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Indonesia
Oil and Gas Sector Study

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Energy and Mining Sector Unit
East Asia and Pacific Region

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CURRENCY EQUIVALENTS

(As of February 9, 2000)

Currency Unit	=	Indonesian Rupiah (Rp)
Rp1.00	=	US$0.000133
US$1.00	=	Rp7,500

ABBREVIATIONS AND ACRONYMS

ADO	Automotive Diesel Oil
Avgas	Aviation Gasoline
BBM	Bahan Bakar Minyak (i.e., price-regulated fuels)
bbl	Barrels
bcf	Billion Cubic Feet
bpd	Barrels per Day
BPPKA	Foreign Contractors Coordinating and Management Body
CIF	Cost Insurance and Freight
CNG	Compressed Natural Gas
CPI	Consumer Price Index
DCF	Discounted Cash Flow
DGEED	Directorate General of Electricity and Energy Development
DWL	Dead Weight Loss
EIA	Environmental Impact Assessment
FOB	Free On Board
FTP	First Tranche Petroleum
GDP	Gross Domestic Product
GWh	Gigawatt Hours
IDO	Industrial Diesel Oil
IOC	International Oil Company
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSWR	Low Sulfur Waxy Residual
MER	Maximum Efficiency Rate
MIGAS	Directorate General of Oil and Gas
MMbbls	Million Barrels
MMBtu	Million British Thermal Units
MME	Ministry of Mines and Energy
MMscf	Million Standard Cubic Feet
MOF	Ministry of Finance
Mogas	Motor Gasoline
PD	Presidential Decree
PGN	Perusahaan Gas Negara
PLN	Perusahaan Listrik Negara
PM	Particulate Matter
PSC	Production Sharing Contract
tC	Tonnes of Carbon
tcf	Trillion Cubic Feet

FISCAL YEAR

April 1 to March 31 till 2000
FY2000 is 9 months, April 1 to December 31
Same as CY from 2001 onwards

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OIL AND GAS SECTOR STUDY

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MAPS

This Report has been prepared by a core team of principal authors comprising World Bank staff, Mohammad Farhandi (Task Management and Pricing), Eric Daffern (Downstream Market), and William Onorato (Legislative Framework). In addition, the Production Sharing Contract (PSC) models were prepared by K. Palmer, Consultant; and J. Ruitenbeek, Consultant, prepared the environmental aspects. Calum Gunn, Consultant, provided critical inputs into overall compilation and integration of the Report.

The Report benefited from comments from the peer reviewers: Messrs. Charles McPherson (Manager, Oil and Gas Division), Roland Peters (Sector Director, Europe and Central Asia Region), and Stephen Howes (Senior Economist).

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This Report is based on the findings of World Bank missions that visited Indonesia between November 1998 and December 1999. The Report findings and preliminary recommendations were discussed with the Government and the industry in February 2000.

The task team is grateful for the cooperation provided by the Ministry of Mines and Energy, including the Directorate General of Oil and Gas (MIGAS). The Bank would like to especially thank the two Ministers who were responsible for the Mines and Energy portfolio during the course of the Study, Dr. Kuntoro Mangkusubroto and Letjen. Susilo Bambang Yudhoyono, who both provided their support and constructive comments during the conduct of the Study.

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Indonesia
Oil and Gas Sector Study
Executive Summary

1. Indonesia's oil and gas (hydrocarbon) sector is vital to the economy. However, the country's hydrocarbon resources are not handled in an economic manner, and the sector performs well below par. The sector needs to be substantially reformed—urgently—given the issues at stake, the fallout from the regional crisis, and the conditions in the global oil industry.

2. This Study, financed with Bank resources, attempts to provide a broad, first cut review of the most pressing issues facing the sector, and to recommend ways to ameliorate or eliminate the problems. The main problems are: (a) petroleum product prices are heavily subsidized at the aggregate level and distorted at relative levels, and thus need to be rationalized within an economic framework; (b) the functions and role of the State oil and gas company (Pertamina) are problematic, and therefore Pertamina must be fundamentally restructured to eliminate the conflicts of interest and inefficiencies; (c) some of the provisions of the production sharing contracts (PSCs) are relatively regressive (particularly under market conditions of low oil prices), and need to be re-evaluated with a view to maximize the contribution of the sector to the economy, and to increase upstream investment by the private sector; (d) existing laws and regulations are inadequate and must be replaced; (e) petroleum products are of poor quality and must be improved, particularly by phasing out the lead from gasoline; and (f) energy sector institutions are weak and must be strengthened.

3. The issues are complex and although it is always difficult to institute sweeping changes, given the new political climate, this is an opportune time for Indonesia to begin the process. As a first step, preparing an official and comprehensive declaration of Government policy for the hydrocarbon sector is critically important, to outline the vision for the sector, the policy objectives, and the policy actions required to achieve these objectives, including measures to solve the sector's problems. Such a declaration would help to provide an overall framework for sector reform and assurance to all stakeholders in the sector.

Energy Product Pricing

4. Pricing is the sector's most pressing issue. At the aggregate level, domestic prices of a composite barrel of the five regulated "BBM" products (motor gasoline; kerosene; automotive diesel oil, also known as ADO or Solar; industrial diesel oil; and fuel oil—which together account for over 97% of the total consumption) are on average about 43% of international prices. The prices of three key products (kerosene, ADO and industrial diesel oil) do not even cover their production costs. Also, the current pricing of natural gas is distorted: the selling price of gas for some users is lower than its economic cost of supply, and for others is just barely sufficient to cover the cost; and with respect to its value to the economy, a substantial amount of economic rents (to the Government) are foregone. The gas price distortion, together with Pertamina's role in the gas sector, are the main obstacles to rapid development and expanded utilization of this economically and environmentally attractive fuel. Further, the pricing structure for electricity is distorted both at absolute and relative levels. Finally, the policy goals of energy taxation are not clear, as to whether taxes are expected to expand revenue, increase sector efficiency or mitigate adverse environmental impacts.

5. **Cost of Subsidies and Relative Distortions.** The cost of the subsidies for the five BBM products during 1999 was about US$4.9 billion, representing about 5% of GDP; over 25% of the Government's routine expenditures, or about 20% more than the total principal payments of the country's huge debt. The loss in economic efficiency resulting from these subsidies in 1999 is estimated at about US$1.4 billion. If the subsidies are not removed, the amount that the Government would have to provide between now and the end of 2005, based on current international prices, will be about US$36 billion. This does not include the cost of relative distortions, which result from distorted patterns of consumption and the associated misallocation of producers' and consumers' resources. These costs have not been quantified.

6. **Benefits from Eliminating the Subsidies.** If the subsidies are gradually removed over the next five years, as is proposed in this Report, the Government's expenditures would be reduced by about US$22 billion over this period, and the value of its additional foreign exchange earnings (due to reduced consumption of fuels) would be about US$11.5 billion. In addition, there would be a net reduction of about US$5 billion in environmental damages resulting from particulate matter and nitrogen oxides, and if the lead in gasoline is phased out, there would be an additional US$6 billion reduction in environmental damages currently resulting from lead poisoning.

7. **Macroeconomic and Social Impacts.** While energy price increases will affect the cost of living and producer costs, the magnitude of these impacts is not expected to be significant in the context of some of the CPI and PPI increases the country has experienced in the past few years. Regarding the social impacts, only a small amount of the total subsidy currently reaches to the poor. For example, in dollar terms, only about US$260 million, or roughly 15% of the total kerosene subsidy of about US$1.8 billion in 1999, reached the poorest 30% of the population. Nevertheless, the poor will suffer more in relative terms since a greater proportion of their budget is spent on fuel. Thus, some sort of safety net is essential, but the associated implementation and administration costs would be significantly less than the cost of the subsidies.

8. **Proposed Price Adjustments and Timetable.** The Table below presents the amount of the adjustment needed for each fuel price to rise to market levels. With respect to timing, it is recommended that the price hikes be gradual, spread over no more than five years, after which the prices should be fully deregulated. However, if the international prices of petroleum products decline, the length of the time to phase out the subsidies should be reduced accordingly.

Table 1: Recommended Pricing Adjustments

	Year					
PRODUCTS	**Sep 2000**	**Sep 2001**	**Sep 2002**	**Sep 2003**	**Sep 2004**	**Sep 2005**
ADO	+20	+20	+20	+25	+15	-
IDO	+20	+20	+20	+25	+15	-
Fuel Oil	+25	+25	+25	+25	+30	-
Kerosene	+20	+25	+30	+35	+40	+50
Mogas	-	-	-	-	+15	+10
Electricity	+30	+20	+28	-	-	-
Natural Gas	-	-	-	+20	+25	to opp value
LPG	-19	-	-	-	-	+25

9. **Implementation.** Prior to implementing the initial price hike, say in September 2000, the rationale for the pricing adjustments should be announced, and the public informed about the cost of the subsidies to the economy and the environment, as well as the impact of other

distortions. After the prices are increased, they must be adjusted periodically (not longer than three months), through an adjustment formula, to reflect the market conditions including the international prices of oil products and foreign exchange rates. Any subsidies to the poor should be direct, treated outside the sector, and be a line item in the budget. Once a sufficiently accurate identification of the targeted groups has been made, a cash payment vouchering system could be used as the mechanism to deliver the subsidy directly to the poor. Vouchers could be distributed through the already-monitored village-level network in place for distributing rice, but the exact implementation details of such a mechanism need to be investigated as soon as possible.

10. **Future Analytical Work.** Two key additional analytical works are required to complete the study of pricing. First, a comprehensive Gas Utilization study should be carried out to establish the economic costs and values of gas in Indonesia, as well as the appropriate pricing policy, rational investment program and institutional arrangements needed to accelerate the development and utilization of the country's natural gas resources. Key decisions regarding the pricing structure for natural gas should be kept in abeyance until the preliminary information from this study becomes available. In the meantime, despite the fact that the price of gas is currently low, the price of gas should not be raised until the price of ADO, and other fuels for which gas can substitute, are able to be increased (as recommended in Table 1 above).

11. Second, an Integrated Energy Product Pricing study should be conducted to: (i) address the pricing of geothermal, hydro and coal resources, and update the recent study on electricity tariffs, in the context of the recommended adjustments to the prices of petroleum products; (ii) review the issue of uniform pricing; and (iii) re-evaluate the entire issue of energy product taxation. However, this study should not delay the implementation of petroleum product and electricity price adjustments proposed in Table 1.

Pertamina's Role and Functions

12. Along with pricing, the other key issue that has a profound impact on the sector is the problematic role and functions of Pertamina. Key concerns are that: (a) Pertamina's direct operation in the exploration and production of oil and gas in its own concession areas is not efficient; (b) Pertamina acts as the Government's sole agent in supervising the activities of the private companies operating in the upstream—thus creating an inherent conflict of interest, since Pertamina competes with the companies it supervises—and this supervisory role focuses more on control than on gaining added value for the Government, consequently contributing to delays and significant inefficiencies; and (c) Pertamina enjoys a virtual monopoly over a huge market in downstream activities, a role which is not conducive to efficiency and reliability (with inefficiencies particularly severe in the refining subsector).

13. **Pertamina's Performance.** This Study has not re-evaluated in detail Pertamina's internal inefficiencies or internal reorganization, because two recently-completed reports have focused on these issues, and their findings strongly support the need to change the company's operational practices, organization and decision-making processes. The Bank's own assessment of the sector's performance also points to some deep-seated issues in Pertamina's role and functions. Although Pertamina does not have direct control over some of the causes of these inefficiencies, it is clear that the company's performance is below that of comparable entities internationally. Thus, there is a clear and urgent need to fundamentally reform Pertamina, by separating out and divesting many of its activities, and to improve its remaining core operations so that it resembles other international industry players.

14. **Necessary Reforms to Pertamina.** In this context, the two previous reports have mainly assessed the options to improve the organization "as is"; whereas the reform to Pertamina's structure needs to be more fundamental, and the timeframe of this reform must be accelerated. Therefore, the Bank recommends that the Government: (a) carry out, with the help of experts, a focused assessment of the alternatives for reforming Pertamina, in particular, considering the formation of several full and legally binding subsidiaries, as well as the initiation of a major divestiture and/or partial privatization program; and subsequently, (b) begin to implement the measures needed for the unbundling of Pertamina; in particular by (i) removing the Foreign Contractors Management Body (BPPKA) from Pertamina and locating it under MME, possibly within MIGAS, or as a separate agency, (ii) ensuring that Pertamina participates in upstream activities on an equal basis with private companies, and (iii) removing Pertamina's monopoly status from downstream activities, while improving the efficiency of refinery operations).

15. **Downstream Liberalization**. The size of Indonesia's domestic petroleum market is sufficiently large by any standard to attract international, regional and local investors if the right framework is put in place to make competition realistic and vibrant. The Bank recommends that the Government move to put in place such a framework for downstream activities; one that: (i) allows open access to facilities such as harbors, jetties and related storage and pipelines; (ii) moves Pertamina's *de facto* monopoly on shipping and transportation to an arm's length, competitive basis; (iii) allows for the sale of the majority of service stations; and (iv) liberalizes the refinery subsector fully, with a view to eventually privatizing those refineries which still prove to be viable. The introduction of effective competition within this framework will require an active program of substantial divestiture of Pertamina's assets in the downstream. The assignment of assets by the Government to either a restructured Pertamina, or for sale, should be made with attention both to maximizing the value of assets to the country and to maintaining effective competition in domestic petroleum product markets. (Full-scale liberalization may not be economic in the small and dispersed island markets. In these markets, the Government should encourage, or regulate, the aggregation of procurement among the marketers, and thus create economies of scale)..

Production Sharing Contracts

16. The Study reviewed the issue of whether the PSCs between the Government and private oil companies are appropriate, both with respect to the type of the contract and their actual provisions. With respect to the type of contract, the basic principle of the PSC is appropriate and should be retained. Further, the fiscal and non-financial terms of Indonesian PSCs are not out of line compared to PSCs in other countries. Nevertheless, some of the provisions of the fiscal regime are not sufficiently progressive, particularly under conditions of low oil prices. Consequently, some re-designing of these provisions should be considered with a view to achieve higher total investment by the private sector, and higher overall State revenue in the medium and long term. .

17. It is recommended that for the new PSCs: (i) the rate of First Tranche Petroleum, or the proportion accruing to Indonesia under the standard contract, be reviewed, to possibly reduce it—particularly for higher cost fields during conditions of low oil prices; (ii) contractors receive the world price for supply they provide to the domestic market, in the period before the domestic market and refineries are liberalized; (iii) the investment credit be applied more equally, extended to all areas, and the rate and mechanism applicable should be reconsidered to enhance the attractiveness of the fiscal regime; and (iv) the State profit oil/gas share be linked directly to a

measure of achieved cash flow. With regard to existing PSCS, only if mutually agreed with the contractor, should the Government renegotiate the terms of existing PSCs along the lines recommended for new PSCs.

Legislative Framework

18. Many of the problems discussed above stem from, and are reinforced by, the existing legislative framework. Indonesia needs new, clear and transparent oil and gas legislation with associated regulations, both appropriate and conducive to the operation of a modern industry. Without a solid legislative framework, the capacity of the sector to grow, which is dependent on increased private investment, will be substantially dampened. This Study outlines international best practice for an oil and gas legislative framework, as well as the Bank's key concerns relating to the previously proposed draft oil and gas law (which did not pass).

19. The Bank recommends that the draft oil and gas law, submitted to Parliament during 1999, be revised to more closely provide the framework for a competitively-based, market-oriented sector operation, involving less Government interference, and to be consistent with international industry best practice. At the same time, comprehensive supporting regulations should be issued consistent with the law(s) and with best practice. Furthermore, a decision should be made, preferably before the law is passed, on the nature, number and establishment mechanisms of the regulatory agencies required for the energy sector (e.g., whether there should be separate agencies for the hydrocarbon and power sectors, or whether a single agency would cover the entire energy sector). Finally, new petroleum product specifications, allowing for the eventual elimination of leaded gasoline, as well as new health, safety and environmental standards relating to the energy sector should be issued, consistent with international best practice.

Weaknesses in Institutional Capacity

20. Sector institutions should be strengthened across the board, particularly where regulatory responsibilities are increased as a result of the reforms. In particular, the administrative apparatus of MME will require substantial strengthening, both in terms of its procedures and capacity, especially if the role of supervising and regulating PSCs is transferred to it from Pertamina.

CHAPTER 1: HYDROCARBON SECTOR OVERVIEW AND KEY ISSUES

1.1 Indonesia's oil and gas (hydrocarbon) sector is vital to the economy. However, the country's hydrocarbon endowments are not handled in an economic manner, and the sector performs well below par. If it is to operate in a commercially, economically, socially and environmentally viable manner, the sector needs to be substantially reformed—urgently—given the issues at stake, the fallout from the regional crisis and the adverse conditions in the global oil industry. For the Indonesian Government to introduce the necessary reforms, it will need to correct several major deficiencies (para. 1.19). Although it is always difficult to institute sweeping changes, given the new political climate, this is an opportune time for Indonesia to begin the process. Conversely, Government inaction would lead to the country's valuable natural resources being used sub-optimally, and the mismanagement and misallocation of precious resources would persist. This, in turn, would bring greater inefficiencies and increase the potential for corruption.

A. Report Objectives and Audience

1.2 Shortly after the change of Administration which occurred in May 1998, the Indonesian Government, through the Ministry of Mines and Energy (MME), requested that the World Bank provide support in four key areas of Government-proposed reforms relating to the hydrocarbon sector. These reform areas were in: (a) creating an efficiency-based pricing structure for hydrocarbon products; (b) devising the framework for a more rationalized structure in the upstream activities of the sector (i.e., exploration and production), with regard to participatory arrangements between the Government, Pertamina and private companies, as well as improved production sharing contracts (PSCs); (c) liberalizing downstream activities (i.e., refining, transportation, marketing and retailing); and (d) drafting a new oil and gas law and supporting regulations, consistent with the planned liberalization of the sector and with the best practices of the international oil and gas industry. This Study, financed with Bank resources, is the Bank's response to the Government's request, and attempts to provide a broad, first cut review of the above issues, as well as recommending ways to ameliorate or eliminate the problems.

1.3 The Bank took a two-pronged approach. First, given the country's urgent need for the Bank's inputs, there was a requirement for "real time" responses to be provided to the Government, particularly in relation to comments on the draft of the new oil and gas law proposed at the time. But second, it was also agreed that more detailed analytical work would be produced by the Bank in four parts, along the lines of the above issue areas, and that as each part was completed it would be informally presented to the Government. This work was completed and submitted between September 1998 and November 1999.[1]

1.4 The purpose of this consolidated Report is to update and elaborate on those four submissions (comprising Annexes 2A through 5C), which had already been discussed with the Government, integrate and summarize the Bank's analysis of the key sector issues

[1] Although the Bank's submissions related to this Study were discussed with the Ministry of Mines and Energy during the previous and present Administrations, these were produced without the benefit of detailed discussions with Pertamina. With respect to the industry, one round of discussions was held with major oil and gas companies involved in upstream activities in Indonesia during the main mission for this Study. However, after the draft Report was completed in February 2000, it was discussed with and submitted to Pertamina (as well as to the Government once again), and the industry was briefed on the key findings. At that stage, Pertamina provided some comments which have been incorporated into the Report.

(Chapters 2-5), and to detail the Bank's recommendations to the Government with regard to reforming the hydrocarbon sector (Chapter 6). The key audience for the Report is the Government, in particular the Ministry of Mines and Energy as well as the Ministry of Finance, but also public and private oil and gas sector entities, development banks and agencies, cofinanciers, and the World Bank Group itself.

B. Indonesia's Hydrocarbon Resources, Production, Consumption and Revenues

1.5 At present, Indonesia's hydrocarbon sector produces about 500 million barrels of crude oil and condensate a year, and 3 trillion cubic feet (tcf) of natural gas, both for domestic consumption and export. This generates about US$5.5 billion per annum, which represents 27% of the Government's total revenues and 5% of GDP, at the current exchange rate. (Annex 1 provides more details on the sector's reserves, production, exports, consumption and revenues).

Table 1.1: Indonesia Energy Balance (1997)

	Thousands of tonnes of oil equivalent								
SUPPLY AND DEMAND	**Coal**	**Crude Oil**	**Petroleum Products**	**Natural Gas**	**Hydro**	**Geotherm**	**Biomass/ Waste**	**Electricity**	**TOTAL**
Indigenous Production	33,888	77,291	-	63,043	515	2,217	44,595	-	221,549
Imports	237	8,706	14,339	-	-	-	-	-	23,282
Exports	-25,507	-39,383	-10,119	-31,537	-	-	-102	-	-106,647
Intl Marine Bunkers	-	-	-331	-	-	-	-	-	-331
Stock Changes	927	-	-	-	-	-	-	-	927
TOTAL Primary Energy Supply	9,545	46,614	3,889	31,506	515	2,217	44,493	-	138,779
Transfers	-	-2,226	2,462	-	-	-	-	-	236
Stat. Diff.	-725	2,496	-1,907	76	-	-	9	231	180
Electricity	-6081	-	-4,862	-5,603	-515	-	-	6,436	-12,843
Gas Works	-	-	-	473	-	-	-	-	473
Refineries	-	-46,884	44,959	-	-	-	-	-	-1,925
Other	-	-	-	-	-	-	-122	-	-122
Own Use	-	-	-1,984	-16,580	-	-	-	-251	-18,815
Losses	-	-	-	-	-	-	-	-741	-741
TOTAL Domestic Demand	2,739	-	42,557	9,872	-	-	44,381	5,674	105,222
Industry	2,739	-	10,653	7,869	-	-	-	2,689	23,950
Transport	-	-	19,866	-	-	-	-	-	19,866
Agr, Com, Res, Other	-	-	10,954	2,003	-	-	44,381	2,985	60,322
Non-Energy	-	-	1,085	-	-	-	-	-	1,085
Elec Gen (GWh)	23,001	-	22,447	20,816	5,990	2,578	-	-	74,832

Source: IEA Energy Balances of Non-OECD Countries (1999)

1.6 At the end of 1998, Indonesia had about 9 billion barrels of oil reserves—approximately half proven and half potential. Assuming that half the potential reserves are eventually proven and production remains at its current level (about 1.5 million barrels a day), the reserves will be depleted in roughly 12 years, lacking new discoveries. Natural gas reserves were estimated at 138 tcf; again, half proven and half potential. As with oil, if half of the potential reserves are proven, given the current rate of production (3.2 tcf per year), these will be depleted in about 30 years.

1.7 Thus, although these substantial reserves place the country among the most well endowed in the Asia Pacific Region, its population of over 200 million and a moderate growth in consumption will cause it to be a net importer of petroleum products in a relatively short period. Indeed, if domestic consumption increases by only about 5% a year after recovery (rising from 2002 onward), the country will need to import all its oil by 2008, at an estimated annual cost of US$11 billion a year (in current dollars). Consequently, energy diversification has for many years been a central part of the Government's strategy for maintaining economic growth. Table 1.1 provides the overall energy supply and demand balance for the country (1997 figures).

C. Sector Institutions

Pertamina

1.8 For the past three decades, Indonesia's hydrocarbon sector has been vertically integrated, and dominated by a strong national petroleum Perum, Pertamina.[2] A decade or so ago, such a situation was not uncommon in the hydrocarbon sectors of many countries. But the predominant worldwide trend is now to move away from such a structure (para. 1.16). Pertamina controls and participates in the exploration and production of oil and gas, is the world's single largest LNG export company, and enjoys a virtual monopoly over Indonesia's entire domestic downstream industry, including: all refineries, the transport of oil and gas, as well as the import, export and retail marketing of refined petroleum products. The company also acts as the *de facto* regulator of the sector, rather than the Government, and consequently private companies are effectively contractors to Pertamina.

PGN

1.9 During the past decade, the Government recognized that developing the domestic gas market would serve to free up additional oil for earning hard currency, and also have significant environmental benefits. With this in mind, the Government charged the national gas Persero, PT PGN, which became a public corporation in 1984, with the primary responsibility for distributing gas to medium-sized and small industries, commercial establishments, and households. Prior to 1994, gas transmission was the exclusive preserve of Pertamina, but since 1994 PGN has also had a mandate to move into transmission, to recruit strategic investors where required to help finance, operate and maintain transmission pipelines, and to supply bulk natural gas consumers. Nevertheless, PGN currently supplies only about 10 percent of the domestic gas market, with the remainder (mostly large industries and power plants) being supplied by Pertamina, and apart from the distortions in petroleum product prices, increased utilization of domestic gas continues to be constrained by the lack of an integrated transmission and distribution pipeline infrastructure.[3]

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2 A Perum is an entity within the Government, whereas a Persero, such as PGN (para. 1.9) and PLN (para. 1.10), is a Government-owned limited liability company.

3 The Government issued a policy of Natural Gas Development in August 1997. This policy was to be partially implemented through a Keppres (Presidential Decree) for natural gas transmission and distribution, the latest draft being July 1998. Among other things, this decree was intended to clarify the relationship between Law 44/1960 and Keppres 37/1994, and consequently the roles of Pertamina and PGN in the domestic gas sector. However, this

Ministry of Mines and Energy

1.10 The Ministry of Mines and Energy is the principal agency responsible for the development and implementation of Government policies in the energy sector, and an inter-ministerial National Energy Board (BAKOREN) coordinates MME's activities with those of other Ministries. The MME was established in 1978 to coordinate the activities of public and quasi-public enterprises operating in the energy sector, including Pertamina, PGN and PT PLN (the State's vertically integrated electricity corporation). The hydrocarbon and geothermal sectors are monitored by MME through its Directorate General of Oil and Natural Gas (MIGAS). MIGAS issues the licenses to the service companies which conduct business in the hydrocarbon sector, enforces safety and environmental regulations, and supervises training for local workers.

Institutional Capacity

1.11 The energy sector entities require substantial capacity building, particularly given the new challenges which they will face during a transition to a more liberalized and market-oriented sector. There are also a number of specific areas that need strengthening. For instance, energy planning/forecasting functions and capabilities are currently spread among many Government agencies, and there are a number of weaknesses in the current approach to developing a cohesive overall energy plan, and supply and demand projections.[4] Further, any new oil and gas law (para. 1.24) is likely to require that many of Pertamina's roles be transferred to MME, in which case MME will require significant capacity building to be able to supervise and regulate PSCs. Also, a program of training will be required to ensure high-quality administration of Government policy.

D. Macroeconomic and International Oil Industry Context

Indonesia's Economy

1.12 The political and economic turmoil which Indonesia has experienced over the past two years, as a result of the Region's crisis, is still a critical backdrop to a discussion of the activities in any sector of the economy. Although the worst now appears to be over, fallout from the crisis is still having a significant, even if temporary impact, on the energy sector as a whole. Throughout the Region, the crisis lowered GDP growth, weakened capital markets, and devalued currencies. Consequently, the lower GDP reduced the growth in demand for energy, and the weakness of capital markets set back many of the plans to privatize sector entities. Further, currency depreciation increased both the cost of sectoral investment and operations, where these depend on imported plant and fuels. While growth in Indonesia is gradually resuming, the crisis has created a major setback in investor confidence and has taken a huge toll on the fiscal position of the Government, with respect to the sector, as well as on the finances of sector entities. For instance, in response to the devaluation of the Rupiah, the Government was unable to adequately adjust the prices of petroleum products in the domestic market. Furthermore, there was a drop in

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Keppres was not issued, partly because the draft oil and gas law (para. 1.17) was seen as being able to fulfil the same purpose (Annex 5A).

4 Functions comparable to MIGAS in the power sector are handled by DGEED (the Directorate General for Electricity and Energy Development), which oversees PLN. DGEED to some extent also encompasses energy forms other than electricity, in particular, renewables. Partly as a result, energy planning and monitoring functions are not consolidated, and are split between MIGAS, DGEED, MME's internal Bureau of Planning, and other related Government agencies.

LNG export volume, due to the impact of the crisis on Indonesia's main LNG customers, Japan and South Korea.

1.13 The highest short-term priority for Indonesia's economy is to maintain the country's recently-gained relative stability by focusing on (a) restructuring the banking and corporate sectors, (b) creating adequate safeguards to protect the poor, in particular ensuring that resources reach the intended beneficiaries, and (c) reducing the huge public debt, through greater domestic resource mobilization and by lowering the level of borrowing.[5] But, to sustain any short term gains, the focus must also be on medium term priorities, which include putting in place a stronger foundation for greater transparency in the formulation and implementation of policies, reforming and enhancing the efficiencies of institutions—particularly in strategic planning, investment programming and process re-engineering—and mitigating adverse impacts on the environment. Given its substantial fiscal, environmental, macroeconomic and social impacts, the relative performance of Indonesia's hydrocarbon sector profoundly affects the achievement of both the short and medium term goals for the wider economy.

International Oil Industry

1.14 Apart from the recent dramatic changes in the economies of the Region, worldwide the economic and financial environment for the oil industry has also changed dramatically. Despite the recent rise in oil prices, it is estimated that over the next several years, investment by international companies will fall by 20%-30%. While it is impossible to predict future oil prices accurately, oil price risks (and, therefore, the industry's cost of capital) have increased. In East Asia, while petroleum demand will gradually rise, renewed investment is still a distant prospect, particularly because of widespread over-capacity. Moreover, major LNG and gas pipeline projects in the region will be much more difficult to complete (a fact particularly relevant for Indonesia) because demand for energy in some of the major gas importing countries has slowed, and the creditworthiness of gas contracting parties has dropped.

1.15 In addition, the global oil industry has sought ways to cut costs—for which corporate rationalization plays a major role. Even large companies such as BP-Amoco, Exxon-Mobil, and Total-Fina identified major economies of scale in carrying out mergers. The result of all these for a producer country such as Indonesia will be less competition for new exploration and a concentrated (reduced) exploration and development budget in fewer hands. Thus, the availability of foreign capital for Indonesia's upstream industry will be constrained and the increase in its export revenue in both oil and gas will be limited.

1.16 Globally, the trend to corporatize and privatize state oil enterprises has accelerated. Many oil companies in Europe and Latin America have had their monopoly status removed or privatized. While the primary motive of governments was their inability to finance public expenditures, corporatization and privatization have sharply improved the performance of the (former) state enterprises, because the now-privatized enterprises enhanced their internal cash flow and access to external capital. Moreover, in many cases, improved transparency and accountability have reduced concerns about mismanagement and corruption.

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[5] For a detailed discussion of Indonesia's short and medium term economic priorities, refer to the World Bank's 1999 Report: "Indonesia: From Crisis to Opportunity."

E. Sector Vision and Objectives

1.17 Cognizant of the need for action to respond to the impact of the regional crisis and developments in the international petroleum industry, as well as to address long-standing problems existing in the sector, the Indonesian Government made a start down the path of sector reform during 1998. In particular, given the prevailing political circumstances, the Government decided to take advantage of the window of opportunity presented by the regional crisis to initiate reform, beginning with the passage of new oil and gas legislation.[6] In this context, the Bank indicated that there should be a clear statement from the outset on both the objectives of any new law and its intended scope of coverage, within the framework of a wider vision of the intended policy objectives for the sector as a whole, for both upstream and downstream.

1.18 As such, the Government discussed its vision and objectives for hydrocarbon sector reform with the Bank. It indicated that its long term vision was to develop a hydrocarbon sector which would: (i) be able to meet the domestic market demand for oil and gas, as well as to provide fuel for Indonesia's economic growth; (ii) maximize the generation of revenue for the country; (iii) ensure security of supply; and (iv) develop national capabilities in the sector. To move significantly closer to the realization of this vision, the Government also indicated that its policy objectives are (a) efficiency and reliability, (b) transparency and competition, (c) minimization of the use of public funds (including through a gradual phasing-out of subsidies), and (d) environmental soundness. However, with the exception of a 1997 policy statement on the development of the domestic gas subsector, these have not yet been formalized into a new statement of Government policy.[7]

F. Sector Performance and Issues

1.19 Although the objectives and the overall vision are laudable, the hydrocarbon sector suffers from a number of substantial problems that stand in the way of realizing this vision and achieving these objectives. The sector performs at a level significantly lower than international industry averages, and several deep-rooted problems include: (a) *petroleum product prices* are heavily subsidized at the aggregate level, distorted at relative levels, and need to be rationalized within an economic framework; (b) *the role and functions of Pertamina* need to be fundamentally redefined and the organization entirely restructured: since, in upstream activities, Pertamina's own operation is not efficient, and its supervisory role vis-à-vis private companies (outside its own operation) creates inefficiencies and conflicts of interest; and in its downstream activities, Pertamina enjoys a virtual monopoly in a huge domestic market; (c) some of the *PSC provisions*

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[6] Although the draft new oil and gas law (for both the upstream and the downstream combined) failed to pass, the Government has, at least in theory, opened up the refinery subsector to private participation, liberalized the market for lubricants, and lifted price controls on aviation fuels. However, more fundamental reforms were unable to be achieved. For instance, attempts by the previous Administration to increase the prices of major petroleum products during 1998 met with strong public resistance.

[7] Bolder actions have been taken in the power sector during the past two years. The Government issued its Power Sector Restructuring Policy in August 1998, and a cross-Ministerial Steering Committee was established to oversee the corporate and financial restructuring of PLN, as well as to rationalize the private power program. In addition, a Government team was established to oversee the implementation of the needed legal and regulatory reforms relating to power. Although a discussion of the restructuring program in the power sector is outside the scope of this Report, the benefits of this program for the power sector will only be fully realized if the reforms recommended for the hydrocarbon sector are implemented in parallel. Harmonizing the reforms in the hydrocarbon and power sectors is of particular importance to resolving the problems relating to the prices of petroleum products, and in designing the regulatory framework for the energy sector as a whole.

are regressive, particularly under a low oil price market and, given the changing economic and oil industry environment, may benefit from some modification; (d) existing *laws and regulations* are inadequate and must be replaced; (e) petroleum products are of poor quality and include leaded gasoline, resulting in *high air pollution levels* in Jakarta in particular;[8] and (f) *energy sector institutions* need strengthening.

1.20 While the resolution of these issues is complex and will take time, the process must begin. As a first step, an official and comprehensive declaration of Government policy for the hydrocarbon sector is critically important, to outline how these problems will be resolved, and consequently, how the policy objectives will be translated into policy actions. This would help to provide an overall framework for sector reform and assurance to all stakeholders in the sector.

G. Report Scope

Energy Product Pricing

1.21 The fiscal impact and efficiency losses associated with the direct subsidies to the hydrocarbon sector are assessed in Chapter 2, with a more detailed analysis provided in supporting Annexes 2A and 2B. Also, an identification of the distortions in relative product prices, and the potential for inter-fuel substitution, is presented. Further, the effectiveness of the subsidies in achieving the Government's objective of providing support to the poor is examined closely. Based on this analysis, a proposal is developed for gradually eliminating the subsidies, while protecting low income groups and minimizing any relative distortions between energy product prices during the transition period.

Pertamina's Role and Functions

1.22 The inefficiencies inherent in Pertamina's current role and functions in both the upstream (exploration and production) and downstream (retailing, processing and marketing) of the hydrocarbon sector are analyzed in Chapter 3 and supporting Annex 3. Recommendations for redefining the relationship between the State, Pertamina and investors are presented, and ways to successfully liberalize downstream hydrocarbon sector operations are suggested, based on current international best practice.

The Terms of Production Sharing Contracts (PSCs)

1.23 The ability of Indonesia's model PSCs to encourage upstream investment by private investors while, at the same time, secure maximum revenues for the Government, is assessed in Chapter 4 and Annex 4A. General and specific recommendations for improving the terms and conditions of the PSCs are provided. Annex 4B provides a comparison of the terms of similar

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[8] The most serious cause of atmospheric pollution in Jakarta is vehicle emissions resulting from the combustion of petroleum products. Reducing the sulfur content in diesel oil and removing lead from gasoline would result in substantial health benefits. In 1996, a presidential directive to phase out lead in fuels was issued, but no tangible process was put in place for implementation. Pertamina had planned to rationalize product specifications and to phase out leaded gasoline grades by revamping the catalytic reforming capacity at several refineries, as well as by increasing imports of high octane unleaded gasoline and octane booster compounds. However, financing either the required refinery modifications or additional imports of high octane gasoline has become difficult under the country's current economic circumstances. Nevertheless, one of the commitments subscribed to by the Government in its letter of understanding with the IMF is to proceed with plans for the complete removal of lead from gasoline.

contracts internationally, and Annex 4C compares investor rates of return under Indonesian PSCs with fiscal regimes in other countries.

Legislative Framework

1.24 General principles for developing upstream and downstream hydrocarbon laws and implementing regulations, in a manner consistent with international best practice, are presented in Chapter 5 and Annex 5A. Annex 5B provides more specific comments on the draft oil and gas law prepared during Indonesia's previous Administration, and Annex 5C contains detailed recommendations on the essential elements of regulations required to support any new law. In particular, the need for the new law to allow for a fundamental redefinition of Pertamina's role is emphasized.

Environmental Issues

1.25 Environmental issues are inextricably linked with the other issues facing the sector. Consequently, although there is not a distinct Chapter in this Report focusing on the environment, the critical importance of the issue is not underestimated, and the related issues are discussed within the context of other concerns. For instance, the environmental benefits that would be realized through rationalizing the petroleum product pricing regime are quantified in Chapter 2, with a detailed analysis provided in Annex 2C, and the environmental justification for rationalizing petroleum product specifications is outlined in Annex 3.

CHAPTER 2: ENERGY PRODUCT PRICING

2.1 A rational pricing policy should be the cornerstone of the strategy for the hydrocarbon sector. In the medium term, such as over the next five years (if not sooner), petroleum prices should be totally deregulated. However, in the transition period before market-based pricing can be fully introduced, a pricing policy that can meet the country's growing energy needs must be designed and implemented. Lacking this, efficiency gains through restructuring and rational investment planning would be difficult if not impossible to achieve. The wrong pricing policy in the energy sector would lead to huge economic losses, because the investments associated with oil, gas, power, coal and geothermal are usually very large and require long lead times; also, disruption of the energy supply could be very costly. This is particularly important for Indonesia, given the critical role energy plays in the economy.

A. Efficiency Pricing Framework

2.2 Prior to deregulation, pricing policy should be designed to meet the country's growing energy needs in an economically, socially and environmentally acceptable manner. Also, given energy's critical role in the economy, it must maximize the country's foreign exchange earnings, meet its energy requirements in a least-cost manner, and address the social and the environmental impacts. It must also allow for timely adjustments, be easy to administer and address existing contractual agreements. Once in place, it will reduce government intervention in energy affairs and provide the right signals for increased private sector participation, and eventual corporatization and privatization of the sector entities.

2.3 The framework for rational pricing of energy products uses the opportunity cost of supply as the basis for economic choices among different sources of energy for different end users.[1] This economic framework is used to produce a practical pricing structure, namely "efficiency pricing," which allows policy makers to meet their objectives and is usually achieved in two-stages. First, the structure and level of prices are formulated to match the opportunity cost of supply of individual energy forms. Second, the efficiency prices are adjusted to reflect the netback value (in effect the allocation of economic rent) to meet all other objectives to the greatest extent possible, such as social and financial. Two critical principles are that the adjustments (a) should not change the relative ranking of the various fuels with regard to their opportunity costs, and (b) should consider the various fuels' price elasticity.

B. Energy Product Prices and Taxation

Petroleum Products

2.4 Pricing is the sector's most pressing issue. At the aggregate level, the pump price of a composite barrel of five BBM products[2] (accounting for over 97% of total consumption) is about US$12 a barrel, while the market price of the same composite barrel is about US$28.50. Thus, domestic prices, which are on average about 43% of international prices, are heavily subsidized.

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1 The definition of opportunity cost of supply (i.e., the economic cost of supply) differs for tradable and non-tradable fuels.

2 BBM (Bahan Bakar Minyak) products are regulated by the Government and, before the crisis, included: Avgas; Avtur; motor gasoline (excluding several unregulated grades of high octane and super gasoline); kerosene; automotive diesel oil (termed ADO, or Solar); industrial diesel oil (IDO); and fuel oil. However, since early 1999, Avgas and Avtur have been deregulated; thus there are now five BBM products.

The prices of at least three key products—kerosene, automotive diesel oil (ADO), and industrial diesel oil (IDO), which represent 66% of total consumption—do not even cover production costs.[3]

2.5 Kerosene accounts for about 20% of total fuel consumption. Its pump price is about 18% of the international price and below its production cost. While officially only 1% is used by industry and the rest by households, evidence suggests that large amounts are used in non-household sectors (such as the commercial and industrial sectors), and are diluted with and substituted for higher-priced products such as gasoline, ADO and IDO.

2.6 ADO represents about 43% of fuel consumption, but only 55% is used in transport; the rest is consumed by industry (30%) and the power sector. Its domestic price is about 41% of the international price and does not include a road-user charge. Such low prices have hindered greater use of natural gas (paras 2.7-2.9) and its significantly lower price differential with gasoline fosters more rapid demand for ADO. IDO, although supposedly an industry fuel, represents only about 2.8% of total consumption (over 90% is used in industry); its pump price is also about 41% of the international price. Fuel oil represents 10% of total fuel consumption, and is used by industry (65%), power plants (25%), and transport; its pump price is about 32% of the international price. Motor gasoline (Mogas) accounts for 22% of total consumption; its price is about 79% of the international price, and, as with ADO, does not include a road user charge.

Natural Gas

2.7 Although Indonesia's reserves of natural gas are among the highest in the Region, its domestic consumption is among the lowest, and the domestic gas industry and associated infrastructure is underdeveloped. While Pertamina's role and possibly some of the provisions of the production sharing contracts are contributing factors to the slow development of natural gas in the country, the main obstacle to rapid development and expanded utilization of this economically and environmentally attractive fuel is the current pricing policy.

2.8 The energy products for which gas has substitution potential are priced below the current price of natural gas. At the same time, the current price of natural gas is itself below its economic value (i.e., netback value), resulting in the development of gas being held back by producers, who are either expecting a more attractive return on their investment, or their actual costs are not being covered. A rough estimate indicates that the average economic cost of gas supply is about US$1.90-US$2.25 per mcf, while the weighted average wholesale price of natural gas is currently about US$2 per mcf. On the other hand, the economic value of gas on average is estimated to be US$3.00-US$3.75 per mcf. Under such a cost-value pricing structure, (a) the selling price of gas in the case of some consumers is lower than its economic cost of supply, and in the case of others is just barely sufficient to cover the cost, and (b) a substantial amount of economic rents (the difference between the economic cost of supply and the netback value) are foregone. Gas is thus not able to penetrate the market since the domestic prices of fuels which have the highest potential for gas substitution (ADO, IDO and some kerosene), are substantially below their opportunity costs.

2.9 Hence, despite the fact that gas is priced below its economic value, it is recommended that the gas price should not be raised for the next 2-3 years, until the prices of ADO and IDO are increased to a level sufficient to compete with gas. Also, as part of future work, it is

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[3] For the purpose of this Report, the cost of production is assumed to be the efficiency-based cost of production.

recommended that a comprehensive gas utilization study be carried out to establish the economic cost and value of gas, a more accurate estimate of gas consumption, and a forecast of future domestic demand and export potential.

Electricity

2.10 As with petroleum product prices, the pricing structure for electricity is distorted both at absolute and relative levels. The subsidies provided to the fuels used for power generation understate the costs faced by the sector, hence distorting investment and operating decisions. Yet, even ignoring this indirect subsidy, as a result of the crisis, the Government has been providing substantial direct subsidies to the state electricity company, PLN, because the average power tariff has fallen to around 3c/kWh, compared to the actual supply cost of about 6-7c/kWh. Consequently, all electricity consumer classes pay less than the actual cost of serving them. And this distortion will worsen, since costs will increase as new independent power producers (IPPs) come on-stream, and as subsidies on generating fuels are eventually lifted. Nevertheless, even if distortions in the aggregate electricity price level were removed, tariffs would still require rebalancing, since there are substantial cross-subsidies between different regions and consumer classes.[4]

Taxes

2.11 There is currently a 10% flat VAT tax on all products (a 5% motor tax is also included for Mogas and ADO). However, since all major products are priced significantly below their opportunity costs, the policy goals of energy taxes are not clear: are they expected to expand revenue, increase sector efficiency or mitigate adverse environmental impacts?[5] Obviously, each tax regime would yield different results and meet different objectives. As an example, while an *ad valorem* tax is a good mechanism to raise revenues and is easy to administer, it is the least desirable environmentally because it taxes all products the same. To the extent that a broad policy objective is to charge for benefits and costs, a specific tax is more appropriate, although it generates less revenue than an *ad valorem* tax and is more difficult to administer.

2.12 The issue of petroleum product taxes, particularly for transport fuels is complex. Further, the general principle of levying taxes on motor fuels may have to be based on environmental considerations, given the serious air pollution problem in Jakarta. Nonetheless, caution must be exercised in relying on a relatively crude device such as petroleum product taxes to deal with air quality problems; rather, a more targeted approach may be required. In particular, it may not be appropriate to subject the whole country to a tax system designed to ameliorate Jakarta's pollution problem. Also, it would be imprudent to introduce a system of different tax rates in different localities, as this would encourage the arbitrage of petroleum products. It is therefore recommended that as part of the proposed Integrated Energy Product Pricing study (footnote 6), a comprehensive study of fuel taxation also be carried out.

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[4] Relative distortions in power tariffs, and the social impacts of adjusting them, have been analyzed in a recent ADB-funded study by Hagler Bailly: "Power Tariff Rationalization Study".

[5] Although the subsidy as defined here refers to when the net-of-tax price is less than its opportunity cost, in the analysis it has been assumed that the current selling prices of petroleum products at the pump are net of tax—because the amount of subsidies is so large that the effect of tax is relatively small.

C. Relative Distortions and Inter-Fuel Substitution

2.13 Relative prices are also distorted, consequently consumers are provided with the wrong signals, since they find one fuel cheaper than another which may not be the economic choice.[6] This distortion in the pattern of consumption results in a misallocation of producers' and consumers' resources. To analyze the relative pricing distortions, this Study reviewed the potential for substituting one fuel with another in three key sectors—industrial, household/commercial, and transport, based on the principle of inter-fuel substitution. This is particularly important in Indonesia, because the industrial sector is expected to resume growth and substantial room exists for fuel substitution in manufacturing. Using the relative prices of energy products in the international market, the percentage that each product's price needs to be raised in each sector to meet efficiency-based criteria was estimated, and used in developing the recommended schedule of price adjustments (para. 2.27 and Table 2.1).

D. Costs of Subsidies and Relative Distortions

2.14 The gross economic subsidy (the difference between the opportunity costs of the five BBM products and their domestic selling prices) during 1999 was about US$4.9 billion. The Government's own subsidy figures, which are derived from a financial- or accounting-based calculation, show the amount to be about 27 trillion Rupiah in 1998, or US$3.4 billion (at an exchange rate of Rp7500:US$1).

2.15 The amount of the economic subsidy (which excludes direct subsidies for electricity) is about 5% of GDP and represents over 25% of the Government's routine expenditures. To put the magnitude of this subsidy in perspective, it should be noted that the country's debt now stands at about 90% of GDP, a four-fold increase from the pre-crisis period. Further, the debt service (mostly external) represents about 38% (i.e., 21.5% in principal and 16.5% in interest) of the Government's routine expenditures. The amount of the fuel subsidy is therefore about 20% more than the total principal payments of the country's huge debt. By any measure, this amount of subsidy is large and, in the long term, untenable.

2.16 The loss in economic efficiency (i.e., the aggregate welfare of consumers and producers taken together with deadweight losses) resulting from these subsidies has also been calculated. The net cost of the subsidies of the five BBM products to the economy in 1999 is estimated at about US$1.4 billion. The deadweight losses for kerosene alone were about US$700 million. The total deadweight losses would reach almost US$2 billion per year by 2005.

2.17 This Study has not quantified the costs resulting from relative price distortions. However, such costs would be substantial, due to the distorted consumption patterns which the price distortions induce, and the subsequent misallocation of resources. Such distortions are

[6] Since all energy products can be substituted for each other in the long term, the price of each one affects all the others. Ideally, a comprehensive analysis of energy prices should be carried out to include all key energy products, but this Report limits the review to oil and, to a lesser extent, natural gas. Electricity has been studied recently (footnote 4), and the key points of that study have been included here. Eventually, the prices of coal, geothermal and hydro need to be integrated into the design of the pricing structure, and therefore it is proposed that this be done under an Integrated Energy Products Pricing study. Such a study also needs to re-evaluate the issue of taxation (para. 2.12), and to consider the distortions created by Indonesia's current uniform pricing policy, whereby prices are not adjusted for differentiated delivery cost on a geographical basis. Notwithstanding the need for some additional analytical work, implementation of the petroleum product price adjustments recommended in Table 2.1 should not be delayed in order to wait for the outcome of the proposed integrated pricing study.

particularly costly in the refining sector. Major investments in refinery configurations have been made (or would have to be made) for the additional production of ADO. Under the efficiency-based pricing system, the consumption of ADO would be substantially below its current level, and such investments would not be required.

E. Eliminating Subsidies: Benefits and Impacts

Fiscal Benefits

2.18 Eliminating the subsidies will increase Government revenues substantially. If the subsidies are not removed, the amount of economic subsidies that the Government would be undertaking between now and September 2005 would be about US$36 billion, and the value of foregone foreign exchange earnings (due to the domestic over-consumption of fuels) would be about US$16 billion. If the subsidies are gradually removed over the next 5 years, as is proposed in this Report (Table 2.1), the economic subsidies would be reduced to US$13 billion, and the foregone value of hydrocarbon export earnings would only be US$4 billion. Consequently, the magnitude of these savings/earnings should mandate the Government to begin the subsidy removal program on an urgent basis.

2.19 Since the benefits are in the form of foreign exchange, they will provide Indonesia with a hedge against exchange rate fluctuations; this is crucial, since about two-thirds of the rise in the external debt was due to a drop in the value of the country's currency.[7] And, given the size of its debt, Indonesia needs to finance its fiscal deficit through sustainable instruments—both on the expenditure and revenue sides. In the short run, fuel subsidies are the prime candidate since the Government could reduce expenditures by eliminating energy subsidies, which are badly targeted and enjoyed mainly by higher income groups (para. 2.23). If this move were carried out together with putting in place a rational pricing structure, the relative distortions would disappear.

Environmental Benefits

2.20 Eliminating the subsidies will also bring significant environmental benefits. Although mechanisms to combat pollution and its deleterious effects have been persistently pursued in Indonesia through numerous pieces of legislation, the huge energy price subsidies overwhelm any regulatory attempts to correct extensive environmental problems. The subsidies lead to an over-consumption of petroleum products, particularly transport and industrial fuels, consequently producing an increase in: (i) emissions of particulate matter (PM) and nitrogen oxides (NOx), which are responsible for respiratory illnesses, the sixth leading cause of death in Indonesia; (ii) emissions of lead, a contaminant which World Health Organization guidelines indicate should be eliminated totally; and (iii) carbon emissions, responsible for global climate change.

2.21 If petroleum product prices were deregulated, then it is estimated that the net damages from PM and NOx caused by subsidies would be reduced by about US$630 million in 2000, and US$1.1 billion by 2005. Similarly, the net damages from lead poisoning could be reduced by US$530 million in 2000, and US$1.5 billion by 2005 (assuming that lead could be totally phased out by 2002). Further, removal of subsidies is estimated to reduce carbon emissions from 25 tC to 16 tC in 2005. This reduction (equivalent to an emission equivalent of about 34tCO_2) would result in a net decrease in the annual damages to the global community of about US$280 million. In addition, under deregulated prices, there are other long term environmental benefits, such as

[7] Refer to the World Bank's 1999 Report: "Public Spending in a Time of Change".

incentives for inter-fuel substitution by cleaner technologies (i.e., natural gas), and deregulating prices provides conditions in which environmental regulatory standards are more likely to have a meaningful effect.

Macroeconomic Impacts

2.22 Although economic pricing will enhance Indonesia's growth prospects through greater allocative efficiency, an improved fiscal situation and better environmental conditions, given the size of the subsidies and the length of time they have existed, removing them will have some macroeconomic and social ramifications. With regard to macroeconomic impacts, the energy price increase will affect the cost of living and producer costs in both the short and long term, directly and indirectly. With respect to the cost of living, in the short term, besides the direct impact due to increased fuel costs, there is an indirect effect from industry's cost increases, which are passed on to consumers in the form of higher prices (i.e., when the transport costs are increased due to increases in the prices of diesel and gasoline). Further, there will be a long-term impact when the entire economy has felt the effect of the fuel price hike (such as when the food cost is increased as the result of higher transport costs). With regard to producers' costs, the impact may be slightly higher. However, the magnitude of these macroeconomic impacts is not expected to be significant in the context of some of the CPI and PPI increases the country experienced in the past few years.

Social Impacts

2.23 Of the total subsidy, only a small amount currently reaches to the poor. The poor represent 18%-20% of the population (1998 data) and the near poor another 10%-12%, but their consumption of kerosene is only about 10 million barrels out of about 65 million consumed a year, because most only use it for lighting, and only half the urban poor use it for cooking (the rest use fuelwood). About 20 million barrels were used in the non-household sector in 1998, and the remaining 35 million were consumed by those households with higher incomes. And for 1999, only about US$260 million, or roughly 15% of the total kerosene subsidy of about US$ 1.75 billion, reached the bottom 30%.

