AN ANALYSIS OF THE PHILIPPINE GAS REGULATORY FRAMEWORK[1]

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I INTRODUCTION

From its discovery more than a decade ago up to its commissioning less than month ago, its development was monitored and supported by four presidents and five energy secretaries who hailed it as a national flagship project. It was considered the biggest and most significant foreign investment to date, an achievement by those who toiled to make it happen. Most importantly, it was a milestone – Malampaya ushered in a whole, new natural gas industry.

Compared with its Southeast Asian neighbour countries, a great part of the Philippine archipelago lies in a geological setting which is not conducive for the generation and accumulation of petroleum. For this reason, with the exception of geothermal energy, the country is not as endowed with commercial energy resources. Indigenous oil production has continuously declined since it started and peaked in 1979. Coal, on the other hand, is relatively low rank compared to internationally traded coals, ranking as lignite/sub-bituminous, some with a significant sulphur content, and difficult to extract efficiently. Also, because of the perceived greenhouse effects of mine-mouth power projects, the development of coal resources has been difficult to pass off to an environmentally conscious populace as an alternative energy source. Natural gas, which has been previously regarded as an unwanted associate of oil has only recently been given serious consideration when commercial quantities were discovered in deepwater areas but are technically and financially challenging to develop and utilize.

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[1] Infrastructure Development in Australia and Overseas Research Paper for University of Melbourne LLM 23 October 2001

Now with the coming on-stream of Malampaya, natural gas is expected to form a significant part of the energy mix and hopefully help alleviate the country's chronic dependence on imported energy. But there is a lot of work ahead for energy regulators. While the backbone of the industry is now in placed, the multiplicity of ad hoc arrangements and risk hedging measures in the Malampaya gas project is, to a large extent, attributed to the lack of a comprehensive regulatory framework to guide natural gas industry operations in the Philippines. There is no doubt that decisions and investments made in this project will have a long-term impact on the future development of the gas industry and must therefore be optimised.

This paper has been organized as follows: Part II gives a brief summary of the forecasted contribution of indigenous gas resources to the energy mix and the legal framework of the petroleum upstream regime; Part III describes the Malampaya natural gas development project, the contractual agreements entered into by the government, the Service Contractor and the off-taker, outlining the commercial provisions, risk allocations, and sovereign guarantee; and Part IV analyses the proposed gas regulatory framework. Given that this new industry is being hyped as a the best thing that ever happened to the Philippine energy industry, we argue that the costs of government guarantees and other financial support will be passed on ultimately to the taxpayer but they can be mitigated nonetheless through the restructuring of the sector by clearly defining the regulator's role and enhancing competition. The challenge then to regulators is to implement structural reforms that would encourage gas market expansion without undue disruption to the existing arrangements or unreasonably high costs of change.

II PHILIPPINE ENERGY MIX

Oil product prices were deregulated in the Philippines after almost twenty-five years of government regulations following the enactment of the *Downstream Oil Industry Regulation Act 1998*.[2] The act paved the way towards institutionalising market-based policy reforms, and creating a competitive environment responsive to the social policy

[2] *Republic Act (RA) No. 8479.*

objectives of the government. The law provided for the imposition of a uniform 3% tariff duty on imported crude oil and refined products, promotion of free trade practices that would prevent cartelisation among oil companies, implementation of conditions of entry to refining, distribution and marketing activities that would further encourage new participants in the industry, provision of incentives for new investments as provided for under the *Omnibus Investment Code 1987*, promotion of retail competition, and the requirement for the initial public offering of the three industry incumbents: Shell, Caltex and the partially state-owned Petron. 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 current laws. This latter tariff was imposed on LNG to facilitate the development of indigenous gas resources particularly the Malampaya field, at the time when LNG was being promoted as a substitute 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. Prices are set by the oil companies according to market conditions and, with all petroleum being imported, market prices will generally reflect international prices, particularly the Singapore export prices for refined products.

Under the Philippine Energy Plan for 2000-2009, primary energy demand was projected to increase at an annual average rate of 6.3% from 256 million barrels of fuel oil equivalent in 2000 to 445 million in 2009. Energy self-sufficiency level will increase from 42% in 2000 to 49% in 2004 due principally to the start of commercial production of natural and condensate from the Malampaya field. Electricity demand will grow at an annual rate of 8.9% from 46,262 Gwh in 2000 to 99,714 Gwh in 2009 and will be supplied mainly by cheaper non-oil alternatives. The share of oil to total power generation is expected to shrink further from 10% in 2000 to 5% by 2009. Overall, Malampaya will be generating about 16% of total electricity supply in the country in 2002 and in the process displace about 26 million barrels of fuel oil.[3]

[3] Department of Energy, Philippine Energy Plan 2000-2009.

To meet the long-term demand for electricity a total of 9,875 MW of new generating capacity will have to be installed in the next ten years. Of this, 5,255 MW are committed projects while the balance of 4,620 MW represents the uncommitted capacity requirement expected to be put-up under a liberalized power market. These indicative capacity requirements are expected to fill in the projected gap in capacity after 2005 which could be filled-up by 1,600 MW of base load capacity, 1170 MW of midrange and 1,850 MW of peaking power plants. With the scheduled retirement of 1,926 MW of old oil and coal-based power plants, the net installed capacity of 2009 will reach 20,289 MW.[4]

A *The Philippine Petroleum Upstream Industry Regime*

The Philippines has a production sharing style of petroleum development regime as contained in *Presidential Decree (PD) No. 87 of 1972, as amended by PD 1857 of 1983*, and service contracts[5] executed between the government and petroleum exploration companies, the principal provisions of which are briefly described as follows:

The petroleum company shoulders the costs of exploration, development and production and assumes the risk that these costs will not be recovered if the exploration is not successful.
The costs of exploration and production can be recovered from the gross proceed once production commences. These include 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.
For other developments, exploration intangible costs are not included in the recoverable costs and the 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

[4] The Philippine Energy Plan can be accessed at http://www.doe.gov.ph/PEP_Demand.htm
[5] The production sharing agreements are called service contracts but are not 'service contracts' per se where the State retains ownership of petroleum and minerals, plant, equipment and other assets acquired for operations while the foreign enterprise works as a contractor under the government's supervision and gets paid for its services, irrespective of the profits or losses. See A.F.M. Maniruzzaman, 'The New Generation of Energy and Natural Resource Development Agreements: Some Reflections' (1993) 11 *Journal of Energy and Natural Resources Law* 207.

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 from all taxes and duties including 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.
Filipino companies participating in the service contract 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 only in deepwater areas is allowable against revenue from other production locations.

The study prepared by Van Meurs and Associates for Barrows entitled 'World Fiscal Systems for Gas', which made a detailed analysis and comparison of worldwide fiscal regimes for gas to assess the competitiveness of various country regimes from the perspective of the private industry, reported that the Philippine regime is reasonable in comparison with its near neighbours Indonesia and Malaysia, both of which have large and well established domestic and export gas industries. The conventional Philippine regime is placed on an equal basis to the Indonesian Frontier regime, which probably fairly reflects the status of the fledgling Philippine gas industry, but is less severe than the conventional Indonesian and Malaysian regimes, which are in more established petroleum provinces. The more favourable deepwater Philippine regime is ranked similarly to the deepwater Indonesian system but is less severe than the Malaysian counterpart.

The principal weakness attributed to the Philippine regime is that it is front loaded or provides the State with too much share of the initial cash flow after production commences, which will have a negative economic effect on the development of fields that have high costs relative to recoverable reserves. Often, these so-called 'marginal fields' are the ones that are suited to supplying domestic markets.

B *Philippine Natural Gas Resources*

Using McKelvey's mineral resource assessment scheme, Philippine natural gas resources are classified into 'discovered' and 'undiscovered'.[6] 'Discovered natural gas resources' refer to those that have been adequately delineated by seismic and other means and measured by drill-stem test in at least one hole per closure. On the other hand, 'undiscovered natural gas resources' are those that have been estimated by various means but not measured by drill stem test, although reached by a hole.

Essentially, quantitative estimates reported as reserve, recoverable reserve and gas-in-place generally fall within the category of 'discovered'. Reported potential reserve, target reserve, resource potential and untested recoverable reserve are in the category of

[6] V.E. McKelvey. 'Mineral Potential of the United States,' in E. N. Cameron (ed), *The Mineral Position of the United States 1975-2000* (1973) 69.

‘undiscovered’. Table 1 lists the quantified natural gas deposits and prospects in the Philippines and their corresponding estimates in trillion cubic feet (Tcf). The total natural gas resources in the Philippines is 25.7-39.5 Tcf of which 3.4-5.4 Tcf is discovered recoverable reserve.[7]

Table 1. Natural Gas Resources in the Philippines[8]

Deposit/Prospect	**Discovered (Tcf)**	**Undiscovered (Tcf)**	**Total (Tcf)**
Camago-Malampaya	2.500-3.200		2.500-3.200
San Antonio	0.002		0.002
San Martin	0.164-0.297		0.164-0.297
Libertad	0.003		0.003
Destacado	0.074-1.238		0.074-1.238
Octon	0.700		0.700
San Marcelino		0.150-0.719	0.150-0.719
Bagong Pag-asa			
Pag-asa Objective		0.006-0.580	0.006-0.580
Nido Objective		0.278-1.384	0.278-1.384
Iloc		0.239-0.642	0.239-0.642
Princesa		0.091-4.931	0.091-4.931
Cliffhead		0.125-1.811	0.125-1.811
Sombrero		0.152-1.961	0.152-1.961
Fuga		18.000	18.000
Sulu Sea		2.000	2.000
Roxas		0.010	0.010
Cuyo & NE Palawan		1.000-2.000	1.000-2.000
Victoria		0.024	0.024
Manila Bay		1.000	1.000
TOTAL	**3,443-5.440**	**22.226-34.062**	**25.669-39.502**

Of the discovered gas resources, only the San Martin, Destacado and Octon deposits, all located in the northwest Palawan shelf, are proximate to the Camago-Malampaya field, which accounts for an additional 1 Tcf in additional proven reserves. The Philippine government forecasts future oil and gas discoveries to yield an estimated reserve potential of at least 9 Tcf.

