

Fossil Fuels – At What Cost?

Government support for upstream oil and gas activities in Indonesia

OCTOBER 2010

BY:

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ACRONYMS AND ABBREVIATIONS

ASCM	Agreement on Subsidies and Countervailing Measures
BBM	Subsidized oil products gasoline, diesel oil, kerosene
BOPD	Barrels oil per day
BBOPY	Billion barrels of oil per year
BPK	The Audit Board of the Republic of Indonesia
BPKP	State Auditors for Finance and Development under the Ministry of Finance
BPMIGAS	Upstream Oil and Gas Regulatory Agency
BPHMIGAS	Downstream Oil and Gas Regulatory Agency
BUMD	Enterprise owned by the Provincial Regional Administration
COW	Contract of Work
CR	Cost recovery, deducted from gross revenue under PSC
DGOG	Directorate General of Oil and Gas, also known as MIGAS, under the MEMR
DMO	Domestic Market Obligation
DPR	Indonesia's House of Parliament
EOR	Enhanced oil recovery
FTP	First Tranche Petroleum
GAAP	Generally Accepted Accounting Principles, in use in PSC accounting procedure
GOI	Government of Indonesia
GSI	Global Subsidies Initiative
ICM	International Capital Market
ICP	Indonesia's Crude Price, oil price reference to calculate cost recovery under PSC
IMO	International Maritime Organization
IOC	International oil company
IPO	Initial public offering
IRR	Internal rate of return
LEMIGAS	Indonesia's Center for Oil and Gas Research and Development
MBOPD	Thousand barrels of oil per day
MEMR	Indonesia's Ministry of Energy and Mineral Resources
MIGAS	Short name for Directorate General of Oil and Gas
MBOPD	Thousand barrels of oil per day
MMBOPD	Million barrels oil per day
MOPS	Mean of Platts Singapore
NOC	National oil company
NPV	Net present value
PERTAMINA	State-owned oil and gas Enterprise, Indonesia's NOC
PIB	Import declaration list
POD	Plan of Development
PSC	Production Sharing Contract
PSCo	Production Sharing Contract Contractor (who has signed a PSC)
PSO	Public service obligation
R&D	Research and Development
SOE	State-owned enterprise
VAT	Value added tax
WA	Work agreement

EXECUTIVE SUMMARY

The objective of the case study is to identify, quantify and assess the impacts of subsidies that are being granted to oil and gas producers for upstream activities in Indonesia. It is being undertaken within the context of the following declaration made at the G-20 summit in September 2009, in which Indonesia was a participant: “We commit to rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption” (G-20 Leaders, 2009)

To date, most countries worldwide have focused on studying consumer subsidies, as they are more transparent and easier to track than producer subsidies. This study is one of the first to focus on producer subsidies in the developing world.

The focus of this study, Indonesia’s upstream activities, consist of exploring for and extracting oil and gas in the country; downstream activities consist mainly of the refining of crude oil to produce oil products and the oil products’ subsequent storage, transportation and delivery to end users.

Researchers in this study identified 17 activities where a subsidy might exist. These activities have been grouped according to the four different types of subsidies identified by the World Trade Organization’s Agreement on Subsidies and Countervailing Measures (see Section 1.1.1.) and are as follows:

- Direct and indirect transfer of funds or liabilities
 - Pertamina’s Work Agreement compared with standard production sharing contract (PSC)
 - Recovery of operating costs
 - R&D support to industry
 - Restoration and rehabilitation of depleted oil and gas fields
 - Investment credit allowance
 - Bank financing support
- Government revenue foregone
 - Tax incentives for imported goods and services
- Provision of goods or services at below market value
 - Application of royalties
 - Equity shares
 - Year-end reconciliation of over- and under-lifting
 - Access to new acreage
 - Access to expired PSCs
 - Bonuses paid by industry
 - Government-provided infrastructure and support services, preferential access to land
- Income or price support
 - Farm in to existing PSCs
 - Oil Domestic Market Obligation (DMO) subsidy to Pertamina
 - Gas DMO subsidy to gas consumers

Each of these activities was analyzed and then re-grouped under three new headings to facilitate understanding the conclusions drawn from this study. The first group includes activities for which subsidies do exist and could be estimated. The second group includes activities for which it was concluded subsidies might exist, but further, detailed research is required to definitively conclude that a subsidy does exist and can be quantified. The third group includes activities where it is judged no subsidies exist. The conclusions drawn were as follows:

(1) Where subsidies exist and have been estimated

Subsidy	Estimated value in 2008
Investment Credit Allowance	US\$ 115 million
Tax incentives for imported goods and services	US\$ 130 million
Oil Domestic Market Obligation (subsidy from industry to Pertamina's refineries)	US\$ 1,554 million
Total	US\$ 1.799 billion

(2) Where subsidies may exist but further research is needed

- Pertamina's Work Agreement compared with standard PSC
- R&D support to industry
- Bank financing support
- Access to expired PSCs
- Access to forested areas
- Application of royalties and equity shares in an international context
- Gas DMO: subsidy for gas consumers rather than gas producers.

(3) Where no subsidies exist

- Restoration and rehabilitation of depleted oil and gas fields
- Year-end reconciliation of overliftings and underliftings
- Access to new acreage
- Farm-in to existing PSCs
- Bonuses paid by industry

While, as stated above, the purpose of the study is to identify oil and gas producer subsidies, an important finding from the research conducted was that subsidies do exist in the downstream oil and gas sector that may not have been identified to date. Certain domestic users of gas benefit from buying gas produced in Indonesia at prices that are significantly below international market prices (gas DMO). In addition, Pertamina's refineries benefit from buying crude oil supplied to them through the oil DMO system, most of which is sold to them at heavily discounted prices. It has been possible to estimate the size of the subsidy generated by the oil DMO, but further research is needed to estimate the size of the subsidy generated by the gas DMO.

Having identified those activities where subsidies do exist, the researchers assessed the direct impacts of the subsidies and the degree to which these subsidies achieve their policy objectives. The study found that both the investment credit allowance and the tax incentives for imported goods and services positively contribute to the GOI's stated objectives of increasing exploration activities and, in particular, encouraging investments in new geological plays. However the study has not established how efficient the subsidies are in achieving these objectives or whether the aims would be better met by alternative means.

1. STUDY PURPOSE, SCOPE AND METHODOLOGY

1.1 STUDY PURPOSE AND SCOPE

1.1.1 DEFINITION OF PRODUCER SUBSIDIES

The Global Subsidies Initiative (GSI, 2010) adopts a three-step approach to *define, measure* and *evaluate* subsidies. This approach starts with a broad definition of “subsidy” with the purpose of identifying all existing subsidies in a sector, and whether those subsidies are considered “good” or “bad.” This approach provides a comprehensive starting point for the analysis. As the study proceeds through the steps, the focus will narrow to those subsidies that are measurable and able to be fully assessed. Therefore, it should not be assumed that because a subsidy is identified at the beginning of the study that it is necessarily in need of reform.

The GSI’s approach is based on the view that a subsidy exists where preferential treatment—financial and otherwise—is provided to producers of oil and gas. Preferential treatment can be provided in three forms:

- To selected companies;
- To one sector or product when compared with other sectors;
- To sectors or products in one country when compared internationally (GSI, 2010).

It is useful to keep these three broad types of preferential treatment in mind when determining whether a specific subsidy is granted. The study defines “subsidy” based on the World Trade Organisation’s (WTO) Agreement on Subsidies and Countervailing Measures (ASCM), which is supported by 153 countries, including Indonesia. Under the ASCM, there are four types of subsidies categorized by the policy instrument used to transfer the benefit. According to the ASCM, a subsidy exists where government:

1. Provides direct or indirect transfer of funds or liabilities,
2. Revenue is foregone or not collected,
3. Provides goods or services below market rates or purchases goods paying higher than the market rate and
4. Provides income or price support.

The GSI has added sub-categories of subsidies to this list that form the framework for this review (Figure 1.1). These are not all necessarily relevant to the oil and gas sector in Indonesia, as this study will reveal, but rather forms a comprehensive framework for identifying and analyzing subsidies in any country. This framework provides the basis for the GSI’s series of country case studies to identify and quantify subsidies to upstream oil and gas activities.

Although the GSI adopts a broad definition of “subsidy,” the definition excludes environmental externalities (such as carbon emissions and pollution), which are better considered in the environmental impact assessments in the third step of the process.

FIGURE 1.1: GSI'S SUBSIDY FRAMEWORK

Direct transfer of funds	Direct spending	<p>Earmarks: Special disbursements targeted at the sector</p> <p>Agency appropriations and contracts: Targets spending on the sector through government budgets</p> <p>Research and Development support: Funding for research and development programs</p>
	Government ownership of energy-related enterprises	<p>Security-related enterprises: Strategic petroleum reserve; securing foreign energy shipments or key assets</p> <p>Municipal utilities and public power: Significant public ownership of coal- and natural gas-fired electricity stations; some transmission and distribution systems for both natural gas and electric power</p>
	Credit support	<p>Government loans and loan guarantees: market or below-market lending to energy-related enterprises, or to energy-intensive enterprises such as primary metals industries</p> <p>Subsidized credit to domestic infrastructure and power plants</p> <p>Subsidized credit to oil- and gas-related exports</p>
	Insurance and indemnification	<p>Government insurance/indemnification: market or below-market risk management/risk shifting services</p> <p>Statutory caps on commercial liability: can confer substantial subsidies if set well below plausible damage scenarios</p>
	Occupational health & accidents	<p>Assumption of occupational health and accident liabilities</p>
	Environmental costs	<p>Responsibility for closure and post-closure risks: facility decommissioning and cleanup; long-term monitoring; remediation of contaminated sites; natural resource restoration; litigation</p> <p>Waste management: avoidance of fees payable to deal with waste</p> <p>Environmental damages: avoidance of liability and remediation to make the environment whole</p>
Government revenue foregone	Tax breaks and special taxes	<p>Tax expenditures: Tax expenditures are foregone tax revenues, due to special exemptions, deductions, rate reductions, rebates, credits and deferrals that reduce the amount of tax that would otherwise be payable.</p> <p>Overall tax burden by industry: Marginal tax rates are lower than other industry.</p> <p>Excise taxes/special taxes: excise taxes on fuels; special targeted taxes on energy industry (e.g., based on environmental concerns or “windfall” profits)</p>

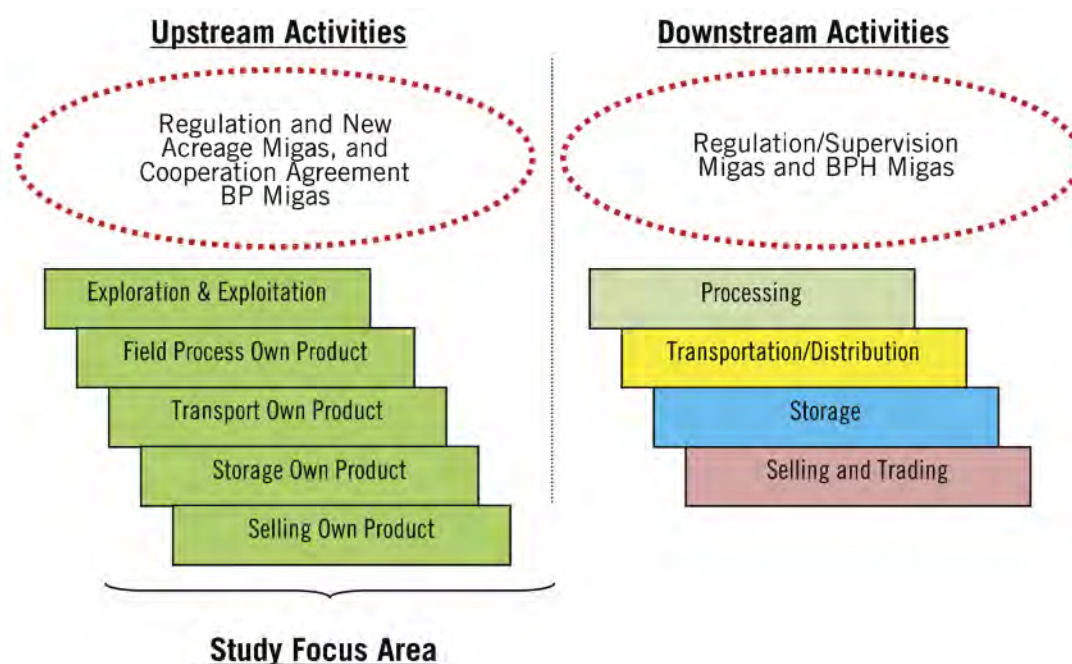
FIGURE 1.1: GSI'S SUBSIDY FRAMEWORK (CONTINUED)

Provision of goods or services below market value	Government-owned energy minerals	<p>Process for mineral leasing: auctions for larger sites; sole-source for many smaller sites</p> <p>Royalty relief or reductions in other taxes due on extraction: reduced, delayed or eliminated royalties are common at both national and sub-national levels. Royalties targeted based on type of energy, type of formation, geography or location of reserve (e.g., deep water)</p> <p>Process of paying royalties due: allowable methods to estimate and pay public owners for energy minerals extracted from public lands</p>
	Government-owned natural resources or land	Access to government-owned natural resources or land: at no charge or for below fair market rate
	Government-owned infrastructure	Use of government-provided infrastructure: at no charge or below fair market rate
	Government procurement	Government purchase of goods or services for above-market rates
	Government-provided goods or services	Government-provided goods or services at below-market rates
Income or price support	Market price support and regulation	<p>Consumption mandates: fixed consumption shares for total energy use</p> <p>Border protection or restrictions: controls on imports or exports leading to unfair advantages</p> <p>Regulatory loopholes: any legal loopholes, either in the wording of the statute or in its enforcement, that transfers significant market advantage and financial return to particular energy market participants</p> <p>Regulated prices set at below-market rates: for consumers (including where there is no financial contribution by government)</p> <p>Regulated prices set at above-market rates: including government regulations or import barriers</p>

1.1.2 STUDY PURPOSE AND SCOPE

The objective of this case study is to identify, quantify and assess the impacts of producer subsidies in Indonesia’s upstream oil and gas sector. The focus of this analysis is government support provided for exploration, development and production activities, but the scope of the study excludes downstream activities such as refining, storage, transportation, distribution and retail. The distinction between “upstream” and “downstream” activities is illustrated in Figure 1.2 below. The reason for focusing on upstream activities or “producer” subsidies is that the downstream activities or “consumer” subsidies are more transparent and have been the focus of other studies.¹ Little work has been done on Indonesia’s producer subsidies to date. The study focuses on identifying where preferential treatment is being provided in the first two instances mentioned in 1.1.1, namely (a) to selected companies, and (b) to one sector or product when compared with other sectors. The study is not focusing on the third instance: undertaking comparisons internationally, which may be undertaken as a follow up research exercise if it is concluded that this would be of value.

FIGURE 1.2: OIL AND GAS SECTOR UPSTREAM & DOWNSTREAM ACTIVITIES



Source: CMS Consulting Group

¹For more detailed analysis on Indonesia’s consumption subsidies see: International Energy Agency (2009). *Energy policy review of Indonesia*; and World Bank (2009). *Spending for development: Making the most of Indonesia’s new opportunities*. Indonesia Public Expenditure Review.

The study provides a comprehensive analysis of the support provided by national government but does not include any subsidies provided by regional or local governments, which are not expected to be substantial. Where possible, estimates of the per annum cost of each subsidy have been provided. Chapter 4 provides a summary of the total support provided by the government of Indonesia on a per annum basis.