2.24 Thus, removing subsidies will, at the aggregate level, affect higher-income households more than the poor. However, experience in other countries has shown that the poor suffer more in relative terms since a greater proportion of their budget is spent on fuel. Therefore, some sort of safety net is essential, but the cost of such a safety net will be significantly less than the cost of the subsidies. As to the method of delivering the subsidies to the poor, although all options have advantages and drawbacks, direct income support is infinitely more effective than indirect aid, such as subsidized energy prices, which are inefficient as well as ineffective. Instead, the Government could arrange a direct payment to the poor, as a clear line item in the budget.

Protecting the Poor

2.25 A voucher scheme could be used to protect the poor from an increase in the price of kerosene, each household receiving vouchers that would compensate them for the difference between the old and the new price. Such a scheme would require several elements: (i) targeting poor households, which can be achieved through the existing list used for distributing rice to the poor; (ii) publicizing the objectives and details of the program to the public through the mass media; (iii) distributing the vouchers, one year's worth at a time but redeemable on a monthly basis, through the already-monitored village-level network in place for distributing rice; and

(iv) redeeming the vouchers, while mitigating the potential for corruption through a witnessed receipt and countersigned redemption procedure. Counterfeiting could be avoided through having the vouchers printed by the mint.

2.26 All retailers of kerosene would be instructed to accept the voucher at its face value (i.e., the amount of the price increase, multiplied by the number of liters subsidized). The retailers could then redeem their vouchers with government agencies for the face value, plus a transaction fee to provide compensation for the inconvenience of accepting vouchers, plus an administration fee. The combined fiscal and administrative cost of implementing such a scheme depends on how rapidly, and to what level, the kerosene price is adjusted.

F. Proposed Price Adjustments and Timetable

2.27 Table 2.1 below presents the amount of the adjustment needed for each fuel price to rise to market levels, during the transitional period before full liberalization. With respect to timing, experience elsewhere has shown that whether the approach is immediate or gradual, it is politically difficult to remove subsidies and reform prices. However, in Indonesia, it would appear that immediate increases to market levels would be unrealistic. Thus, price hikes should be gradual, with different time periods for different fuels, spread over a maximum of five year period, after which the prices should be fully deregulated. Clearly, if the international prices of petroleum products decline, the length of time to phase out the subsidies must be reduced accordingly.

Table 2.1: Recommended Pricing Adjustments

	Year					
PRODUCTS	**Sep 2000**	**Sep 2001**	**Sep 2002**	**Sep 2003**	**Sep 2004**	**Sep 2005**
ADO	+20	+20	+20	+25	+15	-
IDO	+20	+20	+20	+25	+15	-
Fuel Oil	+25	+25	+25	+25	+30	-
Kerosene	+20	+25	+30	+35	+40	+50
Mogas	-	-	-	-	+15	+10
Electricity[8]	+30	+20	+28	-	-	-
Natural Gas	-	-	-	+20	+25	to opp value
LPG	-19	-	-	-	-	+25

2.28 Prior to implementing the reforms, the public should be informed about the goals of, and rationale for, the changes, as well as the continued cost of subsidies to the economy and the environment. Once these facts and the price increases are announced, it is important that prices be actually raised. After they are increased, prices must be adjusted, under an appropriately-designed formula, to reflect the market, and prorated even when prices are still subsidized, when the transition period begins. (An example of such an adjustment formula is presented in Annex 2A). Also, it is essential that the institutions involved must be able to sustain the prices efficiently and effectively during the transition. (A summary of the key recommendations relating to the reform of energy prices is presented in Chapter 6).

[8] The actual increase in the price of electricity should be based on ADB's recommendation as provided in their recent Power Sector Program Loan; but in any event should not be less than the increases proposed in Table 2.1. The Bank-proposed increases for electricity are only the minimum needed to eliminate the distortion relative to the prices of competing fuels in the residential, commercial and industrial sectors, and thus they do not take into account electricity's own cross-subsidies, and the level of tariff needed for cost recovery of the power sector.

CHAPTER 3: PERTAMINA'S ROLE AND FUNCTIONS

3.1 After pricing, the second issue that has a profound impact on the hydrocarbon sector is the problematic role and functions of Pertamina, the State oil, gas and geothermal company. Depending on the exact cost of Pertamina's inefficiencies, these effects could even be more profound than those due to subsidized pricing. Key concerns are that: (a) Pertamina's direct operation and role in the exploration and production of its own share of oil and gas basins is not efficient; (b) Pertamina acts as the Government's sole agent in supervising the activities of the private companies operating in the upstream—this creates an inherent conflict of interest, since Pertamina competes with the companies it supervises—and this role focuses more on control than on gaining added value for the Government, consequently contributing to delays and significant inefficiencies; and (c) Pertamina enjoys a virtual monopoly over downstream activities—since it controls the entire one million barrel per day domestic fuels market—and there are significant inefficiencies in the refining subsector in particular. Consequently, there is a need to redefine the current relationship between Pertamina, the State and private companies, and to fundamentally reform the structure of Pertamina, through a program of functional separation, full and legally binding corporatization, partial privatization and asset divestiture.

A. Generic Performance Issues

3.2 There is no doubt that the causes of some of Pertamina's inefficiencies lie outside of Pertamina's direct control, in particular, as is discussed in Chapter 5 and Annex 5A, those which stem from an outdated legislative framework; one that allows the Government to interfere with Pertamina's operations in a way that inhibits efficient performance, and defines a role for Pertamina that is not consistent with international best practice. Further, the manner in which Pertamina earns its revenue plays a significant part in providing disincentives towards a more efficient operation: it retains 5% of the Government's share of income from upstream activities (excluding its own upstream activities), which after taxes (60%) translates into 2% (typically, this accounts for at least half of Pertamina's profits). The company earns the other half by charging a per barrel service fee for all products refined and marketed in the country.

3.3 On the other hand, notwithstanding such factors outside Pertamina's direct control, taking a benchmarking approach, Pertamina's performance cannot be considered to come close to matching comparable peers (such as Malaysia's Petronas or Argentina's YPF).[1] Two recently-completed reports on Pertamina have focused on quantifying the internal inefficiencies responsible for such below-average industry performance, as well as identifying the conflicts of interest inherent in Pertamina's current role. Consequently, these reports recommend the need to change the company's operational practices, organization and decision-making processes.[2] Overall, inefficiencies stem from Pertamina's vertically integrated and centrally dominated structure, procedures and decision-making processes, particularly with respect to procurement, investment planning and staffing. Like many other oil and gas companies in the Region prior to their restructuring, the company has traditionally been driven by volume targets, rather than cost efficiency, and by social obligations, rather than financial performance or returns on investment.

[1] When it comes to considering international best practice, Pertamina should also look to those better-performing state oil companies in other oil exporting countries.

[2] Boston Consulting Group's Pertamina Restructuring Report, and PriceWaterhouseCooper's Special Audit Report of Pertamina.

3.4 There are a number of generic issues affecting Pertamina's operations as a whole, both in the upstream and the downstream. One such area relates to procurement, which is governed by Keppres (Presidential Decree) 16/1994. Pertamina's conglomerate covers a wide range of purchases—from equipment and materials to crude oil and resale material. Many of the high-price items (representing over half of procurement) are procured centrally rather than at the business-unit level, and the average time required is sometimes over 10 months. Another inefficiency stems from resource allocation, which occurs without any rigorous analytical work such as analysis of economic and financial rates of return. The capital budgeting process is lengthy, and project evaluation is inconsistent. Also, there is a lack of demand planning and forecasting, supply planning, and product inventory management. Overall, inefficiencies attributable to current procurement and resource allocation procedures have been estimated by the Special Audit report to be about US$2 billion (for a two-year period), 80% of which are rooted in operations at Pertamina's headquarters.

B. Upstream Performance Issues

Inefficiencies in Exploration and Production

3.5 Pertamina has a concession from the Government for exploration and production, and according to the Restructuring report (footnote 2), both are carried out inefficiently. With regard to exploration activities, finding costs are relatively high, and oil reserves are declining. With respect to production, Pertamina produces about 14.6 million barrels of oil and 275 bcf of gas annually, but with high overhead costs per barrel and low productivity. On the financial front, Pertamina's exploration and production falls in the bottom quartile of upstream industry returns. Opportunities for savings and value creation (future gains Pertamina could realize from optimizing its operation) have been estimated at US$1.3-2.0 billion, 70% of which would materialize from the exploration and production unit.

Inefficiencies and Conflicts of Interest from Pertamina's PSC Management Role

3.6 Inefficiencies also stem from Pertamina's supervisory role vis-à-vis production sharing contractors, where, as the Government's agent, Pertamina has a statutory monopoly over all exploration, and (rather than the Government) basically regulates the private sector with respect to adherence to laws and regulations.[3] In fact, no significant direct interaction exists between the Government and the production sharing contractors. Rather, Pertamina maintains the links through a unit within its organization—the Foreign Contractors Management Body (BPPKA). This unit has considerable discretionary power to accept or reject a wide range of activities, transactions and business requests covering (a) annual work programs and budgets (WPB), (b) development plans (POD), (c) authorizations for expenditures (AFE), (d) tender and procurement of materials and services, and (e) audits of contractors' personnel policies. Along with cumbersome procurement regulations under Keppres 16 (para. 3.4), this role creates long approval times for WPB, POD, and AFE (sometimes up to one year), as well as overlaps between BPPKA and Pertamina in implementing regulations.

[3] The following chapter (Chapter 4), outlines some of the problems relating specifically to the fiscal (and non-financial) *terms* of the production sharing contracts (PSCs), rather than problems with Pertamina's *role* with respect to the PSCs.

3.7 BPPKA being within Pertamina creates an inherent conflict of interest for Pertamina in its upstream activities. Pertamina engages in exploration, development and production, at the same time as the company, through BPPKA, grants new exploration areas to the private sector. In some countries, such arrangements have allowed state oil companies to hold prospective areas (often the better ones) but not carry out the exploration and development, while preventing the private sector from doing so.

3.8 According to the Restructuring report, redefining Pertamina's management/supervisory role in this respect is estimated to net a benefit of about US$25 billion on a present-value basis over a five year period for upstream activities (which are estimated to have a value of US$85 billion), 80% of which would accrue to the Government. Pertamina/BPPKA could save this US$25 billion by (a) introducing faster approval processes, shorter discovery/production cycles and increased production rates (US$6 billion), (b) improving industry-wide performance through sharing facilities/equipment, lowering costs and adopting new tenders/procurement processes (US$16 billion), and (c) increasing recoverable reserves (US$3 billion).

C. Downstream Performance Issues

3.9 Inefficiencies accrue from Pertamina's downstream activities as well. Pertamina holds a monopoly over the refining, transportation, distribution and marketing of about one million barrels per day of petroleum product. Given such a large market, a system that lacks diverse ownership is not efficient. Further, as with the upstream activities (para. 3.3), the current service fee arrangement–under which Pertamina is paid a fixed amount per barrel of crude processed and product marketed—promotes neither efficiency nor reliability.

Overall Principles of Downstream Liberalization

3.10 Indonesia has a domestic petroleum product end-use market of 40-45 million tons a year. This is large by any standard and should be attractive to international, regional and local investors if the right framework is put in place. It is possible for Indonesia to develop a reliable, competitive and comprehensive retail system like that enjoyed in many developed countries, and this should be the aim.

3.11 To achieve this, there will need to be a number of important changes to make competition realistic and vibrant. Pertamina's *de facto* monopoly on shipping and transporting needs to move to an arm's length competitive basis where there is a choice of shippers and transporters. The monopolistic supply arrangements will need to be separated from the proposed Pertamina marketing subsidiary, so that facilities which are in effect a natural monopoly, such as harbors and jetties, harborside storage and related pipelines and inland tanks attached to these pipelines, all allow non-discriminatory open access to any participant in the domestic market. Also, refineries must supply all marketers on an equal basis, and there must be no "tied" arrangements for the supply of crude or products. The new marketing companies should mainly work on a franchise basis, so that retailers can from time to time change to supplying another marketer's product, or can sell "no name" product. In essence, to entice them to become investors, all marketers must be assured that they will have fair and non-discriminatory access to product. It is the role of the regulator to ensure this equal access and the fairness of the prices relating to it. Finally, there will need to be updated petroleum product specifications in line with international standards, and independent means to verify them. Accurate dispensing pumps will be necessary.

Marketing and Retailing

3.12 Pertamina owns 95% of the 3100 service stations, and the majority of these should be sold off competitively so that Pertamina itself becomes one of a number of important petroleum marketers. The key to success in the retail sector will be for the sale of assets to be done with the primary objective being the development of competition. Each large community will need multiple owners of service stations, and the opportunities for collusion or local dominance should be minimized. Competition policy will also need to ensure that acquisition is not a means for a marketer to develop a dominant role.

Refining

3.13 The refinery sector should have less direct impact on the customer but is an area where the needed changes are technical and managerial. In the past the losses made by the refineries have been absorbed into Pertamina's accounts. What is needed is to allow the refineries to buy whatever crude they want, locally or internationally, but at full price, with no subsidies. Then the profits and losses will become transparent. To facilitate this, each refinery needs to publish its accounts separately. The refineries also need major upgrading to make them produce a product slate that better meets Indonesia's needs, and one that meets international specifications. This will need substantial financing. As part of this, most of the refineries will probably need to be sold, or find joint venture partners, again with the objective of achieving strong competition.

Small Markets

3.14 Parts of Indonesia are not ready for full-scale liberalization, the markets are small and dispersed, and the fragmentation that comes from competition could lead to significantly higher costs unless active measures are taken to offset the inefficiencies. In particular, small markets face a problem of high shipping costs because of the small vessels that are needed, and the solution is to encourage (and if necessary, enforce) aggregation of procurement among the marketers, for each market where this is an issue. Small markets may also show little signs of competition, and the role and power of the regulator are important to keep this under control.

D. The Way Forward: The Need to Reform Pertamina

3.15 The current Report has not re-evaluated Pertamina's internal inefficiencies or internal organization, because the two reports discussed above (para. 3.3) have analyzed these extensively.[4] However, in part due to the terms of reference of those studies, those earlier reports mainly assessed options for implementing changes to the organization "as is". But given the extent of Pertamina's inefficiencies, conflicts of interest, and monopolistic status, stemming the current extremely costly waste of resources will require the Government and Pertamina to go

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[4] This Study has not analyzed in detail the root causes of these inefficiencies; for example, to what quantifiable extent they stem from Pertamina's legal mandates and the Government's undue interventions, as opposed to shortcomings in Pertamina's internal business procedures and structure. This Report's findings are based on an evaluation of the analyses contained in the two previous reports, as well as the Bank's own assessment, all of which clearly indicate that Pertamina's performance is below the industry average. The Bank's dialogue with Pertamina during the course of this Study was not adequate, in part because Pertamina did not support the Bank's recommendations relating to its de-monopolization. Notwithstanding that some of the Bank's findings would have benefited from more in-depth interviews with Pertamina, the general thrust of the Bank's conclusions relating to the role and functions of Pertamina, and to the appropriateness of the PSC model and terms, would not have changed as a result.

well beyond just making internal organizational re-arrangements and procedural improvements. Consequently, the Government needs to consider implementing major changes and reforms, such as corporatization, divestiture and privatization of Pertamina. Moreover, the time frame for implementing any changes must be accelerated.

3.16 Pertamina's conflicts of interest could be entirely eliminated if the Government, rather than Pertamina, were the contracting party to the PSCs, possibly though an independent agency. Pertamina would then participate in upstream activities as a partner with the private sector companies, subject to the same fiscal and non-financial rules (as apply to private companies). At present, the private sector is dissatisfied with the situation where approval for development plans, environmental proposals, etc., is granted by an entity that stands to benefit from these activities. Such arrangements have been changed in many countries, making the Government the regulator of the industry and placing the State oil company on an equal footing with the private sector. Bank experience in these countries has shown that such changes have improved performance; similarly, Pertamina would as a consequence have stronger incentives to be more efficient.

3.17 Therefore, the option of removing BPPKA from Pertamina and locating it under the Ministry of Mines and Energy (MME), possibly within MIGAS, or in an independent oil and gas agency, should be evaluated thoroughly and soon. However, it should be noted that, if this role were to be undertaken by MME, the administrative apparatus of the Ministry would require substantial strengthening, both in terms of its procedures and capacity, to avoid administrative bottlenecks.

3.18 Downstream operations should be liberalized (paras 3.10-3.14) and the operational inefficiencies of the refineries must be substantially improved. At present, substantial quantities of BBM products are imported, and Pertamina has difficulty accessing capital. Thus, it is vital to deregulate the downstream market. However, it is important to recognize that simply deregulating the refining, terminals, import, storage, transport and marketing subsectors, in order to allow open access, is not by itself sufficient to ensure new entrants, and the subsequent advent of competition with its associated efficiency improvements. An active program to divest much of Pertamina's downstream assets will be required before competition in the domestic petroleum market can become effective.

3.19 In summary, both with respect to upstream and downstream activities, the structure of Pertamina needs to be fundamentally reformed, with many of its activities separated out or divested, and major changes are required to improve Pertamina's operations so that the company resembles other international industry players. Such reforms will mean a major change of roles, both for the Government and for Pertamina. For the Government it means the development of a stronger regulatory role, for Pertamina it means a change from being the sole supplier to being one of a number of entities competing in both the upstream and the downstream. The specific role of Pertamina has to be redefined and it needs to be helped to continue to play a key role in Indonesian society. This includes helping Pertamina to improve the efficiency of its remaining operations, and for it to be able to compete effectively as an important competitor among many others. Specific recommendations in this regard are presented in Chapter 6.

CHAPTER 4: PRODUCTION SHARING CONTRACTS (PSCs)

4.1 Over 90% of Indonesia's oil and gas is produced by the private sector, mostly major international oil and gas companies, and virtually all are governed by production sharing contracts (PSCs). One issue is whether the PSCs between the Government and private oil companies are appropriate, both with respect to the type of the contract and their actual provisions. With respect to the type of contract, the PSC, which is the most prevalent "Co-operation Agreement" between the Government (i.e., Pertamina) and private oil companies, is a tried and tested vehicle for upstream investment that can deliver most of the Government's objectives effectively. And in reality, the same Government objectives and economic outcomes can be achieved with either the PSC model (primarily pioneered by Indonesia), or the principal alternative (which is a fiscal-based regime where the Government looks to royalties and taxes as the means of taking the national share of the profits), or some combination of the two. Hence, we consider the basic principle of the PSC to be appropriate and should be retained. It is the substance of the fiscal terms that matter. Both structures can be conducive to efficient regulation of the sector and Government revenue collection, provided these functions are properly allocated.

A. Objectives of the PSCs

4.2 The Government's overall objective in the upstream, and thus from the PSC model, should be to ensure the development and extraction of the hydrocarbon resources to maximize the contribution of the sector to the national economy and to maximize the generation of revenue. Specific objectives should include:

a) encouraging a high rate of upstream investment by the private sector, particularly now that worldwide investment levels are being curtailed and capital inflows into Indonesia are badly needed for oil and gas;

b) developing an optimum fiscal regime such that incentives to explore for and develop hydrocarbons are retained for fields with low profitability, but ensuring that the State is paid a progressively increasing share of life-of-field profits once the private investor has earned a reasonable return on investment (in particular, to retain investment incentives at low oil prices, while ensuring the State is paid a high share of profits should oil prices rise again to higher levels); and

c) handling oil and gas operations efficiently and transparently, including ensuring compliance with good oil field practices and acceptable environmental standards, requiring investors to undertake national personnel training programs, and ensuring active acreage management through work and expenditure obligations and phased relinquishments.

4.3 On the other hand, investor objectives are to obtain a reasonable return on their investment, to see stability in the investment environment, and to experience transparency and objectivity in policy administration.

B. Overall Issue with PSC Provisions

4.4 Since the generic PSC model has been in existence for more than 30 years, it has been varied in light of changing circumstances, and, as a result, various provisions have been added-on to the original structure to keep the terms competitive. Therefore, the total economic provisions of the two main existing PSC models (Standard and Frontier) have become complex and in some areas contradicting. However, as stated, the basic principle of the PSC—that the contractor supplies the risk capital and is compensated from a share of future cash flow (if any)—is appropriate and should be retained. The main issue however is that some provisions of the fiscal regime are not sufficiently progressive, particularly under an adverse oil industry environment. Under the current regime, generally the State share of profit oil is just as high for less profitable ventures when oil prices are low as it is for highly profitable ventures when oil prices are high. This feature causes strong disincentives for investment at low-oil prices. Prevailing fiscal-sharing terms were largely developed, like in many other countries, for a higher oil price environment. Under a low oil price, the investors' expected returns are, in many cases, below their "hurdle rates" of return. The State share of production/profits should be reduced for low-oil price conditions to boost investment but need not be reduced for high-oil price conditions.

4.5 If the terms of the PSCs are not changed and oil prices become low again (as is expected), then the investment levels will likely fall. Consequently, certain features of the PSCs require some redesigning, with a view to achieving higher total investment by the private sector and higher overall State revenues in the medium and long term.

C. Fiscal and Non-Fiscal Terms: Problems and Alternatives[1]

First Tranche Petroleum

4.6 Under the First Tranche Petroleum (FTP) provision, a certain percentage (15%-20%) of the volume of production is taken before operating costs are recovered. This amounts to approximately a 12%-16% gross royalty (depending on the type of contract and price of oil), thus reducing the effective price of the contractor's crude oil profit. This type and level of effective royalty imposes a disproportionately high levy on high-cost fields and can deter investment, particularly when oil prices are low. In fact, in high-cost fields and under a low-oil price scenario, the Government's share of the FTP on its own could absorb more than 100% of the profit. Therefore, in the case of new PSCs, there is a strong case for reducing the rate of FTP or the proportion accruing to Pertamina under standard contract. Although the rate for gas is lower, given the difficulties facing Indonesian traditional export markets for gas, as well as the infrastructure costs associated with supplying local markets, a reduction in the rate for gas may also be in order.

Domestic Supply Obligation

4.7 Another regressive element is the low price (15% of the international price under the Standard and 25% under the Frontier contracts) paid to the contractors for their domestic oil supply obligation (up to 25% of their production). Such a provision at such a low price is highly unusual. The contractors should receive the world price for any supply to the domestic market. If Indonesia's domestic oil refineries and marketing industry were liberalized, this provision would be unnecessary.

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[1] An analysis of the *non*-financial provisions of the current Indonesian model PSCs has also been carried out in this Report (Annex 4A) with respect to procedures for allocating new petroleum rights, responsibilities, scope, terms, exclusion of areas, work program and expenditures, rights and obligations, cost recovery, natural gas, valuation of crude, title to oil and equipment, books and accounts, processing of products and participation.

Investment Credit

4.8 The investment credit currently applies at radically different rates to oil and gas production under the Standard contract for the tertiary and pre-tertiary reservoirs (i.e., about 16% for capital costs associated with oil production from tertiary reservoirs versus about 102% for capital costs associated with oil and gas production from pre-tertiary reservoirs). Further, it does not apply at all under the Frontier PSC. Considerations should be given to extend the scope to all areas and the rate and mechanism applicable should be reconsidered in the light of the need to enhance attractiveness of the Indonesian fiscal regime.

State Profit Share

4.9 The State profit oil/gas share increases are linked to a complex range of proxies for field profitability, such as annual rate of production, whether the field is pre-tertiary or tertiary, it is Frontier or not, and whether the development concerns natural gas or oil. While all these parameters are valid indicators, they only provide a rough proxy for field profitability. A preferable and less complex way would be to link the State profit oil/gas share directly to a measure of achieved cash flow or, even better, achieved discounted cash flow (DCF) profitability. Currently, the profit oil/gas sharing rates are not linked to changes in the key determinant of the profitability, namely, oil and gas prices. One attractive feature of changing from current complex parameters for profitability to that of DCF-based profitability is that it would allow the numerous existing types of contracts to be collapsed into one. Thus, there is a strong case for redesigning the PSC terms to create a direct link between the State profit share and achieved field profitability.

Investor Returns

4.10 An analysis of investor returns under Indonesian and comparator-regime countries (at oil and gas prices of US$13/bbl and US$2.50/mmbtu) shows that the Indonesian oil regimes take a relatively large proportion of discounted net revenues at low prices; both absolutely and relatively to other countries. While the other regimes increase State-take from 50%-55% to 65%-70% of discounted net revenue, as the oil price increases from US$13/bbl to US$23/bbl, the Indonesian regimes take a virtually unchanged proportion (with major disincentives to development at low prices an inevitable consequence). Although the situation with regard to gas is more adequate—as a result of the absence of a domestic gas supply obligation and of Pertamina's lower share of both FTP and profit oil/gas—the difficulty in the market situation for new gas developments needs to be taken into account.

D. Required Action

4.11 The economic use of the country's petroleum resources and their financial benefits to the State are governed by production sharing contracts. Therefore, the contracts need to be equitable to both the State and private investors, and include provisions that can be adapted to the changing environment in the oil industry as well as to changes in Indonesia and the Region due to the recent crisis. Taking into account the above elements and the current effective tax rate on any investor's net project receipts, the overall fiscal burden on the investor for the upstream sector in Indonesia may need to be reconsidered with a view to possible changes to improve its attractiveness in the areas discussed above. Without some of these changes, the State's benefits and private sector investment will most likely be reduced. As countries compete for reduced exploration and development budgets, and the fiscal regimes will change in response to lower oil and gas prices, Indonesia should position itself so as to remain competitive even after other countries improve their terms. Therefore, this is an opportune time for Indonesia to review the terms of its upstream oil and gas regimes and adjust them accordingly. (Specific recommendations in this regard are given in Chapter 6).

CHAPTER 5: LEGISLATIVE FRAMEWORK

5.1 Many of the problems discussed in the previous Chapters stem from, and are reinforced by, an inadequate legislative framework. The existing laws and regulations (the primary legislation was passed in 1971) sanction Pertamina's (and PGN's) sectoral dominance and allow the Government to interfere with the sector in ways that inhibit efficient sector operation and private sector participation. The Government's social obligations and the sector's commercial functions are treated interchangeably. Further, because the regulations that supported the law were issued almost 23 years later (1994), the way the law was applied kept changing and new provisions were added-on. Consequently, the existing legal framework is fragmented, and definitions are vague, inconsistent and sometimes contradictory. Thus, Indonesia's hydrocarbon sector needs a new legislative framework both appropriate and conducive to the operation of a modern economy; one that is competitively-based, market-oriented, clear, and transparent. Without a solid legislative framework, the capacity of the sector to grow, which is dependent on increased private investment, will be substantially dampened.

5.2 Cognizant of these problems, the Government has made significant progress in this area, by drafting a new law for the Mining of Oil and Natural Gas in Indonesia.[1] This was submitted to Parliament in mid-1999. As it stood, the draft law allowed reasonable advancement toward an unbundled sector operation, and it provided a relatively sound basis for achieving reform at the upstream section of the industry. Nevertheless, there were still a number of significant concerns regarding this final draft, which were conveyed by the Bank to the Government. The Bank also presented the Government with a comprehensive set of recommendations on the essential elements of the regulations required to support and implement the law. It was thought that the "package" as a whole (the draft law, regulations and elucidation) would have provided Indonesia with a reasonably sound legal framework. But the draft law did not pass. Consequently, now would be an appropriate time to review the proposed law with a view to improve it further, in order to ensure that the new legislative framework is consistent with the Government's wider vision and objectives for the sector, as well as with international best practice.

A. International Best Practice for an Oil and Gas Legislative Framework

Objectives and Characteristics of a Legislative Framework

5.3 The main objective of a legislative framework for the oil and gas sector is to provide the basic context for and the rules governing petroleum operations, to regulate them, and to define the principal administrative, economic and fiscal guidelines for investment activity in the sector. The framework should create an environment within which the desired sectoral vision and objectives not only can be achieved, but will be actively promoted.

5.4 The key characteristics of this framework should be to provide clarity and transparency to all stakeholders in the sector, both public and private. Clarity of purpose is more likely to be achieved if the law includes from the outset a simple declaration of the law's objectives and intended scope, together with the overall vision and intended policy objectives for the sector (Chapter 1). While the law should contain broad-based principles to provide the basic context for

[1] At the Government's request, the Bank commented on successive versions of the draft oil and gas law between September 1998, and March 1999. The Bank's final set of comments, as well as the recommendations on best practice regulations, are included in this Report as Annex 5B and Annex 5C.

petroleum operations in the country, it should also be concise and accurate (and supported by a set of comprehensive regulations) so as to provide a clear legal context within which to conduct the business of petroleum. Moreover, the law needs to map out the eventual and transitional structure of the sector, and how the key policy objectives, such as the introduction of competition, will be achieved through the law.

Essential Provisions of Primary Legislation

5.5 As well as stating objectives, for best practice the law should clearly assert that petroleum resources are the exclusive property of the State, and identify the division of authority and responsibility between various government agencies. The law should also explicitly define the rights and obligations of the State, Government entities and private investors, as well as providing specific remedies to deal with breaches of the law. It is important to note, however, that it is best practice for the regulatory body (or bodies), charged with the responsibility for overseeing the execution of the regulations, to be established under primary legislation.

Upstream and Downstream Separation

5.6 Under international best practice norms, the upstream and downstream portions of the petroleum industry should be dealt with in separate laws. The upstream business is usually a special purpose, all-inclusive regime, whereas the downstream portion of the sector is one subject to normal commercial and tax laws, applicable to business in general. Unlike the upstream, the downstream sector is not strategic, hence most major countries rely on there being a large number of refiners and/or distributors who will compete with each other. As such, competition provides the primary governance mechanism for the sector, and outside of standard anti-monopoly provisions, there is little need for any special State controls.

Principles of Implementing Regulations

5.7 There should be a well-designed balance between what goes into the law(s), and what becomes part of the supporting regulations. On the one hand, focusing the law itself on broad principles will expedite its initial passage through the legislature, and reduce the risk of incurring lengthy legislative deliberations any time a minor modification or amendment is required. But on the other hand, there are limits to what regulations can achieve. Regulations flow from and are grounded in the basic legal authority of the law from which their existence derives. Accordingly, to be enforceable, the regulations and any changes to them may never be inconsistent with the scope, objectives or letter of that law. Best practice is to have distinct upstream regulations, covering the exploration and production of oil and natural gas, pipeline regulations, relating to the piped transportation of oil and gas, and downstream regulations, relating to refining and marketing activities.

B. Indonesia's Draft Oil and Gas Law

5.8 Given these best practice principles, the key concerns which the Bank conveyed to the Government regarding the draft oil and gas law were: (i) whether the law would promote the desired sectoral vision and objectives, and the lack of clarity arising from combining upstream and downstream legislation; (ii) what the transitional and future role of Pertamina would be, in particular whether competition in the downstream would be adequately promoted; (iii) how the regulatory framework would be implemented; and (iv) the absence of a number of important provisions.

Objectives of the Proposed Legislation

5.9 While the draft law's elucidation contained some language that hinted at the objectives of the new legislation, the law itself did not provide sufficient clarity of purpose. Furthermore, the law did not appear to enable actions to take the steps that would be necessary to achieve the objectives of competition and liberalization. This was particularly important with regard to the refinery and other downstream sectors. The law did not clearly map out the nature of the new sector structure, nor did it spell out how competition would be introduced into the sector. It was not indicated whether it was intended that there be any program of divestitures, and if so, what the objectives of any such divestitures would be.

The Role of Pertamina, and Competition in the Downstream

5.10 Concerns regarding clarity of objectives were of particular note in regard to the transitional and future role of Pertamina. Because the draft law provided for no explicit transfer or divestiture of Pertamina's existing downstream assets, this implied that the status quo of Pertamina's downstream monopoly would be maintained by default. The law should provide, in the context of the transitional provisions, for procedures which would cover the orderly divestiture of Pertamina's existing downstream assets in such a manner as to develop a competitive supply position. The objective would be for Pertamina to retain enough assets so that it can be a capable competitor, but that the assets which enable monopolistic behavior be moved to a separate company, and that a majority of service stations and other such assets be steadily sold over an agreed period. At the very least, the law needs to provide for the issuance of a regulation giving the regulatory body the power to force third-party access, which is the minimum step needed for downstream competition to develop, in the absence of a clear divestiture program. An additional problem was that the draft's definitions and references to marketing linked together five functions: namely, import, export, purchasing, storage, and sale, the intention apparently being to have a single license authorizing such activities. This tends to be anti-competitive; real competition develops when the authorized competitors are very different.

Implementing the Regulatory Framework

5.11 All the references made in the draft law to the supporting regulations appeared to assume that an Energy Regulatory Badan would have already been established prior to the passage of the law. At present, the Government's Power Sector Restructuring Policy states that a single Badan for the entire energy sector will be established. This would imply that the proposed electricity law needs to define the role and powers of a Badan with respect to the entire energy sector. Regulations relating to oil, gas and electricity could then be promulgated which refer back to the relevant petroleum and electricity laws. However, in any event, a decision needs to be made at a fairly early stage on how one (or perhaps more) Energy Regulatory Badan(s) are in place to implement the regulatory framework for not only the oil and gas sector, but for the power sector as well.

Absent Provisions

5.12 There were a number of issues which were not addressed in the draft law. These included provisions for: (i) dealing with the potential conflict between the proposed law and existing contracts, particularly for upstream operations; (ii) allowing the Minister to promulgate regulations on the prices of petroleum products and on any related mechanism for a transitional period; (iii) dispute resolution to be settled by International Arbitration; (iv) dealing with PGN's role, assets and operations; (v) allowing producers to distribute gas without a license; (vi) giving priority to the first use of gas for the purpose of optimal exploitation of the fields from which it is produced; and (vii) providing sufficient budget and resources to the Government/Ministry taking on the responsibilities transferred to it from Pertamina.

CHAPTER 6: KEY RECOMMENDATIONS

6.1 The Bank's key recommendations to the Government regarding the necessary reforms for the hydrocarbon sector, and the requirements for additional analytical work, are as follows.

A. Statement of Government Policy

- The Government should issue an official and comprehensive declaration of its policy for the hydrocarbon sector, comprising: its vision for the sector, the policy objectives, and the policy actions required to achieve those objectives.

B. Energy Product Prices

- The direct subsidies provided to petroleum products (Mogas, kerosene, ADO, IDO, fuel oil and LPG) should be eliminated; but gradually, within a fixed time frame of no more than five years, after which the prices should be fully deregulated. During this period, prices should be increased according to the schedule in Table 2.1, which will allow relative distortions to be removed, as well as time for appropriate mechanisms to protect the poor to be put in place.

- Prior to the implementation of the initial price hike, say in September 2000, the rationale for the pricing increase should be announced, and the public informed about: the cost of the subsidies to the economy and the environment; the impact of other distortions; as well as the measures to be introduced to protect the poor (below).

- While prices are being increased according to the proposed schedule, they should be adjusted periodically (not longer than three months) along the lines of the formula provided in Annex 2A, to reflect market conditions, and pro-rated even when prices are still subsidized.

- Any subsidies to the poor should be direct, treated outside the sector, and be a line item in the budget. Once an accurate identification of the targeted groups has been made, a cash payment vouchering system could be used as the mechanism to deliver the subsidy directly to the poor. The implementation details of such a mechanism should be investigated as soon as possible.

Future Analytical Work

- A comprehensive Gas Utilization study should be carried out during 2000 to establish the economic cost and value of gas in Indonesia, as well as the appropriate pricing policy, rational investment program and institutional arrangements needed to accelerate the development and utilization of the country's natural gas resources. Key decisions regarding the pricing structure for natural gas should be kept in abeyance until the preliminary information from this study becomes available. In the meantime, despite the fact that the price of gas is currently low, the price of gas should not be raised until the price of ADO, and other fuels for which gas can substitute, are able to be increased (as recommended in Table 2.1).

- An Integrated Energy Product Pricing study should be conducted during 2000, to: (i) address the pricing of geothermal, hydro and coal resources, and update the study on electricity tariffs, in the context of the recommended adjustments to the prices of petroleum products; (ii) review the issue of uniform pricing; and (iii) re-evaluate the entire issue of energy product taxation.

C. Role and Functions of Pertamina: Upstream and Downstream

- As soon as possible, the Government should carry out, with the help of experts, a focused assessment of the alternatives for reforming Pertamina; in particular, considering the formation of several full and legally binding subsidiaries, as well as the initiation of a major divestiture and/or partial privatization program.

- Subsequently, the Government should begin to implement the measures needed for the unbundling of Pertamina; in particular by: (i) removing BPPKA from Pertamina and locating it under MME, possibly within MIGAS; (ii) ensuring that Pertamina participates in upstream activities on an equal basis with private companies; and (iii) removing Pertamina's monopoly status from downstream activities, while improving the efficiency of refinery operations.

- Pertamina should begin to improve the performance of the existing refineries by: (i) using a crude slate that matches the refinery configuration, particularly for imported crude, and one that is based on economic analysis rather than contract; (ii) lowering operating costs, particularly energy and utility costs that are substantially higher than average; and (iii) curtailing capital investments in the existing refineries, except for upgrading projects to maximize conversion and deal with environmental issues. (Nevertheless, some existing refineries may not be worth upgrading as they are currently configured). As a transitional measure before full liberalization, Pertamina's refining businesses could be reorganized such that each refinery has separate operational and financial management (e.g., as a Persero subsidiary), with refinery performance improved by the Persero itself, through joint venture with new partners, or as a result of outright sale.

- The Government should act to attract international, regional and local investors into Indonesia's domestic petroleum market, by moving to put in place a framework that makes competition in the downstream realistic and vibrant. Such a framework should include: (i) allowing open access to facilities such as harbors, jetties and related storage and pipelines; (ii) moving Pertamina's *de facto* monopoly on shipping and transportation to an arm's length, competitive basis; (iii) liberalizing the refineries fully, with a view to eventually privatizing those which still prove to be viable; and (iv) selling off the majority of service stations. The introduction of effective competition within this framework will require an active program of substantial divestiture of Pertamina's assets in the downstream. The assignment of assets by the Government to either a restructured Pertamina, or for sale, should be made with attention both to maximizing the value of assets to the country and to maintaining effective competition in domestic petroleum product markets.[1] (Any analytical work needed in this regard, can be carried out as part of the above-recommended assessment).

- The Government should then concentrate on transforming Pertamina's remaining operations and assets into a world-class exploration and production company; one in which its upstream business has distinct operational and profit/loss responsibility and reporting, and is treated in the same manner as other upstream industry players. This reorganization could be accomplished within the framework of an integrated holding company; one which still retains some interests in refining and marketing as well.

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[1] Full-scale liberalization may not be economic in the small and dispersed island markets. In these markets, the Government should encourage (or regulate) the aggregation of procurement among the marketers and thus create economies of scale.

D. Terms of Production Sharing Contracts

- The basic principles of the model PSCs should be retained, but for new PSCs: (i) the rate of First Tranche Petroleum, or the proportion accruing to Government under the standard contract, should be reviewed with a view to reducing it, particularly for high cost fields and under conditions of low oil prices; (ii) contractors should receive the world price for any supply they provide to the domestic market in the period before the domestic market and refineries are liberalized; (iii) the investment credit should be applied more equally, extended to all areas, and the rate and mechanism applicable should be reconsidered to enhance the attractiveness of fiscal regime; and (iv) the State profit oil/gas share should be linked directly to a measure of achieved cash flow.
- Only if mutually agreed with the contractor, should the Government renegotiate the terms of existing PSCs along the lines recommended above for new PSCs.

E. Legislative Framework

- The draft oil and gas law, submitted to Parliament during 1999, should be revised to more closely provide the framework for a competitively-based, market-oriented sector operation involving less Government interference, and consistent with international industry best practice. At the same time, comprehensive supporting regulations should be issued consistent with the law(s) and with best practice. (Specific recommendations in this regard are given in Annexes 5B and 5C).
- A decision should be made before the law is passed on the nature, number and establishment mechanisms of the regulatory agencies required for the energy sector (e.g., whether there should be separate agencies for the hydrocarbon and power sectors, or whether a single agency covers the entire energy sector).
- New petroleum product specifications, allowing for the elimination of leaded gasoline, as well as new health, safety and environmental standards relating to the energy sector should be issued, consistent with international best practice.

F. Institutional Capacity

- Sector institutions should be strengthened across the board, particularly where regulatory responsibilities are increased as a result of the reforms. In particular, the relevant administrative apparatus of MME will require substantial strengthening, both in terms of its procedures and capacity, if the role of supervising and regulating PSCs is transferred to it from Pertamina.

ANNEX 1: Reserves, Production, Processing, Consumption and Revenues

A1.1 While the magnitude of Indonesia's oil and gas reserves places the country among the most well endowed in the Asia-Pacific Region, the country will soon become a net importer of petroleum products, the first member of OPEC to do so. This is because the growing energy demands of its large population (over 200 million) are not being met either by sufficient increased production of, or by substitutes for, oil, even though energy diversification has for many years been a central part of the Government's strategy for maintaining economic growth.[1] This Annex summarizes data relating to the reserves, production, processing, consumption and revenues of Indonesia's oil and gas sector.

Oil Reserves and Production

A1.2 Since commercial production of Indonesia's hydrocarbon resources began in the 1880s, 85 billion barrels of oil have been recovered.[2] By the end of 1998, oil reserves remained at 9 billion barrels, approximately half in "proven" and half in "potential" categories. The greater part of the proven reserves are located onshore in Central (and South) Sumatra, but important oil field development and production also occurs in areas off the coast of northwestern Java, East Kalimantan, and near the Natuna island group in the South China Sea (Table A1.1). Sizable, but as yet unproven, reserves may lie in the numerous, geologically complex and less accessible basins located in Eastern Indonesia (IBRD Map 30921). However, as this Report discusses (Chapter 4 and Annex 4A), further exploration and development of these areas will require the Government to develop an upstream incentive regime that is sufficient to attract the necessary private investment.

Table A1.1: Distribution of Oil Reserves

Location	Oil (Mil Bbl)		
	Proven	Potential	Total
Aceh	4.4	9.5	13.9
North Sumatra	121.3	51.5	172.8
Natuna	200.2	171.5	371.7
Central Sumatra	2,599.1	2,748.4	5,347.5
South Sumatra	330.1	117.5	447.6
West Java	651.2	471.3	1,122.5
East Java	134.5	84.2	218.7
Kalimantan	748.6	555.7	1,304.3
Sulawesi	10.2	0	10.2
Irian Jaya	67.6	15.1	82.7
Total	**4,867.2**	**4,224.7**	**9,091.9**

Source: MIGAS, January 1, 1997

A1.3 Assuming that half the potential oil reserves will become proven, and the production rate continues at the relatively constant level of the past 7-8 years, about 1.5 million barrels per day for oil and condensate combined (500,000-700,000 bpd of which is exported),[3] the reserves will be depleted in about 12 years if there are no additional discoveries. Should domestic consumption increase by only 5% a year (after the year 2002), Indonesia will need to import its entire domestic requirements by 2008, with an estimated present value of US$11-13 billion per year.

1 Table 1.1 in the main text provides an overall energy supply and demand balance for the country.

2 Indonesia's crude oil varies widely in quality, with most streams having gravities in the 28° to 37° API range. The two main export crudes are Sumatra Light, or Minas, with a 35° API, and the heavier 22° API Duri crude.

3 Indonesia's OPEC production quota in May 1999 was reduced to 1.2 million bbl/day.

Petroleum Product Refining and Consumption

A1.4 Overall, Indonesia still relies on oil to supply about 60% of its energy needs. Although growth in oil consumption averaged 5.7% per annum during the ten years prior to the crisis, the contribution of oil to meeting primary energy demand has been declining; in 1990 its share was about 68%. On a regional basis, Java currently uses about 61% of total fuels, followed by Sumatra 20%, Kalimantan 8%, Sulawesi 6%, and other regions 6%.

A1.5 About 30% of the refined petroleum products consumed domestically are imported, and the balance is produced at Indonesia's nine refineries (IBRD Map 30922).[4] These have a combined capacity of about 1 million bpd, slightly in excess of the current consumption of about 900,000 bpd. About 20% of the crude processed in the refineries is imported. (In 1997, imports of crude were 170,000 bpd. In addition, during that year, 260,000 bpd of refined products were imported, and 200,000 bpd exported). Five refined petroleum products, classified as "BBM fuels", represent over 90% of domestic fuel consumption.[5] These are: (i) automotive high speed diesel oil (called "Solar", or ADO), which accounts for about 43% of total consumption; (ii) premium or motor gasoline ("Mogas"), accounting for 21%, and predominantly used by private car owners;[6] (iii) kerosene, for 20%; (iv) fuel oil, for 10%, used primarily in industry and for power generation; and (v) industrial diesel oil (IDO), for 3%.

A1.6 About 55% of ADO is used for transport (i.e., mainly trucks, buses and diesel-engined cars), with the balance being used in industry (30%) and for power generation. In an international context, the widespread use of ADO rather than IDO in the industrial sector is unusual. And similarly, although official statistics indicate that almost 99% of kerosene is used by households, there is overwhelming evidence that it is also widely used to substitute for other products in the non-household sectors, possibly up to as much as 30% of the total quantity. In many cases it is clearly being used to dilute other petroleum products.[7]

A1.7 Table A1.2 provides the Bank's forecast of the future demand for petroleum products, assuming that current price subsidies remain in force.[8] However, given the prevailing political and economic climate, forecasting future energy use in Indonesia is a difficult task.

Table A1.2: Projected Demand for Petroleum Products (Mil bbls)

PRODUCTS	1999	2000	2001	2002	2003	2004	2005	2006	2007
Mogas	70.6	73.2	76.7	81.3	86.1	91.3	96.8	102.6	108.8
Kerosene	65.3	67.6	70.9	75.1	79.7	84.4	89.5	94.9	100.6
ADO	126.6	131.2	137.5	145.7	154.5	163.7	173.6	184.0	195.0
IDO	8.2	8.5	8.9	9.4	10.0	10.6	11.2	11.9	12.6
Fuel Oil	33.7	34.9	36.5	38.7	41.1	43.5	46.1	48.9	51.8

Source: World Bank – Existing Price Subsidies Scenario (Annex 2B)

4 Refining operations are discussed in more detail in Chapter 3 and Annex 3 of this Report.

5 BBM (Bahan Bakar Minyak) fuels are those subject to direct price regulation. Of the seven BBM products extant prior to the crisis, price controls were removed from two of them (the aviation fuels, Avgas and Avtur) in February 1999.

6 Regulated (i.e., BBM) grades of motor gasoline include: 94 RON premium with 0.3 gm lead; 88 RON regular with 0.3 gm lead; and Blue Gasoline for 2 stroke engines. In addition, smaller amounts of unregulated motor gasoline are also utilized: Premix (a mixture of unleaded and MTBE); Super TT (lead free, high octane); and 95 RON super gasoline with 0.005 gm lead.

7 Consumption of the various petroleum products is considered in more detail in Annex 2A of this Report.

8 Other demand forecast scenarios, whereby pricing subsidies are gradually phased out, are presented in Annex 2B. These scenarios are used to examine the benefits of removing the subsidies in Annex 2A.

Natural Gas Reserves, Production and Consumption

A1.8 Indonesia's reserves of natural gas are the highest (along with Malaysia) in the Asia-Pacific Region (representing about 20% of the Region's gas reserves), and Indonesia is the world's largest exporter of liquefied natural gas (LNG). Currently, natural gas reserves amount to about 138 trillion cubic feet (tcf), with approximately half in the proven and half in the potential categories, and 70% of which are located offshore. Existing LNG export trains are at the onshore Arun field in North Sumatra, and at Bontang in Eastern Kalimantan, supplied from the offshore Badak field (IBRD Map 30922). Substantial reserves exist at the Natuna and West Natuna fields, in Irian Jaya, in Sulawesi and also in South Sumatra (Table A1.3). Again, assuming that half the potential reserves will be proven, at the current rate of production, Indonesia's gas reserves will be depleted in about 30 years.

Table A1.3: Distribution of Natural Gas Reserves

Location	Natural Gas (tscf)		
	Proven	Potential	Total
Aceh	5.7	1.2	6.9
North Sumatra	1.3	6.0	7.3
Natuna	29.7	19.1	48.8
Central Sumatra	0.5	0.3	0.8
South Sumatra	4.5	9.6	14.1
West Java	4.8	1.8	6.6
East Java	3.2	2.8	6.0
Kalimantan	25.5	20.1	45.6
Sulawesi	0.6	0.2	0.8
Irian Jaya	0.2	0.5	0.7
Total	**76.0**	**61.6**	**137.6**

Source: MIGAS, January 1, 1997

A1.9 Apart from the country's major natural gas fields, which are tagged for the LNG (or transmission pipeline)[9] export market, Indonesia also has considerable reserves of non-exportable gas in smaller fields that can only be developed for domestic consumption. Nevertheless, Indonesia's existing domestic consumption of natural gas, is among the Region's lowest (about 630 mmcfd), and the domestic gas industry and associated infrastructure is underdeveloped. Currently, natural gas supplies just over one fifth of Indonesia's domestic energy needs, and during the decade preceding the crisis, consumption increased by an average of 8.7% per annum. Over half the natural gas is used by the industrial sector, primarily as feedstock for chemical/petrochemical plants, and about 40% is used for power generation.

Fiscal Significance of the Sector

A1.10 Overall, the sector typically generates about US$5.5 billion a year through annual production of about 500 million barrels of crude oil and condensate, and 3.2 tcf of natural gas, both for domestic consumption and for export. This revenue represents 27% of the Government's total domestic revenue; corresponding to about 5% of GDP. Oil and gas exports are Indonesia's largest foreign currency earners, in recent years having accounted for up to 35% of total export earnings (although this dropped to 25% in 1998 as a result of the crisis). Nevertheless, the outstanding growth that the Indonesian economy experienced in the two decades prior to the crisis, and the consequent expansion of exports from other sectors, has meant that the relative share of export revenue from the oil and gas sector has been on the decline. This contribution from oil and gas export revenues is down from a peak of more than 80% in the early 1980s when the hydrocarbon sector dominated external trade.

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[9] Singapore companies have preliminary agreements with the Indonesian Government for the supply of piped gas from fields in West Natuna and South Sumatra.

ANNEX 2A: Energy Product Pricing

A2A.1 The purpose of this Annex is to review the pricing of energy products. It includes a discussion of: (a) what constitutes an appropriate framework for economic and efficiency pricing; (b) current pricing issues in Indonesia and how present structures differ from efficiency pricing; (c) the costs of current pricing distortions to the country and the adjustments needed; (d) major impacts of removing the subsidies; and (e) a strategy to implement the appropriate pricing policy.

A2A.2 A rational pricing policy should be the cornerstone of the sector strategy. It must be designed to meet the country's growing energy needs in an economically, socially and environmentally acceptable manner. Lacking this, efficiency gains through restructuring and rational investment planning would be difficult if not impossible to achieve. The wrong pricing policy in the energy sector would lead to huge economic losses because the investments associated with oil, gas, power, coal and geothermal are usually very large and require long lead times; also, disruption of the energy supply could be very costly. This is particularly important for Indonesia, given the critical role energy plays in the economy.

A2A.3 However, depending on the country, pricing policies differ. In a competitive market, where private investors are active, import and exports are open, and the areas with natural monopolies and market failures are appropriately regulated, the right policy sustains the conditions for competition and free market pricing. Conversely, in a publicly-dominated energy sector, where free entry and exit into the market are constrained and utilities are mostly vertically integrated, pricing policies need to be set administratively in a way that reflects the opportunity costs of energy supply.

A2A.4 It is hoped that Indonesia can move rapidly towards providing the right environment for increased private sector participation, corporatizing and privatizing its energy enterprises, adopting a policy that reduces government intervention in energy affairs, and eventually liberalizing the sector including the prices of energy products. In the meantime, Indonesia needs pricing policies that will maximize the country's foreign exchange earnings and meet its energy requirements in a least-cost manner. Also, these policies must address social and environmental impacts as well as practical considerations such as the frequency of price adjustments. Moreover, changes to prices must be easily administered and consistent with existing contractual agreements.

Framework for Economic Pricing

Economic Pricing

A2A.5 The framework for pricing energy products uses the opportunity cost of supply as the basis for making economic choices among different sources of energy for different end-users. The definition of opportunity cost of supply (i.e., the economic cost of supply) differs for tradable and non-tradable fuels. Since oil and oil products are easily traded in international markets, their opportunity costs are assumed to be their border parity prices (i.e., export or import parity prices). However, because products such as natural gas, hydro and geothermal are not widely traded in international markets, their opportunity costs are assessed indirectly; that is, if the available supply exceeds present and predicted demand by a vast margin, the opportunity cost is assumed to be equal to the efficient cost of producing them, and would therefore be based on the long-run marginal cost of supply. But, if energy resources are limited, the opportunity cost would have to include (besides production costs), a depletion premium which is usually the discounted cost of the next alternative fuel as a source of supply that would be needed to replace the increase in current consumption. In Indonesia, the opportunity cost of natural gas would have to be based on the latter, because the country's gas reserves (proven and half of the probable) will not last more than about 30 years, based on current domestic consumption (which is relatively very low) and LNG exports.