III THE MALAMPAYA NATURAL GAS DEVELOPMENT

The Philippine gas industry was ushered in with the development of the Camago-Malampaya field, located in deep-water northwest of the island of Palawan.[9] Occidental Philippines, Inc. (Oxy) discovered the Camago field in 1989 under Service Contract 38 (SC38). In 1990, Shell Philippines Exploration B.V. (SPEX) acquired a 50% participating interest and operatorship in SC38. SPEX subsequently explored and discovered the Malampaya gas field in 1992. Malampaya, which geological data indicated is linked to the Camago culmination, lies under 850 meters of water, making it one of the most challenging deepwater developments in the world. Three subsequent

[7] Guillermo R. Balce and Eric F. Pablico, ‘Philippine Natural Gas resources: Maximizing Their Potential’ (1998) 53 *Journal of the Geological Society of the Philippines* 49, 51.
[8] Ibid 52.
[9] Section 2 of *DOE Department Circular No. 95-06-006 ‘Policy Guidelines on the Overall Development and Utilisation of Natural Gas in the Philippines* dated 15 June 1995 provides: ‘The Malampaya/Camago gas field shall serve as the foundation for the Philippine Gas industry by panning and developing it to primarily supply efficient gas-fired power plants starting year 2001.’

exploration wells drilled by SPEX in the Malampaya field confirmed natural gas reserves of at least 2.5 Tcf and 85 million barrels of condensate.[10] In 1998, following a global swap of assets, Shell acquired Oxy's remaining 50% interest in SC38 through Shell Philippines LLC (SPL). Texaco, Inc. agreed in 1999 to acquire a 45% interest in the project from SPEX and the Philippine National Oil Company-Exploration Corporation (PNOC-EC)[11] bought a 10% interest in 2000.

According to the Joint Declaration of Commerciality signed by Occidental, Shell and the Philippine Government in April 1998, the Camago-Malampaya field and the much smaller San Martin field, also located in the SC38 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. But a market had to be found for the power generation capacity and the Philippine government assigned 1,500 MW each to the National Power Corporation (NPC) and Meralco for development.[12]

Three Gas Sales and Purchase Agreements (GSPAs) were concluded in December 1997 and April 1998: NPC for Ilijan 1,200 MW plant near Batangas; First Gas Power Corporation for Santa Rita 1,000 MW plant near Batangas; and First Gas Power Corporation for Calabarzon 500 MW plant in South Luzon. These GSPAs are equivalent to 2,700 MW of generating capacity, short of the capacity of 3,000 MW or 400 mmscfd stated in the Declaration of Commerciality.

SPEX's further studies indicated more than 200 million barrels of oil in place, of which 30 mission barrels are currently estimated to be recoverable. Oil reserves of this magnitude could translate to initial production potential of 20,000-25,000 barrels per day, and a potential for peak output of as much as 50,000 barrels per day by 2003, when SPEX completes construction of additional production facilities.[13] Condensate production will decline over the field life, reducing from a liquid 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.

The Malampaya gas field will start production at an initial annual rate of 145 billion cubic feet, which will be used mainly to fuel 2,700 megawatts of baseload power plants. These are the three combined-cycle gas turbine power plants in Southern Luzon: the 1,200 MW Ilijan; 1,000 MW Sta. Rita; and 500 MW San Lorenzo power plants.

The development of the upstream component of the Malampaya deep water gas to power project necessitated the investment of some US$2 billion. The major components of the

[10] Malampaya Natural Gas Project, 'Malampaya Natural Gas Powers the Future.' This brochure was published by SPEX.
[11] PNOC-EC is the state-owned energy exploration company. It is treated like any other exploration company when applying for an exploration contract with the Philippine government.
[12] NPC is a government-owned and controlled corporation responsible for the generation, transmission and bulk supply of electricity throughout the Philippines. Meralco owns a government franchise to distribute electricity in Manila and Southern Luzon.
[13] Philippines Reserves May Top Forecast, *Platt's Oilgram News*, 9 May 2000.

Malampaya gas development were: 1) the installation at a water depth of 850 meters of five initial development wells and a sub-sea manifold to bring gas from the Malampaya accumulation to a shallow water platform; 2) the construction of a shallow water production platform to process the gas, and to separate and store condensate; 3) the installation of a Catenary Anchored Leg Mooring (CALM) buoy that will be used by tankers lifting condensate from the platform; 4) the fabrication and laying of a 504-kilometre underwater pipeline connecting the platform and the gas landfall site in Tabangao, Batangas;[14] and 5) the construction of a natural gas processing plant at Tabangao, Batangas where dry gas will be treated prior to sale to three power plants.

Natural gas is produced from the Malampaya field through five initial wells interlinked to a sub-sea manifold that can be remotely operated either from the shallow water platform or the landfall facility. All the wellheads and the manifold lie on the seabed under 850 meters of water. The manifold is connected to two 30-kilometer 16" pipelines that bring the natural gas to a shallow water platform.

The shallow water platform is an integrated offshore gas processing facility that is located some 50 kilometers from Palawan. Its topsides contain the equipment necessary to separate water and condensate from the wet gas flowing through the underwater manifold. The condensate is stored temporarily in the platform's base before being loaded onto a tanker. The dried gas is piped to a landfall facility in Batangas via a 24" pipeline.

The 504-kilometre pipeline, regarded as one of the longest deepwater sub-sea pipelines in the world, side steps some of the region's more difficult underwater terrains. Pipe laying was performed by a specialized vessel equipped with some of the world's most advanced technology to enable precise, accurate and competent installation. Detailed preparatory studies of the Malampaya pipeline route were completed prior to pipe laying to avoid passing through areas that would either harm the existing marinelife or pose a threat to the integrity of the pipeline.

The dry gas arrives at a landfall site in Batangas where it is treated according to sales specifications. The gas was made available for power plant commissioning on 01 October 2001. The constructions of three combined-cycle gas turbine (CCGT)[15] power

[14] Batangas is located in the south of Luzon island, the main island in the Philippines and the largest market for power because it is the most populous and industrialized island in the Philippine. Over three quarters of the Philippine generating capacity is located in Luzon, with oil, coal, hydro and geothermal being the principal contributors. Mega-Manila, the largest population center and targeted as market, is located in Luzon island.

[15] The key to the competitiveness of gas is its use in CCGT power stations which have a significantly higher thermal efficiency and are cheaper to build than the conventional power plants which utilize coal and fuel oil. The higher efficiency of CCGTs permits a higher energy price to be paid for gas than coal or fuel oil to generate at the same cost. If gas is burnt in conventional thermal power stations, this efficiency advantage does not apply. It is also possible to burn petroleum distillate fuels such as gas oil and naptha in combined cycle plants, meaning that gas must compete with these fuels on a comparable efficiency basis although plants fired by distillates may exhibit a slightly lower thermal efficiency and have higher operating cost.

plants were executed by various companies. Kepco Ilijan Corporation, wholly owned by Korea Power Corporation,[16] constructed a 1,200 MW power plant in Ilijan, Batangas under a build-operate-transfer (BOT) contract. The Ilijan plant will sell electricity to NPC under a 20-year Energy Conversion Agreement and begin commercial operations on January 2002 using natural gas.

First Gas Power Corporation (FGPC) will operate a 1,000 MW combined cycle power plant in Sta. Rita, Batangas while the 500 MW San Lorenzo power plant (formerly Calabarzon) will be constructed by FGP Corp. adjacent to the Sta. Rita plant. FGPC is a wholly owned subsidiary of First Gas Holdings Corporation (FGHC), which is owned by First Philippines Holdings Corp. (51%)[17], British Gas plc (40%) and Meralco Pension Fund (9%). FGPC was established to implement the 1000 MW CCGT power project in Santa Rita, Batangas. On 30 April 1999, FGPC and SPEX/SPL signed a GSPA for the supply of natural gas to the Sta. Rita power plant. The Santa Rita power station will sell electricity to Meralco under a 25-year power purchase agreement (PPA). The first block (500 MW) of the plant started commercial operations in November 1999 and the second block (another 500 MW) in early 2000, initially using imported condensate.

FGP Corp., another wholly owned FGHC-subsidiary, built another 500 MW plant in San Lorenzo, Batangas adjacent to the Santa Rita plant, the San Lorenzo power plant, which planned to start commercial operations in January 2002.

The point of gas custody transfers from SPEX to the power generation projects, and the limit of the SC38 contract envelop, is at the gas processing plant at Tabangao, Batangas.[18] However, a provision contained in a Memorandum of Clarification between the government and SPEX purports to amend the definition of 'Petroleum Operations' to encompass pipelines for the delivery of gas as well as facilities installed upstream to the point of sale that are used to extract hydrocarbon liquids.

The total development cost of the project, including the cost of the production platforms, offshore pipeline and the power plants was estimated to be US$4.5 billion over a five-year period. During the period cover by the Philippine Energy Plan 1999-2008, the

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The higher efficiency of CCGTs and the chemical composition of natural gas results in very much reduced levels of carbon dioxide emissions per unit of electricity produced compared to coal or fuel generation. In circumstances where Greenhouse Gas issues are of importance, natural gas has significant advantages over these other fuels. Similarly, gas has significant advantages over coal and oil in terms of trace emissions such as particulates, sulphur dioxide and carbon monoxide, unless expensive clean-up equipment is added to conventional plant utilizing these other fuels. Where such environmental costs are internalized into the cost of electricity generation, the value of gas can be significantly enhanced. In the Philippines, however, the cost of compliance with atmospheric emissions using gas is low or non-existent, effectively providing gas with no economic benefit in this respect but it is possible that these benefits may accrue to natural gas in the future when environmental policy is strengthened and compliance costs can be internalized into the comparative cost analysis.

[16] The Korean government's integrated electricity company, which after re-bidding won the rights to develop the Ilijan power plant, also sold equity stakes to Southern Electric, now called Mirant, and to Chubu Electric, a Japanese utility.

