply and Demand

Camago-Malampaya gas field that started commercial operation from 2002 is supplying natural gas to industry sector, transport sector, and three power stations such as Ilijan, Sta. Rita, and San Lorenzo at Batangas. Most natural gas is consumed by power stations. Natural gas consumption for industry and transport sectors is less than 2% of total consumption only. Accumulated gas consumption from Camago-Malanpaya gas field up to 2010 reached 929 billion cubic feet (cf) as shown in Table 4.2-1.

Table 4.2-1 Gas Consumption from Camago-Malanpaya Gas Field

(MMcf)

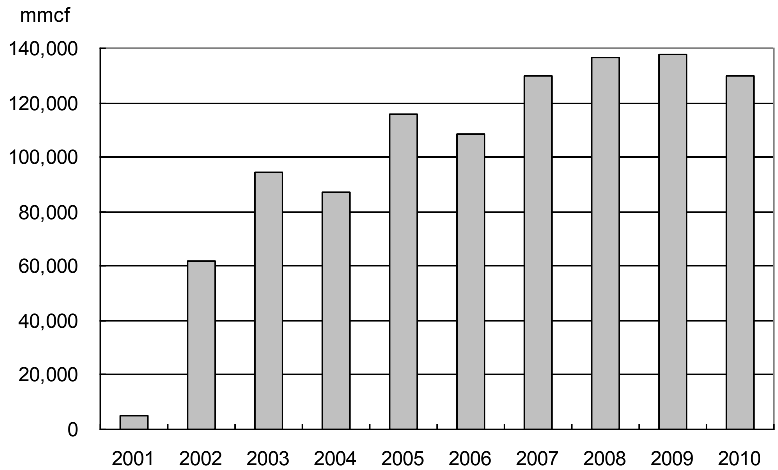
Year	Consumption						
	Power				Industry	Transport	Total
	Ilijan	Sta.Rita	San Lorenzo	Sub-total			
2001	245	4,594	-	4,840	-	-	4,840
2002	17,196	29,772	7,360	54,329	-	-	54,329
2003	26,863	37,990	19,388	84,241	-	-	84,241
2004	25,954	38,006	17,138	81,097	-	-	81,097
2005	39,957	44,777	22,263	106,997	252	-	107,249
2006	34,216	43,429	21,554	99,199	2,193	-	101,392
2007	47,194	47,200	23,398	117,792	3,316	-	121,107
2008	48,704	50,005	24,895	123,604	2,932	15	126,550
2009	51,854	48,758	24,446	125,058	3,019	18	128,095
2010	47,378	46,672	22,759	116,809	3,044	16	119,869
Total	339,562	391,203	183,200	913,965	14,755	49	928,769

Note: MMcf = million cubic feet
Source: DOE

On the other hand, it is said that the reserves of Camago-Malampaya gas field is 2.7 Tcf[8] and accumulated gas production up to 2010 reaches about 1 Tcf. Therefore, R/P ratio of the gas field is only 15 years without new additional reserves. If BatMan 1 gas pipeline is constructed, the gas demand for industry and power sectors will be increased in the future. When considering production plan of Camago-Malampaya gas field, BatMan 1 pipeline will

[8] http://malampaya.com/?page_id=2

received only gas on the equivalent of 100 MW (14,000 Nm^3/h, 500,000 cf/h) from Camago-Malampaya gas field. So, most gas that is supplied by BatMan 1 will be imported natural gas.

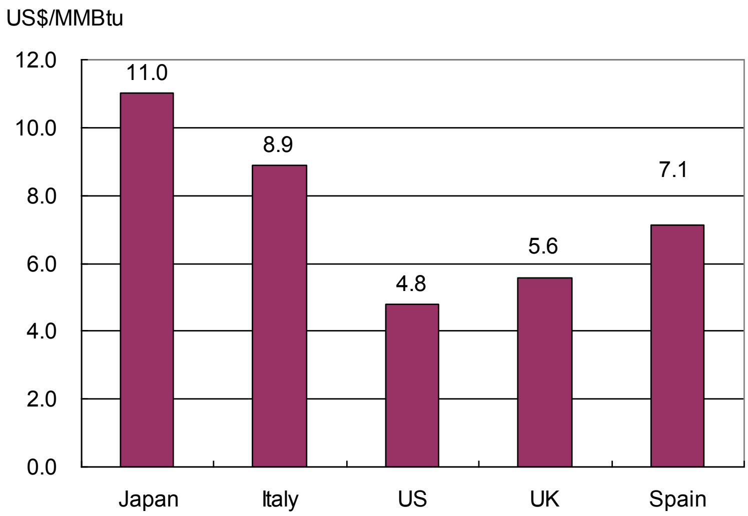


Source: DOE

Figure 4.2-1 Production Trend of Camago-Malampaya Gas Field

4.3 International Trends of LNG Price

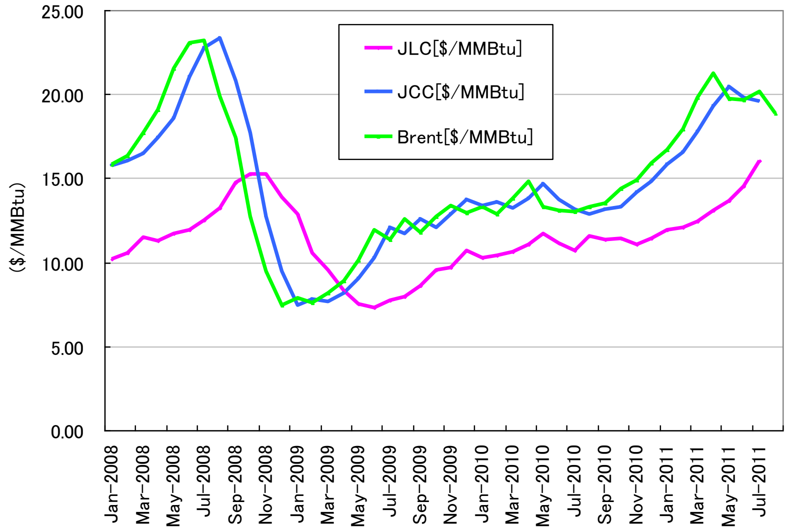
Major markets of natural gas are North America, Europe, and Asia as well as oil markets. Each region has different price formula of natural gas. Natural gas does not have gas price benchmark like WTI, Brent, Dubai as oil price. In general, import LNG price in Asia links to average crude oil CIF price in Japan that is called "JCC: Japan Crude Cocktail". In case of Europe, pipeline natural gas price and import LNG price link to petroleum products price and Brent. In case of USA and UK, natural gas price depends on supply and demand. Therefore, natural gas prices vary from region to region as shown in Figure 4.3-1.



Source : OECD/IEA, ENERGY PRICES & TAXES, 1st Quarter 2011

Figure 4.3-1 Comparison of Import LNG Price (2010)

LNG price in Japan (JLC) gradually increases along with crude oil price and reaches US$16/MMBtu as of July 2011. Figure 4.3-2 shows price trends among JLC, JCC and Brent. JLC remains at a low level than JCC. JLC price will become a price indicator as imported LNG price in Philippines at present. The JLC price is applicable only for Asian LNG market which makes its pricing mechanism different from Europe and USA. In the future, Philippines will not limit sourcing its supply of LNG in Asia but also consider other supply sources such as Russia, Australia and Canada which has a different pricing mechanism against the Asian LNG market.



Source : Handbook of Energy Economic Statistics in Japan, IEEJ

Figure 4.3-2 Price Trends among JLC, JCC and Brent

4.4 Gas Demand for Power Sector

4.4.1 Power Supply and Demand up to 2030

According to Power Development Plan (PDP2010-2030), electricity demand in Luzon will increase at 4.59% annual. Total plant capacity and peak demand in 2010 were 10,197 MW and 7,799 MW respectively. Some power plants are committed from 2011 to 2013. Additional potential gas demand for power sector will arise after 2014. Luzon is required additional capacity with 12,300 MW until 2030 according with increasing power demand. Required reserve margin is set at 23.4% of peak demand.

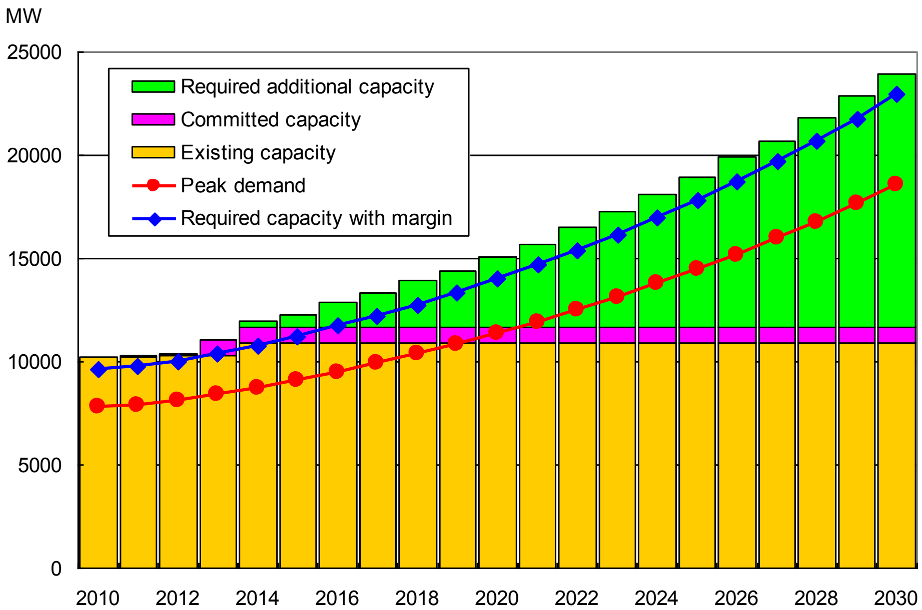
Committed power plants are BACMAN Unit 1 (55MW) and Unit 4 (20MW) in 2011, BacMan Unit 3 (55MW) in 2012, and Coal-Fired GN Power (600MW) in 2013. When these power plants start operation, total plant capacity in Luzon in 2014 will reach 10,927 MW and required capacity (peak demand + reserve margin = 10,728 MW) will be covered. Figure 4.4-2 shows trends of power generation by power sources in Philippines. Power generation increased from 45,290 GWh in 2000 to 67,743 GWh in 2010 at 4.1% of annual growth rate.

Table 4.4-1 Power Supply and Demand Forecast in Luzon

(MW)

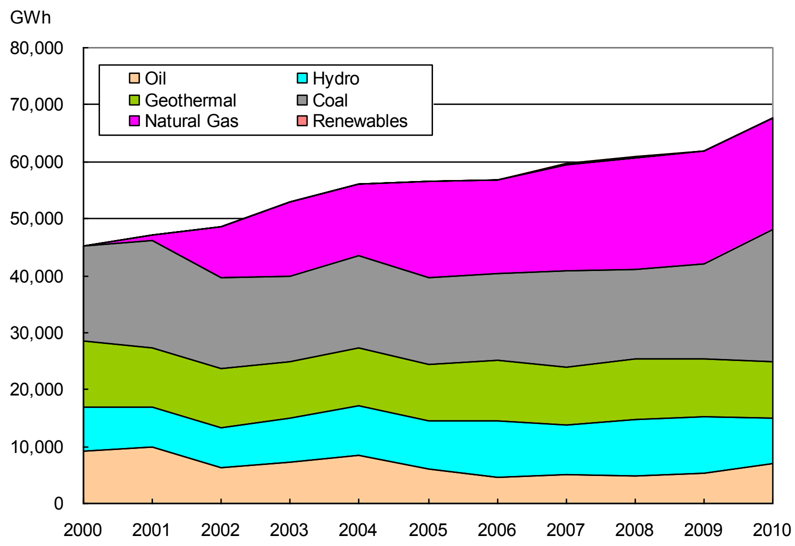
	Required additional capacity	Committed capacity	Existing capacity	Required reserve margin	Peak demand
2010			10,197	1,825	7,799
2011		75	10,197	1,847	7,895
2012		55	10,272	1,890	8,078
2013		600	10,327	1,966	8,400
2014	300		10,927	2,045	8,737
2015	300		10,927	2,128	9,095
2016	600		10,927	2,220	9,489
2017	450		10,927	2,317	9,902
2018	600		10,927	2,420	10,341
2019	500		10,927	2,535	10,834
2020	650		10,927	2,657	11,354
2021	650		10,927	2,786	11,905
2022	800		10,927	2,922	12,486
2023	800		10,927	3,066	13,102
2024	800		10,927	3,218	13,754
2025	800		10,927	3,380	14,444
2026	1,000		10,927	3,551	15,176
2027	800		10,927	3,733	15,952
2028	1,100		10,927	3,925	16,775
2029	1,050		10,927	4,130	17,650
2030	1,100		10,927	4,347	18,578

Source: Power Development Plan, DOE



Source: Power Development Plan, DOE

Figure 4.4-1 Power Supply and Demand Forecast in Luzon



Source : DOE Portal

Figure 4.4-2 Trends of Power Generation by Power Sources

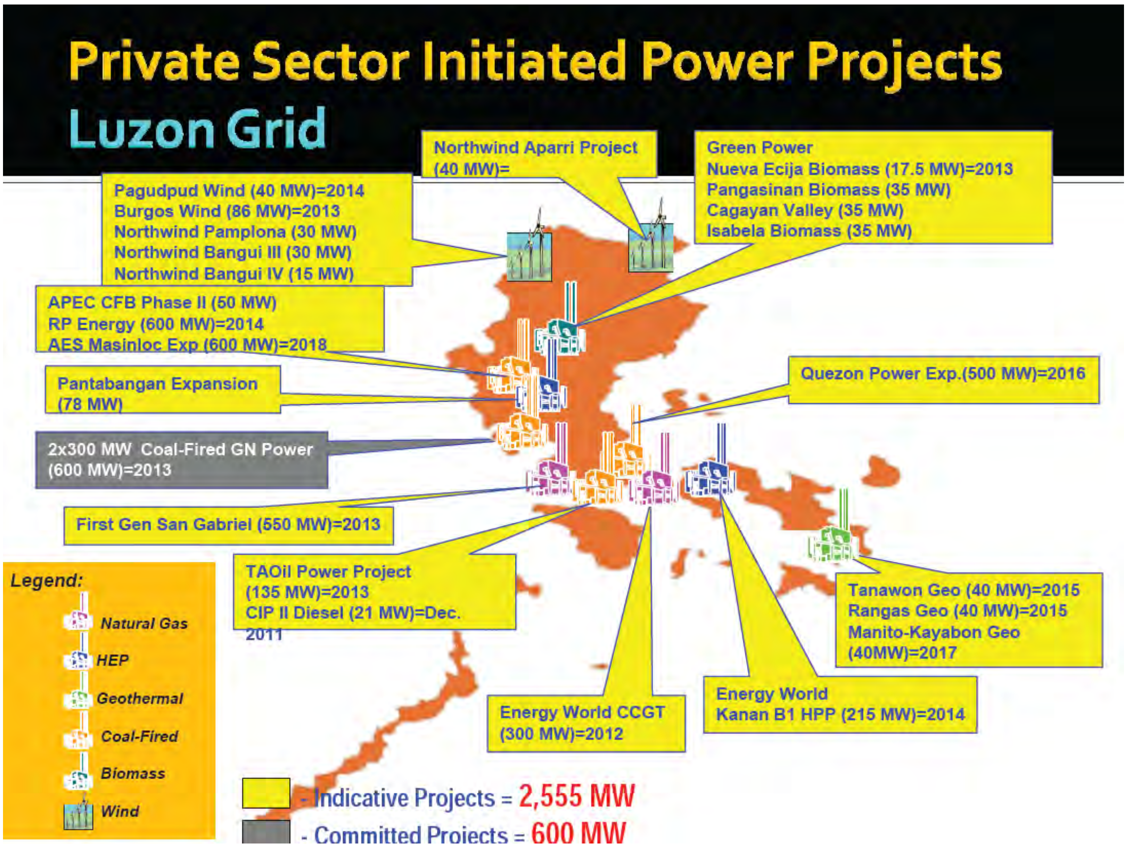
4.4.2 Power Plant Projects by Private Company in Luzon

There are 23 power plant projects by private company in Luzon, of which, gas-fired power plants are Energy World CCGT with 300 MW (Pagbilao) and First Gen San Gabriel with 550 MW (Batangas). Energy World CCGT will consume LNG and First Gen San Gabriel will consume indigenous natural gas. All projects except Energy World CCGT are not started to construct yet. Therefore, planed operating year will be delayed. NA means that planned operating year is not available.

Table 4.4-2 Power Plant Projects by Private Company in Luzon

No.	Name	Capacity (MW)	Type	Planned Operating Year
1	CIP II Diesel	21	Coal	2011
2	Energy World CCGT	300	Natural gas	2012
3	Burgos Wind	86	Wind	2013
4	Nueva Ecija Biomass	17.5	Biomass	2013
5	First Gen San Gabriel	550	Natural gas	2013
6	TAOil Power Project	135	Coal	2013
7	Pagudpud Wind	40	Wind	2014
8	RP Energy	600	Coal	2014
9	Energy World Kanan B1 HPP	215	Hydro	2014
10	Tanawon Geo	40	Geothermal	2015
11	Rangas Geo	40	Geothermal	2015
12	QuezonPower Expansion	500	Coal	2016
13	Manito-Kayabon Geo	40	Geothermal	2017
14	AES Masinloc Expansion	600	Coal	2018
15	Northwind Pamplona	30	Wind	NA
16	Northwind Bangui III	30	Wind	NA
17	Northwind Bangui IV	15	Wind	NA
18	Northwind Aparri Project	40	Wind	NA
19	3Pangasinan Biomass	35	Biomass	NA
20	Cagayan Valley	35	Biomass	NA
21	Isabela Biomass	35	Biomass	NA
22	APEC CFB Phase II	50	Coal	NA
23	Pantabangan Expansion	78	Hydro	NA
	Total	3,533		

Source: Power Development Plan 2010-2030, DOE



Source : Power Development Plan 2010-2030, DOE

Figure 4.4-3 Location of Power Plant Projects by Private Company in Luzon

4.4.3 Examination of Gas –fired Power Plant

As for examination of thermal power plants, gas-fired power plant is only examined because of energy policy (energy diversification) of the Government of Philippines.
According to information from DOE, Sucat Power Plant (850 MW) and Malaya Power Plant (650 MW) are candidate gas conversion power plants. At present, both power plants do not generate. These power plants were oil-fired power plants and thermal efficiency was low at 35% compared with combined cycle power plant. In this section, it is weighed gas conversion of existing power plant against new combined cycle power plant from a economic point of view.

Table 4.4-3 shows precondition of calculation for gas conversion of Sucat Power Plant and new combined cycle power plant. Modification cost for gas conversion is assumed US$24/kW from experience of past another project. Lifetime of Sucat Power Plant is 10 years because of old plant. Thermal efficiency is key indicator for cost analysis. Plant factor is assumed at 80% based on actual performance of existing three combined cycle power plants in Batangas. Generally, it is said that OM cost is 2% of the capital investment cost and OM cost is calculated at 2% of the capital investment cost as shown in Table 4.4-6. Gas price for BatMan 1 is assumed at US$17/MMBtu considering LNG re-gasification cost and pipeline cost (Import LNG price is assumed at US$16/MMBtu).

Table 4.4-4 shows break down of generation cost. Total generation cost of Sucat Power Plant is 16.95 cent/kWh. On the other hand, that of new combined cycle power plant becomes 12.53 cent/kWh. New combined cycle power plant is economical than Sucat Power Plant. Therefore, new combined cycle power plant is recommended from an economic point of view.

Table 4.4-5 and 4.4-6 show details of calculation.

Table 4.4-3 Precondition of Generation Cost

Descriptions	Unit	Sucat	New CCGT
Installed Capacity	MW	850	850
Modification or Construction Cost per kW	US$/kW	24	1,000
Life Time	Years	10	30
Discount Rate	%	10.0%	10.0%
Plant Utilization Factor	%	80%	80%
OM Cost per kWh	USCts/kWh	0.31	0.31
Gas Price	US$/ton	877.00	877.00
Heat Content	kcal/kg	13,000	13,000
Thermal Efficiency	%	35.00%	55.00%

Note：US$17/MMBtu, 51.6 MMBtu/ton

Table 4.4-4 Break Down of Generation Cost

Descriptions	Unit	Sucat	New CCGT
Capital Cost per kWh	USCts/kWh	0.06	1.67
OM Cost per kWh	USCts/kWh	0.31	0.31
Fuel Cost per kWh	USCts/kWh	16.58	10.55
Total Generation Cost per kWh	USCts/kWh	16.95	12.53

Table 4.4-5 Generation Cost for Sucat Power Plant

Descriptions	Unit	
1. Total Construction Cost (2.x3.)	1000 US$	19,200
2. Installed Capacity	MW	800
3. Modification Cost per kW	US$/kW	24
4. Interest during Construction (3.x7.)	US$/kW	0
5. Total Investment per kW (3.+4.)	US$/kW	24
6. Life Time	Years	10
7. Discount Rate	%	10.0%
8. Capital Recovery Factor		0.16275
9. Annual Capital Cost per kW (5.x8.)	US$/kW	3.9
10. Plant Utilization Factor	%	80%
11. Annual Operation Hour (365x24x10.)	hours	7,008
12. Capital Cost per kWh (9./11.x100)	USCts/kWh	0.06
13. OM Cost per kWh (same as New CCG	USCts/kWh	0.31
14. Gas Price	US$/ton	877.00
15. Heat Content	kcal/kg	13,000
16. Thermal Efficiency	%	35.00%
17. Heat Rate (860/16.)	kcal/kWh	2,457
18. Fuel Consumption per kWh (17./15.)	kg/kWh	0.189
19. Fuel Cost per kWh (14.x18./1000x100	USCts/kWh	16.58
20. Total Generation Cost (12.+13.+19.)	USCts/kWh	16.95

Table 4.4-6 Generation Cost of New Combined Cycle Power Plant

Descriptions	Unit	
1. Total Construction Cost (2.x3.)	1000 US$	850,000
2. Installed Capacity	MW	850
3. Construction Cost per kW	US$/kW	1,000
4. Interest during Construction (3.x7.)	US$/kW	100
5. Total Investment per kW (3.+4.)	US$/kW	1,100
6. Life Time	Years	30
7. Discount Rate	%	10.0%
8. Capital Recovery Factor		0.10608
9. Annual Capital Cost per kW (5.x8.)	US$/kW	117
10. Plant Utilization Factor	%	80%
11. Annual Operation Hour (365x24x10.)	hours	7,008
12. Capital Cost per kWh (9./11.x100)	USCts/kWh	1.67
13. OM Cost per kWh (5./11.x2%x100)	USCts/kWh	0.31
14. Gas Price	US$/ton	877.00
15. Heat Content	kcal/kg	13,000
16. Thermal Efficiency	%	55.00%
17. Heat Rate (860/16.)	kcal/kWh	1,564
18. Fuel Consumption per kWh (17./15.)	kg/kWh	0.12
19. Fuel Cost per kWh (14.x18./1000x100)	USCts/kWh	10.55
20. Total Generation Cost (12.+13.+19.)	USCts/kWh	12.53

Note: US$17/MMBtu, 51.6 MMBtu/ton

4.4.4 Gas Demand for Gas-fired Power Plant

If the power plant projects by private company came off new combined cycle power plant will be required after 2020 according with increasing electricity demand. One unit of combined cycle power plant assumes 350 MW (gas turbine: 300 MW, steam turbine: 50 MW) as standard. Two units start operation in 2022 and another two units start operation in 2025. Total capacity of combined cycle power plant is assumed at 1,400 MW.

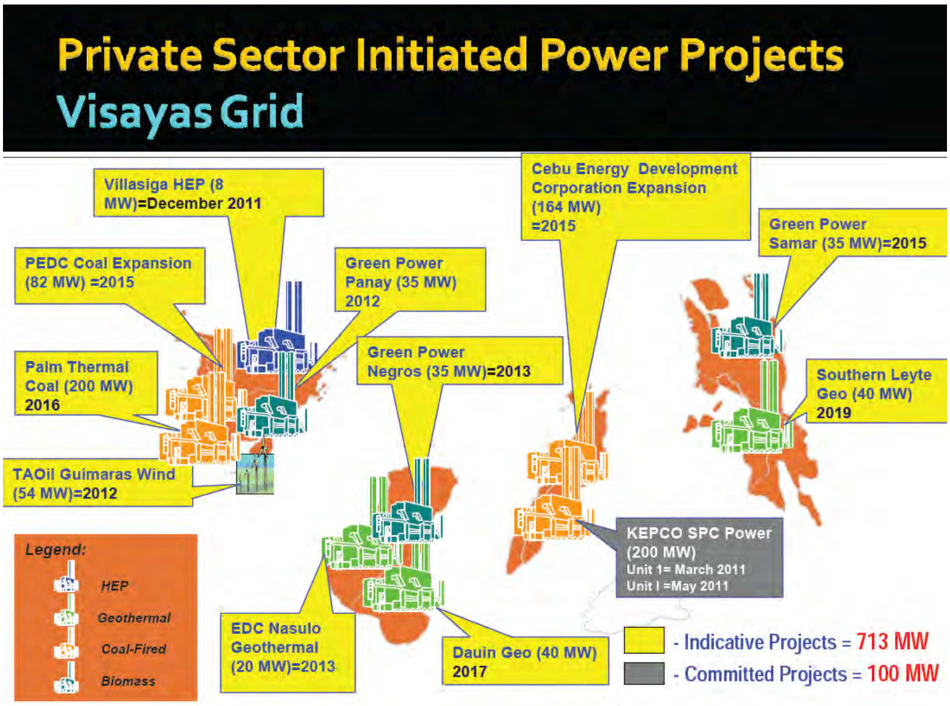
Natural gas consumption for new combined cycle power plant reaches 99,504 Nm^3/h (84 MMcf/d) in 2022 and 199,008 Nm^3/h (168 MMcf/d) after 2025 as shown in Table 4.4-7 under assumptions such as thermal efficiency at 55%, plant factor at 80%, and natural gas heat rate at 11,000 $kcal/Nm^3$. This demand accounts for 26% of Camago-Malampaya gas supply capacity (650 MMcf/d).

Table 4.4-7 Gas Consumption for New Combined Cycle Power Plant

2022		2025	
99,504	Nm3/h	199,008	Nm3/h
3,513,959	cf/h	7,027,917	cf/h
84,335,006	cf/d	168,670,012	cf/d
697	million Nm3/y	1,395	million Nm3/y
24,626	million cf/y	49,252	million cf/y

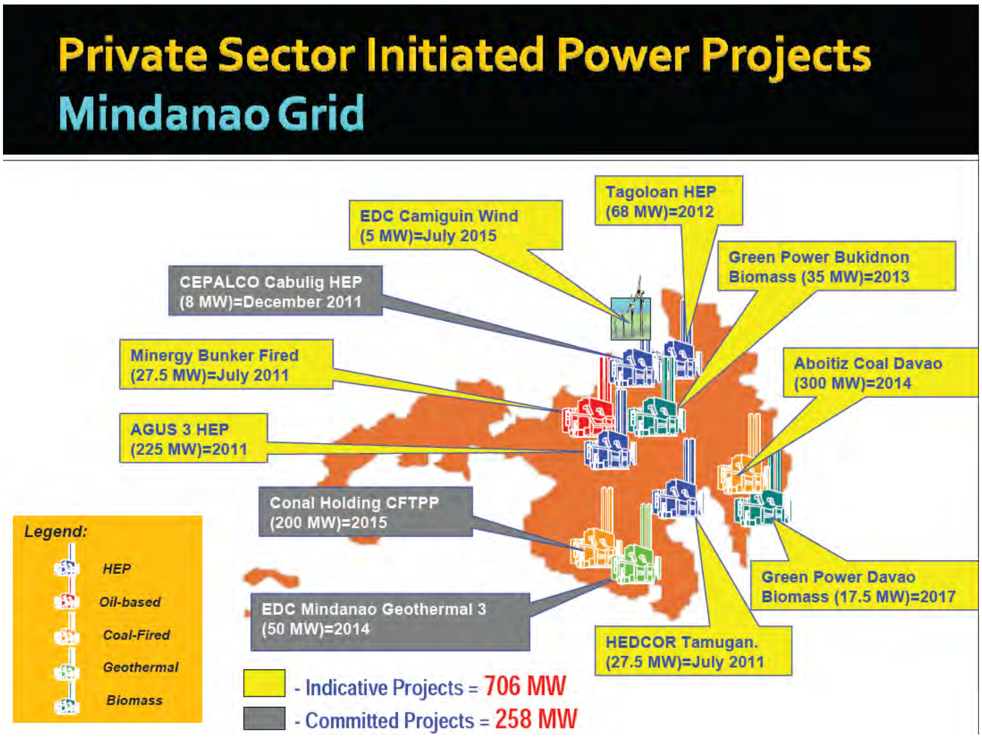
4.4.5 Gas Demand Potential for Power Sector in Visayas and Mindanao

Gas demand potential for power sector depends on the power development plan. According to PDP 2010-2030, there is no plan for gas-fired power plant so far as shown in Figure 4.4-4 and 4.4-5.



Source : PDP2010-2030

Figure 4.4-4 Location of Power Plant Projects by Private Company in Visayas



Source :PDP2010-2030

Figure 4.4-5 Location of Power Plant Projects by Private Company in Mindanao

However, according to information from DOE, there is a 1 MW gas fired power plant that will operate soon in the province of Cebu. Gas supply will be coming from the Libertad gas field. Actually, operation of the power plant was originally scheduled last September 2011, but due to compliance of documentary/regulatory approval, operation of the plant has been delayed and is estimated to operate within 1Q 2012.

4.5 Gas Demand for Industry Sector

Gas demand for industry sector will be estimated by sample survey for industry parks along BatMan 1 gas pipeline. Number of sample survey reached 73 factories. Total number of factories in Laguna and Batangas are estimated about 700 from the area of industry parks and the number of sample survey accounts for about 10% of total factories. At present, factories are consuming petroleum products as fuel. But factories want to use natural gas because the price of petroleum products is higher than that of natural gas as shown in Table 4.5-1.

Table 4.5-1 Fuel Prices

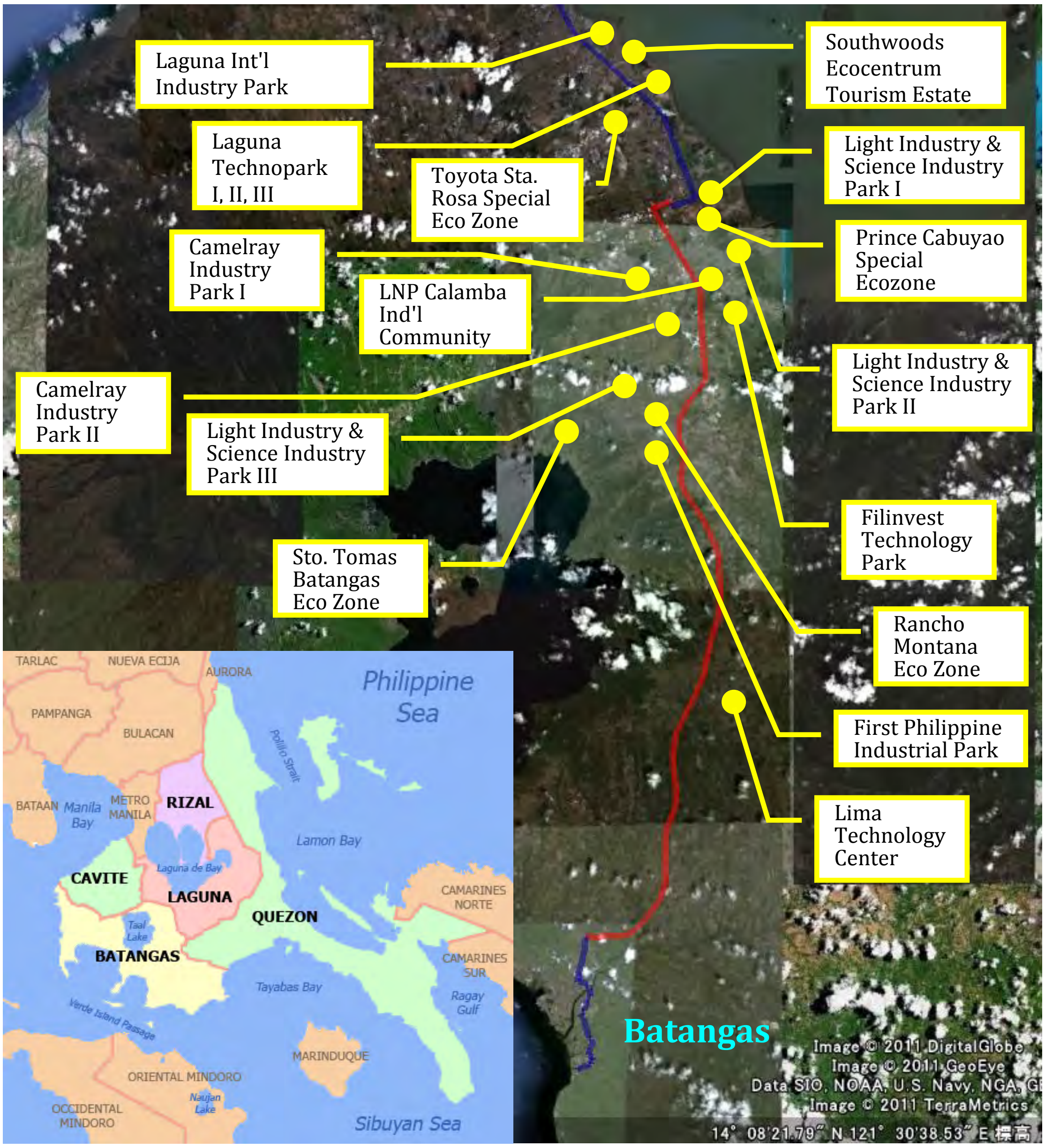
	Original Data		Heat Value		Fuel Price per 10,000 kcal	
Fuel Oil	38.87	PHP/l	10,009	kcal/l	38.84	PHP/10,000 kcal
Natural Gas	9.98	$/MMBtu	252,000	kcal/MMBtu	17.03	PHP/10,000 kcal
Import LNG	17.00	$/MMBtu	252,000	kcal/MMBtu	29.01	PHP/10,000 kcal
LPG	687.5	PHP/11kg	12,136	kcal/kg	51.50	PHP/10,000 kcal
Auto LPG	30.00	PHP/l	12,136	kcal/kg	49.44	PHP/10,000 kcal
Gasoline	53.00	PHP/l	8,266	kcal/l	64.12	PHP/10,000 kcal
Diesel	43.00	PHP/l	9,006	kcal/l	47.75	PHP/10,000 kcal
Kerosene	50.00	PHP/l	8,767	kcal/l	57.03	PHP/10,000 kcal
Coal	3.40	PHP/kg	5,555	kcal/kg	6.12	PHP/10,000 kcal

Note: Natural gas price does not include pipeline cost. Import LNG price includes re-gasification and pipeline costs.
Source: DOE, IEEJ

4.5.1 Industry Park along Gas Pipeline

According to DOE, there are 16 industry parks along planned gas pipeline as shown in Figure 4.5-1. These areas belong to Batangas province and Laguna province in Calabarzon region. Other provinces in Calabarzon region are Cavite Rizal and Quezon provinces.

However, according to web-site of PEZA (Philippine Economic Zone Authority), there are 28 industry parks along the planned gas pipeline (Batangas and Laguna provinces) as shown in Table 4.5-2. If gas supply area is expanded to Cavite province, the number of industry parks increases to 37 parks.



Source: DOE

Figure 4.5-1 Industry Park along Gas Pipeline

Table 4.5-2 Lists of Industry Parks in Calabarzon Region

	Name of Ecozone	Location	Area (ha)	City/Province
1	AG&P Special Economic Zone	San Roque, Bauan, Batangas	40.3	Batangas
2	Cocochem Agro-Industrial Park	Aplaya & Danglayan , Bauan, Batangas	42.0	Batangas
3	First Philippine Industrial Park	Barangays Ulango and Laurel, Tanauan City and Sta. Anastacia, Sto. Tomas, Batangas	331.9	Batangas
4	Keppel Philippines Marine Special Economic Zone	Barangay San Miguel, Bauan, Batangas	22.9	Batangas
5	Light Industry & Science Park III	San Rafael & Sta Anastacia, Sto. Tomas, Batangas	110.5	Batangas
6	Lima Technology Center	San Lucas, Bugtong na Pulo & Inosluban, Lipa City and Santiago & Payapa, Malvar, Batangas	280.2	Batangas
7	Philtown Technology Park	Trapiche, Pagaspas & Baloc-Baloc, Tanauan, Batangas	66.6	Batangas
8	Robinsons Place Lipa	JP Laurel National Highway, Mataas na Lupa, Lipa City	6.5	Batangas
9	Saint Frances Cabrini Medical Tourism Park	Maharlika Highway, Sto. Tomas, Batangas	1.2	Batangas
10	Tabangao Special Economic Zone	Tabangao, Batangas	86.0	Batangas
11	Allegis Information Technology Park	Tulo, Calamba City, Laguna	5.7	Laguna
12	Calamba Premiere International Park	Batino, Parian and Barandal, Calamba City, Laguna	65.6	Laguna
13	Carmelray Industrial Park	Canlubang, Calamba City, Laguna	80.0	Laguna
14	Carmelray Industrial Park II	Punta & Tulo, Calamba City, Laguna	143.0	Laguna
15	Carmelray International Business Park	Canlubang, Calamba City, Laguna	40.0	Laguna
16	Filinvest Technology Park - Calamba	Punta, Burol & Bubuyan, Calamba City, Laguna	51.1	Laguna
17	Greenfield Automotive Park	Don Jose, Sta. Rosa City, Laguna	65.9	Laguna
18	Laguna International Industrial Park	Ganado & Mamplasan, Biñan City, Laguna	34.9	Laguna
19	Laguna Technopark	Sta. Rosa and Biñan City, Laguna	314.9	Laguna
20	Laguna Technopark Annex	Barangay Biñan, Biñan City, Laguna	29.0	Laguna
21	Lakeside EvoZone	Barangays Don Jose and Sto. Domingo, Sta. Rosa City, Laguna	46.0	Laguna
22	Light Industry & Science Park I	Diezmo, Cabuyao, Laguna	68.4	Laguna
23	Light Industry & Science Park II	Real & La Mesa, Calamba City, Laguna	69.1	Laguna
24	Robinsons Place Sta. Rosa	Brgy. Tagapo, Sta. Rosa City, Laguna	0.5	Laguna
25	SMPIC Special Economic Zone	Barangay Paciano Rizal, Calamba City, Laguna	3.3	Laguna
26	Sta. Rosa Commercial IT Park	Barrio San Jose, Sta. Rosa City, Laguna	1.1	Laguna
27	Toyota Sta. Rosa (Laguna) Special Economic Zone	Pulong Sta. Cruz, Sta. Rosa City, Laguna	81.7	Laguna
28	YTMI Realty Special Economic Zone	Brgy. Makiling, Calamba City, Laguna	20.7	Laguna
29	Golden Mile Business Park	Governor's Drive, Maduya, Carmona, Cavite	45.1	Cavite
30	Cavite Economic Zone	Rosario, Cavite	278.5	Cavite
31	Cavite Economic Zone II	Bacao, Gen. Trias, Cavite	53.7	Cavite
32	Daiichi Industrial Park	Maguyam, Silang, Cavite	55.0	Cavite
33	EMI Special Economic Zone	Anabu II, Imus, Cavite	12.2	Cavite
34	First Cavite Industrial Estate	Langkaan, Dasmariñas, Cavite	71.8	Cavite
35	Gateway Business Park	Javalera, Gen. Trias, Cavite	110.1	Cavite
36	People's Technology Complex	Maduya, Carmona, Cavite	59.0	Cavite
37	SM City Bacoor	Gen. Aguinaldo cor. Tirona Hway, Brgy. Habay II, Bacoor	4.1	Cavite
38	Eastbay Arts, Recreational and Tourism Zone	San Roque, Angono & Darangan, Binangonan, Rizal	26.7	Rizal
39	Robinsons Big R Supercenter Cainta Junction	Ortigas Avenue Extension, Barangay Sto. Domingo, Cainta, Rizal	2.0	Rizal

Source: http://www.peza.gov.ph/index.php?option=com_content&view=article&id=98&Itemid=119

4.5.2 Energy Consumption of Industry Park

Energy consumption of industry parks will be estimated by sample survey as mentioned before.