A2A.6 The above is the Bank's accepted framework for economic pricing of energy products and is assumed to provide the reference point to reflect nationally optimal investment and energy-use decisions.

Efficiency Pricing

A2A.7 The application of the above economic framework, however, seldom results in a practical pricing structure for end-users, because there are always other price distortions in the economy, and governments often have other policy objectives, such as financial/fiscal and social. A practical pricing structure is usually achieved through "efficiency pricing", which allows policy makers to meet their other objectives, normally through a two-stage process. In the first, the structure and level of pricing is formulated to match the opportunity cost of supply of individual energy forms; hence defining a "floor" for the economic cost. In the second, the efficiency prices are adjusted to reflect their "netback" value,[1] which in effect is the allocation of economic rent[2] to meet all other objectives to the extent feasible. The netback value thus forms the "ceiling" for the economic cost. Two critical principles in the second stage are (a) adjustments should not change the relative ranking (structure) of the various fuels with regard to their opportunity costs; and (b) adjustments should take into account the price elasticity of the fuels.

Integrated Approach

A2A.8 Because many opportunities exist for fuel substitution (directly and indirectly), the price of one fuel affects the others. Thus, ideally, an analysis of energy prices must be conducted in an integrated and comprehensive manner, embracing all major energy products. However, this Report only reviews the pricing structure of oil, and, to a lesser extent, gas and electricity, and does not consider hydro, coal and geothermal pricing. Further, the issues related to traditional fuels are not be reviewed here, nor are those of "uniform" pricing, which is currently practiced in Indonesia and usually leads to an uneconomic use of resources. Such a study must be carried out soon to provide a complete framework for pricing policy. Accordingly, the Bank recommends to the Government that an Integrated Energy Products Pricing study be conducted in 2000, which would also address the issue of fuel taxation (para. A2A.27). However, the carrying out of such a study should not delay the implementation of the price increases for petroleum products and electricity which are recommended in this Report (Table A2A.14).

Pricing of Oil Products

A2A.9 Three issues arise with the domestic price of petroleum products in Indonesia. First, prices at aggregate level are significantly below their opportunity cost of supply and thus heavily subsidized; in fact, the domestic price of several key products is even below their cost of production.[3] Second, at the relative level, the disparity among fuel prices is large, which distorts the pattern of consumption and results in smuggling and arbitrage, mixing of fuels, altering specifications and potentially creating safety hazards, as well as misallocation of resources (i.e., mismatched refinery configurations). Third, the system of taxation has unclear objectives.

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[1] The netback value here is defined as the maximum value a buyer is willing to pay for a fuel based on either the price of the next cheapest alternative fuel (adjusted for differences in the capital and operational costs of using it) or (for productive uses of energy) the net revenue from the sale of the final product, whichever is lower.

[2] The economic rent is the difference between the economic costs of supply and the netback value to the consumer (i.e., the sum of producers' surplus and consumers' surplus).

[3] In this Report the cost of production is assumed to be based on "efficient" costs of producing, transforming, transporting and distributing petroleum products (para. A2A.7).

Domestic Consumption

A2A.10 Indonesia consumes about 900,000 barrels of products a day, or roughly about 75% of its total crude production (although consumption declined by 4.5% from 1997-1998). Automotive diesel oil (ADO or Solar), at about 43% of the total fuel consumed, represents the highest, followed by motor gasoline and kerosene, at about 21% and 20%. Fuel oil represents about 10% of the total and the industrial diesel oil (IDO), at 2.8%, is the lowest (Table A2A.1). With regard to the sectoral use of fuels (Table A2A.2), the transport sector uses almost half the total fuel consumed, followed by the industrial and household/commercial sectors, each consuming about 20%. The power sector represents the balance.

A2A.11 Although Indonesia produces its own crude, and was ranked 8th in its production quota (1.28 million barrel per day) among the 11 OPEC members in 1998, to meet its domestic consumption, it also imports crude; some 170,000 barrel per day (bpd) in 1997. In addition, in 1997 it imported about 260,000 bpd and exported about 200,000 bpd of refined petroleum products. Table A2A.3 shows the source of fuels for domestic consumption and the export volume of refined products.

Table A2A.1: Domestic Consumption of Fuels

PRODUCTS	1997 (1)		1998 (2)		% Growth Rate
	Volume (Mill. bbl)	% of Total BBM	Volume (Mill. bbl)	% of Total BBM	97/98
Avgas	0.0465	0.02	0.0357	0.01	-23.23
Avtur	7.36	2.32	5.02	1.66	-31.79
Mogas (5)	68.23	21.52	69.12	22.81	1.3
Kerosene	62.79	19.8	63.91	21.1	1.78
ADO	137.59	43.39	123.95	40.91	-9.91
IDO	8.89	2.8	8.01	2.64	-9.9
Fuel Oil	32.17	10.15	32.94	10.87	2.39
TOTAL (6)	317.08	100%	302.99	100%	-4.44
LPG	828,900 MT	NA	839,497 MT (3)	NA	1.28
Natural Gas	633,142 MMSCF	NA	633,142 MMSCF (4)	NA	-
Electricity	64,300 GWh	NA	65,000 GWh	NA	-

(1) USEMB 98/57 (2) FOS/24 (3) Derived Value FOS/32 (4) Assumed since no data available
(5) Mogas is motor gasoline which comprises about 95% Premium, 4% Premix, and 1% TT Super.
(6) Until about February 1999, the prices of these seven products were regulated by the Government. Subsequently, aviation gasoline (Avgas) and jet fuel (Avtur) were deregulated. Although they are included in the analysis (because existing data include them), they are treated as deregulated products.

Table A2A.2: Sectoral Consumption of Fuels

PRODUCTS	1997 (million bbls, and sectoral percentage)					1998 (million bbls, and sectoral percentage)				
	Transp	Ind	Hshld	Power	TOTAL	Transp	Ind	Hshld	Power	TOTAL
Avgas	0.0465 100%	--	--	--	0.0465	0.0357 100%	--	--	--	0.0357
Avtur	7.36 100%	--	--	--	7.36	5.02 100%	--	--	--	5.02
Mogas	68.23 100%	--	--	--	68.23	69.12 100%	--	--	--	69.12
Kerosene	--	0.56 1%	62.23 99%	--	62.79	--	0.57 1%	63.34 99%	--	63.91
ADO	71.96 52.30%	40.22 29.23%	--	25.41 18.47%	137.59	68.09 54.93%	36.85 29.73%	--	19.01 15.34%	123.95
IDO	0.69 7.75%	8 90%	--	0.2 2.25%	8.89	0.68 8.49%	7.2 89.89%	--	0.13 1.62%	8.01
Fuel Oil	2.11 6.56%	18.51 57.54%	--	11.55 35.90%	32.17	3.26 9.90%	21.24 64.48%	--	8.44 25.62%	32.94
TOTAL (Percent)	150.40 47.44%	67.29 21.25%	62.23 19.59%	37.16 11.72%	317.08 100%	146.21 48.26%	65.86 21.74%	63.34 20.90%	27.58 9.10%	302.99
LPG (Met Ton)	--	248,640 30%	580,260 70%	--	828,900	--	251,800 30%	587,700 70%	--	839,500
Nat Gas (MMSCF)	--	345,795 54.62%	55,634 8.79%	231,713 36.60%	633,142	--	345,795 54.62%	55,634 8.79%	231,713 36.60%	633,142

Table A2A.3: Sources of Domestically Consumed Fuels (Refinery and Import) and Export

PRODUCTS	1997 (million bbls)				1998 (million bbls)			
	Refined Products (1)	Import	Export	Total Supply	Refined Products	Import	Export	Total Supply
Avgas	0.0445	--	0.002	0.0465	0.0357	--	--	0.0357
Avtur (2)	7.7	4.61	4.95	7.36	7.2	3.5	5.68	5.02
Mogas	68.23	--	--	68.23	66.75	2.37	--	69.12
Kerosene (2)	47.81	15	--	62.81	53.29	10.62	Neglig.	63.91
ADO	86.27	51.32	--	137.59	91.53	32.42	--	123.95
IDO	4.9	5.85	1.86	8.89	7.79	1	0.78	8.01
Fuel Oil	20.87	11.3	--	32.17	26.32	6.71	Neglig.	32.94
TOTAL BBM	235.82	88.08	6.81	317.09	252.92	56.62	6.46	302.99

(1) Includes local and imported crude
(2) Import and export quantities for Avtur (jet fuel) and kerosene may be slightly inaccurate due to their substitutability
Sources: US Embassy, Jakarta; FOS; MIGAS (multiple sources have resulted in some discrepancies in totals)

Domestic Prices

A2A.12 In February 1999, the prices of two of the BBM (Bahan Bakar Minyak) products, Avgas and Avtur, were deregulated, but they represent a very small fraction of the total fuel consumed. The retail prices of the five remaining BBM products (Mogas, kerosene, ADO, IDO and fuel oil, representing over 96% of consumption) have a weighted average of US$12.32 per composite barrel (Table A2A.4).[4]

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[4] Throughout this Report, the assumed exchange rate is 1US$=7,500 Rp.

Table A2A.4: Domestic Prices of Petroleum Products

PRODUCTS	Rp/Lit (1)	$/bbl @ 7500 Rp/$
Avgas	1,700	36.04
Avtur	1,060	22.47
Premium Mogas (2)	1,000	21.20
Kero	280	5.94
ADO	550	11.66
IDO	500	10.60
Fuel Oil	350	7.42

(1) 10% VAT tax on all fuels. Premium and ADO have a 5% motor fuel tax included in the 10% VAT tax (see footnote 9)

(2) This is an average price of premium gasoline, which includes: Premix (4% of consumption) at 1,300 Rp/Lit (27.56 $/bbl) and TT Super (1% of consumption) at 1,400 Rp/Lit (29.68 $/bbl)

Sources: FOS; MIGAS

Table A2A.5: Prices of Singapore Products and Import/Export Parity Prices (US$/bbl)

PRODUCTS	% Weight	FOB Singapore Prices	Share of Weighted Price FOB Singapore	Ocean Freight	Cost, Insurance & Freight	CIF+ Ocean Losses at JKT	Share of Weighted Price CIF at JKT	Singapore Prices at JKT Pump (Depot) incl $1/bbl dist cost	Share of Weighted Singapore Price at JKT Pump
Avgas	0.01	25.3	0.003	1.2	26.53	26.64	0.003	27.6	0.003
Avtur	1.66	30.7	0.51	1.2	31.93	32.06	0.53	33.1	0.55
Mogas	22.81	24.5	5.59	1.2	25.73	25.83	5.89	26.8	6.11
Kerosene	21.1	30.5	6.44	1.2	31.73	31.86	6.72	32.9	6.94
ADO	40.9	26.3	10.76	1.2	27.53	27.64	11.30	28.6	11.70
IDO	2.64	23.7	0.63	0.8	24.52	24.62	0.65	25.6	0.68
Fuel Oil	10.87	21.2	2.30	0.8	22.02	22.11	2.40	23.1	2.51
TOTAL	100%		26.25				27.50		28.50

Assumptions:

a) Singapore prices are based on Platt's Oilgram Price Report (December 30, 1999 issue), and also assuming a crude Pacific Rim price of US$24.50/bbl

b) Freight cost: $1.20 per barrel for clean fuel, and $ 0.80 per barrel for dirty fuel

c) Insurance cost is assumed to be 0.10% of the CF

d) Ocean losses are assumed to be 0.40% of the CIF

e) Pump prices assume US$1/bbl efficiency-based distribution cost. However, this cost, which is substantially in line with some of the numbers that Pertamina is using, could be a significant underestimate. This is because the cost of terminaling, distributing and marketing, using efficient proxies (i.e., based upon the ex-tax margins for each equivalent product in the US, using 1999 data—margins which represent the difference between US retail and ex-refinery (bulk) price), are as follows:

Product	Distribution/Marketing Margin ($/bbl)	
Regular Gasoline	8.1	Pump Price
Kerosene	14.2	Residential/Commercial Price
Gasoil	4.2	Average All Retail Price
IDO	1.8	Distillate to Industry Price
Fuel Oil	1.8	HSFO All Users
LPG	22.2	Residential Price

If these efficiency-based prices were used, the equivalent "market" prices of the products at the Jakarta pump would be significantly higher, therefore the actual subsidy would be much greater than the present level of US$4.9 billion/year (para. A2A.15).

Opportunity Costs of Oil Products

A2A.13 In this analysis, Singapore market prices are taken to represent the opportunity cost of supply for oil products. FOB quoted product prices were adjusted for ocean freight, insurance and ocean losses to determine the CIF prices at Jakarta port, and adjusted further to reflect inland transport costs, in order to arrive at their opportunity costs at Jakarta pumps (depot). The weighted FOB price of a composite barrel of products (equal to that which is used in Indonesia) at the Singapore market is US$26.25 per bbl; when the same composite barrel arrives at Jakarta's port, the weighted CIF cost is US$27.50 per bbl and when it arrives at the pump is US$28.50 per bbl (Table A2A.5).

Cost of Production

A2A.14 Indonesia meets its domestic market requirements through (a) processing Indonesian crude in local refineries; (b) processing imported crude in local refineries; and (c) importing and exporting refined (finished) products. In 1998, quantities (a) and (b) represented about 80%, and 20%, respectively. The "notional" production cost of petroleum products to supply Indonesian markets therefore is assumed to be the sum of (1) the discounted cost of exploration, production and transmission of the Indonesian crude processed in the local refineries; (2) the cost of international crude imported to Indonesia and processed efficiently in local refineries; and (3) the cost of imported finished products; less the value of the export of the locally-refined products.[5]

Table A2A.6: Jakarta Pump Prices vs Market Prices and Production Cost (US$/BBL)

PRODUCTS	Wghtd FOB Sing	Sing Price at JKT Pump	Share of Wghtd Sing Price at JKT Pump	Prod. Costs at JKT Pump	Share of Wghtd Prod. Cost at Pump	Current Price @ Pump	Share of Wghtd Current Price at Pump	Ratio Current Price at Pump/ Prod. Cost	Ratio Current Price to Sing Price
Avgas	0.003	27.6	0.003	13.75	0.001	36.04	0.004	2.62	1.31
Avtur	0.51	33.1	0.55	16.40	0.27	22.47	0.37	1.37	0.68
Mogas	5.59	26.8	6.11	13.85	3.16	21.20	4.84	1.53	0.79
Kerosene	6.44	32.9	6.94	16.25	3.43	5.94	1.25	0.37	0.18
ADO	10.76	28.6	11.70	18.00	7.36	11.66	4.77	0.65	0.41
IDO	0.63	25.6	0.68	13.35	0.35	10.60	0.28	0.79	0.41
Fuel Oil	2.30	23.1	2.51	11.75	1.28	7.42	0.81	0.63	0.32
TOTAL	**26.25**		**28.50**		**15.85**		**12.32**	**0.78**	**0.43**

Comparison of Prices

A2A.15 The opportunity cost of the composite barrel of products sold for US$12.32 per bbl in Jakarta (Table A2A.6), is US$28.50, based on Singapore market prices (Table A2A.5). This indicates that domestic prices on average are about 43% of international prices, with kerosene as low as 18% of its opportunity cost. Thus, prices at the absolute level are highly distorted, which translates into an average

[5] The actual costs of exploration and production by the international oil companies were calculated based on the discounted value of the capital and operation expenditures from 1992-1997, assumed to represent an average of the annual expenditure required to maintain the existing level of production. Considering the absence of a solid analytical approach for the allocation of the joint cost of petroleum products from the refinery, international market prices have been used as the basis for the LRMC of individual petroleum products. The costs for transportation, refining and distribution of the products were added on the assumption that these are being handled efficiently. The costs of imported crude and petroleum products, as well as the price of exported products, were based on Singapore border parity prices.

US$4.9 billion subsidy. Further, the domestic price of the composite barrel at US$12.32 per bbl is not sufficient to recover its production cost (US$15.85 per bbl), and at least three key products (kerosene, ADO and IDO, together representing about 66% of total consumption), do not even cover their production costs when sold at current prices (Table A2A.6).

A2A.16 With respect to individual fuels:

a) *Mogas.* Although the price of Premix and TT Super gasoline are largely at the level of opportunity costs, they represent only about 4% of the total gasoline consumed. The balance (96%) is represented by premier gasoline sold at US$21.20 per bbl, which is still below the opportunity cost of US$26.80. Further, no provision exists for road user charges. If an added 15%-20% is assumed for road user charges, the efficiency price of gasoline would be about US$32 per bbl (since 100% of gasoline is used for road transport).

b) *Kerosene.* While it yields one of the highest refinery margins, its current pump price (about US$5.94 per bbl) is the lowest among the BBM products, and significantly below its opportunity cost (US$32.90 per bbl) as well as below its production cost (US$16.25 per bbl). For this reason, a good deal of kerosene is smuggled and/or diluted to substitute for higher value products such as gasoline, ADO and IDO. A relatively small amount of kerosene is consumed by the poor, mainly the urban poor because most of the rural poor use kerosene for lighting and wood fuel for cooking.

c) *ADO.* At its current pump price of US$11.66 per bbl, ADO is below its production cost of US$18.00 per bbl and significantly lower than its opportunity cost of US$28.60 per bbl. Again, as with gasoline, the price does not include a road user charge. Assuming a premium of 15%-20% for such a charge, the efficiency price would rise to about US$33-34 per bbl. Hence, ADO is a major source of distortion, particularly when considering the high volume consumed. Only about 55% is used in transport, while about 30% is used in industry and 15% in power generation.

d) *IDO.* The pump price of IDO (at US$10.60 per bbl) is below its production cost of US$13.35, and substantially below its opportunity cost of US$25.60 per bbl. About 90% of IDO is used in industry, 8.5% in transport (mainly barges and locomotives) and 1.5% in power plants. However, because ADO is used in industry and power generation, IDO consumption represents less than 2.8% of total fuel consumption. The subsidies for IDO and ADO are strong disincentives to the use of natural gas and to the development of the domestic gas market.

e) *Fuel oil.* It is used in industry (64.5%), power plants (25.2%) and transport (10%). Its current pump price of US$7.42 per bbl is below its opportunity cost of US$23.10 per bbl.

f) *LPG.* This fuel is not regulated by the Government. LPG's pump price is Rp 840 per liter, or about US$17.81 per bbl. Because the production cost of LPG produced from gas plants is lower than that produced from refineries (about US$14 per bbl), its overall production cost is relatively low. As such, and under a correct pricing policy, LPG could substitute for a substantial amount of kerosene in household use, and the more expensive kerosene could be exported. The overall production cost of LPG is below its domestic price of US$17.81, set by Pertamina.

A2A.17 Table A2A.7 compares the domestic prices of three key products in Indonesia with those in several other countries.

Table A2A.7: Comparison of International End-Use Petroleum Product Prices (1998)

	Premium Leaded Gasoline (US$/liter)	ADO (1) (US$/liter)	Fuel Oil (2) (US$/tonne)
USA	0.330 (3)	0.274	84.9
Japan	0.740 (4)	0.468	154.0
OECD Europe	0.994	0.615	130.4
Thailand	0.305	0.222	155.34
China	0.241	0.241	-
India	0.614 (5)	0.266	129.24
Brazil	0.744 (6)	0.353	173.12
INDONESIA (7)	**0.093**	**0.039**	**33.26**

(1) Commercial use, except in the case of USA, which is for non-commercial use
(2) Heavy fuel oil used in industry (in most cases, high sulfur) (3) Premium unleaded gasoline (95 RON)
(4) Regular unleaded (5) Regular leaded
(6) Weighted average price of all gasolines/alcohol used for transportation
(7) Indonesian prices in this Table are based on IEA foreign exchange assumptions, and hence are different from the other prices used in this Report; Source: IEA Energy Prices and Taxes, 2nd Quarter Statistics 1999

Pricing of Natural Gas

A2A.18 The domestic pricing of natural gas is also problematic. Its price must be market driven and the subsidy on alternative fuels must be removed to allow the gas industry to grow and to substitute for higher value products. Considering that natural gas is a critical part of the country's energy scene, the pricing issues deserve a comprehensive study (para. A2A.8), and, therefore, the following paragraphs provide only an indication of the overall problem.

Producer Price

A2A.19 Currently, the producer price is different for each field and prices are fixed for a designated supply for the duration of a contract. As a result, there are well over 20 different producer prices. In a typical production-sharing contract (PSC), the profit from gas production (net of exploration, development and production expenditures) is usually split 65% for the Government (taxes and rent) and 35% for the contractor. Pertamina purchases the gas (in US$) paying the recovered cost, plus the net contractor share plus the Government's share. The problem is further complicated by the fact that there are still many contracts which do not have provision for gas discovery, and hence there is no predictable basis for forecasting the value to the producer of a possible discovery. Ideally, the contract should include a structure for producer price which would provide: (a) a predictable gas price formula which, prior to exploration, would permit an evaluation of the future value of a gas discovery; (b) a price formula linking gas to its economic value in the market, thereby encouraging exploration when the cost of supply is lower than the value; and (c) an efficient rent tax to retain the resource rent for the country (para. A2A.22).

Economic Cost of Gas Supply

A2A.20 As mentioned before, Indonesia is not considered a gas surplus country (one that can meet its current and forecast demand for the domestic market over the next 30-40 years, and still be able to supply enough gas for export—say, the equivalent of 2-3 major LNG plants), particularly given the appetite of East Asian countries for its LNG, and its very low level of current internal gas consumption compared with its population and future domestic market requirements. Thus, the economic cost of gas supply, in addition to average incremental cost (AIC) of production and transportation, must include an appropriate amount for the depletion premium. However, it is difficult to establish an average cost (of gas supply) without a more detailed study, given the number of fields and the varied costs of exploration, production, operation and transmission to the major consuming or export centers. Nonetheless, to provide an order of magnitude for the purpose of this discussion, based on a cursory review of past studies the average incremental cost of gas supply (exploration, production and transmission) has been estimated to be about US$1.40-1.50 per mcf.[6] To this, a depletion premium was added, which is estimated to be US$0.50-US$0.75 per mcf. Therefore, the economic cost of gas supply is roughly US$1.90-US$2.25 per mcf. When this supply cost is compared with the current weighted average wholesale price of natural gas—which is estimated at US$2 per mcf—and the netback value of gas, major distortions exist which have hampered the development of new gas discoveries and the industry in general.

Consumer Price and Economic Value

A2A.21 Pertamina's wholesale gas prices to different consumers are not market-based and they are subsidized for many industries. As shown in Table A2A.8, the weighted average selling price of gas in Indonesia's domestic market is about US$2 per mcf. However, a crude approximation of the netback value of gas in the economy and in the key sectors indicate that the weighted average economic value (netback value) of gas based on current consumption patterns is estimated to be US$3-3.75 per mcf.[7] Therefore, the economic value of the gas is by far higher than its average costs and current selling price.

Table A2A.8: Natural Gas Consumption and Wholesale Prices

	Gas Quantity (000 mmscf)	PRICE (average) $/MCF (1)
TOTAL Domestic Market (2)	633	
Power	232	2.73
Fertilizer	207	1.50
PGN	56	1.5-1.8
Refineries	39	1.50
Steel	36	1.53
LPG	35	1.50
Petrochemical	19	1.71
Cement	4	2.85
Other	5	1.15

(1) Rp 7,500 = US$1
(2) Total gas production in 1998 was 3.2 tcf; 1.7 tcf was exported

A2A.22 The economic cost of gas supply and its netback value to the economy indicate that (a) the current average selling price of gas is lower than (or just barely sufficient to cover) its economic cost of supply; and (b) significant amounts (US$1.00-US$1.75 per mcf) in economic rent are being foregone. This distorted policy structure has slowed the growth of the gas industry in the country and acts as a disincentive for the producers to supply gas to the market. Given the importance of the issue and lack of adequate data and information, it is strongly recommended that a comprehensive gas utilization study be carried out to establish the economic costs and values in Indonesia, as well as the pricing policy, rational investment program and institutional arrangements needed to accelerate the development and utilization of the country's natural gas resources.

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[6] Although the calculation of AIC is based on a discounted rate of 10%, allowance was made to cover unsuccessful exploration so the investors would still earn a reasonable return on their investment. It should also be noted that although this range is a crude approximation, it is not inconsistent with some of the producers' prices, when the producers' prices are adjusted for the contractors' and Government shares.

[7] This is based on the assumption that the highest netback value for gas would be obtained by substituting for diesel used in power generation.

Pricing of Electricity

A2A.23 As with the hydrocarbon sector, the pricing structure for electricity is distorted both at the absolute and relative levels. Since the crisis, the average tariff of the State electricity corporation (PT PLN) has fallen to around 3c/kWh, compared to current costs of around 6-7c/kWh; these costs will increase as new independent power producers (IPPs) come on stream. Further, all of PLN's customer classes pay less than the actual cost of serving them. If tariffs were increased uniformly to cover average costs, then a large cross-subsidy, primarily from medium and large commercial and industrial consumers to the main residential customer class, would be apparent. The Government has also had a Uniform National Tariff Policy, which requires that customer classes charge the same tariffs regardless of their location in the country. This means that a geographic cross-subsidy would also become evident, extending from Java to outside Java; the magnitude of the geographic cross-subsidy would be similar to that between customer classes, about US$600 million a year. Therefore, in moving towards an efficient pricing structure in the power sector, it is not enough to simply increase the absolute level of the tariff, because the relative levels also require substantial readjustment. The current Study did not review electricity tariffs because a comprehensive tariff study was completed recently.[8] However, the Bank recommends that this exercise also be brought up to date in an integrated manner as part of the proposed Integrated Energy Products pricing study (para. A2A.8).

Taxes

A2A.24 There is currently a 10% flat VAT tax on all petroleum products (a 5% motor tax is also included in this 10% for Mogas and ADO). Since all major products are priced significantly below their opportunity costs, the policy goals of energy taxes are unclear: are they expected to expand revenues, increase sector efficiency (either by reducing consumption or changing its pattern), mitigate adverse environmental impacts, or achieve all three?[9] Obviously, each tax regime would yield different results and meet different objectives. For example, an *ad valorem* tax is a good mechanism to raise revenues and is easy to administer, but it is the least desirable environmentally because it taxes all products the same. Conversely, a carbon tax responds best to environmental concerns, because it taxes coal heavily, oil moderately and natural gas lightly. However, it does not have a large tax base and would not help the Government generate revenue. To the extent that a broad policy objective is to charge for benefits and costs, a specific tax is more appropriate, although it usually generates less revenue than an *ad valorem* tax and is more difficult to administer. Besides, specific taxes need to be reviewed regularly, to reflect in their real value any changes in the international price of petroleum products.

A2A.25 The issue of petroleum product taxes, particularly on transport fuel, is complex. For example, to the extent that taxes are based on road-user charges, it could be argued that diesel should be taxed more heavily than gasoline. However, the income elasticity of gasoline is high and its price elasticity is low, which encourages most governments to use the gasoline tax to generate revenue. Conversely, if the tax system favors diesel over gasoline, it is not justified on economic grounds since diesel is generally more expensive (in terms of cost of production) than gasoline, and the differential is likely to be distortionary—fostering more rapid growth in demand for diesel (as compared with gasoline).

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8 The ADB-funded "Indonesia: Power Tariff Rationalization Study".

9 Although by definition the subsidy exists when the net-of-tax prices of fuels are below their opportunity costs, for the purpose of this Report, the analysis has been simplified by assuming that the pump price is the net of tax price. The reason for this simplified approach is that the amount of the subsidy is so large that the impact of the current tax regime is relatively small. In fact, if taxes are excluded, as they should be, the economic subsidy would be even larger.

A2A.26 Further, the general principle of levying taxes on motor fuels may have to be based mainly on environmental considerations, given the serious air pollution caused by vehicles, especially in Jakarta. The tax on diesel and gasoline should encourage more fuel-efficient vehicles, better vehicle maintenance and less driving. However, this issue is also complex because a diesel-favored tax regime probably reduces the relative degree of pollution from lead (97% of which is caused by gasoline-powered vehicles) but increases relative emissions from particulates (65% of which come from diesel). Besides, caution must be exercised in relying on a relatively crude device such as petroleum product taxes to deal with air quality problems; rather, a more targeted approach may be required. In particular, it may not be appropriate to subject the whole country to a tax system designed to ameliorate Jakarta's pollution problem. Also, it would be dangerous to introduce a system of different tax rates in different localities, as this would encourage smuggling of petroleum products.

A2A.27 Thus, it is not easy to establish an optimal level of taxes for motor vehicles and certainly beyond the scope of this review. For this reason, taxes on energy products must be studied thoroughly (after the efficiency pricing policy is established), and it is recommended that this be carried out as part of the proposed Integrated Energy Pricing study (para. A2A.8).

Relative Price Distortions and Inter-Fuel Substitution

A2A.28 The previous sections reviewed distortions at the absolute level for various energy products, and found major disparities between pump/selling prices and opportunity costs of products. This section reviews relative prices of energy products in three key sectors: industrial, household/commercial, and transport, based on the principle of inter-fuel substitution in each sector. This is particularly important for Indonesia, where the industrial sector is expected to resume its rapid growth and there is substantial room for fuel substitution in manufacturing.

Industrial Sector

A2A.29 Industry in Indonesia mainly uses ADO, fuel oil, IDO, natural gas and electricity. In general, the criteria for use of fuels in industry is the unit cost of the energy generated by a particular fuel (i.e., US$ per mmbtu). Although all the fuels used in Indonesian industries are priced below their opportunity cost, the fuel substitution analysis (Table A2A.9) shows that some are relatively more underpriced than others. For example, the ratio of the price of ADO to fuel oil in the domestic market is 1.70, while in the international market, the ratio is 1.34 (both in common energy unit bases). This implies that ADO is relatively overpriced with respect to fuel oil. Also, natural gas is underpriced in all cases, but to raise its price without raising the price of the fuels for which that gas substitutes, such as ADO, would lead to more distortions. These relative distortions provide consumers with the wrong signals, since they find one fuel cheaper than the other, but it may not be the economic choice. These distortions should be eliminated.

Table A2A.9: Inter-Fuel Substitutions in the Industrial Sector

Products and Potential Substitution	Ratio in Terms of Opportunity Costs (1)	Ratio in Terms of Domestic Prices (1)	Distortion
ADO/IDO	1.14	1.11	0.97
ADO/FO	1.34	1.70	1.27
ADO/NG	1.94	1.19	0.61
FO/NG	1.45	0.70	0.48
Elec/NG	7.12	5.34	0.75
IDO/FO	1.18	1.52	1.29
IDO/NG	1.71	1.06	0.62

(1) All values converted to common energy units

Household/Commercial Sectors

A2A.30 The fuels used in the household/commercial sectors are kerosene, electricity, LPG and natural gas. The relative prices (Table A2A.10) indicate that while the ratio of opportunity cost of electricity to gas is 7.12, the ratio in the domestic market is 5.34, implying that household electricity is underpriced in relation to gas, and that kerosene is significantly underpriced in relation to LPG. Therefore, natural gas should be used to the extent possible in the commercial sectors to substitute for electricity, and LPG should be used to reduce the consumption of kerosene and electricity.

Table A2A.10: Inter-Fuel Substitutions in the Household/Commercial Sector

Products and Potential Substitution	Ratio in Terms of Opportunity Costs (1)	Ratio in Terms of Domestic Prices (1)	Distortion
Kerosene/LPG	1.04	0.24	0.23
LPG/NG	2.21	2.62	1.19
Elec/NG	7.12	5.34	0.75

(1) All values converted to common energy units

Transport Sector

A2A.31 The transport sector uses gasoline, ADO, smaller quantities of IDO and FO, and a limited amount of CNG and electricity. The most significant fuel substitution occurs between gasoline and diesel, and, to a much lesser extent, between diesel and fuel oil in marine transport (Table A2A.11). Although ADO and gasoline are both below their opportunity costs, ADO is far more underpriced, which has led to its considerably higher consumption.

Table A2A.11: Inter-Fuel Substitutions in the Transport Sector

Products and Potential Substitution	Ratio in Terms of Opportunity Costs	Ratio in Terms of Domestic Prices	Distortion
ADO/Gasoline	0.94	0.48	0.51
ADO/FO	1.34	1.70	1.27
Mogas/Kerosene	0.90	3.94	4.38

Distortion in Relative Prices

A2A.32 Based on the above analysis of inter-fuel substitution, in summary:

a) The price of ADO in relation to natural gas in the industrial sector needs to be raised by about 64%;

b) The price of ADO in relation to gasoline in the transport sector needs to be raised by about 94%;

c) The price of fuel oil in relation to ADO in both the industrial and transport sectors needs to be raised by about 27%;

d) The price of fuel oil in relation to natural gas in the industrial sector needs to be raised by about 108%;

e) The price of fuel oil in relation to IDO in the industrial sector needs to be raised by about 29%;

f) The price of electricity in relation to natural gas in industrial and household/commercial sectors needs to be raised by about 33%;

g) The price of kerosene in relation to LPG in the household/commercial sectors needs to be raised by about 3-4 fold;

h) Although the price of LPG in the household/commercial sectors is still below its opportunity cost, nonetheless the LPG price could be reduced by about 20% in order to enable natural gas to compete with LPG in the household sector;

i) Although the current price of natural gas is low, its price should be kept at present level until such a time that the increase in price of ADO would bring it to such a level that natural gas could compete with ADO; and

j) Although the price of gasoline is still slightly below the market price, its price should not be raised until the price of ADO has increased substantially.

Costs of Subsidies and Distortions

Subsidies

A2A.33 GOI/Pertamina define the fuel subsidy as the difference between the cost of delivered products to the pump and the domestic sales price. To calculate the subsidy, the three costs are added: (a) the purchase of crude oil; (b) the purchase of finished products; and (c) operations (including the crude processing costs) and distribution. Next, the export value of the non-BBM products (i.e., other products resulting from processing the local and imported crude in Indonesia's refineries) is deducted in order to arrive at the cost of BBM products. Finally, the selling price of the BBM products is deducted, which gives the total amount of fuel subsidy.

A2A.34 Table A2A.12a below shows a typical subsidy calculation by GOI.

Table A2A.12a: Pertamina/GOI Subsidy Calculation (April 1, 1998 – April 1, 1999)

1. Costs of Supplying Oil & Oil Products (a-e)	**Millions Rupiah**	**Millions Bbl**	**$/Bbl**
(a) Crude oil prorated: Pertamina	275,300	4.734	7.75
Contractor	464,931	17.200	3.60
(b) Crude oil in kind : Pertamina	2,223,388	19.740	15.02
Contractor	17,599,019	148.579	15.79
(c) Crude oil imports	14,590,536	114.227	17.3
(d) Products imports	13,558,336	93.871	19.6
(e) Value of non-BBM Products	(8,799,353)	(108.307)	10.83
2. Changes in Stock in Crude & Products	(1,629,950)		
3. Operating Costs	10,522,053	302.6	4.64
4. Total Cost (1+2+3)	48,804,251	302.6	21.50
5. Net Sale Proceeds	23,604,061		10.40
6. Net Oil Profit/Subsidy in Rupiah	25,200,192	302.6	11.10
7. Subsidy in US$ at US$1:Rp7,500	US$3,360 million		11.10

A2A.35 The above represents an internal accounting-based definition of subsidy, since the production costs of crude used in these calculations are significantly below international prices. In reality, the size of the subsidy could be far larger. Except for the Avgas and Avtur fuels, which represent only 2.3% of total fuel consumption, all other BBM fuels are priced at levels below their opportunity costs. Further, several key products are priced even below their production costs. Accordingly, the economic subsidy (the difference between the opportunity costs of BBM products and their selling price) for petroleum products during 1999 was about US$4.9 billion (Table A2A.12b).[10] Since there was also a subsidy of about US$1.1 billion to the electricity sector, the total subsidy to the energy sector in 1999 was at least US$6 billion or 6% of GDP. By any measure, this is large and, in the long term, untenable. In many years in the past, subsidies for fuels were much larger than public expenditures on health.

Table A2A.12b: Total Amount of Petroleum Product Subsidy

PRODUCTS	Difference between Current Price and Opportunity Cost (US$/bbl)	Total Subsidy at FOB Singapore Price (US$ Million)
Avgas	8.44	0.30
Avtur	-10.63	-53.36
Mogas	-5.60	-387.07
Kerosene	-26.96	-1,723.01
ADO	-16.94	-2,099.71
IDO	-15.00	-120.15
Fuel Oil	-15.68	-516.50 (1)
TOTAL		**-4,899.50**

(1) This amount may be misleading in that substantial quantities of fuel oil are exported

A2A.36 To put the magnitude of this subsidy in perspective, the amount of the fuel subsidy (excluding direct subsidies for electricity) represents over 25% of the Government's routine expenditures. The country's debt now stands at about 90% of GDP, a four-fold increase from the pre-crisis period. Further, the debt service (mostly external) represents about 38% (i.e., 21.5 % in principal and 16.5 % in interest) of the Government's routine expenditures. Thus, the amount of the fuel subsidy is therefore about 20% more than the principal payments of the country's huge debt.

Net Cost to the Economy

A2A.37 When government policy requires that the price charged to consumers be set below that which clears the market, economic efficiency (the aggregate welfare of consumers and producers taken together), is reduced. While a detailed welfare analysis of the subsidies is outside the scope of this study, a simplified methodology was used to calculate the reduction in economic efficiency; i.e., the net economic cost of the subsidy (deadweight losses). The net benefit from the removal of the subsidies is thus represented by the difference between the benefits resulting from elimination of the subsidies and costs resulting from the reduction in consumer surplus. The details of the various price reform scenarios investigated here are presented in Annex 2B (and para. A2A.44).

A2A.38 To establish a demand curve, price and income elasticities had to be assumed because not only were the data not available, but extensive past subsidies, inadequate tariff adjustments and existence of

[10] This calculation is based on 1999 opportunity costs, but 1998 consumption levels.

the BBM Fund would have not allowed the establishment, with a reasonable degree of accuracy, of a correlation between past price adjustments (and income adjustments) and the consumption level and pattern (due to incorrect signals to consumers), even if the data were available. Therefore, other related studies and resulting elasticities were used, and a comparison was also made with other countries in the region to estimate the long run price elasticities for key products such as gasoline, kerosene, ADO, IDO, and fuel oil, in order to develop a simplified demand curve to estimate the impact of price increase on demand consumption and the resulting benefits from removing subsidies as well as calculating the costs associated with the reduction in consumer surplus.

A2A.39 Based on the above, the net cost of the BBM product subsidy to the economy in 1999 was about US$1,432 million. Table A2A.13 below provides the details of the reduction in consumption of each fuel resulting from a price increase, the assumed price elasticities and the deadweight losses. The deadweight loss for kerosene alone was US$710 million in 1999. The total deadweight loss for 2005 is projected to be US$1,963 million, if the status quo continues. Further, the level of fuel consumption would increase by about 40% by 2005, if the subsidies are not removed. On the other hand, if the subsidies are gradually removed over the next five years (para. A2A.57), the level of fuel consumption in 2005 would even be slightly less than present level (despite the 5% assumed increase in consumption due to GDP growth). And, the net cost to the economy would be zero. These deadweight losses do not include those for natural gas.

A2A.40 With respect to the distortions at relative levels, there are other costs which have not been quantified; for example, those resulting from the distorted pattern of consumption and the associated misallocation of producers' and consumers' resources (such as mismatched refinery configurations and end-users' equipment). Although the cost of the relative distortions was not quantified for this Report, it can be assumed that, due to the consumption patterns they induce and the associated misallocation of resources, the costs are huge.

Table A2A.13: Net Economic Cost of Subsidies

PRODUCTS	Own Price Elasti-city	Income Elasti-city	1998 (Base Year)			2005			
			Consmpn Mill bbls @ Current Domestic Prices	Consmpn Mill bbls @ Opp Cost Prices (1)	Ddwght Losses US$ Mill	Consmpn Mill bbls Status Quo	Consmpn Mill bbls Phased Deregltn	Ddwght Losses US$ Mill Status Quo	Ddwght Losses US$ Mill Phased Deregltn
Mogas	-0.5	1.2	69	61.5	23	96.8	86	32	0
Kerosene	-0.5	1.2	64	27.3	695	89.5	38	974	0
ADO	-0.5	1.2	124	79	463	173.5	111	649	0
IDO	-0.7	1.2	8	4.3	34	11.2	6	48	0
Fuel Oil	-0.7	1.2	33	14.9	186	46.0	21	260	0
Total			**298**	**187.0**	**1402**	**417**	**262**	**1963**	**0**

(1) Assumes immediate increase to international prices
Based on World Bank estimates of GDP Growth: 1999 = 1.8%; 2000 = 3%; 2001 = 4%; 2002-2005 = 5%

Eliminating Subsidies

Fiscal Benefits

A2A.41 Eliminating the subsidies will increase Government revenues substantially. If the subsidies are not removed, the amount of economic subsidies that the Government would be undertaking between now and the end of 2005 would be about US$35.5 billion, and the value of foregone foreign exchange earnings (due to the domestic over-consumption of fuels) would be about US$18.7 billion. If the subsidies are gradually removed over the next 5 years, as is proposed in this Report, the economic subsidies would be reduced to US$13 billion, and the foregone value of hydrocarbon export earnings would only be US$4 billion. Consequently, the magnitude of these savings/earnings should mandate the Government to begin the subsidy removal program on an urgent basis.

A2A.42 Since the benefits are in the form of foreign exchange, they will provide Indonesia with a hedge against exchange rate fluctuations; this is crucial, since about two thirds of the rise in the external debt was due to a drop in the value of the country's currency.[11] And, given the size of its debt, Indonesia needs to finance its fiscal deficit through sustainable instrument, both on the expenditure and revenue sides. In the short run, fuel subsidies are the prime candidate since the Government could reduce expenditures by eliminating energy subsidies, which are badly targeted and enjoyed mainly by higher income groups (para. A2A.51). If this move were carried out, together with putting in place a rational pricing structure, the relative distortions would also disappear.

Environmental Benefits

A2A.43 Eliminating the subsidies will bring significant environmental benefits (Annex 2C). Although mechanisms to combat pollution and its deleterious effects have been persistently pursued in Indonesia through numerous pieces of legislation, many of the environmental degradation problems have become intractable during a period of institutional fragility and severe budgetary constraints. Indonesia has relied historically on a strong regulatory element (such as extensive EIA planning and monitoring mechanisms), but now there is less environmental regulatory capability due to reduced government spending. More importantly, market distortions, such as the current huge energy price subsidies, overwhelm any regulatory attempts to correct extensive environmental problems.

A2A.44 The link between energy pricing and environment quality is rather clear: in principle, economic subsidies lead to the over-consumption of petroleum products, and consequently congestion and excess pollution, which in turn has health impacts on all of those exposed. The analysis focused on the BBM products, establishing the pollution impacts in the presence and absence of subsidies between now and 2007. Pollution impacts were then translated into the consequential economic damages from lost productivity, higher medical treatment costs, and lower quality of life. Three scenarios were investigated: a "status quo" case, in which current price subsidies are assumed to persist indefinitely; a "reference" case, which illustrates what would happen under total deregulation; and a "phased price deregulation" scenario, assuming the subsidies are phased out according to the Bank-proposed schedule. (Additional details of these scenarios are provided in Annexes 2B and 2C).

A2A.45 **Urban Air Pollution.** The primary health impacts of particulate matter (PM) and nitrogen oxides (NOx) are respiratory illnesses. Studies in the early 1990s for Jakarta, for example, showed that respiratory illness was the sixth leading cause of death in Indonesia; in Jakarta it accounted for 12.6% of mortality. Under current prices, results show that environmental damages in 2000 are expected to be US$1,638 million from PM and NOx. In 2005, the total environmental damages are US$2,740 million. If prices were set at reference (i.e., market) prices, then damages in 2000 would be US$1,003 million and in 2005 would be US$1,677 million. Thus, the net damages of PM and NOx caused by subsidies are about US$635 million in 2000, and about US$1,063 million in 2005. Removing the subsidies totally would reduce the net damages to zero (although there would still be residual damages from the remaining pollution). Using phased price reforms, the results show elimination of the net environmental costs by 2004.

[11] Refer to the World Bank's 1999 Report: "Public Spending in a Time of Change".

A2A.46 **Lead.** Lead is of particular concern in Indonesia because, unlike other countries in the region, Indonesia has not yet commenced an effective program of lead reduction from fuels, and thus most monitoring still shows that Indonesia has among the highest levels of lead in the region. A lead phase out program typically takes a long time to implement successfully. The morbidity effects of lead are well documented and World Health Organization guidelines now suggest that there is no acceptable minimum standard; zero tolerance is the norm.[12] In terms of a long-term social investment, therefore, reducing lead emissions is generally regarded as a top priority in most developing countries.

A2A.47 The results of the analysis show that in the status quo case (no price changes), lead poisoning is likely to contribute US$916 million in damages in 2000, rising to US$1,536 million in 2005. With prices totally deregulated, the 2000 impacts would be US$386 million and in 2005 impacts would be zero.[13] The net damages from lead, as a result of over-consumption of fuels because of price subsidies, are thus US$532 million in 2000 and US$1,536 million in 2005. Again, with phased price reforms, net damages are zero by 2005.

A2A.48 **Global Climate Change.** Removal of subsidies would reduce carbon emissions from 25.03 tC to 15.71 tC in 2005. This reduction (equivalent to an emission equivalent of about 25tCO_2) results in net annual damages to the global community of $280 million.

A2A.49 Thus, as a result of price subsidies, transport and industrial fuels are over-consumed, creating an excessive amount of pollution and associated environmental impacts. In addition, there are other long term benefits under deregulated prices that have not been addressed, such as incentives for inter-fuel substitution to cleaner technologies (i.e., natural gas). Further, deregulating prices provides conditions in which environmental regulatory standards are more likely to have a meaningful effect. As noted above, residual damage from particulates and NOx in 2005 would still approach $1 billion, and would grow annually as income levels and consumption continued to expand. Addressing these residual damages through proper environmental controls will be facilitated in a deregulated environment.

Macroeconomic Impacts

A2A.50 Although economic pricing will enhance growth prospects and improve allocative efficiency, given the size of the current subsidies and the length of time they have existed, removing them will have certain macroeconomic and social ramifications. With regard to macroeconomic impacts, the energy price increase will effect the cost of living and producer costs in the short and long term, directly and indirectly. With regard to the former, in the short term, besides the direct impact due to increased fuel costs, there is an indirect effect from industry's cost increases, which are passed on to consumers in the form of higher prices (i.e., when transport costs are increased due to an increase in the prices of diesel and gasoline). Further, there will be a long-term impact when the entire economy has felt the effect of the fuel price hike (such as when the cost of food is increased as the result of higher transport costs). With regard to producers' costs, the impact may be slightly higher. Again, a detailed analysis is outside the scope of this study. However, the magnitude of these macroeconomic impacts are not expected to be significant in the context of some of the CPI and PPI increases the country experienced in the past few years.

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[12] This is because lead accumulates through one's entire life and has particularly deleterious effects in young children; it hampers normal mental development and undermines future educational efforts.

[13] This assumes that Indonesia attains its lead phase out targets in association with any moves to reform the pricing structure. The planned phase out is assumed to be: 40% in 2000; 60% in 2001; and 100% in 2002. However, this is not a realistic schedule.

Social Impacts

A2A.51 To examine the social impacts, more information is needed on national income, expenditures and household patterns of fuel consumption. This information and data was not available to the current Study, and the SUSENAS data for 1999 had not been released. However, some of the data available for 1996 seem not to be substantially different from the data for 1990 and 1993; namely that the subsidies are significantly higher for the higher income group (the per capita subsidy is four times higher for the richer 20% of the population than the poorest). This is not surprising as the comparators from other countries support the same conclusion; namely, that energy subsidies are generally regressive, since the higher the household income, the more it benefits from the subsidy—for the obvious reason that higher-income households use more energy.

A2A.52 Based on these fragmented data, it has been estimated that, of the total subsidy, only a small amount reaches to the poor. For example, assuming that the number of poor represent 18%-20% of the population (1998 data) and the near poor another 10%-12%, the consumption of kerosene by this 30% of the population is about 10 million barrels out of about 65 million consumed a year—because most of the poor only use kerosene for lighting, and only half of the poor in urban areas use it for cooking, the rest rely on fuelwood. And, since 20 million barrels were used in non-household sectors in 1998, the remaining 35 million barrels of kerosene were consumed by those with higher incomes. Assuming similar consumption levels for 1999, this means that, in dollar terms, only about US$260 million, or roughly about 15% of the total kerosene subsidy of about US$1.75 billion, reached the bottom 30% of income earners during 1999.

A2A.53 However, while the higher income households receive most of the subsidy, and removing the subsidy will affect them the most, experience in other countries has shown that the poor suffer more in relative terms, since a higher proportion of the family budget is spent on fuel. For this reason, some sort of safety net is needed to protect them, but the cost of such a safety net to the economy would be significantly less than those of current subsidies (para. A2A.68).

Proposed Price Adjustments and Implementation Strategy

A2A.54 It is thus concluded that (a) the price of energy produces is significantly distorted; (b) the economy would benefit substantially if the subsidies and distortions were removed, the country were to move toward market-based prices, promote least cost supply and avoid cross subsidies; (c) removing the subsidies would increase the price of energy products, particularly that of kerosene, diesel oil and fuel oil; (d) such increases would have beneficial fiscal and environmental impacts, but adverse macroeconomic and social impacts; and (e) a safety net is needed to protect the poor from the impacts of price increases, but that the cost of protecting the poor would be significantly less than the subsidies. The question now is how to remove the subsidies in a way that would least disrupt the economy and minimize adverse impacts on the poor. To address this, the amount of the price increase for each fuel, the time frame during which the adjustments should be made, the strategy to implement them, the necessary institutions and the adjustment formula that would sustain the price adjustments over time, all must be determined.

A2A.55 It is recommended that Indonesia develop a four-part implementation strategy. First, an initial transition period should be established during which all energy prices are brought in line with their production costs, followed by a second transition period during which prices are increased further, from the level of production costs to opportunity costs. As part of this step, an adjustment formula should be established to reflect market fluctuations. Second, an effective mechanism for delivering the subsidy to the poor must be developed (para. A2A.64). Third, the public needs to be well informed about the need for price hikes. Finally, the institutional arrangements should be created/reformed with adequate capacity and mandate to regulate the price increases, the removal of subsidies and the protection of the poor in an efficient and transparent manner; and yet the design of the institutional arrangements should be such as to allow the Government to gradually stop setting prices, and ultimately leave this to the market.

Recommended Pricing Adjustment

A2A.56 The following (Table A2A.14) presents findings about the amount of the adjustment for each fuel. It should be stressed that the values and timetable are indicative.

Table A2A.14: Recommended Pricing Adjustments (%Increase/Decrease)

PRODUCTS	Sep 2000	Sep 2001	Sep 2002	Sep 2003	Sep 2004	Sep 2005
ADO	+20	+20	+20	+25	+15	-
IDO	+20	+20	+20	+25	+15	-
Fuel Oil	+25	+25	+25	+25	+30	-
Kerosene	+20	+25	+30	+35	+40	+50
Mogas	-	-	-	-	+15	+10
Electricity	+30	+20	+28	-	-	-
Natural Gas	-	-	-	+20	+25	to opp value
LPG	-19	-	-	-	-	+25

Timing

A2A.57 Experience in many countries shows that both the immediate and gradual approaches to price reform are politically difficult, due to their effect on the poor and the general public; also, that once subsidies are granted, they are difficult to remove. Further, macroeconomic consequences occur as energy price hikes change relative prices in the economy, leading to an increase in consumer and producer prices (para. A2A.50). Considering the length of time required for price increases to become effective in developing economies, and the fact that other economic distortions tend to neutralize the impact of price hikes during long transition period, an argument could be made in favor of immediate increases. However, in Indonesia, such a course would be unrealistic. Thus, increases should be gradual, with different time periods for different fuels, as shown above, spread at a maximum over a five year period, after which the prices should be fully deregulated. Clearly, if the international prices of petroleum products decline, the length of time to phase out the subsidies should be reduced accordingly.

A2A.58 The initial price adjustments are recommended to begin in September 2000, but the exact timing should be based on the political environment. As discussed above, prior to implementation, the rationale for pricing and goals should be announced, and the public should be well informed about the cost of the subsidies to the economy, the environment, and other distortions. Once announced, it is important that prices actually be raised.

Adjustment Formula

A2A.59 Once prices are increased, they must be adjusted to reflect the market. This must occur once the transition period begins, pro-rated even when prices are still subsidized. For this purpose, the adjustment formula for petroleum products should reflect international parity prices and exchange rates. However, as discussed above, each product price increase needs to be limited (i.e., a ceiling must be applied) to the respective percentage increase given in Table A2A.14, to allow a period of several years for reducing the difference between the current domestic prices and the international parity prices. Domestic prices could also potentially be capped by some average of comparable product prices in ASEAN countries. This arguably could benefit Indonesia with respect to its overall competitiveness and lessen the impact of oil product price deregulation.