[17] First Philippines Holdings Corp. is the holding corporation for Mrealco.

[18] The gas processing plant is located at Shell's petroleum refinery.

expected production of 0.8 Tcf that will be consumed by the committed plants will displace roughly 144.3 million barrels of fuel oil equivalent (MMBFOE) of imported oil, generating foreign exchange savings of US$2.2 billion.

A *Contractual Agreements*

A series of agreements and undertakings have been executed to support the GSPAs.[19]

Gas Sales and Purchase Agreements

For purposes of developing a regulatory framework, the terms and conditions in the GSPAs of greatest interests are: Sales Price, Marketing Rights, and Facility Access. The Philippine government has given the Sellers an undertaking not to reduce the price paid for the 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 GSPAs with FGC. Second, the provision creates tension with the so-called 'price' jurisdiction of Energy Regulatory Board (ERB)[20] 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 ($25.30), Dubai Crude Oil ($19.00), and Oman Crude Oil ($19.30) that are used in adjusting 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'.

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, and the Philippine government under subrogation of rights from NPC.

Under the first option, the GSPAs 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 favour of the sellers.

None of the GSPAs contain a 'most favoured nation' clause that would obligate the sellers to reduce the price of gas sold to the buyers if a lower price were agreed with a third party. Furthermore, the pricing formulas do not reduce the price due to a greater efficiency in utilization of the capacity of the gas processing plant and submarine pipeline

[19] Access to the GSPAs and other agreements are restricted by way of policy of the DOE. However, a summary of the commercial terms of these agreements are summarized in a report prepared for the Asian Development Bank by Fuels and Energy Management Group Ltd entitled 'Gas Sector Policy and Regulatory Framework Project' (1999).

[20] The ERB regulates energy prices (e.g. oil, gasoline, diesel and electricity prices). It is also tasked with the non-price regulation of the private power distribution utilities and monitors their performance with respect to the terms in their awarded franchise.

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 GSPAs. Marketing could be handled either by assignment or sale. Third-party access is briefly mentioned in Article 21 – Sellers Reservations. The Sellers expressly reserved the right for the use of the Delivery Facilities to transport natural gas to third parties.

Gas deliveries to Ilijan began 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 Ilijan's output. As a result Ilijan 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%. 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 100% of the ACQ. Based upon the 'Plangas' estimates, the take-or-pay liability for NPC will exceed US$ 558 million within the first seven years. This exposure could be higher due to a general reduction in economic activity or other contingency like an early termination or non-renewal by Meralco of a 3,600 MW bulk power purchase contract with NPC, which expires in 2005.

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 Contractor the authority to market the Government's share of the natural gas. Prior to signing, the Service Contractor 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 Ilijan power plant. The GSIA adopts the approach that claims regarding recovery of sales costs will be subject to DOE validation. Under the GSI funds received as take-or-pay payments are treated as 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.

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 US$ 100 Million.

Administrative Order No. 381

Signed on 17 April 1998, *Administrative Order No. 381* is an important document in the GSPA closing process for NPC, the main purpose of which 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 funds drawn from the Service Contractor's Malampaya take or pay Deferred Payment Facility (DFP). The DFP 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 Ilijan power plant is meeting the generation capacity targets contained in the November 1997 Plangas profile. 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 is a tripartite agreement between DOE, NPC and the Service Contractor, 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 obligations is only effective if the Ilijan power plant is being dispatched at the rate set in the Plangas schedule, which is annexed to the SAPA.

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 Depart of Finance (DOF) have pledged the government's share of net proceeds from petroleum, geothermal and mineral contracts under the SAPA. As this amount is exclusive of funds directed to Local Government Units and Contractor's 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 US$242.32 million by 2003. As a result, the Service Contractors to whom the payments are due have agreed to create a US$ 350 million deferred Payment Facility as a line of credit for NPC to draw upon. Drawings are limited to the so-called 'positive difference' i.e. 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.

Performance Undertaking

A guarantee for NPC's payment obligations under the GSPA signed on 29 April 1998 was a condition precedent wherein the Philippine government 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 Ilijan's annual capacity factors, NPC's take-or-pay liability is approximately US$ 558 million. This amount includes take-or-pay payments for both the Service Contractor's as well as government's share of net proceeds. After the tenth anniversary of the Malampaya 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 Ilijan power plant does not meet the output targets contained in the Plangas projection, there is no obligation for the DOE to provide the Service Contractor with revenues from indigenous resource contracts. This will force the Service Contractor 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 FGPC.

With respect to the Performance Undertaking, SAPA and DPF, the DOE and the DOF are addressing the issues of NPC's reimbursement of DOF for advances, debt service and borrowing and the 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. However, NPC 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 a means of reimbursing for the take-or-pay payments under the Performance Guarantee.

B *Implications of the Malampaya Gas Volume and Pricing*

The Service Contractors and the Philippine government agreed in a Joint declaration of Commerciality that the total volume of gas expected to be deliverable from the field will be at least 400 mmscfd for twenty years. The subsea pipeline from the field to the project landfall and processing plant has a design capacity of 650 mmscfd, 163 percent of the projected daily deliverability and 169 percent of the full-capacity gas consumption of the three power plants. The estimated deliverable volumes and service life would support CCGT electrical generating capacity of about 3.0 MW – 11% more than the 2.7 MW design capacity of the three power plants. The projection of 400 mmscfd corresponds approximately to the daily contract quantity in the GSPA between the Service Contractor and the power plants sponsors. This quantity exceeds by 12.75% the sum of ACQ in the GSPAs, and exceeds by 17.5% the sum of annual take-or-pay obligations for the three plants. Even so, NPC expects to incur take-or-pay obligations under its GSPA because of a deficit in electricity demand, from the commencement of deliveries in the year 2002 through the year 2007.

The positive implication is that commencing in 2002, the Luzon grid can anticipate having access to 100 mmscfd or more of natural gas available for uses other than at the three power plants. 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 take-or-pay liabilities (which the government has agreed to underwrite), in addition to the opportunity costs of shut-in supply and under-utilised producing, transmission, and processing capacity. The overhang of unsold gas from Malampaya can also exert a depressing impact on the incentive to search for or develop additional domestic natural-gas reserves.

In the dispatch model study undertaken by the World Bank in 1997, 'Philippines Energy Strategy and Pricing Study', a price of US$3.80/mmBTU was estimated to be necessary to maintain a gas consumption in the power generation sector of 400 to 500 mmscfd, rising to US$4/mmBtu after 2008. This is near the generation cost for an oil-fired conventional power station. An increase in gas price of more than about US$0.3/mmBtu would reduce gas volumes in the sector to below 400 mmscfd according to the World Bank analysis. The ADB study 'Gas Sector Policy and Regulatory Framework Project' concluded that only gas used to replace some power generation capacity, high value industrial LPG and gas oil and residential and commercial electricity provides a higher netback than the contract price of gas at Tabangao, Batangas. In effect, gas at US$4/mmBtu is uncompetitive in applications such as large industrial fuel oil market at current prices. Gas would have to be priced at about US$3/mmBtu to compete in this market. Under the current gas price contract regime, the non-power sector market for gas is probably under 50 mmscfd and limited to the highly urbanized areas of Metro Manila and southwards. Only a significant reduction in the cost of gas supply, to about US$3/mmBtu or below, will greatly boost the non-power sector market volumes.

C *Identifying Regulatory Risks*

The Service Contractors have taken a contractual approach by seeking amendments to SC38 that allow the construction of pipelines from the location of processing to the point delivery at the buyer's facilities. Thus, the DOE was able to amend the Service Contract on the basis that pipeline construction is part of Petroleum Operations. In addition, s 37 of *Petroleum Service Contracts Act 1972*[21] expressly excluded the majority of the provisions of the *Petroleum Act 1949*[22], including pipeline concessions, from applying to Service Contracts.

There is legal uncertainty in pipeline regulation. On one hand, DOE can approve pipeline construction under the Service Contract but does not have authority under the *Department of Energy Act 1992*[23] to regulate tariffs. On the other hand, the ERB can

[21] *PD 87.*
[22] *RA 387.*
[23] *RA 7638.*

only fix the price of transmission for pipelines that are subject to a pipeline concession issued under the *Petroleum Act 1949* but only Congress can grant the concession. However, in an opinion given by the Department of Justice, the grant of a gas distribution franchise is now vested with the DOE.[24]

The SC38 Service Contractors have been given an undertaking by the DOF, acting under delegation of the full powers of the President of the Philippine government that the gas price in the GSPA with NPC would not be reduced by regulation. There is an outstanding issue then whether such a commitment is legally binding on an independent quasi-judicial regulatory body such as the ERB. This question and the expanded definition of 'Petroleum Operations' under *PD 87* and SC38 to include pipeline construction may be open to a taxpayer's suit to challenge their validity. Some modifications of SC38, such as allowing the Service Contractor to recover costs for gas processing performed at Shell's Tabangao refinery, seem to go beyond the express provisions of *PD 87* and the Model Agreement.[25]

D *Managing Quasi-commercial Risks and Philippine Government Guarantees*

The Philippine government has thus undertaken direct commercial activities through the participation of the state-owned resource exploration company, PNOC-EC in the SC38 joint venture, and NPC as an off-taker of the Malampaya natural gas. In a fully privatized economy such purchase risk would usually be regarded as 'commercial.' However, state ownership of both PNOC-EC and NPC introduces special performance risks that are often regarded as 'political.'