(1) Number of Factories in Industry Parks

Total number of operating industry parks are 246, proclaimed industry parks are 99, and developing industry parks are 216. Total number of approved industry parks reaches 561. There are many IT industries, followed by manufacturing, agro-industry, tourism. PEZA discloses lists of locators (factories) in industry park. But this list shows not only operating locators but also proclaimed locators. Therefore, in this report, number of operating locators is estimated from site area.

Table 4.5-3 Number of Industry Parks in Philippines (as of June 2011)

Operating	246	
Manufacturing	64	
I.T.	153	(119 IT Centers & 34 IT Parks)
Tourism SEZ	12	
Medical Tourism Park	1	
Medical Tourism Center	1	
Agro-Industrial EZ	15	
Proclaimed	99	
Manufacturing	26	
I.T.	62	(46 IT Centers & 16 IT Parks)
Tourism SEZ	8	
Agro-Industrial EZ	3	
Development in Progress	216	
Operating and Proclaimed	345	
Approved	561	

Source: Philippine Economic Zone Authority Home Page

The study team visited two industry parks, Laguna Technopark and Light Industry & Science Park II along planned gas pipeline. Laguna Technopark has 160 locators and its site area is 460 ha (this figure is different from Table 4.5-2 published by PEZA). On the other hand, Light Industry & Science Park II has 24 locators and its site area is 70 ha. Average area per one locator of Laguna Technopark is 2.875 ha and that of Light Industry & Science Park II is also 2.875 ha. So the number of factories is assumed site area divided by 3 ha (30,000 m^2) in this report.

Table 4.5-4 shows lists of industry park and site area along planned gas pipeline. Batangas province has 14 industry parks and total site area is 2,029.4 ha. On the other hand, Laguna province has 21 industry parks and total site area is 1,402.3 ha. Total site area of Batangas and Laguna provinces reaches 3,431.7 ha and the number of factories is 1,143 if average site area for one factory is 3 ha.

Table 4.5-4 Lists of Industry Park and Site Area

	Name of Ecozone	Area (ha)	City/Province
1	RLC Economic Zone	87.4	Batangas
2	First Batangas Industrial Park	53.8	Batangas
3	Rancho Montana Ecozone	900.0	Batangas
4	Sto. Thomas Batangas Ecozone	NA	Batangas
5	AG&P Special Economic Zone	40.3	Batangas
6	Cocochem Agro-Industrial Park	42.0	Batangas
7	First Philippine Industrial Park	331.9	Batangas
8	Keppel Philippines Marine Special Economic Zone	22.9	Batangas
9	Light Industry & Science Park III	110.5	Batangas
10	Lima Technology Center	280.2	Batangas
11	Philtown Technology Park	66.6	Batangas
12	Robinsons Place Lipa	6.5	Batangas
13	Saint Frances Cabrini Medical Tourism Park	1.2	Batangas
14	Tabangao Special Economic Zone	86.0	Batangas
	Total in Batangas	2,029.4	
15	Allegis Information Technology Park	5.7	Laguna
16	Calamba Premiere International Park	65.6	Laguna
17	Carmelray Industrial Park	80.0	Laguna
18	Carmelray Industrial Park II	143.0	Laguna
19	Carmelray International Business Park	40.0	Laguna
20	Filinvest Technology Park - Calamba	51.1	Laguna
21	LIIP Calamba Industrial Community	34.9	Laguna
22	Prince Cabuyao Special Ecozone	25.5	Laguna
23	Southwoods Ecocentrum Touriam Estate	76.0	Laguna
24	Greenfield Automotive Park	65.9	Laguna
25	Laguna International Industrial Park	34.9	Laguna
26	Laguna Technopark	460.0	Laguna
27	Laguna Technopark Annex	29.0	Laguna
28	Lakeside EvoZone	46.0	Laguna
29	Light Industry & Science Park I	68.4	Laguna
30	Light Industry & Science Park II	69.1	Laguna
31	Robinsons Place Sta. Rosa	0.5	Laguna
32	SMPIC Special Economic Zone	3.3	Laguna
33	Sta. Rosa Commercial IT Park	1.1	Laguna
34	Toyota Sta. Rosa (Laguna) Special Economic Zone	81.7	Laguna
35	YTMI Realty Special Economic Zone	20.7	Laguna
	Total in Laguna	1,402.3	
	Grand total	3,431.7	

Note: data are obtained by DOE
Source: PEZA and DOE

(2) Fuel Consumption for Factory

Fuel consumption for factories is estimated by sample survey. Table 4.5-5 shows the number of locators (factories) for sample survey by industry class. Most locator along planned gas pipeline is consuming a lot of electricity for manufacturing electric parts. Table 4.5-6 shows total energy consumption per month of the sample survey. Diesel consumption reaches 530,000 liters/month. Of which, 40% of total consumption (210,000 liters) is consumed by vehicles and could not convert to natural gas. Therefore, 320,000 liters of diesel, 1,800 liters of kerosene, 1.16 million liters of heavy fuel oil, and 57,000 kg of LPG have a potential to convert to natural gas. This potential demand is equal to 1.4 million Nm3/month of natural gas. Here, we assumed that 90% of the above fuels will be converted to natural gas because natural gas price is lower than petroleum products. So, total potential demand for natural gas is 1.26 million Nm3 per month.

Table 4.5-5 Number of Samples by Industry Class

PSIC Industry Class	Number of Locators
Basic Metals	1
Chemicals and Chemical Products	5
Electrical Machinery and Apparatus, N.E.C.	1
Electricity, Gas, Steam and Hot Water Supply	1
Fabricated Metal Products, Except Machinery and Equipment	13
Food Products and Beverages	3
Growing of Crops	1
Machinery and Equipment, N.E.C.	3
Manufacturing, N.E.C.	1
Medical, Precision and Optical Instruments, Watches and Clocks	5
Motor Vehicles, Trailers and Semi-Trailers	9
Office, Accounting and Computing Machinery	1
Paper and Paper Products	2
Radio, Television and Communication Equipment and Apparatus	16
Recycling	2
Rubber and Plastic Products	9
Grand Total	73

Source: Sample Survey

Table 4.5-6 Total Energy Consumption per Month of the Sample Survey

Type of Fuel	Total Consumption
Diesel (liters)	536,023
Kerosene (liters)	1,871
Bunker/Heavy Fuel oil (liters)	1,162,588
LPG (kg)	57,269
Electricity from Grid (kWh)	47,712,315

Source: Sample Survey

In order to use natural gas at Industry Park, it is necessary to construct middle pressure gas pipeline. If natural gas demand for one Industry Park is 1.26 million Nm^3/month and the length of middle pressure gas pipeline is 3 km, the capital investment for the middle pressure gas pipeline can recover within one year.

Capital Investment for the middle pressure gas pipeline
Governor: 10 million PHP
3 km gas pipeline: 120 million PHP (40,000PHP/m × 3,000 m)
Total: 130 million PHP

Table 4.5-7 Payback Period for Middle Pressure Gas Pipeline

Year		0	1	2
Cost	PHP	130,000,000		
Consumption/month	Nm3/month		1,260,000	1,260,000
Annual consumption	Nm3/year		15,120,000	15,120,000
Heat value	10,000kcal		16,632,000	16,632,000
Fuel price gap	PHP/10,000kcal		9.8	9.8
Benefit	PHP		163,492,560	163,492,560
Cash Flow		-130,000,000	163,492,560	163,492,560

(3) Potential of Gas Demand along Gas Pipeline

So far, the number of locators (factories) and gas demand potential for 73 locators (1.26 million Nm^3/month) were assumed. Based on these assumptions, potential of gas demand along gas pipeline are as follows.

Number of factories:	1,143 factories
Average gas consumption/73 locators:	1.26 million Nm^3/month (1,750 Nm^3/h, 61,800 cf/h)
Potential of gas demand :	27,400 Nm^3/h （0.968 MMcf/h, 23.23 MMcf/d）
	1,143 locators/73 locators × 1,750 Nm^3/h＝ 27,400 Nm^3/h

The above potential demand is equivalent to 190 MW of combined cycle power plant. There are 561 industry parks approved by PEZA as shown in Table 4.5-3 as of June 2011. The number of Industry Park near future will increase by 2.2 times. After two months later, the number of Industry Park approved by PEZA increased to 580 as of August 2011. Therefore, the number of Industry Park along planned gas pipeline also expects to increase in the same way. Moreover, the occupancy rate of current industry park is about 70%. So the number of locator will expect to increase year by year. From the above reason, gas demand potential along planned gas pipeline in 2030 is assumed at 960 $MMNm^3$/year (1,056 toe/year). According to energy demand forecast by DOE, energy demand for industry sector in 2030 is 12,523 as shown in Table 4.5-8 and the share of gas demand in 2030 accounts for 9.2% including existing gas demand (85 $MMNm^3$/year).

Table 4.5-8 Energy Demand Forecast by DOE

SECTOR	2010	2015	2020	2025	2030	10-15	10-20	10-30
Agriculture	367	403	452	485	519	1.9%	2.1%	1.8%
Industry	5,943	7,024	8,677	10,485	12,523	3.4%	3.9%	3.8%
Commercial	2,678	3,240	4,077	4,907	5,966	3.9%	4.3%	4.1%
Residential	6,184	6,157	6,401	6,869	7,855	-0.1%	0.3%	1.2%
Transport	9,025	11,348	14,412	17,143	19,449	4.7%	4.8%	3.9%
Total	**24,197**	**28,172**	**34,019**	**39,889**	**46,311**	**3.1%**	**3.5%**	**3.3%**

Source: DOE

Looking at Asian countries that natural gas is already used in industry sector, the shares of gas demand for industry sector are 14.1% of Korea, 9.0% of Japan, and 8.7% of Thailand. It is said that 9.2% of Philippines is reasonable.

4.5.3 Gas Demand Potential in Visayas and Mindanao

Gas demand potential for industry sector in Luzon was already mentioned in previous section. Here, gas demand potential for industry sector in Cebu-Mactan and South Mindanao will estimated by energy demand forecast by DOE and regional GDP. Table 4.5-9 shows natural gas demand forecast by regions except power sector as of 2002.

Table 4.5-9 Natural Gas Demand Forecast by Regions except Power Sector (as of 2002)

MMscfd

		2000	2005	2010	2015	2020	2025
Philippine	N	9.92	6.73	37.06	91.55	161.5	237.17
NCR	L1	5.6	3.68	20.6	51.08	90.23	132.59
S.Tagarog	L2	0.96	0.68	3.47	8.38	14.62	21.29
C. Luzon	L3	0.33	0.24	1.27	3.09	5.43	7.94
Cebu Mactan	C-M	0.32	0.23	1.23	3.04	5.35	7.86
S. Mindanao	D	0.33	0.18	1.03	2.56	4.54	6.7
Study Area	Total	7.54	5.01	27.6	68.16	120.17	176.37

Source: A Master Plan Study on The Development of the Natural Gas Industry in The Philippines, 2002

(1) Regional GDP

Philippines are divided by 16 regions as shown in Figure 4.5-2 and each region has economic statistics. Cebu-Mactan belongs to Region 7 (Central Visayas) and South Mindanao belongs to Region 11 (Davao Region). Table 4.5-10 shows the breakdown of regional GDP in 2009. Regional GDP for industry sector in Region 7 accounts for 6.6% of total GDP and that in Region 11 is 5.2%.

Table 4.5-10 Breakdown of Regional GDP in 2009

Region	Agri. Fishery Forestry		Industry		Service		Total	
	million Pesos	%	million Pesos	%	million Pesos	%	million Pesos	%
NCR Metro Manila	5	0.0	789,261	34.0	2,024,536	48.0	2,813,836	36.6
CAR Cordillera	18,152	1.6	79,414	3.4	51,884	1.2	149,455	1.9
Region 1 Ilocos	67,482	5.9	38,492	1.7	109,100	2.6	215,081	2.8
Region 2 Cagayan Vallet	58,305	5.1	24,746	1.1	55,821	1.3	138,878	1.8
Region 3 Central Luzon	114,392	10.0	185,775	8.0	276,383	6.5	576,568	7.5
Region 4-A Calabarzon	152,838	13.4	270,644	11.7	379,356	9.0	802,863	10.5
Region 4-B Mimaropa	61,591	5.4	61,117	2.6	39,278	0.9	161,994	2.1
Region 5 Bicol	36,560	3.2	68,567	3.0	107,973	2.6	213,106	2.8
Region 6 Western Visayas	100,579	8.8	176,447	7.6	266,115	6.3	543,157	7.1
Region 7 Central Visayas	45,506	4.0	153,606	6.6	319,218	7.6	518,340	6.7
Region 8 Eastern Visayas	50,741	4.5	54,194	2.3	68,391	1.6	173,332	2.3
Region 9 Zamboanga Peninsula	73,953	6.5	40,859	1.8	71,621	1.7	186,441	2.4
Region 10 Northern Mindanao	112,719	9.9	126,772	5.5	150,133	3.6	389,640	5.1
Region 11 Davao Region	81,646	7.2	120,910	5.2	165,348	3.9	367,916	4.8
Region 12 Soccsksargen	100,296	8.8	85,688	3.7	72,952	1.7	258,949	3.4
ARMN Muslim Mindanao	33,769	3.0	6,663	0.3	25,301	0.6	65,736	0.9
Region 13 Caraga	29,800	2.6	35,728	1.5	38,294	0.9	103,826	1.4
Total	1,138,334	100.0	2,318,882	100.0	4,221,701	100.0	7,679,117	100.0

Source: Gross Regional Domestic Product 2007-2009, NSCB

Source: http://www.philippines-travel-guide.com/philippine-regions.html

Figure 4.5-2 16 Regions in Philippines

(2) Gas demand potential in Cebu-Mactan and South Mindanao

Table 4.5-11 shows energy demand forecast for industry sector up to 2030. Energy demand for industry sector will increase from 1,453 ktoe in 2010 to 3,888 ktoe in 2030 at 5% of annual growth rate. When energy demand is allocated by regional GDP, energy demand for industry sector in Cebu-Mactan in 2030 is 826 ktoe and that in South Mindanao is 651 ktoe. Of which, if 9.2% of energy demand can convert to natural gas in the same way of Luzon's estimation, natural gas demand in Cebu-Mactan reaches 69 MMNm^3/year (6.7 MMcfd) and that in South Mindanao is 54 MMNm^3/year (5.3 MMcfd). These figures are smaller than 2002 Master Plan Study, by 15% in Cebu-Mactan and 30% in South Mindanao.

Table 4.5-11 Energy Demand Forecast for Industry Sector

ktoe

SECTOR/FUEL TYPE	2010	2015	2020	2025	2030	10-15	10-20	10-30
INDUSTRY	**5,943**	**7,024**	**8,677**	**10,485**	**12,523**	**3.4%**	**3.9%**	**3.8%**
Coal	1,834	2,015	2,407	2,865	3,405	1.9%	2.8%	3.1%
Natural Gas	70	70	70	70	70	0.0%	0.0%	0.0%
Petroleum	1,078	1,329	1,597	1,870	2,172	4.3%	4.0%	3.6%
LPG	48	105	191	284	388	17.2%	14.9%	11.1%
Kerosene	15	10	8	6	5	-8.4%	-6.7%	-5.6%
Diesel	325	395	476	564	667	4.0%	3.9%	3.6%
Fuel Oil	690	819	923	1,016	1,112	3.5%	3.0%	2.4%
Biodiesel	10	22	26	31	37	16.5%	10.0%	6.7%
Electricity	1,498	1,804	2,221	2,595	2,950	3.8%	4.0%	3.4%
Biomass	1,453	1,783	2,355	3,053	3,888	4.2%	4.9%	5.0%

Source: DOE

Table 4.5-12 Energy Demand Forecast for Industry in Cebu-Mactan and South Mindanao

ktoe

	2010	2015	2020	2025	2030	Share(%)
Philippines	5,943	7,024	8,677	10,485	12,523	100.0
Cebu-Mactan	392	464	573	692	826	6.6
South Mindanao	309	365	451	545	651	5.2

Cebu-Mactan

826 ktoe --> 826×10^6 kg$\times$10,000 kcal/kg$\div$11,000 kcal/Nm$^3\times$9.2%＝69,000,000 Nm^3

South Mindanao

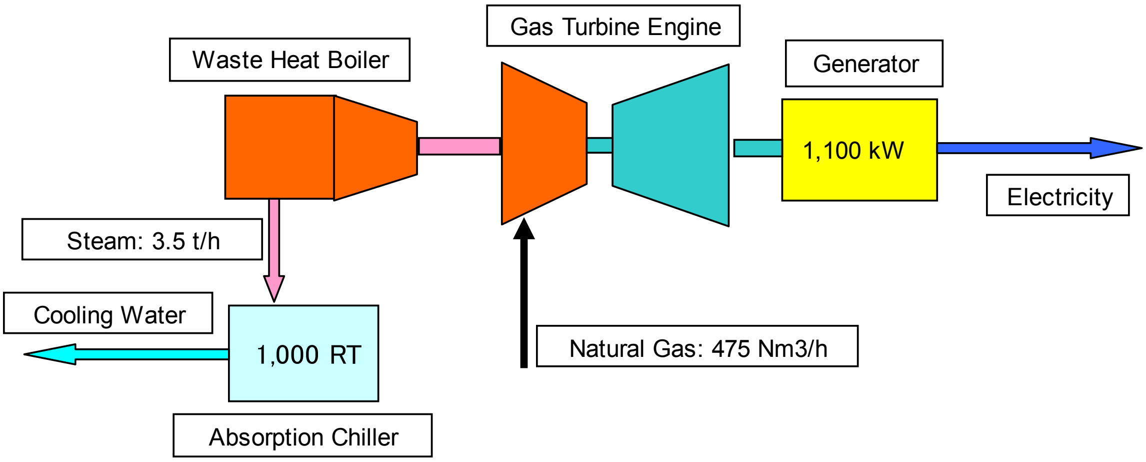
651 ktoe --> 651×10^6 kg$\times$10,000 kcal/kg$\div$11,000 kcal/Nm$^3\times$9.2%＝54,000,000 Nm^3

4.6 Gas Demand for Commercial Sector

There is no gas demand for commercial sector in Philippines. The Philippines is expecting gas demand in commercial sector by introducing heat pump and co-generation system for building. In this section, typical co-generation system in Japan is introduced and gas demand potential for commercial sector will be examined.

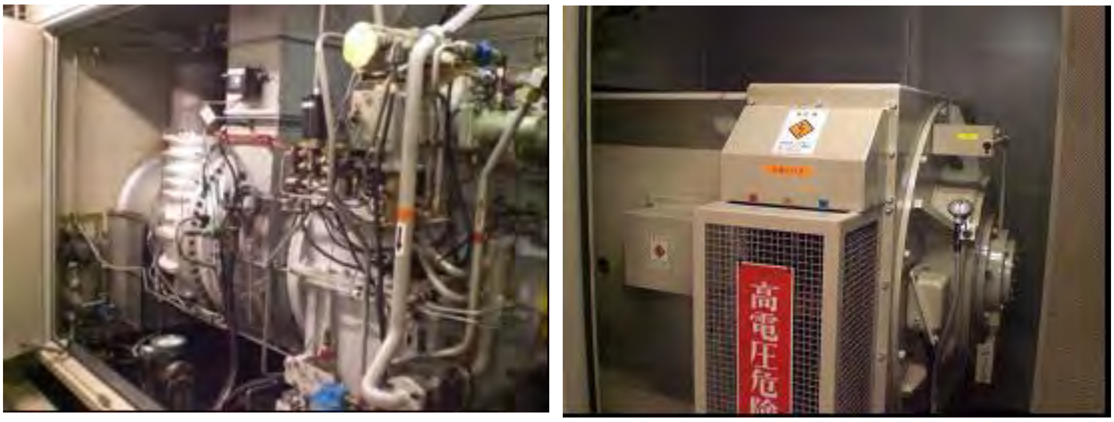
4.6.1 Current Situation of Natural Gas Demand for Commercial Building in Japan

Co-generation system provides electricity and steam by using gas as fuel. Generated electricity and steam are provided to office building that has 40 stories and 150,000 m^2 of total floor space. This system consists of 2 units of gas turbine engine, 1,100 kW generator, and waste heat boiler. Steam from waste heat boiler is sent to absorption chiller and is converted to cooling water as air conditioning. Total efficiency of the system is 70-75% (thermal efficiency is 20-25% and boiler efficiency is 50%).



Note: RT stands for refrigeration ton

Figure 4.6-1 Outline of Co-generation System (1 Unit)



(Left: Gas Turbine Engine, Right: Generator)

Figure 4.6-2 Co-generation System

This system does not operate during the night time and holiday because at that time, the office building does not need steam due to closing building. Required electricity is purchased from utility company during the night time and holiday. Gas consumption during operation for 2 Units is 950 Nm^3/h and the daily gas consumption for 2 units is about 10,000 Nm^3. This co-generation system can cover 30% of total electricity consumption and 50% of energy needed for cooling.

It is recommended to decide introducing the co-generation system at the design stage of the building because the system needs installation site and pipe arrangement.

4.6.2 Current Situation of Energy Demand for Commercial Building in Philippines

There is no heating demand for building in Philippine because it is warm all year round. Only cooling demand is needed. The system that is introduced here, is supplying cooling water to large shopping mall (5 stories and 178,000 m^2 of total floor space, of which 99,000 m^2 is for air conditioning floor space) by electric chillers. This system consists of 6 units of electric chiller (827 RT: Refrigeration Ton) and one unit of electric chiller (415 RT). Usually, three electric chillers (827 RT) is running. Energy for air condition is only electricity and they don't use petroleum products. Estimated electricity consumption for air conditioning is about 800,000 kWh/month.

4.6.3 Estimation of Gas Demand for Commercial Building in Philippines

Future gas demand for commercial buildings is estimated based on the system that is mentioned in section 4.6.2. Two cases of gas demand are estimated. One is a gas fired-absorption chiller. Another is a co-generation system.

<u>Case of gas fired-absorption chiller</u>

827(RT)×3(units)×3.52(kW/RT)×3.6(MJ/kWh)÷40(MJ/Nm^3) = 786(Nm^3/h)

786(Nm^3/h)×11(h)×30(day/month)×12(month/year) = 3,112,560(Nm^3/year)

<u>Case of co-generation system</u>

827(RT)×3(units)÷1,000(RT/unit)×475(Nm^3/h) = 1,178(Nm^3/h)

1,178(Nm^3/h)×11(h)×30(day/month)×12(month/year) = 4,664,880(Nm^3/year)

In case of co-generation system, the system can supply not only cooling water but also electricity as follows.

827(RT)×3(unit)÷1,000(RT)×1,100(kW) = 2,729(kW)

Commercial building can reduce electricity consumption from power grid.

From the above calculation, gas demand potential for one shopping mall has about 3 million Nm^3/year in case of gas fired-absorption chiller and about 5 million Nm^3/year in case of co-generation system. As for potential of gas demand for commercial sector in 2030, it is assumed at 70 million Nm3/year. This is equivalent to 20% of LPG demand in 2030.

4.7 Gas Demand for Transport Sector

In Philippines, CNG buses are operating between Batangas and Laguna as pilot project. At present, there are 61 CNG buses in Philippines and average gas consumption is 1.67-2.0 km/Nm^3 according to information from DOE. There are two gas filling stations, mother station in Batangas and daughter station in Laguna. As for capacity of filling station, mother station is available to fill up gas for 200 buses per day. On the other hand, daughter station can fill up gas for 50 buses per day. Actually, 26 buses are filled up a day. Average filling volume per one bus is 112.9 kg. Price of CNG is PHP18.38/kg. But this price is temporary price for pilot project. After pilot project, this price will be reviewed.

Philippines has the target for promoting CNG buses as shown in Table 4.7-1.

Table 4.7-1 Target Number of CNG Buses in Philippines

Number of CNG Buses (Target)					Diesel Equivalent (million liters)
Year	Luzon	Visayas	Mindanao	Total	
2011	100			100	7.95
2015	1,000			1,000	79.502
2020	1,884	288	328	2,500	198.755
2025	3,768	575	657	5,000	397.51
2030	7,535	1,151	1,314	10,000	795.02

Note: Diesel liter equivalent is based on 254 liters/day at 313 days per annum

Source: DOE

If this target was achieved, gas demand in Luzon for transport sector will be increased as shown in Table 4.7-2.

Table 4.7-2 Gas Demand for CNG Buses in Luzon

Year	Target No. of bus	Total diesel consumption (liters/y)	Total heat value (kcal/y)	Natural gas consumption		
				Nm3/y	Nm3/h	cf/h
2011	100	7,950,200	71,599,501,200	6,509,046	866	30,600
2015	1,000	79,502,000	715,995,012,000	65,090,456	8,665	305,997
2020	1,884	149,781,768	1,348,934,602,608	122,630,418	16,325	576,498
2025	3,768	299,563,536	2,697,869,205,216	245,260,837	32,649	1,152,997
2030	7,535	599,047,570	5,395,022,415,420	490,456,583	65,290	2,305,688

Note: Diesel consumption; 254 liters/day-bus, Annual operating day; 313 days, Diesel heat value; 9,006 kcal/l

4.8 Gas Demand in Luzon

Table 4.8-1 shows gas demand outlook in Luzon up to 2030 based on the assumptions from section 4.4 to 4.7 in this report. Gas demand will increase from 119,869 MMcf in 2010 to 227,990 MMcf in 2030. It is assumed that gas demand for new combined cycle power plant will increase from 2022 as mentioned in section 4.4 and gas demand for industry sector will rise from 2017 when gas pipeline will be completed. Gas demand for transport sector will also rise from 2017 and increase according with the target of DOE. Gas demand for commercial sector will rise from 2020.

Table 4.8-2 shows gas demand outlook in Luzon up to 2030 that is converted from MMcf to MMNm^3.

Table 4.8-1 Gas Demand Outlook in Luzon up to 2030

(MMcf)

Year	Consumption				
	Power	Industry	Transport	Commercial	Total
2001	4,840	-	-	-	4,840
2002	54,329	-	-	-	54,329
2003	84,241	-	-	-	84,241
2004	81,097	-	-	-	81,097
2005	106,997	252	-	-	107,249
2006	99,199	2,193	-	-	101,392
2007	117,792	3,316	-	-	121,107
2008	123,604	2,932	15	-	126,550
2009	125,058	3,019	18	-	128,095
2010	116,809	3,044	16	-	119,869
2011	122,000	3,000	20	-	125,020
2012	122,000	3,000	20	-	125,020
2013	122,000	3,000	20	-	125,020
2014	122,000	3,000	20	-	125,020
2015	122,000	3,000	20	-	125,020
2016	122,000	3,000	20	-	125,020
2017	122,000	19,549	3,111	-	144,660
2018	122,000	20,887	3,517	-	146,404
2019	122,000	22,225	3,923	-	148,148
2020	122,000	23,563	4,331	1,236	151,130
2021	122,000	24,902	5,197	1,360	153,458
2022	146,626	26,240	6,063	1,483	180,412
2023	146,626	27,578	6,929	1,607	182,740
2024	146,626	28,916	7,795	1,730	185,068
2025	171,252	30,255	8,661	1,854	212,022
2026	171,252	31,593	10,393	1,978	215,216
2027	171,252	32,931	12,125	2,101	218,409
2028	171,252	34,269	13,857	2,225	221,603
2029	171,252	35,608	15,589	2,348	224,797
2030	171,252	36,946	17,320	2,472	227,990

Table 4.8-2 Gas Demand Outlook in Luzon up to 2030

(million Nm^3)

Year	Consumption				
	Power	Industry	Transport	Commercial	Total
2001	137	-	-	-	137
2002	1,538	-	-	-	1,538
2003	2,385	-	-	-	2,385
2004	2,296	-	-	-	2,296
2005	3,030	7	-	-	3,037
2006	2,809	62	-	-	2,871
2007	3,335	94	-	-	3,429
2008	3,500	83	0	-	3,584
2009	3,541	85	1	-	3,627
2010	3,308	86	0	-	3,394
2011	3,455	85	1	-	3,540
2012	3,455	85	1	-	3,540
2013	3,455	85	1	-	3,540
2014	3,455	85	1	-	3,540
2015	3,455	85	1	-	3,540
2016	3,455	85	1	-	3,540
2017	3,455	554	88	-	4,096
2018	3,455	591	100	-	4,146
2019	3,455	629	111	-	4,195
2020	3,455	667	123	35	4,280
2021	3,455	705	147	39	4,345
2022	4,152	743	172	42	5,109
2023	4,152	781	196	46	5,175
2024	4,152	819	221	49	5,241
2025	4,849	857	245	53	6,004
2026	4,849	895	294	56	6,094
2027	4,849	933	343	60	6,185
2028	4,849	970	392	63	6,275
2029	4,849	1,008	441	67	6,366
2030	4,849	1,046	490	70	6,456

Chapter 5 LNG Supply-Demand System

5.1 Global LNG Production and Consumption

5.1.1 Global LNG Production and Consumption

Natural gas production grows in every region except Europe, where decline rates at mature fields are likely to reverse the gains since 1975.

Asia accounts for the world's largest production and consumption increments. China drives 56% of the region's consumption growth.

The Middle East has the world's second largest production and consumption increments. The region's share in global consumption is expected to expand from 5% in 1990 and 12% in 2010 to 17% in 2030. Its share in global production grows from 15% in 2010 to 19%.

Despite North America's continued production growth, it is outpaced by other regions and its share in the global total declines from 26% in 2010 to 19% in 2030.

FSU and African production grows strongly to meet export demand.

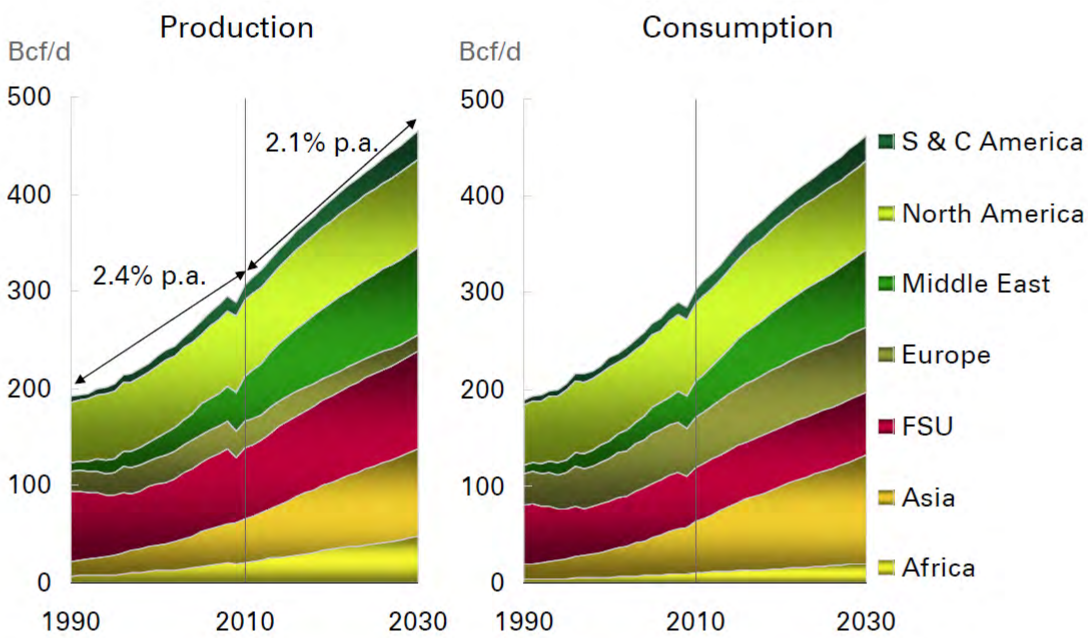


Figure 5.1-1 Production and Consumption of Natural Gas

Source: BP statics, January 2011

5.1.2 LNG Exports and Imports

LNG supply is projected to grow 4.4% p.a. to 2030, more than twice as fast as total global gas production (2.1% p.a.). Its share in global gas supply increases from 9% in 2010 to 15% in 2030

The expansion is in three phases. The first (2009-2011) is predominantly from the Middle East and adds 10 BCF/d (44%) of LNG. This overhang will dissipate as demand grows and the next significant wave does not occur until 2015. Half of the 10 BCF/d (29%) growth in the period 2015-2017 is on the start of major Australian projects. The phase to 2030 is largely determined by demand, with 41% of supply coming from Africa.

Demand is driven by Europe (5.2% p.a., 36% of the global increment) and non-OECD Asia (8.2% p.a., also 36% of the increment). In Europe, the share of LNG in total imports expands from 30% to 42%. In non-OECD Asia, 74% of the demand growth is from China and India.

Middle East net LNG exports could decline after 2020 as regional import growth outweighs output growth from traditional exporters. Australia overtakes Qatar as the world's largest LNG exporter around 2020.

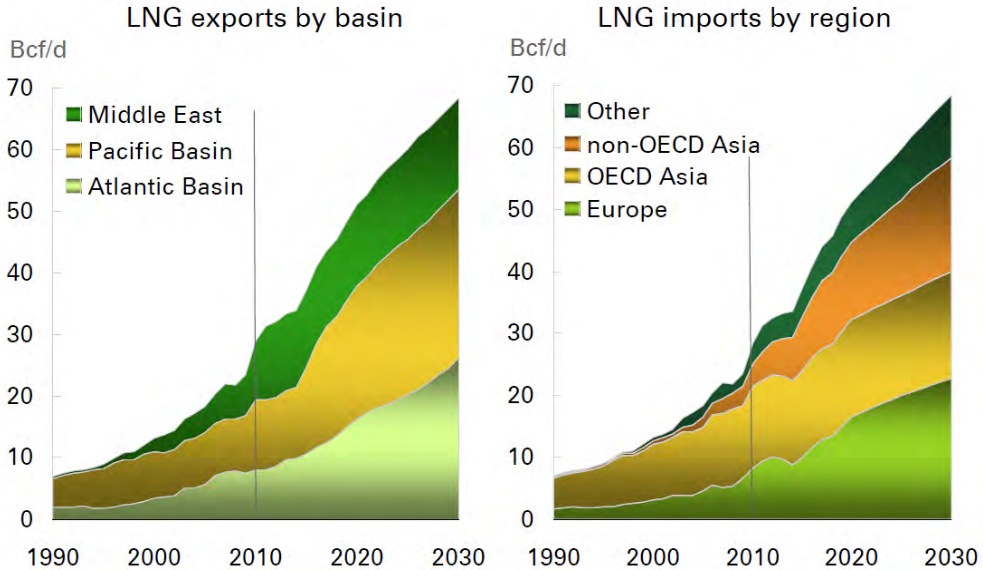
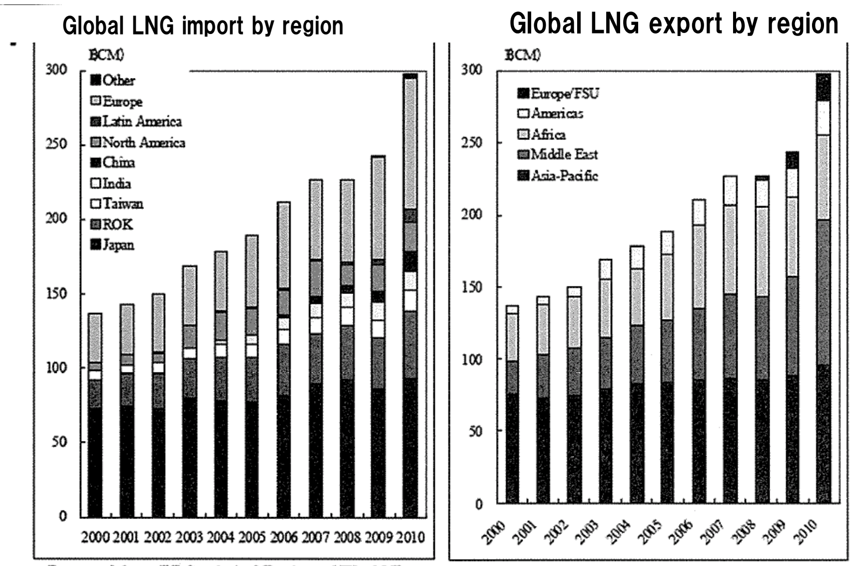


Figure 5.1-2 LNG Exports and Imports

LNG imports increased mainly in Asia, Europe and export increase Middle East.
LNG industry of Indonesia Malaysia Brunei had a little change from 1990 and the share of LNG supply of these countries getting small. On the other hand the share of Qatar Australia is growing.



Source: Prepared from BP Statistical Review of World Energy

Figure 5.1-3 LNG Exports and Imports by Region

5.1.3 Global LNG Supply-Demand Balance (Long-term)

Enough supply potential up to 2030, as far as projects under consideration will start up without any problem.

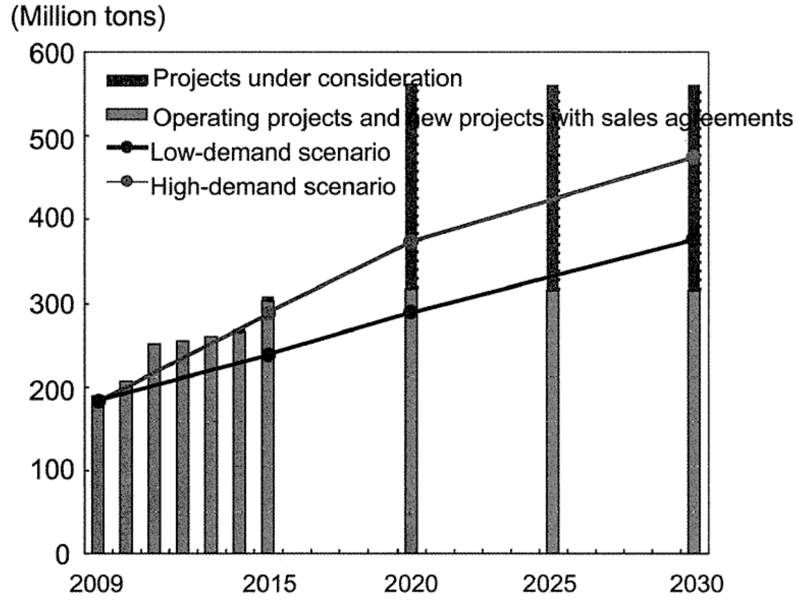


Figure 5.1-4 Global LNG Supply-Demand Balance

5.1.4 LNG Plant in Qatar and Australia

The table 5.1-1 describes the outlines of LNG projects in Qatar and Australia.

Table 5.1-1 LNG Projects in Qatar and Australia

Country	Plant	Capacity（10 thousand ton/year）
Qatar	Qatargas（Train 1-3） Qatargas Ⅱ（Train 4） Qatargas Ⅱ（Train 5） Qatargas 3 Qatargas 4	970 780 780 780 780
	Rasgas（Train1-2） Rasgas Ⅱ Ⅲ	660 2970
Australia	Prelude Wheatstone Australian Pacific Southern Cross, etc	350 860 1400 70-130

5.1.5 Scenario of Gas Supply

Because the Philippines intends to enhance energy security, the promotion of development and utilization of domestic energy resources is regarded as an important position in the energy policy. In the past performance, the self-sufficiency ratio increased after Malampaya gas field had started its production in 2001.