A2A.60 A generic adjustment price formula, which could be applied for gasoline, kerosene, ADO and IDO, is:

$$D_N = \left\{ (P_N + C) - \left[(P_N + C) - \left(\frac{D_0 \times 158.98}{F_0} \right) \right] \left[\frac{A - N}{A} \right] \right\} \times \frac{F_N}{158.98}$$

where:[14]

D_N	=	adjusted Indonesian retail price in Rp/Lit in year N
P_N	=	Singapore bulk price in \$/bbl in year N[15]
C	=	constant term in \$/bbl for freight, terminaling, distribution, marketing etc, specific to each BBM product[16]
D_0	=	Indonesian retail price in base period in Rp/Lit[17]
F_0	=	exchange rate Rp/\$ in base period[18]
A	=	number of years over which subsidy is removed[19]
N	=	year of price calculation (i.e., number of years after base period)[20]
F_N	=	Rp/\$ in year N[21]
158.98	=	conversion factor for liters to bbl

A2A.61 For fuel oil, given that it is usually quantified in the international market in $/MT, the formula would be:

$$D_N = \left\{ (P_N + C) - \left[(P_N + C) - \left(\frac{D_0 \times 1075}{F_0} \right) \right] \left[\frac{A - N}{A} \right] \right\} \times \frac{F_N}{1075}$$

where: the definition of all variables is the same as above, but they are expressed in metric tons (assuming a conversion factor of 6.76 bbl/MT).

Frequency of Adjustment

A2A.62 It is suggested that BBM prices be adjusted quarterly, during the two weeks prior to the start of each calendar quarter. The values of P_N should be based on the average of the previous three months of available data from Platt's Oilgram Singapore monthly average cargo price statistics. Assuming that price increases begin in September 2000, for adjustments to the BBM prices made on January 1, 2001, the adjustment would need to be determined mid-December 2000, using the monthly Singapore cargo prices

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14 There are many approaches to specifying the values of the specific terms in this formula. The following footnotes 15-21 provide one approach.

15 P_N can be based on the quoted price in Platt's Oilgram Price Report (Monthly Averages Supplement) using gasoline 92 (R+M/2) unleaded Singapore cargoes; kerosene on Singapore cargoes; ADO of 0.5% gasoil, Singapore cargoes; IDO of 1% gasoil, Singapore cargoes; and fuel oil of HFSO, 180 Cst Singapore cargoes.

16 The fixed amount C can be used to cover quality differences between Singapore and Indonesian specifications; import/export freight differentials, and internal terminaling, distribution and marketing costs within Indonesia. Based upon current US margins, the proposed values of C for each BBM product are: gasoline, US$10/bbl; kerosene, US$16/bbl; ADO, US$6/bbl; IDO, US$4/bbl; and fuel oil, US$4/bbl.

17 D_0 can be set to the respective base BBM product price at its current level (Table A2A.4).

18 F_0 can be set to the current value of the Rupiah on the international market (e.g., at the time this Report was prepared, the exchange rate was 7500 Rp:US$1).

19 A is the number of years over which the subsidy is removed. The Bank proposed five years for kerosene, and four years each for ADO, IDO and fuel oil.

20 N is the year of price calculation. In the first year following the base period, $N = 1$.

21 The exchange rate in year N can be based on IMF statistics.

for November, October and September. The value of the F_N term in each quarter should be the latest monthly rate between the Rupiah and the US$ as published in the monthly IMF *Financial Statistics* and Market Rates.

Options for Protecting the Poor

A2A.63 Although all options have advantages and disadvantages, evidence is overwhelming that direct income support to the poor is more effective than indirect support, such as through subsidized energy which is consumed by all income groups. Subsidizing energy is a very ineffective and inefficient means of supporting the poor, and once granted, difficult to remove. The Government could accomplish its welfare objectives more effectively if it does not rely on subsidized energy but rather provides a direct payment to poor households. Efficiency pricing would result in an efficient use of energy, while a direct payment would maintain the level of income. Thus, it is recommended that subsidies to the poor be treated outside the sector, and should be a clear line item in the budget rather than achieved by a transfer outside the budget. Further, subsidies should be fiscally neutral; (i.e., they should be funded by the increased tax revenue gained from the efficiency pricing of energy). Although a detailed discussion of the exact method of delivering the equivalent subsidy to the poor is outside the scope of this study, the development of a workable vouchering system should not be complex, (and one approach is discussed in the following subsection).

Kerosene Voucher Scheme

A2A.64 A voucher scheme could be used to protect the poor from an increase in the price of kerosene. Each household would receive a voucher for the difference between the old and the new price. Such a scheme would require several elements: (i) targeting poor households; (ii) publicizing the program; (iii) distributing the vouchers; and (iv) redeeming the vouchers. A list of the poorest households (termed "OPK eligible households") is prepared annually on the basis of data available from the BKKBN census, and the resultant list is already utilized under Indonesia's existing scheme for distributing rice. 1998 data suggests that only 18% of the poor consume no kerosene, hence the level of mistargeting due to not specifically identifying kerosene-consuming households is not unreasonable.

A2A.65 At the time of the Government's announcement of the increases to the petroleum product price (para. A2A.58) the intention of protecting the poor, along with the details of the voucher scheme, should be publicized through the mass media to the general public. Additionally, implementation information should be provided to local officials.

A2A.66 It would be most effective for the vouchers to be distributed down to the village level along with the first distribution of OPK rice. An entire year's worth of vouchers, comprising a set of single vouchers for each month's consumption, could all be distributed at this time. When households come to receive their rice they would also collect and sign for the receipt of the vouchers, and these would be counter-signed by the appropriate village official and the BKKBN cadre involved in the OPK distribution. The household recipient would sign again upon redeeming the voucher.

A2A.67 The face value of the voucher would be the amount of the price increase, multiplied by the number of liters subsidized, and all retailers of kerosene would be instructed to accept the doubly signed voucher at this face value. The retailers could then redeem their vouchers with government agencies for the face value, plus a transaction fee to provide compensation for the inconvenience of accepting vouchers, plus an administration fee.

A2A.68 Obviously, if the program of mitigating the price increases is tainted by corruption, it loses much of its political value. However, such a scheme mitigates corruption in three ways. First, because the voucher scheme is simple to publicize, recipients will be informed of their benefits, and will themselves become "bottom up" monitors. Second, with printing of the vouchers by the mint, counterfeiting is avoidable. And third, since an existing distribution system exists for OPK, creating the new system of controls should be straightforward.[22]

Institutional Arrangements

A2A.69 Besides raising prices to their opportunity costs and developing an appropriate adjustment formula, the institutions must have the capacity to sustain the prices efficiently and effectively over the transition period. They must be able to assess the economic cost of supply and the value of energy products for the end users. In Indonesia, this may also require changes in legislative and governmental set-up as well as the regulatory aspect of the various energy related institutions. Again, a detailed analysis of this has not been provided here, but the need for strengthening of the energy sector institutions across the board is discussed briefly in Chapter 1 of this Report. With regard to pricing, however, experience shows that the long term viable option is to let the condition of the market set the prices. Since it is not expected that during the price adjustment transition, such a fully market based operation will take effect, the prices must be regulated in a clear and transparent manner.

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[22] The combined fiscal and administrative cost of implementing such a scheme depends on how rapidly, and to what level, the kerosene price is adjusted. However, it is estimated that, even if the poorest 30% were compensated for the full impact of the increase, the total cost of the scheme would be Rp 445 billion, compared to the existing subsidy of Rp 1.3 trillion. This estimate is based on implementing the scheme for the last nine months of the 2000 fiscal year, with a monthly voucher cost being Rp 3,530, average household size of 4.5, annual consumption per household being 114.5 liters, and assuming 13.3 million households make up the poorest 30%.

ANNEX 2B: Price Reform Scenarios

A2B.1 This Annex assesses the efficiency losses, changes in fuel consumption and foreign exchange impacts under various petroleum product price reform scenarios, and presents the assumptions which underlie these scenarios. (The environmental benefits associated with the various scenarios are provided in the following Annex 2C).

Basis for Analysis

Price Scenarios

A2B.2 Three scenarios were evaluated. A "status quo" case and a "reference case" represent the two extreme scenarios; in the status quo case, current price subsidies are assumed to persist indefinitely. The reference case illustrates what would happen under total deregulation with all domestic prices determined by international prices, adjusted for transportation differentials. The difference between these cases is used as a basis for calculating deadweight (efficiency) losses (DWL) and for calculating 'net environmental damages' as a consequence of current subsidy levels. The net damages and DWL reduce to zero in the event of complete deregulation. A third scenario is analyzed to illustrate the demand and environmental impacts under a case of "phased price deregulation". Prices under the three scenarios are summarized in Table A2B.1.

Table A2B.1: Prices

Prices ($/bbl)

	Status Quo	Ref	Phased Price Reforms 2000	2001	2002	2003	2004	2005	2006	2007
Mogas	21.20	26.80	21.20	21.20	21.20	21.20	24.38	26.80	26.80	26.80
Kerosene	5.94	32.90	7.13	8.91	11.58	15.64	21.89	32.90	32.90	32.90
ADO	11.66	28.60	13.99	16.79	20.15	25.19	28.60	28.60	28.60	28.60
IDO	10.60	25.60	12.72	15.26	18.32	22.90	25.60	25.60	25.60	25.60
Fuel Oil	7.42	23.10	9.28	11.59	14.49	18.12	23.10	23.10	23.10	23.10

Scheduled Price Increases (mid-year) – Phased Price Reform Scenario

	2000	2001	2002	2003	2004	2005
Mogas	0.0%	0.0%	0.0%	0.0%	15.0%	10.0%
Kerosene	20.0%	25.0%	30.0%	35.0%	40.0%	50.3%
ADO	20.0%	20.0%	20.0%	25.0%	13.6%	0.0%
IDO	20.0%	20.0%	20.0%	25.0%	11.9%	0.0%
Fuel Oil	25.0%	25.0%	25.0%	25.0%	27.6%	0.0%

Analytic Structure

A2B.3 A partial equilibrium approach is taken that considers the impacts of changes in energy prices for only the five fuels under consideration. It is quite possible, and likely, that other feedback effects might occur through other sectors that are not captured in such an exercise. However, a more complex analysis would require a full general equilibrium model of the economy which reflects the potential dynamic changes of price reforms. Such a model is unavailable, and would likely be unreliable in any event given that the "post-crisis" structural conditions are significantly different from those extant five years ago. The modeling approach therefore focuses on the use of long-term partial equilibrium demand elasticities associated with forecasted changes in income (GDP) and own-product prices.

GDP Forecasts

A2B.4 Although Indonesia's economy suffered a severe shock in 1998, signs of macroeconomic stability and recovery are appearing. For the purposes of this analysis, we followed the IMF forecast for short-term GDP growth (Table A2B.2). For the longer term, we forecast GDP growth at 5% annually, which is consistent with most analysts' forecasts for the region as a whole.

Table A2B.2: GDP Assumptions

Year	Real GDP Growth
1999	1.8%
2000	3.0%
2001	4.0%
2002	5.0%
2003	5.0%
2004	5.0%
2005	5.0%
2006	5.0%
2007	5.0%

Demand and Demand Elasticities

A2B.5 1997 and 1998 petroleum product consumption data and prices are used as the basis for demand projections. The analysis focused on the five BBM products: motor gasoline, kerosene, auto diesel oil, industrial diesel oil, and fuel oil. The demand was projected in the presence and absence of subsidies to the year 2007, and these were also used to estimate pollution impacts (Annex 2C) under the three scenarios.

A2B.6 A literature review was undertaken to determine the likely levels of income and own-price elasticities for petroleum products in Indonesia (Table A2B.3). While a vast body of literature exists that can assist in determining appropriate fuel price and income elasticities, few specific studies have been undertaken for Indonesia. And many more recent studies relate only to short-term adjustments arising from small marginal changes in price. The price reforms being considered in this study involve substantial (non-marginal) changes and most of the impacts will be much longer-term in nature. In many regards, such price shifts are similar to those occurring during the petroleum price shocks of the 1970s; our literature survey therefore includes studies that spanned the past 30 years. Price changes in that period provide a comparatively good proxy for the levels of price change that one might witness if prices were deregulated in the near future.

Table A2B.3: Summary of Selected Demand Elasticity Studies

Country	Source/ Analysis Period	Elasticity Results
Asia historical to 1995	Drysdale, P. and Y. Huang (1995)	Drysdale and Huang (1995), among others, have compiled estimates for the income elasticities of energy demand for SE Asian countries. The results reveal that the income elasticity of demand for developing East Asia was 0.6 during 1965-89 compared with 0.5 for the world as a whole. These authors note, however, that the income elasticities have been declining for a number of SE Asian countries: from the early 1970s to mid-1980s it has declined from 1.0 to 0.4 for China; 1.0 to 0.9 for Korea; 1.0 to 0.8 for Hong Kong; 2.6 to 0.9 for Singapore; and 2.5 to 1.5 for Indonesia. As noted by Fesharaki and Wu (1992) studies undertaken by MacRae (1991) and Lucas et al. (1987) demonstrate wide variation in the income elasticities of demand between different countries.

Table A2B.3 (continued): Summary of Selected Demand Elasticity Studies

Country	Source/ Analysis Period	Elasticity Results
non-OPEC 1969-1978	World Bank. 1983.	Average Price Elasticity = -0.55. Average Income Elasticity = 1.10 (Petroleum) These price elasticities are interesting because they represent the period of substantial price increases.
Vietnam (+ comparison to Philippines, Thailand, Korea, China, Myanmar, Malaysia) 1980s-90s	World Bank. 1999.	1990-98 Petroleum Products:Income = 1.2 (Vietnam) 1990-98 Petrol Products:Income = 1.2 (Asia Low income countries) Petrol, Diesel, Avgas: Price = –0.7 (Vietnam) Fuel Oil, LPG, Kerosene: Price = –0.6 (Vietnam) Electricity:Income = 1.7 (Vietnam - Historical) Electricity:Income = 1.64-1.74 (Vietnam - Projected) Electricity:Income < 1.7 (China, Myanmar) Electricity:Income ≥ 1.7 (low-income Asia)
Sri Lanka 1990s	Chandrasiri, Sunil. 1999.	Petrol Price Elasticity = –0.078 Study recommends using technical options for reducing pollution, as opposed to taxation or pricing options because of very inelastic demand. He concludes these are more relevant elasticities than earlier estimates because they reflect liberalized markets.
Sri Lanka 1970-1985	Ranasinghe AP, Samaraweera CP, de Silva APGS. 1989.	Diesel Own Price Elasticities: = -0.034 (Ranasinghe 1989) = -0.026 (Samaraweera 1989) = -1.21 (De Silva 1989) Petrol Own Price Elasticities: = -0.508 (Ranasinghe 1989) = -0.387 (Samaraweera 1989) = -1.55 (De Silva 1989)
Indonesia 1970-1990	Usui, N. 1996.	No estimate of elasticities but essentially argues that many elasticities may not be that meaningful in a CGE framework during rapid macroeconomic adjustments such as price shocks or liberalization. The "Dutch Disease" which in effect makes all products less competitive due to currency strength would also thus have an influence on derived product demand. The main point is simply that many small partial equilibrium price adjustments in the petrol product sector (measured by conventional price elasticities) may be far off the mark during rapid adjustments.
Developing Countries 1980s	Anderson, D. and Cavendish, W. 1992	Average Income Elasticity = +1.20 Price Elasticity of Demand = -0.50 Congestion Price Elasticity of Demand = -0.60 (based on higher initial distortions from congestion)
Developing Countries 1980s	Bates RW and Moore EA 1992.	Price Elasticity = -0.5
Philippines 1990s	M. de los Angeles et al. 1998. Pers comm.	Preliminary results from taxation modeling show result in range of -0.4 to -0.7 for transport fuels.
Bangladesh 1970s	DeLucia RJ and Jacoby HD. 1982.	Price Elasticity for single industrial fuels, depended on industry but was in a range of (negative) 0.5 to 1.7.
Mexico 1990s	Belausteguigoitia, Contreras and Guadarrama (1995)	Analyses of Gasoline Tax impact generated gasoline own price elasticities of: -0.4 (short term) -0.8 (long term)

A2B.7 For own-price response, (which are more relevant to DWL calculations and pollution impacts) most of the evidence suggests motor fuel elasticities in the range of (minus) 0.4 to 0.8 and diesel motor fuel somewhat less elastic. Industrial fuels are generally more elastic. When one accounts for congestion effects (i.e., that there may be quite substantial changes from non-marginal price shifts), there could be a somewhat greater response in demand. One of the studies suggests slightly more elastic demand in the face of high congestion; elasticity changes from -0.5 to -0.6 when congestion effects are included. The only exception to the (minus) 0.4 to 0.8 range is a recent 1999 study from Sri Lanka – it cites very inelastic demand of -0.078. But this relates to a very small price change (of less than 10%) and it is unlikely that demand would remain so inelastic in a major reform; earlier studies in Sri Lanka during the oil crises showed price elasticities in the -0.5 range.

A2B.8 In sum, the results generally showed that price elasticities (ε) would lie in the realm of –0.4 to –0.8, with demand in the industrial sectors being somewhat more elastic than in the transport sector. Moreover, as a whole, income elasticities (η) for Indonesia are anticipated to fall in a range of +1.2 to +1.5. For the purposes of this analysis, transport fuels are modeled at a price elasticity of $\varepsilon = -0.5$ and industrial fuel demand is forecast to respond to prices at a price elasticity of $\varepsilon = -0.7$. All product demand is conservatively forecast to respond to GDP at an income elasticity of $\eta = +1.2$. Values used for the scenarios are given in Table A2B.4, and all calculations are conducted assuming isoelastic demand functions.[1]

Table A2B.4: Elasticity Assumptions

Own Price Elasticity of Mogas	– 0.5
Own Price Elasticity of Kerosene	– 0.5
Own Price Elasticity of ADO	– 0.5
Own Price Elasticity of IDO	– 0.7
Own Price Elasticity of Fuel Oil	– 0.7
Elasticity of Fuel Consumption to Income	+ 1.2

Results: Product Consumption, Economic Efficiency and Foreign Exchange Losses

A2B.9 Table A2B.5 also shows the demand for various products under the three pricing scenarios; Table A2B.6 shows the implied efficiency losses (deadweight losses). In the status quo scenario, deadweight losses in 2000 are approximately $1,483 million, while they increase to $1,963 million by 2005. In the case of phased price reforms, deadweight losses in 2000 would be $1,058 million and they would be totally eliminated by 2005.

A2B.10 These results are quite sensitive to assumptions relating to demand elasticities. If, for example, energy intensity increased more rapidly with income growth ($\eta = +1.5$) and if own price elasticity were $\varepsilon = -0.6$ for transport fuels and $\varepsilon = -0.8$ for industrial fuels, then deadweight losses by 2005 would increase to US$2,430 million.

A2B.11 The analysis also provides a basis for calculating foreign exchange losses to the country as a result of the subsidies. While the subsidies generate higher consumption ("excess consumption" as implied by Table A2B.7a), the total foreign exchange cost is applied to the total consumption. Table A2B.7a, for example, shows that in the year 2005, about 155 million barrels of "excess" fuel would be consumed if prices remain unchanged. The foreign exchange subsidy on this excess consumption

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[1] Where Q is consumption, P is price and Y is income: $Q = Q_o\left(\frac{P}{P_0}\right)^{\varepsilon}\left(\frac{Y}{Y_0}\right)^{\eta}$

alone would be almost $3 billion (Table A2B.7b). The total foreign exchange cost of the total subsidy, however, approaches $6.8 billion. From a planning perspective, this latter figure may be the more relevant as it is not generally possible to eliminate the subsidy on only a portion of the product consumption. With phased price reforms, of course, the foreign exchange subsidy is reduced to zero by 2005.

Table A2B.5: Demand Forecast

Demand (million barrels)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo (no change in prices)										
Mogas	69.12	70.61	73.16	76.67	81.27	86.14	91.31	96.79	102.60	108.75
Kerosene	63.91	65.29	67.64	70.89	75.14	79.65	84.43	89.49	94.86	100.56
ADO	123.95	126.63	131.19	137.48	145.73	154.48	163.74	173.57	183.98	195.02
IDO	8.01	8.18	8.48	8.88	9.42	9.98	10.58	11.22	11.89	12.60
Fuel Oil	32.94	33.65	34.86	36.54	38.73	41.05	43.52	46.13	48.89	51.83
Reference (immediate change to World Prices)										
Mogas	61.48	62.80	65.06	68.19	72.28	76.62	81.21	86.09	91.25	96.73
Kerosene	27.16	27.74	28.74	30.12	31.93	33.84	35.87	38.03	40.31	42.73
ADO	79.14	80.85	83.76	87.78	93.05	98.63	104.55	110.83	117.47	124.52
IDO	4.32	4.41	4.57	4.79	5.08	5.39	5.71	6.05	6.41	6.80
Fuel Oil	14.88	15.20	15.74	16.50	17.49	18.54	19.65	20.83	22.08	23.41
Phased Price Reforms										
Mogas	69.12	70.61	73.16	76.67	81.27	86.14	85.15	86.09	91.25	96.73
Kerosene	63.91	65.29	61.75	57.88	53.81	49.09	43.98	38.03	40.31	42.73
ADO	123.95	126.63	119.76	114.57	110.86	105.11	104.55	110.83	117.47	124.52
IDO	8.01	8.18	7.46	6.88	6.42	5.82	5.71	6.05	6.41	6.80
Fuel Oil	32.94	33.65	29.82	26.73	24.24	21.98	19.65	20.83	22.08	23.41

Table A2B.6: Efficiency Losses

Deadweight Losses (million $)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo (no change in prices)										
Mogas	23	23	24	25	27	28	30	32	34	36
Kerosene	695	710	736	771	818	867	919	974	1032	1094
ADO	463	473	490	514	545	577	612	649	688	729
IDO	34	35	36	38	41	43	46	48	51	54
Fuel Oil	186	190	197	206	218	232	245	260	276	292
Total	1402	1432	1483	1555	1648	1747	1852	1963	2080	2205
Phased Price Reforms										
Mogas	23	23	24	25	27	28	5	0	0	0
Kerosene	695	710	580	438	293	156	49	0	0	0
ADO	463	473	309	179	82	11	0	0	0	0
IDO	34	35	22	12	5	1	0	0	0	0
Fuel Oil	186	190	122	70	33	9	0	0	0	0
Total	1402	1432	1058	725	439	205	54	0	0	0

Note: Conventional calculation of deadweight losses assuming iso-elastic demand function. Deadweight losses in reference scenario are zero.

Table A2B.7a: Consumption and Foreign Exchange Impacts

Change in Fuel Consumption Relative to Status Quo (million barrels)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Reference (immediate change to World Prices)										
Mogas	(7.64)	(7.81)	(8.09)	(8.48)	(8.99)	(9.53)	(10.10)	(10.70)	(11.35)	(12.03)
Kerosene	(36.75)	(37.55)	(38.90)	(40.77)	(43.21)	(45.81)	(48.55)	(51.47)	(54.56)	(57.83)
ADO	(44.81)	(45.77)	(47.42)	(49.70)	(52.68)	(55.84)	(59.19)	(62.74)	(66.51)	(70.50)
IDO	(3.69)	(3.77)	(3.90)	(4.09)	(4.34)	(4.60)	(4.87)	(5.17)	(5.48)	(5.80)
Fuel Oil	(18.06)	(18.45)	(19.12)	(20.04)	(21.24)	(22.51)	(23.86)	(25.30)	(26.81)	(28.42)
Phased Price Reforms										
Mogas	-	-	-	-	-	-	(6.16)	(10.70)	(11.35)	(12.03)
Kerosene	-	-	(5.89)	(13.01)	(21.33)	(30.56)	(40.45)	(51.47)	(54.56)	(57.83)
ADO	-	-	(11.43)	(22.91)	(34.87)	(49.37)	(59.19)	(62.74)	(66.51)	(70.50)
IDO	-	-	(1.02)	(2.00)	(3.00)	(4.16)	(4.87)	(5.17)	(5.48)	(5.80)
Fuel Oil	-	-	(5.04)	(9.80)	(14.49)	(19.07)	(23.86)	(25.30)	(26.81)	(28.42)

Change in Fuel Consumption Relative to Full Deregulation (million barrels)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Phased Price Reforms										
Mogas	7.64	7.81	8.09	8.48	8.99	9.53	3.94	-	-	-
Kerosene	36.75	37.55	33.01	27.76	21.88	15.25	8.10	-	-	-
ADO	44.81	45.77	35.99	26.79	17.81	6.47	-	-	-	-
IDO	3.69	3.77	2.89	2.09	1.34	0.44	-	-	-	-
Fuel Oil	18.06	18.45	14.08	10.23	6.75	3.44	-	-	-	-

Table A2B.7b: Consumption and Foreign Exchange Impacts

Total Foreign Exchange Subsidy Relative to Full Deregulation (million $) [Note 1]

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo (no change in prices)										
Mogas	387	395	410	429	455	482	511	542	575	609
Kerosene	1,723	1,760	1,824	1,911	2,026	2,147	2,276	2,413	2,558	2,711
ADO	2,100	2,145	2,222	2,329	2,469	2,617	2,774	2,940	3,117	3,304
IDO	120	123	127	133	141	150	159	168	178	189
Fuel Oil	516	528	547	573	607	644	682	723	767	813
SUM	4,846	4,951	5,129	5,376	5,698	6,040	6,402	6,787	7,194	7,625
Phased Price Reforms										
Mogas	387	395	410	429	455	482	206	-	-	-
Kerosene	1,723	1,760	1,591	1,389	1,147	847	484	-	-	-
ADO	2,100	2,145	1,749	1,353	937	359	-	-	-	-
IDO	120	123	96	71	47	16	-	-	-	-
Fuel Oil	516	528	412	308	209	110	-	-	-	-
SUM	4,846	4,951	4,259	3,550	2,795	1,814	690	-	-	-

Total Foreign Exchange Subsidy on Excess Consumption (million $) [Note 2]

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo (no change in prices)										
Mogas	43	44	45	47	50	53	57	60	64	67
Kerosene	991	1,012	1,049	1,099	1,165	1,235	1,309	1,388	1,471	1,559
ADO	759	775	803	842	892	946	1,003	1,063	1,127	1,194
IDO	55	57	59	61	65	69	73	77	82	87
Fuel Oil	283	289	300	314	333	353	374	397	420	446
SUM	2,131	2,177	2,256	2,364	2,506	2,656	2,816	2,985	3,164	3,353
Phased Price Reforms										
Mogas	43	44	45	47	50	53	10	-	-	-
Kerosene	991	1,012	851	666	466	263	89	-	-	-
ADO	759	775	526	316	151	22	-	-	-	-
IDO	55	57	37	22	10	1	-	-	-	-
Fuel Oil	283	289	195	118	58	17	-	-	-	-
SUM	2,131	2,177	1,654	1,169	735	357	99	-	-	-

Note 1: This is the total subsidy (P_1-P_2) multiplied by the total consumption in each year. This is in effect the total fiscal cost of the subsidy.

Note 2: This is the total subsidy (P_1-P_2) on just the excess consumption (ΔQ). This might roughly be interpreted as the FX cost to the overall budget from overconsumption. It should be noted, however, that it would presumably be difficult to 'recover' this without eliminating the total subsidy on all consumption.

ANNEX 2C: Environmental Benefits of Rationalizing Petroleum Product Prices

A2C.1 Indonesia's policy makers are well aware of the negative economic impacts of poor environmental quality. Mechanisms to combat pollution and its deleterious effects have been persistently pursued through numerous pieces of legislation, and Indonesia's extensive Adipura ("Clean Cities") program remains as one of South East Asia's more impressive models of local awareness campaigns. But even with strong political will, many of the problems associated with environmental degradation can become intractable during a period of institutional fragility and severe budgetary constraints. Indonesia has relied historically on a strong regulatory element (such as extensive EIA planning and monitoring mechanisms); it now finds itself with less environmental regulatory capability in the face of pressure to reduce government spending.

A2C.2 But what many fail to recognize is that market forces are still among the strongest potential allies in achieving environmental quality goals. This is particularly true when current market conditions are distorted. Environmental regulations are most effective when external policy distortions are absent, and fixing such distortions is often regarded as the first and most important step in achieving environmental goals. Indonesia was one of the world's leaders in demonstrating this lesson when it progressively removed agrochemical subsidies through the 1980s and 1990s. These subsidies had been costing the country hundreds of millions of dollars of foreign exchange, and the resultant overuse of chemicals resulted in the poisoning of waterways and overexploitation of soil quality. Removal of these subsidies improved economic efficiency and environmental quality without any loss of productive capacity.

A2C.3 The energy sector is now in a similar situation. Price subsidies distort markets, overwhelming any regulatory attempts to correct extensive environmental problems. In this Annex, we explore the link between energy pricing and environmental quality, and especially how changes in environmental quality have real economic consequences for human health and productivity.

Key Issues

A2C.4 Although few who experienced Asia's economic meltdown in 1998 would find much good to say about the circumstances, one of the silver linings was a noticeable improvement in air quality. The economic slowdown reduced consumption of all commodities, including energy products, and smog and pollution in the region's urban centers fell to historical lows. The connection between economic activity and environmental quality is therefore one of the most obvious linkages that one can find. But during the same period, Indonesia also experienced a worsening of air quality in some parts of the country as uncontrolled forest and plantation fires covered the region with haze. Estimates of the damages from this episode place health impacts on Indonesia at just under $1 billion over just a three month period; in this case, the linkage between air pollution and human health costs made daily headlines.

A2C.5 Drawing connections between energy price distortions and environmental damages is therefore not that difficult. In principle, economic subsidies lead to over-consumption of petroleum products. Such over-consumption leads to congestion and excess pollution, which in turn has health impacts on all of those exposed. Here, we shall quantify–using simple modeling tools–the extent of such damages. In particular, we focus on the following impacts:

- health impacts associated with urban air pollution;
- health impacts associated with lead; and,
- impacts associated with carbon emissions.

A2C.6 In addition, we treat more generally the lost opportunities for inter-fuel substitution, and the continued need to address residual damages that will persist even if prices are deregulated.

A2C.7 As a starting point, we take 1997 and 1998 petroleum product consumption and prices as a basis for demand projections. We focus the analysis on the BBM products: motor gasoline, kerosene, auto diesel oil, industrial diesel oil, and fuel oil. Our purpose is to project demand in the presence and absence of subsidies to the year 2007, and to isolate pollution impacts under these scenarios. Pollution impacts are then translated, through a dose-response function, into human morbidity impacts (in terms of increased incidence of illness) and the consequential economic damages from lost productivity, higher medical treatment costs, and lower quality of life.

A2C.8 In undertaking these forecasts, a conservative approach has been followed that in general would tend to underestimate impacts. Scenarios investigated are those outlined in Annex 2B. For determining the pollution impacts related to these scenarios, a comprehensive model was developed which translates fuel consumption into air pollution loads, and in turn correlates these to human health through a dose response function. The initial basis for this model was developed during the World Bank's analysis of Jakarta's air pollution problems undertaken for a special 1994 report on Indonesia's environment. The model was subsequently refined, recalibrated and updated with health expenditure data collected subsequent to the 1998 haze episodes. The model was calibrated to replicate a damage assessment for 1998, at which point in time total damages from lead, particulates, and NOx are estimated to be about \$2.3 billion; subsequent damages were forecast as a function of economic growth and the fuel consumption mix, taking into account that different fuel types have different impacts on different pollution loads (gasoline consumption, for example, has the greatest impact on lead pollution). Model parameters are shown in Table A2C.1.

Results

Urban Air Pollution

A2C.9 Separate modeling was undertaken to estimate the impacts of particulate matter (PM), nitrogen oxides (NOx), and lead (Pb). The primary health impacts of particulates and NOx deal with respiratory illnesses, and historical information shows that these pollutants are highly correlated both to morbidity and to mortality. Studies in the early 1990s for Jakarta, for example, showed that respiratory illness was the sixth leading cause of death in Indonesia; in Jakarta it accounted for 12.6% of mortality. While the models we employ here do not estimate the economic costs of mortality, a cost of illness can be calculated through using a damage function that correlates energy consumption to pollution levels to human health. Results are shown in Table A2C.2.

A2C.10 The model projects baseline damages in each of the three pricing/consumption cases; differences in economic damages represent the gains that would be realized from deregulating prices.

A2C.11 Under current prices, results show that environmental damages in 2000 are expected to be \$1,638 million from PM and NOx. Of this, \$594 million is in the form of increased medical costs, \$225 million is lost productivity and \$819 million is a loss in consumer surplus from lower quality of life. In 2005, the total environmental damages are \$2,739 million. If prices were set at reference prices, then damages in 2000 would be \$1,003 million and in 2005 would be \$1,677 million. It is clear that the net damages caused by subsidies are about \$635 million in 2000, and about \$1,062 million in 2005. Removing the subsidies totally would reduce the net damages to zero (although there would still be residual damages from the remaining pollution). Using phased price reforms, the results show (similar to the deadweight loss calculations) elimination of the net environmental costs by 2004.

Table A2C.1: Parameters in Dose-Response Model

Parameter	Value	Description
Population at Risk (POP)	80 million	This represents Indonesia's total urban population subject to air pollution levels exceeding WHO standards.
Base Level Annual Exposure (EXP)	210 days	This represents the potential number of days of annual exposure to excessive pollution levels. It is less than 365 days because of factors such as low pollution days (often on weekends) and days during which local weather mitigates pollution hazards.
Incidence of Seen Cases (INC)	1.5	This is a base level of cases (per day per 10,000 population) typically observed, responding to incidence of diseases related to airborne pollutants.
Ratio of Hospitalized Cases (HOSP)	30%	Of the seen cases, this proportion requires some form of eventual hospitalization or clinical treatments. Other cases are treated as out patients or are simply prescribed single courses of medicines or symptomatic relief.
Ratio of Self-treated Cases (ST)	11:1	Detailed studies in Indonesia show this to be a very high ratio. These include people who do not visit a clinic, visit 'alternative medical practitioners', or (frequently) simply follow the same course of treatment as somebody in their household who did seek formal treatment.
Lost Productivity (LP1 & LP2)	5-10 days	Surveys showed that for hospitalized cases an average of 10 days (LP2) was lost, while for other cases (including self-treated) a typical incident would last about 1 week (LP1).
Cost of Treatment (C1 & C2)	US$20-US$325	Treatment costs for non-hospitalized cases reflect direct medical costs for drugs (C1) while the higher level of treatment represents daily care costs in a clinic or hospital (C2).
Cost of Labor (WAGE)	US$4/d	This corresponds to a wage rate of approximately Rp30,000 daily, and is applied as a proxy for lost productivity. The actual burden of this cost may fall either on the employer, the employee, or (in the case of farming households) on the household. In any event, it is treated as a cost to the economy as a whole.
Adult Share (ADULT)	51%	Lost productivity is applied only to that share of the population that is economically active, construed as 16-65 years of age. Note that a significant proportion of morbidity incidence applies to children.
Ratio of PM:NOx:Pb	65:1:37	This ratio is based on clinical assessment undertaken in Indonesia in 1994, representing the ratio of cases correlated to each of these pollutant types.
Consumer Surplus Factor (CSF)	2:1	Direct costs associated with drugs and lost productivity still understate willingness to pay for improved air quality. This consumer surplus is generally attributed to higher amenity for adults, and higher quality of life for school children because of improved school performance. A ratio of 2:1 is consistent with more detailed consumer surplus surveys that total WTP is typically 2 to 3 times greater than direct cost.

Table A2C.2:Domestic Urban Air Pollution Impacts

Environmental Damages (million $)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo										
Particulates	1453	1512	1613	1758	1957	2178	2424	2698	3002	3342
NOx	22	23	25	27	30	34	37	42	46	51
Lead (no phase-out)	827	860	918	1001	1114	1240	1380	1536	1709	1902
Reference										
Particulates	890	926	988	1076	1198	1333	1484	1652	1838	2046
NOx	14	14	15	17	18	21	23	25	28	31
Lead (with phase-out)*	579	603	386	280	312	0	0	0	0	0
Phased Price Reforms										
Particulates	1453	1512	1485	1486	1517	1532	1552	1652	1838	2046
NOx	22	23	23	23	23	24	24	25	28	31
Lead (with phase-out)*	827	860	517	353	370	0	0	0	0	0

Net Environmental Damages (million $)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo										
Particulates	563	586	625	682	759	844	940	1046	1164	1296
NOx	9	9	10	10	12	13	14	16	18	20
Lead	248	258	532	720	802	1240	1380	1536	1709	1902
Total	820	853	1167	1412	1572	2097	2334	2598	2891	3218
Phased Price Reforms										
Particulates	563	586	497	410	319	198	68	0	0	0
NOx	9	9	8	6	5	3	1	0	0	0
Lead	248	258	132	73	58	0	0	0	0	0
Total	820	853	636	489	382	201	69	0	0	0

* The 'with phase-out' assumptions imply that Indonesia attains its lead phase-out targets in association with any moves to reform price structures. The scheduled phase-out of lead is as follows: 2000 - 40%; 2001 - 60%; 2003 - 100%.

Lead

A2C.12 Lead is of particular concern in Indonesia because, unlike other countries in the region (Box A2C.1), Indonesia has not yet commenced an effective program of lead reduction from fuels. Such programs can take 10 to 20 years to implement successfully and it is not generally possible to intervene quickly (importation of unleaded fuel is an option, but most of the vehicle stock is not configured to use such fuel). Although Indonesia has mandated a lead phase-out schedule for fuels, to date there has been little success in achieving any level of phase-out and most monitoring still shows that Indonesia has among the highest levels of lead in the region.[1] The morbidity effects of lead are well documented and

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[1] Lead in gasoline has a specification of 0.45 g lead per liter in Indonesia. Planned phase-out programs would have seen Jakarta lead-free by the end of 2000, with the rest of the country at 0.14 g Pb/l; by 2001 all of Java would be lead free, and by January 2003 all of the country would be lead free. By contrast, low lead petrol (0.15 g Pb/l) has been mandated in Malaysia since 1985, and the Philippines have now converted entirely to lead free petrol in urban areas.

World Health Organization guidelines now suggest that there is no acceptable minimum standard; zero tolerance is the norm. This is because lead accumulates through one's entire life and has particularly deleterious effects in young children; it hampers normal mental development and undermines future educational efforts. In terms of a long-term social investment, therefore, reducing lead emissions is generally regarded as a top priority in most developing countries.

A2C.13 The model results show (Table A2C.2) that, in the status quo case (no price changes and no attempt at lead phase-out), lead poisoning is likely to contribute $918 million in damages in 2000, rising to $1,536 million in 2005. With prices totally deregulated and with a lead phase-out program on schedule, the 2000 impacts would be $386 million and in 2005 impacts would be nil. The net damages from lead, as a result of over-consumption of fuels because of price subsidies, are thus $532 million in 2000 and $1,536 million in 2005. Again, with phased price reforms, net damages are zero by 2005.

Global Climate Change

A2C.14 Global climate change is currently a concern of industrialized and developing countries alike. The combustion of hydrocarbon fuels increases carbon emissions, resulting in the generation of greenhouse gases. Such emissions increase global warming, which in turn is assumed to cause economic damage. Previous studies for the Intergovernmental Panel on Climate Change have put a value of up to US$30 on the damage caused by a ton of carbon emitted; figures up to this amount are commonly used in international negotiations. The model used in this study calculated carbon emissions in each case (Table A2C.3), and, as an example, it was found that the removal of subsidies would reduce emissions from 25.03 tC to 15.71 tC in 2005. This reduction of 9.32 tC is equivalent to an emission equivalent of about 34.2 tCO_2 [2] and net annual damages to the global community of $280 million.

Table A2C.3: Global Climate Change Impacts

Net Environmental Damages (million $)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Status Quo										
Total Carbon	200	204	211	222	235	249	264	280	296	314
Phased Price Reforms										
Total Carbon	200	204	169	136	102	63	22	0	0	0

Summary

A2C.15 The base case analyses suggest that, as a result of price subsidies, transport and industrial fuels are over-consumed, creating an excessive amount of pollution and associated environmental impacts. As a typical case, we can summarize (Table A2C.4) what the effects would be in 2005 of removing all fuel subsidies (millions of $).

Table A2C.4: Summary of Environmental Impacts

2005	Without Reforms	With Reforms	Net Gain
Particulates and NOx Damages	2739	1677	1062
Lead Damages	1536	0	1536
Carbon	751	471	280
Sum	6988	2148	4840

[2] Based on 12/44 ratio for $C:CO_2$.

A2C.16 The net gain of removing subsidies and reducing lead damages approaches $5 billion. In addition, there are other gains that we have not addressed because they relate primarily to long-term gains that would not be realized within the time period of the analysis of this study.

A2C.17 First, by deregulating prices, there will be added price incentives for long-term inter-fuel substitution to cleaner technologies. In particular, natural gas based fuels and energy would be potentially important for the commercial, industrial, and transport sectors. The environmental benefits of natural gas are well documented. As a cleaner burning fuel, hazardous emissions are virtually absent such that switching thus provides an opportunity to reduce the still significant residual damages from petroleum product fuels.

A2C.18 Second, and perhaps more significantly, deregulating prices provides conditions in which environmental regulatory standards are more likely to have a meaningful effect. In the absence of pricing distortions, other jurisdictions have found that it is more likely that awareness building efforts, vehicular emission controls (e.g., use of catalytic converters), and lead phase-out programs will achieve some level of success. As noted above, residual damage from particulates and NOx in 2005 would still approach $1.7 billion, and would grow annually as income levels and consumption continued to expand. Addressing these residual damages through proper environmental controls will be facilitated in a deregulated environment.

Box A2C.1: Lead Phase-out Programs – Success Stories from Malaysia and Philippines

Lead is a critical pollutant and many jurisdictions in the world have actively sought to reduce lead emissions through a combination of programs. Such initiatives usually encompass education and awareness programs, regulatory changes to fuel specifications and engine characteristics, and, potentially, economic incentives for conversion or retirement of vehicles using leaded petrol. Even with strong political will, however, results often take well over a decade to be realized. This delay is because of many factors: building public awareness is a slow process, aging of vehicle stocks implies that leaded fuel must often remain available for older vehicles, and weak enforcement abilities often create disincentives for converting to low-lead fuels. Nonetheless, experience in Malaysia and the Philippines shows that, eventually, real progress is possible.

Malaysia. Phase-out and regulation of lead in petrol in Malaysia commenced in the late 1970s with public awareness campaigns and discussions regarding lead phase-out. By 1985, specific regulations were passed – "Control of Lead Concentration in Motor Gasoline" – which mandated low-lead petrol of 0.15g/litre. By 1995, all areas of Malaysia had attained the Malaysian air quality guideline of 1.5 $\mu g/m^3$. Over the period 1988 to 1995, detailed monitoring at high-lead sites in Malaysia demonstrated marked improvements from this level: concentration in Selangor had reduced to 0.1 $\mu g/m^3$ while in the busiest areas of Kuala Lumpur concentrations were typically 0.3 $\mu g/m^3$, or 20% of the air quality guideline. The lower lead level was also evident from a shift in fuel use: market share of unleaded gasoline increased from 48.2% to 68.2% over a one year period in 1995.

Philippines. Monitoring of lead levels throughout the 1980s indicated that lead concentrations in Manila were among the highest in the world: concentrations regularly exceeded 1.5 $\mu g/m^3$. Programs to introduce low-lead gasoline were systematically implemented through regulations, coupled with extensive public awareness campaigns into the 1990s. The awareness campaigns were particularly important, primarily to overcome misinformation about the impacts of low-lead fuel on engine performance. Through this period, marked decreases in lead concentrations occurred: by 1994, concentrations had dropped to levels of 0.3-0.5 $\mu g/m^3$. Unleaded gasoline was introduced in the Philippines on 14 February 1994, and under Executive Order it is intended that all leaded petrol will be phased-out. In summary, full lead phase-out will have taken about two decades in the Philippines.

ANNEX 3: The Role and Functions of Pertamina

A3.1 Arguably, having an even more significant impact on the hydrocarbon sector than the problems caused by the subsidies and distortions in the petroleum product pricing regime (discussed in Chapter 2 and Annex 2A), are the problems relating to the role and functions of Pertamina, Indonesia's State oil, gas and geothermal company. There are two key concerns. First, Pertamina is not efficient in its own operations, which include (a) in upstream activities, being directly involved in the exploration and production of its share of oil and gas basins, from which it produces about 14 million barrels of crude/condensate and 270 bcf of natural gas per annum, and (b) in downstream activities, having a virtual monopoly over the entire one million barrel per day domestic fuels market, from refining to transportation, distribution and retailing of petroleum products. Second, there is an inherent conflict of interest (and also inefficiency) associated with Pertamina's role, acting as the Government's sole agent in supervising the activities of the private companies operating in the upstream (the private companies produce the majority of the country's hydrocarbon resources). The conflict of interest results from it regulating the same private sector companies that it competes with. Inefficiencies in this regard stem from Pertamina's supervising role, which is focused more on control than on gaining added value for the Government, consequently contributing to delays and undue interference. The manner in which Pertamina earns its revenue plays a significant part in providing disincentives towards a more efficient operation: it retains 5% of the Government's share of income from upstream activities (excluding its own upstream activities), which after taxes (60%) translates into 2% (typically, this accounts for at least half of its profits). It earns the other half by charging a per barrel fee for all products refined and marketed in the country.

A3.2 This Study did not focus on evaluating Pertamina's inefficiencies and needed internal organizational reforms, because there are two recently completed reports that have analyzed these issues extensively (para. A3.14). Also, the Bank's dialogue with Pertamina during the course of this Study was not adequate, possibly because the company, understandably, did not support the Bank's recommendation to explicitly provide for its de-monopolization in the draft oil and gas law. However, given the findings of the two reports and Bank's own assessment of the sector's overall performance—all pointing out to some deep-seated problems in Pertamina's operations—this shortage of dialogue with Pertamina did not create obstacles for the Bank to arrive at an overall conclusion that Pertamina's inefficiencies and conflicting role are of such a magnitude that they must be addressed urgently.[1]

A3.3 Thus, this Annex provides (a) a brief review of the current global oil industry environment within which Pertamina and the Government need to operate; (b) an overview of Pertamina's problems, by highlighting the key findings of the two reports on Pertamina's inefficiencies, and by briefly discussing Pertamina's conflicting roles in upstream activities; (c) a discussion of how Pertamina's monopolistic role in the downstream can be transformed so that, in line with international best practice, the company is simply one of a number of competitors; and (d) several recommendations of essential reform actions needed to restructure Pertamina, and to fundamentally change its role in both the upstream and the downstream.

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[1] It must be noted that this Study has not analyzed the root causes of these inefficiencies; for example, to what extent they stem from Pertamina's legal mandates and Government intervention. The Study's findings are based on an evaluation of the analyses of the two previous reports, as well as the Bank's own assessment of the sector's performance, which is substantially below the industry average.

International Oil Industry Context

A3.4 Over the past two years the oil industry has witnessed dramatic changes in the economic and financial environment within which it operates. The collapse in short-term crude oil prices from the 'target' OPEC price range of $17 – 20/bbl during 1998, sharply reduced oil industry operating profit and cash flow, which in turn reduced internal resources available for investment. It is estimated that over the next two years total investment by international oil companies (IOC) may fall by 20-30%.

A3.5 Despite a recent recovery, there is an increasing perception that a period of sub-$15/bbl oil prices will soon return, and will be sustained in the medium term. Although it is not possible to predict future oil prices accurately, it is clear that oil price risk (and therefore the industry's cost of capital) has increased. While some oil analysts assume the price will stay in its present range, many of the IOCs are now evaluating investments using a $13-15/barrel oil price in the medium term.

A3.6 Lower oil price expectations and a higher cost of capital will result in sharp reductions in the rate of exploration and development investment. Further, it is likely to require changes in the terms of agreements with governments and State oil companies throughout the world; prevailing fiscal sharing terms have largely been developed for a higher oil price environment and many will offer investors inadequate returns in a lower oil price world.

A3.7 The situation is not very much different in the downstream. It would be imprudent to expect anything but a slow recovery in petroleum demand in the East Asia region. Renewed investment in growth may be a distant prospect, not least because there is widespread over-capacity. The biggest problems will undoubtedly be for domestic revenue generating projects such as gas-to-power, where major deferrals of new investment must be expected in addition to renegotiations of agreements for committed projects, as well as for major gas export projects (LNG and pipelines) where markets will be hard to find and economics will be only marginal. Financing new ventures in the region will be very difficult, time consuming and costly, even for attractive projects. The fiscal and non-fiscal terms for gas production will, therefore, require particular attention to ensure that they facilitate maximum economic investment levels.

A3.8 Most relevantly for Indonesia, major LNG and pipeline gas projects in the Far East will be much more difficult to complete. Not only has domestic energy demand in the major gas importing countries (i.e., South Korea) slowed but the creditworthiness of the gas contracting parties in those countries has reduced. It may still be possible to finance these projects but the gas importers will be less able and willing to provide firm bankable contracts. The sponsors will need to take more risk just when expected returns have fallen.

A3.9 The whole oil industry is looking at ways of cutting costs and corporate rationalization in this regard has a major role to play. It was striking that such large companies as BP and Amoco identified major economies of scale and scope in a merger. They were followed by Total-Fina and Exxon-Mobil. Further, at-market 'mega-mergers' are being promoted by analysts and bankers on shareholder value grounds. The consequence for producer countries such as Indonesia of this consolidation will be less competition for new acreage and the concentration of (reduced) exploration and development budgets within fewer hands.

A3.10 Also, in many countries, the trend toward corporatization and privatization of State enterprises has accelerated -- and State oil industries have not been immune from this trend. While the primary drive has been the inability of governments to finance their public spending plans there is ample evidence that corporatization and privatization have also resulted in a rapid and sharp improvement in the performance of (formerly) State enterprises; and to higher rates of investment, since these enterprises have improved internal cash flow and face improved access to external capital once privatized or part-privatized. Moreover, in many cases the improvement in transparency and accountability reduces the scope for concerns about maladministration and corruption.

A3.11 In Western Europe, most of the formerly State-owned oil and gas production companies are now in the private sector (viz. ENI, Repsol, Elf, Total/Fina, BP/Britoil/British Gas) and operate within a legislative regime which puts each of them on a 'level playing field' with other private sector oil companies, both in terms of their license/contractual position with the State and their obligations to pay royalties/taxes/other State payments. Statoil, although still State-owned, plays no "fiscal" role and its preferred position is limited to a right to take a (paying) interest in licenses. In Latin America many formerly State-owned oil companies have had their monopoly-status removed and in some cases have been fully or part-privatized (viz. Argentina, Brazil and Venezuela). Indonesia needs to address whether it wishes to move in this direction. If so, there are major implications both for the primary legislation and for the structure of the country's oil and gas industry.

Generic Performance Issues Relating to Pertamina

A3.12 For the past three decades, Indonesia's hydrocarbon sector has been vertically integrated, and dominated by Pertamina, a national petroleum Perum. Under Law 8/1971, Pertamina was given the responsibility for all oil and gas (and geothermal) activities, including the supply of oil and gas to meet domestic demand. It is directed by a Board of Directors consisting of the President Director and CEO, who is appointed by the President of Indonesia, and six Senior Vice President Directors. The Board of Directors reports to the Government Board of Commissioners comprising of five Ministers. The present structure of the company consist of six Business Units: Corporate Head Office; BPPKA (which oversees the activities of production sharing contractors); Exploration and Production; Processing; Domestic Supply and Marketing; and Shipping, Harbor and Communication.

A3.13 Pertamina controls and participates in the exploration and production of oil and gas, is the world's single largest LNG export company, has a virtual monopoly over the entire domestic downstream industry (including the import and export of refined petroleum products), and is the *de facto* regulator of the sector, rather than the Government. A decade or so ago, such a situation was not uncommon in the hydrocarbon sectors of many countries. But, as noted above (paras A3.10-A3.11), the predominant worldwide trend is now to move away from such a structure, which is highly conducive to inefficiencies.

A3.14 There is no doubt that the causes of some of Pertamina's inefficiencies lie outside of Pertamina's direct control, in particular, as is discussed in Chapter 5 and Annex 5A, those which stem from an outdated legislative framework; one that allows the Government to interfere with Pertamina's operations in a way that inhibits efficient performance, and defines a role for Pertamina that is not consistent with international best practice. On the other hand, notwithstanding such factors outside Pertamina's direct control, Pertamina's performance cannot be considered to come close to matching comparable peers internationally. As mentioned above (para. A3.2), there are two recent reports on Pertamina which examine the company's performance. The first, Pertamina Restructuring (carried out by the Boston Consulting Group in 1997/98), analyzed the potential cost savings through streamlining Pertamina's procedures and organizational structure. The second report, completed in September 1999 (the Special Audit of Pertamina, conducted by PriceWaterhouseCoopers), was requested by the Ministry of Finance, in order to assess Pertamina's operational efficiency. Both reports detailed Pertamina's inefficiencies and conflicts of interest, and emphasized the need to change its operational practices, organization and decision-making processes.