Chapter 3 of this study analyzes each of the subsidies identified against the following two criteria:

1. Does the subsidy meet the government's objectives in a cost-effective manner?
2. What economic impacts does the subsidy have for the oil industry?

The study concludes with a summary evaluation and next steps for further research and analysis.

1.2 STUDY METHODOLOGY

A seven-step approach has been adopted for this study

- Step 1 Define the term “producer subsidies” to be applied in the study. Consumer subsidies will not be addressed.
- Step 2 Prepare a checklist of potential subsidies that may exist in upstream activities in Indonesia to use as guide for research. This list will not be exhaustive and other forms of subsidy will be reported on if found.
- Step 3 Identify key activities in the oil and gas upstream sector and analyze these to identify whether subsidies exist.
- Step 4 Review government regulations and policy documents that relate to the application of subsidies and, where possible, identify the intended policy objectives set by the Government of Indonesia (GOI) for these subsidies.
- Step 5 Attempt to quantify the subsidy and for each subsidy address the questions: (i) Is the subsidy meeting the GOI objectives? (ii) What economic impacts does the subsidy have on the oil industry?
- Step 6 Detail which upstream activities are being subsidized and who receives the benefits of these subsidies.
- Step 7 Assess each of the subsidies, and potential subsidies (i.e., those where further research is recommended to decide whether or not a subsidy does indeed exist), and identify areas for further research and analysis.

Three main challenges have been encountered in identifying and quantifying the subsidies in the upstream sector.

- (i) Deciding whether or not subsidies really do exist.

In some cases, this is a straightforward exercise, such as the case where an extra incentive is given for the development of “new” oilfields, in the form of an Investment Credit. In other cases it is more difficult to assess this, such as the access that production sharing contract contractors (PSCo) and Pertamina have to forested areas, for undertaking oil and gas operations. It is much more challenging to determine whether the fees they pay for this access adequately cover all the costs of de-forestation in these areas, including environmental costs, whilst balancing this against the value added for producing oil and gas compared with maintaining the forest as it is.

- iii) Identifying a baseline against which a likely subsidized activity can be measured, in order to quantify this subsidy.

This has been challenging in the case of many of the subsidies identified, particularly where preferential treatment is being granted. For instance, how to define a baseline to measure how Pertamina benefits from the greater flexibility it has in offering out portions of its Work Areas to third parties, for joint development, compared with the options open to production sharing contracts (PSCs).

- (iii) Assessing whether the GOI is subsidizing the upstream oil and gas sector, when taking account of the entire range of fiscal and other conditions that apply to PSCos through the PSC system (and to Pertamina through its Work Agreements), compared with other industries in Indonesia and compared with how governments treat the upstream oil and gas sector in other countries.

A recent World Bank study entitled *Fiscal system for hydrocarbons* ranks Indonesia's PSC system at the higher end of government take, and thus the lower end of PSCo take. Does this ranking indeed take into account of all the complex transparent and non-transparent conditions that apply to PSCos (and Pertamina), and if so, should it be concluded from this that the upstream oil and gas sector in Indonesia is less attractive than the norm in other countries? If so, in order to attract more investment to increase oil and gas production, by improving certain terms and conditions, should the GOI redress this balance, and at what stage would these improved terms and conditions be classified as a subsidy? As the task of making this international comparison has been undertaken by others, and is in itself a lengthy and complex process, this has not been addressed in this study, which has focused on undertaking an assessment of subsidies in the upstream oil and gas sector in Indonesia, which does not appear to have been carried out before.

2. BACKGROUND ON THE UPSTREAM OIL AND GAS SECTOR IN INDONESIA

This chapter provides some background about the upstream oil and gas sector in Indonesia, focusing on those aspects of this sector that will assist in understanding the identification and evaluation of subsidies that follows in Chapter 3.

2.1 BRIEF HISTORY OF THE INDONESIAN PETROLEUM INDUSTRY

During the struggle to secure Indonesia's independence, one objective of the independence fighters was to take back control of oil and gas fields, refineries and distribution facilities from the Japanese Army. They succeeded in doing so and in September 1945 the Japanese Army transferred all the oil fields within the area of Pangkalan Brandan in Sumatra to The Indonesia Government, which was witnessed by the United National Committee (Ministry of Energy and Mineral Resources, 2009a).

Following this, National Oil Companies (NOCs) were established to operate these oil fields in Pangkalan Brandan and other oil fields in Jambi, South Sumatra. Meanwhile the struggle continued to take control of other oil fields and refineries that were still being held by the Dutch.

It should be noted that during the early years of independence, there was no government department with specific responsibility for natural resource mining activities in Indonesia. Then in 1960, consistent with the spirit of the Indonesian Constitution, Law No. 44 was passed, which ended the concession system for the exploitation of oil and gas that had been adopted under colonial law since 1899. The passing of Law No. 44 started the process and negotiations to clarify the status of international oil companies (IOCs) such as Stanvac, Caltex and Shell, which had not been clear since independence was declared in August 17, 1945 (Ministry of Energy and Mineral Resources, 2009a).

Following this process in June 1963, the status of Shell, Stanvac, and Caltex was formally changed from that of being a "concession holder" into being "contractor." The creation of this new status provided the foundation of the "Contract of Work" (COW) system. As a result, these three IOCs each signed COWs in June 1963 and became the "contractors" to the NOCs PERMIGAN, PERMINA and PERTAMIN respectively (Ministry of Energy and Mineral Resources, 2009a).

Five years later, in 1968 these three NOCs—PERMIGAN, PERMINA and PERTAMIN—merged to become PERTAMINA. The legal establishment of PERTAMINA was based on Government's Regulation No. 27, Government decree on the establishment of state-owned oil and gas enterprise, 1968 and its responsibilities were further defined by the issuing of Law No. 8 Law on the establishment of state-owned national oil and gas enterprise, 1971. Based on this, Pertamina became responsible for managing the contacts signed with IOCs operating in Indonesia; most of these contracts, were called production sharing contracts (PSCs). Since this initiative was taken about 40 years ago, IOCs have accounted for about the 90 per cent of the "upstream activities" in Indonesia, that is to say, activities related to the exploration for, and production of, oil and gas, with Pertamina accounting for the balance of 10 per cent (Directorate General of Oil and Gas, 2005).

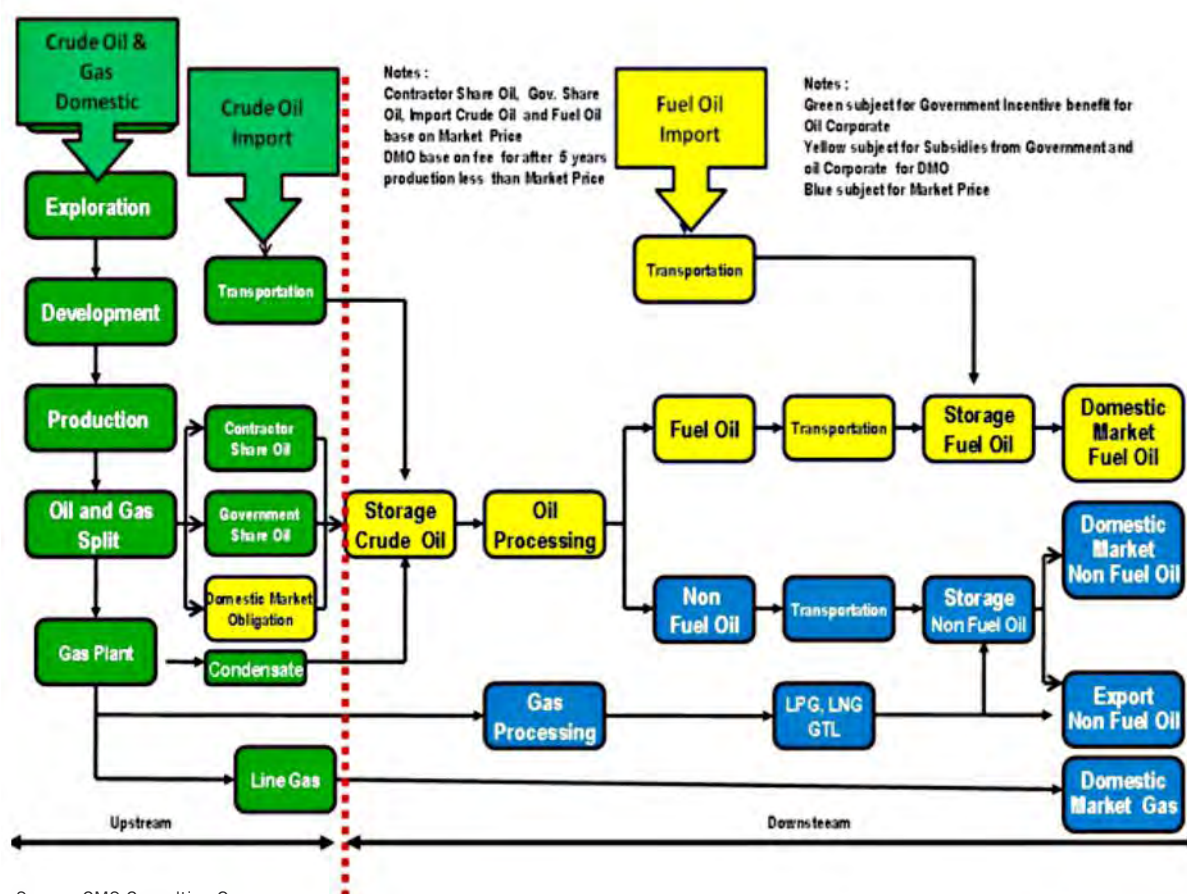
Pertamina also had sole responsibility for the refining, storage, transportation, distribution and marketing of oil products throughout Indonesia (otherwise known as "downstream activities"). This sole right to supply became known as its public service obligation (PSO).

For many years, the GOI has opted to subsidize the oil products that are supplied through this PSO throughout the country, and concurrently, maintain a constant price for each product no matter where it is sold. For undertaking this PSO service, Pertamina was paid a fee.

More recently though, Pertamina has been reimbursed for supplying these subsidized oil products by being paid the difference between the subsidized price and the “market” price, which is based on the Mean of Platts Singapore (MOPS), plus an agreed amount for transportation and distribution, and an agreed margin for Pertamina. The subsidized oil products consist mainly of gasoline, diesel oil and kerosene, which are sold to the general public. Recently, this subsidy for the sale of oil products to certain groups of consumers, mainly industrial consumers and including mining companies, has been removed, and these are sold at market price. The pricing of natural gas has also been regulated and is described in much greater detail later in this study.

The passing of Law No. 22 in 2001 affected Pertamina in two fundamental ways. First, with regards to its upstream activities, its role in managing the IOCs was transferred to a newly created body named Upstream Activities Supervisory and Implementing Agency (known as BP MIGAS), and the status of the Pertamina became no different from any other IOC (or indeed any other national private oil company) operating in Indonesia. Second, with regard to downstream activities, the new law allowed other companies, besides Pertamina, to participate in these activities, thus ending its monopoly status. Also, as mentioned above, this new law changed the way in which Pertamina is paid for supplying subsidized oil products, as part of its PSO responsibility.

FIGURE 2.1: INDONESIA'S OIL AND GAS SUPPLY CHAIN FROM UPSTREAM TO DOWNSTREAM



Source: CMS Consulting Group

As shown in Figure 2.1, the oil and gas supply chain consists of the flow of crude oil and of refined oil products from both imported and domestic sources to meet domestic fuel needs and for any surpluses to be exported.

The GOI seeks to increase crude oil production to keep up with increasing domestic fuel demand, but as will be seen below, in recent years, national crude oil production has been declining, and so imports of crude oil have increased.

Policy-setting and regulatory institutions

Several government institutions are involved in setting policy, and managing, supervising and regulating the upstream oil and gas sector. The Ministry of Energy and Mineral Resources (MEMR) sets policy, and manages and supervises the industry, much of which is done through the Directorate General of Oil and Gas, (often referred to as “Migas” in short), who has a particular responsibility for offering out new oil and gas work acreage. BP Migas supervises the upstream oil and gas operations and ensures the PSCOs comply with all the terms and conditions of the PSCs they have signed, and the chairman of BP Migas signs the PSC on behalf of the GOI. BP Migas manages the process for agreeing to an annual Work Programme and Budget for each PSC, and also issues operational guidelines and carries out audits on behalf of the GOI.

Another body, BPH Migas, regulates the downstream oil and sector, in combination with Migas, and has particular responsibility for regulating the transportation of gas through pipelines.

Other departments, such as the Ministry of Finance and the Ministry of Environment, also have a significant impact on the upstream oil and gas sector.

Regulation of the Gas Sector

Natural gas accounts for just 13 per cent of the total energy mix (MEMR, 2008). One reason for this low share is that the price of gas for domestic use is heavily regulated and generally priced way below the international price of gas. This makes gas attractive for domestic users, but gas suppliers who have the option of exporting their gas will choose to sell this gas overseas. As an example, gas sold as a feedstock to fertilizer plants is typically about US\$1.50 per million cubic feet (MMCF), and gas sold in the recent past for electricity generation has been priced at about US\$2.50 per MMCF, though this has increased and is now getting closer to US\$5.00 per MMCF.

Uncertainties surrounding the GOI’s policy towards the amount of gas production that should be sold into the domestic market have stalled the development of a number of gas projects, one example being the Senoro LNG project in Central Sulawesi.

There is more detail and discussion about the DMO for gas in Chapter 3.

National energy policy

The key objectives of the national energy policy are to ensure there is a sufficient energy supply to meet domestic needs, to increase efficiency in energy utilization, to encourage energy source diversification and to conserve sufficient energy resources for future generations.

Reviewing and updating the national energy policy is the responsibility of the National Energy Council, which reports to the President.

2.2 PRODUCTION SHARING CONTRACT (PSC)

As mentioned in Section 2.1, the GOI introduced the PSC system over 40 years ago, the first such contract having been signed in 1966. The contract was based on cooperation between the IOCs operating in Indonesia and the GOI (the GOI for many years was represented by Pertamina and, more recently, by BP Migas, in the PSC). Some of the key provisions in the PSC are as follows:

- Management is conducted by BP Migas.
- The IOC signing the contract is referred to as a production sharing contractor (PSCo) and is responsible to BP Migas.
- It is oil and gas production rather than profit that is shared between the IOCs signing the contract and BP Migas.
- The PSCo takes title to their share of oil and gas produced at the “point of export” or “point of delivery.” The PSCo’s share is termed their “entitlement,” which is their in-kind share of oil and gas production. The level of production is calculated and agreed upon an annual basis in the Work Program and Budget by BP Migas, with a reconciliation against actual production at year end.