Natural gas consumption as of 2010 is 120 BCF, and nearly 100% of it is consumed by the power plants in Ilijan, Sta.Rita and San Lorenzo which are located in Batangas area. At present, some of the amount are used for Shell Refinery, however, the demand for CNG buses in Batangas is so small.

It is said that the reserves of Camago-Malampaya gas field is 2.7 Tcf and accumulated gas production up to 2010 reaches about 1 Tcf. Therefore, R/P ratio of the gas field is only 15 years without new additional reserves.
So one of the scenarios of gas supply is as follows.

- The pipeline is assumed to be constructed within two years starting from 2015, inaugurating for commencement of business in 2017.

- The LNG regasification terminal will only operate from 2021 onwards, the gas to be transmitted between 2017 and 2020 is assumed to be from Camago-Malampaya

- After the pipeline LNG regasification terminal complete, natural gas demand for industry and power sectors increase, and the economic growth would be. Accelerate.

Chapter 6 BatMan 1 Pipeline Plan

6.1 Natural Gas Supply Volume/Location

With assumptions based on the Chapter 4 Natural Gas Demand Estimates, supply volumes and supply location for natural gas using the BatMan 1 gas pipeline is as follows.

6.1.1 Supply Volume/Location of Natural Gas to Thermal Power Stations

As noted in the Section 4.4.3 Examination of Gas -fired Power Plant, the Sucat power station (850MW) is recommended to be switched to natural gas, and simultaneously to adopt the latest natural gas combined cycle power generation format for its high cost-performance value.

With this understood, we shall establish a supply of natural gas for both cases in which pre-existing Sucat (850W) power generating facilities (generation efficiency: 35%) are used, and cases in which natural gas combined cycle systems (generation efficiency: 55%) are used.

In the case of combined cycle power stations, we are assuming use of a double-sequence 700MW combined cycle, based on the 350MW single-sequence combined cycle (300MW gas turbine, 50MW steam turbine).

Furthermore, we have included an additional scenario in which the Sucat power station is to be relocated, and natural gas combined cycle thermal power station will be created in the Calamba area, a location separate from industrial park areas.

In the case that the new power station is constructed in Calamba, we project two possible cases. The first case once again assumes a 700MW double-sequence, based on the 350MW single-sequence combined cycle (300MW gas turbine, 50MW steam turbine) at the Sucat facility. The second case includes demand from the Malaya power station (650MW), in total 1400MW..

6.1.2 Supply Volume/Location of Natural Gas to Industrial Parks

As noted in the Section 4.5.2 Energy Consumption of Industrial Park, the potential gas demand from industrial parks located alongside the gas pipelines approximated via the total number of factories in such areas and their average fuel consumption volumes, comes to 3.87MMcf/h (109,599Nm^3/h).
Considering that petroleum-based fuel price is two to three times more expensive than natural gas on a per-calorie basis, the fact that the scale of industrial parks is roughly expected to double, and more firms are attracting factories following gas system implementation, the peak natural gas supply volume will be roughly 2.0 times the estimated potential demand, coming in at 7.76MMcf/h (220,000Nm^3/h).

It is assumed that four supply points, located in Santo Tomas, Cabuyao, Carmona, and Alabang will each receive an equal amount (one quarter) of the 1.94MMcf/h (55,000Nm^3/h) supply volume.

6.1.3 Supply Volume/Location of Natural Gas Targeted to the Commercial Sector

As noted in the Section 4.6 Gas Demand for Commercial Sector, we are projecting future demand 70 million Nm3/year, but natural gas will not be a source of HVAC based on a present LNG price (16 - 17USD/MMBtu). We however take into consideration that the elicitation of shale gas price-reduction, we are projecting the peak natural gas supply volume 0.35MMcf/h (10,000Nm^3/h) for future gas demand. Our plans assume the use of business facilities surrounding Quirino highway as supply sites.

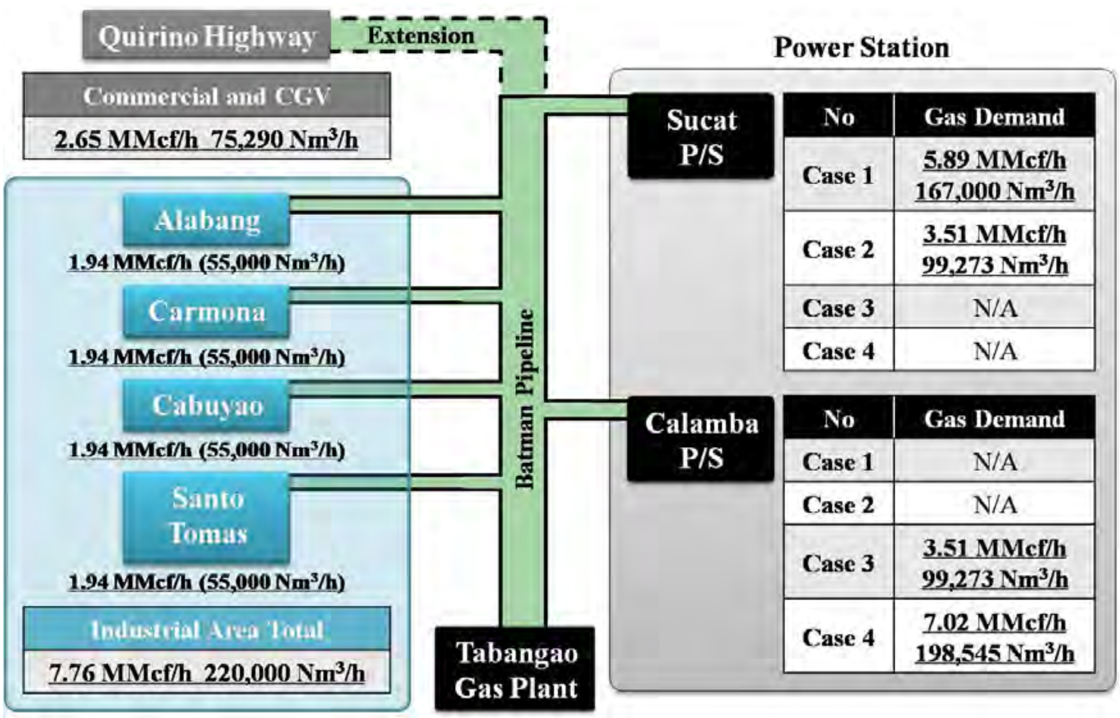
6.1.4 Supply Volume/Location of Natural Gas to the Transport Sector

As noted in Section 4.7 Gas Demand for Transport Sector, we are anticipating use of natural gas filling stations along the Quirino highway as supply sites. The natural gas supply volume as conditions of the pipeline design is shown in Table 6.1-1 below. Figure 6.1-1 displays the peak natural gas supply plans for four potential cases

Table 6.1-1 Natural Gas Supply Volume in 2030

	Power Station Calamba / Sucat	Industrial Area 4 Areas	Commercial and CGV (Quirino)	Total
Case 1	5.89 MMcf/h	7.76 MMcf/h	2.65 MMcf/h	16.3 MMcf/h
	167,000 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	462,290 Nm^3/h
	36.12%	47.59%	16.29%	100%
Case 2	3.51 MMcf/h	7.76 MMcf/h	2.65 MMcf/h	13.92 MMcf/h
	99,273 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	394,563 Nm^3/h
	25.16%	55.76%	19.08%	100%
Case 3	3.51 MMcf/h	7.76 MMcf/h	2.65 MMcf/h	13.92 MMcf/h
	99,273 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	394,563 Nm^3/h
	25.16%	55.76%	19.08%	100%
Case 4	7.02 MMcf/h	7.76 MMcf/h	2.65 MMcf/h	17.43 MMcf/h
	198,545 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	493,835 Nm^3/h
	40.20%	44.55%	15.25%	100%

Source: Formulated by JICA study team



Source: Formulated by JICA study team

Figure 6.1-1 The Peak Natural Gas Supply Volume for Conditions of the Pipeline Design

6.2 Gas Pipeline Route

6.2.1 Overview

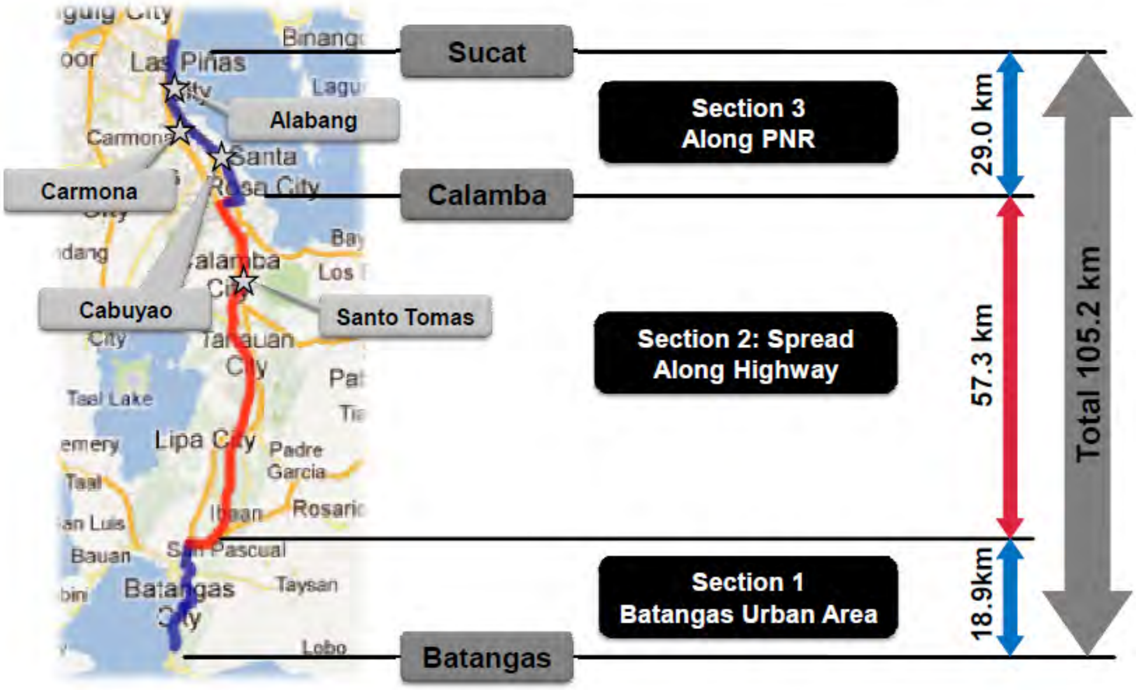
The gas pipeline route runs roughly 105.2km between a new LNG receiving plant in Batangas and Sucat power station. The route was selected based on assumptions of both the case of reusing the Sucat power station, and newly establishing a power station in Calamba, especially focusing on the following points:

(1) The current states and future plans of land utilization.
(2) Difficulty levels of land acquisition and allocation.
(3) The current states and future plans of buried or above ground facilities.
(4) Applicable construction technique
(5) The current states and future plans of road, railway, bridges and rivers.

The following points shall be investigated in detail at the next study:

(1) Details talks to land and traffic administrations.
(2) Dimension and cross-section diagram of the ROW in Section 2
(3) Details talks to buried facilities' administrators such as potable water, sewage and power cable etc and acquisition of their exact location.
(4) Geological survey
(5) Talks to local inhabitant occupied alongside the pipeline.

Branch lines to gas users and exact valve stations' locations are to be determined at the detail design stage.



Source: Formulated by JICA study team

Figure 6.2-1 BatMan 1 Route Selection

Having selected the route according to the above conditions and field environment, the route can be largely divided into three main areas: urban area, prairie area, and area running alongside railroad as shown in Figure 6.2-1.

Section 1 has a total length of 18.9km, starting from inside of new LNG receiving plant in Batangas (KP 0) and will be buried in a major trunk road running north-south through Batangas city. A branch line is to be installed in front of the Tabangaso onshore gas plant for the sake of natural gas supply.

Section 2 of the pipeline will be buried along the north-south running highway which stretches out from Batangas to Calamba, totaling 57.3km. Since this route allows to apply a spread technique, it can be worked with good efficiency better than other 2 areas.
Section 3 of the pipeline will be buried along the railroad which runs on the east side of a highway, in total of 29.0km from Calamba to the endpoint located in the Sucat power station grounds.
Major crossing list such as crossing on railway, road, and river, is shown in Table 6.2-1.

Table 6.2-1 Major Crossing List

No.	KP	Type	Area Name	Desription
1	1.13	River	Section 1	River crossing in Batangas
2	2.5	River	Section 1	
3	7.4	River	Section 1 (Within Tabangao OGP boundary)	River crossing in fronto of Tabangao OGP. (Branch line to Tabangao OGP)
4	8.75	River	Section 1	River crossing in Batangas
5	10.85	River		
6	14.6	River		
7	19.28	River	Section 2	Alongside Southern Tagalog Arterial Road
8	20.25	River		
9	21.65	River		
10	22.65	Road		
11	23.95	Road		
12	27.25	Road		
13	31.95	Road		
14	34.35	Road		
15	37.95	Road		
16	38.45	Road		
17	38.95	Road		
18	46.95	River		
19	59.75	River		Alongside South Luzon Expressway
20	61.15	Road		
21	67.4 - 73.1	River		
22		River		
23		River		
24		Road		
25		River		
26	73.1 - 76.1	River		
27		Road		
28	76.1 - 78.6	Road	Section 3	Local road in Calamba
29		Railway		Philippine national railway
30	78.6 - 87.4	Road		Along side Philippine national railway
31		River		
32		Road		
33		River		
34		Road		
35		River		
36		Road		
37	87.4 - 98.1	River		
38		Road		
39		Road		
40		River		
41		Road		
42		River		
43		Road		
44		Road		
45	98.1 - 101.9	River		
46		River		
47	104.87	Road		

Source: Formulated by JICA study team

6.2.2 Characteristics and Tasks Faced at Each Section of the Route

(1) The entire route of Section 1, the Batangas Urban Area, is plotted out on Figure 6.2-2 to the right, and elevation profile shows in Figure 6.2-3. Detail view of the beginning of the pipeline and the branch line are shown in the attached route map. Section 1 (Batangas Urban Area), stretching from kilometer point zero (KP 0) in new LNG receiving terminal to KP 18.9, faces a number of potential issues in carrying out the pipeline installation. Items such as obtaining permissions to use the road space, explanation to local residents, noise issues and potential traffic obstructions are being foreseen. In addition, there are 3 large scale factories between the LNG plant and Tabangao OGP. Each factory has over bridge facilities on the trunk road and accordingly a pre-consultation with factories' owner is required prior to pipeline construction commencement. As a potential alternative route, the route takes a detour through the north east. This however would take place in a mountainous region, where there are local roads and various scattered settlements. It is thus expected to be difficult to secure the land required for pipeline installation. As such we are presently moving forward assuming the route which runs through urban Batangas.

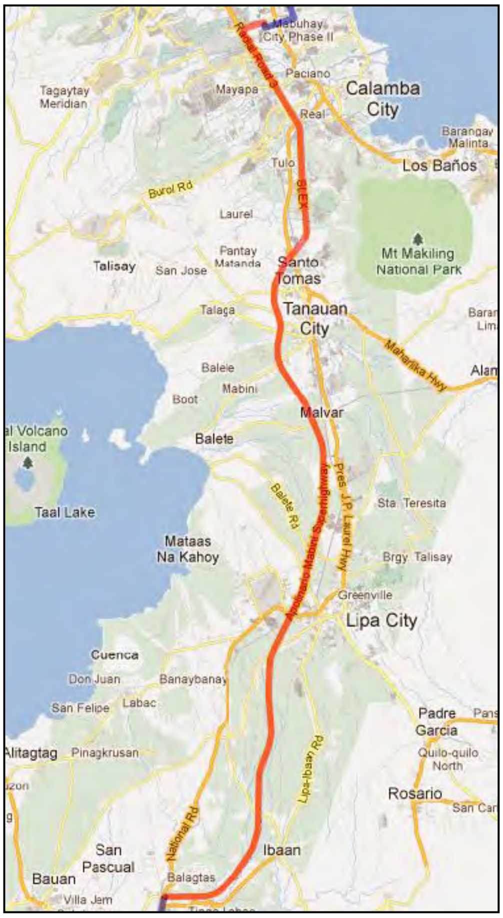
Source: Formulated by JICA study team

Figure 6.2-2 Section 1 Batangas Urban Area

Source: Formulated by JICA study team

Figure 6.2-3 Section 1 Elevation Profile

(2) The total layout of Section 2, running along the highway, is plotted out on Figure 6.2-4 to the right, and elevation profile shows in Figure 6.2-5.
Of the total stretch of 57.3km between KP 11.5 and KP 68.8, ROW has already been acquired for a 42km stretch along the South Tagalong Arterial Road (STAR), via a memorandum from DOE and the highway administrator. Nevertheless detailed ROW measurements and shape specifications are not presently available from DOE, spread technique can be applied to most locations working with good efficiency.
That said, there is a 15.3km length, outside of the aforesaid 42km, where we have yet to acquire ROW, and negotiation is required. In any case, work on the route running alongside the highway will be constructed with spread technique.



Source: Formulated by JICA study team

Figure 6.2-4 Section 2 along Highway

Source: Formulated by JICA study team

Figure 6.2-5 Section 2 Elevation Profile

(3) The Section 3 route along PNR (Philippines National Railway) is plotted on Figure 6.2-6 to the right, and elevation profile shows in Figure 6.2-7. Detail view of the end of the pipeline is shown in the attached route map.

Our proposed pipeline route is to install inside the land of PNR for the 29.0km stretch between KP 68.8 in Calamba to KP 97.8 in Sucat. The reasons for doing so are as follows:

1) In considering the option of laying pipe along the highway for this section of the route which was selected in the JICA M/P(2002), since the high land use rate, land allocation for pipeline installation will be extremely challenging. Beyond that, even if tenable land were to be found, as there are numerous road administrators, the process of getting a hold of all the necessary permissions would be a tremendously difficult and onerous task.

Source: Formulated by JICA study team

Figure 6.2-6 Section 3 along PNR

2) The existing road running along the expressway is the main thoroughfare to Manila, and has a significant amount of traffic both day and night. To this end, coupled with the potential difficulties regarding site space acquisition described above, the actual implementation of a gas pipeline installation along this route is thought to bring an enormous number of challenges.

3) Shifting focus to the PNR land expected to be used, there is 15m of available land on either side of the center of the railroad, totaling a sufficiently spacious 30m. While there are a number of illegal inhabitants found sporadically dwelling along the railways, the passing of vehicles should for all intents and purposes be feasible, which leads to the conclusion that site space acquisition is also sufficiently possible. It is noted that the current trains are diesel-fueled, in considering the possibility of a future switch over to electrical systems, this section of the route in which casthodic protection shall be installed to protect against stray currents.

There is a need to draw approximately 200m of pipeline from near the PNR to Sucat power station. For this particular section, we have selected a location which contains the least amount of buried obstructions. Valve stations with shut down valves will be installed along each section of the route, with one valve station in Section 1, three valve stations in Section 2, and two valve stations in Section 3.

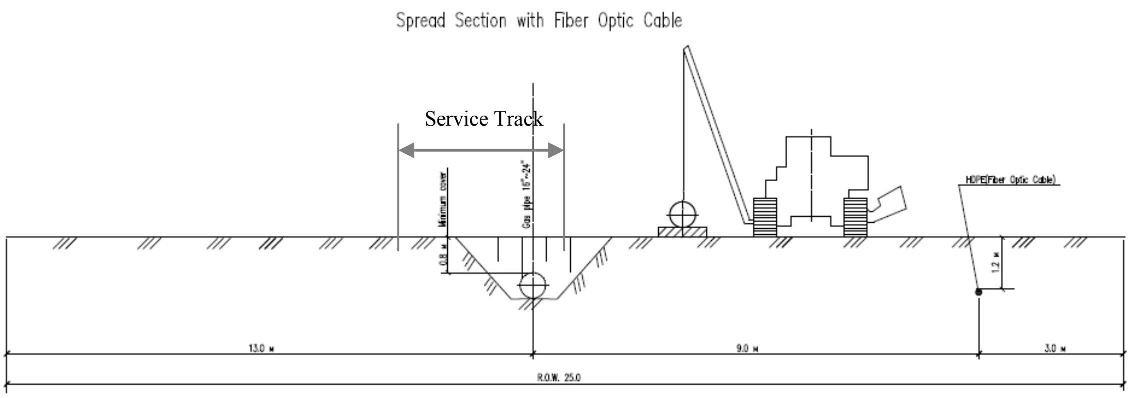
Source: Formulated by JICA study team

Figure 6.2-7 Section 3 Elevation Profile

6.2.3 Land Required for Gas Pipeline Maintenance

While DOE is presently attending to the obtaining of ROW for the pipeline, and its operation and maintenance, only the 42km stretch along the South Tagalog Arterial Road (STAR) has been acquired. For the purpose of as the pipeline, block valve stations, and cathodic protection stations operation and maintenance, a 4m service track running parallel to the buried pipeline is required. Therefore, including the pipeline space, a 6m-wide land is required In the case of access being possible via existing nearby roads however, this width limit does not apply.

It should however be noted that as Section 1 of the pipeline is to be buried in an existing road, a service track is not necessary. ROW typical cross section shows in Figure 6.2-8.



Source: Formulated by JICA study team

Figure 6.2-8 ROW Typical Cross Section Drawing

6.3 Gas Pipeline Design Overview

This section outlines the pipeline basic design and engineering.

The pipeline system is transporting natural gas from a new LNG receiving terminal in Batangas to Manila including branch lines to potential industrial areas in Laguna region.

Related facilities include valve stations used to ensure the safety of the pipeline, metering stations used for managing gas flow, cathodic protection, branch valves, SCADA system, pig launchers/receivers, as well as control and monitoring station.

A service life of the pipeline designed for 40 years, and the pipeline's facilities are designed for 25 years.

6.3.1 Pipeline Transport Capacity Specifications

(1) Applicable Criteria

International standards such as ANSI, ISO, etc. are applied to the BatMan pipeline design. Primary standards are shown in Table 6.3-1.

Table 6.3-1 Primary Standards

ANSI/ASME (American National Standards Institute)
ANSI/ASME B31.4 Liquid Petroleum Transportation Piping Systems
ANSI/ASME B31.8 Gas Transmission and Distribution Piping Systems
ANSI/ASME B16.5 Steel Flanges and Flanged Fittings
ANSI/ASME Factory-made Wrought Steel Butt Welding Fitting
ASME (American Society of Mechanical Engineers)
ASME Boiler And Pressure Vessel Code
ASME Section V Nondestructive Examination
ASME Section VIII Pressure Vessels
ASME Section IX Welding and Brazing Qualifications
API (American Petroleum Institute)
API SPEC 5L
API SPEC6D
ASTM (AMERICAN Society for Testing and Materials)
ASTM A105 Forgings, Carbon Steel, for Piping Components
ASTM A370 Mechanical Testing of Steel Products
NACE (National Association of Corrosion Engineers)
SSPC (Steel Structures Painting Council)
BSI (British Standards Institution)
DIN (Deutsches Institute fur Normung)
DNV (Det Norske Veritas)
ISO (International Organization for Standardization)

Source: Formulated by JICA study team from regulations and codes

(2) Natural Gas Composition, Specific Gravity, and Design Temperature

Natural gas specific gravity will make a major impact on a gas flow volume calculations for the pipeline. We applied 0.65 as a natural gas specific gravity with safe margin even an exact gas specific gravity is 0.647 in accordance with a composition of natural gas from Malampaya. We applied 35° Celsius.

(3) Pipe Materials

Line pipe with high strength and toughness shall be applied for gas pipeline. API 5L X X-80 has higher strength than API 5L X-65, we however applied the X-65 to the gas pipeline due to a reason that the X-65 has better weldability than the X-80. External coating is polyethylene coating and internal is epoxy coating. Induction bends, tee and other fittings are to be same specification as aforementioned.

(4) Location Class

Location class in accordance with ANSI/ASME B31.8 is important criterion to determine a buried depth, and distance between each valve station. The following is a quotation from ANSI/ASME B31.8 with regard to Location Class:

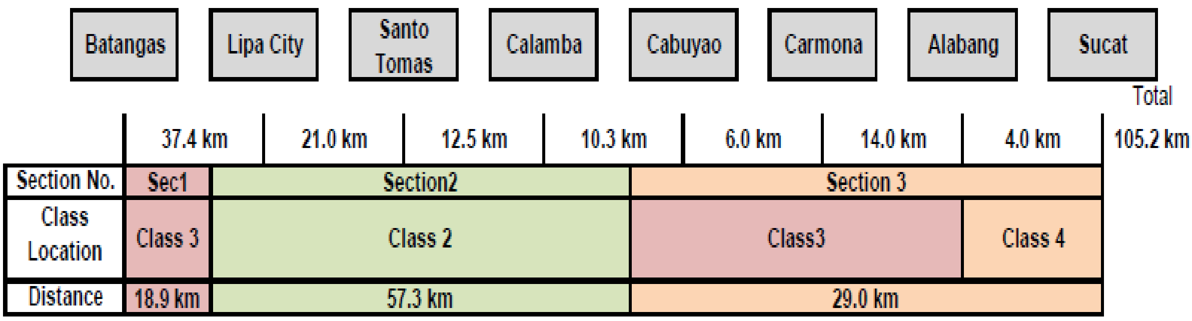
1) *Location Class 1. A Location Class 1 is any 1 mile section that has 10 or fewer buildings intended for human occupancy. A Location Class 1 is intended to reflect areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.*

   (a) *Class 1 Division 1. A Location Class 1 where the design factor of the pipe is greater than 0.72 but equal to or less than 0.80, and which has been hydrostatically tested to 1.25 times the maximum operating pressure.*

   (b) *Class 1 Division 2. A Location Class 1 where the design factor of the pipe is equal to or less than 0.72, and which has been tested to 1.1 times the maximum operating pressure.*

2) *Location Class 2. A Location Class 2 is any 1 mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. A Location Class 2 is intended to reflect areas where the degree of population is intermediate between Location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates, etc.*
3) *Location Class 3. A Location Class 3 is any 1 mile section that has 46 or more buildings intended for human occupancy except when a Location Class 4 prevails. A Location Class 3 is intended to reflect areas such suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.*
4) *Location Class 4. A Location Class 4 includes areas where multistory buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multistory means 4 or more floors above ground including the first or ground floor. The depth of basements or number of basement floors is immaterial.*

The BatMan pipeline location class in accordance with ANSI/ASME B31.8 is shown in Figure 6.3-1.



Source: Formulated by JICA study team

Figure 6.3-1 BatMan Pipeline Class Location

(5) Depth of buried pipeline

A depth of buried pipeline is specified by ANSI/ASME. A guide of buried pipeline depth by ANSI/ASME B31.8 is shown in Table 6.3-2.

Table 6.3-2 Guide of Buried Pipeline Depth by ANSI/ASME B31.8

Location		Buried depth (inch)		
		Normal area	Rock area	
			Pipe OD Less 20”	Pipe OD Over 20”
Class 1	Any 1 mile section that has 10 or fewer buildings intended for human occupancy. A Location Class 1 is intended to reflect areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.	24	12	18
Class 2	Any 1 mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. A Location Class 2 is intended to reflect areas where the degree of population is intermediate between Location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates, etc.	30	18	18
Class 3	Any 1 mile section that has 46 or more buildings intended for human occupancy except when a Location Class 4 prevails. A Location Class 3 is intended to reflect areas such suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.	30	24	24
Class 4	where multistory buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multistory means 4 or more floors above ground including the first or ground floor.	36	24	24
Public road and Railway Crossing for all class location		36	24	24

Source: ANSI/ASMEB31.8

Buried depth at each section of BatMan pipeline is shown in Table 6.3-3. The pipeline will be buried underneath existing roads which located in or adjacent to town area. High pressure gas pipeline will be generally buried less 1.5m (60 inch) in Japan, as well as in overseas pipeline construction, a buried depth is 0.8 - 1.2 meter (32 – 48 inch) in ROW located at wastelands and or mountains. BatMan pipeline depth has been therefore designed taking into consideration that the above mentioned conditions and a safety aspect.

Table 6.3-3 BatMan Pipeline Buried Depth

Location			Depth (inch)
Section 1	Class 3	Trunk road in Batangas city	60
Section 2	Class 2	ROW alongside STAR	32
		Road and or river crossing	60
Section 3	Class 3	Alongside PNR	32
		Road and or river crossing	60
	Class 4	Alongside PNR	32
		Road and or river crossing	60

Source: Formulated by JICA study team

6.3.2 Gas Pipeline Flow Condition

The maximum gas flow from Tabangao gas plant is 650MMscf/d. At the present time in 2011, total energy usage from thermal power plants surrounding Batangas city are 2,700MW (324MMscf/d), allowing for a potential usable gas volume from Malampaya for the pipeline is 326MMcf/d.

Since the gas pipeline service life design is 40 years, the maximum flow capacity of the gas pipeline are designed based on gas flows delivered from an LNG plant which may be erected in the future in addition to the margin of the gas field.

As an example, in the Case 4, it has been designed that the maximum flow volume is 443MMscf/d, which is capable to meet the maximum gas demand in 2030. The beginning point of the pipeline for the flow analysis was at new LNG receiving terminal due to the longest pipeline distance.

Table 6.3-4 shows the natural gas demand in 2030, which is based for the pipeline flow analysis design.

Table 6.3-4 Natural Gas Supply Volume in 2030

	Power Station Calamba / Sucat	Industrial Area 4 Areas	Commercial and CGV (Quirino)	Total
Case 1	5.89 MMscf/h	7.76 MMscf/h	2.65 MMscf/h	**16.3 MMscf/h**
	167,000 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	**462,290 Nm^3/h**
	36.12%	**47.59%**	**16.29%**	**100%**
Case 2	3.51 MMscf/h	7.76 MMscf/h	2.65 MMscf/h	**13.92 MMscf/h**
	99,273 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	**394,563 Nm^3/h**
	25.16%	**55.76%**	**19.08%**	**100%**
Case 3	3.51 MMscf/h	7.76 MMscf/h	2.65 MMscf/h	**13.92 MMscf/h**
	99,273 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	**394,563 Nm^3/h**
	25.16%	**55.76%**	**19.08%**	**100%**
Case 4	7.02 MMscf/h	7.76 MMscf/h	2.65 MMscf/h	**17.43 MMscf/h**
	198,545 Nm^3/h	220,000 Nm^3/h	75,290 Nm^3/h	**493,835 Nm^3/h**
	40.20%	**44.55%**	**15.25%**	**100%**

Source: Formulated by JICA study team

Supply pressure for power stations shall be maintained 2.8MPa which is needed for gas combined cycle power generation.

The scope for the current BatMan 1 gas pipeline has its end point at Sucat power station, however flow volume calculations are to account for 2.65MMcf/h (75,290Nm^3/h) worth of supply to meet potential gas demand from the Quirino highway.

Basic conditions on the gas flow volume calculations for each case are as follows:

CASE-1: Operate the Sucat power stations as is (Generation efficiency: 35%), supply natural gas to industrial areas along the pipeline route totaling 7.76MMcf/h (220,000Nm^3/h), and to Quirino totaling 2.65MMcf/h (75,290Nm^3/h). The supply volume 7.76MMcf/h (220,000Nm^3/h) for the said industrial areas based on assumed natural gas demand in 2030 will be evenly divided into Santo Tomas, Cabuyao, Carmona, and Alabang, i.e. 1.94MMcf/h (55,000Nm^3/h) respectively.

CASE-2: Convert the Sucat power stations as a natural gas combined cycle power station (Generation efficiency: 35%), supply natural gas to industrial areas along the pipeline route totaling 7.76MMcf/h (220,000Nm^3/h), and to Quirino totaling 2.65MMcf/h (75,290Nm^3/h). The supply volume 7.76MMcf/h (220,000Nm^3/h) for the said industrial areas based on assumed natural gas demand in 2030 will be evenly divided into Santo Tomas, Cabuyao, Carmona, and Alabang, i.e. 1.94MMcf/h (55,000Nm^3/h) respectively.

CASE-3: Construct a new 700MW natural gas combined cycle power station in Calamba, supply natural gas to industrial areas along the pipeline route totaling 7.76MMcf/h (220,000Nm^3/h), and to Quirino totaling 2.65MMcf/h (75,290Nm^3/h). The supply volume 7.76MMcf/h (220,000Nm^3/h) for the said industrial areas based on assumed natural gas demand in 2030 will be evenly divided into Santo Tomas, Cabuyao, Carmona, and Alabang, i.e. 1.94MMcf/h (55,000Nm^3/h) respectively.

CASE-4: Construct a new 1400MW natural gas combined cycle power station in Calamba, supply natural gas to industrial areas along the pipeline route totaling 7.76MMcf/h (220,000Nm^3/h), and to Quirino totaling 2.65MMcf/h (75,290Nm^3/h). The supply volume 7.76MMcf/h (220,000Nm^3/h) for the said industrial areas based on assumed natural gas demand in 2030 will be evenly divided into Santo Tomas, Cabuyao, Carmona, and Alabang, i.e. 1.94MMcf/h (55,000Nm^3/h) respectively.

6.3.3 Flow Analysis

One of the most critical point in a pipeline design is the determination of pipe diameter based on long term gas supply plans. The basis for such determination is flow analysis, of which outlet pressure, supply volume, supply pressure, and supply distance are critical variables.

(1) Flow Analysis Conditions

1) Gas plant outlet pressure: 6.8MPa in consideration of feature decline
   (Source pressure:8.2MPa)
2) Minimum supply pressure for thermal power station: 3.0MPa
3) Natural gas temperature: 35° Celsius at either point of gas supply and end user.
4) The Revised Panhandle formula is used for pressure-loss calculation.

$$Q = C\frac{T_b}{P_b}D^{2.5}e\left(\frac{P_1^{\ 2}-P_2^{\ 2}}{LGT_aZ_af}\right)^{.5}$$

Where:

C	Constant, 77.54 (English units); *.0011493 (Metric units)*
D	Pipe diameter (inches) *(millimeters)*
e	Pipe efficiency (dimensionless)
f	Darcy-Weisbach friction factor (dimensionless)
G	Gas specific gravity (dimensionless)
L	Pipe length (miles) *(kilometers)*
P_b	Pressure base (PSIA) *(Kilopascals)*
P_1	Inlet pressure (PSIA) *(Kilopascals)*
P_2	Outlet pressure (PSIA) *(Kilopascals)*
Q	Flow rate (standard cubic feet/day) *(standard cubic meters/day)*
T_a	Average temperature (°R) (°K)
T_b	Temperature base (°R) (°K)
Z_a	compressibility factor (dimensionless)

(2) Flow Analysis Points (actual position)

Flow analysis points, namely the locations at which flow and pressure are confirmed, have been set the industrial areas, power station, and Quirino highway: Lipa City, Santo Tomas, Calamba, Cabuyao, Carmona, Alabang, Sucat, and Quirino, 8 points in total. The supply volume 7.76MMcf/h (220,000Nm^3/h) for the said industrial areas based on assumed natural gas demand in 2030 will be evenly divided into Santo Tomas, Cabuyao, Carmona, and Alabang, i.e. 1.94MMcf/h (55,000Nm^3/h) respectively.

Distances between each analysis point, which is based on the results delivered from the section 6.2, is listed in Table 6.3-5 below.

Table 6.3-5 Flow Analysis Points

from	to	Length [km]	Total Length [km]
①LNG terminal	②LipaCity	37.4	37.4
②LipaCity	③SantoTomas	21.0	58.4
③SantoTomas	④Calamba	12.5	70.9
④Calamba	⑤Cabuyao	10.3	81.2
⑤Cabuyao	⑥Carmona	6.0	87.2
⑥Carmona	⑦Alabang	14.0	101.2
⑦Alabang	⑧Sucat	4.0	105.2
⑧Sucat	⑨Qurino	38.0	143.2

Source: Formulated by JICA study team

6.3.4 Flow Analysis Results

The results of the flow analysis are shown in Table 6.3-6 through 6.3-9.

Table 6.3-6 Flow Analysis Results on Case 1

from	to	Length [km]	Est. Flow [MMNm3/h]	Location class	OD [mm]	Thickness [mm]	U [m/s]	P1 [kgf/cm2]	P2 [kgf/cm2]
①LNG Terminal	②LipaCity	37.4	0.46230	3	610.0	12.7	8.470	68.0	58.2
②LipaCity	③SantoTomas	21.0	0.46230	2	610.0	11.9	9.413	58.2	51.9
③SantoTomas	④Calamba	12.5	0.40730	2	610.0	11.9	8.818	51.9	48.8
④Calamba	⑤Cabuyao	10.3	0.40730	3	610.0	12.7	9.394	48.8	46.0
⑤Cabuyao	⑥Carmona	6.0	0.35230	3	610.0	12.7	7.860	48.8	47.6
⑥Carmona	⑦Alabang	14.0	0.29730	3	610.0	12.7	6.930	47.6	45.5
⑦Alabang	⑧Sucat	4.0	0.24230	4	610.0	15.9	5.828	45.5	45.1
⑧Sucat	⑨Qurino	38.0	0.07530	4	323.9	12.7	9.439	45.1	32.2

Source: Formulated by JICA study team

Table 6.3-7 Flow Analysis Results on Case 2

from	to	Length [km]	Est. Flow [MMNm3/h]	Location class	OD [mm]	Thickness [mm]	U [m/s]	P1 [kgf/cm2]	P2 [kgf/cm2]
①LNG Terminal	②LipaCity	37.4	0.39457	3	610.0	12.7	6.905	68.0	60.9
②LipaCity	③SantoTomas	21.0	0.39457	2	610.0	11.9	7.376	60.9	56.7
③SantoTomas	④Calamba	12.5	0.33957	2	610.0	11.9	6.576	56.7	54.7
④Calamba	⑤Cabuyao	10.3	0.33957	3	406.4	7.9	20.002	54.7	40.2
⑤Cabuyao	⑥Carmona	6.0	0.28457	3	406.4	7.9	13.758	54.7	49.2
⑥Carmona	⑦Alabang	14.0	0.22957	3	406.4	7.9	13.767	49.2	39.5
⑦Alabang	⑧Sucat	4.0	0.17457	4	406.4	9.5	11.179	39.5	37.5
⑧Sucat	⑨Qurino	38.0	0.07530	4	323.9	7.9	11.878	37.5	23.7

Source: Formulated by JICA study team

Table 6.3-8 Flow Analysis Results on Case 3

from	to	Length [km]	Est. Flow [MMNm3/h]	Location class	OD [mm]	Thickness [mm]	U [m/s]	P1 [kgf/cm2]	P2 [kgf/cm2]
①LNG Terminal	②LipaCity	37.4	0.39457	3	610.0	12.7	6.905	68.0	60.9
②LipaCity	③SantoTomas	21.0	0.39457	2	610.0	11.9	7.376	60.9	56.7
③SantoTomas	④Calamba	12.5	0.33957	2	610.0	11.9	6.576	56.7	54.7
④Calamba	⑤Cabuyao	10.3	0.24030	3	323.9	7.9	33.282	54.7	27.2
⑤Cabuyao	⑥Carmona	6.0	0.18530	3	323.9	7.9	15.104	54.7	46.9
⑥Carmona	⑦Alabang	14.0	0.13030	3	323.9	7.9	13.846	46.9	35.7
⑦Alabang	⑧Sucat	4.0	0.07530	4	323.9	7.9	8.289	35.7	34.4
⑧Sucat	⑨Qurino	38.0	0.07530	4	323.9	7.9	15.017	34.4	18.5

Source: Formulated by JICA study team

Table 6.3-9 Flow Analysis Results on Case 4

from	to	[km]	[MMNm3/h]	class	[mm]	[mm]	[m/s]	[kgf/cm2]	[kgf/cm2]
①LNG Terminal	②LipaCity	37.4	0.49385	3	610.0	12.7	9.281	68.0	56.7
②LipaCity	③SantoTomas	21.0	0.49385	2	610.0	11.9	10.579	56.7	49.3
③SantoTomas	④Calamba	12.5	0.43885	2	610.0	11.9	10.184	49.3	45.5
④Calamba	⑤Cabuyao	10.3	0.24030	3	406.4	7.9	15.335	45.5	37.0
⑤Cabuyao	⑥Carmona	6.0	0.18530	3	406.4	7.9	10.296	45.5	42.7
⑥Carmona	⑦Alabang	14.0	0.13030	3	406.4	7.9	7.864	42.7	39.2
⑦Alabang	⑧Sucat	4.0	0.07530	4	406.4	7.9	4.585	39.2	38.9
⑧Sucat	⑨Qurino	38.0	0.07530	4	323.9	7.9	10.978	38.9	25.8

Source: Formulated by JICA study team

6.3.5 Pipe Wall Thickness Calculation

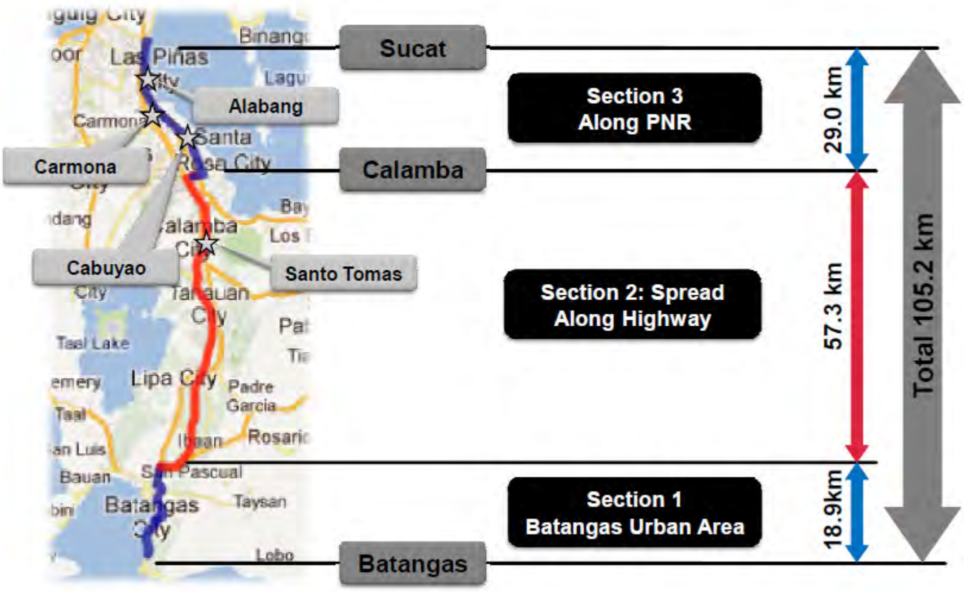
(1) Designed Pressure and Class Location

The designed pressure and class locations for each section are set as follows:

SECTION 1: The gas plant outlet pressure, 8.25MPa (1,200Psig) shall be used as the design pressure. Class location is 3 as an urban area in accordance with ANSI B31.8.