A3.15 There are a number of generic issues affecting Pertamina's operations as a whole, both in the upstream and the downstream. These problems stem from the company's centrally dominated structure, current procedures and decision-making processes, particularly with respect to procurement, investment planning and staffing. Like many other oil and gas companies in the region prior to their restructuring, Pertamina has traditionally been driven by volume targets (rather than cost efficiency), and by social obligations rather than financial performance or returns on investment. The Restructuring report highlights these issues by using a benchmarking approach.[2] When compared with Malaysia's Petronas and Argentina's YPF, Pertamina's adjusted revenue per employee was US$430, compared to US$670 for Petronas and US$940 for YPF. Similarly, Pertamina's staff at headquarters is 25% of the total, while the figure for Petronas is 14% and 11% for YPF. Further, Pertamina's hydrocarbon (oil, gas and condensate) production per exploration and production employee is 42 barrels-of-oil equivalent (BOE), versus 123 BOE for Petronas and 377 BOE for YPF. In refining, Pertamina processes about 90 barrels of oil per refining employee, against 107 barrels for Petronas and 120 barrels for YPF.

A3.16 Procurement, which is governed by Keppres 16/1994, is particularly problematic. Pertamina's conglomerate covers a wide range of purchases—from equipment and materials to crude oil and resale material. Many of the high-price items (representing over half of procurement) are procured centrally rather than at the business-unit level. The average time required is sometimes over 10 months. Even for low-cost purchases, the average lead-time is about six months. Another inefficiency stems from resource allocation, which occurs without any rigorous analytical work such as an analysis of rates of return. The capital budgeting process is lengthy, and project evaluation is inconsistent. Also, there is a lack of demand planning and forecasting, supply planning, and product inventory management. The Special Audit report estimated the inefficiencies attributable to current procurement and resource allocation procedures at about US$2 billion (for a two-year period), 80% of which are rooted in headquarters.

Upstream Performance Issues

Exploration and Production Issues

A3.17 Pertamina has a concession from the Government for exploration and production, and, according to the Restructuring study, both are carried out inefficiently. With regard to exploration activities, finding costs are relatively high, and oil reserves are declining. With respect to production, Pertamina produces about 14 million barrels of crude/condensate and 270 bcf of gas annually, but with high overhead costs per barrel and low productivity. On the financial front, Pertamina's exploration and production falls in the bottom quartile of upstream industry returns. For example, Pertamina's average return on gross investment for 1991-1995 was about 6%, or in the lowest quartile, compared with, say Enron, at 13%, in the top quartile (with the cost of capital during this period at 9%).

[2] While the objectivity of this approach as it relates to Pertamina could be questioned, given that it is difficult to provide for all adjustments necessary to equalize Pertamina's features with those of the benchmarked companies (i.e., apple-to-apple comparisons), nonetheless, at least two of the benchmarked companies chosen by the Restructuring report (Malaysia's Petronas and Argentine's YPF) could provide a reasonable degree of correlation for the purpose of benchmarking: (Petronas, because of its organizational structure, modes of operation and geographical proximity; and YPF, because of its operational similarities and its relatively recent restructuring, with which the Bank is quite familiar). However, when it comes to considering international best practice, Pertamina should also look to those better-performing state oil companies in other oil exporting countries.

A3.18 To give some indications, while the industry's average total production cost for Indonesia's onshore fields was US$1.53 per barrel in 1996, Pertamina's ranged from US$3-US$7. Further, the industry's average direct oil production cost from 1993-1995 was US$1.20 per barrel, while Pertamina's was US$5.00. The industry's average direct gas production costs were US$0.03 per mcf, and Pertamina's were US$0.14. Also, overhead costs per barrel were significantly higher than other companies. As to productivity levels, the lifting per person in two of Pertamina's fields ranged from 24 to 27 million BOE, versus 42 million BOE for Caltex and 114 million BOE for Mobil.

A3.19 The Special Audit report estimated the opportunity for savings and value creation (future gains Pertamina could realize from optimizing its operation) at US$1.3-US$2.0 billion, 70% of which would materialize from the exploration and production unit.

Issues Relating to BPPKA

A3.20 Inefficiencies also stem from Pertamina's supervisory role vis-à-vis production sharing contractors, where, as the Government's agent, Pertamina has a statutory monopoly over all exploration and (rather than the Government) basically regulates the private sector with respect to adherence to laws and regulations set by the Government. In fact, no significant direct interaction exists between the Government and the production-sharing contractors. Rather, Pertamina maintains the links through a unit within its organization—the Foreign Contractors Management Body (BPPKA). This unit has considerable discretionary power to accept or reject a wide range of activities, transactions and business requests covering (a) annual work programs and budgets (WPB), (b) development plans (POD), (c) authorizations for expenditures (AFE), (d) tender and procurement of materials and services, and (e) audits of contractors' personnel policies.

A3.21 Along with cumbersome procurement regulations under Keppres 16/1994 (para. A3.16), this role creates long approval times for WPB, POD, and AFE (sometimes up to one year), and overlaps between BPPKA and Pertamina in implementing regulations. The Restructuring report has estimated that redefining Pertamina's role would net a benefit of about US$25 billion on a present-value basis over a four year period for upstream activities (which are estimated to be valued at US$85 billion), 80% of which would accrue to the Government. According to the report, Pertamina/BPPKA could change its role and save the US$25 billion by: (a) introducing faster approval processes, shorter discovery/production cycles and increased production rates, equivalent to US$6 billion; (b) improving industry-wide performance through sharing facilities/equipment, lowering costs and adopting new tender/procurement processes, US$16 billion; and (c) increasing recoverable reserves (para. 3.25), US$3 billion.

A3.22 The Special Audit report also found a liability associated with BPPKA's operation, in that pre-1995 PSCs are silent on the restoration obligations. Thus, Pertamina or the Government may share a significant liability to remove onshore and offshore facilities and remediate these areas; until now, Pertamina has not quantified this exposure, which the report estimated at US$650 million.

Conflicting Roles in the Upstream

A3.23 The current (and longstanding) legal and contractual arrangements in Indonesia embody several fundamental principles: (a) oil and gas in the ground belong to the State; (b) the extraction of oil and gas should only be undertaken by State enterprises; i.e., Pertamina has a legal monopoly on oil and gas operations; and (c) oil companies (foreign and domestic) act as contractors to Pertamina (they, in practice, invest the risk capital and are remunerated for services rendered through a right to a defined proportion of future production, if any).

A3.24 This participatory arrangement has two important implications: (a) Pertamina has significant discretionary powers vis-à-vis the IOC 'contractors' acting as agent for the State; and (b) Pertamina has a statutory monopoly and a preferred position. These in practice mean the parties are Pertamina and the oil company, with no direct interface with the Government. There are several inherent conflicts of interest in this arrangement.

A3.25 First, where the State petroleum company conducts its own exploration and production activities (as in Indonesia) this will–or will be perceived to–bring it into conflict with its role in allocating PSCs. A risk exists that acreage/projects which might otherwise be explored/developed by the private sector will be held back by the State oil company in the expectation or hope that it will be able to develop them itself at some later date.

A3.26 Second, Pertamina is engaged in other activities, so there is a danger that production sharing revenues from profitable projects may be used by it to subsidize other, loss-making activities (upstream or downstream) in which it is engaged, with the effect that government revenue is reduced, resources are misallocated and essential restructuring deferred.

3.29 Third, Pertamina faces a conflict of interest between its roles as fiscal agent/regulator (on the one hand) and paying participant in some PSCs (on the other). This conflict is increasingly likely to be resolved to the detriment of its regulatory/fiscal function at times of low oil/gas prices when its resources are stretched (for example, if Pertamina is hard-pressed for cash, it may not press so hard for a project to be developed as the Government may wish).

Downstream Performance Issues

A3.27 Inefficiencies accrue from Pertamina's downstream activities as well—such as refining, transporting, distributing and marketing about one million barrels per day of petroleum products—over which Pertamina holds a monopoly. Given such a large market, the refining, transporting and retail marketing, under a system that lacks diverse ownership, is not efficient. While not always obvious to customers, efficient world markets are now substantially unbundled, i.e., the producer, refiner, marketer, transporter and retailer are frequently unrelated companies, and there is sufficient trading between them that the costs of each stage of the petroleum chain are clear. The advantages of an integrated company such as Pertamina, as once was claimed by the "seven sisters," no longer exist. The commercial basis allows for efficiencies, use of spare capacity, economies of scale, and has a positive impact on consumer prices.

A3.28 Indonesia's market for petroleum products, some 40-45 million tons a year, is of a size to be of great interest to private investors, both local and foreign. With a stable framework, funds could be attracted to improve the quality of the products, to upgrade the service to consumers, and to ensure reliable supply with improved access, at a lower economic cost to the country. But, for a vigorous market to develop, the basis on which the companies compete has to be carefully set out. Customers cannot readily verify product quality for themselves, and it is for governmental authorities to ensure that the product offered for sale meets the advertised specifications and that the pumps dispense accurately. The Government also has a responsibility for addressing monopolistic practices through legal and regulatory measures for minimizing the negative effect of such practices on the customer. This role is important both in areas where there is competition and in areas where there is no choice in supply system and supplier. Obvious areas of restrictive practices that harm competition and harm the customer include refineries that will only supply certain companies, harbors and jetties that discriminate between potential clients, and unloading and transport facilities that are not available on a fair basis to all-comers.

A3.29 Indonesia's petroleum refining and marketing sectors are essentially inefficient monopolistic operations. The exact extent to which they are inefficient, and are cross-subsidized, is obscured by the lack of transparent accounts. However, it is clear that many of the refineries are not competitive by international standards. They are losing money compared with imports. Use of fuel within the refineries is unacceptably high, the product losses exceed international norms, and employment is excessive. As with the upstream activities (para. A3.1), the current service fee arrangement–under which Pertamina is paid a fixed amount per barrel of crude processed and product marketed—promotes neither efficiency nor reliability. For example, Pertamina has nine refineries with a total processing capacity of about 1 million barrels a day, and almost all are in the red: operating costs of a typical Indonesian refinery are about US$2.56 per barrel compared with US$1.31 for average South East Asia refineries. The margin for a hydrocracking type refinery in Singapore is US$1.41 per barrel, compared with a loss of US$0.89 per barrel for a similar refinery in Indonesia.

A3.30 The marketing sector is no better. Pertamina is the sole marketer for all products except for LPG, CNG and certain specialty products. The cost of operations is not transparent, the facilities are not good, the service stations are frequently in sub-optimal locations, and generally there has been a failure to enhance profitability through taking good advantage of the site and customer base in the way that is common in more developed countries. Margins taken by the marketer are minimal compared with other countries, they would not permit new entrants to make a profit.

A3.31 An objective of reform should be to change this situation, to bring Indonesia up to the level of developed countries. Once the reform is implemented, it is expected that refineries would be able to compete internationally, they should be strong earners of profits based on their own competencies, rather than through privileged pricing, and that they would save large amounts of foreign currency by processing more efficiently and cost effectively than simply relying on the world markets. In the marketing sector, keen competition, quality service and lower prices, and profitable opportunities for local people to invest in partnership with international companies, are all to be expected. The following subsections examine in more detail issues relating to improving the efficiency of the retailing, refining, and marketing of petroleum products in Indonesia, as well as examining other issues relevant to downstream operations, such as necessary standards, regulations, and further research and development.

Retailing of Petroleum Products: Service Stations

A3.32 The point of interface with the customer is the retail sector. It is here where the customer deals with the oil company, where the transactions occur. It is clear that the quality of service in Indonesia in recent years has failed to live up to international best practice.

A3.33 The objective should be to have a competitive retail sector. This means that there should be genuine choice for the customer between different companies, that the companies compete on price as well as location and service. What Indonesia should seek is to have at least five competing service stations (and as many as wish to set up in business) in any city of over 100,000 people.[3] This minimum number of service stations should not be supplied by the same marketing company, and should not be owned by the same person or company. There should be no maximum number, it is for the investors to

[3] There are measures used by economists to measure concentration, but these are rough measures at best.

decide when and where they want to invest. In smaller cities the number of competitors may have to be less.

A3.34 It is suggested that Indonesia follow the normal practice relating to service station ownership, which is for the major marketing companies to own and operate a minority of service stations. Pertamina owns 95% of the 3100 service stations and the other 5% were financed by Government as a means of broadening ownership. Most service stations in other countries are owned by individuals and small companies, and the major companies often have special support agreements (technical, financial), in effect a franchise operation. Not all service stations publicly acknowledge the interrelationship with a major marketer, sometimes the service station sells unbranded product. The product quality is the same, and small scale ownership does not normally bring technical problems, providing that the retailer has adequate access to safety information. What it does do is bring diversity, which is valuable in ensuring the supply to all parts of the country. Indonesia would be well advised to diversify the ownership among citizens as well as major companies. This would be supported through regulatory control examining this sort of issue before divestitures and amalgamations are authorized.

A3.35 The service stations would sell branded (or in some cases, non-branded) petroleum products. Most service stations would sell gasoline and auto diesel. In the interests of serving their communities they should be encouraged to facilitate the distribution of kerosene to the small distributors, but should not sell kerosene direct for as long as there is such a large price distortion that fuel contamination is of such major potential. Once the kerosene subsidy has been phased out then the service stations could be a useful additional outlet for making this product available to the people. To enhance profitability and enable prices to the customer to be kept low the service stations typically would sell other goods and services, such as vehicle maintenance and car wash, LPG distributorship, or have a food store on the premises. These additional sources of profit help to make the operation as a whole financially profitable. Factors which cause unnecessary costs include having more than one grade of leaded gasoline, having mandatory employment of forecourt attendants, having mandatory opening hours, and for service stations along the toll roads and freeways having a high level of site fees from owners of those roads.

A3.36 Such a competitive system requires certain preconditions. Most importantly, the service stations need access to product in a reliable and even-handed way. They need access to suitable sites, and this is a matter of licensing which focuses on health, safety, environmental and road traffic issues and does not seek to prejudge the numbers of competitors. The service stations need effective monitoring to ensure adherence to the health, safety and environmental regulations, and to ensure the quality of their product and the accuracy of the measurement devices (pumps, weigh scales, etc.).

A3.37 In those parts of the country where prices have been liberalized, Government and provincial authorities (or the regulator, depending on how the system is established) will also need to monitor the price behavior of these companies.

Refining of Petroleum

A3.38 The installed capacity of Indonesia's nine refineries is 1,055,000 bbl/day and the effective capacity is 1,094,000. Five of the refineries are large enough to be made viable (over 100,000 bbl/day), one is of 50,000, and the other three are too small to achieve profitability. Taken together these refineries have a capacity slightly in excess of the 830,000 bbl/day consumption. 22% of the crude used is imported.

A3.39 In the over-heated Indonesian economy prior to the recent crisis about 15 new private sector refineries were given investment licenses, focussed on the export market. Few of these license holders are recognized refining companies. These investment licenses have not been turned into reality, but this is not surprising given the downturn in the East Asian market and the current economic uncertainty. The location of Indonesia close to the big international center of Singapore gives great flexibility in supply and for disposing of surplus products, and the most appropriate strategy for Indonesia would be to see its refineries as an integral part of the world market. As such they should get investment incentives, but should not get subsidized crudes and should not receive any subsidy on their operations. In such a context the refinery strategy is to leave the market to respond to economic signals, but with no specific plan for refinery capacity or location, or for a particular percentage to be refined in Indonesian refineries.

A3.40 The result of such a strategy will be for new refineries to be located near to markets, or near to the oil fields, and one would expect that Indonesia's advantages in this respect will continue to ensure that it is broadly self-sufficient in the sense of its product needs being met largely by local refineries. The necessary preliminary step is to turn the refineries over to profit-oriented skilled refining companies who will flush out the present inefficiencies. Once the ex-refinery pricing policy is reformed and the refineries get rewarded for what they actually do, the new owners will invest in facilities to improve the quality and product mix. Indonesia has less than half of the upgrading capacity that one can find in Singapore, despite a similar crude distillation capacity, and this lack of upgrading capacity is even more a disadvantage given Indonesia's wealth of natural gas, which targets the same market as Indonesia's heavy fuel oil.

A3.41 The specifications for petroleum use in Indonesia will dictate the specifications from Indonesia's refineries. It is recommended that the Government sets standards that are compatible with the range of petroleum product specifications internationally available, both on cost grounds and to ensure mutual support in emergency stocks. There are many examples of governments setting unnecessary non-standard specifications and the country needlessly pays a substantial additional cost for such specialty products. There are also numerous examples of governments setting standards tailor-made to the capability of local refineries. This is pointless, in effect this enables the local refinery to dictate government health policy.

A3.42 Currently all Indonesian refineries are owned by Pertamina, or by the Government with Pertamina as operator. The preferable situation is for there to be a large number of refiners where no-one can dominate. Taking the example of Singapore's four refiners, the aim for Indonesia is to have world-scale refinery companies but with as much competition as possible, and with full freedom for marketers and major users to import. Pertamina intends to start through allowing private investors to take a share in the refineries. On completion of the privatization program the ownership of the refineries should not lead to a tied relationship with a particular marketer, so that, (as in the more developed world) all refineries should supply all customers on an equal basis.

A3.43 It would be economically unwise for Indonesia to expect that all of the products produced from Indonesian refineries will be used within Indonesia. Surplus products are exported and deficit products (some 20% of the total) are imported. These surplus products will include normal export products such as bunker fuels, and surplus LSWR, and other refined and intermediate products that need processing in another refinery. There is no value in requiring the refinery to sell such products to a marketer, for onward sale on the international markets, and there is far more benefit to the nation if the chain is simplified and the refiner has the right to export surplus products as part of their refining license. The imported products are principally kerosene, auto gas oil and fuel oil, and these are the main elements in the $US3 billion Government subsidy to the downstream petroleum sector (Table A2A.12a).

A3.44 There is scope for increasing the output of LPG from the refineries, as a means of cutting back on flaring at the refinery and of increasing exports (Indonesia is already a major exporter of LPG). Indonesia as a large scale producer of natural gas needs refineries that minimize the production of fuel oil (and similar products such as LSWR) as it is in the national interest to use gas domestically rather than to use exportable fuel oil. It also needs to maximize the production of middle distillates. This will need large scale investments and has to be made interesting to those with the investors.

Imports, Transport, Marketing and Supply

Imports and Supply

A3.45 Marketers in Indonesia will source their product mainly from the Indonesian refineries or from imports, depending on where the price is better. While most supply will come from Indonesia's refineries, there is likely also to be significant imports from the international markets, and some marketers may prefer to get supplies from their own refineries. This needs to be monitored, to ensure that competition is really working in respect of petroleum imports. There will be significant shipping of product into markets that have no local refinery both from Indonesian sources and from foreign sources. Shipping is a way that many countries lose money. If done well the costs of bulk supply to these markets can be substantially reduced. The workhorse of the petroleum products trade is the 25,000 ton ship. The cost per ton of a 5,000 ton ship can be almost five times more, but for most Indonesian ports the storage facilities are only adequate for these small ships. Only Java and Sumatra have the capacity to unload large ships of 25,000 tons. Optimization may require the deepening of channels to allow larger ships, and addition of extra unloading facilities and tankage.

A3.46 A number of countries have found it beneficial for marketers to undertake joint shipping for smaller markets, such as those with annual demand below 1 million tons, and this would apply for many of Indonesia's outer islands. The problem of such markets is that if there are sufficient marketers for real competition then individual marketers would have difficulty in utilizing medium-sized ships while simultaneously ensuring the rapid stock turnover needed to maintain product quality. The problem can be solved or mitigated by properly supervised joint shipping. The same issue can make it difficult for new entrants to break into the larger markets such as Java and Sumatra, and ready access to Indonesia's refineries on these islands (or to joint import arrangements) is important for competition to develop further.

A3.47 Most parts of the petroleum product transport system in Indonesia are owned by Pertamina. There is obviously a possibility of conflict of interest if one marketer owns the entire supply chain and it would be preferable for these assets of Pertamina to be fully segregated and put into some form of separate company. Pertamina owns ships, repair facilities, docks, jetties, import facilities, transfer pipelines etc. where for geographical and for economic reasons it is contrary to the national interest for access to such facilities to be restricted, or for pricing of such access to be unfair. Pertamina already provides docking facilities for other parties. Lack of access to the pipelines from port to inland storage is an obvious example where it would be a major disadvantage to any excluded company hoping to compete. Other obvious areas to address include the ownership of harbors and storage. The policy has to be unbundling, and separation of these activities into separate common carrier companies. It would be worth considering in the Indonesian context whether the best solution for ownership of the common facilities could be joint ownership by all of the oil companies that will enter the sector. In the absence of special common carrier companies or joint companies, the best practice is to legislate non-discriminatory third-party access, and for the regulator to supervise such access.

A3.48 Large industrial customers have a variety of needs. Some are large enough to buy direct from refiners, others may lack sufficient storage of their own, or have financial needs, (needing special payment terms), such that they would prefer to buy through the marketers. The aim should be to maximize competition. For those industrial users who prefer to use the marketers, there should be complete pricing freedom so that the marketer can offer the best deal possible. Those large users (for example those with a demand exceeding 10,000 tons, including power plants, and road construction companies needing asphalt) who have the skills to buy direct from a refinery or from a foreign source, and can do so more effectively than the marketers, should have the right to bypass the major distributors. These direct buyers need a special "own use" import license.

Marketing

A3.49 The marketer arranges for the supply of products, for their transport through the country, for their local storage if necessary, and for creating the brand image, which will be supported through agreements with retailers. The marketer will also sell direct to major customers. For the service stations, it is advisable to have at least five equally-sized marketer companies who are competing and where none is able to dominate. It is particularly helpful for competition if the traditional marketers face competition from someone who may adopt a more aggressive approach to solving business problems. The aim should be that no-one has a market share exceeding 25%, with the market being defined as the island, or province, that forms the natural business unit. If market share grows to this level or beyond by skilful marketing, then the authorities should not seek to prevent the operation of market forces. What the authorities should do is have the right to approve mergers and acquisitions, and they should not approve any merger or acquisition where the market share would grow beyond this ceiling.

A3.50 Part of the supply chain is the maintenance of strategic stocks. In the Indonesian context it would be appropriate to maintain stocks but only to shield against refinery break downs, shipping problems, and other supply interruptions, and a minimum inventory of 15 to 30 days would be about the right order of magnitude. It is understood that the present requirement is 34 days. Such stocks would be owned by the refiners and marketing companies; there is no case for the public sector owning such stocks.

A3.51 In addition to ensuring the supply to service stations, the marketers sell direct to industrial and other large customers. Regardless of whether companies are allowed to compete on price at the service station, it is essential for a modern economy that the marketers compete on a range of factors, including price, in supplying major customers. Evidence from other countries shows that competition is intensified if some smaller marketing companies compete with the international companies, even if almost all of the contracts are won by these large distributors. Part of such competition, as already referred to, is for the consumer to be able to buy direct.

A3.52 The support that should be given to large users for them to bypass the marketers does not apply to aviation fuels. Both aviation gasoline (Avgas) and jet kerosene have a short shelf life, the product deteriorates fast, much faster than automobile gasoline. Deteriorated aviation fuels are an ever-present danger, they need proper and skilful handling and strong quality control.

A3.53 Specialty products, such as lubricating oils, are a source of significant profits to the marketers, and are more important to the marketers' overall profitability than they are to the service stations who use and sell them. Competition has never developed in this area in Indonesia because almost all the licenses severely restrict the geographical coverage of the lubes operation, or the companies are not allowed to sell the conventional products. Indonesia has a big enough market for one or two lubes plants of its own to compete with imports by the majors, but the restrictive licensing practices need to be removed. Of the five companies authorized to market lube oils, all except one face significant geographical restrictions on where they can operate. This is not a relevant approach in a competitive market.

Other Downstream Issues

Specifications

A3.54 Governments establish local petroleum product specifications for motor fuels according to local needs. For example, the octane rating of gasoline can be lower in high altitude areas because of the impact of altitude on engine performance. Within the context of the specifications of widely traded petroleum products, Governments also often set higher standards for (minimal) lead content and for pollutants (carbon monoxide, nitrogen oxides and sulfur oxides) in urban areas and for sulfur and particulates from diesel engines. In relation to industrial fuels, it is normal for governments to set smokestack emissions standards, permitting a range of fuel specifications to be offered by suppliers. In this situation the public authorities also need the ability to monitor these emissions and check for compliance.

A3.55 In the Indonesian context, the most appropriate gasoline specifications are probably 95 RON unleaded gasoline (any lead in existing gasoline to be phased out over a period of a few years at most). Indonesia has: Premix (a mixture of unleaded and MTBE); Super TT (lead free, high octane); 95 RON super gasoline with 0.005 gm lead, which is a good fuel until such time as Indonesia goes unleaded; 94 RON premium with 0.3 gm lead, in which the lead will be the cause of health problems in urban areas and should be phased out quickly; 88 RON regular with 0.3 gm lead; and Blue Gasoline for 2 stroke engines. It is not apparent that there should be any place in Indonesia for this low octane high lead product. Indonesian gasolines are all high in sulfur content and consideration should be given to adding desulfurizers to the refineries.

A3.56 The most appropriate auto diesel is probably 48 cetane 0.5% sulfur gas oil, to be moved to 0.2% sulfur over a few years. These levels are based on best international practice. Indonesia uses 45 cetane auto diesel, which needs upgrading to improve engine performance and reduce emissions. The industrial diesel has 1.5% sulfur, which obviously should be a prime target for improvement. As referred to above, the question of desulfurizers in the refineries needs to be given attention.

A3.57 For fuel oil, information was only available to this Study on high sulfur residual fuel oil, with 3.5% sulfur. Internationally it is normal for a 1% sulfur RFO to be available also. The 3.5% should not be used in urban areas unless there are efficient desulfurization facilities at the factory/power plant using the fuel.

A3.58 It is noted that the specifications for motor vehicle CNG and LPG need improvement in respect of sulfur content. LPG specifications need to recognize the dual source from both refineries and gas plants, allowing an adequate safety margin for the higher propane content of gas plant LPG. The regulations should ensure that the fittings on bottles and appliances are interchangeable so that the suppliers need to continue to compete even after the customer has purchased the initial bottles and appliances.

Safety, Health and Environmental Standards

A3.59 The refining, transportation, storage and sale of petroleum have to be subject to internationally acceptable standards and regulations so as to minimize the danger to the public and to the environment.

This Study was unable to review the regulations in Indonesia. However, those in most emerging economies are somewhat out of date, and typically are 15 to 30 years behind those of developed countries. They need to be updated. Petroleum fuels are a key element of Indonesia's Blue Sky Program, and work should be started without delay.

A3.60 Perhaps more importantly, in most emerging economies the health, safety and environment regulations are hardly enforced. For this enforcement to work it needs to be funded in a way that provides immunity from political budget pressures, and to give an active role to the operator. Bringing in experienced foreign marketers will bring improved standards in many cases. However, while many of the more reputable companies will apply their company international standards, some will not, and the standards of some of the smaller companies are very variable. It is apparent that Indonesia's safety, health and environmental standards need improvement. They need to be brought in line with the best international standards and an effective enforcement system needs to be adopted.

Regulatory Issues

A3.61 The basic framework has to be provided by a suitable petroleum law and supporting regulations. A (downstream) petroleum law (together with related competition and standards laws) should set out the main issues and the obligations of the parties, particularly it should give the power to grant licenses, and provide for the drawing up regulations. Broad competition issues should be in the law, including non-discriminatory third party access to key facilities, and joint importing arrangements.

A3.62 The regulations would clarify the law, would set out the details to make the law work, including rules for third party access, pricing and charging principles, would establish petroleum specifications, health, safety and environmental standards, and other details to cover the issues detailed above. (These issues are discussed in more detail in Chapter 5 and Annex 5A).

A3.63 The downstream petroleum industry needs a regulator to promote competition and to ensure good behavior by the industry and to regulate prices in those situations where price control is desirable. The needs of the downstream petroleum sector are fundamentally different from the upstream, and are fundamentally different from the power and gas distribution sectors. The best situation is where the regulator is not controlled by the sector minister and is not dependent on the parliamentary budget. Funding could be through a levy on petroleum imports, on refining and marketing. The primary role would be promotion of competition, together with supervising third party access and joint import arrangements. A good monitoring capability is needed.

A3.64 In parallel with the petroleum regulator there need to be regulators for health, safety and environment, for pipelines, for marine transport and road and rail transport of petroleum, and for ensuring achievement of petroleum specifications and accurate weights and measures for the petroleum trade. The specification problems will result in a need for independent laboratories outside of the refineries.

A3.65 The companies who will operate in the sector need to be licensed to do so. It is obviously better to license only those functions that the operator is likely to undertake. The basic functions that will be licensed are:

- import (or acquisition from the refinery) and storage of petroleum products for own use;
- import (or acquisition from the refinery) and storage of petroleum products for marketing to major customers and to service stations, and export of bunker fuels;
- import of crude, refining, storage of crude and products (including LPG) and export of products;

- operation of a service station, and purchase of (and storage of) petroleum products (including LPG) for sale through the service station;
- operation of CNG or LPG vehicle filling station;
- restricted license for storage and marketing of kerosene and bottled LPG;
- supply of aviation fuels;
- transport by sea of crude and products;
- transport by pipeline of crude and products;
- transport by road of crude and products, and of LPG; and
- transport by rail of petroleum crude and products, and LPG.

A3.66 Good corporate behavior can usefully be encouraged by industry associations. These associations can help in the development of industry codes of practice, and can make recommendations to the regulator and policy makers on the issues of the day. Additionally, industry associations can set up training schemes and help with public awareness campaigns.

A3.67 All countries need to have a strong policy-making capability so as to be in a position to evaluate the claims of the sector participants, and to maintain policy development in the sector. The industry is in the process of responding to international corporate changes and development of changed strategic focus, and the Government needs to be knowledgeable on the issues of the sector and on the way the Government can foster sector competitiveness and efficiency. Training of government employees on petroleum aspects is key.

Issues for Future Research and Development

A3.68 There are several areas that need research in the Indonesian context and are for subsequent action by policymaker and regulator. Some of them are listed below.

A3.69 There is a need for a supply optimization study that would identify the demands island by island and look at the potential sources of supply and transport options, including those that require investment such as additional storage tanks and even the deepening of harbors for exceptional demands. In most countries this is an area which, if properly managed, can bring major earnings. While Indonesia makes use of significant storage along the coasts of Java and Sumatra, in most other islands the coastal storage capacity is small and this will have an impact on the ability of Indonesia to use efficiently-sized ships. Use of the six transit terminals may not be the optimum solution and should be re-examined. In view of the small demands away from the coast, most of the inland depots are not cost effective.

A3.70 There also needs to be a study on reliability of supply and national benefits from improvements, and definition of the target reliability and service level. In other studies it has been found that the typical economic cost of a stockout is ten times the value of the fuel not supplied, and because of this the problem needs to be looked at from a national economic aspect.

A3.71 The supply of energy for the poor (kerosene and LPG) needs review to see if it can be made more cost-effective and convenient, including enhancing the supply points and reducing cost. As the previous system lacked incentives, there is some probability that improvement should be made as Indonesia's prices have been below cost since the start of the economic crisis (Chapter 2 and Annex 2A).

A3.72 A transport fuels assessment could consider alternative fuels appropriate for Indonesia, such as CNG, LNG and LPG, and the extent to which these fuels would be to Indonesia's economic benefit. Aspects of such a study would include direct costs, and the indirect costs such as pollution impacts, and would also pay attention to the consequences for the fuel tax policy and the refinery balances. These technologies are well-proven and it is not envisaged that pilot testing would be needed.

A3.73 Regardless of the outcome of the transport fuels assessment, there needs to be a study on gasoline specifications (octane, lead – with a view to phasing out lead) and auto diesel specifications (cetane, sulfur, pour point).

A3.74 In view of the importance of third party access there would need to be a study of access principles and standards, access pricing principles, and the pricing levels and structure that should apply. The issues to be carefully thought through include who should own these facilities (given that in the past they have been owned by Pertamina for the State) and what are the rights and obligations when capacity needs to be enhanced.

A3.75 Safety in transport of petroleum by road and rail is an urgent issue. Driver practices need review from a safety aspect. This review needs to be both one of framework and regulations and also one of practices and enforcement. Further, environmental practices are an obvious problem for review.

A3.76 It is normal in petroleum operations for there to be physical losses, in transport, refining, storage and handling, with physical losses being higher for the more volatile fuels such as LPG and gasoline. An assessment and quantification is needed to identify excess losses, propose where and how to measure and institute accountability and incentives to improve performance.

The Need to Fundamentally Restructure Pertamina

A3.77 Given the extent of its inefficiencies, conflicts of interest, and monopolistic status, there is an urgent need to fundamentally restructure Pertamina and to redefine the organization's role. In part due to the terms of reference of the Restructuring report referred to above (para. A3.14), that report assessed Pertamina with a view to simply improving the efficiencies of the organization "as is". However, to stem the current extremely costly waste of resources, the Government and Pertamina need to go well beyond just making internal organizational re-arrangements and procedural improvements, and should consider implementing major changes and reforms, such as corporatization, divestiture and privatization. Moreover, the time frame for implementing any changes must be accelerated.

A3.78 By contrast, the earlier version of the draft oil and gas law (Chapter 5, Annexes 5A and 5B) went a long way to preserving the existing status of Pertamina. Both with respect to upstream and downstream activities, considerably more fundamental changes than those proposed would be required to reshape Pertamina so that it resembles other industry players internationally. Therefore, the Bank recommends that the Government should now: (a) carry out, with the help of experts, a focused assessment of the alternatives for reforming Pertamina, in particular, considering the formation of several full and legally binding subsidiaries, as well as the initiation of a major divestiture and/or partial privatization program; and subsequently, (b) begin to actually implement measures needed for the unbundling of Pertamina; in particular (i) removing BPPKA from Pertamina, (ii) ensuring that Pertamina participates in upstream activities on an equal basis with private companies, and (iii) removing Pertamina's monopoly status from downstream activities.

A3.79 Such reforms will mean a major change of roles, both for the Government and for Pertamina. For the Government it means the development of a stronger regulatory role, for Pertamina it means a change from being the sole supplier to being one of a number of entities competing for market share. The specific role of Pertamina has to be redefined and it needs to be helped to continue to play a key role in

Indonesian society. This includes helping Pertamina to improve its remaining operations, and for it to be able to compete effectively as an important competitor among many others.

A3.80 To create a world-class exploration and production company out of Pertamina's existing operations and assets, it will be necessary for Pertamina to focus its efforts on that segment without distractions or cash drains to other industry segments. The Government needs to oversee a transformation of Pertamina in which its upstream business has distinct operational and profit/loss responsibility and reporting, and is treated in the same manner as other upstream industry players. This reorganization could be accomplished within the framework of an integrated holding company; one which still retains some interests in refining and marketing as well. However, a reasonable target for Pertamina's share of refining and marketing would need to be set, with similar objectives being sought for the market share of the companies who would bid to buy Pertamina's downstream assets. How this transition is managed will be very important.

A3.81 Although analyzing these issues in detail is outside the scope of this report, the remainder of this Annex recommends a number of the changes needed to be made to Pertamina's role, and scope of operations, in both the upstream and the downstream, in line with international best practice.

Recommended Upstream Reforms

A3.82 The Government needs to consider options for changing Pertamina's role in upstream activities, such as removing BPPKA from Pertamina and locating it under MME (possibly within MIGAS), or forming an independent oil and gas agency. At present, the private sector is dissatisfied with the situation where approval for development plans, environmental proposals, etc., is granted by an entity that stands to benefit from these activities. Pertamina's conflicts of interest could entirely be eliminated if the Government, rather than Pertamina, were the contracting party to the production sharing contracts (PSCs). Pertamina would participate in upstream activities as a partner with the private sector companies, subject to the same fiscal and non-financial rules as apply to those private companies. The experience in many countries has shown that such changes have improved performance; similarly, Pertamina would as a consequence have stronger incentives to be more efficient.

A3.83 In recent years, upstream arrangements have been modified around the world to create a more balanced relationship, such that:

- The State retains ownership of the oil and gas in the ground.
- PSCs (or licenses, concessions, risk contracts, Co-operation Agreements, etc.) are executed by the responsible Government Ministry (rather than the State oil company) with the oil company investor.
- The State oil company (if any) participates in the domestic oil and gas industry as a partner with the IOCs. It has the same relationship to the State as the IOCs (i.e., it is a co-participant in PSCs, licenses, concessions etc). When creating this 'level playing field', some capital restructuring of the State enterprise may be required. This "normalization" of the status of the State oil company (which also becomes subject to the same taxes as other IOCs operating in the country) is often a prelude to (and is required for) the partial or full privatization of the State oil company.
- For all new PSCs (or concessions, etc.) provision may be included to require the IOC, upon commercial discovery, to facilitate a mechanism for national equity participation. One approach is to grant an equity interest on preferential terms to a State agency but to enshrine in law a right or obligation for the agency to sell the interest (at market price) to national investors. In this way, the

financial benefit of the participation accrues to the State while providing for increased national private sector ownership of the industry. It is important that mechanics for the sale of such an interest are transparent and auditable. The PSCs may also include provisions for additional sales of the IOC's interest to nationals at market prices over time, to achieve gradually increasing involvement of domestic capital in the industry (and facilitate a strengthening of domestic capital markets).

A3.84 Thus, the role seen for Pertamina is that it should become the 'national champion' for oil and gas upstream (and downstream) investment in Indonesia (and possibly for selected investments internationally), and should focus on becoming a world-class oil and gas company, relieved of quasi-Governmental responsibilities and subject to the same laws and regulations as other companies. If some of the PSC benefits accruing to Pertamina (e.g., the domestic oil subsidy) were eliminated, then the Government should review the finances and capital structure of Pertamina to ensure that it retains a financial structure consistent with its planned upstream (and downstream) investment plans.

A3.85 If the State is to become counter-party to the PSCs, the issue arises as to which of Pertamina's current rights and obligations should be assumed by the State, and which should simply lapse (i.e., left in the hands of the private sector). Annex 4A provides specific recommendations of the required changes to the current PSC model, if the State is to become counter-party to the PSCs.

A3.86 The transfer from Pertamina to MME of the regulatory and supervisory functions of one of world's largest oil and gas producing countries will require a substantial strengthening of the human and technical resources of MME, so that it is capable of handling license awards, monitoring, relinquishments and extensions, the approval of work programs, budgets and development decisions (commerciality), monitoring of abandonments, consents to assignments of Contractors' rights/obligations, maintaining databases on hydrocarbon activity and, most importantly, perhaps in collaboration with the Ministry of Finance, the management and supervision of receipts from the State's production share. Many of the middle-level technocrats who currently perform these functions could presumably be transferred from Pertamina, which will have no further need for them. However, the Government will probably wish to inject "fresh faces" into the upper echelons of MME in order to ensure that supervision of the regulatory function is performed to the highest standard. More work, which is beyond the scope of this report, is needed to ascertain the organizational structure, manning levels, job descriptions, budgeting and physical equipment requirements of the expanded and strengthened MME. A program of training will be required to ensure highest quality administration of Government policy.

Recommended Downstream Reforms

Downstream Liberalization

A3.87 Downstream operations need to be liberalized. In particular, the inefficient operation of Indonesia's refineries must be changed. The best strategy would be to improve the performance of the existing refineries by: (i) using a crude slate that matches the refinery configuration, particularly for imported crude, and one that is based on economic analysis rather than contract; (ii) lowering operating costs, particularly energy and utility costs that are substantially higher than average; and (iii) curtailing capital investments in the existing refineries, except for upgrading projects to maximize conversion and deal with environmental issues. (Nevertheless, some existing refineries may not be worth upgrading as they are currently configured, although the sites may be valuable commercially). As a transitional measure, Pertamina's refining businesses could be reorganized such that each refinery has separate operational and financial management (e.g., as a PT subsidiary), with refinery performance improved by the PT company itself, through joint venture with new partners, or as a result of outright sale. Any investments in new refineries should only be through joint ventures or with 100% private capital. Thus, it is vital to deregulate the refining subsector to allow an expanded role for private sector participation.

A3.88 The size of Indonesia's domestic petroleum market is sufficiently large by any standard to attract international, regional and local investors if the right framework is put in place to make competition realistic and vibrant. Necessary reform actions include allowing open access to facilities such as harbors, jetties and related storage and pipelines; moving Pertamina's *de facto* monopoly on shipping and transportation to an arm's length, competitive basis; selling the majority of service stations with the objective of developing competition; and liberalizing the refineries fully, with a view to eventually privatizing those which still prove to be viable. The only exceptions would be the small and dispersed island markets for which full-scale liberalization may not be economic. In these markets, the Government should encourage (or regulate) the aggregation of procurement among the marketers and thus create economies of scale.

A3.89 However, it is important to recognize that simply deregulating the refining, terminals, import, storage, transport and marketing subsectors, in order to allow open access, is not by itself sufficient to ensure new entrants, competition, and consequent efficiency improvements. The introduction of effective competition will require an active program of substantial divestiture of Pertamina's assets in these downstream subsectors. The assignment of assets by the Government to either a restructured Pertamina, or for sale, should be made with attention both to maximizing the value of assets to the country and to maintaining effective competition in domestic petroleum product markets.

Retail Sector

A3.90 The retail sector (service stations) should compete with each other on service, location and price, and on the range of other services they offer the customer. There should be diversity of ownership, and of marketers offering supplies to the service stations. There should be no ceiling placed on the degree of competition, and no regulation of commercial aspects. The Government's role is regulatory in terms of health, safety and environment, quality and weights and measures. Similarly, restrictions on lubes, importing and marketing should be lifted.

Refinery Sector

A3.91 The subsidies and special prices given to the refinery sector should be quickly phased out, and arm's length pricing should be introduced. The Government should adopt internationally recognized petroleum specifications, and ex-refinery pricing should reflect the actual quality of product produced. Investment incentives should be offered so that the new owners will bring the efficiency, product range and specifications up to international standards. The refiners should be responsible for exporting surplus products without needing a marketing license.

The Marketer's Role

A3.92 The aim should be to have at least five marketers in each significant market, with no marketer having more than a 25% market share. Mergers and acquisitions that breach this guideline should not be approved. To help in containing costs yet keeping an adequate number of marketers, marketers should be encouraged to join together for arranging purchase and shipping of product to smaller markets. Shipping, harbors, jetties, storage tanks and pipelines should be available to all through non-discriminatory third party access, and ownership should be separated from the marketing companies. Strategic stocks should be maintained by refiners and marketers, with a minimum inventory of 15 to 30 days. There should be no price control on sales to major customers, and major customers should have the right to buy direct from refineries and foreign suppliers for most petroleum fuels.

Common Issues

A3.93 Indonesia's petroleum specifications need to be brought into line with specifications widely available internationally, and Indonesia's refineries should be required to comply. Independent laboratories are required to test the quality of petroleum imports. Lead should be phased out, and sulfur drastically reduced, on health grounds. Indonesia's health, safety and environmental regulations need to be modernized and enforced. The major companies already in Indonesia have a wealth of information which could help in this respect.

Regulatory Issues

A3.94 Indonesia needs to establish a regulatory system for the downstream petroleum sector that is independent of the political and governmental system, and is separate from other regulators. It needs independent funding. Similarly, there need to be regulators for health, safety, environment, weights and measures, etc. Reinforcement of good behavior can be provided by industry associations.

Further Research

A3.95 While the main thrust of the reforms is clear, a number of areas need to be further researched so that the optimum solution can be identified. They include determining specifications for gasoline and diesel, the update of health, safety and environment regulations and practices, a supply optimization study, a transport fuels study, and further clarification of third party access issues.

ANNEX 4A: The Terms of Production Sharing Contracts (PSCs)

A4A.1 In the upstream hydrocarbon sector, the prime instruments underlying the relationship between the State (through Pertamina) and private companies (apart from the oil and gas laws and regulations themselves, which are discussed in Chapter 5 and Annex 5A), are production sharing contracts (PSCs).[1] Apart from redefining Pertamina's role and improving its efficiency (Chapter 3 and Annex 3), the terms and conditions relating to future PSCs need to be revisited. There are presently two main type of contracts for the PSCs in Indonesia. The "KBI Conventional" (standard) and "KTI and Selected KBI" ("frontier"). Both are profit sharing mechanisms in which the contractor's costs and profits are taken in crude oil or natural gas valued (generally) at market prices. The two PSC models have been continually varied in light of changing circumstances for their more than 30 years of existence; as a result, the total economic provisions of the PSC models have become complex, and in some areas contradicting. More importantly, some provisions of the fiscal regime are not sufficiently progressive, particularly under an adverse oil industry environment. Prevailing fiscal-sharing terms were largely developed, like in many other countries, for a higher oil price environment. Under a low oil price, the expected returns of investors are, in many cases, below their "hurdle rates" of return. If the terms of the future PSCs are not changed and oil prices become low again (as is expected), then both upstream investment levels and the State's revenues will fall. Consequently, some redesign of the production sharing and/or fiscal terms may be required to achieve higher total investment and higher overall State revenues in the medium and long term.

A4A.2 This Annex examines the terms and conditions of PSCs, against the background of potentially adverse international oil industry developments. The review of PSCs has been performed with a view to assessing the attractiveness to prospective investors of the Indonesian model contracts in a lower oil price environment both in absolute terms (whether expected returns are adequate to justify investment) and compared to those of peer-group countries, in order to assess the extent to which Indonesia can expect to attract new investment (at a time when exploration/development budgets worldwide are being sharply reduced). More specifically, the Annex: (i) sets forth Government and investor objectives for upstream petroleum regimes; (ii) assesses how PSCs compare with alternative contract forms in achieving these objectives (with detailed international comparisons provided in Annex 4B); (iii) describes the economic provisions of the model PSCs, as well as evaluating the economic impact of the PSCs in both absolute terms, and relative to peer-group countries (with detailed international comparisons provided in Annex 4C); (iv) recommends how the model PSCs might be changed to allow the State rather than Pertamina to become the counterparty; and (v) analyzes the non-financial provisions of the current Indonesian model contracts.

A4A.3 Any recommendations provided in this Annex relating to changes in the financial terms of the Indonesian model contracts are intended to apply only to *new* PSCs (or other permitted forms of Co-operation Agreements). However, it should be noted that previously agreed terms in respect of existing PSCs – which were negotiated when oil price expectations (and prospects for gas sales) were higher – may, in some cases, leave expected investor returns below their 'hurdle rates', leading to deferral or cancellation of projects. This is particularly likely, for reasons also discussed in this Annex, for gas projects. The Government may, therefore, need to respond positively to Contractors' requests to

[1] Over the past three decades, exploration and production of petroleum has been carried out through PSCs, which differ from concession agreements. Under the PSCs, the country retains ownership and responsibility for management and operations to develop and produce petroleum resources, while contractors (i.e., private oil companies) provide the funds, carry the risks and recover their costs once production is underway. Once contractors recover their costs, production revenues are split between the State and the company; contractors are normally subject to national corporate taxes on their share.

negotiate amendments to existing PSCs, with a view to improving investor economics at very low oil prices, without, however, reducing the State share of benefits should higher oil prices return in the future.

Objectives of Upstream Petroleum Regimes

A4A.4 As discussed above, some redesign of the terms of production sharing contracts may be required to achieve higher total investment and higher overall State revenues. However, to redesign the model PSCs and assess the attractiveness of the upstream petroleum regime to Government and prospective investors, it is first necessary to consider the objectives of the respective parties.

State Objectives

A4A.5 Indonesia, as owner of the resource, wishes to ensure that the development and production of the resource will be in a manner which will maximize the contribution of the petroleum sector to national development. Specifically, Indonesia's objectives should be as follows.

a) *To encourage more investment in oil and gas exploration, appraisal and development.* As mentioned above, sharp reductions in oil and gas investment budgets are expected worldwide. Given the importance of the petroleum sector for Indonesia, it must ensure that the terms on which acreage is made available both offer IOCs the prospect of adequate returns at low oil and gas prices, and that they are competitive relative to other petroleum basins where investment might be allocated; after taking account of the perception that the risks of doing business in Indonesia have increased. Since investment worldwide is being cut substantially, Indonesia will need to improve its terms relative to these other countries if it is to maintain the absolute level of oil and gas expenditure within Indonesia.

b) *To optimize payments to the State by investors to compensate for the extraction of the national resource.* This involves structuring payment arrangements which minimize disincentives to invest (in exploration and development) but transfer to the State a progressively increasing share of 'excess profits' or rents (i.e., returns in excess of the investors' risk adjusted cost of capital) to the owner of the resource. This raises complex issues of timing and risk.

c) *To achieve efficient and transparent regulation of oil and gas operations and to ensure that national financial and non-financial benefits are maximized,* including to: (i) ensure that public sector revenues from oil and gas developments are gathered efficiently, with the minimum leakage and diversion; (ii) ensure compliance with good oilfield practice and national environmental standards; (iii) ensure active acreage management through negotiated work and expenditures obligations and periodic relinquishment requirements; (iv) require investors to undertake national personnel training programs; and (iv) (often) to require, if desired by the Government, some element of national equity participation in commercial developments either by a State-owned company or the national private sector and (sometimes) a requirement for a phased increase in national private sector participation.

d) *To adopt arrangements that are transparent and stable,* such as clearly defining the responsibilities of the State oil company and the Government, and specify criteria and procedures for exercising discretionary powers, with a view to minimize potential for maladministration and corrupt practices.

Investor Objectives

A4A.6 Typically, investor objectives include:

a) *Adequate net risk-adjusted returns*: IOCs compute expected returns on their investments net of all costs, including all payments to the State and any State oil company. Expected return calculations incorporate estimates of expected production rates and capital and operating costs relevant to the area being evaluated. They incorporate an expected oil (and/or gas) price assumption and deduct total fiscal payments to the State and its instrumentalities to determine net annual cash flows. These annual cash flows are discounted to determine a present value at a discount rate which reflects the risk-adjusted cost of capital. Since discount rates tend to be relatively high (10% or more in real terms for development projects and higher for exploration), the investor is very sensitive to the timing of payments to the State. Particularly with low oil/gas price expectations, high front-ended payments to the State can render new ventures uneconomic. In the current oil and gas environment investors are likely to be even more concerned than in the past to achieve rapid investment payback.

b) *Stability*: considering that the oil and gas investment is a long term business, investors place a considerable premium on confidence that terms agreed will not be unilaterally changed to their detriment in the event of success or a material change in circumstances. Mechanisms which automatically adjust fiscal terms with changes in project profitability over the field life in a pre-agreed and predictable manner enhance the prospects for stable contracts – since they continue to be perceived as fair to both sides despite changes in economic circumstances (e.g., a sharp rise or fall in the oil or gas price).

(c) *Transparency*: investors value clarity of arrangements and the minimum of unaccountable discretionary powers in the hands of public sector officials.

Production Sharing Contracts versus "Fiscal" Based Regimes

A4A.7 There is a question whether the PSC type contract is an appropriate form of co-operation contract for Indonesia. This subsection compares the efficiency of the production sharing ("PSC") approach in achieving the Government's upstream oil and gas objectives with the principal alternative of pure, fiscal-based regimes, where the Government looks to royalties, taxes and joint venture participation as the means of taking the national share of the profits from the resource. The discussion provides examples of both types of arrangement drawn from a number of oil and gas producing countries which encourage foreign direct investment in the upstream sector. These are Algeria, Angola, Argentina, Australia (offshore), China (offshore), Malaysia, Nigeria, Norway, Papua New Guinea, Thailand, UK and USA (OCS).

A4A.8 These countries were chosen because of the proximity of their contracts with that of Indonesia. Fiscal terms in contracts from these same countries are used later (para. A4A.31) to analyze the substance of economic terms available in "competitor" countries with those applicable under the Indonesian PSCs.

Types of Regime

A4A.9 These are summarized in Table A4A.1 below, (a more detailed comparison is in Annex 4B).

A4A.10 The distinction between PSC and fiscal-based regimes is in practice blurred.

a) With one exception, the PSC-based regimes examined now require the contractor to pay income tax on its profits, as in Indonesia (in order that US companies can receive domestic tax credits for taxes paid). The only exception is Algeria, where contractors' income tax remains the responsibility of Sonatrach. The Indonesian, Angolan and Malaysian regimes are therefore hybrid PSC/fiscal arrangements.

b) Two ostensibly tax-based regimes (Colombia and PNG) have certain features economically equivalent to those of PSC regimes: in PNG, the State nominee's interest may be "carried" through development (as opposed to having the carry terminate upon a commercial discovery, as is more usual) and then repaid (together with interest) from its share of production. This is economically equivalent to a 22½% production share following full cost recovery, with an annual uplift at the interest rate payable on the carry. In Colombia, Ecopetrol is responsible for paying its 50% of costs but is entitled to an increasing share of revenues (related to the investor's cumulative revenue/cost ratio) following cost recovery.

c) "Pure" fiscal regimes are found in Argentina, Australia, Thailand, the UK and the US – all of which also have no State participation - and Norway, where Statoil pays its way in those licenses where it elects to participate.