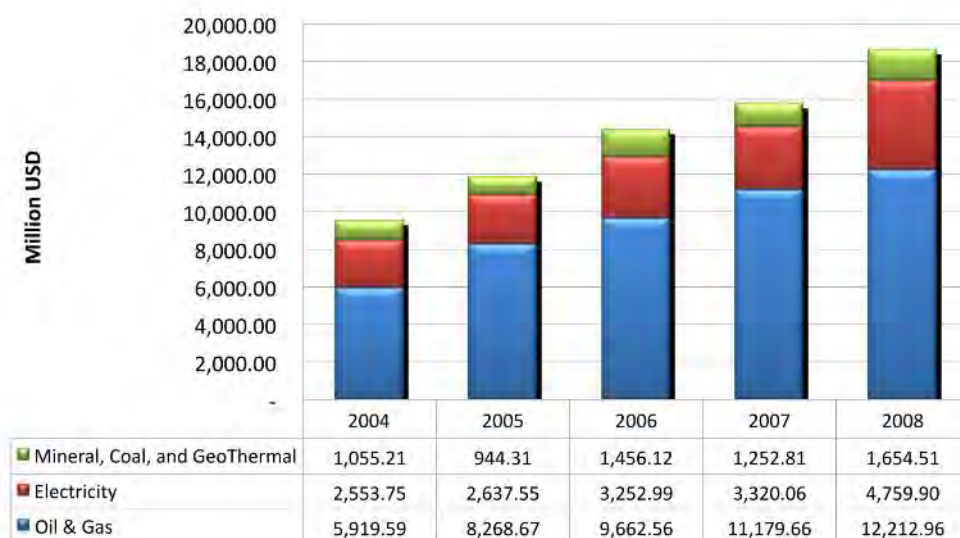
Terms and conditions relating to the PSC system have varied in each of the three PSC “generations” that have been issued. Generation 1 applied from 1965 to 1975, Generation 2 applied from 1976 to 1987 and Generation 3 has applied from 1988 to present. In addition, since the start of Generation 3, four different “incentive packages” have been introduced. The second incentive package was introduced in 1989, with the objective of encouraging exploration and production in offshore areas and in Eastern Indonesia. The third incentive package in 1992 was intended to increase exploration for gas in both conventional and frontier areas. The fourth incentive package in 1994 was designed to further stimulate exploration for both oil and gas in Eastern Indonesia, and in offshore areas generally (Minister of Energy and Mineral Resources, 1993).

Further details of the terms and conditions that apply to each of these three “generations” and each of these four incentive packages are contained in the Appendices and are also referred to in Chapter 3.

2.3 RECENT TRENDS IN OIL AND GAS EXPLORATION AND PRODUCTION AND INVESTMENT

As seen in Figure 2.2, investment in oil and gas, and indeed other major sources of energy, has increased steadily during the period 2004–2008. The increase in oil and gas has been particularly significant, with investments increasing from US\$5.9 billion in 2004, to more than US\$12 billion in 2008, that is to say, it has more than doubled in this 4 year period.

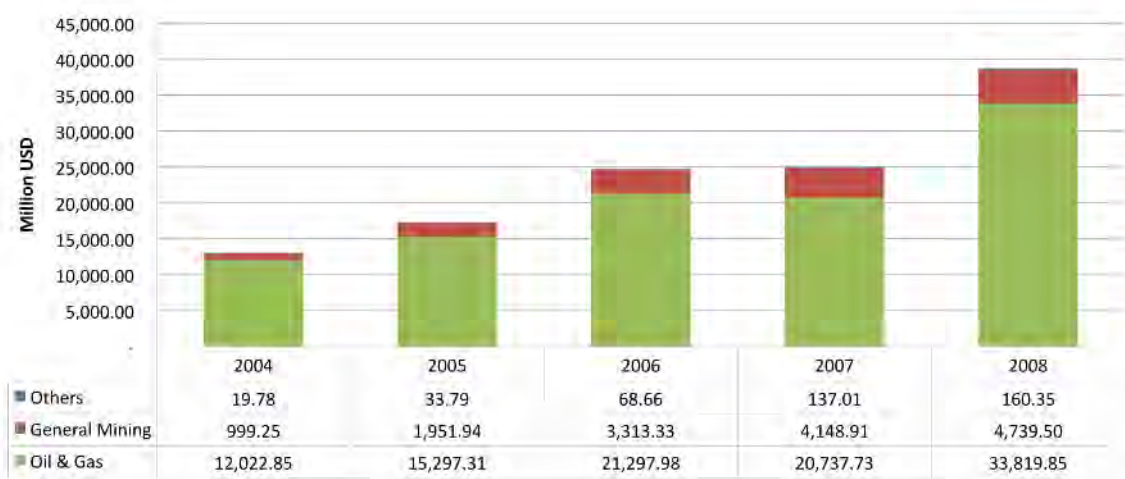
FIGURE 2.2: INVESTMENT TREND IN ENERGY RESOURCES IN INDONESIA



Source: CMS Consulting Group; adapted from Ministry of Energy and Mineral Resources, 2009

Not surprisingly, the revenue that the GOI receives from the production of oil and gas has also increased significantly in absolute terms, increasing from US\$12 million in 2004 to close to US\$34 million in 2008, as seen in Figure 2.3 (Ministry of Energy and Mineral Resources, 2009b).

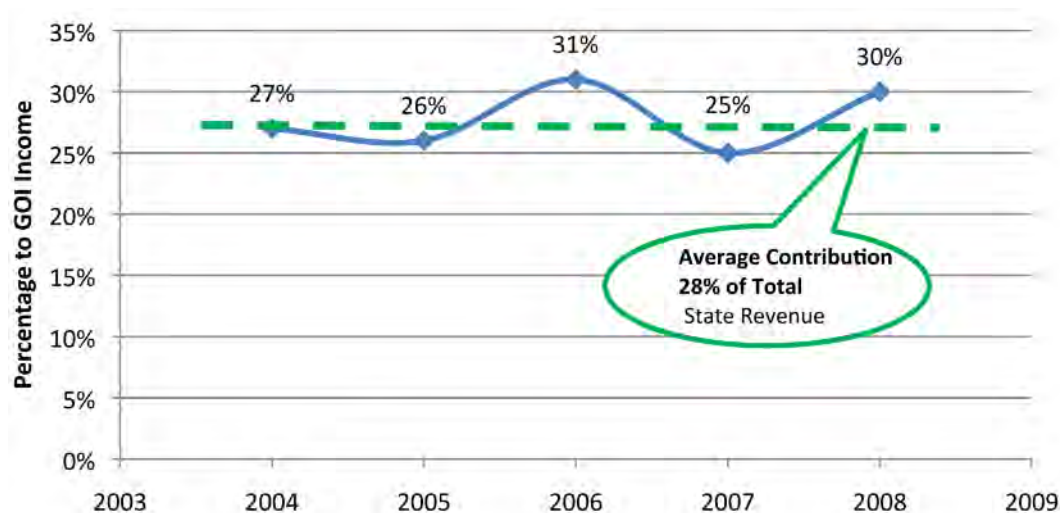
FIGURE 2.3: THE GOI'S INCOME FROM THE OIL AND GAS SECTOR



Source: CMS Consulting Group; adapted from the Ministry of Energy and Mineral Resources, 2009b

The contribution of the oil and gas sector to total State revenue between 2004 and 2008 averaged 28 per cent, and reached 30 per cent in 2008, as illustrated in Figure 2.4 (Ministry of Energy and Mineral Resources, 2009b).

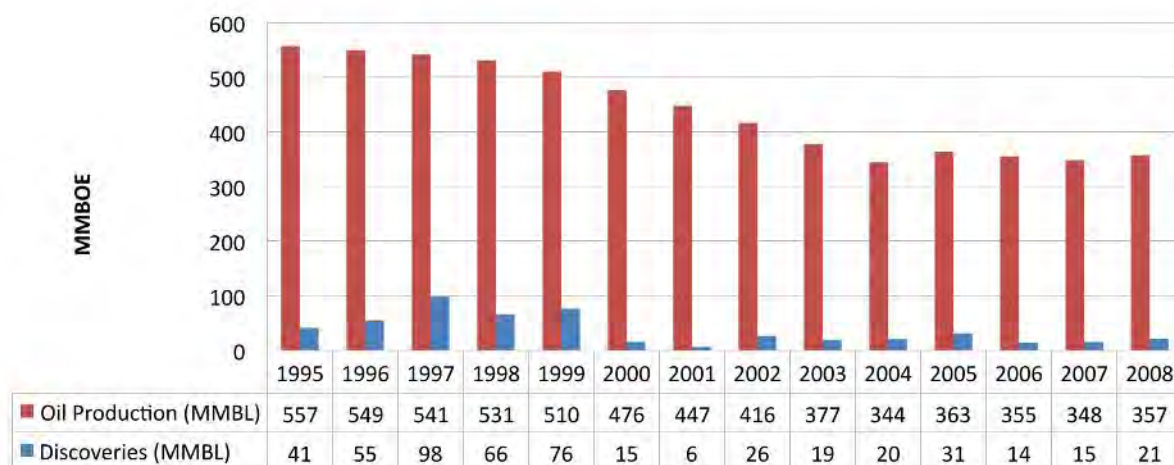
FIGURE 2.4: OIL AND GAS CONTRIBUTION TO THE GOI'S INCOME



Source: CMS Consulting Group; adapted from Ministry of Energy and Mineral Resources, 2009b

However, a deeper analysis reveals that while the overall investment in oil and gas production has increased markedly in recent years, the amount of oil produced each year and the annual discovery of new reserves of oil has been declining steadily, as illustrated in Figure 2.5.

FIGURE 2.5: INDONESIA'S OIL PRODUCTION AND DISCOVERY

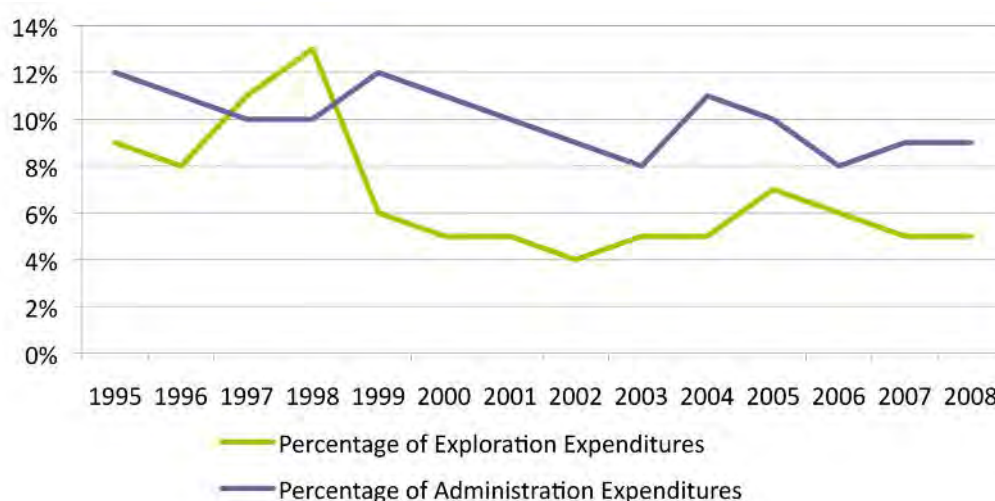


Note: MMBL refers to million barrels; MMBOE refers to million barrels of oil equivalent.

Source : CMS Consulting Group; adapted from BP Migas, 2010

This decline in the discovery of new oil and reserves has been mirrored by a similar decline in investment in exploration activities. As illustrated in Figure 2.6, investment in exploration used to equate to about 10 per cent of total annual work program expenditure in a typical PSC, which happened to be the same percentage of the total annual work program expenditure that the general administration overheads accounted for. However, in recent years the amount of expenditure on general administration now substantially exceeds the expenditure on exploration, such that the latter now accounts for just 5 per cent of total annual program expenditure. This decline in exploration expenditure is having a long-term impact on the addition of new reserves. As illustrated in Figure 2.6, there was a downward step change in exploration expenditure in 1999 and 2000.

FIGURE 2.6: EXPLORATION AND ADMINISTRATION VERSUS TOTAL EXPENDITURES



Source : CMS Consulting Group; adapted from BP Migas, 2010

There may be several reasons behind this decline in exploration activity. One reason is that expenditure on production activities is less risky than expenditure on exploration. As will be explained in greater detail in the next chapter, under the rules of the PSC, expenditure on exploration is only eligible for recovery if the work area/field concerned enters into commercial production. If it does not, the PSCo conducting this exploration activity has to bear the cost themselves.

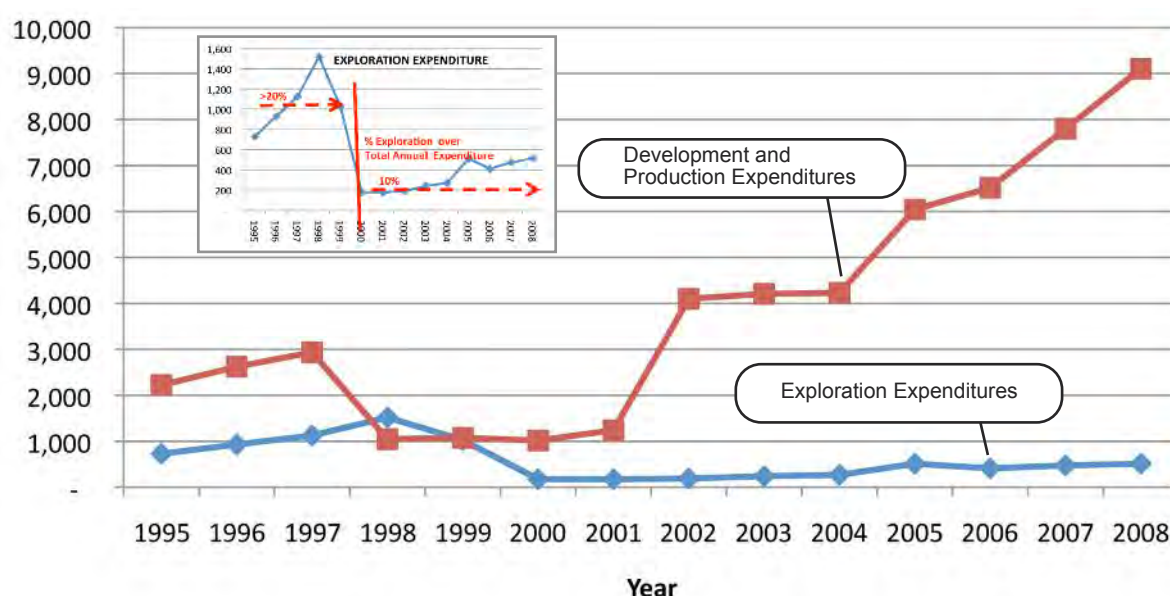
The action taken by the GOI has also been a contributing factor. As mentioned, in recent years there has been a steady decline in oil production. In an attempt to maintain its share of revenue from oil (and gas) production, the GOI has increased its level of management of oil and gas operations to a level referred by some as “micro-management” in the belief that this move would help maximize the GOI’s take from oil and gas operations. As a result, many companies appear to have adopted a “wait and see” attitude, holding back on some major expenditures, particularly on exploration, to see if a more attractive investment climate will emerge in the future.

It should be noted that new reserves are the results of exploration investment in both existing producing work acreages, and also in new work acreage secured from bidding rounds. In our case study, most of the figures

cited were taken from annual work program and budget in the producing acreage, as there have been few discoveries in new acreage areas.

Figure 2.7 confirms that development and production expenditures are concentrated mainly in acreages where there is already some oil and/or gas production. Total expenditures in these acreages increased significantly following the increase in world oil prices. In 1998 exploration expenditures dropped to the level of about 5 per cent out of the total annual expenditure.