SECTION 2: At 11.5km from the gas plant, the design pressure for the stretch beyond the shutdown valve shall be 7MPa (1,000Psig). Class location is 2 as a suburban area in accordance with ANSI B31.8.

SECTION 3: The design pressure shall be 7MPa (500Psig). Class location is 3 as an urban area, and the particular section from Alabang to Sucat is 4 as a congestion area according to ANSI B31.8.



Source: Formulated by JICA study team

Figure 6.3-2 Pipeline Route and Route Segments

(2) Pipe Wall Thickness Computations

The minimum pipe wall thickness for each section is calculated based on the ANSI/ASME B31.8. The results of the said calculations are shown in the Table 6.3-10 through 6.3-17.

ANSI/ASME B31.8 Pipe Wall Thickness formula

$P = \frac{2S\,t}{D} FET$	D :	nominal outside diameter of pipe, in
	E :	longitudinal joint factor
	F :	design factor
	P :	design pressure, psig
$t_u - t_t - C \geq t = \frac{PD}{2SFET}$	S :	specified minimum yield strength, psi
	T :	temperature derating factor
	t :	nominal wall thickness, in
	t_u :	wall thickness to be used
	t_t :	tolerance for wall thickness
	C :	corrosion allowance

Table 6.3-10 Calculation of Pipe Wall Thickness for 24 Inch Class 2

BATMAN1 24" GAS PIPELINE, API 5L-X65, ERW

VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS

PROJECT	:	BATMAN1 PROJECT					
DESIGN BASED ON	:	ASME B 31.8					
LOCATION CLASS	:	AS PER ANSI B31.8	CLASS 2				
DESCRIPTION			Symbol	BU		METRIC	
DESIGN BASIS							
DESIGN PRESSURE			P	1,200	Psig	84	kgs/sq.cm
DESIGN TEMPERATURE			T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER			D	24	Inch	610.00	mm
MATERIAL OF PIPE				**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L							
SPECIFIED MINIMUM YIELD STRENGTH			S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997							
DESIGN FACTOR (for pipe diameter D > 8")							
DESIGN FACTOR			F	0.60		0.60	
REF: ASME B 31.8 TABLE 841.116A							
TEMPERATURE DERATING FACTOR			T	1		1	
FABRICATION TOLERANCE (10%)			a	0.10		0.10	
LONGITUDINAL JOINT FACTOR			E	1		1	
CORROSION ALLOWANCE			CA	0.000	INCH	0.0	mm

CALCULATION

REF: ASME B 31.8 EQUATION 841.11

$$P = \frac{2.S.t}{D}.FET \qquad t = \frac{P.D}{2.S.F.E.T} \qquad t\,tol = \frac{tcal}{(1-a)}$$

CALCULATED WALL THICKNESS	t_{-calc}	0.369	INCH	9.383	mm
WALL THICKNESS + CORROSION ALLOWANCE	$t_{-calc+c.a}$	0.763	INCH	9.383	mm
WALL THICKNESS + CORROSION ALLOWANCE	t_{tol}	0.410	INCH	10.43	mm
+ FABRICATION TOLERANCE					
WALL THICKNESS (STD. SPEC. API 5 L)	t_{-wt}	**0.469**	INCH	**11.90**	mm
REFERENCE MINIMUM WALL THICKNESS	t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS	$t_{-select}$	**0.469**	INCH	**11.90**	mm

Source: Formulated by JICA study team

Table 6.3-11 Calculation of Pipe Wall Thickness for 24 Inch Class 3

BATMAN1 24" GAS PIPELINE, API 5L-X65, ERW						
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS						
PROJECT	:	BATMAN1 PROJECT				
DESIGN BASED ON	:	ASME B 31.8				
LOCATION CLASS	:	AS PER ANSI B31.8		CLASS 3		
DESCRIPTION		Symbol	BU		METRIC	
DESIGN BASIS						
DESIGN PRESSURE		P	1,200	Psig	84	kgs/sq.cm
DESIGN TEMPERATURE		T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER		D	24	Inch	610.00	mm
MATERIAL OF PIPE			**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L						
SPECIFIED MINIMUM YIELD STRENGTH		S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997						
DESIGN FACTOR (for pipe diameter D > 8")						
DESIGN FACTOR		F	0.50		0.50	
REF: ASME B 31.8 TABLE 841.116A						
TEMPERATURE DERATING FACTOR		T	1		1	
FABRICATION TOLERANCE (10%)		a	0.10		0.10	
LONGITUDINAL JOINT FACTOR		E	1		1	
CORROSION ALLOWANCE		CA	0.000	INCH	0.0	mm
CALCULATION						
REF: ASME B 31.8 EQUATION 841.11						
$P = \frac{2.S.t}{D}.FET$		$t = \frac{P.D}{2.S.F.E.T}$		$t\,tol = \frac{tcal}{(1-a)}$		
CALCULATED WALL THICKNESS		t_{-calc}	0.443	INCH	11.260	mm
WALL THICKNESS + CORROSION ALLOWANCE		$t_{-calc+c.a}$	0.837	INCH	11.260	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE		t_{tol}	0.493	INCH	12.51	mm
WALL THICKNESS (STD. SPEC. API 5 L)		t_{-wt}	**0.500**	INCH	**12.70**	mm
REFERENCE MINIMUM WALL THICKNESS		t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS		t_{select}	**0.500**	INCH	**12.70**	mm

Source: Formulated by JICA study team

Table 6.3-12 Calculation of Pipe Wall Thickness for 24 Inch Class 4

BATMAN1 24" GAS PIPELINE, API 5L-X65, ERW						
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS						
PROJECT	:	BATMAN1 PROJECT				
DESIGN BASED ON	:	ASME B 31.8				
LOCATION CLASS	:	AS PER ANSI B31.8	CLASS 4			
DESCRIPTION		Symbol	BU		METRIC	
DESIGN BASIS						
DESIGN PRESSURE		P	1,200	Psig	84	kgs/sq.cm
DESIGN TEMPERATURE		T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER		D	24	Inch	610.00	mm
MATERIAL OF PIPE			**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L						
SPECIFIED MINIMUM YIELD STRENGTH		S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997						
DESIGN FACTOR (for pipe diameter D > 8")						
DESIGN FACTOR		F	0.40		0.40	
REF: ASME B 31.8 TABLE 841.116A						
TEMPERATURE DERATING FACTOR		T	1		1	
FABRICATION TOLERANCE (10%)		a	0.10		0.10	
LONGITUDINAL JOINT FACTOR		E	1		1	
CORROSION ALLOWANCE		CA	0.000	INCH	0.0	mm
CALCULATION						
REF: ASME B 31.8 EQUATION 841.11						
$P = \frac{2.S.t}{D}.FET$		$t = \frac{P.D}{2.S.F.E.T}$			$t\,tol = \frac{tcal}{(1-a)}$	
CALCULATED WALL THICKNESS		t_{calc}	0.554	INCH	14.075	mm
WALL THICKNESS + CORROSION ALLOWANCE		$t_{calc+c.a}$	0.948	INCH	14.075	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE		t_{tol}	0.616	INCH	15.64	mm
WALL THICKNESS (STD. SPEC. API 5 L)		t_{wt}	**0.626**	INCH	**15.90**	mm
REFERENCE MINIMUM WALL THICKNESS		t_{PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS		t_{select}	**0.626**	INCH	**15.90**	mm

Source: Formulated by JICA study team

Table 6.3-13 Calculation of Pipe Wall Thickness for 16 Inch Class 2

BATMAN1 16" GAS PIPELINE, API 5L-X65, ERW					
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS					
PROJECT	: BATMAN1 PROJECT				
DESIGN BASED ON	: ASME B 31.8				
LOCATION CLASS	: AS PER ANSI B31.8		CLASS 2		
DESCRIPTION	Symbol	BU		METRIC	
DESIGN BASIS					
DESIGN PRESSURE	P	1,000	Psig	70	kgs/sq.cm
DESIGN TEMPERATURE	T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER	D	16	Inch	406.40	mm
MATERIAL OF PIPE		**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L					
SPECIFIED MINIMUM YIELD STRENGTH	S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997					
DESIGN FACTOR (for pipe diameter D > 8")					
DESIGN FACTOR	F	0.60		0.60	
REF: ASME B 31.8 TABLE 841.116A					
TEMPERATURE DERATING FACTOR	T	1		1	
FABRICATION TOLERANCE (10%)	a	0.10		0.10	
LONGITUDINAL JOINT FACTOR	E	1		1	
CORROSION ALLOWANCE	CA	0.000	INCH	0.0	mm
CALCULATION					
REF: ASME B 31.8 EQUATION 841.11					
$P = \frac{2.S.t}{D}.FET$	$t = \frac{P.D}{2.S.F.E.T}$		$t\,tol = \frac{tcal}{(1-a)}$		
CALCULATED WALL THICKNESS	t_{-calc}	0.205	INCH	5.210	mm
WALL THICKNESS + CORROSION ALLOWANCE	$t_{-calc+c.a}$	0.599	INCH	5.210	mm
WALL THICKNESS + CORROSION ALLOWANCE	t_{tol}	0.228	INCH	5.79	mm
+ FABRICATION TOLERANCE					
WALL THICKNESS (STD. SPEC. API 5 L)	t_{-wt}	**0.280**	INCH	**7.10**	mm
REFERENCE MINIMUM WALL THICKNESS	t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS	$t_{-select}$	**0.280**	INCH	**7.10**	mm

Source: Formulated by JICA study team

Table 6.3-14 Calculation of Pipe Wall Thickness for 16 Inch Class 3

BATMAN1 16" GAS PIPELINE, API 5L-X65, ERW						
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS						
PROJECT	:	BATMAN1 PROJECT				
DESIGN BASED ON	:	ASME B 31.8				
LOCATION CLASS	:	AS PER ANSI B31.8		CLASS 3		
DESCRIPTION		Symbol	BU		METRIC	
DESIGN BASIS						
DESIGN PRESSURE		P	1,000	Psig	70	kgs/sq.cm
DESIGN TEMPERATURE		T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER		D	16	Inch	406.40	mm
MATERIAL OF PIPE			**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L						
SPECIFIED MINIMUM YIELD STRENGTH		S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997						
DESIGN FACTOR (for pipe diameter D > 8")						
DESIGN FACTOR		F	0.50		0.50	
REF: ASME B 31.8 TABLE 841.116A						
TEMPERATURE DERATING FACTOR		T	1		1	
FABRICATION TOLERANCE (10%)		a	0.10		0.10	
LONGITUDINAL JOINT FACTOR		E	1		1	
CORROSION ALLOWANCE		CA	0.000	INCH	0.0	mm
CALCULATION						
REF: ASME B 31.8 EQUATION 841.11						
$P = \frac{2.S.t}{D}.FET$		$t = \frac{P.D}{2.S.F.E.T}$		$t\,tol = \frac{tcal}{(1-a)}$		
CALCULATED WALL THICKNESS		t_{-calc}	0.246	INCH	6.251	mm
WALL THICKNESS + CORROSION ALLOWANCE		$t_{-calc+c.a}$	0.640	INCH	6.251	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE		t_{tol}	0.273	INCH	6.95	mm
WALL THICKNESS (STD. SPEC. API 5 L)		t_{-wt}	**0.311**	INCH	**7.90**	mm
REFERENCE MINIMUM WALL THICKNESS		t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS		$t_{-select}$	**0.311**	INCH	**7.90**	mm

Source: Formulated by JICA study team

Table 6.3-15 Calculation of Pipe Wall Thickness for 16 Inch Class 4

BATMAN1 16" GAS PIPELINE, API 5L-X65, ERW					
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS					
PROJECT : BATMAN1 PROJECT					
DESIGN BASED ON : ASME B 31.8					
LOCATION CLASS : AS PER ANSI B31.8		CLASS 4			
DESCRIPTION	Symbol	BU		METRIC	
DESIGN BASIS					
DESIGN PRESSURE	P	1,000	Psig	70	kgs/sq.cm
DESIGN TEMPERATURE	T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER	D	16	Inch	406.40	mm
MATERIAL OF PIPE		**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L					
SPECIFIED MINIMUM YIELD STRENGTH	S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997					
DESIGN FACTOR (for pipe diameter D > 8")					
DESIGN FACTOR	F	0.40		0.40	
REF: ASME B 31.8 TABLE 841.116A					
TEMPERATURE DERATING FACTOR	T	1		1	
FABRICATION TOLERANCE (10%)	a	0.10		0.10	
LONGITUDINAL JOINT FACTOR	E	1		1	
CORROSION ALLOWANCE	CA	0.000	INCH	0.0	mm
CALCULATION					
REF: ASME B 31.8 EQUATION 841.11					
$P = \frac{2.S.t}{D}.FET$	$t = \frac{P.D}{2.S.F.E.T}$		$t\,tol = \frac{tcal}{(1-a)}$		
CALCULATED WALL THICKNESS	t_{-calc}	0.308	INCH	7.814	mm
WALL THICKNESS + CORROSION ALLOWANCE	$t_{-calc+c.a}$	0.701	INCH	7.814	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE	t_{tol}	0.342	INCH	8.68	mm
WALL THICKNESS (STD. SPEC. API 5 L)	t_{-wt}	**0.374**	INCH	**9.50**	mm
REFERENCE MINIMUM WALL THICKNESS	t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS	t_{select}	**0.374**	INCH	**9.50**	mm

Source: Formulated by JICA study team

Table 6.3-16 Calculation of Pipe Wall Thickness for 12 Inch Class 3

BATMAN1 12" GAS PIPELINE, API 5L-X65, ERW

VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS

PROJECT	: BATMAN1 PROJECT				
DESIGN BASED ON	: ASME B 31.8				
LOCATION CLASS	: AS PER ANSI B31.8	CLASS 3			

DESCRIPTION	Symbol	BU		METRIC	
DESIGN BASIS					
DESIGN PRESSURE	P	1,000	Psig	70	kgs/sq.cm
DESIGN TEMPERATURE	T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER	D	12	Inch	323.90	mm
MATERIAL OF PIPE		**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L					
SPECIFIED MINIMUM YIELD STRENGTH	S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997					
DESIGN FACTOR (for pipe diameter D > 8")					
DESIGN FACTOR	F	0.50		0.50	
REF: ASME B 31.8 TABLE 841.116A					
TEMPERATURE DERATING FACTOR	T	1		1	
FABRICATION TOLERANCE (10%)	a	0.10		0.10	
LONGITUDINAL JOINT FACTOR	E	1		1	
CORROSION ALLOWANCE	CA	0.000	INCH	0.0	mm

CALCULATION

REF: ASME B 31.8 EQUATION 841.11

$$P = \frac{2.S.t}{D}.FET \qquad t = \frac{P.D}{2.S.F.E.T} \qquad t\,tol = \frac{tcal}{(1-a)}$$

CALCULATED WALL THICKNESS	t_{-calc}	0.196	INCH	4.982	mm
WALL THICKNESS + CORROSION ALLOWANCE	$t_{-calc+c.a}$	0.590	INCH	4.982	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE	t_{tol}	0.218	INCH	5.54	mm
WALL THICKNESS (STD. SPEC. API 5 L)	t_{-wt}	**0.500**	INCH	**7.10**	mm
REFERENCE MINIMUM WALL THICKNESS	t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS	$t_{-select}$	**0.500**	INCH	**7.10**	mm

Source: Formulated by JICA study team

Table 6.3-17 Calculation of Pipe Wall Thickness for 12 Inch Class 4

BATMAN1 12" GAS PIPELINE, API 5L-X65, ERW						
VERIFICATION AND CALCULATION OF PIPE WALL THICKNESS						
PROJECT	:	BATMAN1 PROJECT				
DESIGN BASED ON	:	ASME B 31.8				
LOCATION CLASS	:	AS PER ANSI B31.8	CLASS 4			
DESCRIPTION		Symbol	BU		METRIC	
DESIGN BASIS						
DESIGN PRESSURE		P	1,000	Psig	70	kgs/sq.cm
DESIGN TEMPERATURE		T_{ds}	150	degF	66	degC
PIPE OUTSIDE DIAMETER		D	12	Inch	323.90	mm
MATERIAL OF PIPE			**API 5L-X65 (SEAMLESS or ERW)**			
REF. API 5L						
SPECIFIED MINIMUM YIELD STRENGTH		S	65,000	Psi	4,570	kgs/sq.cm
REF: REGULATION, MINISTER OF MINING & ENERGY No. 300.K/38/M.PE/1997						
DESIGN FACTOR (for pipe diameter D > 8")						
DESIGN FACTOR		F	0.40		0.40	
REF: ASME B 31.8 TABLE 841.116A						
TEMPERATURE DERATING FACTOR		T	1		1	
FABRICATION TOLERANCE (10%)		a	0.10		0.10	
LONGITUDINAL JOINT FACTOR		E	1		1	
CORROSION ALLOWANCE		CA	0.000	INCH	0.0	mm
CALCULATION						
REF: ASME B 31.8 EQUATION 841.11						
$P = \frac{2.S.t}{D}.FET$		$t = \frac{P.D}{2.S.F.E.T}$			$t_{tol} = \frac{tcal}{(1-a)}$	
CALCULATED WALL THICKNESS		t_{-calc}	0.245	INCH	6.228	mm
WALL THICKNESS + CORROSION ALLOWANCE		$t_{-calc+c.a}$	0.639	INCH	6.228	mm
WALL THICKNESS + CORROSION ALLOWANCE + FABRICATION TOLERANCE		t_{tol}	0.272	INCH	6.92	mm
WALL THICKNESS (STD. SPEC. API 5 L)		t_{-wt}	**0.311**	INCH	**7.90**	mm
REFERENCE MINIMUM WALL THICKNESS		t_{-PGN}	**N.A**	INCH	**N.A**	mm
USED WALL THICKNESS		$t_{-select}$	**0.311**	INCH	**7.90**	mm

Source: Formulated by JICA study team

6.3.6 Comparison of Pipeline Diameter between JICA M/P(2002) and 2011

As of JICA M/P(2002), the pipeline diameter of the main pipeline was 16 inch, however that figure has at the present increased to 24 inch. The table 6.3-18 and 6.3-19 calls the results of gas flow analysis in JICA M/P(2002) and 2011, respectively.

Table 6.3-18 2002 Pipeline Flow Analysis Results

from	to	Length [km]	Est. Flow [MMNcmh]	Location class	OD [mm]	U [m/s]	P1 [KSCG]	P2 [KSCG]
①Tabangao	②LipaCity	28	0.22844	2	450.0	6.619	68.0	62.1
②LipaCity	③SantoTomas	22	0.22844	2	400.0	9.827	62.1	52.8
③SantoTomas	④Cabuyao	15	0.21423	4	400.0	10.475	52.8	46.3
④Cabuyao	⑤Carmona	9	0.21064	4	400.0	11.303	46.3	42.1
⑤Carmona	⑥Alabang	11	0.20673	1-2	400.0	12.729	42.1	36.6
⑥Alabang	⑦Bacoor	10	0.07851	4	300.0	9.489	36.6	33.0
⑦Bacoor	⑧Pasay	10	0.07851	4	300.0	10.738	33.0	29.1
⑧Pasay	⑨manila	9	0.07851	1-2	300.0	12.420	29.1	25.0
⑨manila	⑩NCR-N	15	0.04275	1-2	300.0	7.428	25.0	22.7

Source: Formulated by JICA study team

Table 6.3-19 2011 Pipeline Flow Analysis Results

from	to	Length [km]	Est. Flow [MMNcmh]	Location class	OD [mm]	Thickness [mm]	U [m/s]	P1 [KSCG]	P2 [KSCG]
①Tabangao	②LipaCity	30.0	0.46744	3	610.0	12.7	8.299	68.0	60.1
②LipaCity	③SantoTomas	21.0	0.46744	2	610.0	11.9	9.178	60.1	53.9
③SantoTomas	④Calamba	12.5	0.41426	2	610.0	11.9	8.627	53.9	50.8
④Calamba	⑤Cabuyao	10.3	0.41426	3	610.0	12.7	9.165	50.8	48.0
⑤Cabuyao	⑥Carmona	6.0	0.36108	3	610.0	12.7	7.742	50.8	49.6
⑥Carmona	⑦Alabang	14.0	0.30790	3	610.0	12.7	6.895	49.6	47.4
⑦Alabang	⑧Sucat	4.0	0.25472	4	610.0	15.9	5.887	47.4	46.9
⑧Sucat	⑨Qurino	38.0	0.06529	4	323.9	7.9	6.295	46.9	39.5

Source: Formulated by JICA study team

The reasons for increasing the diameter from 16 to 24 inch are summarized as follows:

1) Change in supply volumes to industrial areas and for CNG vehicles
   The supply volumes increased from 3.29MMcf/h (93,400Nm^3/h) in 2002 to 7.76MMcf/h (220,000Nm^3/h) in 2011.
2) Gas supply volume in JICA M/P(2002) to the Sucat power station was 4.09MMcf/h (116,000Nm^3/h). In 2011, this figure increased to 5.89MMcf/h (167,000Nm^3/h). The reason for the increasing volume is that the previous calculations used a power generation efficiency of 45%, whereas it has been confirmed 35% in 2011. The current volume reflects the said change.
3) The specific gravity value of gas used in flow analysis was 0.597 in JICA M/P(2002). However, since natural gas composition from the gas field is unclear, the standard value, 0.670 is used accordingly in 2011.

6.4 Related Pipeline Facilities

This section describes with regard to pipeline facilities.
Pipeline flow diagrams are shown in Figure 6.4-1 to 6.4-4

6.4.1 Pipeline Block Valve Stations

ANSI/ASME B31.8 specifies a distance between each Block valve station on a gas pipeline as follows:

- Location Class 1:20miles (32km) in areas of predominantly
- Location Class 2:15miles (24km) in areas of predominantly
- Location Class 3:10miles (16km) in areas of predominantly
- Location Class 4:5miles (8km) in areas of predominantly

Block valve stations are installed along or at the ends of the pipeline. A standard plot plan of a valve station to shut down a pipeline in Figure 6.4-5

Distances between each shut down valves installed along the pipeline are specified in accordance with the pipeline's class location. Class locations 2, 3 and 4 call for distance between valves of 24km, 16km, and 8km respectively. Drive units are included in the shut down valves to operate remotely as well as on-site operation.

Furthermore, emergency venting line with a valve and vent stack is individually installed at each block valve station to release of gas between valve stations. The emergency venting line is to be buried and connected to a vent stack. The vent stack shall have sufficient height and location where far away from nearby combustible objects to ensure no spread of fire. A height of the vent stack is designed as 12.0 meter in accordance with data from past gas pipeline and valve station construction projects.

The precise locations of block valve stations will be decided at the time of determining route specifics.

6.4.2 Pig Launcher/Receiver Stations

Once the completion of pipeline installation, the whole pipeline shall be pigged to clean up inside of the pipeline. Regular pig cleaning and or intelligent pig corrosion inspections are also executed. Pig launchers and receivers are installed at the valve stations located at both ends of pipeline with equivalent diameters. Pig launchers and receivers for each case are shown in the pipeline's full system map shown in Figure 6.4-1 to 6.4-4.

6.4.3 Cathodic Protection

Since the corrosion of pipeline is dissolution reaction of the iron by the current outflow from an anodal spot, the cessation of the dissolution reaction is required by an external electric current flow which has balanced volume with the current poutflow from an anodal spot. This prevention of corrosion method is called cathodic protection. There are two type of the cathodic protection for pipelines, e.g. SACP and ICCP. BatMan pipeline adopts ICCP considering with a pipeline length and effectiveness.

(1) SACP (Sacrificial Anode Cathodic Protection): Anodes such as aluminum, zinc, and magnesium which has lower electric potential than steel of a pipeline, binds together by an electric wire with a pipeline, and gets an electric current flow for anticorrosion.
(2) ICCP (Impressed Current Cathodic Protection): Using a rectifier along with anodes buried in the ground. The DC powered rectifier supplies electrons to a cathodic protection system stopping corrosion of a pipeline and since the anodes don't surrender many electrons, they don't corrode much either.

Accordingly pipeline and or facilities installed above ground shall be isolated to continue the cathodic protection effectiveness. An operation state of the cathodic protection system shall be recorded and controlled by an SCADA system.

6.4.4 Metering Station

Metering stations, which are installed at pipeline terminal, shall manage and monitor flow volumes of commercial-use gas to end users.

Metering stations on the pipeline are installed at the Batangas gas plant and each power station. Metering stations will be installed at each user in the industrial areas, however they are not to be included in the present investigation.

6.4.5 SCADA System

The SCADA system is to be installed in order to assure reliable and efficient operational performance, as well as for general system monitoring purposes for the pipeline. The system shall be capable to control remotely shut down valve and vent valve in emergency situations such as a gas leak. The system can also gather information from the gas plant such as changes of outlet flow conditions, and reflect such changes in pipeline operation. The operation room shall be established in the office of the pipeline's owner, and will monitor the items below. The SCADA system overview is shown in Figure 6.4-6.

- Gas flow volume, pressure, and temperature
- Measure current of cathodic protection
- Emergency response to sudden and dramatic changes in gas pressure remotely
- Data exchange with related facilities