Table A4A.1: International Co-operation Contracts

Country	PSC or "Fiscal Regime"	Direct State Participation
Algeria	PSC	Yes; 30% Paying Interest
Angola	PSC	Yes; 20% Paying Interest
Argentina	FISCAL	None
Australia	FISCAL	None
China	PSC	Yes; 51% Paying Interest
Colombia	FISCAL/PSC (see below)	Yes; 50% Paying Interest – preferred terms
Malaysia	PSC	Yes; 25% Paying Interest
Nigeria	PSC	Yes; 10% Paying Interest
Norway	FISCAL	Yes; 30% Paying Interest
PNG	FISCAL (but see below)	Yes; 22½% Carried Interest
Thailand	FISCAL	None
UK	FISCAL	None
USA	FISCAL	None

Financial Terms

A4A.11 In reality, the same economic outcomes can be achieved with pure fiscal or PSC regimes or with combinations of the two. For instance, within a production sharing framework, State take can be deferred by reducing (or eliminating) the State share of "first tranche petroleum" (which is economically equivalent to a royalty), by increasing the rate at which capital costs may be recovered from cost oil/gas, by increasing (or eliminating) any ceiling on the amount of cost oil/gas allowed to be taken each year or by allowing (or increasing) "uplift" on the recovery of capital costs (the Indonesian investment credit) from cost oil/gas (or some combination of these). Similarly, a PSC arrangement can be rendered more or less progressive in a more or less sensitive fashion by relating the State's production share to cumulative or daily production levels (as is the case in the Indonesian standard contract for production from pre-tertiary reservoirs), to the ratio of cumulative project revenues to expenditure (as in Algeria) or – best of all, since it relates production share directly to realized profitability – to the contractor's *ex post* rate of return (as in the Angolan "frontier" PSCs). Under a pure fiscal regime front-end loading may be reduced by cutting (or eliminating) royalty, by allowing more accelerated depreciation and/or by allowing "uplift" of capital costs for depreciation purposes. Progressiveness can be improved by increasing marginal tax rates as achieved rates of return increase (as in Australia and PNG). It follows that the debate on the substance of fiscal terms can be divorced from that regarding the form of the contracts, which is the subject of the next two paragraphs.

A4A.12 Production sharing contracts are sometimes said to have the following advantages:

a) they are more flexible than pure fiscal regimes, allowing terms (for new contracts) to be changed/negotiated to suit the prospectivity of the particular acreage involved, market conditions etc;

b) conversely, once signed they have the force of contract and, unlike tax legislation, cannot be amended unilaterally by Government (without breach of contract);

c) they allow the State or its nominee to take production in kind; and

d) they entitle the State (or, as has been the case to date in Indonesia, the State Petroleum Company) to supervise the contractor's obligations.

A4A.13 In fact, an exactly equivalent result can be obtained with fiscal-based contract forms. Taking the points in turn:

a) In practice, "flexibility" - which relies on case-by-case negotiation or assessment - can be a weakness rather than a strength: it leaves considerable discretion and powers in the hands of State petroleum company officials and this discretion may be exploited, abused or simply not employed wisely. Flexibility of a less subjective kind can be built into a pure fiscal system e.g., by separate tax treatments of oil and gas (as in PNG or in Malaysia under its mixed PSC/tax regime), by relating royalty rates to (e.g.) water depth (as in the Gulf of Mexico) and, most sensitively, by relating income tax rates and the point of onset of tax to project realized rates of return (as in Australia and PNG). The experience is that, in general, oil companies prefer flexibility to be automatic and "impersonal" rather than to rely on "case-by-case" negotiations, and there is little doubt that this leaves less scope for maladministration or corruption.

b) To the extent that the State's take is contractually fixed over the project life, this is a big advantage from the IOC's perspective. However, very few PSC arrangements actually provide investors with protection against unilateral action in all major State revenue-raising areas. The fact is that either a tax or PSC regime can be "stabilized" – if this is considered necessary or desirable. To effect this in a "fiscal" regime requires the State to contract (e.g., in a Co-operation Agreement) that the investor will not be subject to any subsequent overall adverse tax changes (perhaps with a right to reduce certain contractual payments in the event that corporate tax payments are increased). In practice, both tax and PSC regimes could do this, if so desired.

c) The advantages of taking production in kind disappear once the production is valued at market prices (rather than a subsidised price are currently in Indonesia). To the extent that the State or the State petroleum company needs crude (or gas) it can contract to purchase this, at market prices in either a PSC or Co-operation Agreement.

d) Petroleum companies' upstream operations clearly need to be subject to regulation; the question is by whom and pursuant to what sort of arrangements. A key issue for the Indonesian Government, which it has addressed to a considerable extent in the draft oil and gas law (discussed in detail in Chapter 5 and Annex 5A),[2] is whether broadly "regulatory" matters such as: the issue, extension and termination of PSCs and other "Co-operation Agreements" (and the areas open to PSCs); approval and monitoring of work programs; decisions as to commerciality; supervision of abandonment; rights to export product and maintain foreign exchange offshore; approval of assignment of interest in PSCs; and valuation of product, should all remain under the

[2] As in Chapter 5, the comments in this Annex relate to the February 10, 1999, version of the draft oil and gas law.

control of Pertamina (via the PSC) or be the prerogative of the Government itself – as is usual under most fiscal-based regimes, where "regulation" is generally the responsibility of the licensing authority (usually the Ministry of Energy or its equivalent). Of equal – or even greater – importance is whether the Indonesian State's take – or such a substantial portion of it – should be routed via the State Petroleum Company.

A4A.14 Conclusions in relation to the "PSC versus Fiscal Regime" debate are that:

- the same "division of spoils" and risk sharing outcomes can be achieved under either arrangement;
- each is capable of flexibility in the face of varying degrees of prospectivity, market risk and realized profitability;
- each can be structured (where applicable, in conjunction with Investment or Co-operation Agreements between the State and the IOC) so as to provide investors with the stability they undoubtedly value; and
- both structures may be conducive to efficient regulation and government revenue collection *provided* these functions are properly allocated.

Analysis of the Economic Terms of Indonesian Model PSCs

A4A.15 The two types of model contracts reviewed here were the "KBI Conventional" (standard) and "KTI and Selected KBI" ("frontier"). The standard PSC attempts to provide for a profit share split in favor of the contractor which is progressive in that it is a reducing share as field profitability increases (as indicated by various proxies for profitability viz. annual production rates, geological horizon, method of recovery). Since the generic PSC model has been in existence for more than 30 years, the model PSCs have been varied in light of changing circumstances to keep the terms competitive. As a result, new provisions have been 'added on' to the original structure and different profit oil and First Tranche Petroleum (FTP) split percentages have been adopted for frontier areas and natural gas. As a consequence, the total economic provisions of the PSC Models have become complex and in some areas conflicting. In this subsection, the economic provisions are described, they are analyzed quantitatively and compared with other peer country terms.

A4A.16 The basic principle – the contractor supplies all the risk capital and is remunerated from a share of future cash flows (if any) – is appropriate and should be retained.

A4A.17 The major economic provisions of the model PSC (KBI Conventional) are as follows.

a) The split of First Tranche Petroleum (para. 6 of the model) amounts to a 12.86% gross royalty on the value of the first 50,000 bpd of oil production from pre-Tertiary and the first 10,000 bpd from other reservoirs, as well as all oil production arising from Tertiary production methods, increasing to 14.65% -16.45% at higher oil production levels. In the case of oil, the result is to reduce the effective price of the contractor's (cost oil and profit oil) crude by at least 12.85% (e.g., if the world price is $10/barrel, the net price is ~$8.70, whereas if it is $15/barrel the net price is ~$13/barrel). This type and level of effective royalty imposes a disproportionately high levy on high cost fields and can act as a strong deterrent to investment particularly when oil prices are expected to remain low. There is a strong case, with new PSCs, for reducing the rate of First Tranche Petroleum and/or the proportion thereof accruing to Pertamina under the standard contract. Although the rate for gas is lower than that for oil the particular difficulties facing Indonesian traditional export markets for gas, as well as the infrastructural costs associated with supplying local markets (and the likelihood that other countries will soften their gas terms), suggest that a reduction is warranted for gas as well.

b) Recovery of operating costs is provided for pursuant to para 6 of the PSCs and the attached Accounting Procedures. Cost oil is taken after delivery of First Tranche Petroleum and the rate of cost recovery is computed using a declining balance methodology over 2-10 years depending on the type of asset, with an estimated average recovery/depreciation rate of around 25% p.a. (declining balance) for both oil and gas under both standard and frontier PSCs. The rate of capital cost recovery is a key determinant of contractor economics because it directly affects the timing of receipt of its cash flows. Whereas the existing model provisions were reasonable in a higher oil/gas price environment, there is now a strong case for revisiting the rate of cost recovery.

c) Domestic Oil Supply Obligation: the very low price (15% of the world price under the standard and 25% under the frontier contract) payable on the share of oil which the model PSCs require be supplied to the domestic market is another major regressive element in the fiscal provisions applicable to oil. If the Indonesian domestic oil refining and marketing industry were liberalized then these provisions would be unnecessary. In any event, for new contracts the price subsidy element should be eliminated and the contractor should receive the world price for any supply to the domestic market.

d) The profit oil/gas sharing provisions (combined with the tax rules) provide a schedule of increasing State profit oil/gas 'take' with profit shares linked to a complex range of proxies for field profitability. In the models, the maximum marginal (not average) State shares of profit oil increase from ±64% (62.5% for gas and under the frontier constraint) to ±82%. (The overall marginal State share – inclusive of FTP and contractor's tax – is significantly higher than this). The profit oil/gas sharing ratios are linked to: (i) the annual rate of production within the Contract Area; (ii) whether a field is pre-Tertiary or Tertiary (presumably on the assumption that pre-Tertiary production is higher cost); (iii) whether a PSC is frontier or not (presumably on the assumption that the former is higher cost); (iv) whether the development is natural gas or oil (again on the assumption that gas is higher cost and faces marketing difficulties); and (v) whether the development is tertiary recovery of enhanced oil recovery (which is again assumed to be higher cost).

A4A.18 Each of these parameters is a rough proxy for field profitability; rough because while there will usually be a link between unit cost and each of the parameters, it is far from being a close link. There may be fields where, for example, pre-Tertiary wells have high productivity and low development costs; or where natural gas is very profitable because of proximity to markets or to existing infrastructure. A preferable and simpler contract form would link State profit oil/gas share directly to a measure of achieved cash flow or (better still) achieved DCF profitability.

A4A.19 Here, whereas the profit oil/gas sharing rates are linked to various cost-related proxies for field profitability, they are *not* linked to changes in the other key (and most uncertain) determinant of profitability, namely, oil and gas prices. Creating a link between State profit oil share and achieved cash flows or profitability would address this limitation of the existing arrangements. There are a number of precedents (discussed later) for this type of link.

A4A.20 Figures A4A.1 and A4A.2 below plot the investor's nominal IRR from model "low" and "medium" cost oil fields with reserves produced from Tertiary reservoirs in the 50mmbbl – 250mmbbl size range, developed under the standard production sharing contract for real oil prices ranging from $11-15/bbl.

Figure A4A.1

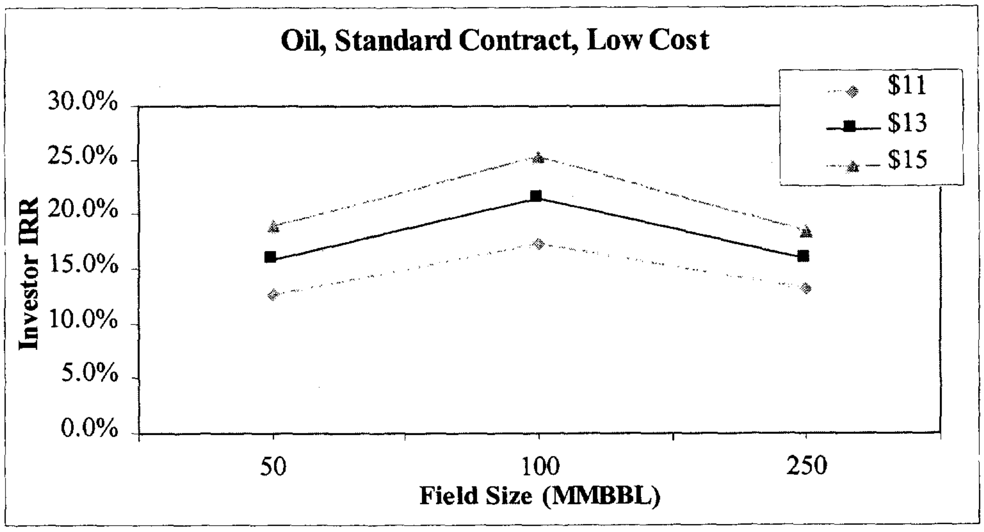
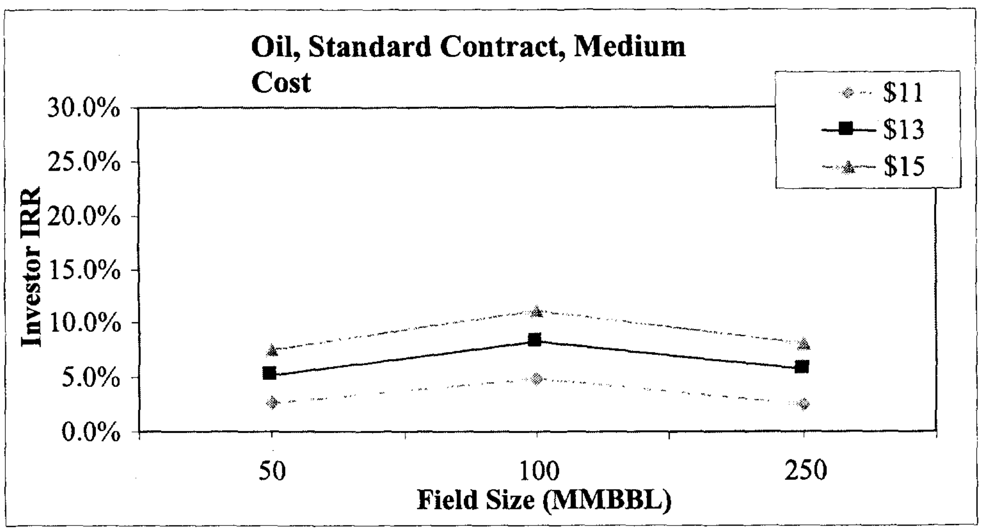
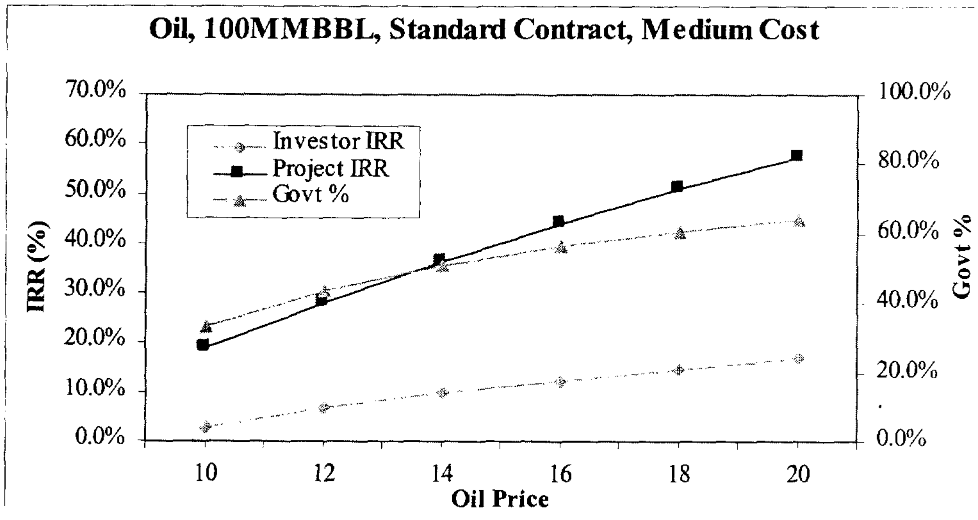


Figure A4A.2



A4A.21 Although these are illustrative, the figures indicate that "medium cost" Tertiary oil fields (as defined) are unlikely to be developed under the current standard contract. The Indonesian Government can do something about this since the problem lies with the contract/fiscal terms and not with the fundamental economics of what are referred to as "medium cost" fields. Figure A4A.3 below plots gross project (pre Government/Pertamina take) and investor internal rates of return ("IRRs"), as well as the share of discounted net revenues going to Government/Pertamina in the case of a 100mmbbl "medium cost" Tertiary reservoir field operating under the standard contract at oil prices between $10 and $20/bbl. Even at a $10/bbl oil price, it shows a gross project IRR of nearly 20% (nominal), which would be higher than most oil companies' hurdle rates, but a Government share of discounted net revenues of over 30%. However, the consequence is the very low post-Government/Pertamina investor IRRs shown in the bottom line (3% nominal at $10/bbl, 7.3% at $12/bbl and below 10% even at $14/bbl).

Figure A4A.3



A4A.22 Figures A4A.4 and A4A.5 show investor IRRs from the same sized fields as in A4A.1 and A4A.2 but under "frontier" rather than standard PSC terms and assuming "medium" and "high" (as opposed to "low" and "medium") development cost scenarios – on the reasonable assumption that frontier regions are likely to involve higher development costs. Given the lower percentage of FTP (15% vs. 20%), lower Pertamina share of both FTP and profit oil and the higher uplift (investment credit) under frontier terms, investor returns are higher than under the standard contract (Tertiary reservoirs), with a medium cost 100 mmbbls field yielding an investor IRR of ±14% nominal at $13/bbl oil. This may be just sufficient to induce an IOC to develop the field – but remains a distinctly marginal return. The graphs also indicate that "high cost" (as defined) oil fields within the 50 – 250 mmbbl range are unlikely to be developed under the frontier regime so long as oil companies' price expectations remain much below $20/bbl.

Figure A4A.4

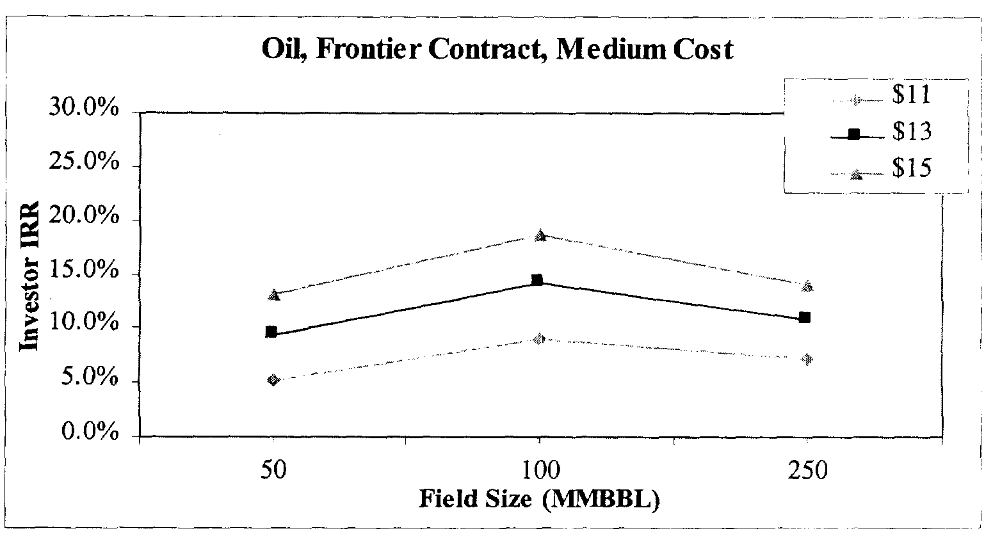
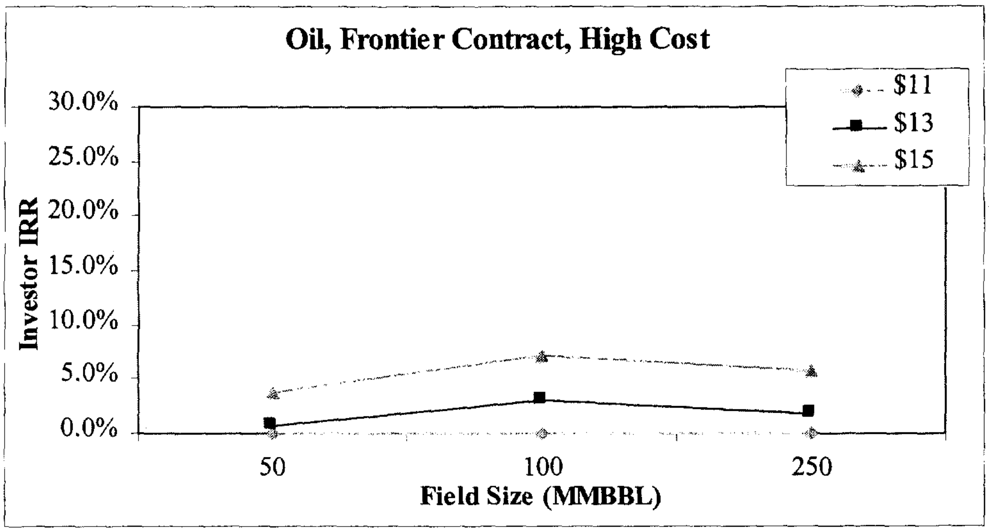


Figure A4A.5



A4A.23 Figure A4A.6 shows that the government share of the marginally economic 100mmbbl "medium cost" oil field is again about 30% on frontier terms even at $10/bbl. This suggests that a reduction in government take at such low oil prices may be more than compensated (at higher prices if not at $10/bbl) by the additional investment which it may generate. Figure A4A.7 suggests "high cost" fields are probably uneconomic under any fiscal terms, until oil companies' price expectations rise and/or technologies can be found to reduce their costs, since even the pre-government take IRR is below investors' hurdle rate, at oil prices at and below $13/bbl.

Figure A4A.6

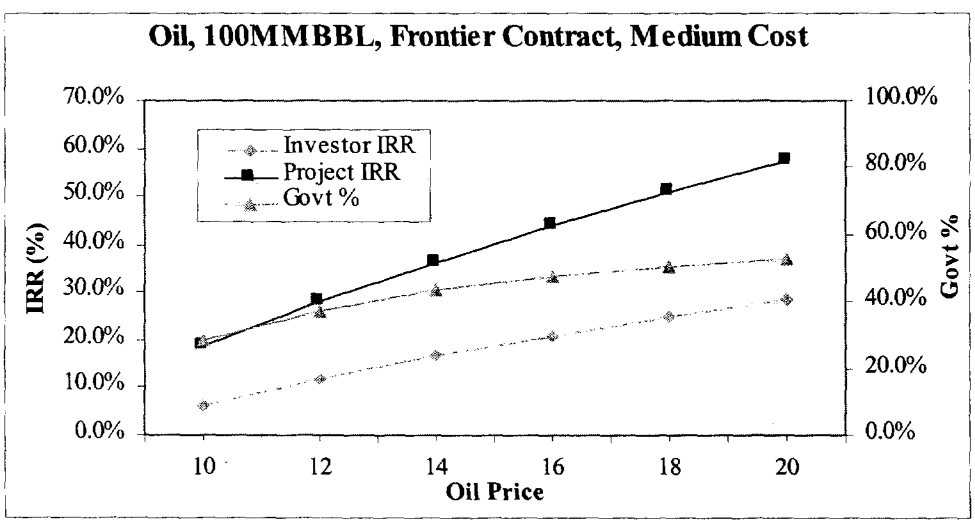
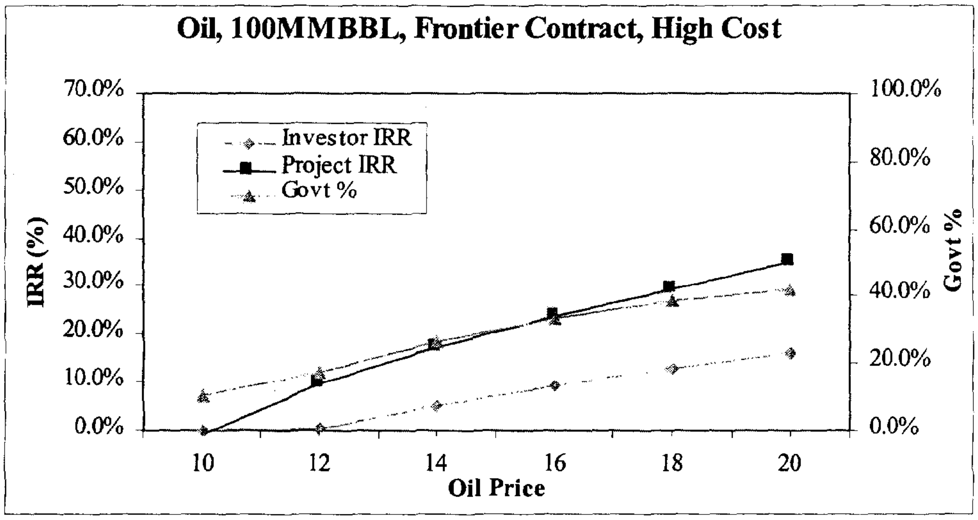


Figure A4A.7



A4A.24 Figures A4A.8, A4A.9, A4A.10 and A4A.11 show investor IRRs from "medium" and "high cost" gas developments from Tertiary reservoirs of 500BCF and 1500BCF, under both standard and frontier terms, and at gas prices of between $2.12 and $2.88/BCF. Despite the more favorable terms enjoyed by gas under both PSCs, these show uneconomic returns to investors from "high cost" fields under the standard regime at prices below $2.88/BCF and distinctly marginal returns from high cost fields under the frontier regime at the same price. Medium cost smaller fields (500BCF) are marginal under both forms of contract at $2.50MCF and lower prices.

Figure A4A.8

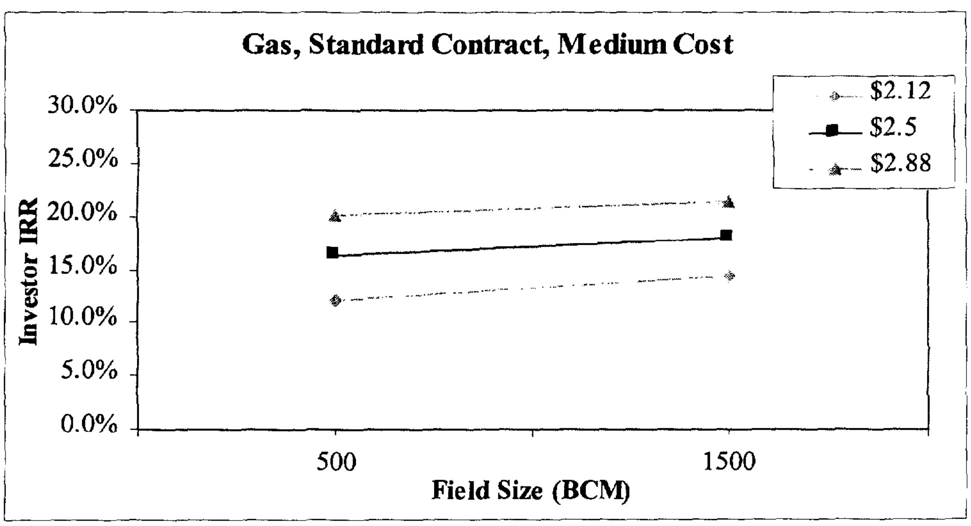


Figure A4A.9

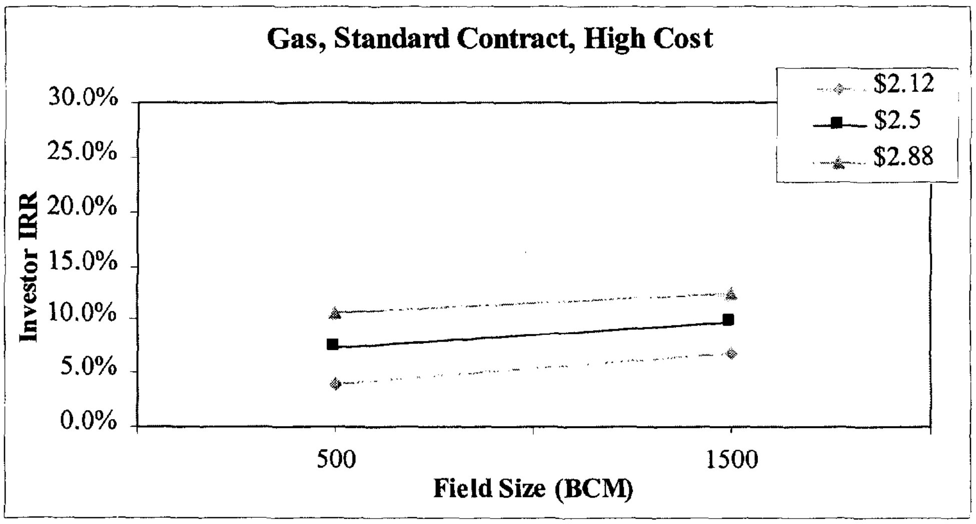


Figure A4A.10

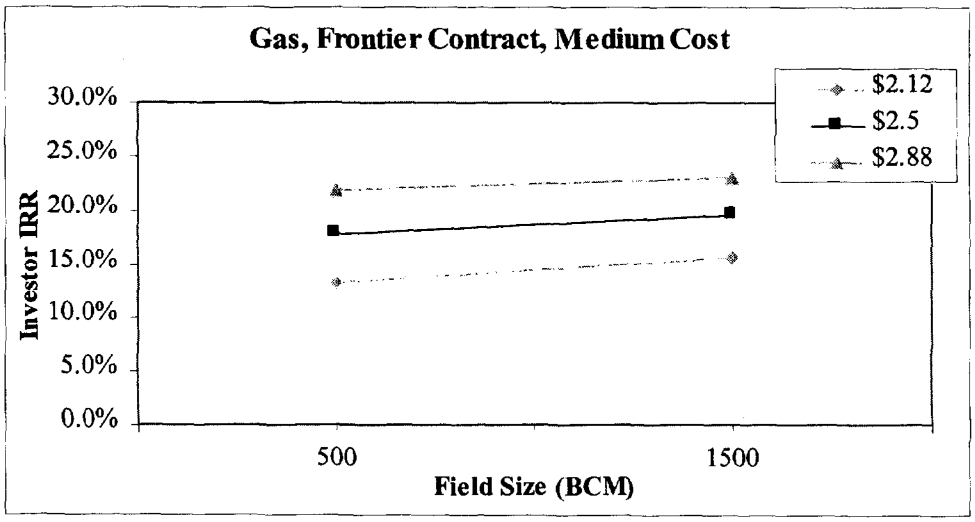
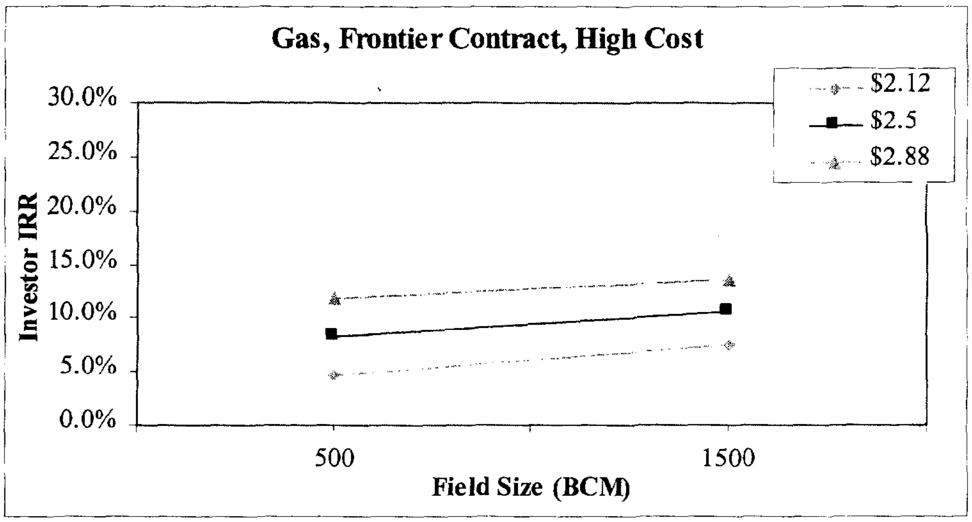


Figure A4A.11



A4A.25 Figures A4A.12 and A4A.13 show the gross project and investor IRRs and the government's share of discounted project revenues for a "high cost" 500BCF Tertiary field developed under the standard regime and a "high cost" 1.5TCF field developed under the frontier regime at gas prices between $1.92 and $3.85/BCF. Although the Government's share of discounted net revenues is lower than oil fields, there is still scope for the Government to reduce its take at low gas prices and, by so doing, increasing investor returns from sub-economic and marginal levels to levels where such fields have a reasonable chance of being developed.

Figure A4A.12

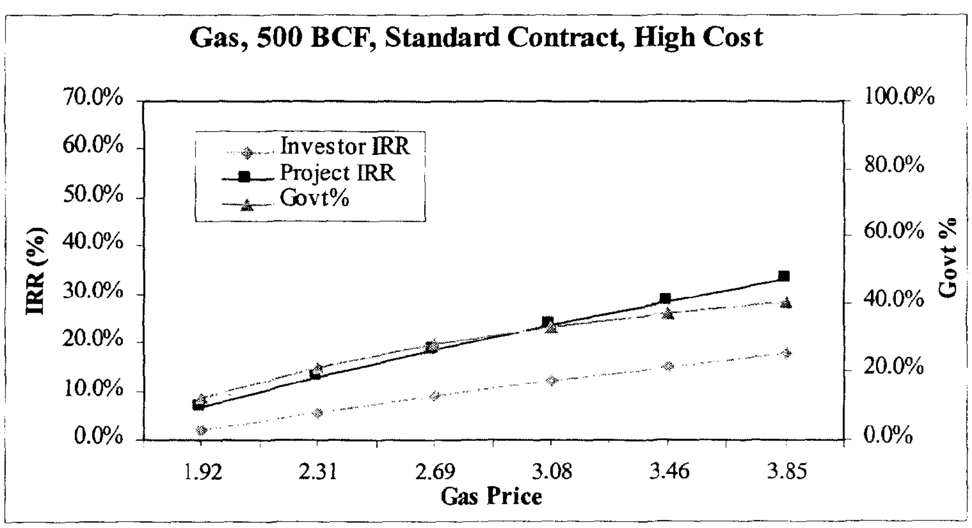
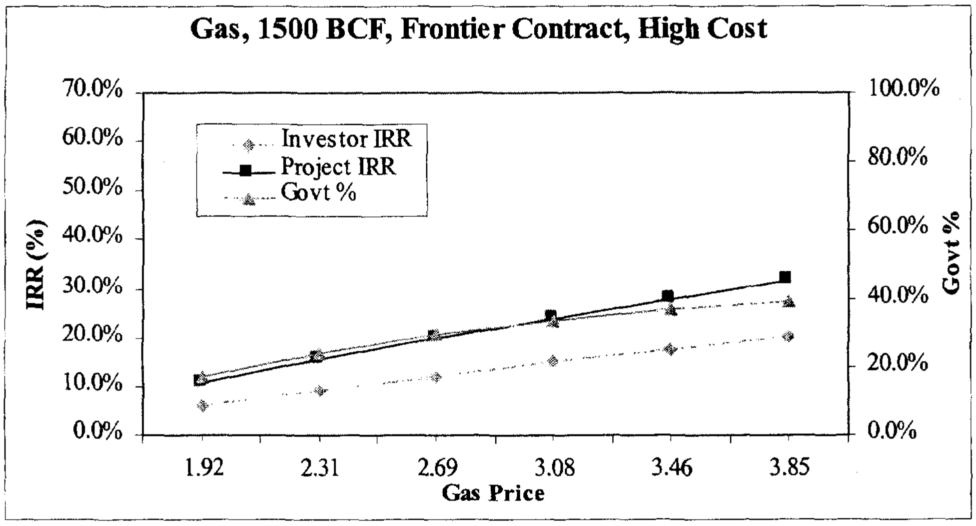


Figure A4A.13



A4A.26 Figures A4A.14 and A4A.15 show investor IRRs at oil prices of $11 - $15/bbl from "medium" and "high cost" developments of pre-Tertiary fields of between 50mmbbls and 250mmbbls under the standard contract.

A4A.27 As can be seen, the reduced Pertamina share of FTP and profit oil and more generous uplift (investment allowance) for pre-Tertiary fields result in higher returns than for Tertiary fields developed under the standard contract – and approximately equivalent investor returns to those earned on similar fields under frontier terms. The "high cost" fields are uneconomic at $13 regardless of tax regime, for the reasons previously explained. Just as under the frontier regime, investor returns from a 100mmbbl "medium cost" pre-Tertiary field are marginal at $13/bbl, and sub-economic in the case of model "medium costs" 50mmbbl and 250mmbbl fields.

Figure A4A.14

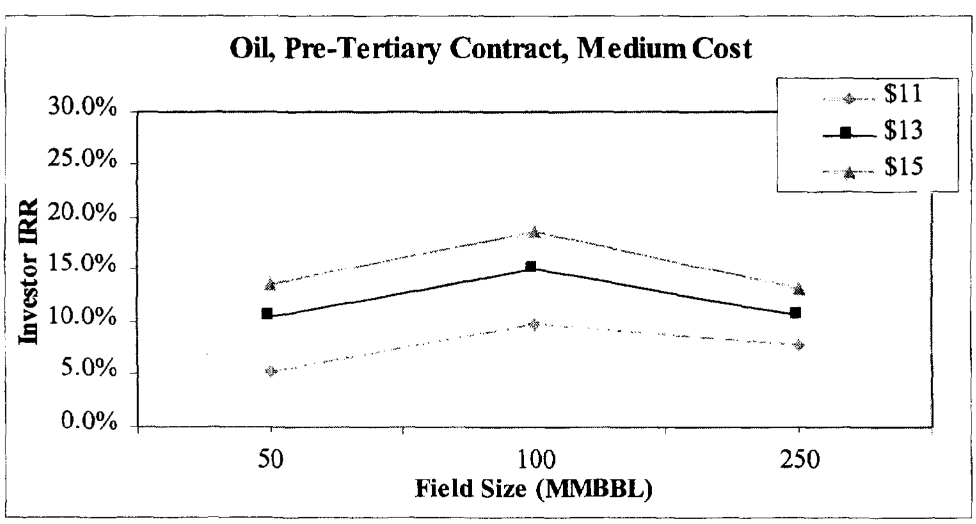
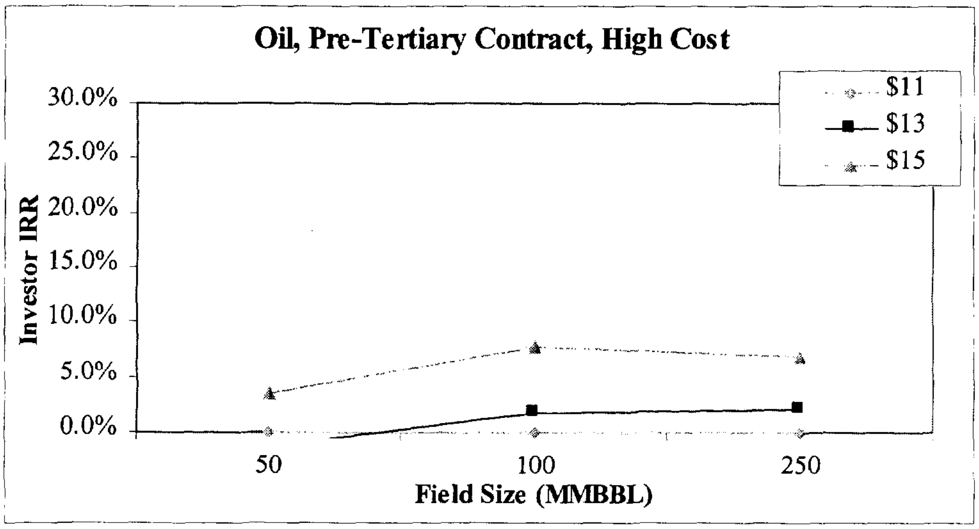


Figure A4A.15



A4A.28 Figures A4A.16 and A4A.17 show project and investor IRRs as well as government share of discounted net revenues from "medium" and "high cost" 100mmbbl pre-Tertiary fields under the standard contract.

A4A.29 Figure A4A.17 confirms there is little (fiscally) that can be done for high cost fields of this size if low oil price expectations persist, but Figure A4A.16 shows considerable scope for reducing government take and increasing investor returns from marginal medium cost fields so as to make their development more likely.

A4A.30 Of course, before firm decisions could be taken on new fiscal terms in Indonesia, more detailed analysis based on Indonesian expected cost projections, would need to be undertaken.

Figure A4A.16

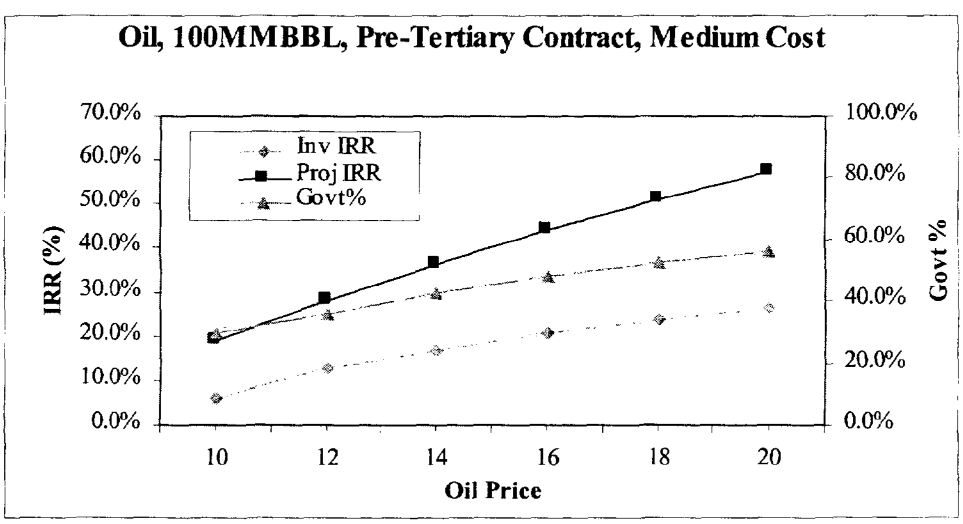
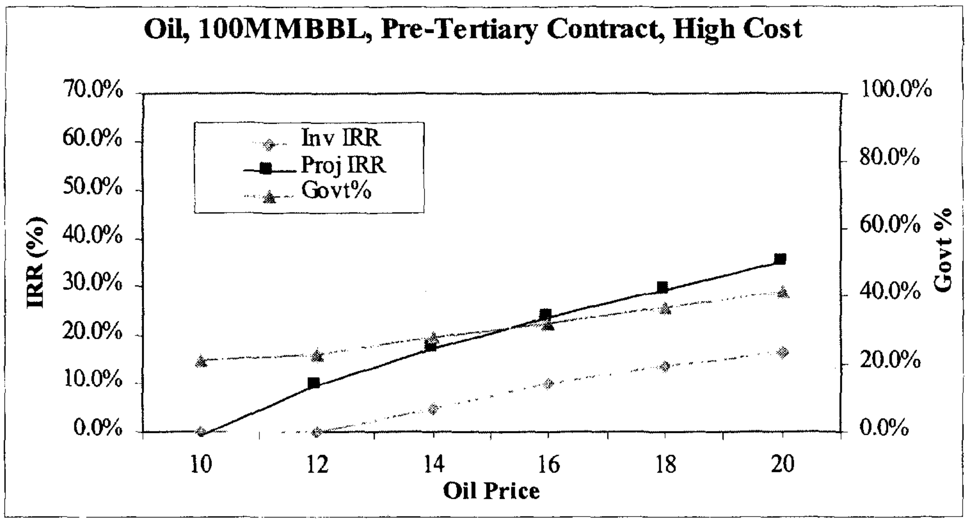


Figure A4A.17



Comparison of Indonesian with Other Upstream Petroleum Regimes

A4A.31 Annex 4C provides a table comparing investor IRRs under Indonesian and other regimes. Figures A4A.18 and A4A.19 plot (left hand scale) State take from Indonesian and comparator regimes in the case of a model 100mmbbl "medium cost" oil field at $13/bbl and a 1500 BCF "medium cost" gas field at $2.50/MCF. The figures also plot the investor nominal IRR from the two fields, at these prices, under each regime (right hand scale).

Figure A4A.18

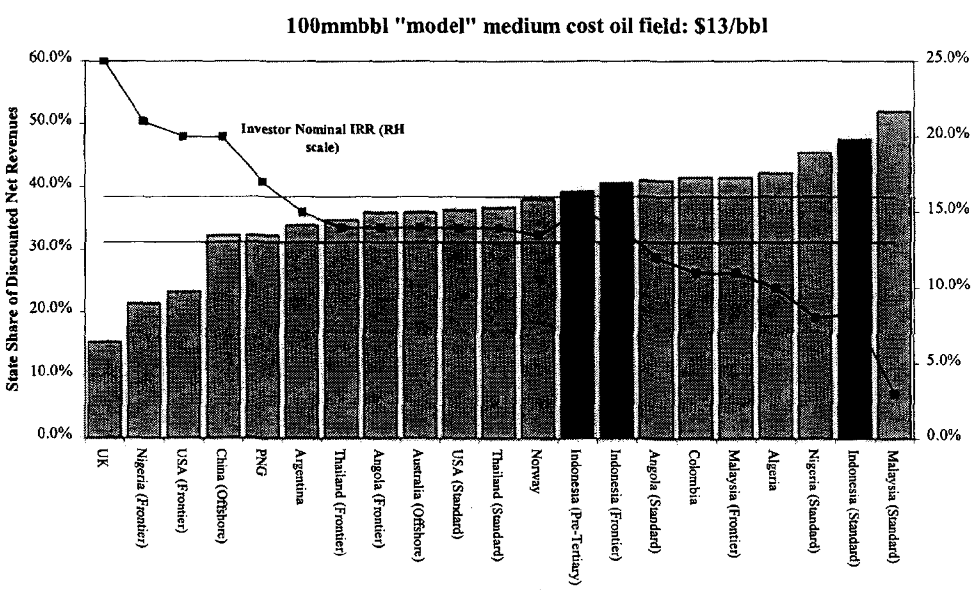
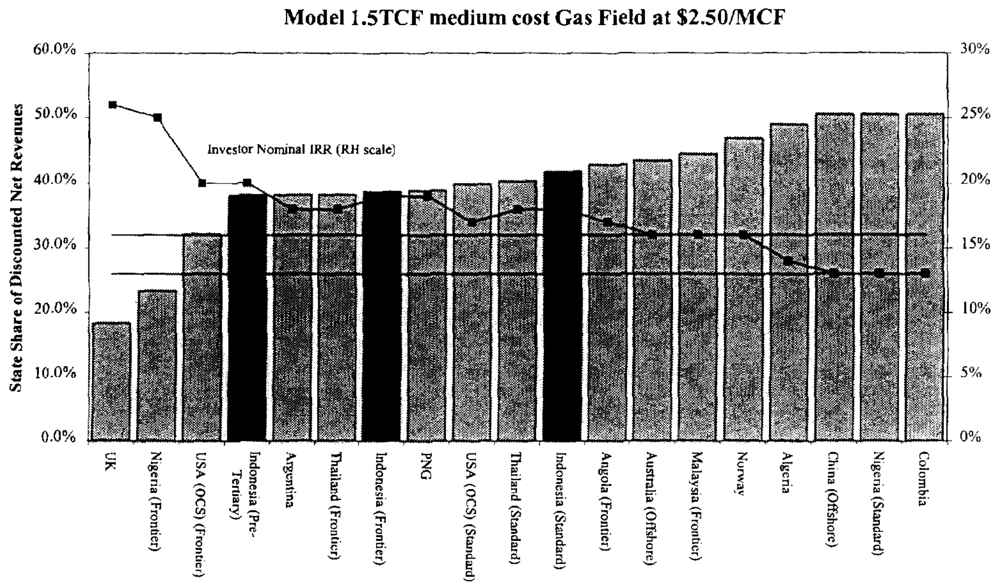


Figure A4A.19



A4A.32 The main problem with the Indonesian regimes is the high proportion of project discounted net revenues which would be taken by the State if these were to be developed at low oil/gas prices – which, of course, is unlikely, since the high government take acts as a fiscal deterrent to their development. The tables below show the Government take under the three Indonesian PSCs (together with three comparators) at prices between $13 and $23/bbl ($2.50 - $4.50/MCF) in the case of a 100mmbbl "medium cost" oil field and 500BCF "medium cost" and a 1500BCF high cost gas field.

Table A4A.2: "Government take" from 100mmbbl "medium cost" oil field (% of 12½% nominal NPV of net revenues)

	$13/bbl	$18/bbl	$23/bbl
Indonesia: (Standard, other)	48%	60%	67%
Indonesia: (Standard, pre-Tertiary)	39%	53%	60%
Indonesia: (Frontier)	41%	51%	56%
Papua New Guinea	32%	41%	53%
USA (OCS) (Frontier)	23%	28%	30%
UK	15%	21%	23%

A4A.33 Of these six regimes, the three comparators produce viable investor IRRs at $13/bbl (between 17% nominal (PNG) and 26% nominal (UK)) whilst the Indonesian regimes do not. Even at $20/bbl, the Indonesian "standard" PSC yields an investor nominal IRR of less than 20%. The need is therefore (a) to increase the progressivity of the Indonesian regimes by reducing the State take *at low prices* while (b) maintaining higher government takes at higher oil/gas prices- subject to not removing all the investor's upside (which risks being the case under the "standard" – but not the "frontier" – Indonesian regime).

Table A4A.3: "Government take" from 500BCF "medium cost" gas field (% of 12½% nominal NPV of net revenues)

	$2.50/MCF	$3.50/MCF	$4.50/MCF
Indonesia: (Standard, other)	39%	48%	53%
Indonesia: (Standard, pre-Tertiary)	26%	36%	43%
Indonesia: (Frontier)	27%	37%	43%
Papua New Guinea	34%	43%	53%
USA (OCS) (Frontier)	16%	21%	23%
UK	23%	27%	29%

Table A4A.4: "Government take" from 1500BCF "high cost" gas field (% of 12½% nominal NPV of net revenues)

	$2.50/MCF	$3.50/MCF	$4.50/MCF
Indonesia: (Standard, other)	30%	40%	46%
Indonesia: (Standard, pre-Tertiary)	26%	36%	43%
Indonesia: (Frontier)	27%	37%	43%
Papua New Guinea	25%	37%	43%
USA (OCS) (Frontier)	28%	32%	34%
UK	13%	17%	20%

A4A.34 The incidence of government take on Indonesian gas fields is lower (both relatively and in absolute terms) than with oil fields. This is because Pertamina's share of (an already lower) FTP is less than with oil, there is no domestic supply obligation and the contractor takes a greater share of profit gas than profit oil. However, State take is still high enough to constitute a deterrent to the development of higher cost projects at low gas prices ($2.50/MCF and below) and could be reduced in a manner which would encourage more of such marginal projects to be brought into production. Again, any such reduction should (and could) be undertaken in a manner which would ensure a progressively higher government take at higher prices and in the case of more profitable developments.[3]

A4A.35 The way to do this is to reduce the incidence of revenue/production based taxes (such as FTP), and tie taxes and/or government production shares (and the rate of such taxes/production shares) to realized profitability. Tying tax rate/profit share to realized profitability not only reduces the risk of tax take/profit share discouraging marginal projects but also ensures the regime is progressive in relation to actual profits, rather than what may be weak surrogates for profits, such as daily or cumulative production levels, field location, the geological horizon from which production arises or the nature of the product (oil or gas).

Recommended Changes to the Financial Terms of Indonesian PSCs

A4A.36 Specific proposals for changes to the financial terms of the current Indonesian regimes are as follows.

a) Switching to a system under which "profit oil/gas" (or tax/royalty take) is shared in accordance with the investor's realized profitability; this would allow the numerous existing models to be

[3] A more detailed analysis of Indonesian upstream gas economics should incorporate more detailed, project specific estimates of gas netback (to field) prices and unit costs.

collapsed into one, which would be simpler and less likely to lead to unintended and/or inequitable outcomes. In what follows it is assumed that this change is made and so the recommendations apply to all new arrangements entered into, wherever located and whatever the product.

b) As suggested earlier, there is a strong case to reduce the proportion of FTP oil which goes to Pertamina/the Government so as to reduce the economic disincentive to develop marginal fields.

c) Again, in order to improve the economics of marginal fields, the domestic market oil supply price subsidy should be abolished.

d) At present, unrecovered expenditure within a Contract Area cannot be deducted against income from other Indonesian PSCs. This is a disincentive to explore for existing contractors with production. There is merit in giving consideration to allowing exploration expenditure to be deducted as cost oil against any PSC Area in Indonesia since this would improve the marginal economics of exploration. Before doing so, it would be necessary to check whether IOCs would gain any net benefit; to the extent that they can deduct the expense in their home tax jurisdiction such a measure might simply transfer revenue from Indonesia to the home country.

e) The concept of "uplift" should be retained within the range which currently exists in Indonesia, but at a variable level which is directly linked to the "payback" period of each development.

f) The tax rate applicable to profits or, if a PSC arrangement is retained, the aggregate tax and production share applicable, should be related directly to the investor's realized internal rate of return.

A4A.37 Figure A4A.20 below shows investor IRRs for a 100mmbbl "medium cost" oil field under both the existing standard Tertiary Indonesian regime and the proposed regime described above ("New"), together with the State's share of the discounted present value of net returns from the field under all four regimes at oil prices between $10/bbl and $20/bbl. Figure A4A.21 does the same thing for a 1500BCF "high cost" gas field.

