

1. INTRODUCTION

1.1 The Philippine Energy Sector

The supply of primary energy in the Philippines is dominated by imported petroleum and indigenous new and renewable energy resources (NRE), the latter largely being biomass fuels used for residential and industrial purposes. Apart from NRE, other principal forms of indigenous energy supply are hydro and geothermal energy used for power generation. Coal supplies are a mix of imported and indigenous products, with indigenous product currently providing about 15% of total coal consumption, a proportion unlikely to rise above 30% in the long term according to the DOE Energy Plan.

Table 1.1
Primary Energy Supply 1998
mbFOE

	Coal	Oil	Hydro	Geotherm	Gas	NRE	Electricity	Total
Primary Energy								
Indigenous Production	3,911	42	2,939	5,170	12	70,177		82,251
Imports	14,474	139,086 *						14,474
Exports		6,225						6,225
Bunkers		4,191						4,191
Stock Change	17	-56						-39
Net Primary Energy Available	18,402	128,656	2,939	5,170	12	70,177		225,356
Transformation								
Electricity Generation								
Output	-5,170	-11,087	-2,939	-5,170	-12		24,378 *	0
Fuel Consumed	12,304	30,355	2,939	5,170	12			50,780
T&D Losses							3,388	
Own Use and Refinery Loss	225	4,860					909	5,994
Net Consumer Energy Supply	5,873	93,441	0	0	0	70,177	20,081	480

DOE Energy Plan 1999

** Adjusted to Balance Table*

Imported petroleum products contribute the largest source of energy for power generation. With a significant input also from imported coal, the Philippines electricity sector therefore has a significant exposure to international energy prices. Natural gas's present share of the energy market is very small, restricted to the San Antonio gas field in northern Luzon which feeds into a 3 MW power plant. When the planned production from the Camago-Malampaya gas field comes on stream, the contribution from gas will increase to up to 10% of total primary energy supply.

The Philippines consumer energy profile is shown in Table 1.2, with oil consumption split into quantities for individual products. Apart from gasoline and diesel fuel usage in the captive transportation sector, fuel oil is the dominant petroleum product used in the Philippines, used widely in industry as the primary thermal fuel. LPG also is used extensively as a bulk fuel for industry although over 60% of LPG volumes are supplied as bottled product through the retail market to households and commercial users. Much of the gas oil consumed by industry is used to generate own-use electricity in reciprocating engines or turbine generators.

Fuel oil also is the principal petroleum fuel used in power generation, supplying about 85% of oil's contribution to the power sector. The remaining 15% is gas oil which is used in gas turbines or combined cycle power plants.

According to Department of Energy forecasts, demand for energy is expected to increase over the period 1998 to 2008 at average annual rates of:

- Residential 4.5%
- Agri-Industry 6.5%
- Commercial 6.8%
- Transport 5.5%

Over the same period, electricity supply is expected to average growth of 7.8% per annum although there remains considerable uncertainty over future growth because of the economic reversals at the end of the 1990's and their longer term impact on demand. Growth in consumption for all petroleum products is put at 4.5%, although this is distorted downwards by an anticipated decline in the use of fuel oil for power generation. Rates of increase for petroleum products in other sectors range between 5% and 8%.

1.1.1 Energy Prices

Oil product prices were deregulated in the Philippines earlier in 1998. Prices are now set by the oil companies according to market conditions and, with all petroleum being imported, market prices will generally reflect international prices, in particular the Singapore export prices for refined products. Typical market prices in the Metro Manila area during mid 1998 and early 2000, the period over which this project took place, are shown in Table 1.3. During this period world crude oil prices have been extremely volatile. After remaining within the \$12 to \$15/bbl range for most of 1998, prices fell to less than \$10/bbl at the end of 1998 and early 1999. However, prices moved steadily upwards during 1999 as OPEC curbed its production to reduce worldwide inventories and tighten supply. At the time of the project Tripartite meeting in January 2000, the oil price was over \$25/bbl and subsequently moved to a high of over \$30. This exceeds OPEC's target range for a sustained level of price and production constraints are expected to be relaxed. However, the longer run price of oil is extremely hard to predict under these volatile conditions as the price rise largely has been driven by a degree of cohesion amongst producers not experienced since the early 1980's without a material change in the potential availability of oil.

Table 1.2
Consumer Energy Demand

mbFOE

	Coal	Oil									NRE	Electricity	Total
		Gasoline	Kerosene	Gas Oil	Fuel Oil	LPG	Avfuel	Naphtha	Other	Total			
Net Consumer Energy Supply	5,873	19,352	4,388	37,375	21,656	7,124	1,761	-15	1,800	93,441	70,177	20,081	189,572
Statistical Difference	568	-96	-17	1,392	-370	299	-14	-57	298	1,435	0	281	2,284
Consumption													
Industry	4,516		213	2,970	9,989	62				13,234	70,177	7,220	95,147
Transport		18,455		29,278	2,786		1,775			52,294	0	17	52,311
Residential		45	3,100	105		4,123				7,373		6,923	14,296
Commercial			1,079	1,080	9,137	2,640				13,936	0	5,141	19,077
Agriculture		948	13	2,550	114					3,625	0		3,625
Others, Non-Energy Use	789							42	1,502	1,544	0	499	2,832
Total Energy Consumed	5,305	19,448	4,405	35,983	22,026	6,825	1,775	42	1,502	92,006	70,177	19,800	187,288

DOE Energy Plan 1999

Table 1.3
Petroleum Products Prices
(Peso/litre)

	Market Price P/litre		Excise Duty	Tariff
	mid 1998	early 2000	P/litre	
LPG Retail*	13.76	20.64	0.00	3%
LPG Bulk	6.19	8.92	0.00	3%
Gasoline	12.00	14.20	4.80-5.35	3%
Kerosene	6.76	9.24	0.60	3%
Diesel	8.35	9.89	1.63	3%
Fuel Oil	5.00	7.80	0.30	3%

* P/kg

Coal from the Philippines mines has been subsidised to support the coal mining industry although it is understood that these subsidies are likely to be removed. Most Philippines coal is relatively low rank compared to internationally traded coals, ranking as lignite/sub-bituminous coals, some with a significant sulphur content. As the majority of coal is imported, coal users are effectively exposed to international prices for steaming coal. Current CNF import prices for Indonesian and Australian steaming coals are about \$40 per tonne and up to \$35 per tonne for Chinese coal. Delivered prices for Philippine coal range between P 840 to 1,700 per tonne, depending on quality, with the most commonly used coal costing about \$1.7/mmBtu.