It is sometimes suggested that undertaking infrastructure developments as public-private joint ventures may reduce an investor's exposure to political and regulatory risks. This is based partly on the hypothesis that a government may be less likely to prejudice the profitability of an enterprise in which it has a direct commercial stake and partly on the notion that popular resistance to private sector involvement may be reduced.[26] However, there are many weaknesses in this strategy since the government's roles not only as resource owner, but also as joint venture participant, off-taker, and regulator (in the case of PNOC-EC, NPC and DOE respectively) are easily blurred, undermining the credibility of the regulatory framework. A direct government interest in the firm's profitability may also create incentives to erect or maintain unnecessary monopolies, as it is notoriously

[24] *DOJ Opinion No. 46, Series of 2000.*
[25] The principal regulatory instruments have been DOE Forms No. 2 – Model Agreement for the Service Contract and No. 2A – Accounting Procedures.
[26] Warrick Smith, 'Covering Political and Regulatory Risks: Issues and Options for Private Infrastructure Arrangements' in Timothy Irwin, Michael Klein, Guillermo E. Perry, and Mateen Thobani (eds), *Dealing with Public Risk in private Infrastructure* (1997) 58.

difficult to maintain a level playing field if competition is introduced between a public-private joint venture and a private firm.[27]

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Quasi-commercial risk can be defined as uncertainty over the willingness or capacity of government-owned enterprises to meet their contractual obligations in private infrastructure projects. Those defaults might arise deliberately, through direct political interference in what would otherwise be commercial dealings, or from the poor creditworthiness of government-owned enterprises that are not operating in a fully commercial manner.[28]

The nature and extent of the risk will depend in large part on the nature of the government entity. When the entity has been 'corporatised'- and hence has a commercial charter, autonomous management, and the ability to recover cost-covering prices and borrow in its own right - the supply or purchase risks may approximate those of a private firm. Government entities that lack these attributes will be more susceptible to political interference and are less likely to be creditworthy in their own right. The ultimate issue is one of enforcing the entity's obligations. As these obligations will be in contractual

[27] Ibid.
[26] Warrick Smith, 'Covering Political and Regulatory Risks: Issues and Options for Private Infrastructure Arrangements' in Timothy Irwin, Michael Klein, Guillermo E. Perry, and Mateen Thobani (eds), *Dealing with Public Risk in private Infrastructure* (1997) 58.
[27] Ibid.
[28] Ibid 54.

form, the issues are substantially the same as with respect to regulatory commitments included in contracts. As quasi-commercial risks often involve entities that lack taxation powers and may be uncreditworthy in their own right, their ability to meet compensation obligations in the event of default is often a key source of risk for their contractual partners - a risk which is then passed on ultimately to the government.[29]

The weaker the separation between the government and the entity, the greater the potential for political interference and hence the stronger the case for treating performance risks as a responsibility of government rather than as a normal commercial risk.[30] The increasingly common solution is to privatise agents performing commercial activities to ensure an effective separation from government. Appropriate sequencing of private involvement can do much to reduce the need for sovereign guarantee or other supporting instruments. If privatization is not feasible in the near term, risks can be reduced through policy reforms that help insulate government-owned enterprises from political interference. Specific commitments can also be anchored in contracts that are subject to international arbitration.[31]

In structuring guarantees - and indeed in deciding whether the guarantee instrument is the right form of government financial support - it is useful to think in terms of comparative advantage in risk bearing and to allocate risks to those in best position to affect or manage them. Allocating risk appropriately ensures that incentives are in place to control risk effectively and that all information on the nature and level of risk employed.[32] This reinforces the conventional wisdom that country/policy risk should be borne by government, since government causes the risks, while purely domestic firms have pervasive exposure to country risk, and private project promoters should bear all commercial risks linked to the quality of internal project decision-making.

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[29] Ibid.
[30] Ibid.
[31] Ibid 76.
[32] Ignacio Mas, 'Managing Exchange Rate- and Interest Rate-Related Project Exposure: Are Guarantees Worth the Risk?' in Timothy Erwin, Michael Klein, Guillermo E. Perry, and Mateen Thobani (eds), *Dealing with Public Risk in Private Infrastructure* (1997) 121.

A parallel criterion is that risks should be borne by the party with the greatest ability to absorb them in terms of the relative concentration or diversification of risks, the correlation with its own portfolio, the access to hedging markets, and the relative degrees of risk aversion. This criterion challenges the conventional wisdom that guarantees should be used to attract foreign investors.[33] An international investor like Shell or Texaco are generally in a better position to diversify away the systematic risk of individual countries given their broad international presence. They may be in a better position to hedge a country's macroeconomic risk if it is correlated with, say, foreign interest rates, the price of a primary commodity, or prospects in a major trading country. In contrast, local residents may not be able to tap the appropriate international hedge markets.

Macro guarantees generally transfer macro risks from foreign investors to local taxpayers (including payers of inflation tax) for whom country risk is pervasive and inescapable. Their effect is thus to concentrate systematic risks on those least able to absorb them.[34] Government support could lower overall project cost only if the government had a lower cost of capital than private parties. Although government borrowing costs are often ostensibly lower than private borrowing costs, government borrows at lower rates not because they tend to operate lower risk projects but because taxpayers stand behind them, providing unremunerated credit insurance. If taxpayers were remunerated for their exposure, the ostensible advantage of government finance would presumably disappear.[35]

Government guarantees have also undesirable consequences that may offset the benefits of privatization. First, they reduce the incentives of firms to perform efficiently. Second, they weaken the incentives to screen projects for white elephants. Third, although they reduce current government expenditures, they shift obligations to future periods and administrations. While these contingent liabilities may be valued and

[33] Ibid 122.
[34] Ibid.
[35] Mansoor Dailami and Michael Klein, 'Government Support to Infrastructure Projects in Emerging Markets' in Timothy Erwin, Michael Klein, Guillermo E. Perry, and Mateen Thobani (eds), *Dealing with Public Risk in Private Infrastructure* (1997) 33.

typically included in the year-to-year budget or counted as government debt, many of these guarantees may become effective during recessions and may trigger a new type of debt crisis.[36] Also contracts are often renegotiated when the project turns out to be less successful than the service contractors/project sponsors expected, and losses are eventually absorbed by the state or by users.[37] Macro guarantee programs may also increase macroeconomic instability by aggravating the fiscal burden in the event of bad policy outcomes when the guarantees are called for which reason, the guarantees may not be worth the risk and alternative policy solutions should instead be designed to mitigate asymmetries in information or inefficiencies in the redistribution of risks.[38]

Although guarantee programs are ineffective in the longer-term, they may support private infrastructure as an interim measure while reforms are put in place that will allow the financial sector to handle risks on its own. Before the reform process actually bears fruit, government needs to assess the relative merits of promoting private infrastructure investments though a limited guarantee program versus sticking to a purist market-based reform program that may delay necessary infrastructure development. A guarantee program that is actually designed to be phased out over a period of five to ten years has the duel advantages of raising the credibility of the government's reforms and building public support for the reforms by allowing some benefits from the reform process to materialise earlier.[39]

E *Securitisation*

The Philippine Government anticipated that it could raise as much as US$500 million using future state earnings from the Malampaya natural gas as it hopes to earn at least US$13 billion, which include royalties and revenues of the local government apart from the earnings that will go to the national government, over 20 years from

[36] Eduardo Engel, Ronald Fischer, and Alexander Galetovic, 'Infrastructure Franchising and Government Guarantees' in Timothy Erwin, Michael Klein, Guillermo E. Perry, and Mateen Thobani (eds), *Dealing with Public Risk in Private Infrastructure* (1997) 90.
[37] Ibid 98.
[38] Mas, above n , 123.
[39] Ibid 126.

Malampaya.[40] The Department of Finance (DoF) has made a pronouncement that it is studying the possibility of selling bonds securitised by the future earnings of the Philippine government from Malampaya. The DoF disclosed that it has received an offer from an investment bank to underwrite a US$200-million to US$500-million loan using future earnings as collateral to partly finance its absorption of the US$4-billion debt of NPC.[41]

Securitisation can be described as a transaction structure whereby the Philippine government, as the owner of a pool of assets in the form of its shares in the production of natural gas from Malampaya by virtue of the SC 38 production sharing agreement, 'packages' or 'bundles' assets, producing one or more income streams, in order to monetise these assets through a private placement of securities which is dependent on the income streams generated from those assets. Those assets are transferred from the Philippine government to a special purpose vehicle (SPV), either a corporation or a trust, which then markets to investors securities backed by the assets transferred to the SPV and uses the net proceeds it receives from the issuance of the securities to make payments to the Philippine government for the acquired assets, thereby providing immediate liquidity to the latter.[42] Among the most interesting aspects of securitisations of oil and gas receivables is that securitised assets are frequently comprised of future receivables, the creation of which is dependent upon future production.

A principal advantage of a securitisation is that it allows the SPV to separate its own credit rating from the Philippine government. By transferring its assets to an SPV, the Philippine government effectively segregates its credit rating from the SPV, thereby minimizing credit risk that otherwise would increase the cost to the sponsor of obtaining asset-based financing. In this way, segregation may not only enable the government to access capital, but also enable it to do so at an acceptable cost. In addition, segregation

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[40] Clarissa S. Batino, Future Malampaya Earnings Seen Backing Up $500-M Loan, Philippine Daily Inquirer, 19 July 2001.

[41] The debt absorption is contained under the *Electricity Power Reform Act 2001*, which calls for the privatization of NPC.

[42] Thomas J. Gordon, 'Securitisation of Executory Future Flows as Bamkruptcy-Renote True Sales' (2000) 67 *U. Chi. L. Rev.* 1317, 1321-1322.

allows potential investors to focus on the economic risks presented by the portfolio being securitised by analyzing the credit quality and liquidity of the assets, without having to factor in the credit risks and restructuring presented by the sponsoring government. The segregation process is critical to all securitisations irrespective of their structure or the nature of the underlying assets.[43]

The most significant disadvantage of securitisation transactions is their potential complexity. As a consequence of their complexity, these transactions generally require more time and cost to implement than many other financing structures. The Philippine government should also bear in mind that it may be restrained to divulge certain information by reason of confidentiality undertakings with the Service Contractors or if not, the Service Contractors' competitors may obtain access to information as a result of disclosures which may be required pursuant to the transaction implementation documentation, such as security disclosures, disclosures made in connection with concession and permit applications and filings, and disclosures made in connection with private placement memoranda. Securitisation, then, is an appropriate alternative to traditional financing only if the savings derived from the lower-cost funds that may be accessed, or other benefits that may be obtained by it exceeds the costs of the securitisation.[44]

The following risks may have to be analysed in determining the rating to be assigned to the securitised debt instruments of Malampaya: the sovereign risks associated with the SPV as an agency of the Philippine government which is a party to a production sharing contract under SC 38; generation risks associated with Malampaya's proven petroleum reserves; collection risks associated with the ratings of NPC and FGHC as the designated customers for the natural gas, and the historical delinquency and default rates of these customers; and payment risks related to the mechanics by which payments would be made to the investors.