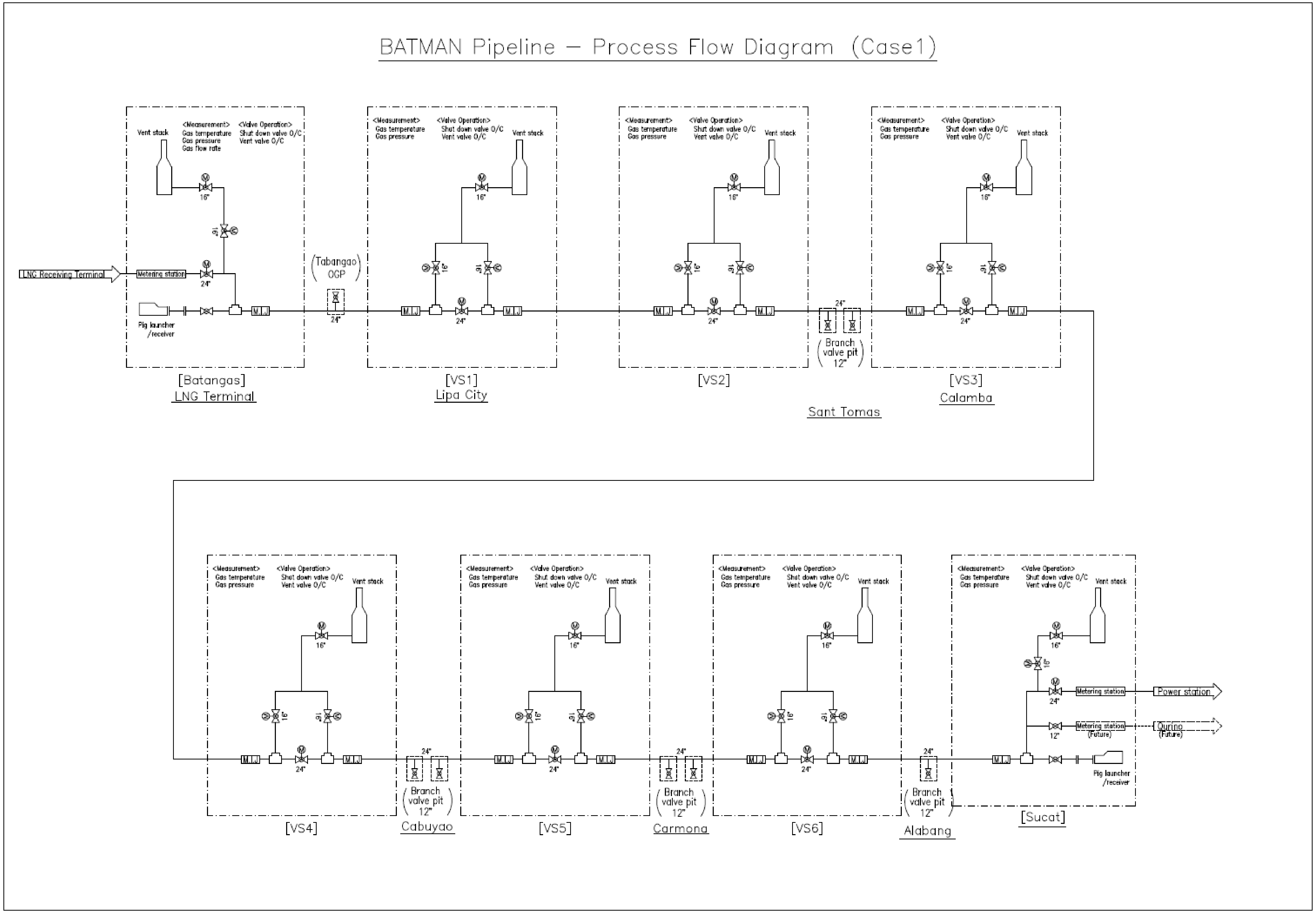


Figure 6.4-1 Pipeline Flow Diagram on Case 1

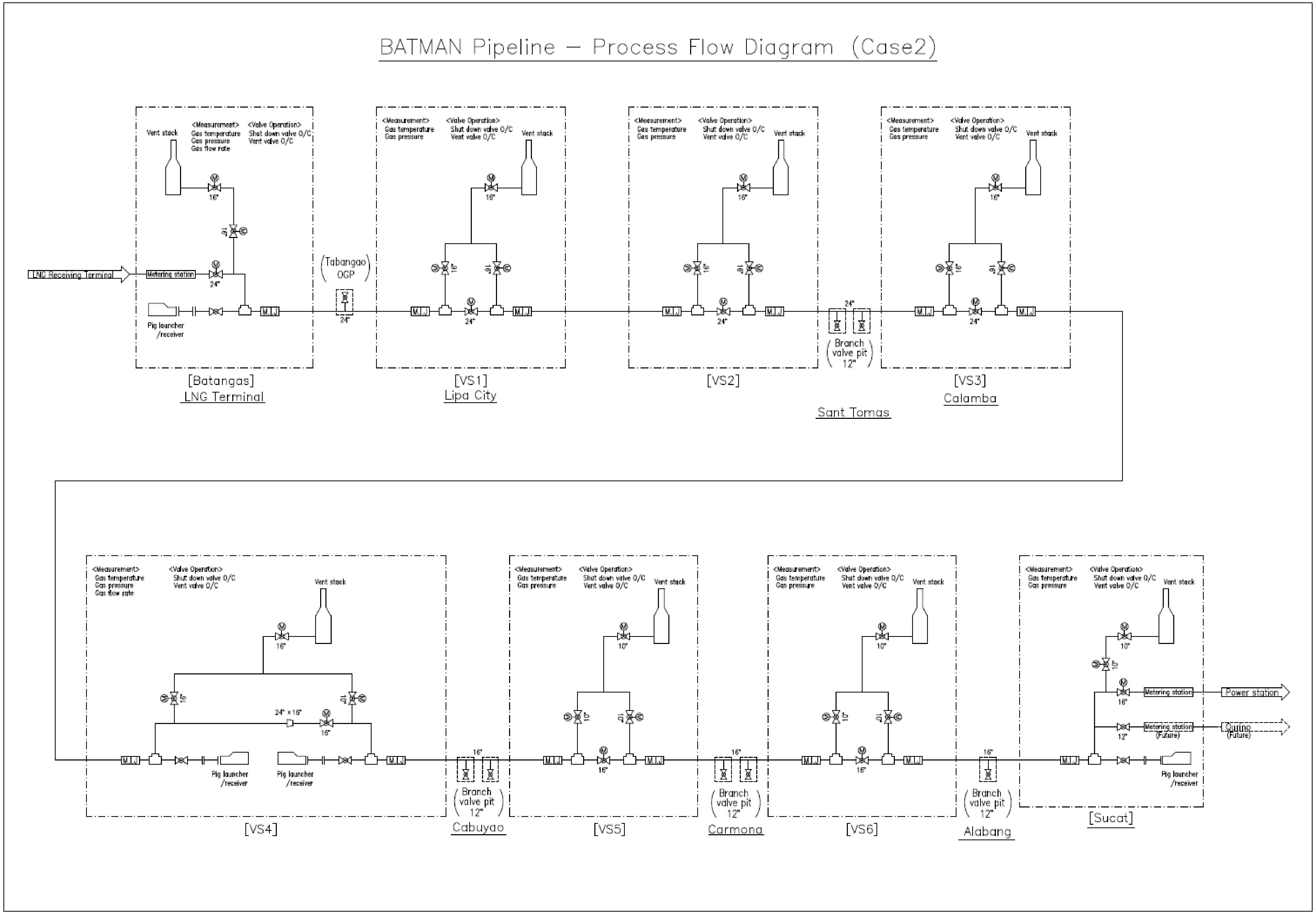


Figure 6.4-2 Pipeline Flow Diagram on Case 2

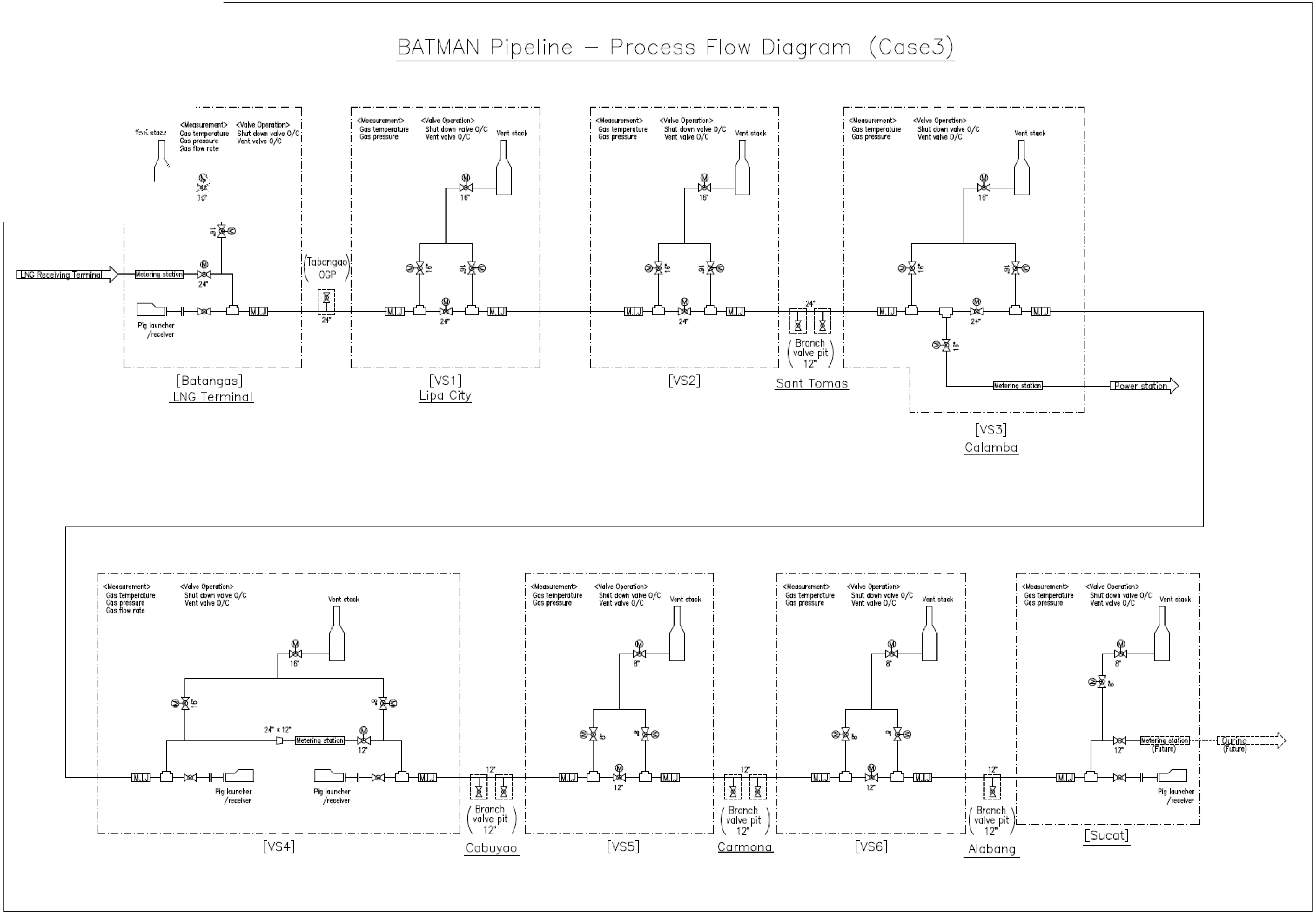


Figure 6.4-3 Pipeline Flow Diagram on Case 3

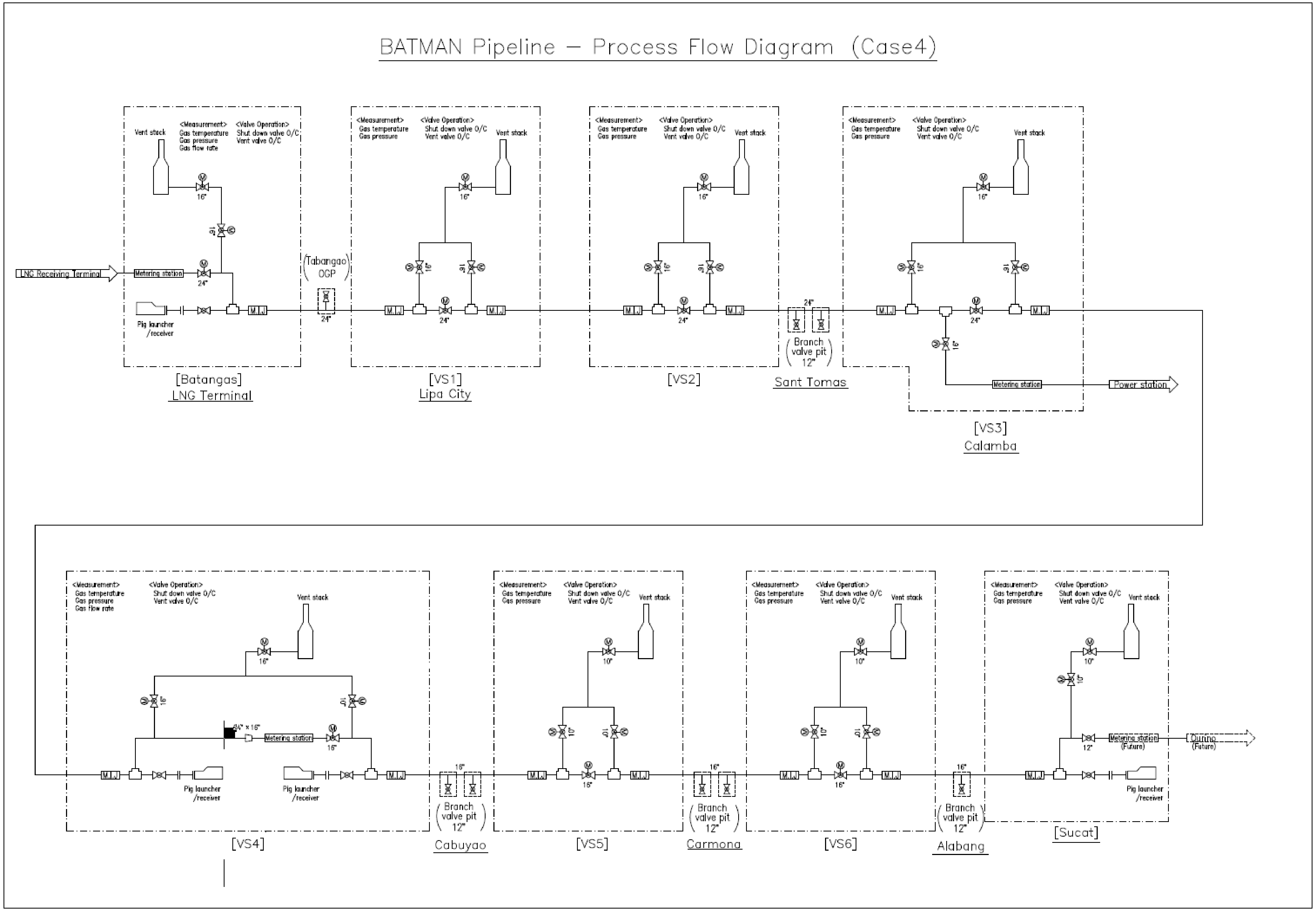
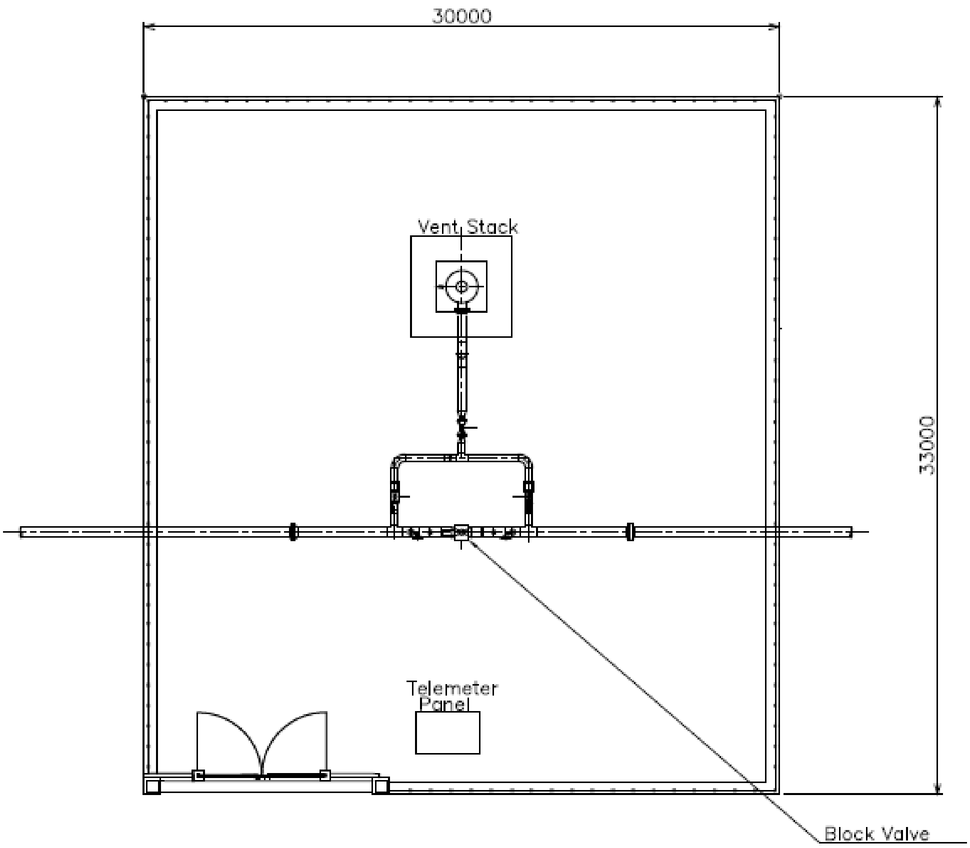
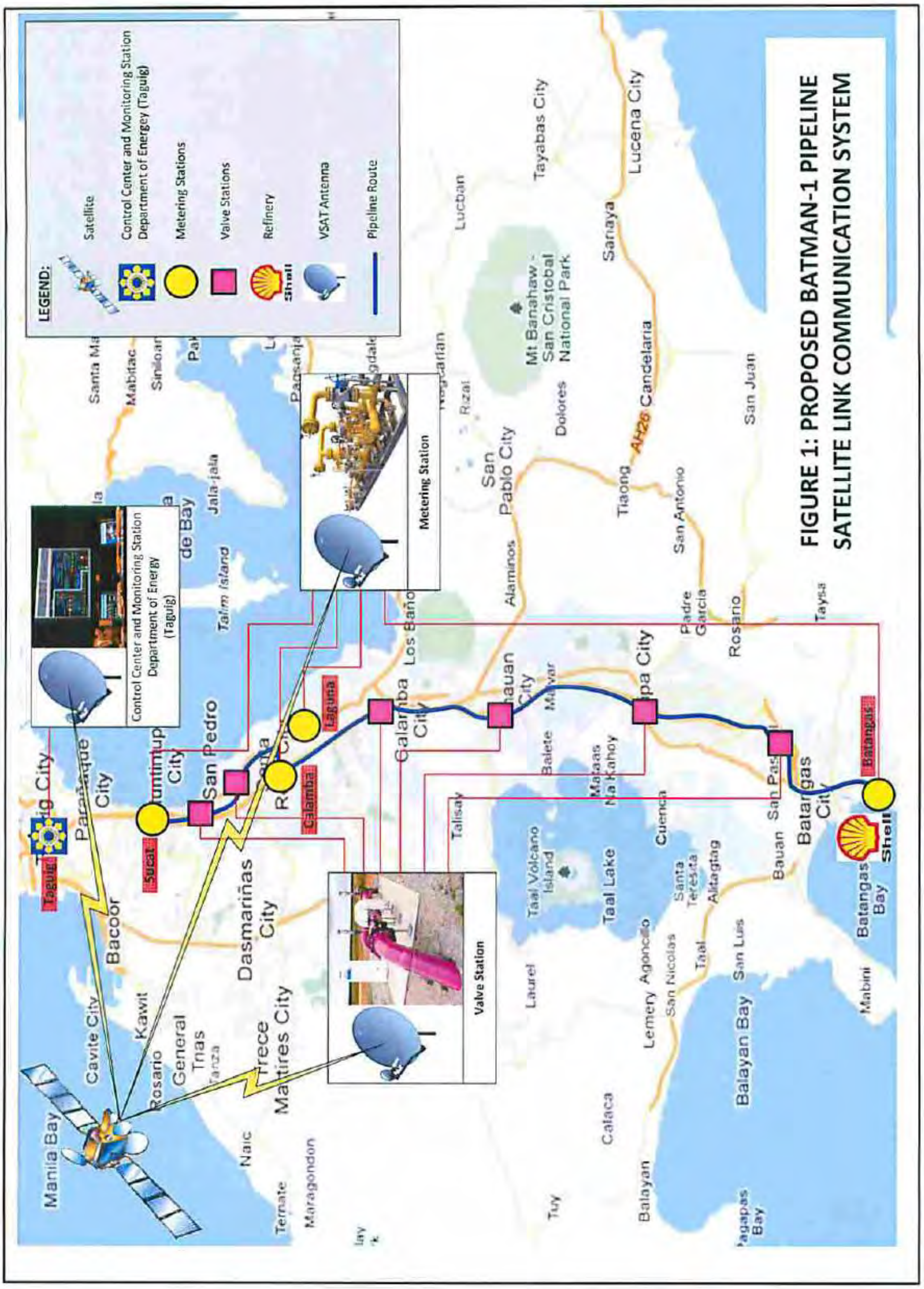


Figure 6.4-4 Pipeline Flow Diagram on Case 4



Source: Formulated by JICA study team

Figure 6.4-5 Standard Plot Plan of a Valve Station to Shut Down a Pipeline



Source: JRC

Figure 6.4-6 SCADA System Overview (Proposed by JRC - Japan Radio Co., Ltd)

6.5 Consideration of Project Implementation

6.5.1 Construction Costs

(1) Cost Estimate Conditions and Its Structure

Conditions to calculate the cost estimate are as follows:

- Pipeline installation work is as a turnkey EPC project which is normally applied in such construction project.
- The schedule is calculated to be supposed 365 days operation per year, and 10% downtime due to heavy weather.
- For the sake of convenience, the schedule assumes that engineering work will commence since January 2015.
- As for the exchange rate for the estimation, Japanese Yen is 85.0 for 1 US dollar as well as Philippine peso 43.0 for 1 USD.

Table 6.5-1 Predicted Progresses of Pipeline Installation

	Distance (m)	Predicted Progress (m/D)	Target Duration (Days - Net)	Required Work Crew
Section 1	18,900	10	360	**5**
Section 2	57,300	500	110	**1**
Section 3	29,000	20	360	**4**

Source: Formulated by JICA study team

1) Section 1

Considering the pipeline installation work is to be done under a heavy-traffic road in Batangas urban area, a predicted daily progress deems 10 m/d. 5 work crews will be stationed and the said construction is expected to complete within net 360days, 380 days including the downtime rate. If 6 or more crews are to be stationed on the section, a daily production is calculated higher. However, in this case, crews would be fairly close to each other in a particular section, which will make heavy traffic and a negative impact to local environment, also human resources of management team will be increased. Considering the said potential issues, 5 crews stationed in the section is to be the ideal formation.

2) Section 2

Construction cost is estimated in a case that Spread technique can be applied in the section except at the end points of the section, and areas crossed existing roads. It is supposed that using an internal and external automatic welding machine, a predicted production rate is 500 m/d.

3) Section 3

The section is within PNR boundary. Construction costs are estimated to suppose that 15m either side of the railway is obtained. 4 crews will be stationed in the section, and expected daily production rate is 20 m/d, thus the pipeline installation in the section will be completed within net 360days, 380 days including the downtime rate. Note that illegal dwellings have sporadically occupied within this section of the route. As computing dwellings relocation costs is quite difficult, such costs are not included in the current estimation.

(2) Costs Estimated and Calculation Method

1) Pipeline Material Costs

Cost estimates for materials such as polyethylene-coated line pipe, induction bends, and fittings are based on quotes obtained through Nippon Steel Engineering, procurement department. The materials are to be procured from Japan. For purposes of cost estimation for this Study, it is assumed that materials are to be procured from Japan.

2) Valve Stations and Other Related Facilities Costs

Cost estimates for materials and construction for valve stations, metering stations, SCADA and cathodic protection systems are based on actual costs from similar projects undertaken in the past both domestically and abroad by Nippon Steel Engineering. For purposes of cost estimation, it is assumed that the materials are to be procured from overseas except SCADA system, which is to be procured from Japan.

3) Construction Costs

For all related costs to pipeline and its facilities construction, such as labor, machinery, consummable, material stockyards, shipping, residence, and personnel transportation costs, a request for a quotation was issued to a local construction company. Thus construction costs have been estimated based on the local company's quotation into consideration alongside the similar past project data provided by Nippon Steel Engineering.

4) Engineering and Management Costs

Engineering and management costs, including construction planning and management, quality control, and safety control associated with the execution of detailed pipeline design and construction are computed as an actual percentage of these costs to total costs experienced on similar past projects performed by Nippon Steel Engineering.

5) Contingency Costs

Contingency costs are not included but only a base cost has been estimated.

6) Incentive

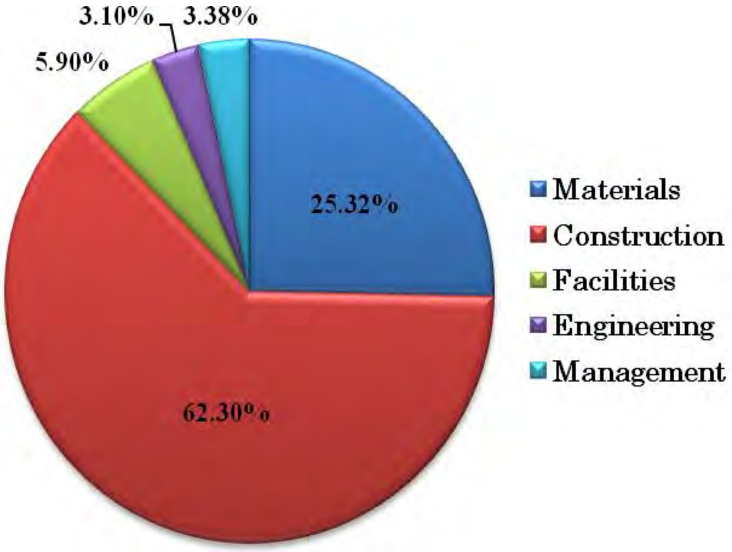
The present cost estimation does not include any incentive.

(3) Estimate Results

As pipe diameter and wall thickness vary according to each case, cost estimations are on a per-case basis. The results are listed in Table 6.5-2, and a percentage breakdown of the case 4 estimated items is plotted on Figure 6.5-1.

Table 6.5-2 Per-Case Estimate Results

Case	Currency Rate: JPY/USD=	85	Section 1 18.9km		Section 2 57.3km		Section 3 28.5km		Total	
Case 1	Joint number		1,663 jts		5,042 jts		2,552 jts		**9,258 jts**	
	Distance		18.9 km		57.3 km		29.0 km		**105.2 km**	
	inch-m		453,600 inch-m		1,375,200 inch-m		696,000 inch-m		**2,524,800 inch-m**	
	Grand total	(x 1,000 JPY | USD)	JPY	USD	JPY	USD	JPY	USD	**JPY**	**USD**
			3,408,030	40,094	7,231,073	85,071	4,581,325	53,898	**15,220,427**	**179,064**
	Cost / inch-m	(JPY | USD)	7,513	88.39	5,258	61.86	6,582	77.44	**6,028**	**70.92**
Case 2	Joint number		1,663 jts		5,042 jts		2,552 jts		**9,258 jts**	
	Distance		18.9 km		57.3 km		29.0 km		**105.2 km**	
	inch-m		453,600 inch-m		1,375,200 inch-m		504,000 inch-m		**2,332,800 inch-m**	
	Grand total	(x 1,000 JPY | USD)	JPY	USD	JPY	USD	JPY	USD	**JPY**	**USD**
			3,408,030	40,094	7,072,153	83,202	3,150,049	36,643	**13,630,231**	**159,939**
	Cost / inch-m	(JPY | USD)	7,513	88.39	5,143	60.50	6,250	72.70	**5,843**	**68.56**
Case 3	Joint number		1,663 jts		5,042 jts		2,552 jts		**9,258 jts**	
	Distance		18.9 km		57.3 km		29.0 km		**105.2 km**	
	inch-m		453,600 inch-m		1,375,200 inch-m		408,000 inch-m		**2,236,800 inch-m**	
	Grand total	(x 1,000 JPY | USD)	JPY	USD	JPY	USD	JPY	USD	**JPY**	**USD**
			3,407,737	40,091	7,287,943	85,741	2,513,429	29,570	**13,209,109**	**155,401**
	Cost / inch-m	(JPY | USD)	7,513	88.38	5,300	62.35	6,160	72.47	**5,905**	**69.47**
Case 4	Joint number		1,663 jts		5,042 jts		2,552 jts		**9,258 jts**	
	Distance		18.9 km		57.3 km		29.0 km		**105.2 km**	
	inch-m		453,600 inch-m		1,375,200 inch-m		504,000 inch-m		**2,332,800 inch-m**	
	Grand total	(x 1,000 JPY | USD)	JPY	USD	JPY	USD	JPY	USD	**JPY**	**USD**
			3,408,030	40,094	7,291,159	85,778	3,026,633	35,607	**13,725,821**	**161,480**
	Cost / inch-m	(JPY | USD)	7,513	88.39	5,302	62.38	6,005	70.65	**5,884**	**69.22**



Source: Formulated by JICA study team

Figure 6.5-1 Estimate Items: Percentage Breakdown

(4) Procurement Detail of Primary Items

Table 6.5-3 shows procurement detail of primary items.

Table 6.5-3 Procurement Detail of Primary Items

PHP/USD= 43 JPY/USD= 85	Case 1	in USD	%	Case 2	in USD	%	Case 3	in USD	%	Case 4	in USD	%
JPY (x 1,000)												
Pipe Materials	3,583,083	42,154		3,100,361	36,475		3,001,695	35,314		3,066,568	36,077	
SCADA	270,000	3,176		270,000	3,176		270,000	3,176		270,000	3,176	
JPY Total (x 1,000)	**3,853,083**	**45,330**	**27.4**	**3,370,361**	**39,651**	**26.7**	**3,271,695**	**38,491**	**27.2**	**3,336,568**	**39,254**	**26.3**
USD (x 1,000)												
Materials for Valve Station	2,880	--->		2,500	--->		2,406	--->		2,500	--->	
Materials for Metering Station	1,129	--->		960	--->		1,694	--->		1,694	--->	
Materials for Branch Lines	118	--->		118	--->		118	--->		118	--->	
Pig Launcher/Receiver	706	--->		600	--->		547	--->		600	--->	
Cold Bending Machine	691	--->		691	--->		691	--->		691	--->	
USD Total (x 1,000)	**5,524**	--->	**3.3**	**4,868**	--->	**3.3**	**5,456**	--->	**3.9**	**5,603**	--->	**3.8**
PHP (x 1,000)												
Construction Work Force	4,744,364	110,334		4,282,162	99,585		4,110,919	95,603		4,314,412	100,335	
Const. Equipment and Plant	103,038	2,396		94,517	2,198		5,784	135		94,517	2,198	
Power Cable	54,761	1,274		54,761	1,274		54,761	1,274		54,761	1,274	
Materials for Cathodic Protecti	30,100	700		30,100	700		30,100	700		30,100	700	
PHP Total (x 1,000)	**4,932,262**	**114,704**	**69.3**	**4,461,539**	**103,757**	**70.0**	**4,201,563**	**97,711**	**69.0**	**4,493,789**	**104,507**	**70.0**
Total in USD (x 1,000)		**165,558**	**100**		**148,276**	**100**		**141,657**	**100**		**149,363**	**100**

Source: Formulated by JICA study team

(5) Construction Cost Comparisons to JICA M/P(2002)

When compared with JICA M/P(2002) construction costs, inch-meter unit prices in 2011 come in around 2 times higher USD basis. Main causes of the difference are that costs of human resources, line pipe, materials, and logistic has soared. Also as the result of the current study, expected daily progress in the section 1, Batangas urban area, is poor.

Table 6.5-4 shows the JICA M/P(2002) to 2011 cost comparison. From Figure 6.5-2 to 6.5-4 displays the price escalation and Philippines' GDP growth in last 10 years.

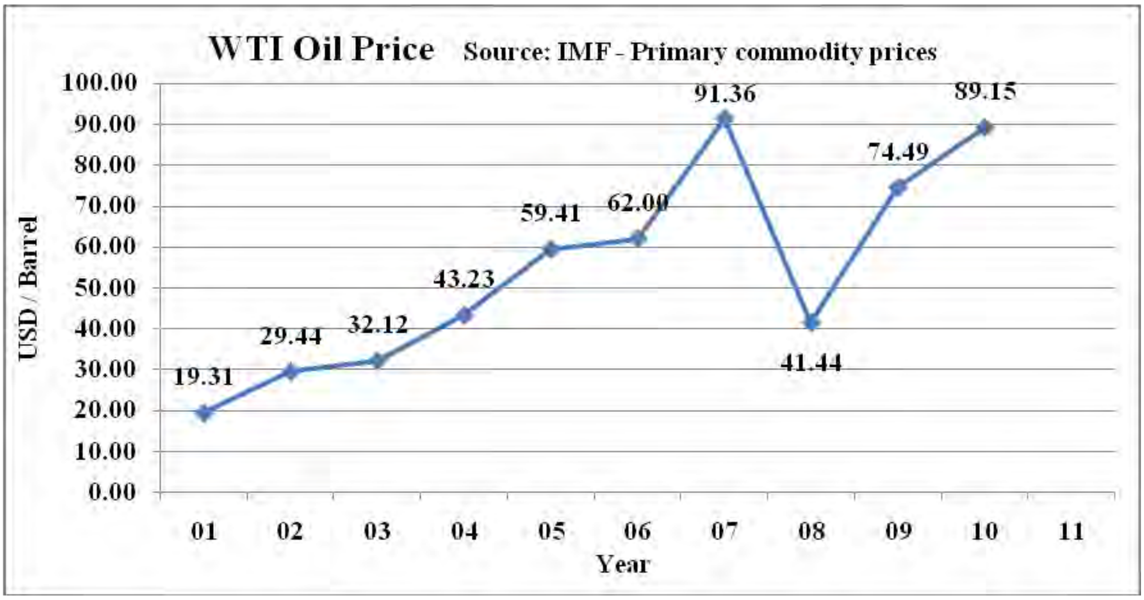
Table 6.5-4 Estimation Comparative Table: JICA M/P(2002) and 2011

Pipeline Diameter	Section 1 (USD / Inch-m)		Section 2 (USD / Inch-m)		Seciton 3 (USD / Inch-m)	
	2002	**2011**	**2002**	**2011**	**2002**	**2011**
24”	39.58	88.39	18.75	61.86 (Case 1)	29.17	72.5
16”	40.63	N/A	21.87	N/A	31.25	70.6 (Case 4)
12”	50	N/A	25	N/A	37.5	72.5 (Case 3)

Source: Formulated by JICA study team

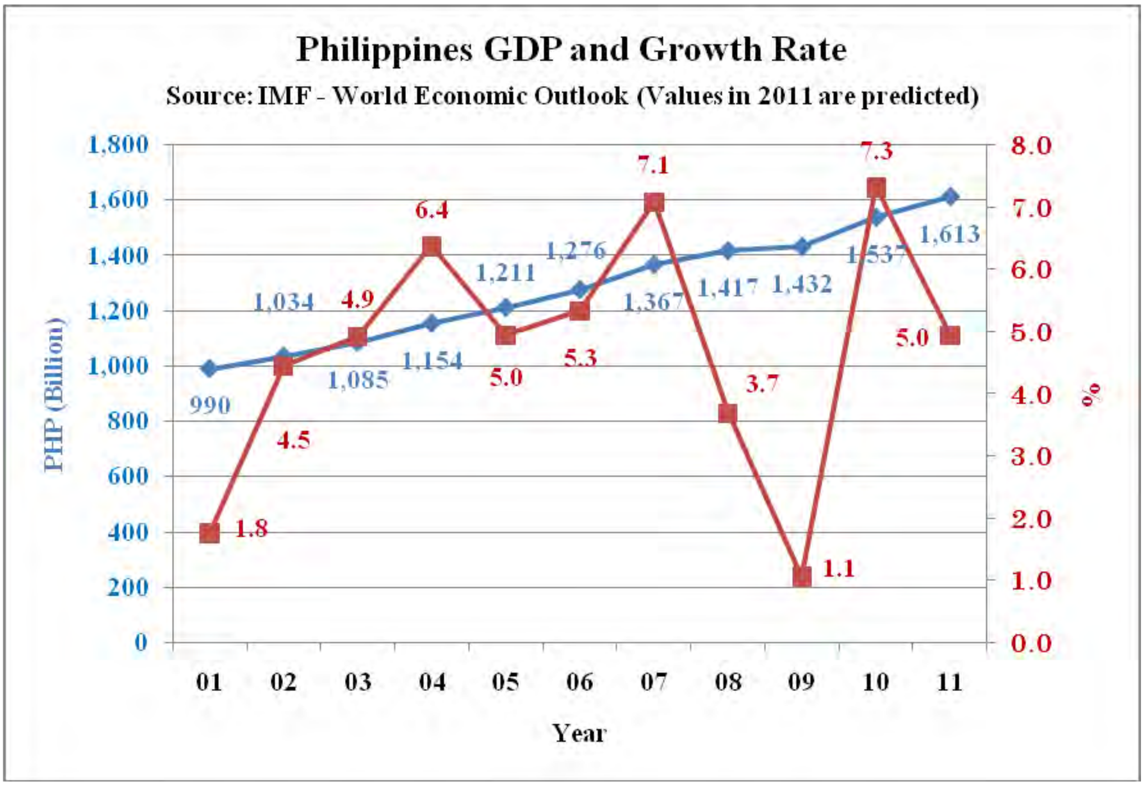
Source: Japan Metal Daily

Figure 6.5-2 Steel Plate Price in Japan



Source: IMF

Figure 6.5-3 WTI Oil Price



Source:IMF

Figure 6.5-4 Philippines GDP and Growth Rate

(6)Recommended Case from Pipeline Construction View Point

From pipeline construction view point, the case 4 is recommended due to the reason that the ratio of Construction Cost to Natural Gas Supply Volume is lower, i.e. Natural Gas Supply Capacity is the highest and it has flexibility to meet future increased gas demand. Ratio construction cost to natural gas supply volume is shown in Table 6.5-5.

Table 6.5-5 Ratio Construction Cost to Natural Gas Supply Volume

	a: Total Cost (USD)	b: Gas Flow Volume (scf/h)	a / b
Case 1	179,063,851	16,300,000	**10.99**
Case 2	159,939,471	13,920,000	**11.49**
Case 3	155,401,277	13,920,000	**11.16**
Case 4	161,480,246	17,430,000	**9.26**

Source: Formulated by JICA study team

6.5.2 Construction Schedule

(1) Prerequisite Conditions

Conditions to calculate the construction schedule are as follows:

1) A case that a contractor is awarded BatMan pipeline and its facilities as a turnkey EPC project.
2) The schedule is calculated to be supposed 365 days operation per year, and 10% downtime due to heavy weather.
3) For the sake of convenience, the schedule assumes that engineering work will commence since January 2015.
4) ROW has been acquired and ready to use.

(2) Schedule Overview and Basis

As a result of schedule calculation for Engineering, Procurement, Construction and Commissioning, the total pipe-laying period is expected to be 2.1 years. Main items' duration is as follows:

1) Engineering: 0.5 years
2) Procurement: 1.5 years (conducted simultaneously)
3) Construction (pipeline installation): 1.1 years
4) Construction (pipeline inspection and completion): 0.2 years
5) Commissioning: 0.1 years

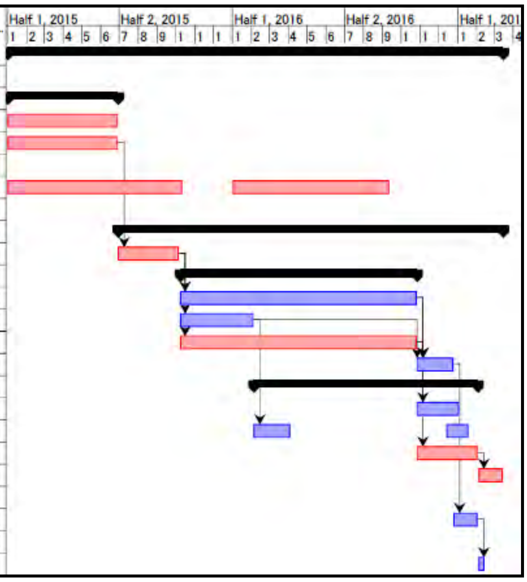
Predicted progresses to calculate the construction schedule at each section are shown in Table 6.5-6. Since it shall keep reasonable intervals of around 5 km each other in the section 1 to prevent heavy traffic and a negative impact to local environment, 5 crews, who work in parallel, will be stationed in particular section where expects the lowest progress and is on a critical path on the schedule. Based on the aforementioned reason, the pipeline installation duration is about 1.1 year, and the project including engineering, procurement, commissioning and etc. will be finished 2.1 year. In addition, pig lauchers/receivers are one of long term procured items, i.e. mother pipe milling in Japan, shipping to a factory at overseas, process and structure, and shipping to the site. This is a reason why procurement duration is calculated as 1.5 year. The construction schedule is displayed in Figure 6.5-5.

Table 6.5-6 Predicted Progresses of Pipeline Installation

	Distance (m)	Predicted Progress (m/D)	Target Duration (Days - Net)	Required Work Crew
Section 1	18,900	10	360	**5**
Section 2	57,300	500	110	**1**
Section 3	29,000	20	360	**4**

Source: Formulated by JICA study team

		Name	Duration	Start	Finish	Pr...	R...
1		**Batman pipeline EPC**	**805 days**	**15/01/01 8:...**	**17/03/15 17:...**		
2		**Engineering**	**180 days**	**15/01/01 8:...**	**15/06/29 17:...**		
3		Design Engineering	180 days	15/01/01 8:00	15/06/29 17:00		
4		Construction planninng	180 days	15/01/01 8:00	15/06/29 17:00		
5		Procurement	620 days	15/01/01 8:00	16/09/11 17:00		
6		**Construction**	**625 days**	**15/06/30 8:...**	**17/03/15 17:...**		
7		Mobilization and site preparation	100 days	15/06/30 8:00	15/10/07 17:00	4	
8		**Pipeline Installation**	**385 days**	**15/10/08 8:...**	**16/10/26 17:...**		
9		Section 1: 18.9km	385 days	15/10/08 8:00	16/10/26 17:00	7	
10		Section 2: 57.3km	120 days	15/10/08 8:00	16/02/04 17:00	7	
11		Section 3: 29.0km	385 days	15/10/08 8:00	16/10/26 17:00	7	
12		Pre-commissioning / 4 times	60 days	16/10/27 8:00	16/12/25 17:00	9...	
13		**Reinstatement**	**365 days**	**16/02/05 8:...**	**17/02/03 17:...**		
14		Section 1: 11.5km	70 days	16/10/27 8:00	17/01/04 17:00	9	
15		Section 2: 57.3km	350 days	16/02/05 8:00	17/01/19 17:00	10	
16		Section 3: 29.0km	100 days	16/10/27 8:00	17/02/03 17:00	11	
17		Demobilization	40 days	17/02/04 8:00	17/03/15 17:00	16	
18		Start-up and Commissioning	40 days	16/12/26 8:00	17/02/03 17:00	12	
19		Takeover	10 days	17/02/04 8:00	17/02/13 17:00	18	



Source: Formulated by JICA study team

Figure 6.5-5 Construction Schedule

Chapter 7 LNG Receiving Terminal

7.1 Design Conditions for LNG Receiving Terminal

7.1.1 Type of LNG Re-gasification Terminal

LNG receiving terminal has two types, which are onshore plant and offshore plant. Table 7.1-1 shows the comparison between onshore plant and offshore plant.

Table 7.1-1 Comparison between Onshore Plant and Offshore Plant

	Onshore Plant	Offshore Plant (Floating Storage Unloading Re-gasification : FRSU)
Capital expenditure	Relatively High (It depends on the situation of harbor and installation site.)	Relatively Low
Operational expenditure	Same between onshore and offshore	Same between onshore and offshore
Construction period	Long due to the long EPC period of LNG storage tank	Short in case of a used carrier's remodeling
Operational Flexibility	High flexibility No restriction of available LNG carrier	Many restrictions such as gas send-out pattern and unloading timing
Reliability of gas send-out	High Reliability (Large amount of LNG storage volume)	Low reliability due to the small amount of LNG storage volume
Expansion ability	Infinite in case of no restriction of land and harbor	Possibility of the additional install of FSRU in case of no restriction of harbor

Source: Formulated by JICA study team

If LNG re-gas Terminal has to be installed and started up in a short term, it is seemed to be better that an offshore plant which is a remodeling type of a used LNG carrier is applied to it. However when it can be installed and started up in a long term, an onshore plant should be applied to LNG re-gas terminal due to the high reliability of gas send-out. And then the capacity of LNG re-gas terminal should be expanded according to the increase of gas demand. From the point of long-term view, an onshore plant should be applied and studied in this feasibility study due to the high reliability and expansion ability.

7.1.2 Location of the LNG Receiving Terminal

The following conditions will be considered for receiving terminals:

(1) Harmony with/ Acceptance by Local Community

How to maintain local environment after accepting the siting of an LNG receiving terminal will be important for secure operation. This requires the confidence of local residents regarding safety, protecting preferred local distinctions such as natural landscape and monuments, and maintaining the everyday lives of the residents. It is preferred not just to maintain them but to improve them when introducing terminals.

(2) Proximity to Transmission and Use

The location of an LNG terminal should accommodate easy connection to gas transmission, and eventual distribution and end use. Furthermore, utilities supply situation such as power, industrial water, and drinking water is one of the selection criteria.

(3) Easy Reception of LNG Ships

The size of generally used LNG ships is up to 266,000 m^3. It is necessary to select a port to allow this scale ships docked securely and safely by checking the data of meteorological, oceanographic seismic, and soil.

(4) Supply Security

When two or more geographically separate markets or distribution areas are conceived, and thus two or more terminals are planned, such terminals should be located in a certain distance from each other to accommodate a good gas network balance to raise security, and thus eventual economies.

(5) Sea water/ Port Conditions

If the concentration of copper ions or suspended matter in seawater is high, it is necessary to take action on the vaporizer design. If there is a big river near the receiving terminal, the frequency of dredging will increase. These factors increase construction costs.

7.1.3 Volume of Imported LNG

Table 7.1-2 shows the volume of LNG that would need to be imported based on the natural gas supply and demand forecast. When the terminal starts operation in 2020, the required LNG imports would be about 0.7 million ton, and the required LNG imports would be about 2.5 million ton in 2030.

Table 7.1-2 Required LNG Imports (thousand /year)

Year	Power	Industry	Transport	Total
2020	0	556	102	658
2021	0	588	123	710
2022	581	619	143	1,343
2023	581	651	164	1,395
2024	1,163	682	184	2,029
2025	1,163	714	204	2,081
2026	1,163	746	245	2,153
2027	1,163	777	286	2,226
2028	1,163	809	327	2,298
2029	1,163	840	368	2,371
2030	1,163	872	409	2,443

Source: Formulated by JICA study team

7.1.4 LNG Vessel

LNG vessels were generally about 125,000 m^3 - 153,000 m^3 capacity. Becoming large in recent years, Q-Flex type (216,000 m^3) in 2007, and the Q-Max type in 2008 (266,000 m^3) were built. By corresponding to all sizes of LNG vessels, the owner's natural gas bargaining power rises. The specifications of LNG carriers for this study are shown below, which has the largest capacity in the world as of year 2011, because the candidate passage and anchorage are very deep and dredging is not needed. Ordinary vessels can also come into this jetty.

LNG Capacity:	266,000m^3
Length of ship:	345m
Beam:	53.8m
Loaded draft:	11.9m
Loaded displacement:	124,690t

7.2 Main Facilities and Equipments of LNG Receiving Terminal

7.2.1 LNG Receiving Facilities

(1) Passage and Anchorage

The passage width shall be 172.5m and the turning basin shall be 690m in diameter (circle). The depths of the passage and the anchorage shall both be 14m.

(2) Jetty

Pier alignment shall be determined based on passage, turning basin, capacity of LNG carrier, frequency of arrival and leaving of carriers, operability of carriers, installation plans for send-out pipelines, and meteorological and ocean meteorological conditions. In this study, a pier shall be extended 300m up to a 14m deep position to minimize dredging work, and shall be of the dolphin type.

(3) Unloading Arms

The 16-inch x 60-feet unloading arm, which is the main type used in Japan, shall be adopted. This one is of the rotary counterweighted marine arm-suspended type, wherein the pressure retaining members and suspension members are isolated from each other so that thermal stress does not act on the pressure members. Furthermore, all of the arms shall be provided with an emergency release system and automatic disconnect hydraulic couplers

(4) Unloading Pipeline

Two lines with 750mm diameter shall be installed so as to allow gas receiving at a rate of 11000m^3-LNG/h. Installation of two pipelines permits gas receiving operation even when one line cannot be operated for some reason.

7.2.2 LNG Tanks

(1) Type

According to the recent trend of LNG storage construction, the above-ground type PC tank (integral type of outer container and PC dike) is the main steam tank and is adopted in this study. The above ground PC tank has 2 types which are full-containment type and suspension deck type. The full-containment type is better seismic performance than the suspension deck type, so it is adopted in Japan and Taiwan. However, suspension deck type is cheaper than full-containment type. Suspension deck type is world standard because of its price, so in this study, we adopted the suspension deck type.

(2) Calculation of Required Number of Storages

The required reserve at an LNG terminal is calculated using the following equation:

Required reserve = Storage + Seasonal differentials + LNG for receiving + LNG Vessel Capacity

Although the quantity maintained in storage may vary depending on the importance to consumers of a continuous supply for power and gas, and our assessment of the risks present in the LNG chain, for the purposes of this report we assume a storage amount plus LNG for receiving equal to 15 days average daily send-out. Accordingly, if we assume an annual handling volume of 2.44 million tons (in 2030), storage would be:

$$2.44 \text{ million t/y} \div 0.46 \text{ t/m}^3 \div 365 \text{ d/y} \times 15 \text{ days} = 220{,}000 \text{ kl}$$

Considering the climate in the Philippines, we may disregard seasonal differentials.

For greater transportation efficiency, a large LNG vessel (263,000 kl) is presumed.
Thus, the requisite LNG in storage is

220,000 kl + 263,000kl = 483,000 kl.

If we assume a 180,000 kl LNG storage with a dead capacity of 3% (the amount that can not be sent out by LNG pumps), the number of tanks required would be four, according to the following equation:

483,000 kl/(180,000 ×0.97) = 2.6

Hence, in 2030, three 180,000 kl LNG storages should be deployed. If we assume, with the same calculation as in 2020, two 180,000 kl LNG storages are also needed.