The 3% tariff on imported energy is applied across all petroleum products and coal, although the tariff level for LNG is set at 10% under the current laws. This latter tariff was imposed on LNG to facilitate the development of indigenous gas resources, in particular the Camago-Malampaya field, at the time when LNG was being promoted as a contender as a power generation fuel.

Excise tax is applied to diesel fuel used in power generation although it is exempt when the fuel is being used as a standby when natural gas is unavailable. No excise duty is applied to LPG except when it is used as an automotive fuel.

1.1.2 Energy Policy Environment

The government of the Philippines has adopted a number of broad policy objectives relating to the development and governance of the energy sector. In the context of the major commercial energy sources, these include:

- Enhancement of energy self sufficiency
- Diversification of sources of energy supply
- Provision of reliable, adequate and economic supply of energy
- Promotion of judicious and efficient use of energy

- Encourage greater private sector investment and participation

Programmes and strategies underway to achieve these objectives include the development of indigenous energy resources such as natural gas and the institutional reform of some parts of the energy sector. In the context of institutional reform, industry deregulation and restructuring and the privatisation of government companies and agencies are amongst the strategies of government. The downstream oil distribution and marketing industry has been deregulated to encourage competition and new legislation currently is being debated in Congress to restructure the power sector.

- ***Downstream Oil:*** Government has ceased to regulate wholesale or retail prices in the downstream oil industry, reducing its role in that respect to one of monitoring and publishing market prices. Conditions of entry to refining, distribution and marketing activities is being simplified and government is intending to actively promote the participation of more companies beyond the existing three industry incumbents: Shell, Caltex and the partially state owned Petron. Petron is to be fully privatised. Moving from a regime of price regulation and close control over market participation and activities, the principal regulatory controls are now fair trade and safeguards against cartelisation and predatory pricing.
- ***Electricity Reform:*** Restructuring of the power sector is aimed at the creation of a competitive wholesale market between generators and distributors and large users. The National Power Corporation is to be retained only as a transmission company with its generation assets sold to private companies and will act as a regulated utility providing open access to generators and users. IPP's already are significant contributors to the generation mix and distributors commonly are private franchise holders. Unbundling of prices will be a feature of the new regime although price regulation will continue to be maintained at the retail level.

The government has a specific policy of promoting the development of natural gas, including the development of domestic gas markets. This policy is contained in the Department of Energy Circular 95-06-006 which is outlined in Section 1.1.5 of report.

1.1.3 The Power Sector

Total electricity energy sales in 1996 was over 33,000 GWh, about 87% of which was consumed in the island of Luzon. The large majority was generated by the National Power Corporation using its own plants or through energy conversion contracts with IPP's. NPC supplies to co-operatives, public utilities and directly to major power consumers.

IPP's increasingly are supplying directly to public utilities, a trend expected to increase rapidly from a current 5% of total generation, particularly after 2000 when new private capacity is commissioned. Notably, Meralco, the private utility supplying Metro

Manila, will purchase directly from 1,500 MW of gas fired plant from 2002. As a result the growth in electricity sales by NPC is expected to track significantly below the national forecast of over 7%. NPC's own forecast indicates average growth rates fluctuating between 5.3% and 6.6% for the Philippines and 2.9% and 3.4% for Luzon.

Over three quarters of the Philippines generating capacity is located in Luzon, with oil, coal, hydro and geothermal being the principal contributors. The 300 MW BNPP nuclear power station is located at Bataan in Luzon but has not been commissioned and has been the subject of investigations for conversion to natural gas.

Table 1.4
Philippines Power Generation Capacity
(MW)

	Luzon	Visayas	Mindanao	Total
Hydro	1268	7	984	2259
Geothermal	846	350	47	1243
Coal	1300	160	0	1460
Oil	4243	486	593	5322
NRE	0	0	8	8
	7657	1003	1632	10292

Source: NPC Power Development Plan 1997

NPC owns 76% of the generating capacity although one third of this capacity is operated by private companies. About 90% of the privately owned and operated capacity consists of thermal plant, two thirds of which is oil fired and the remainder coal fired. In comparison, 48% and 9% of NPC's own capacity is oil and coal fired respectively.

NPC's thermal capacity is a mix of conventional plant fired by coal and fuel oil and combined cycle gas turbine (CCGT) and peaking gas turbines fired by distillate fuels. Its programme for capacity additions and retirements for thermal plant in the Luzon grid is summarised in Table 1.5.

Table 1.5
NPC Capacity Additions and Retirements to 2010
Luzon Grid Only

Plant Type	Fuel	Existing	New			Retired
		MW	MW	Years	MW	Years
Conventional	Coal	1300	1600	1997-8		
Conventional	Fuel Oil	2900	400	2001-8	1275	1999
					400	2000
					210	2004-9
CCGT	Distillate	600				
Gas Turbine	Distillate	550	310	2003-5	450	2006-9
CCGT	Natural Gas		1200	2002		

Virtually all of this new capacity is being constructed by private companies contracted to NPC through energy conversion contracts, including the 1200 MW Ilijan gas fired CCGT plant planned for construction near Batangas. In addition to this plant, 1500 MW of private gas fired CCGT capacity is being constructed for direct supply to Meralco. These gas fired plants and the imminent retirement of a significant portion of conventional oil fired capacity represents a significant swing away from oil use in power generation.