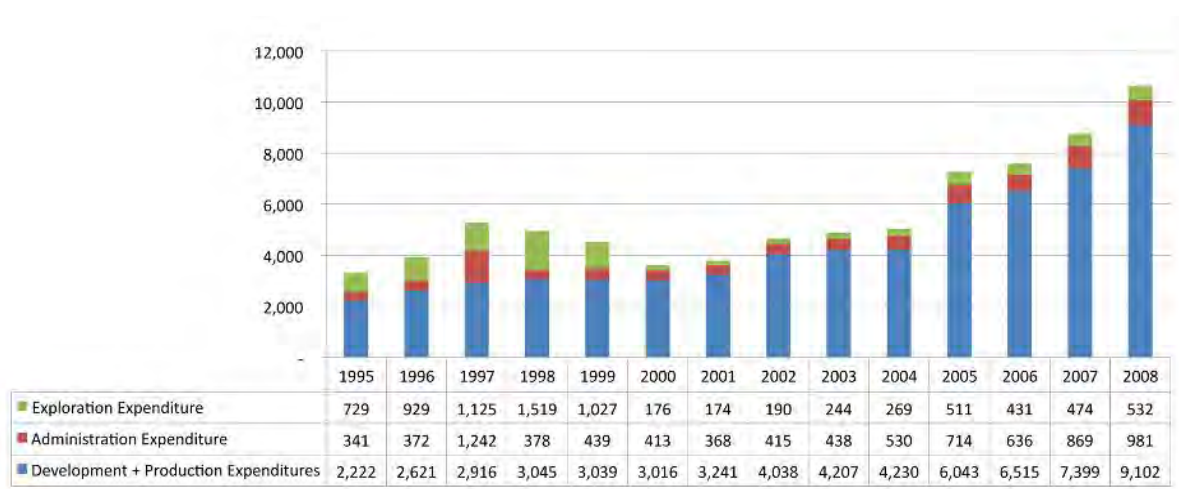
FIGURE 2.7: ANNUAL EXPLORATION AND TOTAL EXPENDITURE



Source: CMS Consulting Group; adapted from BP Migas, 2010.

Figure 2.8 illustrates how exploration expenditure is concentrated in acreage where there is existing oil or gas production. Exploration expenditure, in areas where there is no existing production, has increased from US\$176 million in 2000 to US\$512 million in 2008. However this expenditure is relatively small compared with the the development and production expenditures of US\$1,016 million and US\$9,102 million in these years respectively.

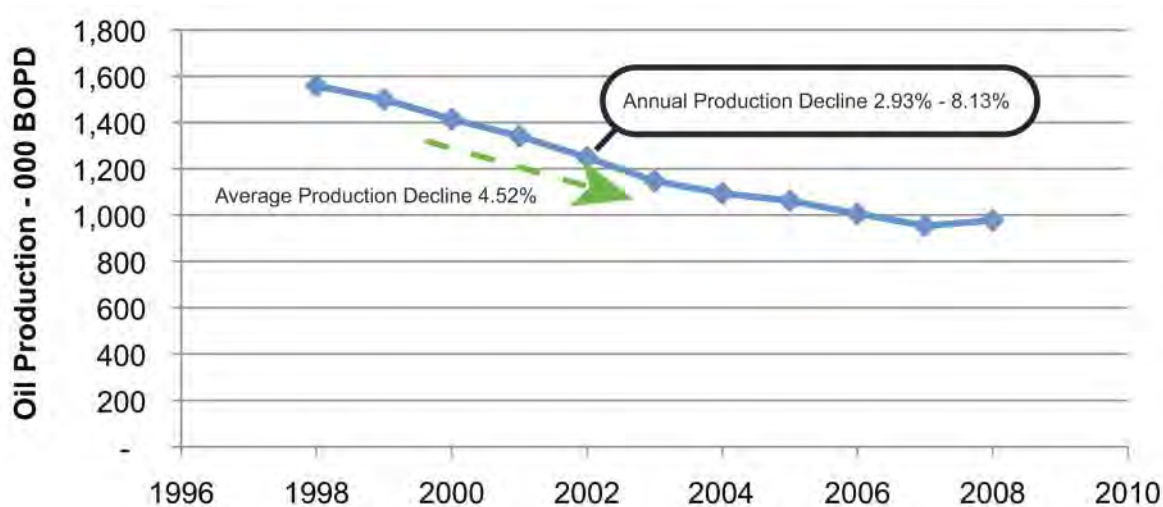
FIGURE 2.8: EXPENDITURE BREAKDOWN



Source: CMS Consulting Group; adapted from BP Migas, 2010

Figure 2.9 provides a further illustration of the decline in oil production

FIGURE 2.9: ANNUAL OIL PRODUCTION

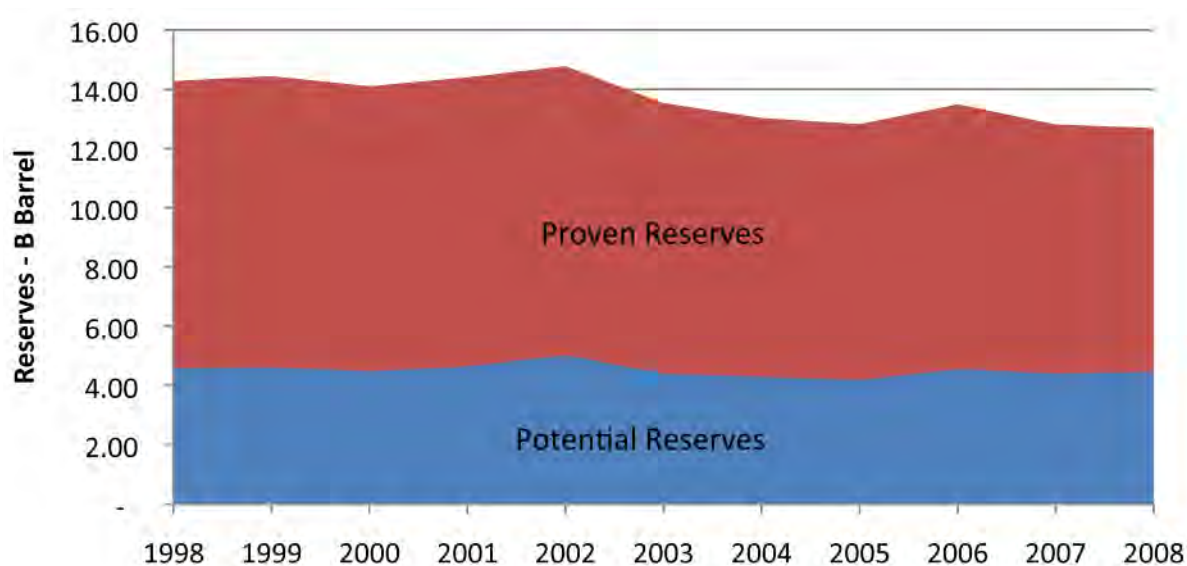


Source: CMS Consulting Group; adapted from BP Migas, 2009b

Annual oil production as seen in Figure 2.9 has been declining since 1996 at an average rate of about 4.5 per cent. According to reservoir and petroleum engineering experience, a decline of this magnitude is relatively small compared to the natural rate of decline of many oil reservoirs. It could be argued that the steps the GOI have taken to maintain oil production by offering certain fiscal incentives to PSCos have at least slowed the rate of decline.

However, this low level of exploration expenditure referred to above has had a long-term impact on the addition of new reserves, as illustrated in Figure 2.10

FIGURE 2.10: PROVEN AND POTENTIAL OIL RESERVES

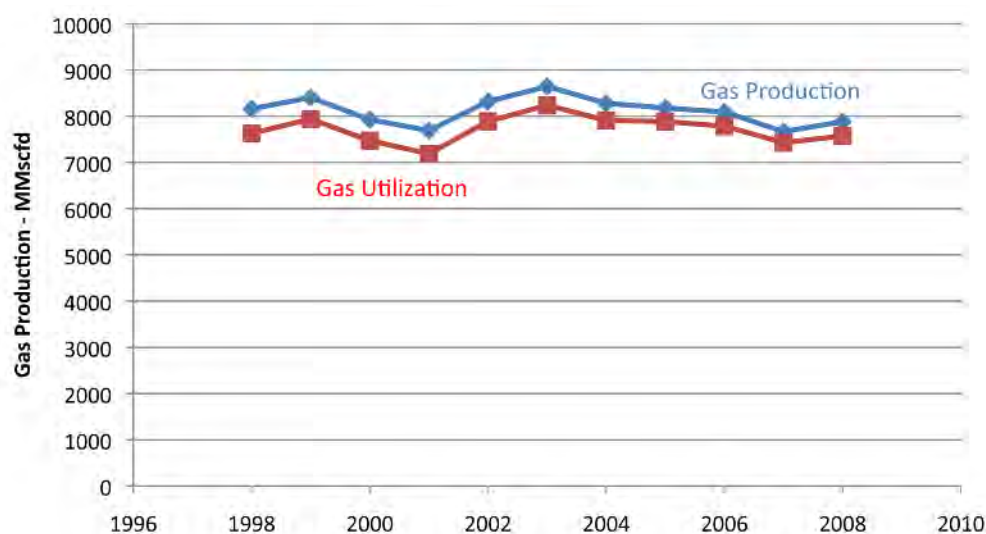


Source: CMS Consulting Group; adapted from BP Migas, 2009b

Figure 2.10 shows how total oil reserves, a combination of proven and potential reserves, have declined. Potential reserves consist of reserves that could be converted into proven reserves with the application, for instance, of more efficient production technologies, such as Enhanced Oil Recovery technology (EOR).

In contrast to the decline in oil production, gas production has remained relatively stable, as illustrated in Figure 2.11.

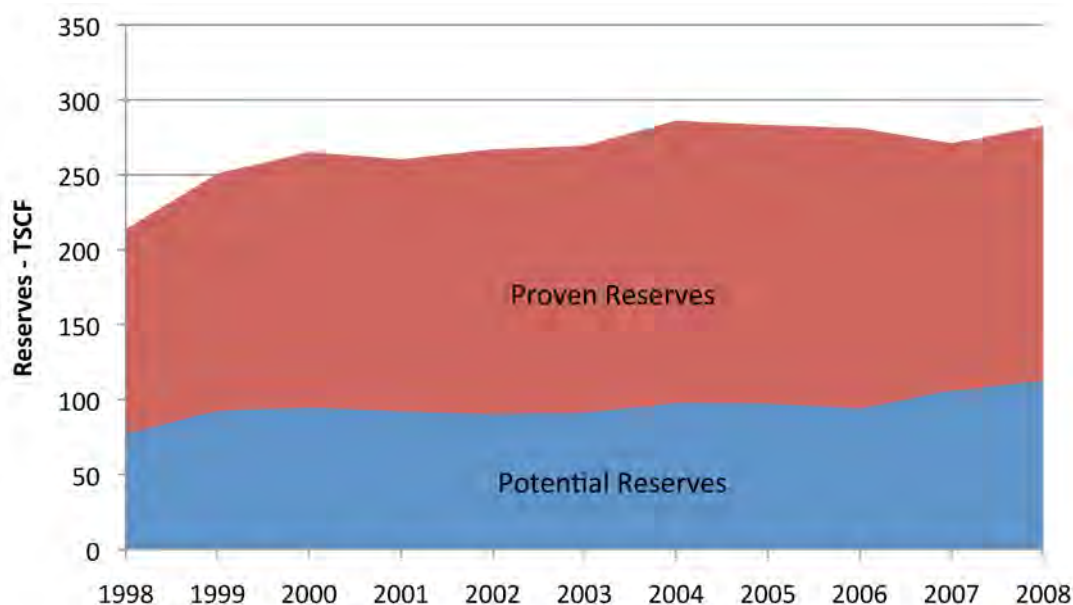
FIGURE 2.11: ANNUAL GAS PRODUCTION AND UTILIZATION



Source: CMS Consulting Group; adapted from BP Migas, 2009b

Also, as seen in Figure 2.12, both proven and potential gas reserves continue to grow. This shows that large gas reserves remain in place, waiting to be commercialized when there is a sufficient opportunity and incentive to do so.

FIGURE 2.12: PROVEN AND POTENTIAL GAS RESERVES



Source: CMS Consulting Group; adapted from BP Migas, 2009b

3. IDENTIFICATION OF PRODUCER SUBSIDIES IN UPSTREAM OIL AND GAS INDUSTRY

This chapter focuses on activities where it is believed producer subsidies could exist. Background information is provided on each of these activities, and an assessment is made as to whether a subsidy does exist or not. In those cases where it is concluded that a subsidy does indeed exist, an attempt is made to estimate the size of this subsidy. In addition, the subsidy is evaluated by asking the questions: “Is the subsidy meeting the GOI’s objectives?” and “What economic impacts does this subsidy have on the oil industry?” It should be noted that in several instances it is proposed that further research be conducted to fully answer some of these questions (including the estimation of the size of the subsidy).

3.1 DIRECT AND INDIRECT TRANSFER OF FUNDS OR LIABILITIES

3.1.1 GOVERNMENT OWNERSHIP OF ENERGY-RELATED ENTERPRISES

3.1.1.1 PERTAMINA WORK AGREEMENT COMPARED WITH STANDARD PSC

Background

As mentioned in Chapter 2, the new oil and gas law passed in 2001, changed the status of Pertamina and required this national oil company to be treated like any other oil and gas company involved in exploring for and producing oil and gas. One big change for Pertamina was that it should have in place a contract (or “Work Agreement”) with BP Migas for each of its Work Areas, which should be similar to the PSCs that other oil and gas companies operate under.

As part of this study, a comparison has been made between a standard Pertamina Work Agreement (WA) and a standard PSC to assess whether the terms of the Pertamina WA provides Pertamina with any preferential treatment that might constitute a subsidy. This comparison reveals that the terms and conditions of Pertamina’s WA are mostly the same as those in a PSC, but there are a few notable differences, which are as follows:

- The duration of the Pertamina WA is 30 years, even if exploration has already been conducted. The duration of a PSC is 6 years for the exploration phase (with the possibility of two extensions of two years each), and then 20 years for the production phase.
- In the Pertamina WA there is a special provision addressing cooperation with other parties (in the form of setting aside work acreage for business cooperation), which does not feature in the PSC. In the case of the WA, Pertamina may establish cooperation with other parties for all of, or a certain portion of, its work acreage, whereas if a PSC decides to cooperate with another party it can only do so for the entire acreage and cannot restrict this to a certain portion.

In the case of the WA, the forms of cooperation that Pertamina is allowed to establish with third parties can be in terms of equity ownership or technical assistance for portions of the work acreage. Pertamina must first decide whether an area is to be treated as a “focus area” that it can develop on its own or it is to be treated as a “non-focus area” that Pertamina can either jointly develop with another party or can outsource to a third party. Pertamina operates under the following general rules when undertaking cooperation through a Joint Operating Agreement:

- (a) Pertamina must obtain the GOI's approval through BP Migas regarding its intention to work with a third party or to outsource a particular area of interest.
- (b) Pertamina shall propose the boundary and geodetic coordinates of the work acreage to be set aside, along with the candidate partner's credentials and the business terms of this cooperation.
- (c) Pertamina's technical experts shall be invited to become a member of the work acreage bidding team to participate in the evaluation of candidate partners and also to participate in selecting the partner of choice.
- (d) The partner in such cooperation shall own a portion of rights and interests in the set aside work acreage, including the rate of equity split and DMO as specified in the agreement.
- (e) The MEMR retains the final right to decide on the party that will be selected, and the portion of the rights and interests to be given to this party, including the terms of cooperation for this particular acreage.

Pertamina may also cooperate with another party by way of Technical Assistance Contract, in which the other party holds no rights or interest in the contract acreage. The other party only has a contractual obligation with Pertamina and not with BP Migas. Such cooperation follows the following rules:

- (a) This Technical Assistance Contract requires BP Migas approval.
- (b) The other party is compensated in-kind by some oil and/or gas portion of Pertamina's equity. The amount of compensation must be less than the standard PSC equity oil share that the other party may have obtained from BP Migas in a PSC in neighbouring acreage. (The aim here is to ensure that this cooperation with Pertamina is not used to give a PSCo the ability to secure better terms from cooperating with Pertamina than it can obtain by participating in a PSC).
- (c) Compensation by the other party may be taken from Pertamina's lifting after the point of delivery.