[43] Charles E. Harrell, James L. Rice III, and W. Robert Shearer, 'Securitisation of Oil, Gas, and Other Natural Resource Assets: Emerging Financing Techniques' (1997) 52 *Bus. Law.* 885, 887-888.
[44] Ibid 888.

Securitisation of the government share in Malampaya presents a special case since the originator is not a state-owned company which is a party to the production sharing agreement but the Philippine government itself, though PNOC-EC owns 10% of the project and NPC is an off-taker of the gas with take-or-pay obligations under the GSPA. The presence of credit enhancements, which may be provided by third parties such as banks or insurance companies in the form of letters of credit, to minimize the risk that a nonpayment by an obligor like NPC on a securitised asset will cause the special purpose vehicle to suffer a loss or to be unable to satisfy its obligations with respect to the issued securities, will further complicate inter-creditor issues. The Philippine government will then have a three-tiered exposure in Malampaya since PNOC-EC's equity is highly leveraged, NPC's take-or-pay obligations in the GSPA unlike First Gas' are backed by a sovereign guarantee under the SAPA, Deferred Payment Facility and Performance Undertaking, and the Malampaya asset securitisation may have credit enhancements.

F *Regulatory Implications of the Electric Power Industry Restructuring*

On 8 June 2001, the Philippine Congress enacted the *Electric Power Industry Reform Act 2001*[45] which seeks to restructure the electricity industry by creating an environment of competition and accountability to achieve greater operational and economic efficiency and provide for an orderly and transparent privatization of the assets and liabilities of NPC.[46] The electric power industry was divided into four (4) sectors, namely: generation, transmission, distribution and supply. The generation of electric power, considered a business affected with public interests, is made open and competitive. Power generation is not considered a public utility operation and any person or entity engaged or which will engage in power generation and supply of electricity shall not be required to secure a national franchise. The prices charged by a generation company for the supply of electricity shall not be subject to regulation by the Energy Regulatory Commission (ERC).[47]

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[45] *RA 9136.*
[46] Ibid s 2.
[47] Ibid s 6.

The transmission of electric power shall be a regulated common carrier business subject to the ratemaking powers of the ERC.[48] The National Transmission Corporation (TRANSCO) shall assume the electrical transmission function of NPC and will assume the latter's responsibility for the planning, construction, and centralized operation and maintenance of high voltage transmission facilities, including grid interconnections and ancillary services. The transmission and sub-transmission facilities of NPC and all other assets related to transmission operations, including the nationwide franchise of NPC for the operation of the transmission system and grid shall be transferred to TRANSCO. TRANSCO shall provide open and non-discriminatory access to its transmission system to all electricity users.[49] Likewise plans will be drawn up for the privatization of TRANSCO and the disposition of any remaining sub-transmission functions, assets and liabilities.[50]

The distribution of electricity to end-users shall be regulated common carrier business requiring a national franchise. Private distribution companies, cooperatives, local government units, and other duly authorized entities, subject to regulation by the ERC, may undertake distribution of electric power to all end-users.[51] A distribution utility shall have the obligation to provide distribution services and connections to its system for any end-user within its franchise area and shall provide open and non-discriminatory access to its distribution system to all users. Any distribution utility shall be entitled to impose and collect distribution-wheeling charges and connection fees from such end-users as approved by the ERC. A distribution utility shall have the obligation to supply electricity in the least cost manner to its captive market, subject to the collection of retail rate duly approved by the ERC. To achieve economies of scale in utility operations, distribution utilities may, after due notice and public hearing, pursue structural and operational reforms such as but not limited to, joint actions between or among the distribution utilities, subject to the guidelines by the ERC.[52] The power to

[48] Ibid s 7.
[49] Ibid s 8.
[50] Ibid s 21.
[51] Ibid s 22.
[52] Ibid s 23.

grant franchises to persons engaged in the transmission and distribution of electricity shall be vested exclusively in Congress.[53]

The supply function, considered a business affected with public interest, will be separated from distribution and will be subject to open-market competition. All suppliers of electricity to the contestable market shall require a license from the ERC. The sector will be gradually opened up in phases subject to techno-economic consideration. Retail sale of electricity to competitive consumers will be contestable among distribution utilities within their franchise areas, or by suppliers, generating companies, and other entities. Competitive consumers will be free to choose their own supplier. The supply of electricity to the contestable market shall not be considered a public utility operation and any person or entity, which shall engage in the supply of electricity to the contestable market, shall not be required to secure a national franchise.[54]

A universal charge to be determined, fixed and approved by the ERC, shall be imposed on all electricity end-users[55] for the following purposes:

- Payment for the stranded debts in excess of the amount assumed by the National Government and stranded contract costs of NPC[56] and as well as qualified stranded contract costs of distribution utilities resulting from the restructuring of the industry;
- Missionary electrification;[57]

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[53] Ibid s 27.
[54] Ibid s 29.
[55] Ibid s 34.
[56] See s 32. *NPC Stranded Debt and Contract Cost Recovery.* – Stranded debt of NPC shall refer to any unpaid financial obligations of NPC.

Stranded contracts costs of NPC shall refer to the excess of the contracted cost of electricity under eligible IPP contracts of NPC over the actual selling price of the contracted energy output of such contracts in the market. Such contracts shall have been approved by the ERB as of December 31, 2000.

The national government shall directly assume a portion of the financial obligations of NPC in an amount not to exceed Two hundred billion pesos (P200,000,000,000.00).

x x x

[57] See s 70. *Missionary Electrification.* – Notwithstanding the divestment and/or privatization of NPC assets, IPPcontracts and spun-off corporations, NPC shall remain as a National Government-owned and

- The equalization of the taxes and royalties applied to indigenous or renewable sources of energy *vis-à-vis* imported energy fuels;
- An environmental charge equivalent to one-fourth of one centavo per kilowatt-hour (P0.0025/kWh), which shall accrue to an environmental fund to be used solely for watershed rehabilitation and management; and
- A charge to account for all forms of cross-subsidies[58] for a period not exceeding three (3) years.

The law also created the ERC, an independent, quasi-judicial regulatory body, and abolished the ERB whose powers and functions were transferred to ERC including all applicable funds and appropriations, records, equipment, property and personnel as may be necessary.[59]

Furthermore, an inter-agency committee was created to undertake a thorough review of all IPP contracts. In cases where such contracts are found to have provisions which are grossly disadvantageous, or onerous to the Government, the Committee shall cause the appropriate government agency to file an action under the arbitration clauses provided in said contracts or initiate any appropriate action under Philippine laws. The government shall also diligently seek to reduce stranded costs.[60]

While the enactment of the electricity reform law act may have provided a breather to the NPC since the consumers will ultimately assume its the stranded debt and contract cost recovery which include, among others, its take-or-pay obligations of Malampaya gas, the Philippine government has given notice to IPP contractors that

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controlled corporation to perform the missionary electrification function through the Small Power Utilities Group (SPUG) and shall be responsible for providing power generation and its associated power delivery systems in areas that are not connected to the transmission system. The missionary electrification function shall be funded from the revenues from sales in missionary areas and from the universal charge to be collected from all electricity end-users as determined by the ERC.

[58] Consumers in Luzon pay a higher rate for electricity which 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 – Visayas and Mindanao – result in a higher cost of generation and transmission. This subsidy has been justified before on the basis of the greater affluence of Luzon consumers.

[59] Ibid ss 38-44.

[60] Ibid s 68.

contracts may be renegotiated. This will be an opportune time for assessment in view of the reduction in energy demand in contrast to the optimistic forecasts under the Philippine Energy Plan, and the high exchange risk associated with power purchase agreements for power plants funded primarily with foreign resources particularly those sourced before the devaluation of domestic currencies experienced during the Asian crisis. All of these nevertheless will depend to a large extent on the political will of the finance and energy bureaucracy.

G *Monopoly Issues*

The formation of the Shell and Texaco joint venture constitutes a partial consolidation between the participants and may offer panoply of justifications such as the promotion of the efficient allocation of financial and technical risk and the achievement of the desired economies of scale. The joint venture is better able to tackle the large and complex technological problem particularly for the development of the deepwater Malampaya gas reserves and of course, better source the financing.

However, the formation of these joint ventures are met with suspicion as anti-trust advocates regard the world's major petroleum companies as striving to spin a complex web of controls in order to eliminate the threat of global competition. They see joint ventures as traditional manifestation of the symbiotic interrelationship in establishing an intimate community of interests among the 'Seven Sisters' for the worldwide control of oil.[61] 'Technology sharing' can be a subterfuge for market sharing, 'co-production' a euphemism for market control. A proliferation of transnational joint ventures institutionalizes an attitude of circumspection and bonhomie between ostensible rivals. Prof. Adams argue:

> More seriously, the evidence shows, an intricate network of organizational linkages between world rivals can serve as the institutional glue for an existing cartel, or as the organizational superstructure on which to hang a new one. At a minimum, the existence of transnational joint ventures contradicts the critics' contention that a plethora of

[61] Walter Adams and James W. Brock, 'The "New Learning" and the Euthanasia of Antitrust' (1986) 74 *Calif. L. Rev.* 1515, 1529.

international rivals assures fierce global competition when, in fact, those rivals may be intimately intertwined with one another as partners rather than competitors.[62]

It should be worthy to note that Pilipinas Shell has the highest market share in the petroleum downstream industry while Texaco has equity in Caltex Philippines, also one of the major players in the industry. Potential small producers may be concerned about the structure of the transmission sector and seek ways to shield themselves from perceived or threatened discriminatory practices. At the other end of the pipe, off-takers will seek greater assurance that transport charges are 'fair'.