The IPP programme was implemented in the early 1990's after the Philippines suffered from persistent power shortages. Whilst the IPP's have relieved that problem in the meantime, electricity costs are the highest in the region after Japan and it is apparent that there will be significant generation over-capacity with committed plant coming on stream in the next few years, despite the retirement programme. If the Ilijan plant is not operated at 80% plant capacity factor, NPC will be unable to meet its take or pay commitments for gas purchases at the Ilijan plant during the first eight years of plant operation. It is possible that this over-capacity could worsen after downward revisions of growth after the regional economic downturn during 1998.

NPC's average wholesale and Meralco's average retail electricity prices are shown in Table 1.6 for the first half of 1997 and 1998.

Table 1.6
Philippines Electricity Prices
(First Half Year Average P/kWh)

1997	1998
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NPC Wholesale Price		
Luzon	2.26	2.68
Visayas	2.10	2.44
Mindanao	1.35	1.52
Meralco Retail Price		
Residential	3.45	3.94
Commercial	3.46	3.88
Industrial	3.15	3.47

Source: NPC Annual Report 1998

The higher prices in Luzon can be attributed to a cross subsidy of consumers in this grid to power users elsewhere as the topography and smaller transmission network in the two other regions result in a higher cost of generation and transmission. This subsidy has been justified on the basis of the greater affluence of Luzon consumers.

1.1.4 The Petroleum Development Regime

A production sharing style of petroleum development regime is used in the Philippines. The principal features are contained in the Presidential Decree 87 of 1972, and its subsequent amendment in PD 1857 of 1983, and Service Contracts signed by the companies and government. These principal features are summarised:

- The oil company as the operator pays for the cost of exploration, development and production and thereby assumes the project risk in that these costs will not be recovered by the company unless there is revenue to pay for the costs.
- Costs of exploration and production can be recovered from the project gross proceeds once production commences. This includes tangible (capital) costs, although the extent to which these can be recovered depends on the conditions of development:
 - For deepwater developments (in which 85% of the development area is in waters deeper than 200 meters), intangible exploration costs can be recovered in full. Tangible exploration costs can be recovered over a period of 5 years. Intangible and tangible costs of development and production are treated on the same basis. In respect to these items, the Camago-Malampaya field development is the same as a deepwater development.
 - For other developments capital costs of development and production are recovered over a 10 year period.
- The gross proceeds are based on market values or spot rates of the petroleum produced or rates contained in contracts approved by the government.

- The maximum level of costs which can be recovered in any year is equivalent to 70% of the gross proceeds from production. Any shortfall in the amount claimed can be claimed in subsequent years.
- The net proceeds (being the difference between gross proceeds and the recoverable costs) are split 40/60 between the contractor and the government.
- The contractor is exempt all taxes and duties except income tax on the proceeds of production. Capital items for exploration and development are depreciated over a period of ten years, and deductions are allowable to the extent of two-thirds of interest paid to finance operations, except interest to finance exploration. In the case of the Camago-Malampaya field, the contractor is indemnified from paying income tax, the government is to provide tax receipts to the contractor for taxes paid by the government on behalf of the contractor.
- When Filipino companies participate in the service contract, the contractors will receive the Filipino Participation Incentive Allowance (FPIA). This applies to interests between 15% and 30% with a maximum level of 7.5% of the gross proceeds.
- Cross recovery of exploration costs in deepwater areas is allowable against revenue from other production locations.

1.1.5 Gas Development Policy

Policy relating to development of natural gas resources was released in the Department of Energy Circular 95-06-006, June 15, 1995. This is summarised:

1. The government shall promote the role of natural gas into the energy supply mix of the country by creating conditions for a gas industry that economically serves a broader variety of users, including efficient gas fired power plants, industrial, commercial and residential users.
2. The Camago-Malampaya gas field shall serve as the foundation for the industry into efficient power plants from 2001.
3. The gas industry shall be consistent with the government's own policy of encouraging private sector participation and reducing the government's direct involvement in the ownership of assets and facilities. Government will confine itself to policy direction and regulation, unless government involvement is demonstrated to provide substantial reduction in the costs of natural gas and economic benefit to the people.

4. Government regulation of the development and operation of the industry facilities shall be structured to facilitate the safe operation and growth of the industry and equitable non-discriminatory access to all industry participants.
5. The facilities shall be constructed and operated in compliance with Philippine environmental regulations and international safety standards.
6. The gas industry shall be primarily promote the policy of utilising indigenous energy resources to stabilise energy prices.

At present, there are no confirmed plans to distribute natural gas to the industrial or residential energy sectors although this is being investigated by PNOC-EC, First Gas and possibly Shell. A franchise for gas distribution is held by the Manila Gas Company, a former distributor of manufactured towns gas, which is owned by the National Development Corporation and now operates as a distributor of LPG. It had a pipeline network located in the Manila and Rizal areas, which was rehabilitated after World War II but was last used to reticulate LPG and has not operated for some years. The network had about 5,000 connections at the time of closure, down from a maximum of 20,000 of which 80% were residential. Manila Gas is now up for privatisation.

1.2 The Philippines Gas Project

The basis of the Philippines Gas Project (GPG) is the development of the Camago-Malampaya field, located in deep water north west of the island of Palawan. Occidental Philippines originally discovered the field in 1989 under Service Contract 38 (SC38) and was subsequently joined by Shell Philippines Exploration as a joint venture participant in the contract. In September 1998, Occidental transferred its interest to Shell as part of a world-wide rationalisation of petroleum interests. During 1999, Shell transferred 45% of its interest to Texaco and is presently negotiating to transfer a further 10% to PNOC-EC, which will leave Shell with a 45% interest.