(3) LNG Pumps

Table 7.2-1 shows the maximum amount of send-out rate. Operating rate of the power plants is calculated at 80%, but we estimate the maximum amount of send-out rate using the data which all power plants are running

Table 7.2-1 Maximum Amount of Send-out Rate

Year	Power	Industry	Transport	Total
2020	0	63	12	75
2021	0	67	14	81
2022	83	71	16	170
2023	83	74	19	176
2024	166	78	21	265
2025	166	81	23	271
2026	166	85	28	279
2027	166	89	33	287
2028	166	92	37	296
2029	166	96	42	304
2030	166	100	47	312

Source: Formulated by JICA study team

The number of LNG pumps to be established is determined by the maximum amount of send-out rate. If we assume the primary (1ry) pump has a capacity of 150 t/h, and the secondary (2ry) pump capacity 150 t/h, the number of pumps required in a terminal would be five which is included two back-up pumps.

7.2.3 LNG Vaporizers

(1) Types of LNG Vaporizer

A vaporiser uses seawater as a LNG heating source, because LNG terminals are mostly constructed along seashores. An open rack-type LNG vaporiser (hereinafter abbreviated as ORV) and a shell & tube-type LNG vaporiser (hereinafter abbreviated as STV) are currently available as LNG vaporizers using seawater as the LNG heating source. In addition, a submerged-type LNG vaporiser (hereinafter abbreviated as SMV) is also available, which recycles the heat that results from LNG combustion. Generally, either ORV or STV is employed considering running costs. On the other hand, the SMV is adopted as a countermeasure against peak gas demand. This study adopts the ORV, which is adopted world-wide, taking comprehensive consideration of operability, maintainability, and cost. However, depending on the sea condition (in case, concentration of suspended matter is high), there is the potential to adopt the SMV.

(2) Calculating Required Numbers

The capacities of LNG vaporizers are determined by the maximum send-out rate per hour. Using ORV (open rack vaporizer) with a send-out capacity of 150 t/h, the number of vaporizers required would be:

312 t/h ÷ 150 t/h・unit = 2.1.

If we were to use one back-up vaporizer, the number would increase to 4.

7.2.4 BOG (boil-off gas) Treatment Facilities

(1) BOG Generation

Factors influencing BOG generation include:
1) BOG due to spontaneous heat input to LNG tanks and pipes;
2) BOG due to heat loss of rotating equipment including LNG pumps;
3) BOG when unloading from an LNG tanker; and,
4) BOG from unloading arms.

Because (1) is permanently generated, the following is assumed.

1.5 t/h・tank unit + 2.5 t/h (piping)

BOG generated when unloading tanks is assumed to be 10 t/h. The rate of BOG generation with unloading operation would be 17.0t/h and without unloading operation 7.0t/h in 2030. The rate of BOG generation with unloading operation would be 15.5t/h and without unloading operation 5.5t/h in 2020.

(2) BOG Reliquefaction Facilities

When there is sufficient LNG send-out to meet needs, BOG may be reliquefied by mixing it with LNG. Suppose BOG can be reliquefied using the amount of LNG which corresponds to 30% of the average send out rate. Since, to be reliquefied, a ton of BOG needs 7 tons, the amount of BOG which can be reliquefied can be calculated. (See Table 7.2-2)

Table 7.2-2 Amount of BOG Reliquefaction

Year	2020	2030
Imported LNG (million t/year)	0.658	2.443
Maximum send-out rate (t/h)	75	312
Minimum send-out rate (t/h)	23	94
Available BOG reliquefied (t/h)	3.2	13.3

Source: Formulated by JICA study team

(3) Types of BOG Compressor

A reciprocal compressor and a centrifugal compressor are generally used in LNG receiving terminals. These two types of compressor are compared in Appendix. The operability of the reciprocating compressor is better than the centrifugal compressor for both start-stop and cool down performance. On the other hand, the centrifugal compressor is excellent in terms of maintainability and is more compact than the reciprocating compressor. From the comparative results, this study adopts the reciprocating type with the good operability and low power cost.

(4) BOG Compressors and Reliquefaction Facilities Installation Plan

Assuming a capacity of 10 t/h for a BOG compressor capable of raising the atmospheric pressure to 1.0 MPaG, the number of compressors required would be

13.3t/h÷10 t/h・unit = 1.3 unit

Accordingly, in all cases, the number of compressors required would be 2. If we include one back-up compressor, the number would be 3.

BOG which is not reliquefied by reliquefaction facilities have to be compressed to mix gas line. The maximum rate will be 12.3 ton / h in case of unloading operation in 2020.
When we adopt a BOG compressor (High pressure) with a maximum capacity of 5 ton / h, the number of required BOG compressors would be:

12.3 t/h ÷ 5 t/h･unit = 2.7.

Specifications of the BOG treatment facilities are provided in Tables 7-2-3.

Table 7.2-3 BOG Treatment Facilities

Year	2020	2030
Number of BOG compressor units (Low pressure)	2	3
Number of BOG compressor units (High pressure)	3	3
Number of BOG reliquefaction units	2	2
BOG reliquefaciton capacity (t/h)	Max 3.2	Max 13.3

Source: Formulated by JICA study team

7.2.5 Seawater Facilities

(1) Required Seawater Volume

Seawater facilities supply water drawn from the sea to a vaporizer and a disaster control facility. Supply capacity depends upon the number of vaporizers. Assuming the design seawater temperature to be 10℃, the required seawater volume for an open rack vaporizer (our plan) would be

35t/t-LNG.

Accordingly, the volume of seawater required for one vaporizer would be

150 t/h × 35 = 5,250 m^3/h･unit.

Table 7.2-4 indicates the volume of seawater required for vaporizers, together with that for the seawater electrolyte and the disaster-control facility. The volume for disaster-control is based on a disaster affecting one tank.

Table 7.2-4 Required Sea Water Volume for Vaporizers and Chlorinator Equipment

Year	2020	2030
Number of vaporizer units	2(1)	4(1)
Sea water volume for vaporizers (m^3/h)	5,250	15,750
Sea water volume for chlorinator equipment(m^3/h)	150	150
Sea water for disaster prevention (m^3/h)	5,200	5,200

Source: Formulated by JICA study team

(2) Seawater Pumps and Seawater Lines

Seawater pumps for vaporizers are with 7,000 m^3/h of capacity and 30 m of lift with two back-ups, booster pumps for disaster control are centrifugal types with 3,000 m^3/h of capacity and 80 m of lift with one back-up. The intake is installed where the required water depth is assured, taking into account ocean topography, currents, and waves. For greater reliability, one back-up should be included for the intake and intake line. The diameter of the intake opening is based on a maximum flow of 0.2 m/s, and that of the seawater main pipe on a maximum flow of 2 m/s. We take the supply for the Malampaya into consideration because expansion of sea water facilities is not easy. Specifications of the main seawater facilities are provided in Table 7.2-5.

Table 7.2-5 Sea Water Facilities Plan

Year	2020	2030
Number of sea water pumps	3(2)	5(2)
Number of booster pumps for disaster prevention	3(1)	3(1)
Sea water intake end portion 9000φ	1	1
Sea water main pipeline 2800φ	2(1)	2(1)

Note: Numbers in parentheses show the number of back-up pumps.
Source: Formulated by JICA study team

7.2.6 Gas Send-out Facilities

(1) Odorizers

The Gas Utility Industry Law in Japan requires that "the concentration of city gas must be at a level that is detectable when diluted in the atmosphere at a volume of 1/1,000." Ten mg/Nm^3 of a mixture of DMS (dimethyl sulphide) and TBM (tertiary butyl mercaptan), which Osaka Gas uses, will be employed as an odorizer. A facility plan assuming an odorizer tank capacity of thirty days' worth is shown in Tables 7.2-6.

Table 7.2-6 Installation of Odorant Facilities

Year	2020	2030
Imported LNG (million t/year)	0.658	2.433
Nominal LNG handling volume (million Nm^3/day)	2.2	8.0
Odorant (kg/day)	22	80
Capacity of odorant tank (m^3)	0.8	2.9

Note: Specific weight of odorant 0.827
Source: Formulated by JICA study team

(2) Measurement and Quality Control

The send-out pipe is equipped with measuring instruments and quality control devices.
The orifice meter and the delta meter can be used to measure the volume of gas, and the calorimeter, the specific weight meter, and the analyzers including gas chromatography can be used to control quality.

7.2.7 Utility Facilities

A list of the required utility facilities is provided in Table 7.2-7.

Table 7.2-7 Utility Facilities

Name of facility	Specification
Chilling water facilities	$300m^3/h$ unit×3 units
Compressor for instrument air	$1000m^3/h$ unit×3 units
Nitrogen facilities	$20m^3/h$ unit×2 units
Portable water facilities	$500m^3$
Sewage treatment facilities	$20m^3$/day

Source: Formulated by JICA study team

7.2.8 Electrical Equipment

(1) Basic Design Concept

The capacity of the power-receiving equipment must accommodate the future maximum power demand.

To manufacture and supply gas during regular maintenance periods, two systems will be necessary for the power-receiving equipment. One system should be usually used, and in case of blackout, the system should be switched after gas supply is stopped.

The distribution equipment should be separated according to the equipments. The importance equipments, such as loading, should be able to access to electricity in case of the maintenance.

The importance equipments should be able to access to the emergency power generation equipment.

Emergency power should be installed 100% back up.

If commercial power fails, back-up power needs to be secured by means of back-up power generation equipment. The capacity of this power generation equipment must be large enough to operate disaster-control facilities.

Monitoring and control must be centralized.

(2) Power Demand

The integration of electric power for gas manufacture/supply and maintenance is shown below.

Table 7.2-8 Required Electric Power

Equipments	Required power
LNG 1ry pump	170kW×3
LNG 2ry pump	1,450kW×3
Sea water pump	780kW×3
Sea water electrolyte equipment	320kW×1
BOG compressor (Low pressure)	1,100kW×2
BOG compressor (High pressure)	1,000kW×3
Minimum basic electric power	2000kW
Electric power required for plant construction	1000kW
Total electric power	15,720kW
Required power receiving capacity	24MVA

(Note) Power factor 0.8; Allowance factor 1.2
Source: Formulated by JICA study team

Table 7.2-9 Required Minimum Electric Power for Fire Prevention and Extinguishing

Equipment name	Motor capacity	Number of unit	Required power	Required total power	Rash power at starting
Minimum basic electric power	1,000 kW	—	1,000 kW	1,000 kW	2,000 kW
Hi-Ex, Water pump	500 kW	1	500 kW	1,500 kW	2,500 kW
Sea water pump for fire fighting	900 kW	2	1800 kW	3,300 kW	4,300 kW

* "Rush power" is pre-start electric power surge (capacity of respective motor × 2).
Source: Formulated by JICA study team

Emergency power generation equipment or diesel generator:
Gas turbine 2,150 kW (2,700kVA power factor: 0.8) × 2 unit, designed at 40 Celsius

(3) Outline of Equipment

(Power-receiving/distribution equipment)

Power-receiving equipment must entail two systems capable of supplying enough power to manufacture/supply gas and unload LNG while commercial power equipment is being inspected.

Power-receiving transformers must entail two systems of equipment capable of supplying enough power to manufacture and supply gas. They must be capable of meeting an increase in power demand when unloading LNG, running the two systems together. The two systems must operate independently.

The bus-line configuration of the distribution equipment must be capable of supplying enough power to manufacture and supply gas when one bus-line is disconnected for regular maintenance and others.

The equipment supplies power to large motors and regional transforming equipment. Power is supplied to regional transforming equipment via two systems.

1) Power-receiving equipment
   Method 69 kV – 60 Hz, two lines (permanent, reserve)
   Capacity 50 MVA/line (420 A)
   Type GIS (gas insulation switch gear), installed outdoors

2) Power-receiving/transformer
   Capacity 25 MVA x 2
   Type 69 kV/6.24 kV, hydraulic self-cooling, installed outdoors
   Operation Operate two systems independently

3) Distribution equipment
   Type Single bus line divided into five
   System Metal-clad switchgear, installed indoors
   Operation Operate two systems independently

(Areal transforming equipment)
Areal transforming equipment is responsible for supplying power to small- and medium-sized motors and lighting equipment.

The bus-line configuration of the distribution equipment must be capable of supplying enough power to manufacture and supply gas when one bus-line is disconnected for regular maintenance and others.

1) Areal transforming equipment
- Metal-clad switchgear, installed indoors
- Use combination starter for high-voltage distribution equipment
- Operate two systems independently
  - Transformer for distribution Power 6.24 kV/440 V, Lighting 6.24 kV/110-220 V, installed outdoors

(Building for substation room)
The substation room must be of the enclosed type, ferro-concrete, and equipped with an air-conditioner.

The transformer should be installed outside.

(Distribution in the plant)
Cables must be constructed in an open-pit.
Fire-retardant CV cables must be used.

7.2.9 Control and Supervision Systems

(1) Design Policy

This LNG terminal has the responsibility to maintain a stable gas send-out capability according to varying gas demand for town gas consumption, electric power generation, and NGV vehicles.
The process control and supervision system must consider the following items.

- Gas send-out reliability and system and facilities redundancy in case of mal function or incident.
- Terminal management efficiency and labor reduction.
- Easy and efficiency maintenance.

- Easy and efficiency system expansion according to increment of gas demand in future and system hardware replacement almost every 15 years.
- Adoption of experienced and proven technology, especially the integrated information system.

So, this system is based on Distributed Control System (DCS), Safety Interlock System (SIS), and Plant Information Management System (PIMS).

(2) System Composition.
To realize stable, reliable, and efficient management of latest LNG terminal, several systems will be required, and all system information shall be integrated.
Required major systems are as follows.

- Distributed Control System (DCS) of LNG facilities that include high-voltage electric power supply equipments, and Plant Information Management System (PIMS).
- Disaster prevention facilities control and supervision system for detecting LNG and/or gas leakage, fire detection and control of fire extinguisher and/or water deluge system of LNG tanks.
- Fire and Gas System (F&G), Laboratory system for unloaded or storage LNG and gas analyzer for send-out gas.
- Mooring monitoring system (MMS) included for weather, tidal and wave condition monitoring.
- Unloading arm supervision system, which is closely related to arm operation.
- As an independent system, intruder supervision and alarm system for Guardhouse.
- Closed circuit television system for the entire terminal area.
- Paging system for the entire terminal area.
- Standalone system for software debugging when changing or adding programs, and training of new operators.

Note;

This system excludes Vessel Navigation System for harbors. This kind of navigation system is assumed to be controlled and supervised by a Governmental Organization or others.

Also exclude personnel affairs, organizational management, financial data saver, and other systems related to company management. These systems shall be realized for office automation systems.

Abbreviations

DCS = Distributed Control System
SIS = Safety Interlock System
F&G = Fire and Gas System
MMS = Marine Monitoring System
PMS = unloading arm Position Monitoring System
ESD = Emergency Shut Down system
PIMS = Plant Information Management System

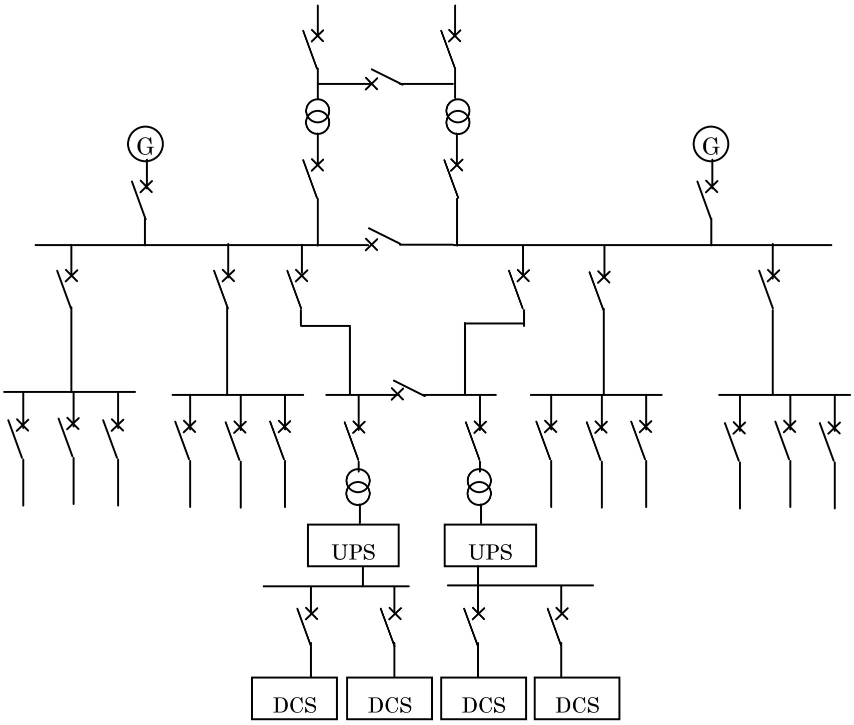
(3) Design Concept
1) System Segregation and Integration.

- DCS, SIS, F&G, and PIMS segregate each other and should be avoided interference in control level.
- DCS segregate SSS (Safety and Security System), because of importance and operability in case of an accident.

- DCS segregate PMS (unloading arm Position Monitoring System), MMS (Marine Monitoring system).
- All data are integrated in PIMS, and could be connected to an office network through Data server and firewall.

2) Redundancy and Reliability.

- DCS and SIS are composed independently. CPU of DCS is required a germination, and self-diagnosis function to avoid sudden shut down. Control System is composed singly.
- SIS which has over SIL3 and is officially recognized is composed singly.
- One DCS unit doesn't control more than one forth of the gas supply capacities.
- The terminal is controlled by two groups which control one half of the gas supply capacities and are based on some DCS units.
- Fig 7.2-1 shows the feed model for these two groups.



Source: Formulated by JICA study team

Figure 7.2-1 Feed Model

(a) Common elements such as Data way, operator consoles, and printers have as dual structure or over for redundancy.

3) Automatic Operation

According to the gas demand, some equipments in the terminal start/stop automatically to save electricity consumption. The automatic operation equipments are below.

(a) LNG pumps
(b) Sea water pumps for vaporizers
(c) Vaporizers
(d) Odourisation system
(e) Instrument air compressors

(f) BOG reliquefaction facility

These equipments are operated manually.
(a) Unloading arms
(b) BOG compressors
(c) Sea water pumps for hydrant
(d) Utility Facility

4) Maintenance
Most of the equipments have to be stopped for maintenance. Some extra operator consoles should be installed for maintenance.

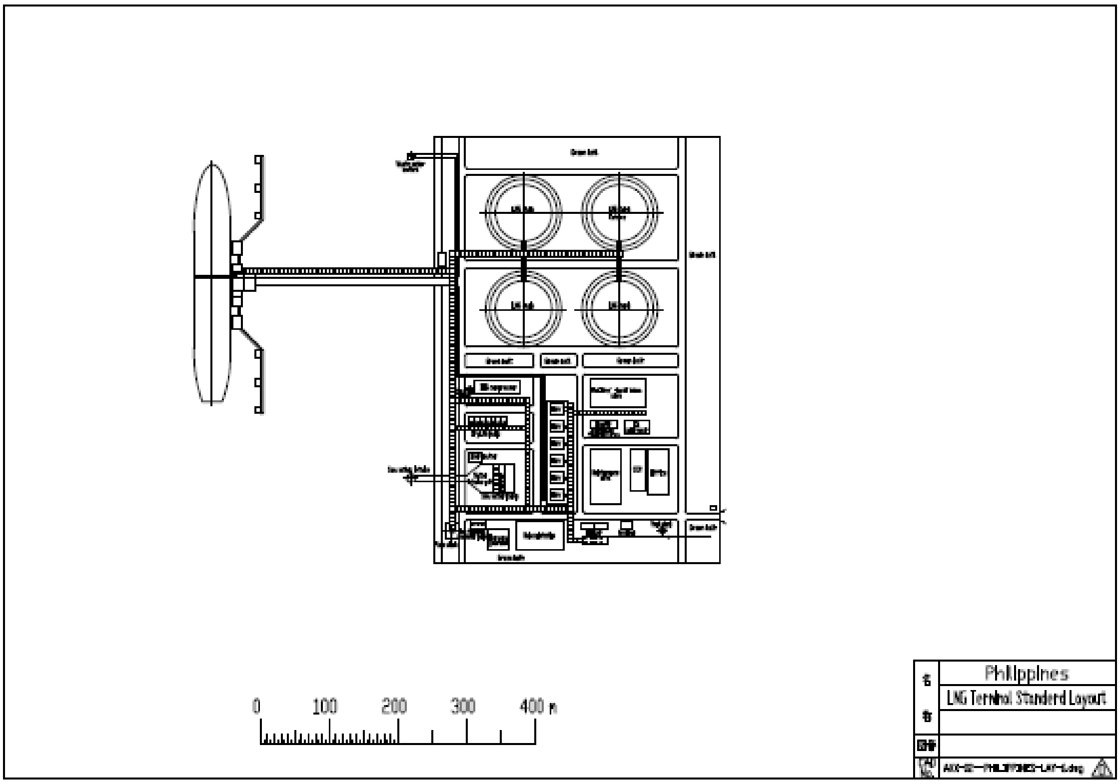
7.2.10 Main Facilities and Layout
Table 7.2-10 shows a list of the main facilities. Figure 7.2-2 shows the layout of LNG receiving terminals.

Table 7.2-10 Main Facilities and Equipment

Facility name	Specifications
Unloading arm	Arms for LNG: 3 lines Arms for return gas: 1 line 16B×60Ft
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 20m^3/h, Sampling holder, Gas compressor, Gas calorimeter (density meter), Gas chromatograph 1 unit
LNG storage tank	Above ground type PC tank Capacity 180,000kL×3 units 2,900mmAq, Inner tank 9%Ni
LNG pump	(1) Primary pump Capacity 150t/h×5 units, Intank pump 10kg/cm^2, 220kW (2) Secondary pump Capacity 150t/h×5 units, Submerged pump 80kg/cm^2, 1450kW
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
Flare stack	40t/h× 1 unit
BOG compressors	Reciprocating type 10t/h×3 units 0→10kg/cm^2, 1,100kW Reciprocating type 10t/h×3 units 10→100kg/cm^2, 1,000kW
BOG reliquefaction facility	BOG reliquefaction 15t/h×2 units
LNG vaporizer	Open rack 150t/h×4 units
	Design pressure 100kg/cm^2
Sea water pump for vaporizers	Capacity 7,000m3/h×5 units
	30m, 780kW
Sea water pump for	Capacity 3,000m3/h×3 units
Hydrant	80m, 1,200kW
Chlorinator equipment	100kg/h×2 units, 320kW
Odourisation system	Tank capacity 2.9m3×2 units
	Pump 3l/h×2units, 90kg/cm^2
	Blower, Deodorant
Metering system	One unit
Vent stack	500A×60m×1 unit
Utility Facility	(1) Cooling water facility
	Cooling water tower 300m^3/h×3 units
	Cooling water pump 300m^3/h×3 units, 50m
	(2) Instrument air compressors
	Reciprocating type 1,000m^3/h×3 units, 7kg/cm^2

	Dryer 2 units, Tank 15m^3×2 units
	(3) Nitrogen facility
	L-N2 tank 20m^3×2 units
	HP N2 vaporizer 100m^3/h×1 unit
	LP N2 vaporizer 100m^3/h×2 units
	(4) Portable water facilities
	Tank 500m^3, Pump 30m^3/h×2units,45m
	(5) Seawage treatment facilities
	Activated sewage treatment 20m^3/D
Sea water intake facility	Main intake mouth 33,000m^3/h
	8mΦ×2 lines
	Intake pipeline 33,000m^3/h
	2.8mΦ×2 lines
Draining facility	40,080m^3/h
Analyzers	1 unit

Source: Formulated by JICA study team



Source: Formulated by JICA study team

Figure 7.2-2 Layout of LNG Receiving Terminals

7.3 Project Execution Study

7.3.1 Terminal Cost

Total terminal cost from inhouse database is shown in Table 7.3-1. Others include civil & Buildings, Jetty, Electrical/Instrumentation etc. Site preparation cost is not included.

Table 7.3-1 LNG Terminal Cost

（million USD）

Required LNG imports (million t /y)	250
LNG storage tanks	320
Mechanical & Piping	185
Others	105
Engineering	30
Total	640

Source: Formulated by JICA study team

7.3.2 Operating Organization and Operating and Maintenance Costs

(1) Operating Organization

Table 7.3-2 shows the operating and maintenance manpower needed for terminal, based on data for LNG terminals under operation.

Table 7.3-2 Operation and Maintenance Manpower
（Nominal Annual LNG Quantity:4-6 million t/year）

(Unit:person)

Operation	Shift chief	1
	Supervisor	1
	Operators in each shift	2
	Patrollers in each shift	1~2
	Sub-total in each shift	5~6
	Planning Staff (including marine operation)	20~25
	Total	45~55
Maintenance	Mechanical supervisor	1
	Mechanical engineer	4
	Electrical/Instrument supervisor	1
	Electrical/Instrument engineer	4
	Total	10
General affairs, Security, managements and others		25
Total 1（without maintenance workers）		80~90
Maintenance Workers (can be contracted out)	Mechanical	10~15
	Electrical/Instrument	10~15
	Total	20~30
Total 2（with maintenance workers）		100~120

Source: Formulated by JICA study team

(2) Operation and Maintenance Costs
Operation and Maintenance costs were calculated as follows, referred to actual data for LNG terminals under operation.

Table 7.3-3 Operation & Maintenance Costs

(USD/LNG-ton)

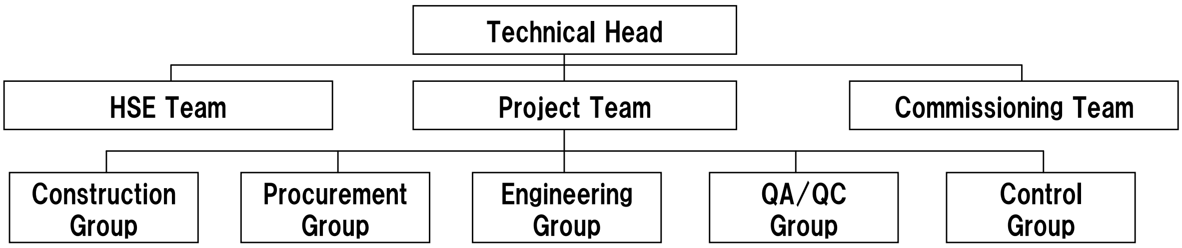
Regasification & Send-Out Cost	5.3
Maintenance Cost	0.6
Labor Cost	0.4
Utility & Overheads	6.3
Total	12.5

Source: Formulated by JICA study team

Remarks are as follows;

- Electricity cost is 0.2$/kWh
- Monthly labor cost is 1875$/person.
- Utility & Overheads includes costs regarding water, steam, chemicals, communication, tax, insurance and other items.
- 1US$ is 80yen.
- The costs can vary by about 30%, according to operating conditions

7.3.3 Organization
Table 7.3-4 shows the organization of owner side. About 30-40 people are organized for the project.



Source: Formulated by JICA study team

Figure 7.3-1 Organization Chart

7.3.4 Procurement

Table 7.3-4 shows a vendor/subcontractor list.

Table 7.3-4 Vendor/subcontractor List

ITEM	List of Vendors	Country
LNG unloading arms	SCHWELM	GERMANY
	FMC	FRANCE
	NLS	JAPAN
LNG storage tanks	IHI	JAPAN
	TKK	JAPAN
	KHI	JAPAN
	CBI	USA
	Whessoe	UNITED KINGDOM
1ry Pumps	NIKKISO	JAPAN
	EBARA	UNITED KINGDOM
	SHINKO	JAPAN
2nd Pumps	NIKKISO	JAPAN
	EBARA	UNITED KINGDOM
	SHINKO	JAPAN
BOG compressors	IHI	JAPAN
	KOBELCO	JAPAN
	BURCKHRDT	SWITZERLAND
	NUOVO-PINGNONE	ITALY
	DRESSER-RAND	FRANCE
ORV	KOBELCO	JAPAN
	SUMITOMO	JAPAN
Process control System (PCS)	ABB	UNITED KINGDOM
	FOXBORD	UNITED KINGDOM
	HONEYWELL	The Netherlans
	YOKOGAWA	JAPAN

Source: Formulated by JICA study team

7.3.5 Project Schedule

Table 7.3-5 shows the overall project schedule for this project.

Table 7.3-5 Overall Project Schedule

ACTIVITY NAME	(YEAR) 2015	2016	2017	2018	2019	2020
MILE STONE	▽ ITB	▽EPC contract ▽Completion of site preparation ▽Start Construction			LNG tank C/D ▽ Commercial Operation▽	
BASIC DESIGN						
EPC CONTRACT						
DETAILED DESIGN						
PREPARATION OF ARTIFICIAL ISLAND (INCL.RECLAMATION)						
SOIL INVESTIGATION						
SITE RECLAMATION						
MARINE FACILITY						
BREAKWATER						
SEA CHANNEL						
LNG JETTY						
PREPARATION WORK						
SEA WATER INTAKE						
LNG TANK						
EQUIPMENT INSTALLATION						
PIPING WORK						
INSTRUMENT WORK						
ELECTRICAL WORK						
FIRE FIGHTING						
BUILDING/CIVIL						
SUPPLY PIPELINE WORK						
PRECOMMISSIONING						
COMMISSIONING						

Remark :The time for application to authority should be taken into consideration

Payment schedule												
			▼Contract									
			15%									
				▼Engineering completion								
				10%								
				▼Procurement of Long Lead Items								
				30%								
						▼FOB of Long Lead Items						
						25%						
										▼Mechanical completion		
										10%		
											▼Performance test	
											10%	
Remains			85%	45%		20%				10%	0%	

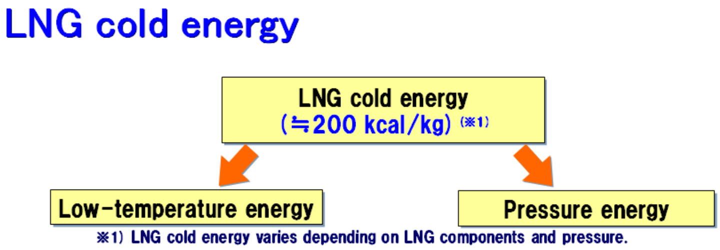
Source: Formulated by JICA study team

7.4 LNG Cold Energy Utilization

7.4.1 What is LNG Cold Energy Utilization

LNG has cold energy of about 200kcal/kg. The cold energy depends on its composition and pressure. The composition also varies according to the production places of the LNG. Also the pressure depends on the pipeline pressure of the area. The LNG cold energy is usually thrown away to the sea in order to vaporize LNG.

The LNG cold energy utilization can reduce the refrigerated power of some facilities, as a result, it can contribute to energy saving and reduction of CO_2 emission.



	Low-temperature Energy	Pressure Energy
Origin	LNG temperature, **-160C**, is very low compared with ambient temperature.	LNG becomes **1/600 in volume** compared with natural gas.
Conventional process	Temperature energy is mainly **thrown away to sea water** through vaporizers.	Pressure energy is mainly consumed by **transportation** from LNG terminal to customers.

LNG cold energy has a big potential to reduce power consumption and CO_2 emission in various cooling processes.

Source: Formulated by JICA study team

Figure 7.4-1 LNG Cold Energy

7.4.2 Example of LNG cold energy utilization

(1) Air Separation & Liquefaction Plant

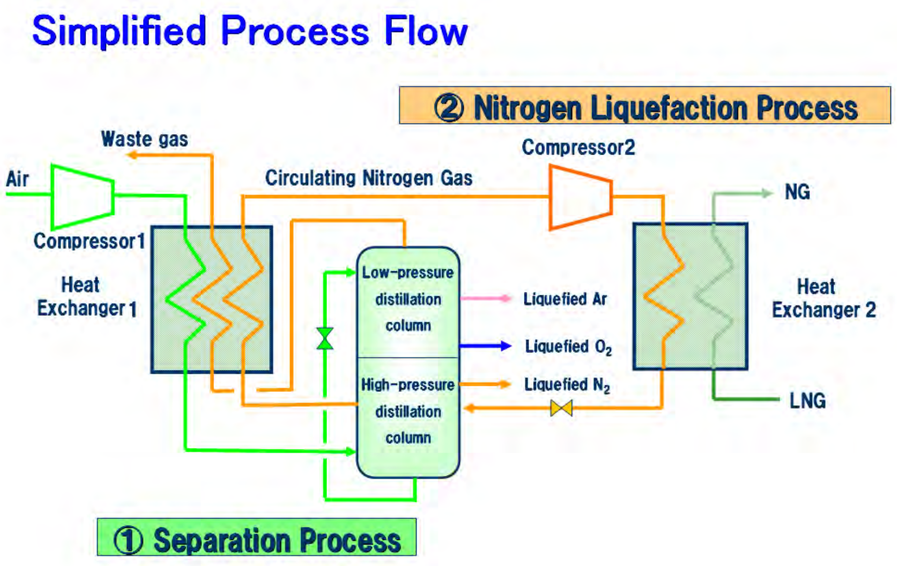
Features

Air separation & liquefaction plant produces “liquefied nitrogen”, “liquefied oxygen” and “liquefied argon”, utilizing the temperature difference of each gas boiling point. And the produced liquid is supplied to the factories such as steel plant, petrochemical plant and refinery plant.

This conventional process without LNG cold energy is usually consumed a large amount of electricity in order to install refrigerated cycle and generate cold energy. In case of LNG utilized process, LNG cold energy can reduce the electrical consumption at the refrigerated cycle drastically.

Generally, operational cost of LNG cold energy utilized process can be half compared with that of the conventional process without LNG cold energy. This advantage contributes to the economics.

The simplified process is described below.



Source: Formulated by JICA study team

Figure 7.4-2 Air Separation & Liquefaction Plant Process Flow

(2) Cryogenic Power Generation with LNG Cold Energy

Features

Cryogenic power generation plant can generate electrical power, utilizing temperature difference between LNG and sea water. This system is similar to steam turbine generation system which is popular in the world. The steam turbine system is Rankine cycle of heat medium “H2O” with temperature difference between sea water and steam which is produced with boiler. In case of cryogenic power generation system, the temperature difference is changed from “sea water and steam” to “LNG and sea water”. And the heat medium is changed from “H2O” to “hydrocarbon”.

When this cryogenic power generation plant is installed in LNG re-gas terminal, the generated power can be consumed inside the terminal. In other words, electrical consumption of the terminal can be reduced by this system. The electrical power which is generated at cryogenic power generation plant is CO_2-free electricity.

The simplified process flow is described below.

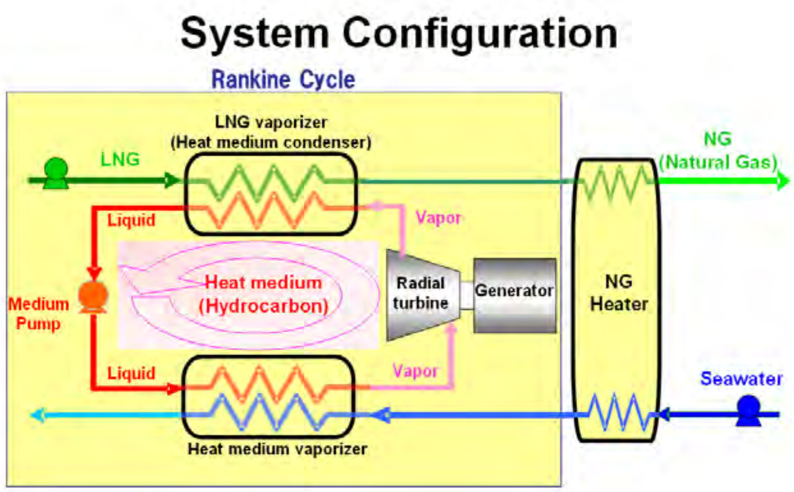


Figure 7.4-3 Cryogenic Power Generation Process Flow

(3) Refrigerated Warehouse

Features

Various kinds of foods are stored at various temperatures in refrigerated warehouse. For example, vegetables are stored at around 0 deg C, and many of frozen foods at –25 deg C. Storage of frozen tuna requires especially low temperature of –55 deg C. LNG cold energy provides a very low temperature of –150 deg C. Accordingly, LNG cold energy can be utilized more effectively at lower temperatures in the warehouse.

The refrigerated warehouse utilizing LNG cold energy is a combination of existing technologies. Two warehouses of this type are already in operation in Japan. It is reported that there are no technical problems to be solved.

The simplified process flow is described below.

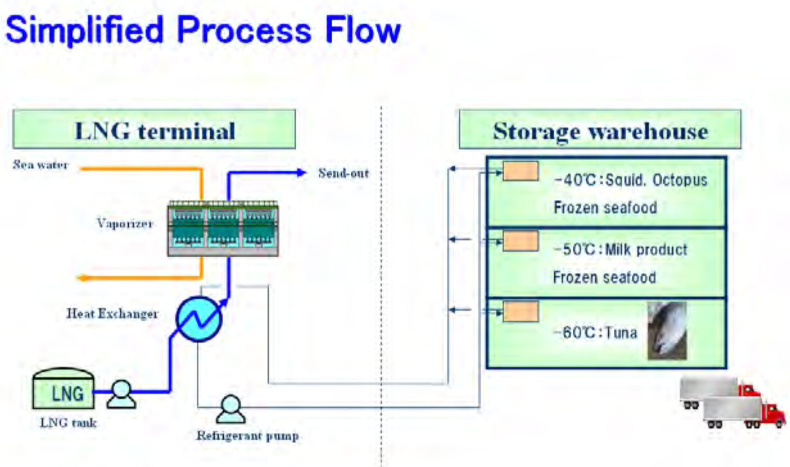


Figure 7.4-4 Refrigerated Warehouse Process Flow

(4) Others

- CO_2 liquefaction plant
- Cold source for petrochemical plant

7.4.3 Track Records in Japan

Table 7.4-1 Track Records in Japan

LCEU Processes	Air Separation & Liquefaction	Cryogenic Power Generation	Refrigerated Warehouse	CO_2 Liquefaction
LNG utilized in Japan (1,000 t/year)	2,600	8,500	80	100
LNG Flow for LCEU (t/h)	1.1 ~ 100	42 ~ 170	4.7 ~ 5	3.6 ~ 9.0
Temperature level (deg C)	-150	-120 ~ -40	-60 ~ -20	-55

Source: Formulated by JICA study team

7.4.4 Advantage of LNG Cold Energy Utilization

- Reduction of influence of cold sea water which is heat-exchanged with LNG and spread to sea---Reduction of influence of sea creature
- Environmental friendly system ---Reduction effect of CO_2 emission (Reduction of electricity consumption)
- Employment promotion by new industry generation by LNG cold energy utilization.

Chapter 8 Project Scheme

This chapter addresses on possible business schemes of gas pipeline as well as the LNG regasification terminal. Business mentioned here includes designing financing, owning constructing and operating (which may include marketing) procedures.

8.1 Current Regulation

In the Philippines, as for a project model of gas pipelines construction and operation, public (governmental), private and public-private joint ventures are all eligible to participate subject to granting of business franchisee status. Those who conduct the business can take various forms of business formations. For example, outsourcing of pipeline operation business from the owner of gas pipeline infrastructure, as well as section separation by section may also be possible. However, there are currently no existing examples of gas pipeline project model in the Philippines apart from those pipelines under their own gas utilization.

On the other hand, LNG regasification business is regarded as to be within the fully privatized business activities, which are, in principle, expected to be carried out by the private sector. Construction and operation of LNG regasification terminal therefore will have to be onducted without recourse to governmental financial support.

According to the current BOT law, companies constructing and operating the infrastructures in the Philippines may obtain financing from foreign and/or domestic sources and/or engage the services of a foreign and/or Filipino contractor: provided, that, in case an infrastructure or a development facility's operation requires a public utility franchise, the facility operator must be a Filipino or if a corporation, it must be duly registered with the Securities and Exchange Commission and owned up to at least sixty percent (60%) by Filipinos. The requirement applies to not only the owner of assets but also to the operation and maintenance entity, even in the case of operation separation model. This requirement by the BOT law is applicable to gas pipeline business as it is deemed to be social infrastructure defined in the law.