Assessment of subsidy

The main advantage that Pertamina has is the greater scope and flexibility for cooperating with a third party, than that granted to a PSCo under a PSC. The question is, how material is this advantage? The conclusion reached is that this advantage is likely to be marginal. Pertamina can offer to a third party a more limited area than a PSC can, which will limit the risks a third party may be exposed to (such as the financial risks of having to fund its share of exploration programs that might be undertaken in other fields in the selected area). However, this will also limit the potential upside a third party could benefit from by participating in a larger area, where the exploration programs, beyond those originally identified, might prove successful and result in new discoveries. Thus, giving third parties access to a more limited acreage (as may be the case with the Pertamina model) can be advantageous in terms of limiting financial risks; however, giving third parties access to more extensive acreage (as is likely to be the case with the PSC model) can be advantageous in terms of providing a third party with a higher chance of benefitting from the discovery of new reserves. Both models have attractions and drawbacks.

This aside, it should also be borne in mind that all PSCos have the right to "farm-out" (i.e., offer out) a share in the PSC acreage to third parties to help share risks, resources, etc.

Fiscal Estimate

For reasons mentioned above, the advantage Pertamina may have is at best likely to be marginal, and it is very difficult to put a value on, and quantify, this benefit. Identifying a baseline against which to measure this benefit is particularly challenging.

Evaluation: Is the subsidy meeting the GOI's objectives?

It is believed that the GOI's objective in extending some preferential treatment to Pertamina is to help them achieve their plan to significantly increase their level of oil and gas production. During the years that Pertamina managed the IOCs (i.e., until a new oil and gas law was passed in 2001), in addition to exploring for and producing oil and gas, much of Pertamina's focus was on executing its role in managing all the PSCos. As a result, at the start of this decade, Pertamina only accounted for about 10 per cent of national oil and gas production (Directorate General of Oil and Gas, 2005). The GOI now wish to substantially increase Pertamina's contribution to national production.

To support this, Pertamina's Medium-Term Plan for 2009–2011 seeks to increase oil production from the current level 127 thousand barrels of oil per day (MBOPD) to 179 MBOPD in 2011 (Pertamina, 2009a; Pertamina 2009b). Their strategy to achieve this includes:

- Implementing a new exploration concept to discover new reserves
- Reactivation of suspended production wells
- Enhanced Oil Recovery programs
- Production Optimization programs

Pertamina will require a substantial amount of capital to fulfill this plan, which may not be readily available. To help address this capital need, Pertamina is opening up portions of their 140,000 square kilometre work acreage and inviting outside investment partners to share the risks (Penawaran 2009; Petrominer, 2007).

An increase in production of approximately 50 MBOPD in two years would require at least US\$500–\$600 million. Pertamina is in need of about US\$200–\$300 million of external funding to be able to meet their production target (BP Migas, 2010).

- Evaluation: What impacts does this have on the oil industry?
- The impact of Pertamina's greater flexibility in "farming out" some its acreage might reduce the number of opportunities that PSCos have for farming out their own PSCs, but some of the PSCos (with adequate financial and technical resources) may also benefit from this in giving them greater opportunity to enter into cooperation agreements with Pertamina, in Pertamina's own acreage.

3.1.2 DIRECT SPENDING

3.1.2.1 RECOVERY OF OPERATING COSTS

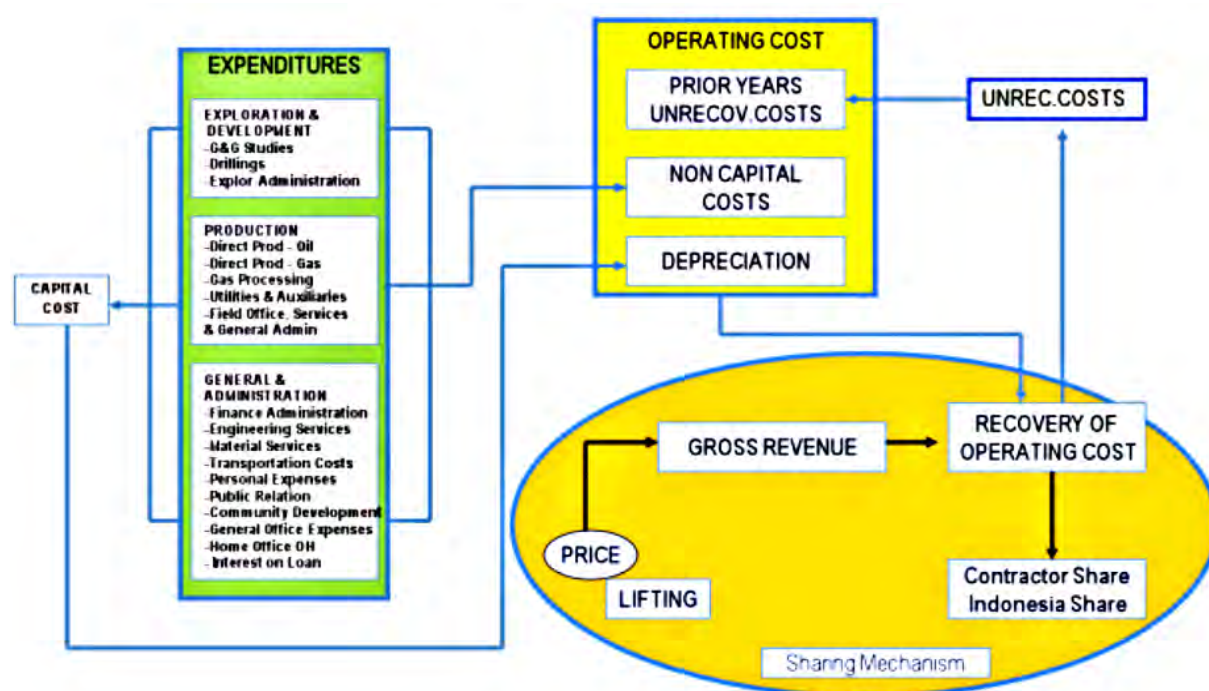
Background

General rules

Under the PSC system, the PSCo is entitled to recover all allowable operating costs related to exploration, development and production costs. However, this recovery of operating costs is only permitted when a project commences production. Exploration costs incurred at other sites within the same PSC, other than where production is taking place, are recoverable. However, if there is no production from any site within the PSC, there is no opportunity to recover any of the exploration costs. All equipment brought into Indonesia for oil and gas exploration and production belongs to the government, and most of it is eligible for cost recovery.

It should be noted that the PSC adopts a system, whereby each Work Area is assigned to one PSC, and each PSC is a separate corporate entity. Under the PSC system, a “ring fencing” system is applied in which the recovery of costs incurred in a PSC Work Area can only be offset against the revenue earned in that same PSC.

FIGURE 3.1: CHAIN OF COST STRUCTURE AND REVENUE SPLIT - PSC



Source: CMS Consulting Group

As shown in Figure 3.1 on the previous page, the operating costs that can be recovered under the PSC system consist of:

- (a) Non-Capital costs: costs associated with exploration, development and production, and also costs associated with general and administration activities (limited to those itemized above);
- (b) Depreciation of capital costs; and
- (c) Prior year's unrecovered costs.

It should also be noted that the amount of general and administration costs that can be recovered is limited to 10 per cent of the total expenditure in a PSC, and the amount of general and administration costs related to a PSCo's head office that can be recovered is limited to a maximum of 2 per cent of the total expenditure in a PSC.

If the costs eligible to be recovered in a particular year exceed the revenue from production in that year, then unrecovered costs may be recovered in the following year.

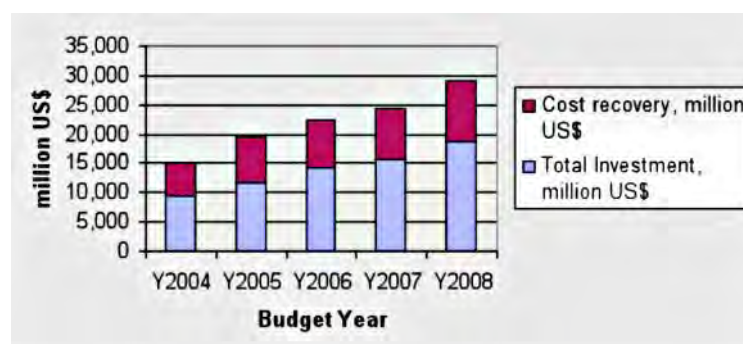
If the costs are lower than the revenue from production, the excess revenue is called equity to be split, and will be apportioned between the GOI and the PSCo according to the prescribed PSC terms and conditions (but see also reference to First Tranche Petroleum in 3.3.1.1).

The recovery of operating costs is governed by the Generally Accepted Accounting Principles (GAAP) adopted by the PSC, and is also based on the application of sound petroleum operations and engineering practices. The cost recovery amount is based on actual expenditure, and is subject to technical judgements from time to time, based on standard industry engineering practices and available technology.

It should be noted that the cost of operations and their recovery under the PSC rules are subject to several layers of auditing. State audit institutions representing the GOI will conduct this cost audit (such as BPK, BPKP and BP Migas: see Glossary of terms). Similarly, company auditors and shareholders' auditors will conduct audits for their respective stakeholders, as will the Internal Revenue Service for U.S.-based oil companies. All auditors use the same rules as set forth under the oil and gas GAAP. The parties signing the PSC will be well aware that the application of GAAP is mandated in the PSC, as is referred to in the appendices of the PSC. All PSCos are expected to operate within the GAAP guidelines and to observe good business practices and ethics.

In 2008, despite the audit controls mentioned above, and in part because of the steady increase in recent years in total recoverable costs for oil and gas exploration and production (see Figure 3.2 below) while national oil production levels were actually falling, the GOI initiated closer monitoring of the cost recovery system with the aim of eliminating the recovery of costs that are not essential to exploration and production operations. As a result, the GOI was pressed to issue a regulation to control cost recovery more rigorously. A draft Ministerial Decree was circulated for discussion in 2008, which defined those costs that could be recoverable and those that would no longer be recoverable. However, this Decree was not enacted. Following this, in 2009, BP Migas did place a cap on the total amount of costs that could be recoverable, initially just for one year. However BP Migas recently announced at the Indonesian Petroleum Association Annual Convention in 2010 that this cost recovery cap may not be continued due to concerns that this appeared to be deterring oil and gas companies from bidding for new acreage (as evidenced by the poor level of interest shown in the new acreage bidding rounds during 2009).

FIGURE 3.2: OIL AND GAS COST RECOVERY STATISTICS



Source: CMS Consulting Group; adapted from BP Migas, 2009b

However there is some continued public perception that the cost recovery process is not sufficiently controlled and that some costs that are recovered, should not be, and that private oil companies may be taking advantage of the Indonesian petroleum industry.

There are several ways to address this issue, one of which is to refer to the International Capital Market (ICM) accounting ethics. Under the ICM code of accounting, the mark up of operating costs and the mark up of reserve sizes are both illegal. Cost mark up means the inclusion of costs that are not directly related to operating costs as defined under the accounting and operating norms in petroleum operations. Companies pay a severe penalty for breaching these rules.

Measurement of the efficiency of petroleum operations is based on a combination of factors, including proven reserves, production recovery factor and cumulative production. Assessment of upstream petroleum industry cost efficiency has to be measured based on cumulative production up to a certain point in time, and take into account the production profile characteristics such as optimum production level and subsequent production natural decline and depletion phase. The new field's Plan of Development should be able to help in the assessment of the field's production profile and the corresponding cost of production and efficiency in reserve recovery. A simple efficiency calculation carried out by relating production capacity to a time-based cost unit cannot be used to accurately measure upstream petroleum operations.

As a final point, it should be noted that the PSC definition of operating costs is narrower than operating costs, as defined under the GAAP. As an example, "acquisition costs" (which in the case of a PSC would include costs such as signature bonuses) are not treated as an operating cost under the PSC, but are treated as an operating cost by GAAP.

Assessment of subsidy

While there are many checks and controls in place to prevent abuse of the process by which PSC's operating costs can be recovered, it must be recognized there may still be scope for some parties to take advantage of the system. However, within the scope of this study, it has not been possible to estimate to what extent this occurs in practice.

The question may also be asked: Does the entire process by which PSCOs are able to recover their operating costs represent a subsidy, given that this is certainly not the norm in other non-regulated industries? In addressing this, it must be recognized that this system exists because the GOI only permits companies who wish to explore for and produce oil and gas, to do so as a "contractor." As such, all the capital equipment these contractors (PSCOs) procure to undertake these activities immediately become the property of the GOI as soon it is delivered to the PSC work area. This is certainly not the norm in other industries. The recovery of operating costs enables PSCs to be repaid over time for capital equipment they have initially paid for and that the GOI has taken ownership of.

3.1.2.2 RESEARCH AND DEVELOPMENT SUPPORT TO INDUSTRY

Background

The GOI has established research and development (R&D) agencies under various ministerial departments. For example an R&D agency focusing on forestry is under the Ministry of Forestry, and similarly an R&D agency dedicated to oil and gas is under the Ministry of Energy and Mineral resources.

Under former President Suharto's administration, a special research agency dealing with advanced applied technology was established to develop new technologies. As most IOCs have, for many years, owned their own R&D facilities, which are generally located in their home country and provide scientific and technological support to their companies operating abroad, this special research agency in Indonesia, when established, would have been mainly for the benefit of Pertamina.

In the case of oil and gas and energy related R&D, the main R&D institute which deals with oil and gas in particular is the Institute of Oil and Gas Research and Development Center (LEMIGAS), which covers research into geosciences, engineering, production, etc. LEMIGAS receives funding through the state budget. However, in recent years, LEMIGAS has been instructed to charge for its services, and now all companies that use the services provided by LEMIGAS, pay for them. In addition, other research activities may also be conducted in cooperation with foreign research institutions, either at a government-to-government level or at a private level, under the umbrella of a joint study or research grant. Examples of foreign institutions involved in such arrangements are: the French Petroleum Institute, British Geological Survey, Australian Bureau of Mineral Resources, and several others.

Generally, the results of R&D activities, reports, maps, etc. are available to the general public at a cost. However, research reports that are produced as a result of a joint study, for example a government-level joint study with British Geological Survey, may not be available to the public, but only to the institutions that sponsored the research up to a certain point in time.

In addition, oil companies may work in cooperation with R&D institutes in Indonesia, directly or in cooperation with their own R&D organizations. This is done through a service agreement with the local R&D institute and the service agreement will define the terms and conditions for this cooperation.

Assessment of subsidy

While in the past R&D services were provided free of charge and were funded by the GOI, in recent years the GOI has required the R&D institutions to charge for their services, which has certainly been the case with LEMIGAS, by far the largest government institute in oil and gas R&D.

It could be concluded that, in the past, the provision of R&D services, at no charge, has constituted a subsidy, whereas today the size of this subsidy would be limited to any difference there may be between the payments these research institutions receive for providing these services and the full cost of providing these services. This data is not readily available and further research would be needed to evaluate this.

3.1.2.3 RESTORATION AND REHABILITATION OF DEPLETED OIL AND GAS FIELDS

Background

Indonesia's oil and gas production began in 1883 when the Dutch Administration was still in power. The standard procedures for the protection of the environment, including health and safety, in petroleum operations were then set under the Mining Policy Regulations #341 (MPR 341). These detail the health and safety and environmental procedures to be followed in activities related to oil exploration through to production, and also to the post-production phase, including abandonment of wells. Under this regulation, these costs incurred both during and after the production phase were to be born entirely by the concession's holder.

Up to the year 1970, Indonesia's oil and gas operations were confined to onshore locations. However, in the early 1970s, oil and gas operations started to extend into offshore areas as well, about the same time that PSCs were introduced to the industry. The MPR 341 regulations were still in effect and Migas acted as the MPR 341 implementing institution on behalf of the GOI. The PSC defines health, safety and environmental protection as part of, and inseparable from, oil and gas operations, covering the entire value chain from exploration through to post production.