IV PROPOSED GAS REGULATORY FRAMEWORK

Infrastructure investments in developing countries involve substantial risks that may stem from an uncertain policy environment and inherent macroeconomic instability, the novelty of the technology, the relatively long gestation period before returns on investment are reaped, and uncertain prospects for local market growth.[63]

The Philippine Department of Energy (DOE) seeks to encourage a gas industry based on a private sector and commercially driven investments that enable a secure and price-competitive gas supply and is considering the following policy directions for the gas industry:

- Government's role will be confined to facilitating the availability of information on gas supply and demand, ensuring competition to enable the entry of new players and fair prices to consumers, and ensuring compliance of all gas industry facilities to international safety and environmental standards;

- Development of domestic gas potential is encouraged but gas imports either through transnational pipelines or in the form of LNG will be allowed provided they are competitive with domestic gas supply and other energy options;

[62] Ibid 1528.
[63] Barry Eichengreen, 'Financing Infrastructure in Developing Countries: Lessons from the Railway Age' Policy Research Working Paper 1379. Washington, D.C.: World Bank.

- Competition in the gas industry will be encouraged by allowing the entry of as many players as possible in the competitive or potentially competitive segments such as production and gas supply, while maintaining government oversight on natural monopoly operations such as transmission and distribution pipelines, with the view to discourage exercise of market power and to avoid manipulation of prices; and

- To encourage efficiency in production and resource allocation, gas supply in competitive markets will be freely negotiated between sellers and buyers while gas supply to captive markets and small consumers will be subject to regulation.[64]

The Asian Development Bank published guidelines,[65] which are to be the principal criteria in a regulatory framework. The current policy for the regulation of the Philippine gas sector has been evaluated in accordance with these criteria.

- Accountability: A regulator's decisions must be subject to legislative and judicial oversight.

  The Philippines does not have a separate Natural Gas Act that establishes administrative authority and accountability for the gas sector in a single agency. Although the DOE has legislative authority to promulgate regulations, broader issues regarding access and pricing have not gone beyond expressions of policy intent. The DOE has addressed issues affecting the Malampaya project through amendments or interpretation of SC38. As a result, gas sector policy is largely driven by upstream considerations according to issues on which the Service Contractor has sought clarification as amendment to the original contract.

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[64] Department of Energy, *Philippine Energy Plan 2000-2009:DOE* Manila , 19.

[65] Asian Development Bank, *Governance: Sound Development Management,* August 1995; Asian Development Bank, *Governance and Regulatory Regimes for Private Sector Infrastructure Development: Final Report RETA 5758-REG,* 1998.

- Participation: Any party with an economic interest in the regulatory outcome must have access to the process through consultation or hearings.

  The only participants in the policy process have been major governmental departments and the commercial parties. Regulatory bodies such as the Energy Industry Administration Bureau (EIAB)[66] and the ERB have not interpreted their jurisdiction to include oversight for gas sales contracts or pipeline concessions. There have been no public hearings on any aspect of the Malampaya project.

- Predictability: Decisions made by the regulator must be consistent with regulations and amendments to the regulation involving the participation of investors.

  Uncertainty over authority for pipeline easements stemming from DOE's position that only Congress can grant Distribution Franchises and Pipeline Concessions has resulted in parties seeking franchise legislation from Congress. The only precedent for future gas developments are the positions reflected in contractual arrangements and as these are confidential between the parties, existing participants have an advantage in dealing with new entrants.

- Transparency: Regulators must be obliged to explain their decisions.

  Regulators prepare written opinions on cases within their administrative jurisdiction. Hearings before the EIAB and ERB are conducted according to rules for practice and procedure that provide participants with the opportunity to make submissions, cross examine witnesses, and test the accuracy of written evidence. Despite these procedural rules, substantive regulations governing the issuance of permits for the construction and operation of pipelines as well as the methodology

[66] The EIAB, an attached bureau of the DOE, regulates downstream energy industries by overseeing activities such as allocation of oil and coal importation licenses/quotas, approval of additional gas service station applications, and setting technical standards for the power industry with the Bureau of Product Standards.

for setting rates for the transportation and sale of natural gas have not been adopted.

- Autonomy: Regulatory bodies must function under specific enabling legislation and are free from political intervention.

  Fragmentation of administrative responsibility has meant that decision-making authority rests with the President of the Philippines. ERB is intended to function as an independent regulator under Executive Order 172. The undertaking given by the DOF restricting the regulation of gas contract prices could be seen as being inconsistent with the delegation of authority. The reaction at ERB has been to treat gas sales contracts involving Service Contracts as being outside its jurisdiction. Although the DOE prepares policy advice for the Office of the President, the Secretary is often tasked with implementing the objectives of the incumbent administration irrespective of policy implications. This was particularly evident in the case of Malampaya.

- Clarity: Roles and objectives for regulation must be separated from policy making and commercial management.

  Within DOE, roles and objectives for regulation are separated from policy development. However, the Energy Resource Development Bureau (ERDB)[67] faces a substantial dilemma in acting as the upstream regulator as well as representing the commercial interests of the government in receiving a share of net proceeds under the Service Contract. Both ERB and EIAB are uncertain of the scope of their respective jurisdiction for the gas sector.

[67] The ERDB, an attached bureau of the DOE, is in charge of the country's energy resource development plan. The government through other agencies such as the Department of Trade and Industry may also provide incentives to private enterprise to support this plan. Clearly the policy is to stimulate the development of indigenous energy resources, given the country's net deficit in energy supplies.

- Feasibility: Regulations should allow for an acceptable rate of return on investment.

  At present no structure has been established for the regulation of natural gas prices. The rate structure adopted for investor-owned electric distribution utilities allow a maximum Return on Rate Base (RORB) of 12%,

- Sustainability: Price controls and tariffs should be at rates that allow the industry to meet long-term costs.

  At present, natural gas is being treated as a premium priced fuel that is best suited for use as a fuel in the generation of electricity by power plants that are located in close proximity to the sea cost. The cost structure resulting from the rigid fiscal regime of *PD 87* means that other industrial and commercial applications of natural gas will not be economically feasible. In the long run, the exclusive nature of the market will deter further exploration.

- Methodology: Tariff components should be differentiated according to depreciation, return on capital, and cost categories.

  The RORB methodology developed for electrical utilities categorises costs according to components that will be recovered through either Demand Charges or Energy Charges. This approach is similar to a two-part tariff structure for natural gas where the selling price is the combination of capacity and demand charges.

- Stability: Contracts should be long term with provisions for adjusting the economic balance between buyer and seller as dictated by events.

  Given the present contractual commitments embodied in the Malampaya project, competition issues are focused on the next tranche of gas that will either come from the Malampaya field or another discovery. The surplus capacity at the platform and in the submarine pipeline gives Shell a substantial bargaining power with new users or producers. This is particularly the case as the existing customers have underwritten the cost of capital facilities. The role of the regulatory framework for the gas sector should be to establish more stable and competitive environment for the volume of gas that is developed above that committed under contract for Malampaya.

A *Gas Pricing*

In the private sector environment, the producer price for natural gas was indexed usually indexed to that of crude oil, since during exploration it was not known whether oil or gas, or both would be found, and the terms of the production sharing contract, which governed exploration, linked the two. The consumer price for natural gas was driven by the economic prices of appropriate traded substitute fuels. When unbundling takes place in the gas industry, the consumer price will comprise the regulated transmission and distribution charges and the price of gas at the production point determined through a process of negotiation between the producers and buyers in a competitive environment. However, unbundling of the gas sub-sector can be done in a meaningful manner only if a basic backbone gas transmission system is in place and a regulatory agency established.[68]

Questions have also been raised as to whether gas prices should be regulated in the face of competition with deregulated oil products. Theoretically, commodity prices can be deregulated in a market where perfect competition exists, i.e., there are a large number of buyers and sellers none of whom dominate the market or receive preferential treatment. The product must also be a homogenous commodity, so that buyers are indifferent from whom they buy and price information is readily available.

[68] Asian Development Bank, 'Energy 2000: Review of the Energy Policy of the Asian Development Bank' (2000) 31-34.

Given this framework, the specific circumstances under which gas is marketed must be considered. In the sale of Malampaya gas to NPC and FGHC, the absence of regulation of the gas as a commodity is offset by other mechanisms to encourage competitive and economic pricing. In the sale of gas to NPC, the competitive bidding for the contract to convert the gas should have enabled NPC to determine the highest netback value for the gas (i.e., the maximum price that it should pay) against alternative power generation options. On the other hand, in the sale of gas to FGHC, the ERB regulation of Meralco's retail rates should give Meralco enough incentive to procure the gas-based power from FGHC at the lowest price possible. In addition, transport tariffs need not be regulated for as long the pipelines are dedicated to the power plants.

If gas is sold in a market where it would compete with deregulated oil products, gas commodity prices may not be regulated if it does not receive any preferential treatment e.g. in terms of market allocation. The transport tariffs, however, will have to be regulated to ensure that there are adequate incentives to reduce costs and that there are no opportunities for excess profits since the pipeline operator would be a monopoly.

Considering that gas is a new product and that for strategic reasons government may want to promote its use, it is hard to imagine that it will simply be allowed to compete freely with other fuels. If the private investors take the initiative and risks to promote the use of gas, they should be rewarded for their efforts and reasonable costs incurred, by allowing them to pass on such costs to the gas tariffs. However, should government intervention becomes necessary, then regulation should ensure that the privilege accorded to gas does not allow investors to reap excess profits.

In reality, the present regulatory regime for gas exploration and development is seen to limit the competitiveness of gas to replace oil products except for high cost products such as LPG and diesel in industry and even residential electricity.[69] This may

[69] The pricing methodology of the GSPAs is a potential constraint to marketing surplus capacity in the Malampaya development and any reserve upside in the development. This approach to gas pricing may not be consistent with policies for achieving energy self-sufficiency because natural gas provided an economic

not necessarily apply to other lower cost gas field developments than Malampaya, which has a deepwater occurrence. Royalty and taxes account for about half of the gas price. Reducing these components will transfer the benefits of developing natural gas directly from the government to the consumers through lower electricity prices. Increased use of natural gas will, in turn, provide economic benefits through foreign exchange savings from foregone oil importation and reduced environmental impact of the country's overall energy balance.