Three power plants are to be constructed to utilise the gas produced from the GPG. First Gas Power Corporation Ltd. ("FGP", a joint venture of British Gas International and a private Philippine company) sponsors two of these plants and the National Power Corporation ("NPC"), an entity of the Department of Energy, sponsors one. Shell is presently negotiating to sell gas to Magellan Utilities for use in a fourth power plant, which will bring the total gas-fired generation capacity to about 3,000 MW. These high-efficiency, low-pollution state-of-the-art power projects are the first of their kind in the Philippines.

Not only are the power plants the sole market support so far for the PGP, but they constitute the only market that has yet emerged for any substantial amount of natural gas in the Philippines, from either domestic sources or imports.

A series of contracts signed in the first half of 1998 largely achieved the objective of DOE Gas Policy to supply natural gas for “efficient gas-fired power plants”. The commercial and financial structure for the PGP is composed of entitlements and obligations created in thirteen separate agreements. Figure 1.1 illustrates the complexity of the PGP, which has been established on the basis of the gas sale and purchase agreements with FGP and NPC only, the negotiation with Magellan for the relatively small tranche of gas for its 300 MW power plant occurring after the project go-ahead.

Although the gas reserves available from Camago-Malampaya materially exceed the anticipated demand associated with the three power plants of NPC and FGP, there is no way of knowing whether large additional domestic reserves of natural gas will be discovered and developed in commercial quantities in the plannable future, either as part of the PGP, adjacent to it, on other offshore structures, or onshore.

1.2.1 Gas Reserves

The Camago-Malampaya gas field has proven reserves of about 2.5 TCF and is relatively rich in condensates. Results of three independent estimates of gas reserves provided by Shell are shown in Table 1.7.

Table 1.7
Reserve Estimates of Camago-Malampaya

	Gas TCF: Proven	Condensate mm Barrels: Probable
DeGolyer & McNaughton	1.84	91
British Gas	2.19	
Gaffney, Cline & Associates	2.21	110
Shell Philippines	2.53	121*

**Expectation*

Shell’s expectation reserve estimation is 3.18 TCF which is close to British Gas’s most likely gas reserve estimate of 3.12 TCF. The lower reserve estimates of DeGolyer and McNaughton arise from using more conservative cut-off criteria for determining gas in place and those of Gaffney Cline from more conservative assumptions on porosity distribution. The Department of Energy’s estimate is close to that of Shell, the medium and high estimates being 2.448 TCF and 3.650 TCF respectively, with the wide range resulting from variances in the reservoir porosity.

According to the Joint Declaration of Commerciality signed by Occidental, Shell and the Government of the Philippines in April 1998, the Camago-Malampaya field and the much smaller San Martin field, also located in the SC 38 area, have “gas reserves which

could sustain an average daily production of 400 mmscfd of natural gas (3,000 MW of power generation capacity) for a period of 20 years". This is equivalent to about 2.9 TCF produced over the life of the field.

Condensate production will decline over the field life, reducing from a liquids to gas ratio of about 45 bopd/mmscfd at the commencement of the project to about 25 bopd/mmscfd at the end of the field life.

1.2.2 Project Development

Camago-Malampaya is situated in water up to 850m deep off the coast of Palawan island. It is proposed that production commence from the Malampaya field in 2002 with production wells drilled at Camago in 2009/10. The principal features of the development planned by Shell are:

- Subsea wells at the Camago and Malampaya fields manifolded to two wet gas flow lines feeding to a production platform.
- A production platform set closer inshore in 45 meters of water outside the SC38 area where liquids are to be separated from the gas. The liquids will be loaded from the platform through a loading buoy onto tankers for transport to refineries. Capacity of the platform and gas processing facilities is 500 mmscfd. Produced water will be processed and discharged at the platform.
- Depletion compression facilities will commence operation in 2014.
- A 504 kilometre subsea pipeline to transport the processed gas from the platform to the Tabangao landfall near Batangas on the island of Luzon. The capacity of the pipeline can be increased to 650 mmscfd with the installation of additional compression facilities to provide extra capacity for additional gas volumes from outside SC38 or other potential discoveries outside SC38. This pipeline is included within the SC38 ringfence.

- A desulphurisation plant located at the Shell oil refinery at Tabangao, bringing the gas up to market quality. The gas custody transfer point will be at Tabangao.
- Onshore pipelines direct to the gas consumers, discussed in detail below.

Total projected capital cost of the project is estimated at about \$ 2,200 million, expressed in nominal dollars (dollars of the day) at a constant 3% inflation from 1997. Details of the costs as provided by Shell are shown in Table 1.8 which also includes operating costs over the project life. In 1997 dollars, the capital costs are estimated at \$ 1,890.

The point of gas custody transfer from Shell to the power generation projects, and the limit of the SC 38 contract envelop, is at the gas processing plant at Tabangao. The NPC and FGP plants are situated near Batangas and will be supplied directly by dedicated pipelines from the gas processing plant:

- In the case of FGP's Santa Rita and San Lorenzo plants, the 7 km pipeline will be installed by Shell (using an amendment to the GSPA) on an overland route with an underwater route across Batangas Bay to be used as a standby in the event of major right of way obstacles.
- NPC has awarded a turnkey contract to NACAP ECCO Asia to construct the 15 km pipeline to Ilijan, which will run across some isolated hill country from Tabangao.
- Prior to deciding to locate the San Lorenzo plant (previously called the Calabarzon power plant) adjacent to its Santa Rita plant, First Gas investigated locating the plant at Cabuyao to the south of Metro Manila with gas supplied by pipeline from Tabangao. Despite obtaining access to some of the land for this route, right of way issues contributed to FGPs decision to locate the plant adjacent to its Santa Rita plant near Batangas.