By the late 1990s there were close to 300 production platforms spread out in offshore producing areas in South East Sumatra, West Java Sea, East Java Sea and off East Kalimantan and the Makassar Strait, a number of which were located in international sea-lanes. In order to meet its commitments under the United Nations Convention on the Law of the Sea, the GOI amended the PSC in 1996 to require PSCOs to set aside costs for future offshore platform abandonment, and put these in an escrow insurance account (Pertamina, 1996).

More specifically, the PSC states that the PSCo shall, after the PSC expiration, termination or relinquishment of part of the Contract Area, or abandonment of any field, remove all equipment and installations from the area in a manner acceptable to the GOI and perform all necessary site restoration activities, in accordance with the applicable government regulations to prevent hazards to human life and the property of others and the environment.

The PSCo must submit, as part of their Plan of Development for each commercial discovery, an abandonment and site restoration program together with a funding procedure for such a program. The amount of funds estimated to be required for this program are determined each year in conjunction with the Budget of Operating Cost for the Plan of Development and all such costs are to all be treated as an operating cost in accordance with the PSC accounting procedures. Hence these costs are recoverable.

Assessment of subsidy

As mentioned, operating costs will include all expenditures incurred in the abandonment of all exploratory wells and the restoration of their drill-sites, together with all estimates of funds required for any abandonment and site restoration program established in conjunction with an approved plan of development for a commercial discovery.

Expenditures incurred in the abandonment of exploratory wells and the restoration of their drill-sites shall be treated as operating costs in accordance with Article II of the PSC. However, some questions have been raised about whether these costs should be eligible for cost recovery, given these are provisions for future expenditure.

Estimates of monies required to fund any abandonment and site restoration program established shall be charged as an operating cost on the basis of accounting accruals beginning in the year of first production. The amount charged each year will be calculated by dividing the total estimated cost of abandonment and site restoration for each discovery by the total estimated number of years of economic life of each discovery; such estimates shall be reviewed on an annual basis and it shall be adjusted each year as required.

Since all costs associated with abandonment and site restoration are clearly part of the PSC operating costs, and are to be borne by the PSCos, it is concluded there is no subsidy involved.

3.1.3 CREDIT SUPPORT

3.1.3.1 INVESTMENT CREDIT ALLOWANCE

Background

In the PSC system, an investment credit allowance is applied to production before recovery of operating cost, but after the application of First Tranche Petroleum (FTP) and before equity split.

The development of this investment credit allowance in Indonesia's PSC, starting with the Incentive Package II in February 1989, is shown in Figure 3.3.

FIGURE 3.3: INVESTMENT ALLOWANCE AS INCENTIVE UNDER PRODUCTION SHARING CONTRACT - SUMMARY

Area Classification	Investment allowance for oil		Investment allowance for gas	
	Pre 1992	Post 1992	Pre 1992	Post 1992
Geologically Conventional	17%	17%	0%	0%
Frontier Area	17%	127%	0%	110%
Deeper water	0%	142%	55%	125%

Note: Investment allowance is categorized as income to PSC
Subject to tax at prevailing rate.

Source: CMS Consulting Group; adapted Directorate General of Oil and Gas, 2009

The investment credit is an allowance, which is calculated based on capital expenditures directly related to production facilities only, that is to say, it does not apply to all operating costs as defined for the PSC.

The investment credit is designed to provide an incentive to a PSCo to discover and develop new fields. Any costs that cannot be recovered in one year can be carried forward to the following year.

Assessment of subsidy

This investment credit allowance may be considered as a subsidy to oil and gas producers in that it gives them additional income beyond that to which they are entitled to through their equity share. The investment credit allowance is also part of the various incentive packages under the PSC system introduced by the GOI to boost development of oil and gas fields in Indonesia.

In order to quantify this subsidy, it is necessary to access data on the facilities that are eligible for an investment credit allowance. Because this investment allowance relates only to certain “new” fields in “new geological plays,” in total it represents a relatively small amount of money, for instance, if it were compared with the total amount of operating costs that are recovered. The definition of a “new” field is based on the American Association of Petroleum Geologists’ definition. Some relevant data for years 2007 and 2008 follows.

Capital expenditure directly required in the construction of production facilities amounts to US\$2.087 billion in 2007 and US\$2.774 billion in 2008. In trying to promote the discovery and the development of these “new” fields, the GOI issued the investment credit allowance as an incentive. In 2007, the amount of investment credit allowance that applies to “new” fields only was US\$355 million (gross); after tax, the net amount was US\$87 million. Similarly, the gross investment credit allowance for 2008 was US\$472 million, and net after tax was US\$115 million (BP Migas, 2008a; BP Migas 2009a).

Evaluation: Is the subsidy effectively meeting the GOI's objectives?

The GOI objective is to increase the development of new oil and gas fields in Indonesia. The data shown in Figure 2.9 indicates that the average annual decline in production is substantially less than the normal rate of decline in a production field, which suggests that the discovery of new fields is helping to slow the rate of decline. Some further research would need to be carried out to identify how much of these new discoveries have come from “new” oilfields, or “new geological plays” as defined and referred to above.

Evaluation: What impacts does this have on the oil industry?

The investment credit allowance appears to be encouraging PSCos to invest in exploration in “new” oil and gas fields, but as mentioned above, some further research could help to quantify this impact more precisely.

3.1.3.2 BANK FINANCING SUPPORT

Background

The PSCo is required to have the financial ability to conduct petroleum operations in accordance with the PSC. Bank financing support is not required by the PSC and, in principle, the PSCo is not allowed to claim the interest expenses (financing costs) for cost recovery purposes. An exception is the case in which reimbursement of interest expenses for capital expenditure can be recovered if it can be clearly shown that the internal rate of return (IRR) is less than the standard petroleum investment IRR. This is governed by the incentive package in the PSC. The IRR is identified in the Plan of Development.

Assessment of subsidy

The case in which partial reimbursement of interest expenses are recoverable, as mentioned above, is provided as an incentive for the company to increase the economic feasibility of the field. Most PSCos, however, finance the field development costs using their own internal financial resources. Comparing these two cases, it is clear that the income received by the GOI through the PSC is less when a PSCo is able to recover these costs. It can be concluded that this constitutes a subsidy. The value of the subsidy is the difference between the free cost of capital that some PSCos receive, where the IRR is shown to be below the IRR for standard petroleum investment, and the internally set rate of return which PSCos may achieve when projects are financed internally. Some further research would be needed to calculate this difference.

It should also be mentioned that, based on initial research, there is no evidence to suggest that there are banks in Indonesia that are extending special privileges to oil and gas producers in their financing terms conditions, due to some form of GOI support and directive.

3.2 GOVERNMENT REVENUE FOREGONE

3.2.1 TAX BREAKS AND SPECIAL TAXES

3.2.1.1 TAX INCENTIVES FOR IMPORTED GOODS AND SERVICES

Background

Exemption from Import Duty and Value Added Tax (VAT) on Imported Goods for Oil and Gas Exploration and Exploitation Activities

Decree of Minister of Finance number 177/2007 grants an exemption from import duty on goods imported for upstream oil and gas activities. This facility applies retroactively to July 16, 2007. In addition, companies that paid a guarantee to release their goods from customs are not required to pay the import duty if the goods were imported between July 16, 2007 and December 31, 2007.

In addition, with regard to VAT, Decree of Minister of Finance number 178/2007 states that VAT will be borne by the GOI on imported goods that are used in certain upstream oil and gas exploration activities. In order to take advantage of this facility, these goods must be listed in the Import Declaration list (PIB) with a registration number obtained from customs dated on or after January 1, 2008. The Ministry of Finance Decree No. 177, issued in 2007 states that the GOI will reimburse the contractor for the VAT paid on exploration activities once production commences; however, if the contractor does not move to production, the VAT cannot be recovered. This latter exception highlights the financial risks associated with exploration activities.

These two facilities regarding both VAT and import duty may be applied for, provided the following apply:

- The goods to be imported are not produced in Indonesia;
- The goods are produced in Indonesia but do not meet the required specifications; or
- The goods are produced in Indonesia but are in short supply.

The application must include an import plan of goods for 12 months, approved and validated by the appropriate department in MEMR (namely Migas).

Assessment of subsidy

This exemption from import Duty and VAT can be regarded as a subsidy.

Fiscal estimate

Quantifying this subsidy is not straightforward. The rate of VAT imposed on the importation of goods in other sectors is currently 10 per cent of the total value of the goods imported, while the rate of the import duty varies depending on the classification of the goods and sectors. By imposing a 0 per cent rate for both import duty and value added tax for imported goods used in oil and gas exploration and production, the GOI can be viewed as giving a subsidy of at least 10 per cent of the total value of goods imported for use in the upstream oil and gas industry.

Deferment of VAT during the exploration stage, based on Minister of Finance Decree number 177 of 2007, amounted to US\$37.6 million in 2007. This amount is about 10 per cent of total purchases of goods and services for exploration. The figure for the VAT exemption in 2008 was US\$49.9 million. Total VAT and levies amount to US\$469 million in 2007 and US\$624 million in 2008, out of which the amount of VAT and levies exemption was US\$ 98 million in 2007 and US\$130 million in 2008, based on PSC equity split of 15 per cent to PSCo and the remaining 85 per cent is retained by the government (BP Migas, 2008b; Migas, 2009b). VAT and levies exemption in oil and gas production activities is calculated as follows:

FIGURE 3.4: VAT AND LEVIES EXEMPTION IN OIL AND GAS PRODUCTION ACTIVITIES

Calculation of VAT and levies in oil & gas production activities (US\$ million)		
	2007	2008
Total materials of goods & services purchased	3,427	4,555
VAT	375	499
Levies	94	125
Total VAT+levies	469	624
PSC VAT and Levies exemption @15%	98	130
Net GOI Take from VAT & Levies @85%	371	494

Source: CMS Consulting Group

Evaluation: Is the subsidy effectively meeting the GOI's objectives?

It is understood that the GOI is granting this exemption from VAT and import duty to oil and gas producers, at least in part, in order to help reverse the decline in national oil production that has been apparent in recent years. It may also be aimed at further increasing the production of gas, to support the drive for more gas to be made available in the domestic market. However, many other factors are also having an impact on levels of oil and gas production, so it is hard to evaluate the success of the GOI policy in this context.

Evaluation: What impacts does this have on the oil industry?

These tax exemptions improve the economics for the oil and gas producers.

3.3 PROVISION OF GOODS OR SERVICES BELOW MARKET VALUE

3.3.1 GOVERNMENT-OWNED ENERGY MINERALS

3.3.1.1 APPLICATION OF ROYALTIES

Background

The GOI owns all the mineral resources in Indonesia and allows others to exploit them in return for specific compensation. The GOI's income is derived from having a (majority) share of oil and gas production and from tax on the PSCo's share of oil and gas production. As mentioned previously, the GOI's and PSCo's respective equity splits are calculated after the deduction of operating costs.

During the early period of the PSC system, there was no cap on the amount of operating costs that could be deducted from the revenue earned from the sales of oil and gas production (“gross sales”). Consequently, if there remained an amount of costs that could not be recovered from these gross sales, there was no income from gross sales to be shared between the GOI and the PSCo, so the GOI would not generate any revenue.

First Tranche Petroleum (FTP) was introduced in February 1989 to ensure the GOI derives some revenue from a newly developed field and before any deduction from recovery of operating costs. FTP effectively puts a cap on the amount of costs a PSCo can recover from gross production (see further explanation of recovery of operating costs in Section 3.1.2.1). FTP was originally set at 20 per cent of the gross production from the PSC during each year and was divided between PSCos and the GOI according to the equity oil split that is specified in the PSC. Since the 2001 Oil and Gas Law passed, the FTP has been reduced to 15 per cent (which has applied in all cases but one, in which the FTP was set at 10 per cent). FTP has continued to be split between the PSCo and the GOI according to the equity oil split in the PSC. The FTP is considered to be part of the GOI's and PSCo's equity split.

Assessment of subsidy

FTP could be seen as an additional form of tax for the PSCo, which is taken by the GOI up front. It could also perhaps be regarded as a “royalty” in that it is related directly to the level of production. However it is categorized, the important question for this study is to assess whether the imposition of FTP is at a level that provides some form of benefit to PSCos.

Due to the complex nature of the PSC in Indonesia, it is very difficult to make any meaningful like-for-like comparisons of this type of “royalty” that apply to the oil and gas industries in other countries. This has also been referred to elsewhere in this study. A comparison of the total fiscal structures embodied in the PSC, with the total fiscal structure applied in other countries, would need to be conducted, to identify whether a subsidy is being applied by the GOI, in this context. Conducting such an international comparison was not within the scope of this study, and so it is hard to draw any conclusions about the application of FTP in the absence of this comparison.

3.3.1.2 EQUITY SHARES

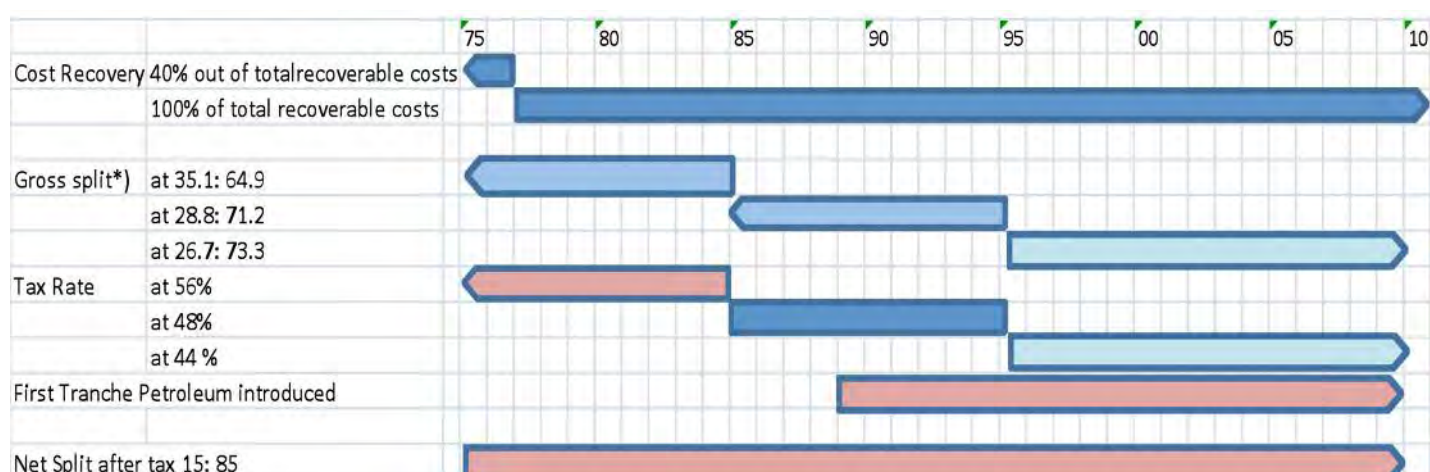
Background

Since the first PSC was issued in 1966, the terms and conditions of the PSC have gone through many changes. These changes have usually been made in order to respond to changes in the external environment, such as the international price of oil, the level of international competition for investment in oil and gas exploration and production, and the commercial risks associated with developing oil and gas resources in Indonesia.

The changes in PSC terms and conditions have usually been incorporated in new “generations” of the PSC (although, in some instances, terms and conditions have been modified within the duration of a PSC generation).