B *Third Party Access*

For a durable asset that has limited alternative use such as a gas pipeline, the security of investment is of paramount importance. Contracts must be secured at both ends of the pipeline to ensure that the owner will be able to recover his investments and earn a reasonable return. In the Malampaya project, structure, the GSPAs are designed to ensure that there is sufficient volume of marketable gas to justify investments in the pipeline and in the gas field development.

With the prospect of additional gas deposits within and around SC38, efficiency suggests that the capacity of the Malampaya pipeline be expanded to provide for additional gas supply contract area.[70] It makes economic and technical sense for future producers to have access to the existing pipeline network and this does not preclude the possibility that future gas producers may opt to sell their gas to SPEX and let SPEX market the gas to downstream users or traders. Increasingly, however, the trend is to prevent gas producers who own pipelines from being involved in gas marketing as a

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benefit when substituting lower value fuels, such as fuel oil, and it is the policy of the Philippine government to promote the use of indigenous energy resources in industry.

[70] The Malampaya development represents the higher extreme of field development costs. Water depth at the field is very deep in comparison to the large majority of offshore gas projects and the 504 km pipeline to the Luzon landfall is a major contributor to project capital cost. It is probable therefore that any subsequent gas discoveries will attract lower costs than Malampaya, either by being located near the Malampaya field and so able to link into the field's pipeline or processing facilities or being located nearer to shore or onshore. In any event it is extremely difficult to attempt to describe 'typical' prospective developments because of the large influence local factors have on development costs and the fact that the location of future discoveries is presently unknown, except for some prospective fields near Palawan which could be linked into the Malampaya development.

means of enhancing competition. In both cases some form of pipeline regulation may have to be considered. Specifically, regulation must provide for the mechanism to recover the cost of providing for extra capacity, i.e., whether to pass it on to the tariffs of the initial tranche of gas or let SPEX assume the incremental costs and recover it in future deliveries.

With regard to the pipeline network expansion, the question of who should determine the appropriate configuration of the pipeline must also be addressed, i.e., whether the government should influence it or leave it as a business decision of investors. A satisfactory pipeline-licensing regime must provide for clear procedures, which promote an integrated national transmission and distribution system and must thus include approval of design, routing and expansion of gas pipeline facilities. However, a compromise solution should be reached so as not to encourage investors to under-invest or over-invest in the industry.

One of the most troublesome aspects in planning and authorizing construction and operation of a new transmission or distribution pipeline is the choice of an initial design combination of routing (including intake and delivery points) and capacity (including diameter and pressure). The exceptionally strong economies of scale that characterize pipeline transport imply that it is often socially desirable to 'overbuild' initial capacity well in excess of firm requirements of the applicants themselves, other identifiable shippers, or 'the market' as a whole.

That may well be the case for the pipelines that must be built to supply NPC and FGHC power plants with gas from Malampaya. Perhaps one of these lines should be extended into the outskirts of Manila and sized to accommodate the expected surplus of Malampaya. Initial rates could be designed either to impose incremental unit costs for unused capacity on either:

- initial shippers by dividing the inflated investment cost of an overbuilt pipeline by the actual throughput rather than the design throughput;

- the pipeline's initial owners by dividing the design throughput into the lesser investment cost that would have been needed to accommodate the actual throughput rather than the larger actual investment cost; or
- on some combination of shippers and investors.[71]

Until and unless the expected growth of demand actually appears, a decision to overbuild in order to meet unknown and unknowable future needs is a costly and risky business. Someone must bear the increased costs, but regulators and regulations can not assure that the hoped-for future benefits will indeed materialize or that benefits, if and when they occur, will be captured by the parties that paid extra to finance the added capacity. For the regulators to require the applicant to build in excess capacity at its own expense for the sake of unknown beneficiaries poses a serious risk of fatally deterring investment.

Understanding the full effect of one cost-responsibility policy or another will require analysis of the induced impacts of rate changes on electricity costs, dispatch orders, and sales, and the probable impact of diminished or delayed returns on the incentives of investors or lenders to finance pipeline construction. Alongside such puzzles regarding the initial allocation of responsibility for excess-capacity costs are questions about the allocation of the future benefits of scale economies among old and new shippers. These and a host of other benefit-cost and rate-design questions are complex. Economic principles of regulation seldom offer 'correct' answers to such questions, even in theory.

A related issue is the assignment of responsibility for the cost of expanding capacity or adding new intake or off-take points. Depending on specific features of the status quo and the proposed expansion, the net incremental cost of serving added demand can be materially more or less than the average cost of serving existing demand. In the former case, expansion will leave incumbents expected to implement the expansion worse-off; in the latter, all customers will enjoy a net benefit whether or not they bear any

[71] Asian Development Bank, 'Gas Sector Policy and Regulatory Framework Project' (1999) 6-28.

of the direct costs. The allocation of costs and benefits is therefore often uncertain, ambiguous, or perverse. As a result, the U.S. Federal Energy Regulatory Commission, Canada's National Energy Board and the California Public Utilities Commission have each devoted years to litigating disputes over whether charges for the use of specific pipeline capacity expansions should be based on incremental or average costs.[72]

On the other hand, public utility regulation, particularly traditional cost-of-service regulation model, is generally inadequate as a mechanism for encouraging, designing, and financing the infrastructure framework of an entirely new industrial sector. From time to time in the development of an industry or national economy, there appear clusters of development tasks whose aggregate benefits to the community, if designed and developed in concert, would be greater than the sum of private benefits associated with the individual tasks.

In order to create private incentives for proposing and implementing more expansive, forward-looking, and therefore risky infrastructure projects, it is not sufficient to have rules, policies, and procedures that allow investors to build ahead of demand, or rate designs that provide a return of and on invested capital that currently is not strictly 'used and useful.' Under-utilised infrastructure investments can be a debilitating, even fatal, drag on otherwise viable and socially beneficial electrical generation or other projects, even if those infrastructure investments are purchased at declining marginal costs. For this reason, the regulators should not expect or require NPC or FGHC, in their capacity as sponsors of electrical generation projects, to compromise the viability of these projects in order to design, organize or take financial responsibility for pipeline capacity that exceeds the scale required to fuel those plants, or for any gas-distribution or marketing functions outside of their scope.[73]

[72] Ibid 6-29.
[73] Ibid 6-30.

C *Right of Way, Rehabilitation, and Decommissioning Issues*

A satisfactory licensing regime for gas transmission and distribution pipelines cannot be realized without the ability of pipeline owners to acquire right-of-way for the pipeline and easements for facilities by voluntary negotiation as well as court-supervised, compulsory acquisition. Pipeline operators should be able to apply to a court for immediate access subject to lodging a bond as security for damages. A later hearing can be conducted to determine the amount of compensation to be paid for the value of the land and any damages to the interests of the property owners and occupants.

It was reported that SPEX has set up a US$ .5 million rehabilitation fund for the Malampaya project through a Memorandum of Agreement with the DENR creating an Environmental Guarantee Fund (EGF), which will be used for the rehabilitation of areas in the event of environmental damage or deterioration as a consequence of the project's construction, operation and abandonment. The same agreement also required SPEX to set up a US$ .1 million Environmental Monitoring Fund, which will finance the activities of a Multipartite Monitoring team that will monitor SPEX's compliance with the conditions of its Environmental Compliance Certificate. The monitoring period covered the period from construction stage until its commissioning.[74] With the magnitude of the Malampaya project, it is submitted that the amount for the EGF and EMF are deficient.

In the Philippines, decommissioning must be addressed within the framework of the production sharing contract system. The problems related to decommissioning in a production sharing contract system relate to the operation of the cost oil recovery mechanism. In any field, the production will reach a plateau, after which the volume produced will decline. The removal of installations and structures generally occurs when no more petroleum remains to be produced, at which point, there is no income from which the contractor can finance the cost of removal. However, this problem is indirectly addressed in the current production sharing contract regime in the Service Contract and

[74] Earl Warren B. Castillo, 'SPEX Establishes P22.5-M Malampaya 'Green Fund', *BusinessWorld* (Manila, Philippines) 11 September 2000.

PD87 where the only provision for decommissioning mandated by the Philippine government at the close of the petroleum operations was a requirement to plug wells and take other unusually undefined measures appropriate to 'good oilfield practice.' If the decommissioning obligation instead falls on the Philippine government as the owner of the natural resources, the government is left with the problem of making provisions to finance the cost of removal.

A second problem relates to the accounting period for cost oil recovery. Every calculation period, a portion of oil produced is recovered as cost oil. Expenditures not recovered are carried forward to the next calculation period. Ideally, all of the contractor's expenditures are recovered by the end of the period of the production-sharing contract. However, a situation may arise in which the contractor has unabsorbed cost oil at the end of the production-sharing contract. If the contractor must then finance the cost of the removal of petroleum installations, there is no mechanism to permit the contractor to recover its expenditures or to pay for the cost of the removal. A further problem arises in those cost oil recovery mechanisms that restrict recovery of cost oil based upon contract areas when each production sharing contract has its own contract area and the contractor may not be allowed to recover expenditures incurred in one production sharing contract area from income produced in a different area ('ring fence' provisions).[75]

Under the present upstream regulatory framework, there is no separation of the fiscal authority from the developing or operating authority. In order to recover removal costs by fiscal means, the government must be willing to forego revenue. One area, which might be examined, is the tendency to classify removal as a capital expenditure, rather than as a capital expenditure incurred in producing the income, on grounds that the structure is no longer utilized for producing income at the time when it is abandoned.[76]

[75] Peter Cameron 'Tackling the Decommissioning Problem' (1999) 14 *Nat. Resources & Env't* 121, 123.
[76] Ibid.