1.2.3 Service Contract No. 38

As the foundation agreement for the PGP, Service Contract No. 38 principally contains the terms and conditions of the Model Service Contract. The Work Program committed the Contractor to annual expenditures of \$5 million for the first seven years and to drill one well each year. The Contractor is permitted to apply seventy percent of the gross proceeds of annual production to the repayment of costs. Remaining net proceeds are shared between the Contractor and the DOE on a 40:60 ratio.

The conditions of additional significance to the PGP are contained in a Memorandum of Clarification. In particular the Contractor is authorised to sell the Government's share of gas production to NPC. Furthermore, the document purports to amend the definition

of “Petroleum Operations” to encompass pipelines for the delivery of gas as well as facilities installed upstream from the point of sale that are used to extract hydrocarbon liquids.

Joint Venture Agreement

The Contractor is a joint venture between two separate foreign corporations Shell Philippines LLC, which is the successor to Occidental Philippines, Inc., and Shell Philippines Exploration B.V. Under the Joint Venture Agreement, Shell Philippines Exploration B.V. is the Operator for the Service Contract. As noted, Texaco has assumed a 45% interest in the contract.

1.2.4 Gas Sales and Purchase Agreements

Three Gas Sales and Purchase Agreements (GSPAs) were concluded in December 1997 and April 1998:

- National Power Corporation for the Ilijan 1,200 MW plant near Batangas (the Korean Electric Power Corporation, KEILCO plant)
- First Gas Power Corporation for the Santa Rita 1,000 MW plant near Batangas
- First Gas Power Corporation for the San Lorenzo 500 MW plant near Batangas.

These GSPA’s are equivalent to 2,700 MW of generating capacity, short of the capacity of 3,000 MW or 400 mmscfd stated in the Joint Declaration of Commerciality. The quantity of gas, which is to be delivered yearly and the level of the take-or-pay obligations for NPC and First Gas Power Corporation under the GSPA’s shown in Table 1.9.

**Table 1.8
Contracted Gas Quantities**

Gas purchaser:	First Gas Power Corporation		NPC
Plant:	Santa Rita	Calabarzon	Ilijan
Capacity:	1,000 MW	500 MW	1,200 MW
Daily Contract Quantity	158.8 TJ (NCV)	76.2-87.3 TJ (NCV)	164 TJ (GCV)
Annual Contract Quantity	49.7 PJ (NCV)	23.8-27.3 PJ(NCV)	60 PJ (GCV)
Annual Take or Pay	43.0 PJ (NCV)	20.6-23.6 PJ(NCV)	60 PJ (GCV)
	Approximate Gas Flow (mmscfd)		
Daily Contract Quantity	161	77-88	150
Annual Contract Quantity	138	66-76	150
Annual Take or Pay	119	57-65	150

GCV: gross calorific value, NCV: net calorific value

For purposes of developing a regulatory framework, the terms and conditions in the GSPA's of greatest interest are:

- Sales Price
- Marketing Rights
- Facility Access

The Government has given the Sellers an undertaking not to reduce the price paid for gas under the GSPA signed with NPC. There are two significant aspects in this limitation. First, the undertaking does not extend to the prices set in the two GSPA's with FGP. Second, the provision creates tension with the so-called "price" jurisdiction of ERB under Executive Order 172. This results from the provision of NPC's GSPA which fixes the prices for the first 24 quarters of Gas Oil, Dubai Crude Oil and Oman Crude Oil that are used in adjusting the Base Price. As these price levels have exceeded the prevailing market prices for the referenced crude oils, the ERB may have been inclined to assert its jurisdiction under Section 3 of Executive Order No. 172 to conduct a hearing on whether the adjustments were "fair and reasonable".

The schedule of prices in the GSPA's, including adjustment to the NPC price to account for the pre-arranged oil price indices, and the weightings given to the escalators are shown in Table 1.10. These prices are effective at the custody transfer point at the Tabangao gas processing plant.

Future gas sales to third parties could be made in the following manner:

- The Sellers to other buyers
- The Buyers through an assignment under the GSPA
- The Buyers through a separate on-sale
- The Government of the Philippines under subrogation of rights from NPC

Table 1.10

GSPA Gas Price Schedules

Gas Price \$/GJ (GCV)			
	First Gas	NPC	
Quarter	Base	Base	Adjusted
1-12	4.076	4.029	4.245
13-24	3.981	3.934	4.145
25-32	3.886	3.839	3.839
33-40	3.791	3.744	3.744
41-48	3.696	3.649	3.649
49-56	3.602	3.555	3.555
57-64	3.507	3.460	3.460
65+	3.412	3.365	3.365
Weighting of Escalators			
US CPI	43.0%	53.0%	
MSFO	15.0%	7.5%	
Gas Oil	10.0%	7.5%	
Dubai Crude	7.5%	7.5%	
Oman Crude	7.5%	7.5%	
None	17.0%	17.0%	

*NPC prices adjusted in first six years with pre-arranged oil price escalation factors.
The same schedule of prices apply to both the First Gas contracts.*

Under the first option, the GSPA's contain a provision in Article 12 which gives the Sellers the right to sell natural gas produced from either within or outside of the Service Contract Area to other buyers. Under the Gas Sale Implementation Agreement, an irrevocable agency was created which gives the Service Contractor the right to market the Government's share to other buyers as well. This marketing right in the GSPA is expressed as a reservation in favor of the Sellers.

Only the FGP GSPA's contain a 'most-favored-nation' clause which obligates the Sellers to reduce the price of gas sold to the Buyers if a lower price were agreed with a third party. For the clause to be activated, the third party must be an electricity generator, supplying predominantly into the Luzon grid using CCGT technology. Furthermore, the pricing formulas do not reduce the price due to greater efficiency in utilisation of the capacity of the gas processing plant and submarine pipeline in the event that additional quantities are sold to third parties.