Figure A4A.20

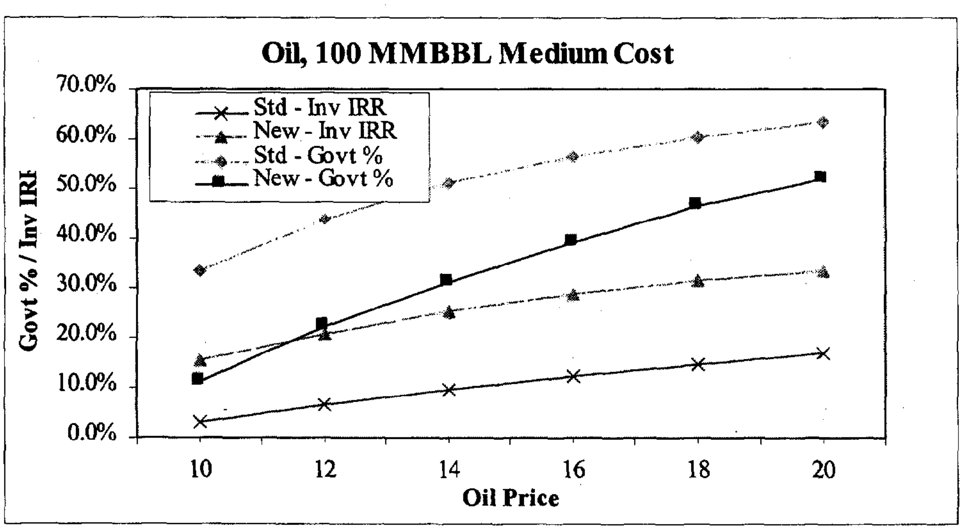
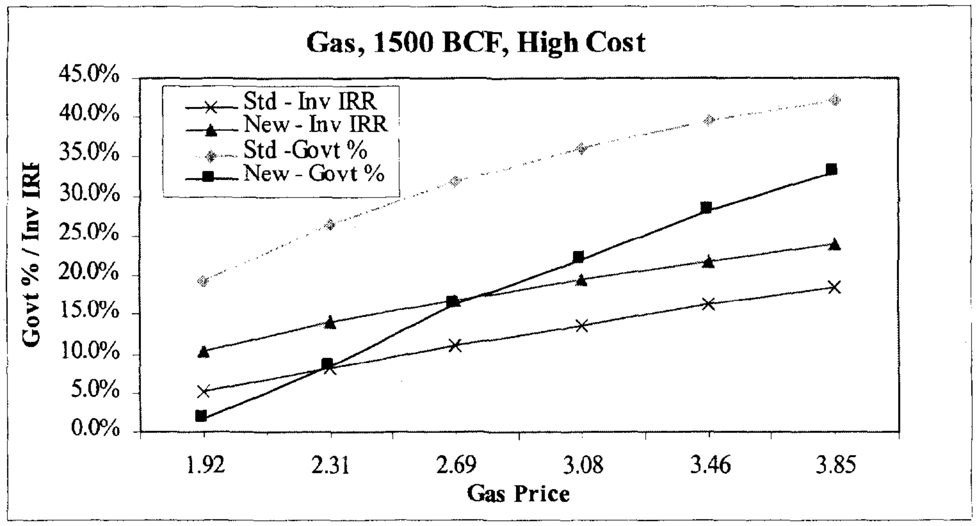


Figure A4A.21



A4A.38 Figures A4A.20 and A4A.21 show how the proposed new regime, if adopted, would substantially remove the fiscal disincentives presently blocking the development of "marginal" oil and gas fields. They also demonstrate the greater progressivity of the new regime with the State take increasing markedly at higher oil/gas prices with approximate equivalence with the old frontier/pre-Tertiary regimes occurring at (it is estimated) ±$24/bbl oil and ±$4.50/MCF gas.

A4A.39 Since the Government has a wider economic interest in promoting investment in the oil and gas sector and since the returns it actually receives are a production of both the theoretical return *if* a field is developed and the number of fields *actually* developed, it may be in the Government's interest to make changes along the lines suggested in order to encourage the development of projects which are marginal at current oil and gas prices and which would otherwise be unlikely to go ahead. It is important to remember that reducing the State take on marginal fields does not reduce State revenues – since if investment is not undertaken then State revenues will be zero.

Recommendations for Changes to Model PSCs—Case of State/PSC

A4A.40 If the State is to become counterparty to the PSCs, as is recommended in Chapter 3 and Annex 3, the issue arises as to which of Pertamina's current rights and obligations should be assumed by the State (and by which instrumentality), and which should simply lapse – i.e., be left entirely in the hands of the private sector. Based on what is regarded as "best international practice" we propose the following (references are to sections of the "KBI Conventional model PSC").

A4A.41 **Section II ("Term")**. Responsibility for approving PSC extensions and development decisions should be switched from Pertamina to the Ministry of Mines and Energy ("MME").

A4A.42 **Section III ("Exclusion of Areas")**. MME should assume the right to require the Contractor to submit a new exploration program or relinquish (section 3.5) and be the recipient of Contractor's notice of relinquishment under section 3.6. Consultations regarding the shape and size of areas being relinquished (section 3.7) should take place between MME and the Contractor.

A4A.43 **Section IV ("Work Program and Expenditures").** Rights to consent to carry forward of under-expenditure (section 4.2) and approve or amend annual Work Programs and Budgets (sections 4.3 and 4.4) should be transferred from Pertamina to MME. The qualification that approval will not be unreasonably withheld (section 4.7) should remain, but be recast to apply to MME.

A4A.44 **Section V ("Rights and Obligations of the Parties").**

- The obligations of the Contractor to remove equipment from an abandoned site (section 5.2.5c) should be performed to MME's satisfaction – not Pertamina's. The existing qualification that the obligation becomes Pertamina's if it takes over a field prior to its abandonment should be recast to provide that the "clean-up" obligation will be assigned if the Contractor validly assigns its rights under the Contract with the State's (MME's) prior approval. The Contractor should not be released from its obligation if the State has terminated the Contract due to Contractor's default.
- Notification of assignments of rights under the Contract to affiliates (section 5.2.6) should be to MME, and the right to consent to transfers to third parties (section 5.2.7) should be limited to the Government (i.e., the Pertamina consent should be deleted) and, again, we suggest the relevant government entity be MME.
- Contractor's right of access to Pertamina's information on the Contract Area should be restated as a right of access to MME's information and – as part of the "normalization" of Pertamina - it should be required to deliver all of its data and information to MME, retaining copies only in respect of information regarding the Contract Areas where it retains a participating interest.
- Similarly, Contractor's current obligation to submit to Pertamina copies of all information it derives from the Contract Area (section 5.2.11) should be changed to an obligation to deliver the same to MME. In those areas where Pertamina retains a non-operating Participating Interest, its on-going rights to information from Contractors should be established in a separate industry-standard Joint Operating Agreement (to which the State would not be party).
- If the domestic supply obligation (section 5.2.15) is retained, the obligation should be on the Contractor to supply the State (again, we suggest in the form of MME) or its nominee – thereby permitting MME in practice to assign the right to the owner of an Indonesian refinery.
- Consent to disclose information to third parties (section 5.2.19) should be required from MME – and no longer Pertamina.
- Section 5.3.1 (Pertamina responsibility for management) should be deleted rather than seeking to involve Government in lieu of Pertamina (i.e., management is an area which is best left to Contractors).
- Pertamina's responsibility under section 5.3.2 to pay certain of Contractor's taxes should be replaced by equivalent exemptions granted by whichever arm(s) of Government is/are empowered to grant these.
- Section 5.3.3 (Pertamina's assistance to Contractors in effecting the Work Program) should be largely deleted. Instead, a short statement that the Government will ensure Contractors receive the necessary work permits, visas etc. is proposed.
- The obligation to supply Rupiah (section 5.3.4) should become an obligation of the Central Bank or Ministry of Finance.
- Title to original data (section 5.3.5) should be vested in MME.

A4A.45 **Section VI ("Recovery of Operating Costs and Handling of Production").**

- The authorization/obligation to market crude (section 6.1.1) should be granted by the State.
- As discussed elsewhere – and consistent with the draft oil and gas law – the rights to a share of profit oil (section 6.1.3 (a), (b), (c) and (d)), Natural Gas (section 6.2.2) and FTP (sections 6.3.2 and 6.3.4) should be switched from Pertamina to MME, on behalf of the State.
- Approval of field developments (section 6.1.3 (a), second sub-para) should be the responsibility of MME, not Pertamina.
- If the Government wishes to retain a right to take production in kind (section 6.1.6) it should substitute MME for Pertamina – but include a provision granting MME the right to assign this right to a third party owner of a refinery.
- Pertamina's right to decide on the viability of gas projects should be switched to MME and should be suitably qualified in a manner capable of objective, third party arbitration.
- The right to take gas which would otherwise be flared should become an assignable right of MME's, with the assignee requiring to be of suitable technical and financial standing.

A4A.46 **Section VII ("Valuation of Crude Oil").**

- As replacement recipient of what was formerly Pertamina's production share, the Government should continue to benefit from the "arms' length" and other protections afforded to Pertamina by this section.
- Pertamina's right (subject to pre-existing Sales Agreements) to take over the marketing of its own crude if it can obtain better terms should be replaced by an (assignable) right on the part of MME.

A4A.47 **Section VIII ("Compensation, Assistance and Production Bonus").** Signature and production bonuses (8.1 and 8.3) should be made to the Government (possibly Ministry of Finance) in lieu of Pertamina.

A4A.48 **Section IX ("Payments").** Reference here to Pertamina should be deleted.

A4A.49 **Section XI ("Consultation and Arbitration").** Should be replaced by a similar provision covering disputes between Contractor and Government.

A4A.50 **Section XIII ("Termination").** Notices and consultation should be to/with MME, not Pertamina.

A4A.51 **Section XIV ("Books and Accounts and Audits").** In order to accord with usual international practice, this section should be reversed: an obligation should be placed on Contractors to maintain books and records in accordance with good petroleum industry and accounting practices and the Government (acting through appropriate agency(ies) – perhaps MME and the Auditor-General's (or its Indonesian equivalent's) office – and, if it so chose, using outside professional accountants, should have a right of access to, and periodic right to audit, Contractor's books.

A4A.52 **Section XV ("Processing of Products").** If the Government wishes to preserve a local refining obligation, it should be vested in MME, with a right on its part to assign to a local refinery.

A4A.53 **Section XVI ("Participation").** As discussed earlier, the State may wish to retain a right for Indonesians to participate in future discoveries. If so, we suggest that the right contained in section 16 be switched from Pertamina to the State, with a right for that interest to be sold to Indonesian nationals pursuant to a transparent market process, in which Pertamina (and others) could participate.

Analysis of the Non-Financial Provisions of Indonesian Model PSCs

A4A.54 The Indonesian PSC arrangements have operated satisfactorily for many years. However, there have been significant changes in the relationship between the State and international oil companies (IOCs) particularly during the 1990s in other countries, and it is appropriate to consider whether changes in the current legal and contractual arrangements (i.e., the non-financial provisions of the model PSCs) are desirable.

Procedures for Allocating New Petroleum Rights

A4A.55 There is a choice of procedure for the allocation of new petroleum rights (whether PSCs or other forms):

- negotiating the specific terms under a range of headings (work and expenditure commitments, production share splits, bonuses etc) on an *ad hoc* basis; or
- allocating new rights through bidding rounds, where the contract terms are specified – except for a limited number of headings – and oil companies are invited (by the Government, assuming the new oil and gas law is passed in the form of the February '99 draft and it assumes this responsibility from Pertamina) to bid the contract terms to which they will commit;
- bidding rounds, if properly designed, have important advantages over bilateral negotiations;
- competition for the rights allows the Government to benefit from the terms offered by the most aggressive (i.e. optimistic) oil company;
- if the fiscal term parameters are determined through a bidding process then there is a much reduced risk that economic parameters will be set at levels which will deter investment; and
- well designed bidding rounds offer a highly transparent procedure for allocating petroleum rights.

A4A.56 If bidding is to be adopted then, to facilitate comparison of bids, it is important that the number of bidding variables is limited and that these are restricted to those components which are least likely to deter a winning investor from proceeding with a project if its bid turns out to have been "too high". Typically, the entire contract terms would be fixed other than (a) minimum work and expenditure commitments and (b) the production sharing splits and/or the rate of cost recovery uplift. Elements such as FTP should be fixed (at a relatively low level).

Other Issues

A4A.57 We have set out below comments on the PSC Model Contract terms (other than the fiscal terms, covered earlier). The comments address whether the contracts in their current form meet the Government and investor objectives noted in paras A4A.5-A4A.6. The comments relate to the Conventional PSC but the same comments apply to the Frontier and Technical Assistance contracts which differ from the Conventional primarily in the economic benefit sharing terms.

A4A.58 **Parties and Responsibilities**. The PSC is currently executed by Pertamina. If the relationship of the investor with the State were to be revised – as is proposed in the new oil and gas law and which we support - then the contracting party would be the State (Ministry of Mines and Energy) and all references to Pertamina (except where we specify otherwise below) would be replaced by references to the Government.

A4A.59 **Scope**. There seems no good reason to maintain that Pertamina (or the Government, as the successor counterparty to the PSCs or other Co-operation Agreements) 'manages' operations, and it is suggested that this provision be deleted.

A4A.60 **Term**. The Exploration Period is set at 6 years plus an extension of 4 years. These periods should relate to the time required to undertake in a timely fashion a thorough exploration program. While appropriate for new areas, shorter periods may be appropriate in respect of areas where significant exploration data is available. Para 2.4 gives Pertamina (or, under the proposed new oil and gas law, the State) discretion to determine that a discovery is not commercial. This should be qualified such that any rights of consent relating to this economically vital decision is subject to objective and arbitrable criteria (e.g. "Pertamina/the State shall not withhold consent if the contractor has presented a development plan in accordance with good oil field practice and compliant with all national laws...").

A4A.61 **Exclusion of Areas**. Progressive relinquishment is appropriate but the pace and percentages set out in the contract may need to vary depending on the extent of prior exploration in the contract area.

A4A.62 Paras 3.3 & 3.4: At the end of the Exploration Period all of the Contract Area other than any part corresponding to the surface area of any field for which a development decision has been taken should be relinquished. This will enhance the incentive to explore all prospects during the initial and extended Exploration Period.

A4A.63 Para 3.5: Assuming that the State takes over from Pertamina as counterparty to the PSC, the first reference in para 3.5 to "Pertamina" is one which should be deleted rather than replaced by "the State", since the State will (and should) have no responsibility for "maintaining an exploration effort".

A4A.64 **Work Program and Expenditures**. These should either be bid (with minima set in the bid document) or negotiated at levels which ensure a sustained exploration effort for so long as the acreage is held.

A4A.65 Para 4.2 might be clarified to confirm the presumed intent that if the contract lapses after year 6 then obligations in respect of years 7-10 also lapse.

A4A.66 Para 4.3 currently gives Pertamina (and, in future, may grant the State) a right of approval (not to be unreasonably withheld) in respect of Annual Work Plans and Budgets. Elsewhere the Contractor has to submit plans and budgets consistent with the obligations to the authorities for information, not consent. As a minimum the provision should be clarified to confirm that if consent is required then the approving authority cannot require changes which increase expenditures above those set out in para 4.2.

A4A.67 Para 4.5: restricts the Contractor's right to change the Work Program if the effect would be to increase expenditures above those in the Budget. This is presumably to protect Pertamina from unexpected cash calls but is unusual and undesirable from Government's perspective in discouraging increased expenditures. The international norm would be to constrain changes which *reduced* the Contractor's expenditures.

A4A.68 **Rights and Obligations**. Paras 5.2.1, 5.2.2 and 5.3.4 should be clarified to confirm: (i) that the Contractor is responsible for providing all funds to meet both foreign currency and Rupiah costs; (ii) the Central Bank – not Pertamina – is required to make available Rupiah (against delivery of Contractor's foreign currency) to pay local costs.

A4A.69 Para 5.2.6: the rationale for the proviso at the end of this para is unclear (to us). If the intent is to mirror Article 7 of the draft oil and gas law and establish a "ring fence" around each Contract for (e.g.)

tax purposes, we would query if this is desirable in the current economic climate when some further fiscal incentive to exploration and development expenditure may be warranted.

A4A.70 Para 5.2.7: the right to approve here should be limited to Government – i.e. the reference to Pertamina should be deleted.

A4A.71 Para 5.2.8: this right should not be restricted to leased property only.

A4A.72 Para 5.2.13: the right to export product, hold proceeds offshore and establish foreign currency bank accounts should be granted by the relevant branch(es) of government (e.g., the Central Bank).

A4A.73 Para 5.2.15: the domestic supply obligation requires the contractor to sell to Pertamina up to 25% of its "profit oil" share of all oil produced at 15% (25% in frontier areas) of the world price. This provision is used to underwrite the large petroleum product subsidies in the local market. These subsidies should be phased out; the provision should be deleted from all new PSCs. As discussed earlier, the effect of this provision is to deter investment in otherwise economic fields and has no counterpart in any of the other countries reviewed.

A4A.74 Para 5.2.7: If article 2.2(i)(a) of the draft oil and gas law is passed in its current form (which we would support) this para should be amended to refer to tax law "at the time the Contract is signed".

A4A.75 Para 5.3.1: as with "*Scope*" (see above), the provision that Pertamina (or, for that matter, Government) is 'responsible for the management of the operations' should be deleted.

A4A.76 Para 5.3.2: should be converted into equivalent exemptions granted by Government.

A4A.77 Para 5.3.3: If Pertamina's status were normalized, para 5.3.3 would be deleted (and the Contractor might contract with Pertamina to provide those services and recover the cost via cost recovery).

A4A.78 Para 5.3.4: see first para of "Rights and Obligations" above.

A4A.79 Para 5.3.5: Government should have title, not Pertamina.

A4A.80 **Natural Gas**. Para 6.2.1 A blanket right to flare gas is now unusual. This is an area where consent by the Ministry might be required but not withheld if the contractor can demonstrate that economic alternatives are not available. (This is an objective, arbitrable, test).

A4A.81 Para 6.2.2: like 2.4, gives Pertamina discretion to determine that a discovery is not commercial. If retained as a Governmental discretion, we recommend that it be qualified and that the decision be arbitrable.

A4A.82 Para 6.2.4: this should become a right of the Ministry, not Pertamina. The Ministry would then be entitled to procure a party (which might be Pertamina or another suitably qualified and capitalized party) to utilize the gas.

A4A.83 **First Tranche Petroleum**. Discussed earlier.

A4A.84 **Valuation of Crude Oil**. If the contracting party were Government then the same obligations on the contractor to market the State share of production (if requested) would continue to apply.

A4A.85 **Books and Accounts**. Most of this could be replaced with a standard requirement to provide audited information to the Ministry with rights of access/audit/further information for the State (the Ministry and, perhaps, Tax Office and Auditor-General's office).

A4A.86 **Employment and Training of Indonesian Personnel**. Assuming that the Government takes over as counterparty to the PSC or other form of Co-operation Agreement we suggest retaining an obligation on the Contractor to assist in the training of Government personnel or personnel from other Indonesian institutions or companies which Government may nominate.

A4A.87 **Processing of Products**. If the oil refining and marketing business and product prices were liberalized then paras 15.4.1 – 15.4.2 would be unnecessary. Decisions on where crude was refined, and new refining capacity, would be taken by the market (subject to usual Government, not Pertamina, consents). If retained, 15.4.4 should specify that payment should be in US dollars, offshore.

A4A.88 **Participation**. As discussed earlier, the State may wish to retain a right for Indonesian nationals to participate in future discoveries. The right to a participating or carried interest in new discoveries (as proposed in para 16) could be retained but granted to the State; and new legislation would provide for that interest to be sold to Indonesian nationals (according to a transparent market process in which Pertamina and others could participate) within, say, three years following commencement of commercial production.

ANNEX 4B: Comparison of International Co-operation Contracts

Country:	ALGERIA	ANGOLA		ARGENTINA	AUSTRALIA	CHINA	COLOMBIA	MALAYSIA	
Contract Type:		(FRONTIER Deep Water)	(STANDARD)		(OFFSHORE)	(OFFSHORE)		(FRONTIER) (OVER 200M)	(STANDARD)
Bonuses:	None	Yes: signature	Yes: signature	None	None	Yes: signature	None	None	None
Royalty:	12.5% (Zone B)	Nil	Nil	12%	None	Oil (mbopd) / Gas (mmcfd) / Rate 0-20 / / 0% 20-30 / / 4% 30-40 / / 6% 40-60 / / 8% 60-80 / / 10% >80 / / 12½% / 0-200 / 0% / 200-350 / 1% / 350-500 / 2% / >500 / 3%	20%	10% + 10% export tax on profit oil	10% + 10% export tax on profit oil
Development Cost Recovery:	5 years straight line	4 years straight line; UPLIFT of 40%	5 years straight line; UPLIFT of 40%	N/A	N/A	All expensed	N/A	All expensed	All expensed
Cost Recovery Cap:	Cost Recovery + Profit Share ≤ 49% gross (Excess entitlements carried forward)	50% gross (raised if development costs unrecovered after 4 years)	50% gross (raised if development costs unrecovered after 5 years)	N/A	N/A	62.5% gross	N/A	75% gross for oil 60% gross for gas [negotiable]	50% gross for oil 60% gross for gas [negotiable]
Contractor's Profit Share:	"R":<1.0 50% 1-1.5 45% 1.5-2.0 40% 2.0-2.25 30% 2.25-2.5 20% >2.5 15% R = cum revenues / cum expenditures	R < 20%: 60% 20% - 25%: 50% 25% - 30%: 40% > 30%: 20% R = rate of return	Cumulative Production: 25mmbbl/175BCF: 50% 25–50mmbbl/175–400BCF: 30% 50-100mmbbl/400-900BCF: 20% >100mmbbl/>900BCF: 10%	N/A	N/A	Contractor's share after royalty, VAT and cost recovery Incremental daily oil production (mbopd) / Contractor's share 0-20 / 100% 20-40 / 95% 40-60 / 90% 60-100 / 85% 100-150 / 80% 150-200 / 70% >200 / 60% Gas / 30%	See under Participation	OIL (Contractor %) 0-50 MBOPD 70% 50-100 MBOPD 55% > 100 MBOPD 50% (or cumulative 250mmbbls) GAS 60% up to 2TCF cum prod;40% thereafter	OIL (Contractor %) 0-10 MBOPD 50% 10-20 MBOPD 40% > 20 MBOPD 30% (or cumulative 50mmbbls) GAS 50% up to 2TCF cum prod; 30% thereafter
Domestic market, supply obligation:	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Income Tax:	Effectively nil; Paid by State	50% profit share	50% profit share	35%	36%	33%	35%	38% (oil); 28% (gas) of cost recovery and profit share less opex, royalty, export tax and depreciation	[As for frontier areas]
Depreciation:	N/A	?	?	Unit of production	8 years straight line	6 years straight line	10 years straight line	Development costs 28% year 1; 8% p.a thereafter	[As for frontier areas]
WHT:	Nil	Nil	Nil	Nil	15%	Nil	7%	Nil	Nil
Other Taxes:	Nil	Nil	Nil	Provincial Sale Tax (3% in Neuquen)	PRRT @ 40% (expensable against Income Tax)	VAT: 5% of gross	None	CESS Tax: 0.5% of cost recovery oil plus profit share less export tax	CESS tax as per frontier areas
State Participation:	30%; no reimbursement of E&A; State pays its share of development costs	20% from day one; pay all costs	Nil	Nil	Nil	51%; no repayment of E&A costs; pay development costs	50%; reimburses E&A costs but pay (50%) development costs. Private investor's share decreases above 60 mmbbls (360 BCF) cumulative production as follows R<1 50% R: 1-2 (50/R) R>2 25% R = Investor's accumulated Revenue / Investor's accumulated Costs	15%; no reimbursement of sunk E&A costs; pay development costs	25%; no reimbursement of sunk E&A costs; pay development costs

Country:	NIGERIA		NORWAY	PNG	THAILAND		UK	USA
Contract Type:	(FRONTIER)	STANDARD (<200M)			FRONTIER	STANDARD		(OCS)
Bonuses:	Yes: (signature and production)	Yes: (signature and production)	None	Nil	Nil	Nil	None	Yes: signature
Royalty:	Water depth (m) / late 200-500* / 12% 500-800 / 8% 800-1000 / 4% > 1000 / 0% * Assumed for analysis	16.67%	None	2% (1¼ expensable, ¾% creditable). 2% "development levy" may be introduced under new Oil and Gas Bill	Incremental daily prod / Rate Oil Mbopd / Gas mmcfd / 0-2 / 0-20 / 3.5% 2-5 / 20-50 / 4.375% 5-10 / 50-100 / 7.0% 10-20 / 100-200 / 8.95% >20 / >200 / 10.5%	Incremental daily prod / Rate Oil Mbopd / Gas Mmcfd / 0-2 / 0-20 / 5% 2-5 / 20-50 / 6.25% 5-10 / 50-100 / 10.0% 10-20 / 100-200 / 12.5% >20 / >200 / 15%	None	Cumulative Production Depth (m) / Oil mmbbl / Gas BCF / Rate 0-200 / All Production / 16.66% 200-400 / 0-17.5, > 17.5 / 0-105, > 105 / 0%, 16.66% 400-800 / 0-52.5, > 52.5 / 0-315, > 315 / 0%, 12.5% >800 / 0-87.5, > 87.5 / 0-525, > 525 / 0%, 12.5%
Development Cost Recovery:	Intangible: expensed Tangible: 5 years straight line	Intangible: expenses Tangible: 5 years straight line	N/A	N/A	N/A	N/A	N/A	N/A
Cost Recovery Cap:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Contractor's Profit Share:	Cum production after costs, royalty & tax / Contractor share Oil mmbbls / Gas BCF / % 0-350 / 0-2100 / 80 351-750 / 2101-4500 / 65 751-1000 / 4501-6000 / 55 1000-1500 / 6001-9000 / 50 >1500 / >9000 / 40	Incremental daily production after costs, royalty and tax / Contractor share Oil mbopd / Gas mmcfd / % 0-30 / 0-60 / 40% 30-50 / 60-300 / 38% >50 / >300 / 35%	N/A		N/A	N/A	N/A	N/A N/A
Domestic market, supply obligation:	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Income Tax:	50% (oil); 35% (gas)	50% (oil); 35% (gas)	28%	50% (oil) 30% (gas)*	50% (SRB expensed)	50% (SRB expensed)	31% (30% from April 99)	35% (royalty expensable)
Depreciation:	5 years straight line; 50% uplift	5 years straight line; 20% uplift	6 years straight line	12½% DB provided that additional depreciation may be take up to the point where after tax, pre interest cash flow = 25% Initial Capital Investment	5 years straight line. Revenue reduced by 7% first 4 years; 5% in years 5-7 and 3% in years 8 and 9	As for frontier	25% DB	Unit of production
WHT:	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Other Taxes:	N/A	Other	SPT = 50% of taxable income (less uplift of 5% of development costs for 6 years)	APT at 50% (oil); 30% (gas) when after tax cash flow exceeds 27%	Special Remunatory Benefit (SRB) Variable % (0%-75%) on revenues less opex less 25% tangible development costs	SRB, variable % (0%-75%) on revenues less opex less 10% tangible development costs	Nil	Nil
State Participation:	Nil	Nil	30% from day one	22½% carried	Nil	Nil	Nil	Nil

* Proprietary model does not include lower tax rates now applicable to gas projects so understates investor returns and overstates government take from these.

Country:	INDONESIA		
Contract Type:	(STANDARD)		(FRONTIER)
Bonuses:	Yes, signature and production		Yes; signature and production
Royalty:	Oil: Pre-tertiary reservoirs: 1st 50,000 bopd: 50,000-150,000 bopd: >150,000 bopd: Other reservoirs: Under 10,000 bopd: Other: Tertiary recovery: Gas:	 12.86% 14.65% 16.43% 12.86% 14.65% 12.86% 7.5%	5.625% (oil) 4.285% (gas)
Development Cost Recovery:	approx 25% DB over 5 years Uplift 102% (pre-tertiary); 15.78% (other)		approx 25% DB over 5 years No Uplift
Cost Recovery Cap:	100%		100%
Contractor's Profit Share:	Oil: Pre-tertiary reservoirs: 1st 50,000 bopd: 50,000-150,000 bopd: >150,000 bopd: Other reservoirs: Under 10,000 bopd: Other: Tertiary recovery: Gas:	 35.71% 26.79% 17.86% 35.71% 26.79% 35.71% 62.50%	62.5%
Domestic market, supply obligation:	25% Contractor's share of FTP/profit oil of all oil @ 15% mkt from year 6 of production; Nil for gas		25% Contractor's share of FTP/profit oil of all oil @ 25% mkt from year 6 of production; Nil for gas
Income Tax:	44% effective incl WHT, royalty expensable		44% effective incl WHT, royalty expensable
Depreciation:	approx 25% DB, balance in year 5		approx 25% DB, balance in year 5
WHT:	(In Income Tax)		(In Income Tax)
Other Taxes:	Nil		Nil
State Participation:	10%; reimburse 150% E&A costs from 50% of its share of production; pay development costs		10%; reimburse 150% E&A costs from 50% of its share of production; pay development costs

ANNEX 4C: Investor IRRs under Indonesian and Comparator Regimes

($13/bbl oil/US$2.50/MCF gas)

Reserves:	50mmbbls			100mmbbls			250mmbbls			500BCF			1500BCF		
Development Costs:	High ($6/bbl)	Medium ($4/bbl)	Low ($2/bbl)	High ($5.25/bbl)	Medium ($3.50/bbl)	Low ($1.75/bbl)	High ($4.50/bbl)	Medium ($3/bbl)	Low ($1.50/bbl)	High ($1.05/BCF)	Medium ($0.70/BCF)	Low ($0.35/BCF)	High ($0.90/BCF)	Medium ($0.60/BCF)	Low ($0.30/BCF)
Algeria	0%	5%	27%	0%	10%	35%	0%	9%	26%	0%	12%	34%	5%	14%	34%
Angola (frontier)	0%	11%	[23%]	4%	15%	[28%]	7%	13%	[24%]	8%	15%	[27%]	10%	17%	[30%]
Angola (standard)	0%	10%	24%	1%	12%	28%	5%	9%	17%	8%	12%	[27%]	7%	12%	[26%]
Argentina	0%	11%	34%	2%	16%	43%	4%	14%	31%	7%	17%	39%	9%	18%	39%
Australia (offshore)	4%	12%	28%	7%	15%	35%	7%	13%	34%	9%	15%	32%	10%	16%	32%
China (offshore)	4%	15%	37%	7%	20%	45%	6%	16%	32%	2%	11%	23%	7%	13%	25%
Colombia	0%	8%	28%	0%	11%	33%	1%	10%	22%	5%	13%	33%	7%	13%	28%
Indonesia (frontier)	1%	9%	[28%]	3%	14%	[36%]	2%	11%	[25%]	8%	18%	[38%]	11%	19%	[40%]
Indonesia (stndrd pre-Tertiary)	[0%]	11%	[24%]	2%	15%	[32%]	2%	11%	[22%]	9%	19%	[39%]	11%	20%	[40%]
Indonesia (standard, other)	[0%]	5%	16%	[0%]	8%	21%	[0%]	6%	16%	7%	16%	[36%]	10%	18%	[37%]
Malaysia (frontier)	0%	8%	[25%]	1%	11%	[32%]	1%	10%	[23%]	5%	14%	[34%]	8%	16%	[35%]
Malaysia (standard)	0%	2%	18%	0%	3%	19%	0%	3%	14%	4%	12%	30%	7%	14%	32%
Nigeria (frontier)	4%	17%	[36%]	9%	23%	[46%]	8%	18%	[33%]	12%	24%	[47%]	13%	25%	[51%]
Nigeria (standard)	0%	5%	16%	0%	8%	21%	0%	7%	17%	3%	11%	24%	5%	13%	27%
Norway	5%	11%	[31%]	7%	14%	[28%]	6%	12%	[22%]	8%	14%	[27%]	10%	16%	[28%]
PNG	4%	13%	[32%]	7%	17%	[37%]	7%	15%	[29%]	9%	18%	[35%]	11%	19%	[35%]
Thailand (frontier)	1%	12%	[32%]	3%	15%	[39%]	4%	13%	[29%]	7%	17%	[38%]	10%	18%	[38%]
Thailand (standard)	1%	11%	31%	2%	14%	38%	3%	12%	28%	7%	16%	37%	9%	18%	37%
UK	6%	20%	[47%]	10%	26%	[58%]	10%	21%	[40%]	13%	26%	[53%]	15%	26%	[53%]
USA (OCS) (frontier)	4%	16%	[41%]	7%	21%	[50%]	5%	16%	[34%]	11%	21%	[46%]	11%	20%	[44%]
USA (OCS) (standard)	[0%]	10%	33%	[0%]	14%	41%	[2%]	13%	30%	[6%]	16%	38%	[9%]	17%	38%

Notes:

- IRRs are in nominal terms assuming 3% p.a US$ inflation and are calculated post royalties, taxes, participation by State oil companies and other government imposts
- Operating costs are calculated as 3%/5% of development costs for gas/oil respectively plus $1/bbl (oil) and $0.35 - $0/MCF for gas (depending on field size)
- Shaded returns are those at or below 16% nominal (±12.6% real) and considered marginal or uneconomic
- Bracketed returns are those for development cost scenarios considered unlikely for the particular country/area/regime

ANNEX 5A: Legislative Framework

A5A.1 Indonesia's hydrocarbon sector requires a legislative framework that is both appropriate and conducive to the operation of a modern economy; one that is competitively-based, market-oriented, clear, and transparent.[1] The main reasons for the need for a new framework are: (i) to attract the necessary private investment into both the upstream and downstream parts of sector; (ii) to redefine the roles of the State and Pertamina, in a manner that will allow the sector to operate competitively and efficiently; and (iii) to remedy the inconsistencies and contradictions inherent in the existing legislative framework.[2] This Annex details the reasons why a new framework is required, provides an outline of international best practice for oil and gas legislation, and reviews Indonesia's draft oil and gas law.

The Need for a New Legislative Framework for the Hydrocarbon Sector

A5A.2 Whatever the magnitude of capital required to meet the future investment needs of Indonesia's hydrocarbon sector, it is certain that the public sector cannot provide the finance alone, nor for that matter, can the private sector. The public and private sectors need to cooperate and meet this challenge together. Although this cooperation is already evident in the upstream hydrocarbon sector, improvements are required to make this partnership more efficient. And, with the exception of a single privately-financed refinery currently under construction, the downstream has yet to be opened up to private sector investment at all. Attracting the necessary private sector investment into both the upstream and downstream requires clear and transparent rules of the game, protecting both public and private sector interests alike. The current legislative framework for Indonesia's hydrocarbon sector does not provide such an environment. Without a solid and transparent legislative framework, the capacity of the sector to grow will be substantially dampened, particularly in domestic petroleum product markets.

A5A.3 Indonesia's main law dealing with the hydrocarbon sector, passed in 1971, sanctions Pertamina's dominant role and allows both the Government and Pertamina to interfere with the sector in ways that inhibit efficient operations and private sector participation. The Government's social obligations and sectoral commercial functions are treated interchangeably, and the law does not promote the kind of competitive, market-based operation that the country needs now. Further, because the regulations that supported this law were not issued until 23 years later, in 1994, the way the law was

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1 In general, such a legislative framework comprises: (i) primary legislation (i.e., the actual law(s), and associated elucidation(s), passed by the legislature); (ii) secondary legislation (i.e., regulations for implementing the law); (iii) the fiscal and tax regime, the essential elements of which can be included in the law; and (iv) model contracts and agreements. The tax regime, as well as the model contracts and fiscal regime (i.e., PSCs), have already been discussed in detail in Annex 4A of this Report. This Annex focuses on primary and secondary legislation. However, it should be noted that, underlying the legislative framework of Indonesia's hydrocarbon sector (and thus any law, existing or future) is Article 33 of the Indonesian Constitution. This Article states that: the production branches which are important to the State, and which affect the life of the majority of the people, should be under the control of the State, and should be utilized to maximize the people's prosperity.

2 In 1960, Indonesia revoked the old colonial mining law and enacted its first petroleum law (Law 44), which explicitly recognized the country's sovereignty to control its natural resources. However, the contracts signed under this law still contained elements of concession practices. As the result, a new form of contract, the PSC, was adopted, mainly out of practice, and not fully in accordance with Law 44. In 1971, Law 8 was enacted, and this remains the main law for the sector. It reserved all mining of oil and gas for a single state enterprise, and Pertamina was established. The law also allowed Pertamina to "cooperate" with another party, under Government "Regulation". However, it was not until 1994 that the Government issued Regulation 35, providing guidelines for the PSCs, and conditions governing the contractor's qualifications, production sharing and the like. In the same year, Keppres 37/1994 was issued in order to delegate some of Pertamina's responsibilities in the domestic gas sector to PGN, however, this decree is by no means fully consistent with Law 8/1971.

applied kept changing and new provisions were "bolted on" to the production sharing contracts (PSCs). Consequently, the law has been interpreted in a fragmented, inconsistent and sometimes contradictory manner.

A5A.4 Apart from the need for legislative changes to redefine the State and Pertamina's role in both the upstream and downstream, and to provide incentives for optimal private sector participation (issues that have been discussed in detail in Chapters 3 and 4 of this Report), the legislative framework cuts right across the other issues facing the sector as well. For instance, transitional measures to increase and liberalize petroleum product prices (discussed in Chapter 2) could be achieved by issuing a Keppres (Presidential Decree). However, the establishment of a truly competitive domestic oil and gas market, where prices can freely adjust to changes in demand, would best be supported by new primary legislation. And improvements in urban air quality (discussed in Annex 2C and Annex 3) will require new petroleum product specifications to be incorporated into any regulations governing the downstream. Consequently, successful implementation of the entire package of reform, discussed throughout this Report, requires Indonesia to enact a new oil and gas law (or laws), along with comprehensive supporting regulations.

Indonesia's Draft Oil and Gas Law

A5A.5 The Government has by no means been unaware of these problems with the existing legislative framework, and made significant progress toward achieving substantive legislative reform, by drafting a new law for the Mining of Oil and Natural Gas in Indonesia. This was submitted to Parliament in 1999; however, it did not pass.

A5A.6 Beginning with a set of comments provided to the Government in early September 1998, the Bank commented on successive versions of this draft new oil and gas law, and the last version reviewed by the Bank was dated February 10, 1999 . Although this version provided remedies to many of the problems existing in the current legislative framework, there were still a number of significant shortcomings in that draft, and the Bank conveyed these to the Government (Annex 5B). Given that the draft law did not pass, now would be an appropriate time to review whether the proposed law could be improved, in order to ensure that the new legislative framework is consistent with the Government's wider vision and objectives for the sector as a whole (Chapter 1), as well as with international best practice.

A5A.7 The Bank's final set of detailed comments on this draft, which were provided to the Government in March 1999, are attached as Annex 5B. In addition, the Bank presented the Government with comprehensive recommendations on the essential elements of the regulations required to support and implement any law (or laws) passed for the sector. The purpose of offering these recommendations was not only to provide the Government with an example of international best practice, but also to suggest ways that some of the deficiencies identified in the draft law could be remedied through the regulations, should the law have been passed in its then-current form. These recommendations are also attached to this Report as Annex 5C.

International Best Practice for Oil and Gas Legislation

Objectives and Characteristics of a Legislative Framework

A5A.8 The main objective of a legislative framework for the oil and gas sector is to provide the basic context for and the rules governing petroleum operations, to regulate them; and to define the principal administrative, economic and fiscal guidelines for investment activity in the sector. The framework should create an environment within which the desired sectoral vision and objectives not only can be achieved, but will be actively promoted. In Indonesia's case, like most other countries with substantial hydrocarbon resource endowments, what is envisaged is a hydrocarbon sector that functions in an efficient, competitively-based, and market-oriented manner.

A5A.9 The key characteristics of this overall framework should be to provide clarity and transparency to all stakeholders in the sector, both public and private. Clarity of purpose is more likely to be achieved if the law includes from the outset a simple declaration of the law's objectives. Although the elucidation part of primary legislation can be helpful in clarifying objectives, the elucidation should not be seen as a substitute for articles within the law itself. The legislation's intended scope of coverage needs to be carefully defined, together with the overall vision and intended policy objectives for the sector. Moreover, the law needs to map out the eventual (as well as transitional) structure of the sector, and how the key policy objectives, such as the introduction of competition, will be achieved through the law.

Essential Provisions of Primary Legislation

A5A.10 As well as stating objectives, for best practice, the law should clearly assert that petroleum resources are the exclusive property of the State, and identify the division of authority and responsibility between various government agencies (wherever possible). In particular, the agency responsible for implementing Government policy and for negotiating and contracting with foreign investors must be identified. It should be made clear that such negotiation or contracting is not vested in the national petroleum company. The national petroleum company can, on behalf of the State, act as the contract administrator, but should not hold sovereign and/or regulatory functions.

A5A.11 In addition, the legislation should include specific remedies to deal with breaches of the law (including dispute resolution mechanisms), as well as explicitly defining the rights and obligations of the Government, Government agencies and companies, and private investors (i.e., contractors). This is particularly desirable where, as in Indonesia's case, the existing laws, regulations and commercial codes have been perceived, fairly or unfairly, to be sketchy, vague and inconsistent, and where this problem has been compounded by a sparse track record of judicial interpretation. While any law should contain broad-based principles to provide the basic context for petroleum operations in the country, it should also be concise and accurate so as to provide a clear legal context within which to conduct the business of petroleum.

A5A.12 Finally, any law will need to be supported by a comprehensive set of implementing regulations. It is important to note, however, that it is best practice for the regulatory body (or bodies), charged with the responsibility for overseeing the execution of the regulations, to be established under the law itself.

Upstream and Downstream Separation

A5A.13 Under international best practice norms, the upstream and downstream portions of the petroleum industry should be dealt with in separate laws. The upstream business is usually a special purpose, all-inclusive regime, whereas the downstream portion of the sector is one subject to normal commercial and tax laws, applicable to business in general. Correspondingly, the legislative framework will have greater clarity if there are distinct upstream and downstream laws. Unlike the upstream, the downstream sector is not strategic, hence most major countries rely on there being a large number of refiners and/or distributors who will compete with each other. As such, competition provides the primary governance mechanism for the sector, and outside of standard anti-monopoly provisions, there is little need for any special State controls. Specific provisions of the downstream law would include: (i) common carrier principles for the transportation of crude oil and natural gas through pipelines; (ii) conditions governing private sector participation in the refining sector; and (iii) entry and exit criteria for entities involved in the distribution and marketing of petroleum products.

Purpose and Principles of Implementing Regulations

A5A.14 There is a fine balance between what goes into the law(s), and what becomes part of the supporting regulations. On the one hand, focusing the law itself on broad principles will expedite its initial passage through the legislature, and reduce the risk of incurring lengthy legislative deliberations any time a minor modification or amendment is required. But on the other hand, there are limits to what regulations can achieve. Regulations flow from and are grounded in the basic legal authority of the law from which their existence derives. Accordingly, to be enforceable, the regulations and any changes to them may never be inconsistent with the scope, objectives or letter of that law.

A5A.15 The law must expressly empower the appropriate State authority (e.g., in Indonesia's case, the Minister of Mines and Energy) to issue regulations that will provide the necessary detail and procedures for implementing the objectives and policy of the law. The regulations are themselves only subsidiary instruments, not intended for legislative consideration or enactment. Matters neither covered nor provided for in the law itself cannot be the subject of any regulatory provisions. Moreover, it is best practice not to attempt to over-regulate, but rather to leave much of the specific detail to the natural influences of market forces. Correspondingly, regulations are also intended to provide maximum flexibility should timely changes in policy and/or procedures be required, in response to any developments which arise in the sector as a result of such forces. Furthermore, to avoid confusion, definitions used in the regulations should be identical to those used in the governing law.

Essential Elements of Regulations

A5A.16 **Upstream Regulations.** Regulations associated with an upstream law will relate to the exploration and production of oil and natural gas. To be consistent with international best practice, these upstream regulations should, among other things, define: responsibilities for upstream policy development, upstream licensing, operational supervision and for regulation; procedures for licensing and conducting bid tenders for contract areas; contractor obligations, including accounting, valuation and auditing requirements; the fiscal and financial regime; prohibitions on the flaring of gas; assignment of rights provisions; land access and usage regulations; environmental protection and safety requirements; any preferences for the utilization of local goods and services; confidentiality requirements; and the nature of any indemnities and penalties.

A5A.17 **Pipeline Regulations.** Associated with a downstream law will be regulations for: (i) the transportation of oil and gas by pipeline; and (ii) refining and marketing activities. To be consistent with international best practice, the pipeline regulations should, among other things, define: the powers, duties and objectives of the energy regulatory body with responsibility for regulating the transportation of petroleum products by pipeline; administrative requirements for pipeline construction; technical specifications of pipeline systems; constraints on pipeline routings; technical and fiscal aspects of pipeline operation; requirements for pipeline inspection; third party and open access conditions and exceptions; provisions for handling capacity constraints; and procedures for setting pipeline tariffs.

A5A.18 **Downstream Regulations.** Similarly, the downstream regulations should, as a minimum, define: the powers, duties, objectives, and rights to information of the regulatory body with responsibility for downstream regulation; petroleum product specifications, and prohibitions against product mixing; access requirements to marine facilities, to shore storage and to the product from refineries and pipelines; procedures for the award and renewal of licenses; requirements on maintaining security stocks; provision for supplier compensation in the event of severe product shortages; any system for setting ex-refinery prices or for retail price control; health, safety and environmental requirements; provisions for independent verification of measuring devices and product quality; any restrictions on cross-ownership and acquisitions; and any transitional provisions relating to the role and status of sector entities operating in the downstream. As noted above, more details regarding these essential elements of regulations for the upstream, for pipeline transportation, and for the downstream, are all presented in Annex 5C.

The Draft Oil and Gas Law

A5A.19 As it stood, the version of Indonesia's draft oil and gas law dated February 10, 1999, allowed substantial progress toward unbundled sector operation, and provided a reasonably sound basis for achieving reform in the upstream section of the industry. Most importantly, it introduced significant elements of competition into the upstream, particularly through the revised tendering procedures. Its proposal to replace Pertamina by the State, as counter-party to the PSCs, was warranted and long overdue. Nevertheless, there were still a number of significant shortcomings in that draft which the Bank conveyed to the Government, and during the subsequent reviews of the draft law during the Parliamentary process, it is possible that some of the difficulties inherent in earlier drafts may have been reintroduced.

A5A.20 Given the best practice principles discussed above, and apart from the detailed comments on specific Articles of the draft law that are provided in Annex 5B, there are still a number of overall concerns: (i) whether the law will promote the desired sectoral vision and objectives; (ii) what the transitional and future role of Pertamina would be, particularly in the downstream sector; (iii) whether competition in the downstream would be adequately promoted; (iv) how the law would relate to other legal requirements in the wider energy sector, particularly with regard to implementing the regulatory framework; (v) the lack of clarity arising from combining upstream and downstream legislation; and (vi) the absence of a number of important provisions from the law. While it has already been discussed (para. A5A.13) that it is best practice to have separate laws for the upstream and the downstream, the other concerns are briefly summarized in the following paragraphs.

Objectives and Clarity of the Proposed Legislation

A5A.21 While the draft law's elucidation contained some language that hinted at the objectives of the new legislation, the law itself did not provide sufficient clarity of purpose. Furthermore, the law did not appear to enable actions to take the steps that would be necessary to achieve the objectives of competition and liberalization. This was particularly important with regard to the refinery and other downstream sectors. The law did not clearly map out the nature of the new sector structure, nor did it spell out how competition would be introduced into the sector. It was not indicated whether it was intended that there be any program of divestitures, and if so, what the objectives of any such divestitures would be (e.g., maximizing competition or revenue).

The Role of Pertamina

A5A.22 Concerns regarding clarity of objectives were of particular note in regard to the transitional and future role of Pertamina. With respect to pipelines and transport facilities, the language in the draft law posed significant barriers to achieving the kind of regulatory atmosphere that is a pre-requisite for a modern economy. For instance, Pertamina appeared exempt from the requirement for licensing, at least during the two year transitional period leading up to its establishment as a Persero, and to have the right to maintain its existing operations. Although new operations were subject to licensing, liberalization of the sector was severely restricted by not allowing for the possibility that Pertamina's existing operations could be licensed to other parties. It would hence have been useful if the law elaborated, in clearer terms, on the treatment of other parties in respect to both existing and future operations.

Competition in the Downstream

A5A.23 Because the draft law provided for no explicit transfer or divestiture of Pertamina's existing downstream assets, this implied that the status quo of Pertamina's downstream monopoly would be maintained. Pertamina would continue to own the refineries and could restrict supplies to itself, it would own the shipping fleet, the harbors, the jetties, the storage facilities, the pipelines, and almost all of the filling stations, as well as retaining its contracts with major customers. The law should provide, in the context of the transitional provisions, for procedures which would cover the orderly divestiture of Pertamina's existing downstream assets in such a manner as to develop a competitive supply position. The objective here would be for Pertamina to retain enough assets so that it can be a capable competitor, but that the assets which enable monopolistic behavior should be moved to a separate company (rather like the separation of gas transmission and gas marketing), and that a majority of service stations and other such assets should steadily be sold over an agreed period. At the very least, there should be an obligation for third party access. Although the law was permissive in this respect, it was unlikely to be sufficient to allow the issuance of a regulation giving the regulatory body the power to force access, which is the minimum step needed for downstream competition to develop in the absence of clear divestiture program.

A5A.24 In addition to the concerns regarding whether the changes to the role of Pertamina, as outlined in the draft law, were sufficient to allow effective competition in the downstream sector, competition may also be constrained by the law's provisions relating to downstream licensing. The law's definitions and various references to marketing linked together five functions, namely import, export, purchasing, storage, and sale. It appeared that the intention was to have a single license that would authorize such activities. This tends to be anti-competitive; real competition develops when the authorized competitors are very different. (For example, in the United States, UK and France, some of the strongest competition comes when supermarkets compete for gasoline sales with the major oil companies. The oil companies in turn are competing in the convenience food business. Furthermore, large customers, such as power stations and road construction companies, should have the option of shopping around and importing directly if this appears economic. Since such companies will not be undertaking all five functions, it would be better to separate the licenses). Furthermore, whether the law allowed competition to be adequately promoted in the domestic gas sector was also a concern, and this is highlighted below (para. A5A.26).

Implementing the Regulatory Framework

A5A.25 All the references made in the draft oil and gas law to the Government's supporting regulations appeared to assume that an Energy Regulatory Badan (i.e., agency) would have already been established prior to the passage of the law. As noted above (para. A5A.12), it is international best practice for the regulatory body (or bodies) to be established through primary legislation. At present, the Government's Power Sector Restructuring Policy of August 1998 states that a single Badan for the entire energy sector will be established. This would imply that the proposed electricity law needs to define the role and powers of a Badan with respect to the entire energy sector (i.e., oil and gas, geothermal and electricity). Regulations relating to oil, gas and electricity could then be promulgated which refer back to the relevant petroleum and electricity laws. However, in any event, a decision needs to be made at a fairly early stage on how one (or perhaps more) Energy Regulatory Badan(s) are established to implement the regulatory framework for not only the oil and gas sector, but for the power sector as well. Difficulties will arise if regulations exist without a regulatory body in place to exercise them.

Absent Provisions

A5A.26 There were a number of issues which were not addressed in the draft law. These included:

a) Dealing with the potential conflict between the proposed law and existing contracts, particularly for upstream operations. It might have been appropriate for the General Provisions section to include an Article stating that existing contracts will be governed by the rulings under which they were awarded.

b) Provision should have been made in the law for the Minister to promulgate regulations on the prices of petroleum products and on any related mechanism for a transitional period (the maximum time of which to be defined). This provision was necessary since it would have not been possible to move immediately to full market pricing upon the passage of the law. Further, the principles of pricing subsequent to this transitional period should have been defined.

c) A mechanism should have been outlined for allowing disputes on the validity, interpretation or performance under Cooperation Contracts with foreign contractors to be settled by International Arbitration. To omit this would have been be a serious disincentive to foreign direct investment.

d) No explicit provision had been made with regard to PGN. PGN's role would have clearly changed under the new law, since a single entity would have been be unable to engage in both natural gas transmission and marketing. A transitional provision would have been useful to indicate what would happen to PGN's assets and operations.

e) The law omits the ability of a producer to distribute gas without a license. It is necessary for the producer to have the right to sell directly to very large customers, and that very large customers should have the right to buy directly from producers. This is a key issue relating to competition in the domestic gas sector, and is needed to prevent local distribution companies from exploiting a monopoly position.

f) A provision should have stipulated that priority to the first use of gas will be given for the purpose of optimal exploitation of the fields from which it is produced.

g) Provision should have been made for a budget with adequate resources and competent and experienced staff that would have enabled the Government/Ministry to carry out the responsibilities transferred to it from Pertamina for the management and supervision of the petroleum sector.