V TRANS-ASEAN GAS PIPELINE

The Philippine government views the plan for a Trans-ASEAN gas pipeline (TAGP) as an assurance that the present gas infrastructure being planned will not run short of natural gas supply over the long term. The scheduled phasing of the Trans-ASEAN pipeline development, as proposed in the recently concluded feasibility study by the ASEAN Energy Management and Training Center and the European Union, is considered in consonance with the Philippine gas industry development plan. Regionally, the presence of abundant natural gas resources within the boundaries of ASEAN provides its member countries a distinct opportunity for further ensuring energy supply security. Thus the TAGP Project has emerged a vital and challenging collaborative project given its magnitude and complexity, particularly with regard to financial, technical, legal and management issues.

At the 19th ASEAN Ministers on Energy Meeting held in Brunei Darussalam, the Master Plan Study for the TAPG was presented before the energy ministers. The study identified seven new possible gas pipeline interconnections in ASEAN, which include the East Natuna,Indonesia-Sabah,Malaysia- Palawan,Philippines interconnection. The realization of the TAPG Infrastructure Project is premised on an evolutionary process of stepwise integration of the 'National Gas Pipeline Infrastructure Project' amongst member countries i.e. evolving from bilateral arrangements into multi-lateral agreements to have cross-border interconnection amongst member countries. Whether cross border pipelines and gas trade are bilateral or multi-lateral in nature, there are cross border issues or barriers that have been identified that need to be addressed,[77] as follows:

- Legal Instrument
  - Governing Law;
  - Political Risk;
  - Title and ownership of pipelines;

[77] Mohd. Farid Mohd. Amin, 'Trans-ASEAN Gas Pipeline Project – Regional Perspective and Challenges' (Paper presented at the Seminar on Management and Operations of Gas pipeline Systems, Manila, June 2001). Dr. Amin is the Lead Co-ordinator of the Asean Council on Petroleum TAPG Task Force.

- Regulatory Framework
  -Transit rights/third party access;
  - Harmonisation of taxes;
  - Dispute resolution mechanism;

- Financing and Pricing
  - Financing arrangements/modes;
  - Principles of Gas Pricing: which allows for flexibility to adjust to market forces, prices of substitutes or competitive fuels in the energy market and that would facilitate project financing/funding;
  - The study assumes that the gas price would be competitive to alternate fuels such as MFO or coal;

- Technical Considerations
  - Harmonisation and standardization of technical matters, e.g. design parameters and construction standards, operation and maintenance guidelines, safety standards, measurement standards;
  - Operatorship; and
  - Health, Safety and Environmental guidelines.

Already, officials of PNOC-EC are already in preliminary talks with their counterparts from Petronas on the proposal to construct an offshore 1,000-kilometre gas pipeline to connect the gasfields of Sabah and the western Philippine island of Palawan, which would serve as the Philippine leg of the proposed TAGP.[78] Royal Dutch Shell, on the other hand, holds concession to some offshore Sabah gas fields, part of an estimated gas reserves of 6 to 8 Tcf for which there is no market.

[78] Cecilia Quiambao, 'Malaysia, Philippines to Discuss Gas Link Part of Trans-ASEAN Network' *Platt's Oilgram News,* 12 April 2001.

However, Philippine bilateral relations with Malaysia have been lukewarm at best. At the center of this has been the Sabah issue, a long-standing dispute involving claims on that Malaysian state by the Philippine government and the heirs of the Sultanate of Sulu.[79] The Sabah issue has been an impediment to resolving other long-standing issues between the two countries including a border-crossing and joint-patrol agreement, the status of Filipino migrants in East and West Malaysia, and trade and investment concerns, particularly in the growth triangle involving the Southern Philippines and Malaysia. [80]

Expanding domestic demand for natural gas enhances the commercial feasibility of international energy transportation infrastructure projects in Asia, the most anticipated of which is the TAGP project. But cross-border gas pipeline projects have both political and diplomatic ramifications for countries with border disputes. In addition they entail legal risks, which although mitigated by uniform legal and regulatory policies have still to be threshed out through reforms in the participating countries' framework.

VI IMPACT OF THE ASIAN FINANCIAL CRISIS

The sudden drop in the value of domestic currencies and the sharp increase in public debt needed for stabilising the economies affected by the financial crisis had considerable impact on the energy sector even as a new financial crisis is looming in the horizon as the West wages a war against terrorism. While capital flows from the more developed countries had helped meet the vast energy investment needs of the developing countries, the crisis highlighted the major exchange risk involved as revenues in the

[79] The Sabah question has been an irritant in ties between Manila and Kuala Lumpur ever since former Philippine president Diosdado Macapagal revived a claim to the state when it became independent and joined Malaysia in 1963. The Philippines has never formally renounced its claim to Sabah. Attempts by previous Philippine administrations to drop the Sabah claim have been shot down by the Senate and relations between Kuaka Lumpur and Manila have been broken off twice because of the row. The Philippine government is seeking to intervene in the case between Malaysia and Indonesia on sovereignty over the Sipadan and Ligitan islands because of its concern at some interpretations put on treaties and agreements before the International Court of Justice in the Hague may affect the Filipino claim on 'the territory of North Borneo.' The intervention was opposed by both Malaysia and Indonesia.

[80] Roberto R. Romulo , 'Philippine Foreign Policy: New Policy in a Changing World Environment' (1993) 17 *Fletcher F. World Aff.* 131, 134-135.

energy sector were generally in local currencies. The financial crisis has also demonstrated that long term planning based on optimistic economic growth projections can result in large errors in the short and medium term. Implementation of new projects targeted at providing adequate capacity can lead to over capacities, if the deteriorating macroeconomic situation is neglected or, in general, developers to the macroeconomic context of their investments give inadequate attention.

Particularly true for Malampaya, the state-owned electricity utility acted as the buyer on the basis of a long-term take-or-pay contract for the full output in terms of capacity (MW) and energy (gigawatt-hours), and some form of government assurance of the utility's payment obligations covered the transaction. While the need for clear, long-term contracts was understandable to attract private sector investors in the face of various risks, in hindsight, the contracts could have been less rigid and allowed for flexibility to adapt to rapidly changing circumstances such as those experienced recently in the region.

The financial crisis has highlighted some of the dangers arising from contracts due to foreign exchange, maturity, and capacity mismatches. Since these contracts did not usually provide for invoking *force majeure* and relaxing the fulfillment of obligations, the Philippine government is now looking for ways to deal with the situation. It has been relatively easier to address the contractual issues when (i) a major portion of the power sale price was not linked to the exchange rate; (ii) capacities under BOT contracts constituted a small part of the country's capacity; and (iii) parties were prepared to renegotiate some of the terms, like commercial operation date, in view of the lower demand growth.[81]

In the Philippines, the large devaluation of domestic currencies experienced during the Asian crisis bared the high exchange risk associated with power infrastructure projects funded primarily with foreign resources. The slowdown of the economy also caused stagnation or reduction in energy demand. Structural weaknesses that prevented further efficiency improvements in the sector were accentuated during the financial crisis,

[81] ADB, above n , 47.

but the slowdown in demand growth and accordingly lower investment requirements have provided a window of opportunity for unbundling various activities as governments distance themselves from management of a more competitive energy sector by increasing the role of independent regulators.

Following the chronic power shortages experienced by the country during the early 1990's, the government implemented the IPP programme. The programme brought in the needed power plants but consumers still reel from the effect of the plants negotiated at peak load rates making electricity costs the highest in the region after Japan. It is now very apparent that there will be significant generation over-capacity with committed plant coming on stream in the next few years, despite the imminent retirement of conventional oil-fired capacity which represents a significant swing away from oil use in power generation. During the first eight years of the Ilijan plant operation, NPC will be unable to meet its take or pay obligations for gas purchases. With the global economic downturn already forecasted and further aggravated by the September 11 World Trade Center terrorist attack making it harder for the struggling Philippine economy to recover from falling export revenues, weak investment and consumer confidence, the worsening of the generation over-capacity is not a remote possibility.

VII CONCLUSION

The Malampaya natural gas project has certainly provided the backbone for the natural gas industry. It brought in a reliable, clean and most importantly, indigenous energy supply. Natural gas provides an economic benefit when substituting lower value fuels but exploiting Malampaya gas came with a premium. It can only be commercially feasible if priced against high-value fuels set in a long-term off-take agreement with take-or-pay obligations and backed by a sovereign guarantee from the Philippine government.

The Malampaya project as an energy business must explicitly recognize all costs including hidden subsidies and implicit guarantees, like opportunity costs of equity investment, risk-adjusted cost of debt, depreciation, open market cost of the effort utilized in developing a project proposal, risk-adjusted project implementation cost, insurance, and costs related to other provisions that become necessary to continue business in adverse conditions. In addition policy directives on monopolies and decommissioning issues must be addressed.

The jury is still out on the consequences of government guarantees and other forms of financial support. Though they may have increased the volume of investment, they may not have solved the underlying problems. It is now inevitable that there would be significant amount of generation over-capacities and government exposure to exchange risks, and these unfortunately have to be borne by consumers and taxpayers as part of the bitter pill to swallow for the sake of competitive electricity markets. The silver lining will be the window of opportunity to restructure the sector by unbundling various activities, establishing independent regulation, and enlarging private sector participation in a more competitive framework.

The Philippine government must have for its agenda the establishment of a comprehensive, fair, and transparent framework as a prerequisite for public sector withdrawal through commercialization, corporitisation, and privatization of national petroleum companies, as well as for the transfer of regulatory and policy functions to the government. Merchant power infrastructure projects must be implemented as the regulatory framework becomes clear and project developers can reasonably forecast the sales revenue over the life of the project.

Policies should support the construction of gas transmission pipelines to enable cross border trade. It is also imperative that a regulatory framework must be clearly in place before transnational energy transmission projects can materialise. More importantly, the Philippine government may have to reconsider its diplomatic position on the Sabah territorial claim if a negotiation for an integrated gas pipeline transmission is progressed with the Malaysian government. If that is not the case, natural gas, subject to achieving minimum economies of scale, can be supplied from one country to another in a liquefied form under long-term take-or-pay contracts between a dedicated supplier and a dedicated consumer.