The Buyers' ability to market gas is more limited. They do not have a right of first refusal that is commonly agreed when so-called 'foundation' users have underwritten the economical development of a gas field. This means that the Buyers can only market the gas committed to them under their respective GSPA's. Marketing could be handled either by assignment or sale. If a new buyer were to take an entire or partial assignment of a Buyer's gas entitlement, the GSPA's require:

No Party shall be entitled to assign or transfer its respective rights and obligations arising under this Agreement without the consent in writing of the other Parties, provided that such consent shall not be withheld if the Party who wishes to assign or

transfer its rights and obligations has demonstrated to the reasonable satisfaction of the other Parties that the proposed assignee or transferee has adequate financial, technical and legal ability to exercise the rights and observe and perform the obligations to be assigned or transferred.

In such situations, the GSPA's do not provide for an outright assumption and novation of the Buyer's contract entitlements which means the Buyer would remain directly obligated to the Sellers irrespective of the assignment to a third-party.

A direct on-sale is possible so long as the agreement is not a 'transfer' of the Buyer's contractual rights under the GSPA. Again, the Buyer retains primary obligations under the GSPA.

Finally, it is also possible that the Government would be able to market gas in the situation where the Sellers have made a call on the payment guarantee. The DOF Performance Undertaking makes the following provision:

Entitlement to Annual Deficiencies

The Republic reserves the right to give you written notice through the Secretary of Finance and the Secretary of Energy that NPC's right to recover Annual Deficiencies under clause 9.3 of the GSPA is subrogated to the Republic to the extent that payment is directly made by the Republic of Guaranteed Obligations, provided that the Republic notifies NPC of such direct payments and gives proof of such notice to you.

The Support Assignment and Payment Agreement restates the Government's right of subrogation and requires that the Government and NPC agree on the terms and conditions for the exercise of this right. To date no agreement has been prepared. Additionally, in exercising the subrogation rights for Annual Deficiencies under the GSPA, the Government would be subject to the limitations on their recovery. Primarily, this means that no recovery of the outstanding balance of Annual Deficiency is permissible until “. . . the Buyer has taken delivery of a quantity of Natural Gas equal to the Provisional Take-or-Pay Quantity . . .” for that year.

Third-party access is briefly mentioned in the Article 21 – Sellers Reservations. The Sellers expressly reserved the right for the use of the Delivery Facilities to transport natural gas to third parties.

All GSPA's have definitions of Delivery Facilities that are substantially similar to that contained in the contract with NPC as follows:

. . . such wells, offshore facilities, offshore and onshore pipelines, dehydration, separation and treatment plant and machinery, measuring stations and equipment and other facilities necessary from time to time for the Sellers to produce from the Reservoir and tender for delivery to the Buyer as the Delivery Point the quantities of Natural Gas required to be tendered for delivery under this Agreement and to process any associated liquids.

The GSPA's with FGP also include a definition of "Gas Pipeline" as being included with Delivery Facilities such as the following from the Santa Rita contract:

Gas Pipeline shall mean the pipeline facilities to be constructed from the transmission of Natural Gas from the Delivery Point to the Plant.

Gas deliveries to KEILCO are to begin in October 2001 with deliveries for commissioning to be made for a period of three months. Although full contract quantities are to be available for delivery in 2002, the demand for power will limit KEILCO's output. As a result KEILCO will operate to reduced capacity factors in the first seven years of operation. The Annual Contract Quantity (ACQ) of the NPC GSPA is equivalent to a capacity factor of 80%.

Table 1.11
Capacity Factors KEILCO Power Plant

Year	Capacity Factor %
2002	37
2003	44
2004	48
2005	52
2006	60
2007	67
2008	74

The excess generation capacity will have a significant impact on NPC's take-or-pay obligations under the GSPA as the annual take-or-pay requirement is the same as the ACQ. The impact is shown in the following table.

Table 1.12
Accumulation of NPC's Take-or-Pay Liability

Year	ACQ <i>PJ</i>	Price * \$/mmBtu	ToP Deficiency \$ million
2002	59.9	4.48	135.24

2003	59.9	4.48	114.02
2004	59.9	4.48	101.28
2005	59.9	4.37	86.47
2006	59.9	4.37	61.60
2007	59.9	4.37	40.87
2008	59.9	4.05	18.66

* *Adjusted for predetermined escalators, 2005-2007*

Within the first seven years, the take-or-pay liability for NPC will exceed \$558 Million based upon the ‘Plangas’ estimates. This exposure could be higher due to a general reduction in economic activity or other contingency such as MERALCO’s decision for either early termination, or non-renewal of the 3,600 MW bulk power purchase contract with NPC which expires in 2005.

1.2.5 Other Contractual Arrangements

A series of other agreements and undertakings have been executed to support the GSPA’s and are outlined in this section.

Gas Sales Implementation Agreement

The Gas Sales Implementation Agreement (GSIA) was signed by the Secretary of Energy on 30 April 1998 to satisfy the condition precedent in the GSPA to give the Service Contractors the authority to market the Government’s share of the natural gas. The authorisation for the Service Contractor to market the Government’s share is expressed as follows:

Section 1. Pursuant to SC 38, the GOVERNMENT hereby irrevocably authorizes the SELLERS to (I) sell the GOVERNMENT SHARE of NATURAL GAS on the terms and conditions set forth in each of the ILIJAN GSPA, the SANTA RITA GSPA and the CALABARZON GSPA and (ii) to market and sell such GOVERNMENT SHARE of NATURAL GAS under other GSPAs on the same terms and conditions as will apply to the sale of the CONTRACTOR SHARE of NATURAL GAS. Subject to the SUPPORT AGREEMENT, such GOVERNMENT SHARE shall be sold by the SELLERS for and on behalf of the GOVERNMENT.

Prior to signing, the Service Contractors requested that the GSIA include conditions that would allow cost-recovery for damages due to NPC under the GSPA for alternative fuel that must be supplied if upstream facilities cannot be completed within the time to commission the KEILCO power plant. The GSIA adopts the approach that claims regarding recovery of “sales costs will be subject to DOE validation”.