ANNEX 5B: Comments on Indonesia's Draft Oil and Gas Law

A5B.1 This Annex contains the last two sets of comments submitted by the Bank to the Government regarding the draft law for the Mining of Oil and Natural Gas in Indonesia. The main set of comments, provided to the Government on February 1, 1999, relate to the version of the law dated December 30, 1998. These are split into general comments, and more detailed comments which refer to specific Articles within the draft.

A5B.2 A slightly revised version of the law was issued on February 10, 1999, and some additional comments on this later version were passed on to the Government by the Bank on March 12, 1999. It should be pointed out that neither of these two drafts are the very final version that was not passed by the Indonesian Parliament, since additional changes to the draft were made during the Parliamentary review process. The Bank did not have the opportunity to comment on any of these subsequent versions.

General Comments on the December 30, 1998, Version of the Draft Oil and Gas Law

A5B.3 Beginning with a set of comments provided to the Government in early September 1998, the Bank has commented on successive versions of the draft Law on the Mining of Oil and Natural Gas in Indonesia, including a set of comments submitted to the Government as part of the Bank's November 1998 mission.

A5B.4 The latest version of the draft law is dated December 30, 1998. A large number of the Bank's earlier comments have been incorporated into this new draft. As it stands, the law allows substantial progress toward an unbundled sector operation and provides a reasonably sound basis for achieving reform at the upstream section of the industry. Most importantly, it introduces significant elements of competition, particularly through the revised tendering procedures. However, there are still a number of significant concerns which are expressed in this memorandum.

A5B.5 As outlined in the Bank's previous comments, the key characteristics of the petroleum legislative framework should be to provide clarity and transparency. Whenever possible, the law should clearly identify the division of authority and responsibility between various government agencies. In addition, the legislation should include specific remedies to deal with breaches of the law, as well as explicitly defining the rights and obligations of the Government and private investors. This is particularly desirable where the laws, regulations and commercial codes are perceived, fairly or unfairly, to be sketchy or vague—and this problem may only be compounded by a sparse track record of judicial interpretation. While the law should contain broad-based principles to provide the basic context for petroleum operations in the country, it should also be concise and accurate (and supported by a set of comprehensive regulations) so as to provide a clear legal context within which to conduct the business of petroleum.

A5B.6 Given the above principles, and apart from more detailed comments below, there are still a number of overall concerns:

- Whether the law will promote the desired sectoral vision and objectives.
- How this law will relate to other legal requirements in the wider energy sector, particularly with regard to implementing the regulatory framework.
- The lack of clarity arising from combining upstream and downstream legislation.
- The absence of a number of important provisions from the law.

Objectives of the Legislation

A5B.7 Greater clarity might be achieved if the law included from the outset a simple declaration of objectives. The legislation's intended scope of coverage should be defined, together with a vision of intended policy objectives for the sector, both upstream and downstream. While the Elucidation contains some language that hints at these objectives, as it stands now, the draft law itself does not appear to enable actions to take the steps necessary to achieve the stated objectives of competition and liberalization. This is particularly important with regard to the refinery and downstream sectors. The law does not clearly map out the nature of the new sector structure, nor does it spell out how competition will be introduced into the sector.

A5B.8 These concerns mainly relate to Chapter IX, where the transitional and future roles of Pertamina are discussed. Particularly with respect to pipelines and transport facilities, we feel that the present language in the draft legislation, at least in English translation, poses significant barriers to achieving the kind of regulatory atmosphere that is a pre-requisite for a modern economy. For instance, as the draft reads now, Pertamina appears exempt from the requirement for licensing, at least during the two year transitional period leading up to its establishment as a Persero. Article 41 appears to grant Pertamina the right to maintain its existing operations (see comments on articles 41-44). Although new operations appear subject to licensing, liberalization of the sector is severely restricted by not allowing for the possibility that Pertamina's existing operations could be licensed to other parties. It would hence be useful if the law elaborates, in clearer terms, on the treatment of other parties in respect to both existing and future operations.[1]

Implementing the Regulatory Framework

A5B.9 Decision needs to be made at a fairly early stage on the establishment of an Energy Regulatory Badan to implement the regulatory framework for not only the oil and gas sector, but for the power sector as well. At present, under the Power Sector Restructuring Policy of August 1998, a Badan for the entire energy sector will be established. All the references made in the draft petroleum law to the Government's supporting regulations assume that the Badan will have been previously established prior to the passage of the petroleum law, and that the Electricity Act would define the role and powers of the Badan with respect to the entire energy sector (i.e., electricity, oil and gas). Regulations relating to oil, gas and electricity could then be promulgated which refer back to such legislation, as well as to the relevant petroleum and electricity laws.

Upstream and Downstream Separation

A5B.10 Under international best practice norms, the upstream and downstream portions of the petroleum industry would be dealt with in separate laws. The upstream business is usually a special purpose, all-inclusive regime, whereas the downstream portion of the sector is one subject to normal commercial and tax laws applicable to business in general. In the course of this review and the preparation of the principles for the supporting regulations, the difficulties arising from combining upstream and downstream operations under one law has become quite apparent. For instance, as discussed below, such an approach introduces a number of definitional problems (e.g., for the activity of transportation). Although it is recognized that because of expediency and legislative necessities under the

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[1] Perhaps our concern on this score result from the unofficial English translation of the law, which possibly does not capture the true meaning or intent of the legislation. We would like to suggest, therefore, that an official translation of the draft law be prepared for the benefit of all interested parties, including the international oil industry.

current environment in the country, the draft law may have to be combined into one package, it is strongly recommended that the Government consider developing separate laws for upstream and downstream operations as soon as feasible.

Additional Provisions

A5B.11 There are a number of issues which have not been addressed in the law. These include:

a) Dealing with the potential conflict between the proposed law and existing contracts, particularly for upstream operations. It may be appropriate for the General Provision section to include an Article stating that existing contracts will be governed by the rulings under which they were awarded.

b) Provision should be made in the law for the Minister to promulgate regulations on the prices of petroleum products and any related mechanism for a transitional period (the maximum time of which to be defined). This provision is necessary since it will not be possible to move immediately to full market pricing upon passage of the law. Further, the principles of pricing subsequent to this transitional period should be defined.

c) Also missing from the draft legislation is a mechanism for allowing disputes on the validity, interpretation or performance under Cooperation Contracts with foreign contractors to be settled by International Arbitration. To omit this would be a serious disincentive to foreign direct investment.

d) No explicit provision has been made with regard to PGN. PGN's role will clearly change under the new law, since a single entity will be unable to engage in both natural gas transmission and marketing. A transitional provision would be useful to indicate what happens to PGN's assets and operations.

e) Provision should be made for a budget with adequate resources and competent and experienced staff that would enable the Government/Ministry to carry out the responsibilities transferred to it from Pertamina for the management and supervision of the petroleum sector.

f) A provision, preferably under Article 11, should stipulate that priority to the first use of gas will be given for the purpose of optimal exploitation of the fields from which it is produced.

Detailed Comments on the December 30, 1998, Version of the Draft Oil and Gas Law

Chapter I: General Provisions

A5B.12 **Article 1**. There has been substantial improvement in this article, which deals with definitions of terms. However, there is still the need for further clarity and inclusions. As stated above, it is quite possible that some of the vagueness we perceive here is the result of a less than polished translation from Indonesian to English.

A5B.13 Some of the items that still need further clarifications are:

a) *Processing*: Whether liquefaction (of natural gas into liquefied natural gas—LNG) is included in the processing.

b) *Transportation*: Whether it includes the movement of products from interim/final storage depots to other storage depots or the market, and whether the shipment of LNG is included. A broader issue is whether upstream transportation (i.e., field pipelines and gathering system, gas transmission lines from field to LNG liquefaction plants, etc.) and downstream transportation should be treated separately.

c) *Marketing*: The definition of marketing should differentiate between the role of a distributor and that of a retailer, and it should separate the function of importer and exporter.

d) *Business License*: The definition does not include the Permanent Establishment. Therefore, it is not clear how transportation activities as defined relate to field pipelines, the gathering system, and LNG transmission lines, or whether the Companies need a license when operating in the field.

e) We suggest including a definition for "market price."

A5B.14 **Article 2**. The English translation still uses the word "control" (by the State), rather than indicating that these natural deposits are the assets of the State. Although this terminology is most probably to make the law consistent with the Constitution, it might be advisable to stipulate that the State "owns" these assets.

A5B.15 **Article 3**. General survey is not included.

A5B.16 This Article calls for the establishment of a Cooperation Contract for "operations" which includes processing, transportation, etc. Whereas, under the definitions, the Cooperation Contract applies to Exploration and Exploitation.

A5B.17 We suggest that the word "grant" be used rather than "award"—in the context of the Minister awarding Business Licenses—since any such award should be non-discretionary and reasonably automatic to qualified applicants.

A5B.18 With regard to utilization of local goods and services, while the sentence now specifies "in a transparent and competitive manner," we suggest that due to its importance the following words should also be added: "provided that they are competitive internationally, as to the price, quality and timeliness of supply.

A5B.19 The Article does not permit explicitly for a license to import or to export. There may well be situations where a major customer--such as a power utility company or a highway authority importing bitumen-- will want to import for its own direct use. Example of exports could be the refinery, or a company that only supplies bunker.

A5B.20 **Article 4**. The sentence "corporate bodies" should be incorporated with Company, to read "can be performed by any Company and other corporate bodies----- "

A5B.21 We suggest the addition of "as determined by the Minister" to the end of the sentence dealing with financial, technical, and operational competencies.

Chapter II: Exploration and Exploitation

A5B.22 **Article 5**. We still see do not see the need to subject the Cooperation Contract to advance approval of the President. The Competent Authority (i.e., the Minister) should have the authority to approve the Cooperation Contract.

A5B.23 It is not clear whether the Cooperation Contract includes the Work Contract, and whether Permanent Establishment can carry out the Work Contract. If not, then the provisions referred to in paragraph 3 of this Article will not apply to Work Contract.

A5B.24 **Article 8**. This Article is important only in that it makes a reference to the Government's supporting regulations for further elaboration of guidelines, procedures and requirements in implementation of provisions of Articles 5, 6, and 7. As such, it is suggested that this Article be deleted as a stand alone article, and such reference be included in each of Articles 5, 6, and 7 separately. This would make it stylistically consistent with the rest of the document.

A5B.25 Article 8 should instead state that Regulations will be promulgated under this Law by the Minister in no more than 6 months from the effectiveness (enactment) date of the Law, and, thereafter, the Minister may update and revise such regulations, from time to time, as shall be necessary and desirable in view of evolving circumstances.

A5B.26 **Article 9**. With respect to General Survey, as the holder of the Mining Authority, the Government should only announce the areas that are intended to be granted, and then appoint a service company to carry out the survey. (This was in the earlier versions but has now been deleted). Although the Article includes provisions that indicate procedure and requirements in this regard will be further elaborated by a Ministerial Decree or by Government regulations, it is important that the Law provides for the assignment of this function by the Government to some other party.

A5B.27 **Article 10**. There is no reference in this version to the ownership of data obtained from General Survey.

A5B.28 The law should provide that in exceptional cases, and upon approval of the Minister, the data may be provided to third parties; the intent here is to provide for such public interest disclosures as are occasionally required of US oil companies, for instance, when they submit data to the US Security and Exchange Commission.

A5B.29 **Article 11**. The first paragraph of this Article may not be needed as the obligation to submit field development plan is provided for in the last paragraph of Article 5. Further, since under Article 5 this requirement is to be included in the Cooperation Contract, it would necessarily have to be submitted before the production of oil and natural gas.

A5B.30 It is not clear whether the reference to supporting regulation intends to permit the Government to regulate or mandate production rates of oil and gas. International best practice discourages this practice and encourages Maximum Efficient Rate (MER) production. While this is recognized in the Elucidation, the optimization of field development is an important issue that should be raised in the primary legislation.

A5B.31 **Article 12**. As indicated above, the "market price" needs to be defined. Or, alternatively, it could be said that the sale to meet the domestic market obligation should be at a price which otherwise could have been obtained if such products were sold in international markets, adjusted for transportation costs.

Chapter III: Processing, Transportation , Storage and Marketing

A5B.32 **Article 13**. The Article needs to include "Imports" and "Exports" as applicable under this Article, and also provide for their definitions in Article 1.

A5B.33 Given that transportation as defined under Article 1 covers all modes of transport, the question is whether the transportation business licenses are required for all modes of transport, including, road, rail and barges.

A5B.34 The Article needs to allow for separate licensing of Distribution and Retailing activities, and also provide for their definitions in Article 1.

A5B.35 **Article 14**. The Article needs to include a reference that provisions under this Article (i.e., other technical requirements, etc.) shall be further stipulated by the Government's supporting regulations.

A5B.36 **Article 15**. In the English translation, this Article is not clear. It states that the processing, transporting, storing and/or marketing (which is understood to include imports/exports) can be utilized jointly. The use of the word "can" may be misleading since the intention is that the Minister may choose to direct the companies to cooperate. It is very important to ensure that the Minister has powers in this respect, and to include crude and product pipelines either here or elsewhere in the Law.

A5B.37 **Article 18**. While this is an essential Article in that it makes reference to Government's supporting regulations for further elaboration of Articles 13 and 17, it is suggested that this Article be deleted as a stand alone article, and such a reference be included in each of the Articles 13 and 17 separately, consistent with the rest of the document.

A5B.38 **Article 20**. Paragraph 2 provides for third party access to natural gas transmission pipelines. Comparable third party access is required for all facilities that are monopolistic in their nature either through physical limitations (e.g., lack of space in a harbor) or through economic limitations (where there is a major difference between incremental costs and the costs of initial installations). Hence, the Minister should have the power to require third party access for all harbors and docks, and for product pipeline and related storage. In respect to gas, the third party access would apply to distribution lines for large customers, but not for small customers as the norm is to have an exclusive gas marketing franchise for the medium/low pressure network. Further, there need to be dispensations when the Minister judges that the third party access is inappropriate (e.g., in immature markets, with a time and location limited exclusivity). It is suggested that the provision to permit third party access to all downstream facilities be included in Article 13.

A5B.39 Paragraphs 5 and 6 are not clear in English translation, with respect to developed/non-mature markets, and large and small customers.

Chapter IV: State Revenue

A5B.40 **Article 21**. The translation in English is not sufficiently clear. Given the importance of this section, the law should clearly state the various taxes, levies, import duties, bonuses for the Central Government as well as for the regional governments. It should also be recognized that (i) any substantial increase in taxes (in various forms) would be a disincentive to investors; and (ii) if the proposed regime is substantially different than the existing fiscal arrangements, the implementation of the new regime would be difficult.

A5B.41 **Article 22**. The sentence "other liabilities" under this Article needs to be defined.

Chapter V: The Relationship Between Oil and Natural Gas Mining and Land Titles

A5B.42 **Articles 23-26**. The Articles dealing with the use of land in connection with petroleum operations are not sufficiently clear with respect to regulation and procedure for "just" compensation to the land title holders or land user title holders. Further, it is not clear how the issue is decided upon, if agreement is not reached between the Company or Permanent Establishment and the land rights holder.

Chapter VI: Development and Supervision

A5B.43 **Article 29**. The definition of Marketing should differentiate between the distributor and retailer.

A5B.44 It should be noted that such an extensive supervision of the industry by the Government, as stipulated under this provision, requires substantial manpower and expertise to be invested in the Ministry.

A5B.45 **Article 30**. While this is an essential Article in that it makes reference to the Government's supporting regulations for further elaboration of Articles 28 and 29, it is suggested that this Article be deleted as a stand alone article, and such a reference be included in each of the Articles 28 and 29 separately, consistent with the rest of the document.

A5B.46 **Article 31**. This Article is still too weak and vague on environmental protection and safety. Minimum environmental protection requirements should be set out in the Law and then cross-referenced to applicable Environmental Laws. Provision should be made in this Law for an environmental assessment or impact study to be carried out prior to the commencement of any petroleum operations.

Chapter VIII: Criminal Provisions

A5B.47 **Articles 33-40**. As indicated before, the criminal provisions are harsh and it is questionable whether such penalties (monetary and imprisonment) are necessary.

Chapter IX: Transitional Provisions

A5B.48 **Articles 41-44**. While the English translations are not very clear, these articles imply that Pertamina will continue to own the refineries, the import/export facilities, the present gas transmission pipelines, some of the transport facilities, the oil product pipelines, and almost all the distribution functions and many of the retailers. This arrangement is not conducive to competition and efficient operation.

A5B.49 It is not clear who in the Government will take over the interest transferred from Pertamina.

Comments on the February 10, 1999, Version of the Draft Oil and Gas Law

Overall

A5B.50 As discussed in our previous communication, the draft law provides a reasonably sound basis for achieving reforms in the upstream section of the industry. However, we continue to be concerned that in certain areas, such as natural gas, downstream activities, and particularly with respect to the role of Pertamina, the most recent draft is still not consistent with the market-oriented and competitively-based objectives set out in the Government's vision for sector operation. While recognizing that this draft has already been submitted to DPR, and therefore it may not be easy to change the law's basic structure to more closely reflect international best practices, we recommend that the content of the law be clarified to allow best practices to be achieved through the regulations. Nevertheless, there are limits to what regulations can achieve. As it stands, the law does rely heavily on regulatory instruments, but to be enforceable, these regulations need to be compatible with the law and should not go beyond the law. We consider that, for the application of the regulations to be effective, the present draft law still needs to be amended to address the issues raised in our earlier fax, as well as the following points.

Natural Gas Sector

A5B.51 In the natural gas sector, the new article 21 now omits the ability of a producer to distribute gas without a license. The previous draft clause went too far in what it permitted, but the idea behind that clause is still vitally necessary, which is that the producer should have the right to sell directly to very large customers, and that very large customers should have the right to buy directly from producers. This is a competition issue, and is aimed at preventing local distribution companies from exploiting a monopoly position. (Previously we raised the issue of granting temporary waivers from the third party access requirement, and it seems that the law as drafted would permit this to be covered by the regulations).

Downstream Sector

A5B.52 Elaborating on our earlier comments, the definitions and various references to marketing (for example, Article 1, definition 11) link together five functions, namely import, export, purchasing, storage, and sale. It appears that the intention is to have a single license that will authorize such activities. This tends to be anti-competitive. Real competition develops when the authorized competitors are very different. (For example, in the United States, UK and France, some of the strongest competition comes when supermarkets compete for gasoline sales with the major oil companies. The oil companies in turn are competing in the convenience food business. Furthermore, large customers, such as power stations and road construction companies, should have the option of shopping around and importing directly if this appears economic. Since such companies will not be undertaking all five functions, it would be better to separate the licenses).

Role of Pertamina

A5B.53 As discussed in Jakarta and in our previous communication, the draft law transfers certain functions of Pertamina which relate to the upstream sector (in particular the PSAs) to MIGAS. However, there is no such explicit transfer for existing downstream assets, which implies that the status quo of Pertamina's downstream monopoly will be maintained. Pertamina will continue to own the refineries and may restrict supplies to itself, it will own the shipping fleet, the harbors, the jetties, the storage facilities, the pipelines, and almost all of the filling stations, and will retain its contracts with major customers. We feel that the law should provide, in the context of the transitional provisions, for procedures which would cover the orderly divestiture of Pertamina's existing downstream assets in such a manner as to develop a competitive supply position. The objective here would be for Pertamina to retain enough assets so that it can be a capable competitor, but that the assets which enable monopolistic behavior should be moved to a separate company (rather like the separation of gas transmission and gas marketing), and that a majority of service stations and other such assets should steadily be sold over an agreed period. At the very least, there should be an obligation for third party access. Although the law (Article 18) is permissive in this respect, we are unsure that it will be sufficient to allow the issuance of a regulation giving the regulatory body power to force access, which is the step needed for competition to develop, in the absence of clear divestiture program.

Upstream Sector

A5B.54 In addition to the comments provided in our previous communication, we recommend addressing the following issues for the upstream.

a) *Article 7.* This seems to be aimed at "ring-fencing" each area. Ring-fencing makes an area less attractive and it may not be appropriate under current depressed market.

b) *Article 12.2.* This deals with gas flaring. The wording of the draft law needs to be further clarified. Instead of the present wording, we suggest that the law permit flaring in cases of technical emergency, and that this further be dealt with through the regulations.

c) *Article 15.* While this article deals with the information in a license, it would be very useful to set out the criteria on which a license is awarded.

ANNEX 5C: Recommendations on the Essential Elements of Regulations

A5C.1 This Annex contains the Bank's recommendations on the essential elements of best practice regulations needed to support the proposed law on the Mining of Oil and Natural Gas in Indonesia. These recommendations were presented to the Government on February 1, 1999. Note that, although these comments were prepared based on the assumption that, contrary to international best practice, a single sectorwide law would be passed, they remain applicable to the situation where an upstream law is supported by upstream regulations, and a separate downstream law is supported by pipeline regulations and downstream regulations.

Overriding Principles

A5C.2 There are several important overriding principles which form an essential part of any *best practice* regime for framing Regulations under a modern framework Petroleum Law. These are that:

a) Regulations flow from and are grounded in the basic legal authority of the Petroleum Law from which their existence derives. Accordingly, such Regulations, and any changes thereto, *may never be inconsistent with the policy, objectives or letter of that Petroleum Law;*

b) The Petroleum Law expressly empowers the appropriate party (e.g. Minister; Competent Authority) to make such Regulations—initially and from-time-to time–providing the necessary detail and procedures to implement the policy and objectives of the Petroleum Law, by reference to specific, enabling provisions thereof;

c) Regulations under a Petroleum Law are *subsidiary instruments,* not intended for legislative consideration or enactment;

d) Such Regulations are intended to provide *maximum flexibility*, allowing for rapid response to any current developments in the sector which would require timely changes in policy and procedures; and

e) Regulations should be *comprehensive within defined parameters.* They are intended fully to cover all necessary details and procedures *to implement the corresponding and applicable enabling provisions of the Petroleum Law.* They are **not** intended, however, to regulate the entire sector, outside the limits of the enabling and corresponding provisions of the Petroleum Law. As subsidiary instruments, they can rise no higher than their source, which is the Petroleum Law. Matters neither covered nor provided for in the Petroleum Law cannot be the subject of any purported Regulations under the Law. It is *best practice* not to attempt to over regulate but, rather, to leave much specific detail to the natural influences of ***market forces*** to find their appropriate level.

A5C.3 In the case of Regulations to the proposed Indonesian "Law on the Mining of Oil and Natural Gas" (herein, "Petroleum Law"), it would appear that such Regulations should be divided into at least three Sections or Chapters, being:

(A) Exploration and Production of Oil and Natural Gas ("Upstream Regs");

(B) Transportation and Distribution by Pipeline of Oil, Natural Gas and Petroleum Products ("Pipeline Regs"); and

(C) Refining and Marketing ("Downstream Regs")

Essential Elements of Regulations

For All Regulations

A5C.4 **Definitions.** There should be one set of comprehensive Definitions defining all terms of art used in the Regulations. These Definitions should be *identical*, where applicable, to identical terms used in the Petroleum Law. New terms, used only in the Regulations, should be fully defined. As an acceptable legislative shortcut, one could also *incorporate by reference* all definitions used in the Petroleum law and then define all new, additional terms used only in the Regulations;

Upstream Regulations

A5C.5 **Upstream Petroleum Sector Licensing and Regulation.** This provision details the duties and functions of the Government parties with primary responsibility for upstream petroleum sector matters. Ideally, this is separated out into three individual functions: (a) Policy; (b) Operations; and (c) Regulation, and each such function is described in detail, with appropriate duties, functions and responsibilities; e.g., Policy to the Minister; Upstream Licensing and Operational Supervision to the Ministry; and Regulation to the Upstream Regulator(s), who (collectively) is/are a member(s) of the Energy Regulatory Board [Badan], which shall be created under Law.

A5C.6 **Petroleum Licensing.** Procedures are established here to delimit prospective acreage (graticulation) and then to offer it for licensing by officially and publicly advertised bid tenders. It should be considered whether provision should be made here for the possibility of direct negotiations. Uniform shapes for Contract Areas to be offered and minimum/maximum sizes should be specified in this section.

A5C.7 **Bid Tenders.** Here procedures are detailed by which such bid tenders will be conducted, including such matters as the issuance of bid packages, maps, brief descriptions of the geology and topography of the areas to be offered, bid sheet listing criteria for bid evaluation, format for bids, the inclusion of a Model Contract against which bid exceptions must be identified, procedures for submittal, evaluation, award and negotiations of a PSA/Cooperation Agreement and the amount of any required bid guarantee. The Competent Authority is obliged to publish bid tender details in the Official Journal or in widely-read newspapers- domestic/foreign, trade journals. Bidders must purchase bid packages, but it is advisable to keep their cost down to the cost of producing such packages and/or the administrative costs of the bid tender. Bids are required to be submitted sealed. They are to be publicly opened. Evaluation procedures and maximum time limit for decision/award and negotiations are set out here. The possibility of rejection of all bids and re-bidding should also be considered and addressed in this section.

A5C.8 **Petroleum Operations.** This section addresses specific requirements imposed on a Contractor in carrying out petroleum operations under a PSA/Cooperation Agreement, including:

a) submission of Annual Work Program;

b) timing and procedures for approval of same;

c) submission of copies of all geological, geophysical, well and other Contract Area technical data;

d) use of only the best available machinery, equipment and supplies in petroleum operations, in accordance with international best practices;

e) Contractor's guarantee of reasonable and timely access for personnel of the Competent Authority to all portions of the Contract Area for the purposes, *inter alia*, of inspection and monitoring of the implementation of applicable Regulations;

f) Contractor's obligations to notify the Competent Authority in advance of the drilling of any proposed well and the parallel obligation to plug and abandon unsuccessful wells (both onshore and offshore) in an environmentally and safety conscious manner; and

g) procedures for the metering and measuring of oil and natural gas produced and transported from a Contract Area, for the purposes of accounting for such oil and natural gas.

A5C.9 **Prohibition on Flaring of Gas**. Flaring of all natural gas produced is prohibited. Exceptions may only be granted by the Competent Authority, in its sole discretion, upon an application by a Contractor which demonstrates both justifiable economic necessity and environmental precautions, satisfactory to the Competent Authority. In cases of *bona fide* emergency, however, where damage to life and property is imminent or actually occurring, Contractor may flare only such gas as is necessary to abate any such emergency.

A5C.10 **Petroleum Agreements**. This section provides such details as:

a) lengths of the various contract phases (exploration, appraisal, production/development) and any permissible extensions thereto;

b) minimum work obligations (MWO), expressed both quantitatively and monetarily, including penalties for failure to fulfill the agreed MWO;

c) periodic relinquishments of portions of the Contract Area during the exploration phase, providing indicative times and percentages;

d) timely reporting of all discoveries by Contractor to the Competent Authority along with Contractor's determination, after any appraisal, as to whether any such discoveries are to be declared commercially developable;

e) regarding those discoveries declared to be commercial, Contractor's obligation to present the Competent Authority with an agreed development plan and to proceed to such development in timely fashion;

f) an elaboration of any special retention rights permitted in the Law for gas prone areas/gas discoveries to encourage gas development; and

g) any special extensions of the various contract phases, such as the exploration phase, to encourage exploration and development of oil and gas located in deep water areas.

A5C.11 **Fiscal and Financial Regime**. This section provides more specific details of fiscal terms adopted in the Petroleum Law, such as (for the existing contract regimes) :

a) setting of rates and ranges of land rental and/or contract administration fees payable, if any;

b) establishing times and amounts of any bonuses payable (e.g. - signature, commercial discovery, production levels); and

c) indicating the acceptable ranges of production splits for profit oil at indicative levels of production, as well as the acceptable ranges or levels of cost recovery oil.

A5C.12 If Indonesia were also to employ a non-PSA regimes (tax and royalty), then the specific details of fiscal terms adopted in the Petroleum Law should include items such as;

a) setting flat rate or range of sliding-scale, negotiable royalty;

b) confirming the application or limitation of the generally applicable profits tax to Contractor's profits, as well as any Petroleum Revenue Tax *in lieu*; and

c) setting the rate ranges for any Additional Profits Tax.

A5C.13 **Accounting, Valuation and Auditing**. Here is specified how the Contractor is to account for petroleum revenues and profits. The Contractor is to maintain clear and accurate records in an agreed unit or currency of account, consistent with *international standard petroleum industry best accounting practice*. The Competent Authority has the right itself to audit, or have these accounts audited, annually. The Contractor is to provide periodic reports to the Competent Authority, pursuant to the Accounting Procedure to be annexed to all PSAs/Cooperation Contracts, which will set forth internationally recognized method(s) to value crude oil and natural gas produced from Contract Areas. Contractor's periodic reports to the Competent Authority will give full and accurate account of all quantities and qualities of oil and natural gas produced from the Contract Area and the ultimate disposition of same.

A5C.14 **Assignment of Rights**. Rights under a PSA/Cooperation Contract may be assigned:

a) to an Affiliate, on prior notice to the Competent Authority, but without the necessity of its prior consent, provided, however, that the assignor remains primarily liable for the performance of the agreed MWO and its other obligations under the PSA/Cooperation Agreement;

b) to other consortium members, on a minimum of 30 days prior notice to the Competent Authority, with consent therefrom, such consent not to be unreasonably withheld; and

c) to a third party, on a minimum of sixty (60) days prior notice to the Competent Authority, only with consent therefrom. Such notice to include all information concerning the proposed transferee which is required of an applicant for a license or permit, *ab initio*. The notice also to include an unconditional undertaking by the proposed transferee to be bound by all of the transferee's obligations under the PSA/Cooperation Agreement.

A5C.15 **Land Access and Usage**. The Competent Authority is to facilitate the Contractor securing, or, where applicable, provide and deliver to Contractor all licenses and permits required under existing laws for the conduct of petroleum operations; ensure Contractor reasonable access to and use of public and private lands, roads, means of communication, water and minerals for such purposes. Privately-owned land may be encumbered, temporarily or permanently, by easement or through *eminent domain*, but payment of just and adequate compensation to landowner whose land is encumbered must be provided. Also, the regulations need to include procedures for State-taking by Competent Authority and payment by Contractor of Authority's administrative costs for State-takings.

A5C.16 **Environmental Protection and Safety**. This section elaborates the environmental protection and safety requirements mandated in the Petroleum Law and establishes and detail norms of conduct, consistent with existing Indonesian legislation on the Environment and on Safety, to:

a) minimize ecological damage;

b) avoid waste to petroleum and its production environment;

c) prevent pollution and waste to land, structures, fresh water resources, crops, marine and animal life;

d) establish emergency clean-up obligations and procedures; and

e) set out procedures and requirements for the restoration of the environment at the conclusion of petroleum operations.

A5C.17 **Unitization**. Where Contractors in adjacent Contract Areas prove or have reason to believe that each have discovered petroleum form a common structure which extends across the boundary line of their respective blocks, provision must be made for them to develop the discovery as a single unit, on a non-competitive basis, in the interests of maximum efficient recovery of the State's natural resource. The Contractors involved must either agree a voluntary plan of unitization for approval by the Competent Authority or, failing such an agreement, the Competent Authority is empowered to order such unitized development by the Contractors.

A5C.18 **Preference for Local Goods and Services**. As provided for in the Petroleum Law and as will be agreed by Contractor in its PSA/Cooperation Contractor, preferences will be given to Indonesian goods, services and labor in carrying out petroleum operations, provided, however, that such goods, services and labor are competitive internationally as to price, quality and timeliness of supply.

A5C.19 **Records and Reports**. The Contractor is to be required to keep full and accurate technical, geological and geophysical records of all petroleum operations conducted for review by the Competent Authority, on demand. The Contractor is under a duty to report regularly and periodically to the Competent Authority on such operations at required intervals and in required format(s).

A5C.20 **Production Rates**. *International best practice* generally discourages the setting or mandating of production rates for reservoirs and Contract Areas. Rather, these Regulations should adopt the international standard, maximum efficient rate (MER), which is the rate of production from a reservoir which achieves the maximum, ultimate economic recovery of petroleum, subject, however, to it conforming with the general prohibition on flaring of gas (para. A5C.9).

A5C.21 **Measurement of Petroleum**. The Contractor is required to measure, meter and weigh all petroleum produced by methods customarily used in good oilfield practice, as approved by the Competent Authority, and periodically to test and recalibrate, as necessary, all such equipment used in these processes.

A5C.22 **Confidentiality**. Both the Contractor and the State are mutually to maintain confidentiality, for periods defined in these Regulations and agreed in their PSA/Cooperation Contract, over information, documents, data and materials related to a Contract Area and acquired or exchanged between them in the course of the conduct of petroleum operations.

A5C.23 **Indemnities**. The Contractor is obliged to indemnify the State and/or the Competent Authority and to hold them both harmless from any and all loss or damage to third parties or property caused by or occurring in the course of the conduct of petroleum operations by the Contractor.

A5C.24 **Penalties**. This section sets out offenses in contravention of the Law, along with a schedule of penalties for individuals or corporate entities found guilty of any such offenses.

A5C.25 **Model Forms**. To facilitate application for a license or permit to conduct petroleum operations under a PSA or Cooperation Agreement, it is useful to append to the Regulations, as annexes, model forms to be used by the applicant or prospective Contractor in making such application, either under a bid tender or for direct negotiations. These model forms will be keyed to specific requirements in the Petroleum Law and Regulations, covering such basic requirements/information as:

a) Basic Information on Applicant;

b) Contract Area Application/Bid;

c) Proposed Schedule of Bonuses; and

d) Land Rentals and Administrative Service Fees.

Pipeline Regulations

A5C.26 **Pipeline Regulator**. This section sets out the powers, duties and objectives of the member of the Energy Regulatory Body with primary responsibility for pipeline regulation [Pipeline Regulator (s)]. It will establish the method of appointment, qualifications and skills required, duration of term. The Pipeline Regulator (s), as a member of the Energy Regulatory Body will be independently funded and provided with adequate budget and staffing. Interim regulation arrangements prior to appointment of the Pipeline Regulator(s) should be established. Oblige and empower the Pipeline Regulator(s) to promote competition, intervene in any anti-competitive situations and to reduce barriers to entry. Empower the Pipeline Regulator(s) both to monitor all pipeline operations and to regulate the charges pipeline/storage companies make to others.

A5C.27 **Pipeline Construction**. This section deals with the details of permits, Licenses, rights of way, access to land and other administrative requirements to construct pipelines, including the time limit/period of licenses and procedures for their succession/transfer or abandonment. It sets out the required qualifications of parties seeking to construct a pipeline, both technical and fiscal. A threshold determination is first to be made by the Pipeline Regulator(s) that the proposed pipeline is both required and in the public interest to construct. Provision should be made here for a system of technical consents at key points—both in initial construction and for subsequent expansions, if any—with inspection of the work by qualified inspectors and submission of documentation.

A5C.28 **Technical Specifications**. Technical specifications for pipeline systems will be in compliance with established international codes and norms. The technical specifications applicable to any given pipeline system will first be agreed and then setout and incorporated into the License issued by the Pipeline Regulator(s) to the pipeline constructor/operator. The Pipeline Regulator(s) will be specifically empowered stringently to enforce all License provisions. Operating pressures for pipeline systems should be addressed here as well. Similar provisions and considerations will apply for storage facilities related to pipelines.

A5C.29 **Pipeline Routings**. Here are detailed such matters as: minimum distances from dense population centers; alternative safety measures for small communities; avoidance of national strategic areas; specific details for river crossings; optimal environmentally and commercially sound routings; avoidance of antiquities, holy sites, burial grounds, areas of special scientific or environmental concern and other nationally protected areas.

A5C.30 **Pipeline Operation**. This section deals with the technical and fiscal aspects of pipeline operation. It sets out environmental protection and safety requirements, measurement of quantities and verification of the meters and shipper responsibility for all costs relating to product quality. These Regulations apply to storage and other monopoly facilities, where duplication may be impractical or uneconomic. The pipeline operator is guaranteed the right to employ sufficient, experienced expatriate employees.

A5C.31 **Pipeline Inspection**. An efficient inspection system must first be developed and then detailed here. Pipelines and storage facilities are pressure vessels and inherently dangerous if not properly managed. The pipeline owner/operator is obliged to maintain its pipeline in safe condition as well as to have adequate fire fighting and other safety equipment.

A5C.32 **Third Party and Open Access**. Third party access is made available to all without undue discrimination. Spare pipeline capacity is to be available to third parties, provided that their batches to be shipped are compatible with those already in the pipeline. Details of terms, conditions and costs of access to pipelines by third parties and non-owners are provided here. All pipelines and storage, other than those oil or gas field specific, are regarded as part of the national infrastructure and potentially available to any user on reasonable terms. Larger industrial and commercial customers are granted rights both to access and to transit local distribution networks for gas.

A5C.33 **Policy Exceptions to Open Access**. Provide for such exceptions in start-up situations, where a company may invest in a new pipeline but needs for there not to be gas-to-gas competition for a number of years to produce reasonable assurances that earnings will be sufficient to repay the original investment. This will be limited, however, to well-defined time periods and to well-defined monopoly areas. Also to be excepted are field (gathering) pipelines.

A5C.34 **Special Open Access Situations; Bypass.** As it is common practice in most countries for gas distribution companies to have monopolies of their gas supply areas, for the majority of consumers open access to the distribution lines is not a normal policy, except in special situations where:

a) large industrial consumers with connections to the local network but not to the high pressure network should be permitted to "bypass" the local distribution company, and have the option of paying a transmission fee to the local company while buying from the producer via the high pressure grid. They should also have the right to a direct connection to the high pressure grid if this makes economic sense; and

b) the distribution company should be obligated to carry gas through its area for third parties, charging only a transport fee;

A5C.35 **Handling Capacity Constraints**. Provisions should be included that depending on the circumstances:

a) the pipeline owner will be obligated to increase capacity to meet firm and commercially binding commitments of others, with suitable safeguards to ensure that payment is received; or

b) the party requiring the increased capacity to provide the capital investment funds needed for capacity enhancement, and for the owner of the basic system to be obligated to cooperate, provided that the case is technically appropriate.

A5C.36 **Tariffication**. Set out here the chosen tariff methodology, principles, structure and formulae, including the relationship of tariffs to costs. Detail the procedures for setting, reviewing and revising tariffs on a regular and predetermined basis, in light of actual inflation and currency devaluation and in timely fashion. Set out the applicable procedures for appealing tariff decisions by the Pipeline Regulator(s). Detail the public utility aspects of pipeline operation, selecting either a regulated rate of return or a price cap approach. State which of certain monopolies are either permitted or prohibited. Determine specific pipeline tariff issues such as "rolled-in" or "incremental' tariffs and replacement costs for each pipeline user.

A5C.37 **Consumer Supply**. This is an absolute right to all small consumers. Set out procedures for terminating such supply in certain cases.

A5C.38 **Emergency Operations**. This section covers the details of priority use by the State of pipelines in situations of national emergency or shortages.

A5C.39 **Accounting Provisions**. Provide for the maintenance of crude oil pipeline accounts in US dollars or other hard currency, same as with E&P operations (a foreign currency market), whereas product pipeline and gas distribution accounts are to be maintained in local currency, as with any other Indonesian business (local currency markets). (Make choice of foreign or local for gas transmission pipelines).

Downstream Regulations

A5C.40 **Downstream Regulator**. This section details the powers, duties and objectives of the member of the Energy Regulatory Body with primary responsibility for downstream regulation [Downstream Regulator(s)]. It will establish the method of the appointment, qualifications and skills required, duration of term. The Downstream Regulator(s), as a member of the Energy Regulatory body, will be independently funded and provided with adequate budget and staffing. Interim regulation arrangements prior to appointment of the Downstream Regulator(s) should be established. Establish a mechanism for an aggrieved party to appeal a decision by the Downstream Regulator(s).

A5C.41 **Downstream Regulator's Role**. Empower the Downstream Regulator(s) to promote competition and to reduce barriers to entry. Charge the Downstream Regulator(s) with the duty of monitoring of arrangements to ensure that all marketers have ready access to product in each market, on non-discriminatory terms. Empower the Downstream Regulator(s) both to regulate charges one oil company makes to another, (e.g. for storage and for pipeline transport) and to intervene in any anti-competitive situation.

A5C.42 **Access to Product on Islands Without Adequate Refining Capacity**. Ensure here that there are adequate arrangements for providing non-discriminatory access to product, through, for example, joint procurement, or the dominant marketer making product available to others at a reasonable cost. Require fair access to marine facilities and shore storage for the new entrant, until such time as it has been economically able to build its own.

A5C.43 **Access to Product on Islands with Adequate Refining Capacity**. Ensure here that all marketers have access to the refinery product on equal terms, both at the refinery itself and from any pipeline system. Include this requirement in the Business License for the refinery (and of the pipeline).

A5C.44 **Open Access**. In essentially monopoly situations, provide the details of rules for open access to import facilities, storage, pipelines etc, the principles of charging and the situations in which open access is mandatory. Set out what should be the cooperation to be provided if capacity addition would be required. These basic rules are to be incorporated into the Business License.

A5C.45 **Award and Renewal of Licenses**. Provide here for different Licenses for different groups of products (the main products, and separately for aviation fuels, lubes, bitumen). Provide for different Licenses for marketers as opposed to retailers, and for those who are importing for own use and will not be trading. There should be Licenses for refining, for importing, for transporting by pipeline, for transporting by road or rail, for marine transport, for storing, for marketing/distributing and for retail. A License applicant must satisfy the Downstream Regulator(s) (including requirement to invest), and the need for an applicant for a marketing license to build (or contract for) his own storage. Licenses should be non-exclusive and automatically awarded to qualified applicants. Include a clear statement that it is not for the Downstream Regulator(s) to question the economic merits of the proposal, or the impact on others, but only whether the applicant has the experience, will observe the technical (e.g. safety) and tax requirements, etc.

A5C.46 **Security Stocks**. These are to be maintained by the private sector at its own expense, including contractual arrangements whereby one private sector party would be permitted to maintain stocks on behalf of another. Such stocks need not be in separate tanks, and they must be actively turned over. Detail how these stocks have to be diversified across relevant key islands where the company concerned is active. In view of the closeness of international refineries and the existence of Indonesia's own crude and refineries, these security stocks could be lower than OECD norms. Set out what are the periods allowed for achieving these stocks.

A5C.47 **Severe Product Shortages**. Set out the prioritization of uses and the compensation to the supplier (to ensure its supply, not to counter international price movements). The appropriate prices would be the applicable international prices plus supplier's normal markups. Define when and under what circumstances such provisions would come into effect.

A5C.48 **Anti-Contamination**. Provide here against illegal mixing and use of product, with appropriate fines and penalties for any such violations.

A5C.49 **Downstream Regulator's Right to Information**. Detail the procedures whereunder the Downstream regulator may obtain required information. List the information which a Licensee is obliged to supply. Provide for confidentiality (normally not appropriate, however, unless it relates to individual customers). Establish which of certain information must be published.

A5C.50 **Petroleum Product Specifications**. Provide details of lead and sulfur reduction programs, as well as programs to bring all specifications into line with international standards.

A5C.51 **Ex-Refinery Prices**. State here whether there is to be a system for setting *ex-refinery prices* or whether each refinery is expected to make itself competitive with international supply. If there is to be a system for ex-refinery prices, then it should be defined. Define what adjustments are to be made to ex-refinery prices in case the products are not in line with international specifications. Set out the method to determine prices for crude supplied to a refinery (same FOB as it can get for exports for otherwise exportable crude, plus freight, etc.). If the refinery reaches international standards of efficiency, it should then be making large profits because of access to cheap crude (due to saving in ocean transportation costs and losses). Set out how to deal with any special profits that might thus accrue. This should be anticipated. (For example, Argentina had a similar situation but did not anticipate this problem. The result is enormous profits at the refineries).

A5C.52 **Interim Arrangements for Refinery Protection**. ***NOTE:*** *Interim arrangements cannot be drafted until the extent of the financial problems of the refineries are determined.* It would be better if this is through targeted and time-limited subsidy, rather than through price control.

A5C.53 **Retail Price Control**. If it is decided to have a retail price setting system, provide details of how this would work in as automatic a way as possible. (A model for this can be provided). Decide whether such system is to be permanent or for a transition period only. Include an immediate move from fixed prices to ceiling prices. It is absolutely essential to have reliable, prompt and frequent price adjustments for changes in import price/ex-refinery price. Limit the locations where prices are controlled, for example, at the ports, at the locations of the refineries, at the ends of the pipelines. Avoid covering a large number of inland towns.

A5C.54 **Health, Safety and Environment**. Set out procedures for dealing with spills. Address pressure questions for LPG containers. Establish specifications for road and rail tankers and, in particular, the need for regular independent inspections. Detail safety regulations, including whether road tankers can travel at night and what is the maximum "day" for a tanker driver. Require safety training for all drivers, operators, etc. Establish the responsibility of boat/road/rail/marine tanker operators for safety of product transport and for ensuring that the entire commodity loaded into the tanker is delivered (subject to losses within international norms). Provide for independent inspections of storage facilities.

A5C.55 **Independent Verification**. Provide for independent professional verification to ensure the accuracy of measuring devices, pumps, etc.(this is a weights and measures function). Mandate independent verification of product quality. Detail the role of the refinery laboratory in verifying import quality.

A5C.56 **Restrictions on Competition**. Consider the possibility of and limitations on cross-ownership and possibility of Downstream Regulator refusing to permit acquisition of competing companies, if as a result, competition is materially diminished. Detail the right of the Downstream regulator to set conditions and objectives of such conditions.

A5C.57 **Transitional Provisions**. Ensure that open access is built into relevant divestitures Clearly set out here:

a) what is to be the role of Pertamina during a transition period?;

b) what will be the duration of such a transition period?;

c) will there be a program of divestitures?; and

d) what will be the objective of such divestitures (competition rather than price)?

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MAP SECTION

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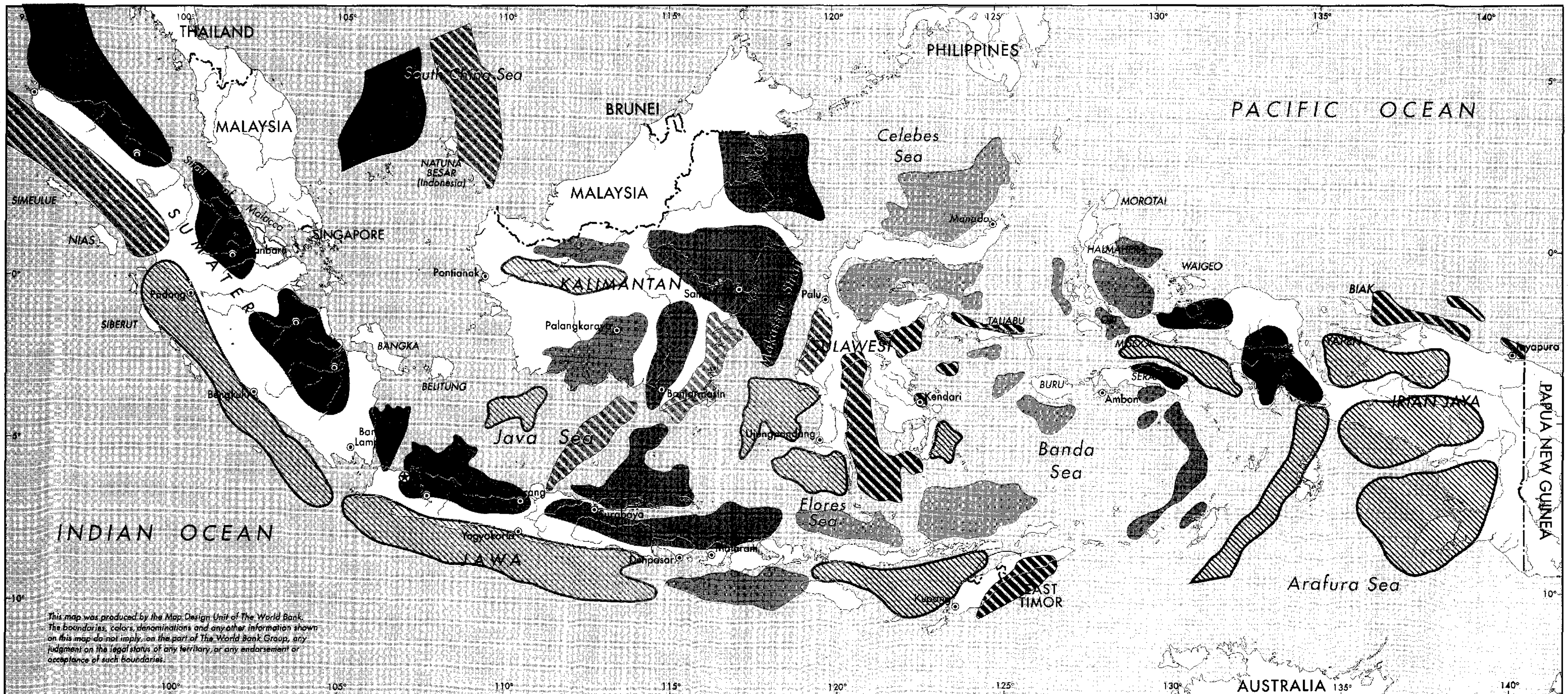
INDONESIA
OIL AND GAS SECTOR STUDY
TERTIARY SEDIMENTARY BASINS

0 200 400 600 800 KILOMETERS

BASINS NOT YET DRILLED
BASINS DRILLED, NO DISCOVERY
BASINS WITH DISCOVERY, NOT YET PRODUCING
PRODUCING BASINS

PROVINCE CAPITALS
NATIONAL CAPITAL
RIVERS
INTERNATIONAL BOUNDARIES



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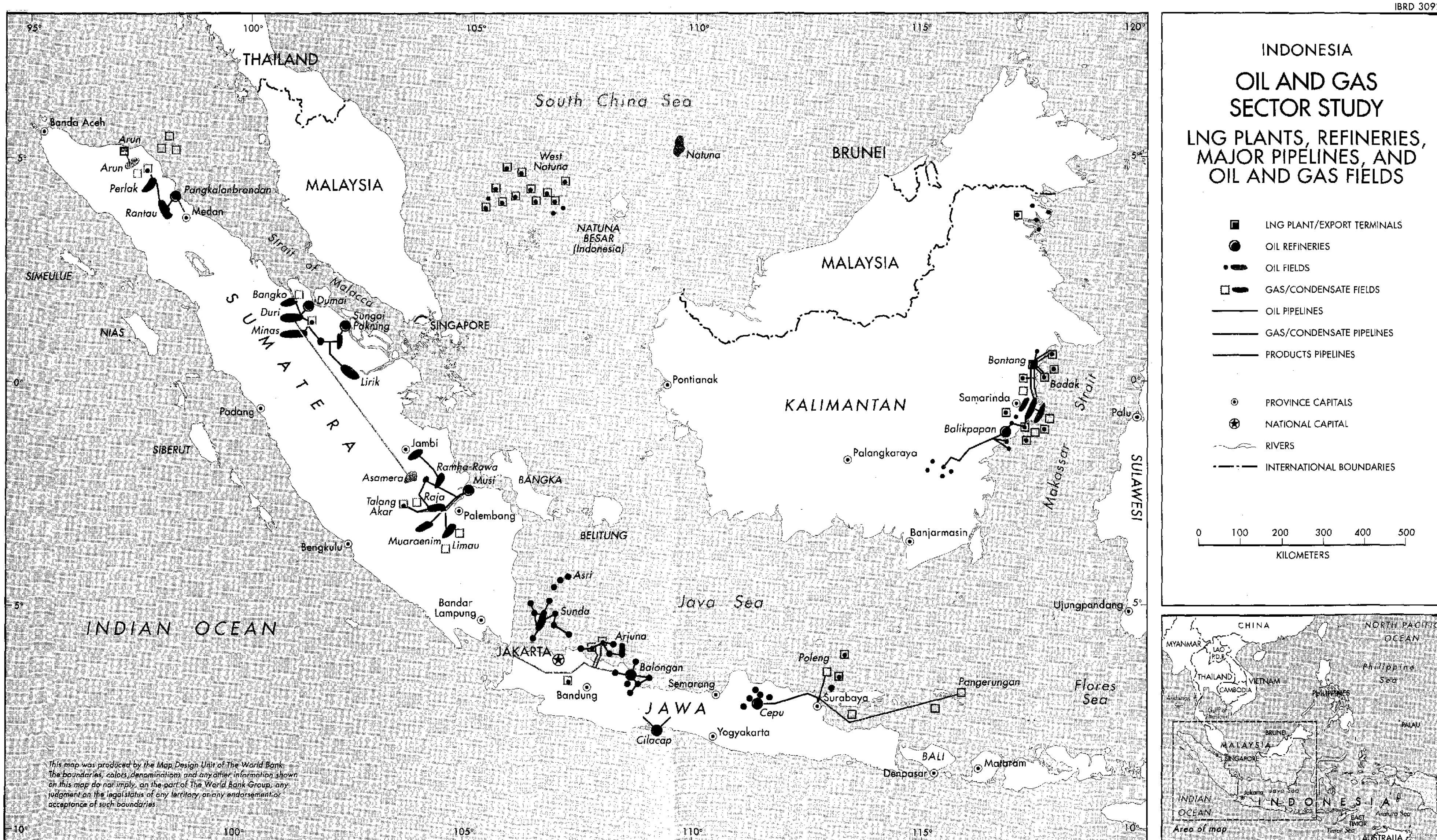

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