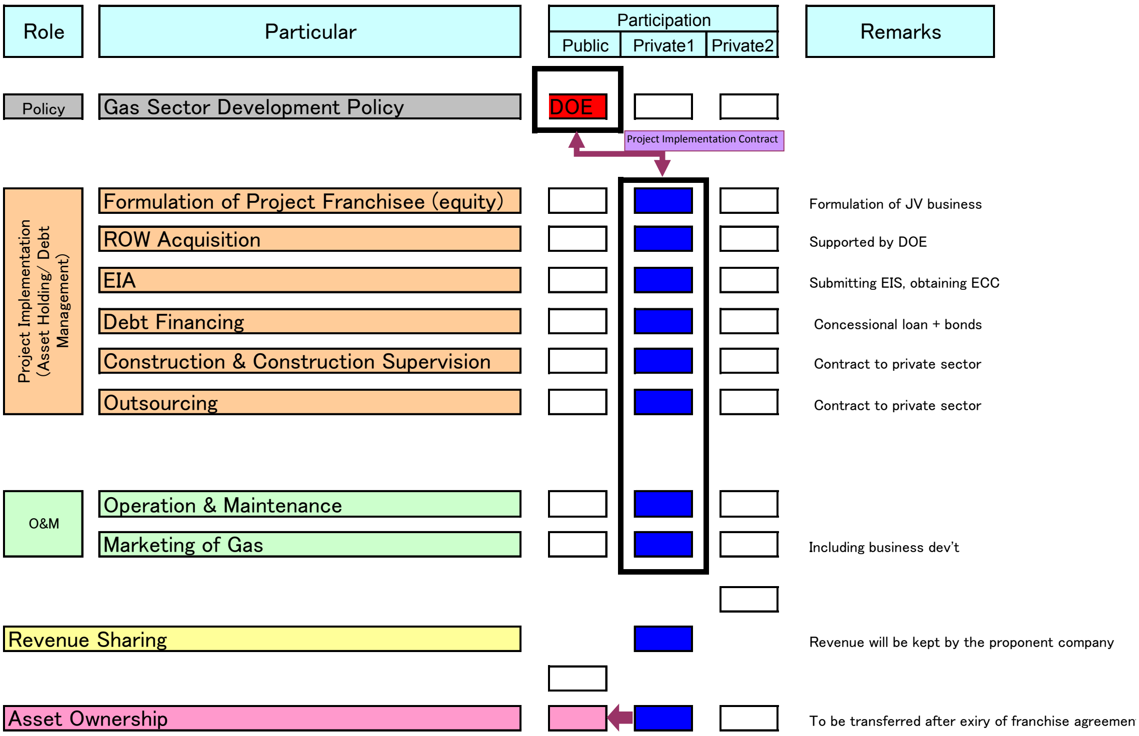
8.2 Pipeline

8.2.1 Proposed Scheme

As for the pipeline business ownership and management structure, three project model options are considered; Model 0, 1 and 2. Model 0, as shown in Figure 8.2-1, is a conventional BOT model in which a private proponent owns the asset and conducts all of the core business activities. Model 0 features a privately driven project model, which is suitable to give flexibility for the proponent to design, build, finance and operate the gas pipeline through its own initiative. Tendering of the project is expected to induce competition among the potential proponents, resulting in more efficient project compared with when the project is being carried out as a public work by the government.

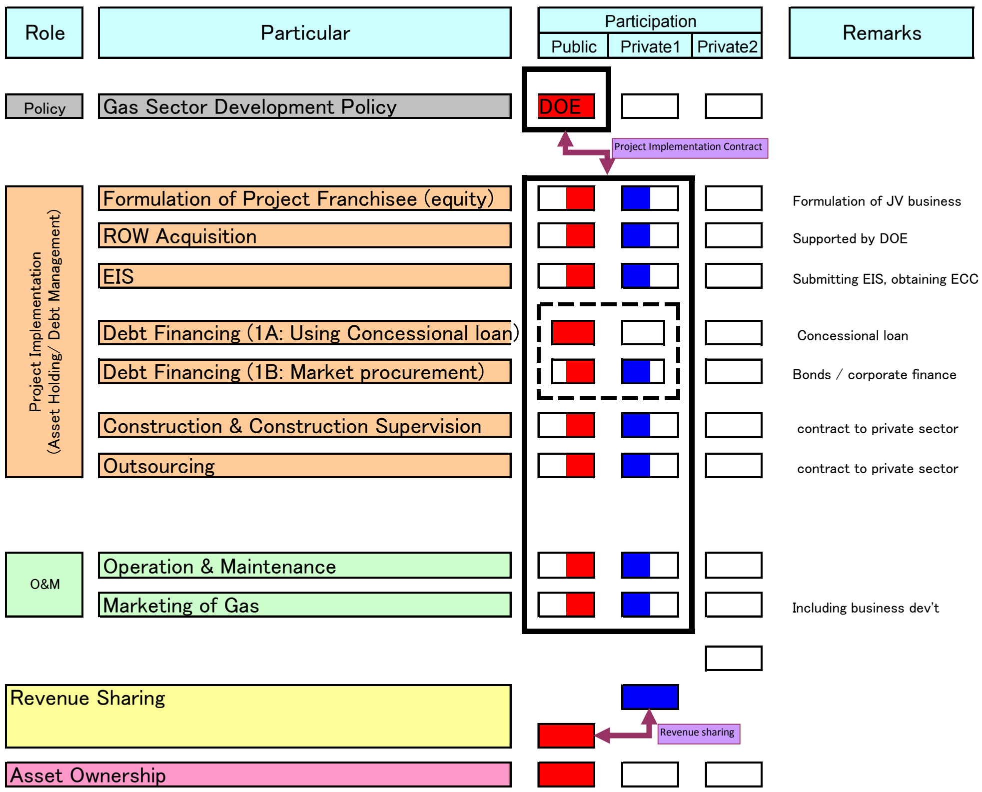
Model 1, the Integrated Execution Organization Model, as shown in Figure 8.2-2 features a public-private joint venture, where tasks within the business entity is shared among the public and private, depending on their capacities. For example, debt financing and asset ownership are expected to be borne by the public sector due to their advantages in creditworthiness. The private participant is expected to improve efficiency of the business, especially in designing, constructing and operating segments. The model is intended to make the most of the advantages of both public and private sectors.

The model shown in Figure 8.2-3 is the Operation and Maintenance Separation Model (Model 2) in which the operation and maintenance portion of the task is outsourced to pure private company. Model 2 is intended to promote the participation of private companies not only as the joint venture partner for infrastructure development but also on the form of operation and maintenance company. The aim of separation of O&M from asset owning is in selecting and introducing a more competitive operator through the outsourcing process. This is expected to further reduce the cost of O&M business.



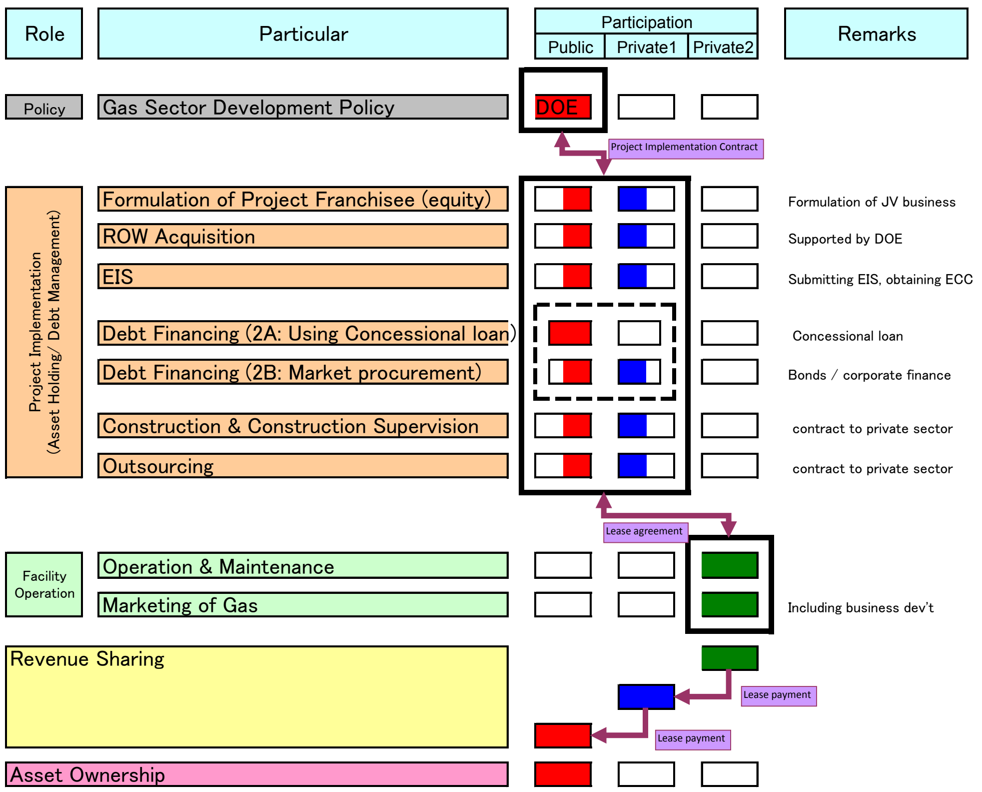
Source: Formulated by JICA study team

Figure 8.2-1 Model 0: Conventional BOT Model



Source: Formulated by JICA study team

Figure 8.2-2 Model 1: Integrated Executing Organization Model



Source: Formulated by JICA study team

Figure 8.2-3 Model 2: Infrastructure-Operation Separation Model

Two financing options are considered for Models 1 and 2. One is an option of obtaining a concessional loan at a preferable condition (low interest rate with long grace period and long repayment duration). Another is an option of capital procurement in commercial market, by issuing 10 year maturity term bonds. Models 1 and 2 are therefore further separated into two project models each, suffixed with “A” for concessional loan financing, and “B” for bond financing. Altogether, five patterns are considered (Table 8.2-1).

Assumption is based on Case 4 of pipeline infrastructure development options as outlined in Chapter 6 of this report (c.f. Table 6.5-2). The pipeline is assumed to be constructed within two years starting from 2015, inaugurating for commencement of business in 2017. As the LNG regasification terminal will only operate from 2021 onwards, the gas to be transmitted between 2017 and 2020 is assumed to be from Camago-Malampaya pipeline, with limited availability of 123 million Nm^3 per annum, which is equivalent to supply for a 100 MW power plant.

The cost of infrastructure investment therefore is unique across all project models at USD 161 million. Based on this assumption the amount of debt to finance the initial investment was set at USD 121 million which is 75% of the total initial investment for Model 0 to comply with the BOT law, and USD 145 million (90%) of the total initial cost for all other project models. The total amount of procured capital, however, differs from models to models due to various level of working capital requirement. The difference in the demand for working capital is mainly due to the prudent cash flow assumption to have debt service coverage ratio (DSCR) above 1.1 for each of the operation years (1.0 when sufficient cash is accrued from previous years).

O&M costs (including additional capital investment required in maintenance and refurbishing) is set at constant annual amount of 5% of initial investment, at USD 8.1 million in Model 1. For Models 0 and 2, in which more efficient operation can be expected due to introduction of competitive selection, the rate of O&M cost is set to be 4% of the initial investment, at USD 6.5 million per year .

Table 8.2-1 Proposed Project Model Patterns and Their Cost of Capital

Model Name	Model 0	Model 1A	Model 1B	Model 2A	Model 2B
Project model	Model 0 (Conventional BOT)	Model 1 (Integrated Execution)		Model 2 (Separation)	
	[Model 0]	[Model 1A]	[Model 1B]	[Model 2A]	[Model 2B]
Finance	Market Procurement	Concessional Loan	Market Procurement	Concessional Loan	Market Procurement
Initial Investment			USD 154 million		
Annual O&M cost	USD 6.1 million	USD 7.7 million		USD 6.1 million (For O&M company)	
Amount of Equity	USD 150 million	USD 43 million	USD 82 million	USD 38 million (For asset holding company)	USD 77 million (For asset holding company)
Expected Yield for Equity		20%		20% (For asset holding company)	
Amount of Debt	USD 138 million	USD 138 million		USD 138 million (For asset holding company)	
- of which is Concessional Loan (Interest) [repayment]	None	USD 138 million (0.2%) [40 years]	None	USD 138 million (0.2%) [40 years]	None
- of which is market procured (Interest) [maturity]	USD 138 million (16%) [refinanced every 10 years]	None	USD 138 million (6%) [refinanced every 10 years]	None	USD 138 million (6%) [refinanced every 10 years]
Weighted Average Interest Rate of Debt	16%	0.2%	6.0%	0.2% (For asset holding company)	6% (For asset holding company)
WACC: Weighted Average Cost of Capital	16%	4.9%	10%	4.4% (for asset holding company)	9.9% (for asset holding company)

Source: Formulated by JICA study team

The costs of capital for each model are as follows:
Model 0: The private company procures the capital through issuing of bonds at annual yield of 16%. Models 1A and 2A assume the utilization of concessional loans as the source of debt. Debt, at prudently 90% of the initial investment cost, is procured by the public sector comprising the Joint Venture. The concessional loan condition applied in this study is the Japanese STEP International Yen Loan (interest rate of 0.2%, reimbursement period of 40 years, among which the grace period is the first 10 years). This Japanese loan is the option currently offering one of the most favorable conditions among various concessional loans available. Models 1B and 2B assume financing patterns resorting to commercial procurement of capital.

Borrowing by public entity, enables the project to procure capital at low interest rate of 6%, backed by the government's creditworthiness (PNOC mentions that it can procure USD corporate finance debt at the spread of 2%).

Remainder of the capital required is assumed to be procured through equity. Expected yield for the equity finance is set at 20%. Weighted average cost of capital (WACC) was calculated as 16% for Model 0, 6.0% and 11% respectively for Models 1A and 1B, 4.6% and 10% for Models 2A and 2B respectively.

WACC can be calculated as follows:

Whereas:

n = number of source of capital
ri = required rate of return for capital "i"
Vi = market value of capital "i"
ti = effective tax rate for capital "i"

8.2.2 Scheme Comparison through Financial Analysis

Financial analysis based on discounted cash flow (DCF) method was conducted for each of the project models. Financial internal rate of return (FIRR) was calculated so as to verify the financial sustainability of the project based on each of the models.

The striking financial characteristics of the pipeline business, common to all from project models considered in this study, are that the net balance of profit and loss for the first several years of operation is expected to be negative. This is mainly due to the low availability of gas to be supplied prior to the commencement of operation of the LNG regasification terminal. The pipeline, being developed with expectation to induce gas businesses in the Philippines will have to bear with the low demand and supply until the industry begins to stand on its feet. The pipeline, as a public utility, will require support from the public sector unless a large amount of money charged onto the wheeling charge.

Ways to avoid a high wheeling charge imposed on the gas users is to minimize the financial burden during the first years of operation. Loan repayment during the operational years with only a limited availability of gas will become a heavy burden for the pipeline business. The arrangement of concessional loan with a long grace period is an appropriate option to relieve such burden. Cost cut by introducing an efficient operation and maintenance method is another option for reducing the cost of the project. Introduction of private sector through competitive bidding will be an effective measure for the O&M cost cuts.

Models are therefore compared from the viewpoint of difference in required wheeling charges as well as their viability. Advantages and disadvantages for each of the project models and financing patterns as outlined in Table 8.2-1 are compared as follows:

(1) Gas Transmission (Wheeling) Charge

Revenue expected for each Model will be dependent on the amount of gas transported and the unit tariff for the transmission by the pipeline. As natural gas is to be supplied to an unspecified number of customers, the gas transmission (wheeling) charges are likely to be regulated by the Energy Regulatory Commission (ERC). However, ERC is yet to establish a method for regulating the wheeling charges of natural gas pipelines. In conducting the analysis the revenue from providing the pipeline business service, the wheeling charge was considered and treated as a variable based on the current situation where regulatory mechanism for gas transmission service is not existent. The wheeling charges for each of the project models were set so as to realize the FIRR of approximately 2 percentage points above WACC, to ensure financially sustainable operation of the business.

The assumed setting is a type of cost recovery scheme, which allows the operating entity to recover from wheeling charge revenue, the operating expense (OPEX) and the capital expenditure (CAPEX), to meet the weighted average cost of capital (WACC). Additional profit to cover the business risks will also be required. The assumption in this analysis, therefore, allows the operator to conduct a financially sustainable business at a given cost and profit.

(2) Comparison of the Project Models

First, wheeling charges are set so that the FIRR becomes approximately 2 percentage points above WACC for each of the project models. Models 2A and 1A, taking advantage of the preferential concessional loan, offer the lowest wheeling charge of 0.017 USD/Nm^3 and 0.018 USD/Nm^3 respectively. Wheeling charges in Models 2B and 1B, procuring debt from the market, will be 0.011 USD/Nm^3 higher than the concessional loan patterns, at 0.028 USD/Nm^3 and 0.029 USD/Nm^3 respectively. Conventional BOT model is seen to require more than twice the wheeling charge compared with the concessional loan patterns, at 0.047 USD/Nm^3.

Table 8.2-2 Wheeling Charge to Meet the Equity Return Requirement

Model Name	[Model 0]	[Model 1A]	[Model 1B]	[Model 2A]	[Model 2B]
Project model	Conventional BOT	Model 1 (Integrated Type)		Model 2 (Separation)	
Finance	Market Procurement	Concessional Loan	Market Procurement	Concessional Loan	Market Procurement
Wheeling Charges [USD/Nm^3]	0.047	0.018	0.029	0.017	0.028
WACC	16%	6.0%	11%	5.4% (For asset holding company)	10% (For asset holding company)
Financial IRR (=FIRR)	19%	8.4%	13%	7.2% (for asset holding company) 8.4% (for project overall)	12% (for asset holding company) 13% (for project overall)

Source: Formulated by JICA study team

Sensitivity analysis was carried out by moving the wheeling charges between 0.017 USD/Nm^3 and 0.047 USD/Nm^3. The result shows that the Models 1A and 2A will benefit due to their low WACC. Model 2A will be financially viable in any wheeling charge settings within the moving zone. Model 1A will become marginal when the wheeling charge is set at 0.017 USD/Nm^3.

Table 8.2-3 FIRR Comparison under Referential Wheeling Charges

Model Name	Model 0	Model 1A	Model 1B	Model 2A	Model 2B
Project model	Conventional BOT	Model 1 (Integrated Type)		Model 2 (Separation)	
Finance	Market Procurement	Concessional Loan	Market Procurement	Concessional Loan	Market Procurement
Wheeling Charge = 0.047 [USD/Nm^3]	FIRR = 19% WACC = 16%	FIRR = 18% WACC = 4.8%	FIRR = 18% WACC = 10%	18% (for asset holding company) 19% (for project overall) WACC = 4.4%	18% (for asset holding company) 19% (for project overall) WACC = 10%
Wheeling Charge = 0.029 [USD/Nm^3]	FIRR = 13% WACC = 16% <u>NOT VIABLE</u>	FIRR = 13% WACC = 5.5%	FIRR = 13% WACC = 11%	13% (for asset holding company) 13% (for project overall) WACC = 5.1%	13% (for asset holding company) 14% (for project overall) WACC = 10%
Wheeling Charge = 0.028 [USD/Nm^3]	FIRR = 13% WACC = 16% <u>NOT VIABLE</u>	FIRR = 13% WACC = 5.6%	FIRR = 13% WACC = 11%	12% (for asset holding company) 13% (for project overall) WACC = 5.1%	12% (for asset holding company) 13% (for project overall) WACC = 10%
Wheeling Charge = 0.018 [USD/Nm^3]	FIRR = 8.9% WACC = 17% <u>NOT VIABLE</u>	FIRR = 8.4% WACC = 6.0%	FIRR = 8.5% WACC = 11% <u>NOT VIABLE</u>	8.8% (for asset holding company) 7.2% (for project overall) WACC = 5.4%	8.4% (for asset holding company) 9.2% (for project overall) WACC = 11% <u>NOT VIABLE</u>
Wheeling Charge = 0.017 [USD/Nm^3]	FIRR = 8.9% WACC = 17% <u>NOT VIABLE</u>	FIRR = 7.9% WACC = 6.0% <u>MARGINAL</u>	FIRR = 8.0% WACC = 11% <u>NOT VIABLE</u>	8.4% (for asset holding company) 7.2% (for project overall) WACC = 5.4%	7.8% (for asset holding company) 8.7% (for project overall) WACC = 11% <u>NOT VIABLE</u>

Source: Formulated by JICA study team

(3) Model Comparison Summary
Comparison results show that the use of concessional loans, as in Models 1A and 2A are financially advantageous, being able to offer the lowest wheeling charge for the gas customers. Models 1B and 2B, taking advantage of governmental creditworthiness enabling capital procurement at low cost also is seen to be financially effective, being able to offer the wheeling charge only 0.011 USD/Nm3, or 70 to 80% higher than the concessional loan models. Conventional BOT resulted in the wheeling charge becoming significantly higher, at 280% of the concessional loan models.

Further, comparison of Model 1 and 2 shows that outsourcing of O&M, to realize more efficient operation through competition, will bring about financial advantage to the project. Although the impact of Separation might be minimal for lowering the wheeling charge, profitability in terms of project financial IRR differs significantly compared with the integrated model, under the same wheeling charge.

8.3 LNG Regasification Terminal

8.3.1 Proposed financing Scheme and Financial Analysis
The LNG regasification terminal for project scheme analysis and comparison is assumed to be constructed under the specifications stipulated in Chapter 7 of this report. Initial investment cost is estimated at USD 640 million (c.f. Table 7.1-1), and O&M cost of USD 28 million at annual regasification of 2,931 million Nm^3 (c.f Table 7.3-3, calculated from 1,000 JPY/ton, at exchange rate of USD = JPY 85, and 1 ton of LNG = 1,220 Nm^3). The LNG regasification terminal is assumed to be constructed during the five years starting from 2015, inaugurating for commencement of business in 2021.

Financing options for LNG regasification terminal business is limited as public financial support is not an available option. The business therefore is assumed to procure its fund from the market. The main source for financing is the debt (bonds), yielding 6% interest and with maturity period of 10 years. The bonds are assumed to be refinanced every ten years. This financing condition is equivalent to those of Project models 1B and 2B, in which an entity with high creditworthiness (e.g. PNOC) procures finance under preferential conditions.

The amount of debt against total initial investment cost was set at is 90%. Remainder of the funding requirement is assumed to be met through equity of expected yield of 20%.

Table 8.3-1 Proposed Financing Arrangements for the LNG Regasification Terminal

	Proposed financing arrangements for LNG regasification terminal
Initial Investment	USD 640 million
Annual O&M cost	USD 0.0096 /Nm^3 (USD 28 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)
Amount of Debt (Interest) [maturity]	USD 576 million (90% of initial investment) (Interest rate: 6%) [refinanced every 10 years]
Amount of Equity [Expected yield]	USD 204 million [20%]
Total financed amount	USD 780 million
WACC: Weighted Average Cost of Capital	9..7%

Source: Formulated by JICA study team

Considering that the LNG regasification terminal is a stand-alone facility from financial viewpoint, the revenue of the project is deemed to be from regasification charge. The charge was set at 0.07 USD/Nm^3, to have the FIRR calculated at 12%, which is approximately 2 percentage points above the weighted average cost of capital (WACC).

The result of the financial analysis for the LNG regasification terminal proposed in this study shows that the project will be financially viable under the condition that the capital can be procured at average interest rate of 9.7%, and that the charge for regasification can be charged at 0.07 USD/Nm^3. Fluctuation in costs (initial investment costs and O&M costs) as well as in gas demand will be the factors which may either underpin or hinder the financial viability of the project which is demonstrated from the analysis.

Unlike the pipeline business the LNG regasification terminal enjoys a favorable business environment from the first years of operation, enabling it to earn from the very first year. This is due to the assumption that the pipeline which links the LNG regasification terminal with the offtakers is already in operation. The pipeline, which functions to structure the value chain of gas business can be said to be playing an essential role for the entering businesses to be viable, relieving the demand and supply risks of gas businesses.

Table 8.3-2 Financial Analysis Results for LNG Regasification Terminal

	Financial Analysis Results
Regasification charge	0.07 USD/Nm^3 (USD 205 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)
WACC	9.7%
Financial IRR (=FIRR)	12%

Source: Formulated by JICA study team

Two other cases under different financing arrangements were considered for reference. These are the cases with less amount of debt, at 75% and 50% of the initial investment amount. The difference in debt amount resulted in different amount of equity required. Cases with less amount of debt require more equity, but less amount of initial investment cost as the total fund requirement. Weighted average cost of capital rises by few percentage points to 11% and 14% respectively for the cases with debt at 75% and 50% of initial investment.

Charges for regasification were set at a level to achieve the FIRR of approximately 2 percentage points above WACC, for each of the arrangements. Regasification cost will have to be increased to 0.07 USD/Nm^3 and 0.10 USD/Nm^3 each, for the cases with debt at 75% and 50% of the initial investment. The result of the analysis show that financial arrangement with less debt amount will require less funding while higher cost will have to be charged to compensate for their high cost of capital. The financing arrangement should therefore be optimized under the given capital procurement environment, and also with regard to the creditworthiness of the proponent business entity.

Table 8.3-3 Financial Analysis Results for Other Financial Arrangement Cases

Percentage of debt against initial investment	90%	75%	50%
Initial Investment	USD 640 million		
Annual O&M cost	USD 0.0096 /Nm^3 (USD 28 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)		
Amount of Debt market procured (Interest) [maturity]	USD 576 million (90% of initial investment) (Interest rate: 6%) [refinanced every 10 years]	USD 480 million (90% of initial investment) (Interest rate: 6%) [refinanced every 10 years]	USD 320 million (90% of initial investment) (Interest rate: 6%) [refinanced every 10 years]
Amount of Equity [Expected yield]	USD 204 million [20%]	USD 277 million [20%]	USD 398 million [20%]
Total financed amount	USD 780 million	USD 757 million	USD 718 million
WACC: Weighted Average Cost of Capital	9.7%	11%	14%
Regasification charge	0.07 USD/Nm^3 (USD 205 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)	0.08 USD/Nm^3 (USD 235 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)	0.10 USD/Nm^3 (USD 293 million for 2,931 million Nm^3 of regasification from 10th year of operation onwards)
Financial IRR (=FIRR)	12%	13%	16%

Source: Formulated by JICA study team

8.4 Economic Analysis

While the financial analysis focuses on the financial viability, i.e. the financial sustainability of the project, the economic analysis will look into the economic worthiness of the project for the society. The analysis will conducted to see whether a project is worth being carried out for the sake of the society as a whole. Negative result of the analysis will therefore suggest that the project should not be carried out (or, that the resources should be allocated to other projects).

Economic analysis is carried out for a set of the two projects, namely LNG regasification terminal and pipeline projects combined. This is due to the technical difficulty in separating the benefits from each of the infrastructures. Benefits to the society will rather be realized when both of these infrastructures operate. Costs and benefits of the two projects, i.e. pipeline and LNG regasification terminal projects are therefore combined into one analysis.

8.4.1 Benefits

Benefits to be included in the calculation are not limited to gains recoverable by the project owner. Any benefits that may be brought by the project should be considered and included in the analysis, as long as they are quantifiable. Economic benefits to the society due to investment are commonly calculated through input-output analysis. On the other hand, benefits from operation of the facility are commonly evaluated by discounted cash flow (DCF) method. Economic analysis in this study focuses on the latter, the benefit from operation of LNG regasification terminal and Batangas – Manila Pipeline.

Benefits other than the revenue gained through business should also be included in the calculation. Among various benefits that will be brought about by making natural gas available to the society, one of the most significant and quantifiable benefit will be the cost reduction compared with the use of fuel oil. As mentioned in Chapter 4 of this report, the current unit cost of fuel oil in the Philippines is calculated as 2.2 times the unit cost of nationally available natural gas, or 1.3 times the unit cost of imported natural gas (c.f. Table 4.5-1). Although the fuel cost saved by energy consumers will not be collected by the gas business entities, it is the economic advantage for the society that can be directly quantified. The benefit is calculated by multiplying the unit cost difference between natural gas and fuel oil, and by the amount of gas provided through the pipeline.

8.4.2 Costs

Costs for the project were calculated as the sum of investment and O&M costs for both the regasification terminal and the pipeline. Tax levies were deducted and internal transactions (e.g. lease paid by the operator to the asset holding company) were balanced out to ensure the accuracy of the calculation. Standard conversion factor (SCF) to adjust the local portion of the costs to international costs was set at 0.95 (All costs excluding material, engineering and management costs were considered as the local costs).

Three indicators were calculated to evaluate the result of the analysis, namely cost benefit ratio (CBR), net present value (NPV) and economic internal rate of return (EIRR). Definitions for these indicators are as explained in the following table:

Table 8.4-1 Economic Analysis and Sensitivity Analysis Results

(1) CBR

$$CBR = \sum_{t=1}^{n} \frac{B^t}{(1+r)^t} \Bigg/ \sum_{t=1}^{n} \frac{C^t}{(1+r)^t}$$

(2) NPV

$$NPV = \sum_{t=1}^{n} \frac{B^t}{(1+r)^t} + \sum_{t=1}^{n} \frac{C^t}{(1+r)^t}$$

(3) EIRR

Discount rate which will make NPV=0

$$NPV = \sum_{t=1}^{n} \frac{B^t}{(1+r^*)^t} + \sum_{t=1}^{n} \frac{C^t}{(1+r^*)^t} = 0$$

Whereas:

CBR: Cost benefit ratio
NPV: Net present value
B^t : Benefit incurred during year "t"
C^t : Cost incurred during year "t"
r : Discount rate
EIRR(r^*) : Economic internal rate of return

Source: Formulated by JICA study team

Result of the economic analysis shows that the economic internal rate of return is 31%, which is well above the social discount rate of 16% (The social discount rate of 16% is the commonly employed rate for evaluation of public works in the Philippines). Net present value (NPV) of the project at social discount rate was calculated as USD 1,576 million, with the cost benefit ratio (CBR) of 2.7. The result, by showing that the investment in the project will bring about the benefit worth 2.7 times the investment amount, implies that the project is robustly worthwhile being conducted.

Table 8.4-2 Economic Analysis and Sensitivity Analysis Results

	Referential condition (Specification = Case 4) (Project model = 2A)	Project cost [+20%]	Commercial Revenue [-20%]	Initial Investment [+20%] and Commercial Revenue [-20%]
Economic IRR (=EIRR)	31%	28%	31%	27%
Net present value (=NPV) at Social Discount Rate	USD 1,576 million	USD 1,388 million	USD 1,463 million	USD 1,275 million
Cost Benefit Ratio (=CBR) at Social Discount Rate	2.7	2.2	2.6	2.1

Source: Formulated by JICA study team

Sensitivity analysis was conducted under various cost and revenue conditions. First the EIRR under the assumption that the project cost will incur at 120% of the referential condition resulted in 29%. This is a figure to show the robustness of the project despite of the cost increase. Another case in which the revenue declines 80% of what can be gained in referential condition also shows that the EIRR will not change significantly. The third case, in which the cost increases by 20% while the revenue declines at 20% simultaneously, shows that the project is still well economically viable.

Economic robustness of the project is due to significant benefit that will be brought about by cutting the cost of fuel for energy users. The project therefore can be said to be well worthy to be conducted from the viewpoint of effectiveness and efficiency of investment.

Economic viability of the project may further improve if the benefit of greenhouse gas (GHG) emissions reduction were to be quantified in monetary terms. Shift from use of fuel oil to natural gas will significantly reduce the emission level of carbon dioxide due to the nature of the fuel. Quantifying the benefit of GHG reduction will be possible through application of credit mechanisms for emissions reduction including Clean Development Mechanism (CDM) and bilateral offset credit mechanism.

Chapter 9 Implementation of BatMan 1 Pipeline Project

Project identified to have the highest priority is BatMan 1 natural gas transmission pipeline which is expected to catalyze the growth of gas industry in the Philippines by linking the source of natural gas with various end users. This Chapter clarifies the actual steps to be taken to materialize the project focusing on the role of the project owner. The report also reflects the outputs from numerous dialogues conducted under close communications with Department of Energy (DOE) and Philippine National Oil Company (PNOC) during the extension stage of the Study.

9.1 Development of a Physical Link between Sources and Offtakers

Infrastructural project to link Batangas, as the current major source of natural gas, with industrial and urban agglomeration of Greater Manila and its periphery area, was first identified as one of the top priority projects in the preceding JICA Masterplan which was prepared in 2002. Justification for the project has always been on the necessity to structure the backbone of the gas industry in the Philippines. Experience of the past ten years have shown that the absence of such result in private businesses not being able to enter into the market due to the fact that both supply and demand risks will have to be borne by these entrepreneurs. Further, the continuation of the current situation, where there is a lack of backbone structure, will inevitably encourage isolated form gas utilization businesses in which each business entity creates their closed loop of gas. Such will miss the opportunity to benefit from the economies of scale.

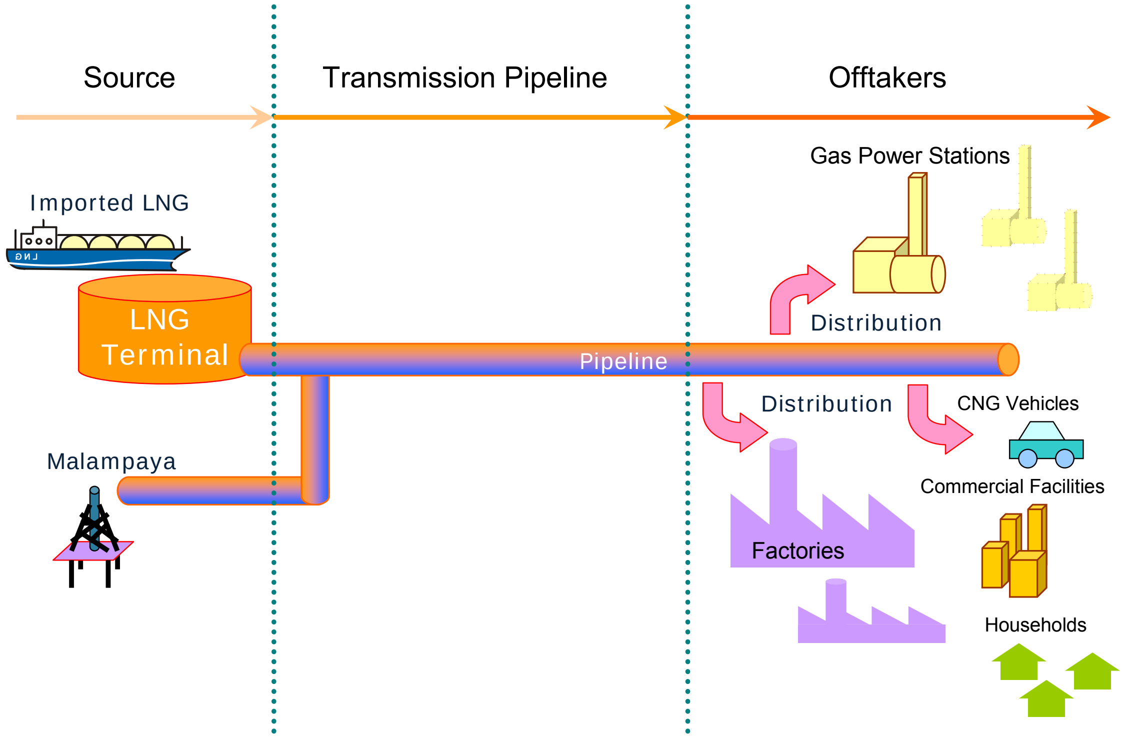


Figure 9.1-1 Gas Transmission Pipeline Structuring the Gas Value Chain

Source: Formulated by JICA study team

A value chain of gas industry, starting from the source (whether imported or from its own well) intermediated by transmission line and aggregators, down to the end users, will have to be structured. The existence of a value chain will facilitate private companies to enter into the business by lowering the hurdles to overcome supply and demand risks. BatMan 1 gas transmission pipeline can become an assurance for the distribution businesses in Greater Manila and its periphery area on supply. Companies will be encouraged to embark on distribution businesses once the gas supply will be secured.

Development of a natural gas transmission pipeline will be beneficial not only to the gas industry but also to the society as a whole. As opposed to the road transport being currently conducted for the Natural Gas Vehicle Program for Public Transport (NGVPPT), gas transmission pipeline will be offering better safety, reliability, efficiency and less negative impacts on the environment.

9.2 Project Implementing Entity

Since the identification of the project, various efforts have been made to materialize the project including government-driven development concepts and proposals for unsolicited projects from the private companies. These efforts were, however, not effectuated due to the complexity of the situation where various constraints and restrictions were in place, including impediments such as the followings:

- Supply of gas from Malampaya could not be secured;
- Safety and other technical specifications to be imposed on the project implementing entity were not ready;
- Roles and responsibility of the public sector was not defined;
- Market regulatory framework was not yet designed;

Requisite conditions not being met, as with the examples stated above, is the consequence of the absence of decision on the implementing entity of the project. Government, as the project owner, with the aim to promote the development of the gas industry, is expected to formulate a policy on how the project will be implemented. Initial decision to be made is who should the project implementing entity will be.

9.2.1 Government's Initiatives in the Cases Overseas

(1) Examples Overseas

Many of the examples of natural gas transmission pipeline development show that the infrastructure was developed through government initiative. Korea established KOGAS, a government-owned gas company with the strong commitment to develop a gas value chain from the scratch. Financial resource from the governmental budget was allocated intensively to the company so as to materialize the strategy to develop a whole gas industry.

In Europe, both UK and France, as with many other countries, also developed their gas infrastructure through government initiatives (the companies were government owned in case of UK while they were government regulated in case of France). Companies serving as city gas companies were already in operation in both countries when necessity of trunk transmission line emerged. It was therefore these publicly owned / regulated city gas companies that were in a position to undertake the development of natural gas transmission pipelines.

Germany (former West Germany), as in some states of US, was in a different situation where various regional city gas companies under purely private management were already existent. These regional private gas companies, when interlinked, were in a position to cover major built up areas that there was not a need for a government's role to enter into the market. It is against this background that the gas transmission pipeline network in Germany could be developed under the initiative of private sector.

India's national gas operation company GAIL was incorporated with the initial task of developing and operating a trunk line pipeline, which reflects the country's intention to develop the infrastructure under the government's initiative. States in India also established their public sector gas business enterprises, including the State of Gujarat. The cases of India shows a different development pattern compared with the other countries and regions in that private participation is sought from an initial stage of the development of gas infrastructure. Possibilities for the private companies to participate are often seen as good investment opportunities, as rapid growth of the gas consumption is anticipated. These private companies who will be forming JVs with the public companies will be able to enjoy dividends from gas business which will be conducted under the government's initiative, without competition.

Examples of the gas transmission pipeline development initiatives in some of the countries and regions are as in the following table. The main trends, apart from some of the cases in which the private city gas companies were already dominant, the initiative of the transmission pipelines development are with the governmental sector.

Table 9.2-1 Examples of Transmission Pipeline Development Initiatives

Country/region	Pipeline developer	Context	Trend
UK	British Gas Corporation	Now privatized. Owned and operated by National Grid. Gas industry has been unbundled.	Privatization, Open access
France	GdF, GSO, CFM	Developed by state regulated existing gas companies through concessions	Withdrawal of concessions, Open access
Germany	Ruhrgas, Wingas, etc.	Privately developed, deriving from existing private city gas companies	Open access
Korea	KOGAS	Nationally driven to promote LNG usage	Gradual privatization
Taiwan	CPC (China Petroleum Corporation)	Nationally driven to promote the use of its own gas reserve + LNG	-
Thailand	Petroleum Authority of Thailand	Owned and operated by PTT	-
India (Gujarat)	GSPL (Gujarat State Petronet Ltd)	Public-private JV was formed with private companies to further develop its network.	Private participation is being sought

Source: Formulated by JICA study team, with reference to IEEJ Situation of Government Interventions for the Development of Natural Gas Pipelines in Various Countries, and updates from official information sources.