Under the GSIA, funds received as take-or-pay payments are treated in the same manner as income from the delivery and sale of natural gas. This means that the Government is in the position of guaranteeing that it will receive its own share of the take-or-pay moneys. Presumably, this provision will also obligate the national government to pass on a share of the take-or-pay payments to Local Government Units just as it will funds from gas sales. It would have been more efficient to simply limit the guarantee to the proceeds going to the Contractor.

Parent Company Guarantees

The parent company for the foreign petroleum companies has given a guarantee to NPC. These guarantees cover the full, prompt and complete payment of the Seller's obligations under the GSPA. However, the aggregate liability under the Guarantee is limited to \$200 million.

Due to the change in control of Occidental Petroleum (Philippines) LLC, the parent company for Occidental Philippines, Inc., NPC has been asked to accept a substitute guarantee from Shell Petroleum Inc. and to release Occidental Oil and Gas Corporation from its prior obligation. This request should not be implemented without receiving a financial statement from Shell Petroleum Inc. and consideration of possible changes that are favorable to NPC, DOE or DOF in other agreements.

Administrative Order No. 381

President Ramos signed Administrative Order No. 381 on 17 April 1998 ("A.O. 381"). Although its was not an express condition precedent, A.O. 381 is an important document in the GSPA closing process for NPC. Other than reciting the national benefits of the PGP, the main purpose of A.O. 381 is to establish the authority for the transfer into an earmarked account of the Net Government Share of proceeds from "all petroleum, natural gas and geothermal contracts, and coal operating contracts". This account is to be used for the purpose of repaying the funds drawn from the Service Contractor's Camago-Malampaya ToP Deferred Payment Facility (DPF).

The DPF was created in order to loan NPC the funds to meet its take-or-pay obligations under clause 9.2 of the GSPA. The funds are not capable of being applied to NPC's take-or-pay liability unless the KEILCO Power Plant meets or is above the generation capacity targets contained in the November 1997 Plangas profile but below the TOP quantity. If the output from the power plant is below Plangas levels, the Service Contractor's only recourse will be to call on the credit guarantee provided in the DOF Performance Undertaking.

Support Assignment and Payment Agreement

The Support Assignment and Payment Agreement has been signed by the Secretary of Energy. The SAPA is a tripartite agreement between DOE, NPC and the Service

Contractors which allows NPC's take-or-pay obligations to be paid from the government's share of net proceeds under petroleum, geothermal and mineral contracts. Support for NPC's obligation is only effective if the KEILCO power plant is being dispatched at the rate set in the Plangas schedule. The Plangas schedule is annexed to the SAPA and contains the following figures:

**Table 1.13
Plangas Gas Consumption Profile**

Year	PLANGAS
2002	28PJ
2003	33PJ
2004	36PJ
2005	39PJ
2006	45PJ
2007	50PJ
2008	55PJ
2009 and thereafter	Full Take-or-Pay Quantity

This limitation could become an Achilles heel for all parties if the overall economic performance reduces the demand for power. In this event, the SAPA and DPF will either need to be amended, otherwise a claim will be made under the Performance Undertaking.

Deferred Payment Facility

Even though the Government has provided a Performance Undertaking to guarantee payment of NPC's obligations for take-or-pay along with actual deliveries, a source of stand-by support was further needed as an alternative to foreign debt. In this respect, DOE and DOF have pledged the government's share of net proceeds from petroleum, geothermal and mineral contracts under the Support Assignment and Payment Agreement. As this amount is exclusive of funds directed to Local Government Units and Contractor's indemnified income tax, the flow of funds under the SAPA may not be sufficient to match the level of NPC's take-or-pay obligations in the period 2002-2010. The residual shortfall is forecast to reach \$242.32 million by 2003. This amount will accrue as follows:

**Table 1.14
NPC's Take-or-Pay Shortfall**

YEAR	SHORTFALL
2002	\$88.97 Million
2003	\$67.58 Million
2004	\$54.80 Million

As a result, the Service Contractors to whom the payments are due have agreed to create a \$350 Million Deferred Payment Facility as a line of credit for NPC to draw upon. Drawings are limited to the so-called "Positive Difference", that is the amount of take-or-pay due once NPC has met the target set for the generation of electricity from Ilijan. If NPC does not meet this performance standard the commitments under the SAPA and DPF are not applicable and a call is made on DOF under the Performance Undertaking.

A Term Sheet has been prepared for the DPF and a detailed agreement will be negotiated in 1999. The detailed agreement is expected to be a complex document and DOE may benefit from outside assistance.

Performance Undertaking

A guarantee for NPC's payment obligations under the GSPA was a condition precedent. DOF Undersecretary Soriano signed the Performance Undertaking on 29 April 1998. The Government of the Republic of the Philippines has pledged its "full faith and credit" to the payment of NPC obligations for gas delivered to it as well as the take-or-pay obligations. Using the Plangas forecast of KEILCO's annual capacity factors, NPC's take-or-pay liability is approximately \$558 million. This amount includes TOP payments for both the Contractor's as well as the Government's share of net proceeds. After the tenth anniversary of the PGP start-up the level of the guarantee will be reduced to 80% of the take-or-pay obligation. This means that subsequent financing by the Service Contractor, such as bonds, will have the benefit of a government guarantee.

The Performance Undertaking was intended to be a backstop for the Deferred Credit Facility. However, a downturn in the general economy of the Philippines may easily result in depressed power demand. If the KEILCO Power Plant does not meet the output targets contained in the Plangas projection, there is no obligation for the DOE to provide Shell with revenues from indigenous resource contracts. This will force Shell to make a call on the Government under the Performance Undertaking. Such a call would force the government to borrow funds from the international capital markets to meet NPC obligations. The Government has a right of subrogation for any of the gas paid for under this guarantee. However, the ability to have the gas delivered would still be subject to NPC's make-up rights which require that in any year the full amount of the contract must have been delivered and payment made before the seller is obligated to deliver from the take-or-pay balance.