Figure 3.5 summarizes some of these key changes. It should be noted that the Net Split After Tax refers to the standard split for oil. Further details of the split for gas, along with variations of these splits for both oil and gas under certain conditions, are contained in Figure 3.6.

FIGURE 3.5: EVOLUTION OF PSC FISCAL TERMS, 1975–2010



Note: *all splits are in favour of the government

Source: CMS Consulting Group

Various terms and conditions in the PSC have been changed over time and include the following:

- Setting of taxes. In early PSCs, all taxes such as levies, dividend tax and VAT were fixed for the duration of the contract under a *lex specialis* concept; whereas in more recent PSCs, such as those issued under the 2001 Oil and Gas Law, some taxes are subject to prevailing regulations.
- The percentage sharing of production “equity oil” between the GOI and PSCo. For PSCs issued before 1976, the pre-tax share of equity was 65:35 in favour of the GOI. As such, PSC net equity after income tax was 15 per cent. When the new tax law was introduced in 1985, the income tax rate was reduced to 44 per cent, lower than the previous tax law rate of 56 per cent. The PSC equity split was adjusted accordingly with the new tax rate, in such a way that PSCo net equity after tax remained at 15 per cent.
- Recovery of operating costs provisions. There has also been a change in the mechanism regarding the recovery of operating costs. Recovery of operating costs of the PSCs issued before 1976 was capped at 40 per cent of gross production with no capital expenditure depreciation allowance, while from 1976 onwards 100 per cent recovery of costs has been allowed with capital expenditures depreciation, thus improving PSCo’s key financial performance parameters (such as cash flow, Net Present Value [NPV], IRR and Pay Back Time).
- Other terms such as Investment Credit, FTP and DMO, have also been changed over time, each of which are described in more detail in other sections of this study.

PSCos receive revenue from two main sources:

- A share of production as in kind payment for cost recovery (CR).
- An entitlement to a percentage share of production, known as “equity oil,” which is an after-tax share.

Generally the PSCo can sell its equity oil share where it chooses, with the exception of the oil it must sell through the oil DMO. Some smaller PSCos who do not have their own crude oil export facilities, may sell their equity oil to Pertamina, in which case it will be priced according to the Indonesian Crude Price (ICP), or they may export their equity oil through Pertamina’s facilities and pay Pertamina a fee for this. The fees that Pertamina can charge are regulated by BP Migas. In many cases there may be no other facilities available besides those that Pertamina operates.

BP Migas generally appoints Pertamina to transport the GOI’s equity oil share to the delivery point or sales point.

Figure 3.7 shows, in detail, the after-tax equity oil and gas shares granted to PSCos in each incentive package that has been introduced in PSC Generation 3. Further details on the key terms and conditions that apply to each of the three PSC Generations are also shown in Appendices 3 to 8.

FIGURE 3.6: EVOLUTION OF PSC INCENTIVE PACKAGE 1988 – 1994

DESCRIPTION	BEFORE INCENTIVE	INCENTIVE I (Aug 1988)	INCENTIVE II (Feb 1989)	INCENTIVE III (Aug 1992)	INCENTIVE IV (Jan 1994)
OIL FIELD					
a. Development Before August 1992					
Conventional – Standard	85/15	85/15			
Conventional – Marginal	85/15	85/15	85/15	85/15	85/15
Conventional – Tertiary	85/15	85/15	80/20	80/20	80/20
Conventional - Pre tertiary	85/15	85/15	80/20	80/20	80/20
			Up to 50 mbcd 80/20	Up to 50 mbcd 80/20	Up to 50 mbcd 80/20
			51 - 150 mbcd 85/15	51 - 150 mbcd 85/15	51 - 150 mbcd 85/15
			Up 150 mbcd 90/10	Up 150 mbcd 90/10	Up 150 mbcd 90/10
Frontier - Marginal	85/15	85/15	75/25	75/25	65/35
Frontier - Tertiary	85/15	85/15	80/20	80/20	65/35
Frontier - Pre Tertiary	85/15	85/15	Up to 50 mbcd 75/25	Up to 50 mbcd 75/25	Single split 65/35
			51 - 150 mbcd 80/20	51 - 150 mbcd 80/20	
			Up 150 mbcd 85/15	Up 150 mbcd 85/15	
b. Depth Sea					
600-4500 feet	85/15	85/15	Up to 50 mbcd 80/20	Up to 50 mbcd 75/25	Up to 50 mbcd 80/20
			51 - 150 mbcd 85/15	51 - 150 mbcd 80/20	51 - 150 mbcd 85/15
			Up 150 mbcd 90/10	Up 150 mbcd 85/15	Up 150 mbcd 90/10
Up 4500 feet	85/15	85/15	Up to 50 mbcd 80/20	Up to 50 mbcd 75/25	Single split 65/35
			51 - 150 mbcd 85/15	51 - 150 mbcd 80/20	
			Up 150 mbcd 90/10	Up 150 mbcd 85/15	
New Contract Frontier	85/15	85/15	Up to 50 mbcd 80/20	Single - 75/25	Single - 65/35
			51 - 150 mbcd 85/15		
			Up 150 mbcd 90/10		
GAS FIELD					
a. Development Before August 1992	70/30	70/30	70/30	70/30	70/30
b. Development After August 1992					
Depth Sea Up 4500 feet	70/30	70/30	70/30	60/40	60/40
New Contract					
Conventional				65/35	65/35
Frontier				60/40	60/40
Depth Sea Up 4500 feet				55/45	55/45

Note: the percentage splits refer to post tax equity oil shares for the GOI and PSCo respectively.
Source: Directorate General of Oil and Gas (Migas), 2009

Assessment of subsidy

While in the various PSC “generations” and more recently the changes made on the “incentive packages” made in PSC Generation 3, various changes have been made to equity oil shares, and fiscal terms generally, the underlying PSC structure and philosophy has remained constant. These changes appear to have been made in response to the changes in conditions connected to the commercial environment, such as the international price of oil and the level of international competition for oil and gas investment.

The higher equity shares that have been introduced for certain types of Work Areas mentioned above again appear to help offset the higher costs and higher risks, that oil companies face in exploring for and producing oil and gas in these more challenging conditions/locations.

It has been concluded that there is no evidence that the equity oil and gas shares received by the PSCOs, and the changes that have been made to these shares, represent a subsidy to the PSCOs. These equity oil and gas shares are unique to the oil and gas sector in Indonesia, so it is not possible to draw like-for-like comparisons with other industries. At the same time, no evidence has been revealed that some PSCOs receive an equity oil and gas share, which is higher than that they are entitled under the regulations, so there does not appear to be any preferential treatment.

3.3.1.3 YEAR END RECONCILIATION OF OVERLIFTING AND UNDERLIFTING

Background

The process for agreeing on the precise amount of equity oil that the GOI and the PSCOs can lift in a given year is as follows. In the fourth quarter of each year, each PSCo prepares a Work Program and Budget that is submitted to BP Migas. It contains a projection of monthly production and expectation of crude oil price for the year ahead. Then at the end of each quarter during the year, a meeting is held between the PSCo and BP Migas, at which actual crude oil prices, and production levels and costs, are recorded for the year-to-date and production and price forecasts are updated for the remainder of the year. At year-end, a further reconciliation meeting is held, within 30 days of the year-end, and a re-calculation of lifting entitlements takes place based on actual prices, production and costs for the full year and a cash settlement is made to compensate for any underlifting or overlifting is made by April of the following year.

There are several reasons why the sharing of crude oil entitlements under the PSC system (between the GOI and PSCo) is subject to this year-end reconciliation:

- The recovery of operating costs is done through in-kind payment in crude oil entitlement (as mentioned above). This is done on a monthly basis. The valuation of crude oil is based on the weighted average price for the year, which can only be calculated at year-end, and is likely to differ from the calculations made on a monthly basis.
- The monthly recovery of operating costs is also based on the estimated levels of production each month, as defined in the PSCo's annual Work Program and Budget.

The actual levels of production will not be known until the year-end, which will likely be different from the estimated production.

Assessment of subsidy

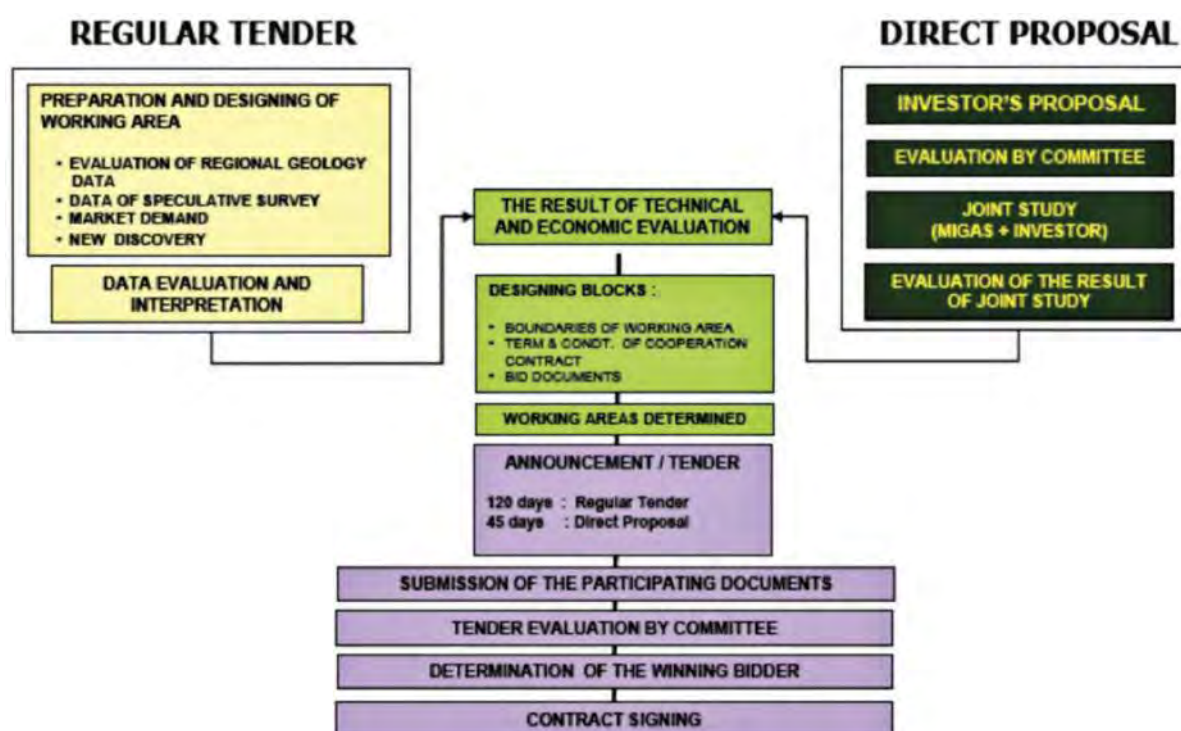
The main advantage a PSCo could obtain from this system is a cashflow benefit that could arise from setting a higher budgeted level compared with the actual liftings during the year. However, this advantage is largely offset by the PSCo's obligation to submit monthly installments of projected tax payments for the year, at the fifteenth day of every lifting month and the following month, based on budgeted levels. Also, as mentioned, each quarter, adjustments are made to the annual budgeted level of liftings for the remainder of the year, based on the previous quarters overliftings or underliftings, so the variances for the year as a whole, are not likely to be substantial. It is therefore concluded that this process of reconciling overliftings or underliftings at year-end does not generate a subsidy. The payment of monthly tax installments is likely to offset any cash flow incentive there may be to overestimate the level of liftings during the year; the adjustments that can be made every quarter, will also effectively counter this.

3.3.1.4 ACCESS TO NEW ACREAGE

Background

Two routes are available for companies to get access to new work acreage. Under one route, new acreage blocks are made available through a Migas announcement, which is made periodically in a call for tender and open bid. Under the second route, the so-called “direct proposal,” which also falls under Migas, new acreage is made available through the Joint Study mechanism. The general procedure is shown in Figure 3.7.

FIGURE 3.7: PROCEDURE TO ACCESS NEW OIL AND GAS WORK ACREAGE



Source: Directorate General of Oil and Gas (Migas), 2009b

The Joint Study procedure starts when an interested company proposes to Migas an area of interest. The Joint Study is an open procedure that applies to anyone who is interested to secure an area of interest in order to explore for oil and gas. The Joint Study is intended to speed up the geological assessment and development of an area of interest that otherwise would lie dormant, as the GOI does not have sufficient funds to conduct an in-depth study in every geological basin in Indonesia. Usually, the company that applies for a Joint Study has preliminary knowledge of the area of interest from scientific reports and publications, studies done by consulting companies, scientific papers from the Annual Convention of the Indonesian Petroleum Association, etc., all of which are available to the public. If no other companies apply for the same area within 14 working days after the Joint Study proposal has been submitted, Migas appoints the interested company to conduct a Joint Study. Otherwise, the area of interest will be offered for open bid. Migas appoints a representing

university to conduct the study jointly with the company. Prior to the study, the company will deposit some amount of funds to guarantee the execution of the study. If, after the Joint Study has been completed, the company considers the area of interest to be feasible, then the company requests Migas to put up the area of interest for open bid. In contrast to the normal procedure, the area of interest is designated as a “direct proposal” and is limited to an area of no more than 4,000 square kilometers.²

The company doing the Joint Study shall follow the same procedure as other companies to participate in the bid but obtains a “right of first refusal,” in which it has the right to match the most favourable investment commitment offered through the open tender process.

Companies that have not been involved in the Joint Study, may also participate in the tender in order to access new acreage. However they must acknowledge that another party may have secured a right of first refusal to a particular Work Area on offer, having conducted the Joint Study. In this situation, it may appear that one party is receiving preferential treatment, but a clearly regulated procedure is being followed.

In some instances, Work Areas that are offered out for tender may not attract any bids. In this case, Migas will add these to a list of Work Areas that are available for direct negotiation or direct award (meaning that Migas will not put these Work Areas into another future tender). Any company interested in these Work Areas should make a proposal to Migas and if this is accepted the two parties will then negotiate the proposed commitment; once agreed, the Work Area will be awarded to the company that has submitted the proposal.

Assessment of subsidy

In the direct proposal case, the company proposing a Joint Study usually has preliminary knowledge of the area of interest. In many cases, this knowledge may come from previously employed staff of companies that operated the area of interest prior to relinquishment. For this reason, several international consulting companies with a speciality in this area, have opened offices in the region. Theoretically, all data shall be returned to the government on the relinquishment date of acreage in a PSC, however, there is no guarantee that the company will not keep copies of original data and its analyses. Furthermore, the knowledge gained by the staff of the company might be used in application for the area of interest for a direct proposal. During the Joint Study period, the company has the right to access the data by paying the data fee. With this procedure, it is clear that the company that applies for the direct proposal will have access to more information than other parties have. However, it is difficult to consider this procedure as evidence of a subsidy. The process is open to all parties to participate in and certainly there is no evidence of just one or two parties dominating the submission of Direct Proposals. The GOI objective in adopting this process is to encourage investors to be proactive in seeking new blocks to invest in and to risk spending money on carrying out surveys and research, which, if successful, the GOI will benefit from through the PSC system.

3.3.1.5 ACCESS TO EXPIRED PSC

Background

The Work Areas for all expired PSCs (i.e., those for which the allowable PSC extension periods have been exhausted) must be returned to the GOI, namely to Migas, through BP Migas. Similarly, any portion of the

²This is equivalent to about one eighth of the size of the province of West Java. More details can be obtained from the Ministry of Energy and Mineral Resources booklet, *Indonesia Second Bidding Round 2008*.

total acreage that a PSCo is obliged to relinquish during and according to the terms of the PSC within the PSC duration must also be returned to the GOI.