(2) Analysis: Necessity for Initiative by the Government

Examples of pipeline development in some of the other countries and regions imply that whether it is the government or the private who implement the project is broadly relevant with the intention behind the necessity of the project and maturity of the gas industry. Intentions may be categorized into two cases: one is the intention to replace oil or coal by imported gas, while another is the intention to enhance the utilization of its natural gas reserve. Maturity can be categorized by existence of city gas companies.

An example of Korea, in which the government initiated a comprehensive development of gas industry from almost zero to develop the whole value chain by a designated government owned company KOGAS, is a typical case where strong commitment by the government is apparent.

Taiwan and Thailand also followed a similar path in having the government owned company developing and implementing the actual business in the whole industrial value chain, from the source to the end users. These two cases, however differs from the case of Korea in that Thailand and Taiwan possessed their own source of gas from its wells as opposed to Korea. Government initiative of Thailand and Taiwan, to certain extent, were based on their intention to make a better use of their natural resources while that of Korea was on the promotion of gas usage, as a policy to diversify its source of energy. Korea, in order to promote the use of natural gas, chose to develop the entire value chain under the central government's strong initiative with an aim to make gas available at reasonable price, by means of economies of scale.

UK, France Germany and Thailand developed their gas infrastructure to make use of their gas reserves for their domestic economic activities. Among these cases the European countries were already with a mature city gas industry for manufactured gas. UK gas industry was originally private but was nationalized by the time natural gas transmission pipelines were to be built. Gas companies in France were private but regulated and guaranteed by the government. As the consequence of the existence of these government controlled city gas industries the natural gas transmission pipelines were logically developed under governmental initiative. The case of Germany follows the similar path with UK, France and other European countries except for that their already-established city gas companies were all private companies.

The logic of the development initiative of natural gas transmission pipelines can be visualized as in the following flow chart.

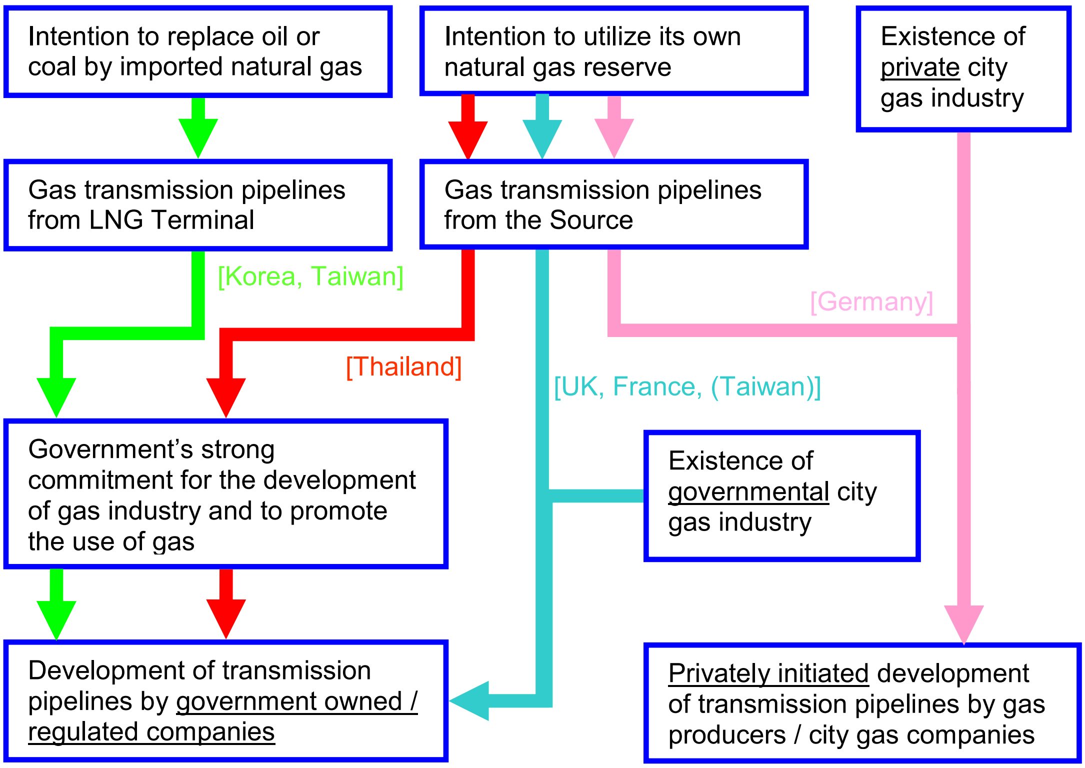


Figure 9.2-1 Analysis of Gas Transmission Pipeline Initiatives

Source: Formulated by JICA study team

9.2.2 Government's Role as the Market Regulator

Natural gas transmission pipeline can catalyze the development of gas industries, both in supply and user ends. This is the consequence of the pipeline being in a strategic position that can influence the whole value chain of the gas industry. Under a fully liberalized market condition, a business entity whether a suppler or a offtaker, who is favored by the transporter / marketer operating the transmission pipeline will be advantageous against their competitors in the same value chain segment, due to supply / demand risks being relieved.

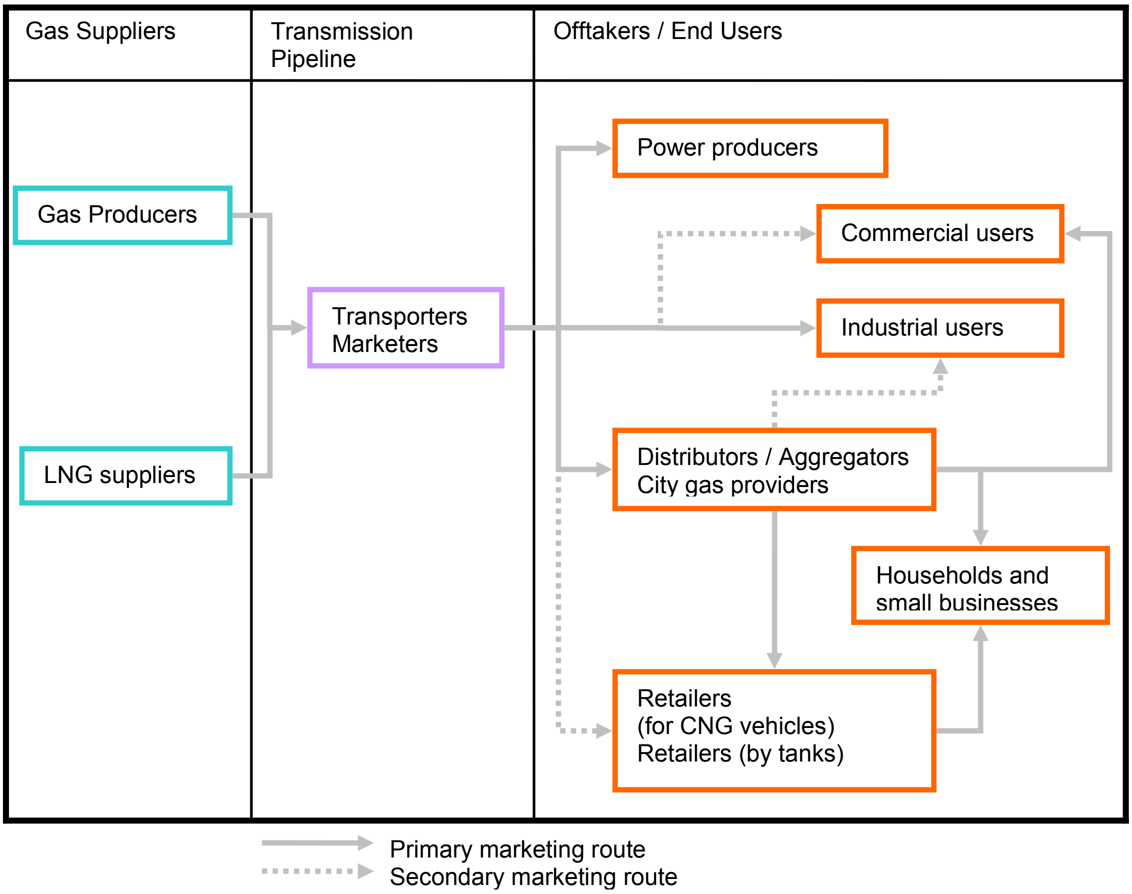


Figure 9.2-2 Strategic Positioning of the Gas Transmission Pipeline

Source: Formulated by JICA study team

Market regulation to avoid certain business entity being advantageous due to linkage with the other segment should therefore be enforced to allow for fair competition within each of the value chain segment. Open and fair access for all stakeholders in need for pipeline usage will have to be ensured. European Directive and US Federal Energy Regulatory Commission (FERC) Order are examples of such open and fair access requirements for the pipelines under public utility.[9] [10]

Further, with the case of the European Directive, a principle of "unbundling" of the business activities in each of the value chain sector is stipulated to be enforced. The unbundling requirement is introduced with the aim to avoid conflict of interest among the business entities

[9] EC Directive (2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC)
[10] FERC Order No. 636

in different value chain segments, by ensuring independence among the entities. Forms of unbundling can be categorized into following four types:[11]

- Accounting unbundling
- Functional unbundling
- Legal unbundling
- Ownership unbundling

Accounting unbundling is the most common type of unbundling and is employed in France, Germany, Belgium, among other countries. Ownership unbundling is the form applied in UK.

Market regulation on open and fair access, including transparent tariff for the transmission pipeline is a condition for encouraging competition in the gas industry to be nurtured. Government is in a position to regulate the market, either by means of establishing an independent regulatory body or, as a tentative structure, enforcing the principle by public body.

Hence, the government will have to play an essential role not only in development of the transmission pipeline but also in enforcing appropriate regulations to promote fair competition in the gas market.

9.2.3 Government's Role to Ensure Low Tariff for the Users

Commitment to nurture a gas industry will have to be accompanies by incentive that will encourage more potential gas users to positively consider switching from other energy sources. Commonly available instruments for a government to extend incentives to the users may be subsidy, guarantee, tax relief, low interest credit, in-kind supports. Subsidy will not be a preferred option for the Philippines, where liberal market policy is already applied to its energy market. Additional tax relief, on top of what will be offered by the Board of Investment (BOI) will be available for Public-Private Partnership (PPP) projects. Low interest credit, by means of guarantee may be sought in particular cases when approved by Department of Finance (DOF).

If BatMan 1 project were to be implemented by the private sector, either as solicited or unsolicited project, it is probable to be covered by the Philippine BOT Law. [12] Infrastructure development projects conducted under private initiative based on the Philippine BOT Law, in most of the cases in which BOT scheme is applied, require private finance for whole or part of the project cost. This private finance will be arranged through bank loans and equity, with expected debt service and dividend at market rate or higher. As the consequence, the cost of capital will be come higher compared with the public finance which may be procured at considerably lower rate against the government's creditworthiness.

BatMan 1 project, with the aim to promote the development of a gas industry from its infancy, will have to be conducted by lowest capital cost available, i.e. public finance. The following table shows a simple comparison of representative financing means which might be considered for the project. Financing by government budget backed by concessional loan(s) will be the realistic and appropriate option, followed by governmental bonds.

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[11] Various document citing the EC Directive, e.g. Gilardoni A, The World Market for Natural Gas: Implications for Europe (Springer, Berlin, 2008)

[12] Act No. 6957, Entitled "An Act Authorizing the Financing, Construction, Operation and Maintenance of Infrastructure Projects by the Private Sector, and for Other Purposes", as amended by Act No. 7718

Table 9.2-2 Comparison of Representative Financing Options

Financing options	Cost	Constraints	Notes
Government budget	Lowest	Lack of liquidity foreseen	Unlikely option under current fiscal balance
Government bonds	Modest	Subject to credit line of the government	PNOC has not issued bonds in the past
Government budget backed by concessional loans	Low	Currency fluctuation risk	Technical assistance / transfer will be available with many of the cases
Private Finance	High	Available only with private initiatives	Not suitable for projects with marginal return

Source: Formulated by JICA study team

Expected wheeling charges were compared in Chapter 8 of this report, for the cases in which the project is conducted on BOT basis with the case when government utilizes the concessional loan. The result turned out to be that the wheeling charge for the concessional loan case was 0.017 USD/Nm^3, while that of BOT case was seen to require more than twice the wheeling charge compared with the concessional loan patterns, at 0.047 USD/Nm^3.

Table 9.2-3 Comparison of Wheeling Charges under Various Financing Options

Model Name	[Model 0]	[Model 2A]	[Model 2B]
Project model	Conventional BOT	Model 2 (Separation)	
Finance	Market Procurement	Concessional Loan	Market Procurement
Wheeling Charges [USD/Nm^3]	0.047	0.017	0.028

Source: Formulated by JICA study team (extract from Table 8.2-2)

Given the non-negligible difference in expected wheeling charge between public and private financing options, BatMan 1 project, with the aim to promote the growth of a gas industry, will desirably be financed through public finance, backed by concessional loan.

9.2.4 Option for the Philippines: Government Owned, Government Financed

Three topics, namely: examples in other countries, importance of proper market regulation, and requirements for low capital cost, all indicated the necessity for the government to implement this BatMan 1 project. The common conclusions from three topics discussed are all derived from a common goal: to promote the growth of gas industry in the Philippines. In other words, the project, if implemented by the private sector, the approach to the goal is likely to become significantly different from the current assumption: to encourage fair competition among the companies.

An appropriate option for the development of BatMan 1 gas transmission pipeline is to have it implemented by the government. This does not signify that the government can be, and should be, taking care of all of the tasks in the project. Active participation of private sector is an essential factor for the project to become efficient and sustainable. Actual scheme to encourage private sector participation will be elaborated in the next section.

9.3 Project Model to Encourage Participation of the Private Sector

Appropriate modality, or project model, will now have to be considered based on the assumption that BatMan 1 project will be conducted under the initiative of the government. The project model to be identified should, first of all, enable the government to be able to finance, own and regulate the gas transmission pipeline. Further, with the aim to enable the project to be pursued in an efficient manner, participation of private sector will also have to be encouraged.

A model to encourage private participation will have to be considered with regard to the required tasks within the project. Tasks may be sorted into two groups; one is the tasks suitable to be taken by the public sector, and the other, by the private sector. Tasks may therefore be allocated to either public or private depending on their characteristics as well as on the capability of each of the sectors.

9.3.1 Major Tasks and their Allocation

Tasks or functions, which will be required in an infrastructure development project, will broadly be the following five tasks: designing constructing, financing, owning and operating. Operation may further be broken down to management, technical maintenance & repairs, marketing.

(1) Designing

Specifications and detailed design will be provided by the project implementing entity, which is assumed to be the government. Desirable form of specification is the output-based specification (or requirements), as opposed to conventional input-based specifications / requirements.[13] This will allow the EPC contractor to introduce innovative considerations for the facility to be constructed and maintained in more efficient manner, at the same time as meeting the standards stipulated in the specification.

(2) Building

The task, whatever the project model, is likely to be pursued by an EPC contractor who will work under the supervision of the designing and controlled under the construction management consultant which is commonly the role of the designing consultant. The EPC contractor is expected to liaise with the technical maintenance & repair company so as to avoid interface risk after the completion / handover of the infrastructure. For this reason, EPC contract and technical maintenance & repair service contract, although separate as two contracts, may be awarded as a set to a single entity.

(3) Financing

Government finance if the preferred option so as to ensure that the cost of capital will be maintained at minimal level, allowing the pipeline usage tariff to be kept low to be able to encourage the development of the gas industry. In case of BOT, as well as with the privately initiated projects, the financing cost will become considerably high, as mentioned in Chapter 8 of this report.

(4) Owning

If market regulatory requirement, i.e. open and fair access is imposed, the act of owning of the infrastructure, as the task itself, will not bring about commercial benefits. Private businesses are therefore unlikely to show interest in owning the infrastructure. Government is expected to own the infrastructure and to provide requirement to whoever will manage and maintain the infrastructure.

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[13] c.f., for example, Farquharson E et al., How to Engage with the Private Sector in Public-Private Partnerships in Emerging Markets (PPIAF-World Bank, New York, 2011)

Table 9.3-1 Task Allocation for Proposed Separation Project Model

Tasks		Characteristics of the task	Entity who will pursue the Task: Proposed Separation Project Model	Entity who will pursue the Task: Conventional BOT
Designing		Task of the management entity / proponent, or may be outsourced to engineering consultants based on basic requirements stipulated by the management entity / private proponent.	Engineering consultant (outsourced under service delivery contract from the management entity	Private Proponent (or its subcontracting consultants)
Building		Pursued by the management entity / proponent or through EPC contract.	Contractor (outsourced under EPC contract from the management entity.	Private Proponent (or its subcontractor)
Financing		Private finance and / or government finance. High creditworthiness of the government will enable low cost capital to be available, resulting in low tariff.	Government	Private Proponent (Government, in the case of BTO)
Owning		No commercial interest in owning the infrastructure. The owner must provide the management entity with specifications to appropriately use and maintain and further invest in the infrastructure.	Government	Private Proponent (Government, in the case of BTO)
Operating				
	Management	The management entity will make decision for business development, further investment, interface with the regulator, etc. Actual transactions will be conducted by outsourced private companies, or in case of BOT model, by the private proponent and their affiliated companies.	Public sector management entity	Management entity = Private Proponent
	Technical maintenance & repair	Carried out by the management entity / proponent, or to be subcontracted from these entities based on specifications provided.	Subcontractor (outsourced from by the management entity), desirably the same entity as the EPC contractor to avoid interface risk.	Private Proponent (or its subcontractor)
	Marketing	Trading of transmission function and / or gas sales. The transaction will be conducted under regulatory control, by a private marketing company, within the scope of regulated tariff structure.	Private marketing company (outsourced from the management entity).	Private Proponent

Source: Formulated by JICA study team

(5) Operating - Management

The management entity will oversee the whole project as the BatMan 1 project management entity. Subcontracts will be awarded by this management entity, and other decision on further investment, business development will be made by this entity. Most of the actual business transactions, i.e. designing construction, marketing, technical maintenance & repairs, will be conducted by outsourced private companies. It is desirable for the management entity to be fully nationally owned so as to promote capacity development of the Filipino nationals.

(6) Operating - Technical Maintenance and Repairs

This purely technical task will be conducted by a private company under outsource contract from the management entity. As mentioned in (2) above, the task of technical maintenance and repairs will be better conducted by the same or affiliated company of the EPC contractor to avoid the interface risk. The outsourcing contract for the task, therefore, may be awarded in conjunction with the EPC contract.

(7) Operating - Marketing

Marketing of the gas transmission pipeline may be conducted in two forms transactions: (a) intermediary and (b) transmission entrusted (either from a supplier (b1) or an offtaker (b2)). Marketing transaction will be conducted by a designated private company who will be given the flexibility to conduct either form of businesses. Marketing company, however, will not be engaged in supply or distribution segment of the gas value chain if unbundling principle is to be applied.

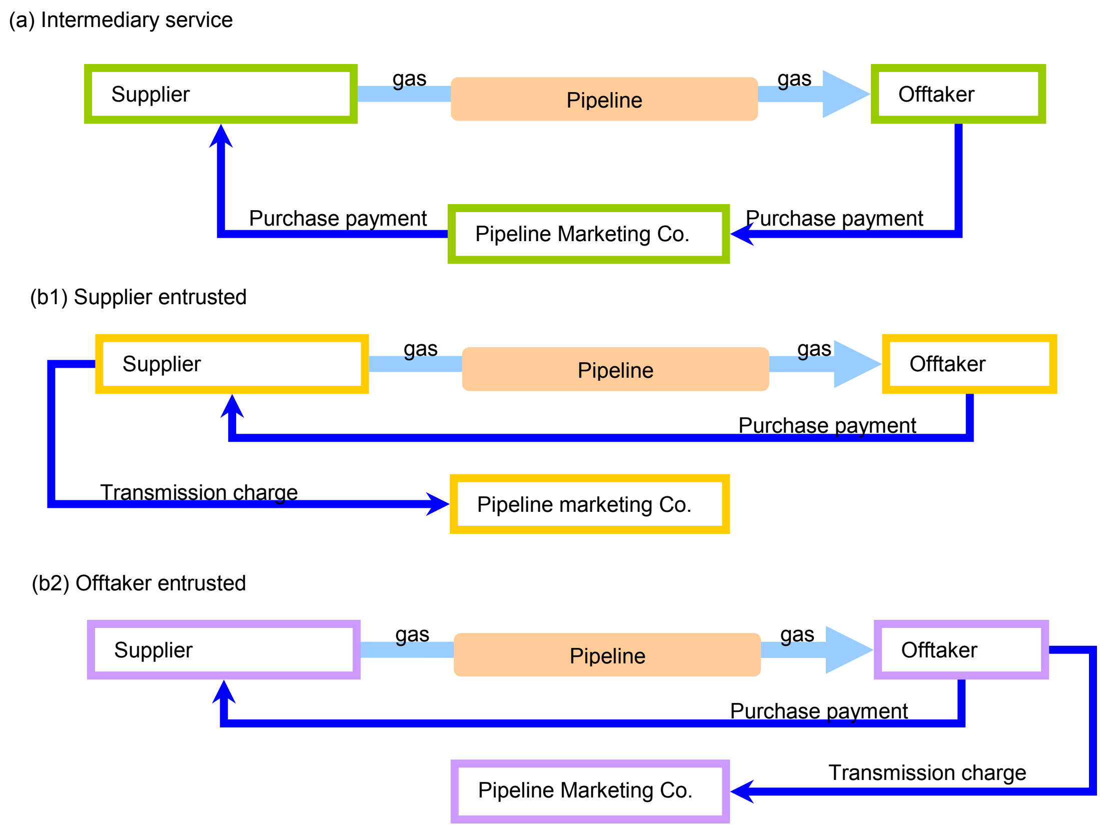


Figure 9.3-1 Intermediary and Entrusted Marketing Transactions

Source: Formulated by JICA study team

9.3.2 A Project Model for BatMan 1 Pipeline Project

Proposed project model, based on the task allocation considered in the preceding subsection, will be a PPP model, with the combination of Build - Transfer (BT) arrangement and Outsourcing of technical maintenance and marketing tasks. Franchise will be granted from PNOC to a newly established purpose company for the overall management of BatMan 1 project. The new management company will now award an EPC contract under condition that technical maintenance task will also be conducted by the same or affiliated entity. This technical maintenance outsourcing contract will be a separate contract from EPC, but will be tendered in conjunction with the EPC contract.

Marketing activities will be outsourced to a private company from the management company. The marketing company will be conducting gas intermediary and transmission businesses utilizing the pipeline. Certain amount of the company's revenue may be paid to the management company to fund the operation and maintenance cost, including the payment to technical maintenance and repair company. Remaining amount from the received revenue may be pooled for future investment, as well as to be paid back to DOF, if required by the initial financing arrangement.

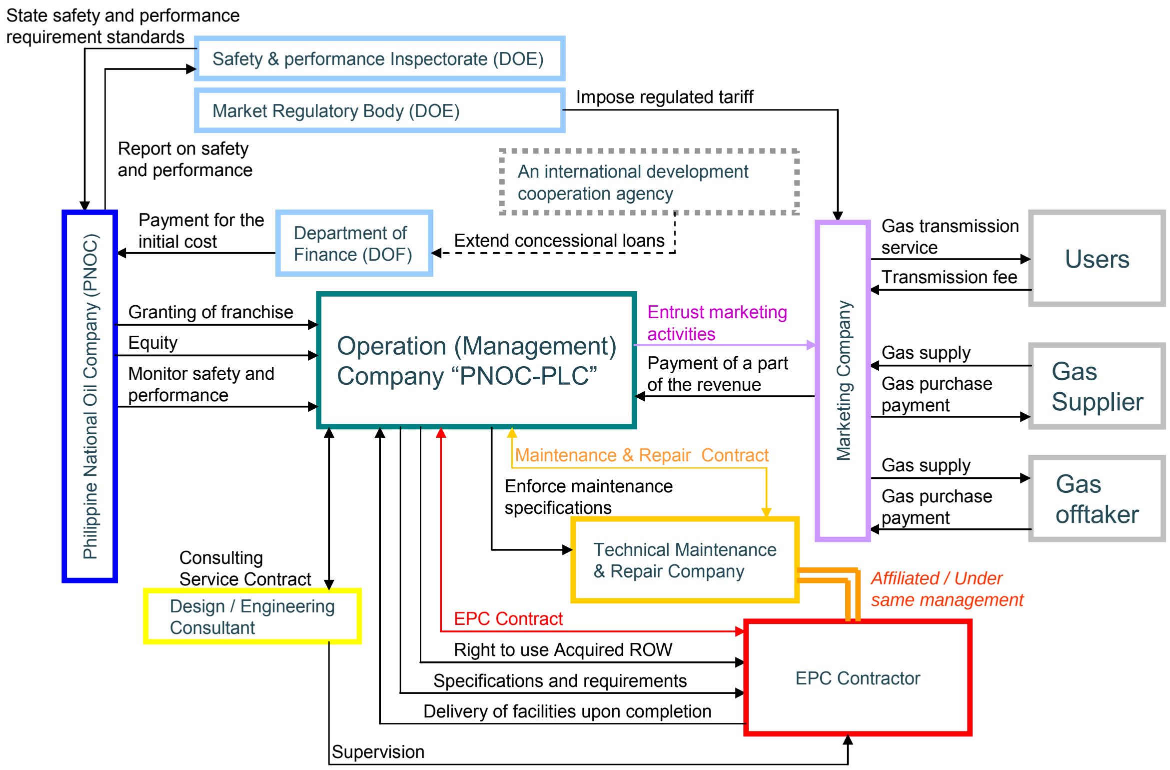


Figure 9.3-2 Proposed Project Model for BatMan 1

Source: Formulated by JICA study team

The project model proposed above, will fall under Philippines BOT Law, and will enjoy incentives such as prolonged tax holiday of seven years. Further, the project, under the proposed model, will not be bound by maximum 50% limit for the government funding.[14]

[14] Confirmed through an interview with the PPP Center conducted on 2 March 2012

Chapter 10 Recommendation for Project Implementation

10.1 Basic Understanding of DOE for Project Implementation

Current natural gas management administration activities are conducted based on policies stipulated in the following statutory instruments:

- DOE Act of 1992 No. 7638
- DOE Executive Order No. 66 Designating DOE as the Lead Agency in Developing the Philippine Natural Gas Industry
- DOE Circular No. 2002-08-005

Further, the JICA Master plan, prepared in 2002 is also functioning as a reference for the direction of the gas industry development.

The Study Team acknowledged that the priority projects for promotion of development of the gas industry have now been listed in the Medium Term Public Investment Program (PIP) of DOE, to be published by National Economic Development Authority (NEDA) in the first half of 2012. The list will include not only BatMan 1 pipeline project but also other projects in the supply segment as well as the end user segment.

The Study Team also acknowledged in February 2012 that, with the finalization of this study, a Steering Committee (formerly named Technical Working Group) will be established to promote the implementation of the priority projects. The team, as the follow up activity of the study, initially intended to further support DOE to push forward the project by (i) preparing a framework document for proceeding with the top priority project, which is BatMan 1 project; (ii) supporting the preparation of bid documents based on the project model proposed by the team; (iii) supporting market sounding and stakeholder consultation by holding a focus group seminar on BatMan 1 project model decision, and; (iv) to invite a high ranked official with one technical staff of DOE to Japan to share among the team and DOE decision makers, the necessity to introduce strict safety standards and efficient operation & management system for gas transmission pipelines.

As DOE requested the team to support the discussions at the Steering Committee on natural gas projects the follow up activities conducted in February to March 2012 was focused on (i) mentioned above, without (ii) (iv) and the seminar mentioned in (iii). The outcomes of the follow up activities are mostly reflected in Chapter 9 of this report. Results from the dialogues with the private stakeholders were reflected and incorporated in the context rather than referring to their actual comments.

The Study Team conducted several high-level meetings with DOE and the consultations with the stakeholders in both of the public and private sectors as well as the information and view sharing at the final presentation. The basic understanding and the agreed views on the project implementation, which have been obtained and shared among the concerned project-related parties, are the followings:

- Considering the current development status of the Philippines, it is preferable to have the gas pipeline developed and owned by the government given the nature of the public utility infrastructure and also to promote the growth of the gas industry. Since the knowledge and experiences of the private sector will be effective for the operation (mainly marketing and maintenance), the project may be developed by applying the ownership-operation separation model;
- The formulation of the implementing organization will be carried out under coordination among the government offices, related organizations and institutions. DOE will examine the detailed procedures in the coming months;
- The project preparation and implementation will require the selection of the

implementing organization, the feasibility study, and the development of institutional framework. DOE has requested the additional support to JICA on these tasks, and;

- DOE will establish a Steering Committee comprised of DOE, PNOC and PPP Center, to elaborate and consider the implementation of the proposal by the JICA study team.

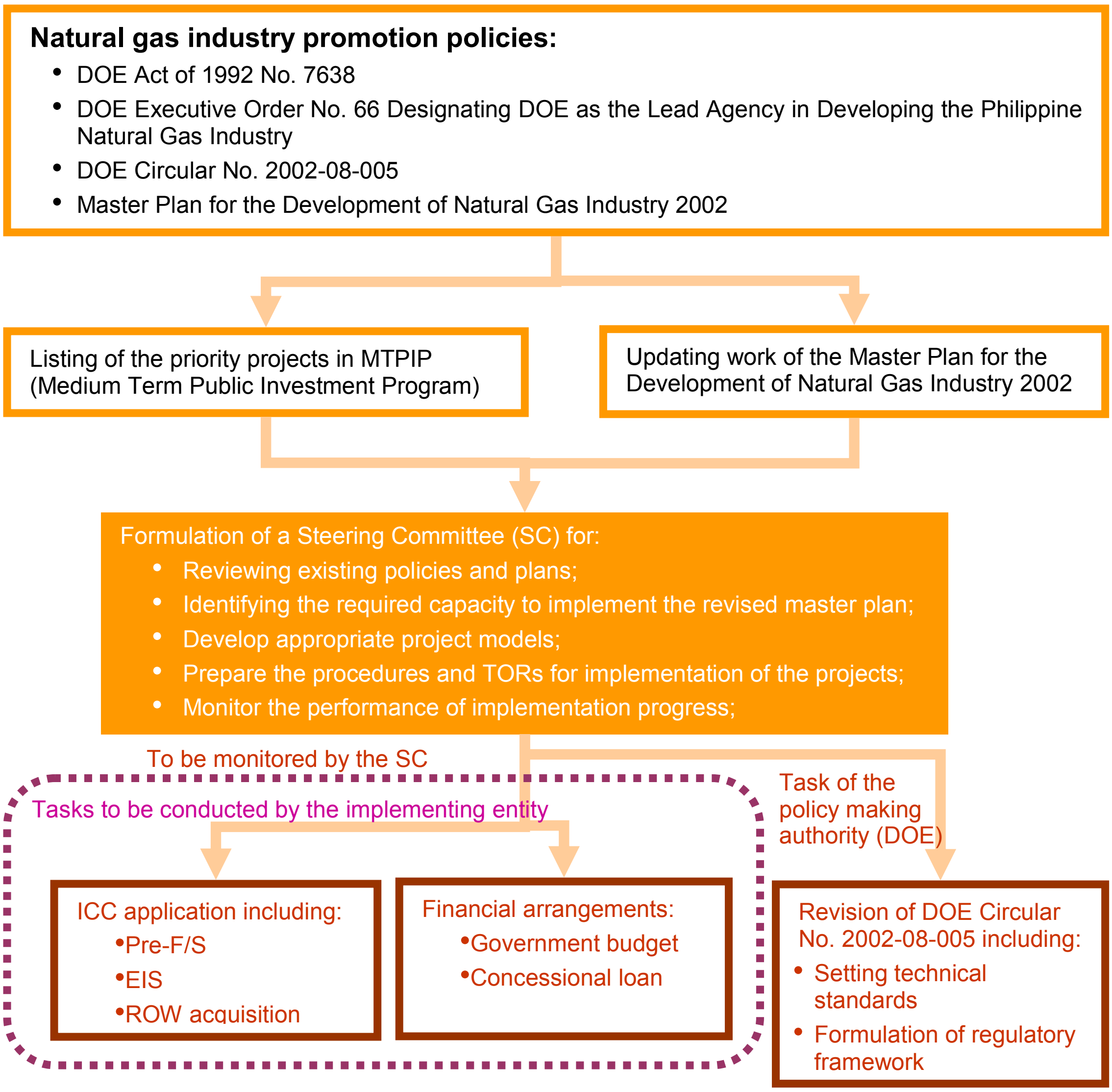


Figure 10.1-1 Orientation for the implementation of the Master Plan Projects
Source: Formulated by JICA study team

Based on the above understandings and on the study findings, the project preparation will require the examinations on the project formulation such as (a) the institutional development for legal and regulatory systems, (b) project implementation scheme and finance, and (c) the procedure for project implementation. The subsequent sections discuss the tasks in detail.

10.2 Institutional Development for Legal and Regulatory Systems

The gas sector in the Philippines, still developing, has not established the technical criterion such as the safety rules and the facility standard. Since the gas projects and the facility development are expected to increase in the coming years, it is understood that the government may need to clarify the opinions on the technical matters and to develop the legal and regulatory frameworks. While the gas supply is primarily planned and implemented by the gas suppliers, the central government offices will need to study the supply security and the necessary supports for the suppliers from the viewpoints of the energy supply security and the improvement of the policy to attract industries. The action items would include the following. The schedule for the action items are also summarized at the end of this chapter.

- Review of laws and regulations on the gas sector
- Study of the current circular on the gas sector
- Study of the establishment of the regulatory commissions on the gas sector
- Study of the regulations on the approvals of the gas pricing
- Study of the standards for safety, security and inspection

10.3 Feasibility Study for Project

The Study conducted the basic design for the gas project, including the gas pipeline and the LNG terminal, based on the data available at hand at the time of the study period. Since the Study rests in the category of the pre-feasibility study, the feasibility study needs to be carried out in order to enhance the accuracy of the projections in the study. This would aim to develop the documents that can be applied to the project bidding through the design of the structures and facilities based on the basic information such as the topographical map, geological data, meteorological and oceanographic data, and seismic information. The data required for the study will include;

- Oceanographic data (water depth, wave, wind, current, tide level)
- Foundation data
- Land use and Right-of-Way data
- Information on underground structures

The report also needs to be developed based on the data required for the environmental and social impact assessment. The detailed information on the right-of-way for project development, for instance, should be compiled and presented to the project-implementing agency. It is understood that the environmental and social issues should be basically addressed by the implementing agency. It is however necessary for the central government offices to confirm the relevancy of the countermeasures by the implementing agency. The conditions in the JICA guideline also needs to be met in order to clear the loan appraisal in addition to the environmental and social considerations by the Philippines laws.

The supply source for the gas pipeline tentatively expects the utilization of the Malampaya gas supply. The detailed conditions of the transaction should be examined. The overall future gas supply scenario should also be studied as to the suppliers, amount and the purchase conditions.

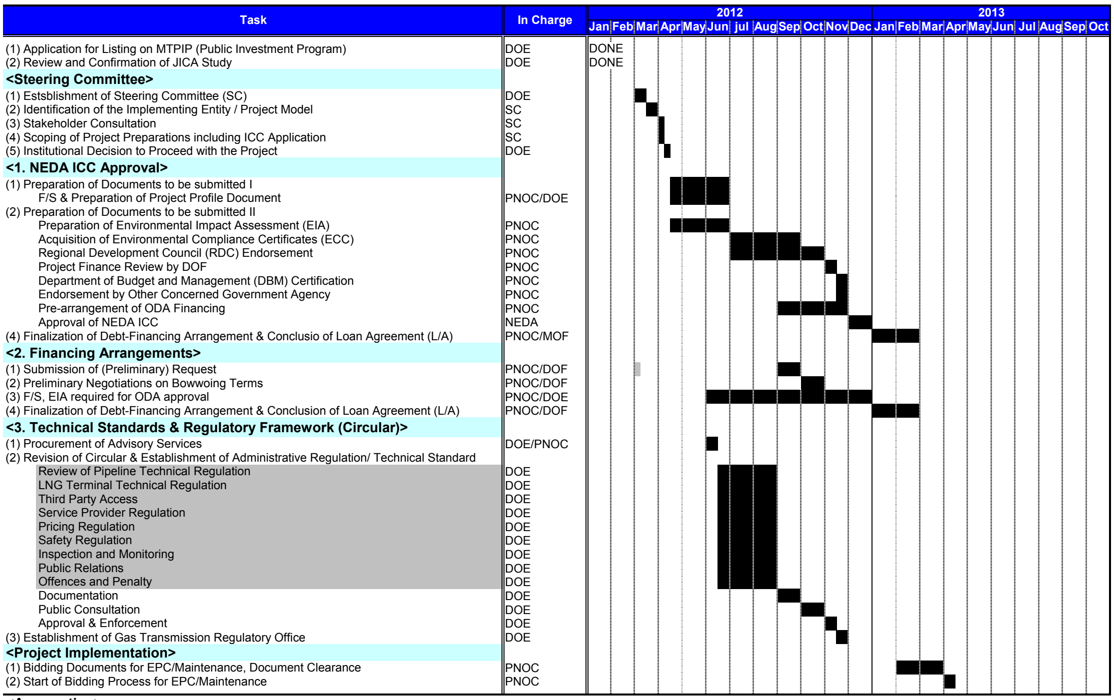
10.4 Project Model Scheme and Finance

The first action would be the decision making of the implementing organization from those candidates including the institutions that carry the current franchise right. There is also a need for the government to conduct the detailed design of the public private partnership, coordinate with the relevant organizations on the funding sources and procedures, and to put together the first draft of the business scheme. Moreover it is important to share the information with the private sector and to obtain the understanding on the project implementation.

In connection with the financing for the project, it is important to confirm the required procedures for the relevant organizations if the project seeks the public finance and/or the donor funding such as JICA ODA loan. Finally, the country does not have any large-scale gas pipeline projects, there is a need to study the approval and change processes, and the conditions for approval of the wheeling charge of the pipeline projects.

10.5 Procedures for Project Implementation

The next phase of the project preparation will look into the procedures and negotiations for project implementation. These can be categorized by the relevant organizations and stakeholders into four types; (i) Procedures for project implementation within the government offices, (ii) Project preparation in DOE, (iii) Negotiation with the implementing agency, and (iv) Preparation with the financial institutions. The procedures within the government offices would be mainly with DOF and NEDA such as budgetary arrangements and funding approval. The project preparation in DOE will be the regulatory arrangements for the gas sector including the safety rules and business regulations. The negotiations with the implementing agency will include the decision on the implementing agency and the negotiation on the project promotion. Additionally, if the project seeks the borrowings from the financial institutions, the detailed discussion should be made on the funding term and conditions in parallel with the coordination with DOF and NEDA. The below table summarizes the actions for DOE.



<Assumption>
1. DOE assigns PNOC as the project implementing entity for Batman 1project.
2. Government finance backed by Concessional Loan
3. No manjor issues on eodorsement by local government and concerned government agency.
4. No major issues on project processing by stakeholders.
5. Close coordination with donor.

Figure 10.5-1 Actions and Timelines for Implementation of the Projects

Source: Formulated by JICA study team

Some of the above-mentioned tasks have already been started during the study period. The study team is currently discussing with Doe the details of the tasks that have been identified as the actions for the next step.

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