The Performance Undertaking appears to restrict the Government from regulatory intervention that would reduce the gas price negotiated under the GSPA with NPC. This limitation is not worded to include the contracts signed with FGP.

DOE-DOF Interagency Agreement

DOE and DOF are preparing an agreement to coordinate their functions in respect to the Performance Undertaking, SAPA and DPF. The issues being addressed include:

- NPC's reimbursement of DOF for advances, debt service and borrowing
- Authority for DOE to determine how gas will be delivered under the right of subrogation the government obtains by making NPC's take-or-pay payments.

The new president of NPC, has advised DOF that the negative pledge conditions of the corporation's loans from multilateral development banks prevent the creation of any reserve accounts which would earmark revenue from the sale of electrical power as means of reimbursing for the take-or-pay payments under the Performance Guarantee.

Subrogation Agreement

Under Section 3 of the Performance Undertaking, the Government's payment of NPC's take-or-pay deficiency gives it a right of subrogation to take delivery of that quantity of natural gas. The source of the payment can be from either a call on the Performance Undertaking or the use of the net proceeds received from Service Contracts.

Article IV of the Support, Assignment and Payment Agreement states that the terms of the Subrogation Agreement are to be agreed by NPC and the Government. The parties have not entered into this agreement.

Energy Conversion Agreement

The Energy Conversion Agreement is the fuel supply and power purchase contract for KEILCO. Contractually speaking, the only outstanding milestone for the PGP's critical path is the financial closing date for the KEILCO (Ilijan) Power Plant.

Financial closing was to have initially occurred by 15 December 1998 and has been extended to March 1999. Despite financial upsets in Korea, the sponsor for the KEILCO power plant, Korean Electric Power Corporation, considers that it will be able to obtain most of its financing from the U.S. Export-Import Bank and Japan Export-Import Bank. Conceptual design is complete. Raytheon has been selected to be the EPC contractor, and Mitsubishi Heavy Industries is to supply the turbines and generator sets.

Finally, KEILCO's financial closing was not a condition precedent to NPC's obligations under the GSPA. This means that the full level of take-or-pay is due even if the construction of the power plant is delayed or cancelled due to lack of financing.

Local Government Unit's Share of Net Proceeds

In the Philippines, Local Government Units (LGU) are entitled to receive a share of the net proceeds received from a "production sharing agreement in the utilisation and development of the national wealth within their territorial jurisdiction". Section 290 of the Local Government Code authorizes LGU's to receive forty percent of the gross collection obtained by the national government. Among LGUs, the forty-percent is further allocated between Provincial and Municipal governments according to a formula contained in the Article 389 of the implementing rules and regulations for sharing national wealth.

The Support Assignment and Payment Agreement recognizes that the net proceeds which the Government has committed to support NPC's obligations under the GSPA do not include funds that are taken for the payment of the Contractors income tax, or the proceeds shared with LGUs.

1.2.6 Conclusion

The PGP Service Contractors¹ and the Philippine government agreed in a Joint Declaration of Commerciality regarding Camago-Malampaya that the total volume of gas expected to be deliverable from the field will be at least 400 million cubic feet per day [mmcf] for 20 years.² The estimated deliverable volumes and service life would support CCGT electrical generating capacity of about 3,000 MW — 11 percent more than the 2,700 MW design capacity of the three power plants. The projection of 400 mmcf corresponds approximately to the daily contract quantity ["DCQ"]³ in the gas sales and purchase agreements ["GSPAs"] between SPEX and sponsors of the power plants. This quantity exceeds by 12.75 percent the sum of annual contract quantities ["ACQ"] in the GSPAs, and exceeds by 17.5 percent the sum of annual take-or-pay ["TOP"] obligations for the three plants. Even so, NPC expects to incur TOP obligations under its GSPA because of a deficit in electricity demand, from the commencement of deliveries in the year 2002 through the year 2007.

¹ In Philippine parlance and law, oil and gas exploration and production ["E&P"] activities elsewhere carried out by "lessors" or "concessionaires" are the function of "Service Contractors." The Service Contract governing Camago-Malampaya takes the form of a production-sharing agreement.

² The subsea pipeline from the field to the project landfall and processing plant at Tabangao has a potential design capacity of 650 mmcf, 163 percent of the projected daily deliverability and 169 percent of the full-capacity gas consumption of the three power plants.

³ The DCQ in a gas-sales contract is both the minimum daily volume the seller must make available for purchase and the maximum daily volume the buyer has a contractual right to purchase.

The implications of this outlook are two-sided. The more positive side is that, commencing in about 2002, there is potential capacity to supply additional gas reserves to uses other than at the three power plants. Shell is currently negotiating with Magellan Utilities for part of this capacity. However, if the Philippine private or government entities are unable to grasp these opportunities profitably, the negative aspects of a gas surplus will include NPC's TOP liabilities (which the government has agreed to underwrite), in addition to the opportunity costs of shut-in supply and underutilised producing, transmission, and processing capacity. The overhang of unsold gas from Camago-Malampaya can also exert a depressing impact on the incentive to search for or develop additional domestic natural-gas reserves.

The failure or prolonged delay of either the gas-producing venture at Camago-Malampaya, or one or more of the power plant ventures, would therefore mean a definitive setback for the emergence of a Philippine natural-gas industry, as well as loss of anticipated national economic benefits from the projects themselves.

Both the commercial viability and the prospect of national economic benefits associated with the project command a high degree of confidence. The following factors are reasons to have confidence in the PGP:

- Investments already undertaken in developing the PGP, and the confirmed volumes of gas deliverable on the basis of these investments.
- Low installed costs per unit of capacity, and the high operating efficiencies of the gas-fired CCGT installations planned for the power plants.
- Low emission levels for air-borne and other pollutants per unit of electricity supplied by such gas-fired generating plants.