Based on evidence to date, in most instances the Migas will put this relinquished acreage up for offer, following the procedures mentioned above.

Some preferential rights to acquire these expired PSCs, however, are given to Pertamina (as long as 100 per cent of Pertamina's shares are owned by the State—which could change if, for instance, Pertamina undertakes an Initial Public Offering [IPO] for some of its subsidiaries), and also to local and regional business entities. In this respect, Government Regulation No. 35/2004 on Upstream Oil and Gas Activities Article 28 (9) and (10) stipulates the following:

(9) PT. Pertamina (Persero) may submit a request to the Minister for a Work Area whose contract period has ended.

(10) The Minister may approve a request as mentioned in clause (9), considering the work program and technical and financial capability of PT. Pertamina (Persero), as long as 100% (one hundred percent) of the shares of PT. Pertamina (Persero) are owned by the State, and other matters related to the Cooperation Contract concerned.

Assessment of subsidy

It could be argued that this preferential access for Pertamina could provide them with opportunities that other companies may not be able to access, however it should be noted that Pertamina can only submit a “request” for a Work Area, which the GOI is under no obligation to agree to. This special treatment was introduced at a time when Pertamina was a minor producer of oil and gas (in volume terms), having for many years focused on fulfilling its role as a manager of the oil and gas sector (prior to the passing of the 2001 law). The GOI hoped that, by giving Pertamina this opportunity to request the right to acquire an expired PSC from the GOI, it would at least ensure that Pertamina would be considered as a candidate applicant for the expired PSC.

During the past 40 years Pertamina has exercised this right in only three expired PSCs, consisting of two blocks in East Kalimantan and one onshore block in Cepu, in East Java. This may be due to Pertamina either not having sufficient funds to take on the ongoing operation or the further development of these assets, or because they have decided the likely return they will receive from them is not attractive.

However, it should be noted that in 2010 the GOI set the short term (2010), medium term (2014) and longer term (2025) objectives for upstream national oil and gas activities which sets the goals of achieving at least 40 per cent national involvement and participation by 2014 and in the longer term 50 per cent national involvement in exploration and production by 2025 (Directorate General of Oil and Gas (Migas), 2010). This goal encourages Pertamina to acquire 100 per cent interest in North West Java Offshore in 2009. The acreage was previously operated by BP, and Pertamina has recently been expressing increasing interest in acquiring other PSCs acreage, such as the Mahakam PSC in East Kalimantan, which is currently operated by Total, and which will expire in 2017 (Directorate General of Oil and Gas (Migas), 2010).

There has also been one case in which a BUMD was able to participate in an expired PSC, which is located in Central Sumatra, and this has been in partnership with Pertamina, which they are now jointly operating. This was seen as a political decision made by the GOI around the time that Law No. 22 of 2000 on Regional Autonomy and Law No. 33 of 2004 on Balanced Finance between the Central Government and the Regional Administration was passed.

This preferential right to an expired PSC, which has been granted to Pertamina and a BUMD, could be considered a subsidy. In order to quantify this subsidy, it will be necessary to obtain detailed information about the return the BUMD and Pertamina have obtained from operating the field and comparing this with an assumed standard return for the industry.

3.3.1.6 BONUSES PAID BY PSC

Background

In the early stages of the Indonesian oil and gas industry, the GOI through Law No. 8 of 1971, introduced the PSC to the oil and gas industry, enabling international companies to secure investment in the sector. Bonus payments were not the main criteria in the awarding of work acreage; rather, it was the commitment to take risks and invest in exploration, development and production operations that mattered most in the contract award.

However, the environment has changed over time, and as competition for new acreage intensified, tender participants supplemented their investment commitment by offering bonuses. The amount of bonus is offered under open tender when the GOI makes available a PSC WA (Work Area). As has been described in section 3.3.1.4, the WA tender procedure begins with a GOI announcement and invitation to companies who are registered with Migas. Any company may participate in the tender so long they are registered and submit an expression of interest to Migas. During the tender period, all geological and engineering and other data pertinent to the area is made available to participants. The data also includes a model PSC contract which participants would have time to study at the same time as assessing the petroleum prospect of the area of interest. It is during this study period, which normally takes three to four months, that participants will have time to evaluate the block on offer and judge whether or not they will submit their bid. All bidding participants including Pertamina must submit their bids by the deadline to the Tender Committee in closed and sealed envelopes, containing the completed PSC Model contract they have obtained from the Tender Committee. The Tender Committee will evaluate all submitted bids, and will recommend to the MEMR which bidding participant should be declared the winner. In the meantime, there is no communication between the Tender Committee and the bid participants. The MEMR will declare who is the bid winner in an open announcement and set a date for the formal signing ceremony of the new PSC WA. This tender process ensures there is no scope for manipulating the bid result, including negotiating bonus after it has been submitted. All bonus figures are inserted into the appropriate section (left blank for them to complete) in the PSC model contract, and all participants use the same model contract.

Bonus payments have become a standard feature in the industry. In addition to signature bonuses, which are payable right after a PSC award, PSCOs are required to pay a production bonus after reaching certain increased levels of production, and they are also required to pay educational assistance bonuses, and an equipment and services bonus.

Assessment of subsidy

The payment of bonuses by PSCOs does not appear to involve any subsidy payment to these PSCOs given that it involves money being paid to the GOI rather than the other way around.

As described above, there is no opportunity for the GOI to accept lower bonus payments from some parties, and still declare them as winners, as, in recent bidding rounds, the bonus payments offered by participant are made public.

However, the question needs to be asked: Does this system in which the selection of the winner is based mainly on the size of bonus payment being offered ensure that the most “able” participant wins? A separate study of recent bidding rounds, who the participants were, and who the winners were, would need to be conducted in order to attempt to answer this question.

3.3.2 GOVERNMENT-OWNED INFRASTRUCTURE AND LAND

3.3.2.1 GOVERNMENT-PROVIDED INFRASTRUCTURE AND SUPPORT SERVICES, PREFERENTIAL ACCESS TO LAND

Background

Access to any facilities, including production facilities or export facilities, are negotiated at a commercial level. As a result, some PSCOs, including Pertamina may be able to obtain better terms and conditions than others. Since the passing of the 2001 Oil and Gas Law, the owners and operators of some facilities, such as gas transmission pipelines, are required to offer “open access” to third parties, which are overseen by a newly created regulatory body, BPH Migas.

Regarding the Use of Land for Oil and Gas Exploration and Production, Indonesia’s Law No. 41/1999 regarding Forestry, Article 38.3 stipulates that:

Use of forest areas for mining activities shall be based on a license of land-use issued by the Minister (of Forestry), taking area limitations, timeframe and environmental sustainability into account.

This means that the use of forest areas for mining activities, including oil and gas exploration and exploitation, is possible as long as the license for land use issued by the Minister of Forestry is in place and as long as steps are taken to ensure sustainability of the environment.

However, the GOI recently announced that Land Zoning Law of 2007 is to be amended to allow mining operations to be conducted in protected forests. Under this new law, while the Minister of Forestry must still issue a licence, the process by which this licence is issued is more transparent than was previously the case.

Assessment of subsidy

The existence of a subsidy in this case is only present in the form of the GOI’s preference to allow the use of forested areas for oil and gas exploration and production (and mining activities) rather than simply for forestry. More specifically, the subsidy is only present in the form of government’s willingness to “sacrifice” these forests in order to allow oil and gas exploration and production activities to be conducted.

Fiscal estimate

The amount of subsidy, in terms of its financial value, however, is hard to quantify. It requires further research to quantify the value of the forest (including its environmental value), which is being replaced by the oil and gas operations, and to identify if, for instance, this value is being reflected in the land acquisition costs.

Evaluation: Is the subsidy effectively meeting the GOI's objectives?

The objective of the GOI in allowing mining activities to be undertaken is understood to be a reflection of the GOI's prioritization and ranking of the use of natural resources. It has been decided that the exploitation of oil and gas resources in forested areas is likely to create higher value (for the State and for the people) than leaving these forested areas untouched and the oil and gas resources in the ground. The fact that oil and gas exploration and production in some forested areas is occurring suggests that this objective is being met, but what still needs to be assessed is whether the value created by these oil and gas activities exceeds losses incurred from using some of these forested areas (including all the environmental costs).

Evaluation: What impacts does this have on the oil industry?

The application of this subsidy is enabling oil companies to explore for, and if found, exploit oil and gas resources in forested areas.

3.4 INCOME OR PRICE SUPPORT

3.4.1 MARKET PRICE SUPPORT AND REGULATION

3.4.1.1 FARM-IN TO EXISTING PSCS

Background

When PSCOs with participating interests in a certain PSC allow one or more third parties to buy a certain percentage of participating interest in the PSC work area, it is referred to as a “farm-in.” These farm-ins are negotiated at a business-to-business level, between the incumbent PSCOs with participating interests and the party wishing to farm-in. BP Migas ensures that the regulations for farm-ins are followed and BP Migas approval is needed for all farm-ins.

Some parties do have special rights to farm-in. For instance, under the 2001 Oil and Gas Law, local companies that are owned by regional governments (known as BUMD's) have the right to buy a 10 per cent share in a newly developed field in a PSC acreage, which they must exercise within a defined period (usually 12 months from the date on which the PSC is declared commercial or the date on which a proposal to develop a Plan of Development [POD] is approved by BP Migas). The PSCo must submit a POD to BP Migas for approval before a newly discovered field can start commercial production. Other nationally owned companies (which would include companies such as PT. Pertamina, PT. Medco Energi, PT. Energy Mega Persada) can also exercise this right if not exercised by a BUMD. BUMDs, or any other interested parties including Pertamina, must go through a commercial negotiation, normally with the PSC operator (who acts on behalf of all the PSCOs with participating interests in the PSC). To date, only Pertamina has exercised this option. Prior to the passing of the 2001 Oil and Gas Law, Pertamina alone had this right to buy a 10 per cent share. To date, Pertamina has only exercised this right on three occasions.

It should be noted that this special pre-emptive right or “option to participate” only applies to a 10 per cent participating interest in the PSC and that all companies are free to buy into a PSC by negotiating terms on a commercial basis with the PSCOs.

Assessment of subsidy

The pre-emptive right that is given to local and regional business entities and possibly to national oil companies to acquire a 10 per cent participating interest in the development of a new oil and gas field does not necessarily generate a clear financial benefit. This is due to the fact that the PSCo operator of the block and the interested entity must reach mutual agreement in determining the value of the participating interest. It is a commercial deal so it could happen that the value offered may or may not be attractive to a party. In addition, in order for these entities to participate they must be able to show that they have access to sufficient funds to buy this 10 per cent share. If they can demonstrate this and take a 10 per cent stake in the project, then they are exposed to the same economic and financial risks that face other investors in the project. It is therefore hard to argue that this privilege represents any form of subsidy.

It should be added that if the parties who are eligible to take this option, exercise this right, and reap the rewards of having a 10 per cent participating interest but also fail to contribute some or all of their share of the financing that is expected of them, then under the terms of a standard Joint Operating Agreement they must return their 10 per cent share to the original PSCo(s) operating the block.

3.4.1.2 OIL DMO

Background

The PSCo is required to supply crude oil to domestic refineries up to a maximum of 25 per cent of the PSCo's percentage share of total production from the PSC. This is known as the Domestic Market Obligation (DMO). The DMO also applies to the GOI share of oil production from the PSC.

It should be noted that the oil DMO percentage as stated in the PSC is set at a maximum of 25 per cent of PSCo's share of equity and applies to all PSCs, as it is one of the PSC standard terms. While a constant DMO rate in percentage terms is applied, the actual volume of "DMO oil" produced from each PSC will of course vary according to each PSC's level of production. The word "maximum" is meant to indicate that the GOI won't oblige the PSCo to submit more oil than the 25 per cent out of its share of equity.

The GOI buys this oil from PSCos at heavily discounted levels and, as seen on Figure 3.9, this discounted price has varied over time.

In implementing this DMO policy, in 1976 the GOI introduced a distinction between "DMO new oil" and "DMO old oil." The aim of this distinction was to encourage the exploration and development of "new oil fields" in new reservoirs or new geological environments, so that PSCos did not restrict their exploration and development activities to just known, conventional reservoirs or geological environments. The precise definition of "new oilfields" is the definition applied by American Association of Petroleum Engineers.

If an oilfield complies with the definition of a "new oilfield" then, for the first 5 years of commercial production from this field, that oil DMO portion is priced at market price, that is to say, it is not discounted. After 5 years, this DMO oil is priced at a heavily discounted rate. The precise discounted price depends on when the PSC was signed, and when the oilfield entered production as this has changed over time (see Figure 3.9).

The DMO fee is clearly stated in the PSC model contract. While a lower DMO fee has applied to the older PSCs, the PSCos involved in these PSCs might have an opportunity to take advantage of the current higher DMO fees, once the original PSC term has expired, and they are granted the right to extend the PSC term.

The progression of the DMO oil fee over time is shown in Figure 3.8. It shows that the discounted DMO fee that applies to all the production from old DMO oilfields, and to the production from new DMO oilfield after the first 5 years of production, has gradually increased over time, but is still below market price.

FIGURE 3.8: DMO FEE EVOLUTION

Description	Before Incentive	Incentive I (Aug 1988)	Incentive II (Feb 1989)	Incentive III (Aug 1992)	Incentive IV (Jan 1994)
Fee DMO New Oil	Market Price	Market Price	Market Price	Market Price	Market Price
Years of Production	49–60	49–60 Months	60 Months	60 Months	60 Months
Fee DMO Old Oil					
Field prod. Before Feb 1989	US\$ 0.20	US\$ 0.20	US\$ 0.20	US\$ 0.20	US\$ 0.20
Field prod. Feb 1989– Aug 1992			10% of Market Price	10% of Market Price	10% of Market Price
Field prod. Aug 1992– Jan 1993				15% of Market Price	15% of Market Price
Field prod. After Jan 1993					25% of Market Price

Source: Directorate General of Oil and Gas (Migas), 2009

Assessment of subsidy

In those instances where PSCos sell oil under the DMO at prices below market levels, this represents a de facto tax for them and a corresponding subsidy for the party receiving this lower-priced oil. The question, is Pertamina the beneficiary as the direct recipient of this oil, or is it the GOI? Research conducted during this study concludes that it is Pertamina that benefits from this.

The amount of the subsidy received by Pertamina can be derived from all the volumes of the DMO oil that are sold at below market prices and constitutes the crude oil input for the Pertamina's refineries. It is a subsidy for Pertamina because there is no offset against the manner in which Pertamina is reimbursed by the GOI for selling subsidized oil products (known as BBM). As mentioned in Chapter 2, under this reimbursement system, the GOI pays to Pertamina the difference between the subsidized price of oil and the price at which Pertamina could have sold this oil for (if not subsidized), that is, at market price. This market price is based on a formula that consists of oil priced at MOPS, plus 8 per cent. The 8 per cent is to cover storage, transportation and distribution costs, and also a retailer margin. This is paid to Pertamina for all the BBM volume that is sold, regardless of the fact that some of this volume will have been refined from crude oil that will have been bought at below market price through the DMO.

For the year 2008, the estimated subsidy is as follows (BP Migas, 2008b and 2009b):

- The volume of crude oil sold to Pertamina through the DMO at a price that was below market price was 21,746,000 barrels
- The difference between the average crude oil market price for 2008³ and the average crude oil DMO price (below market) was US\$71.02 per barrel.

³The average crude price for 2008 was assumed to be US\$80.60 per barrel, taken from the published MOPS. Mean Oil Platts Singapore (MOPS) is published daily by Platts and Oilgram Singapore, taking daily oil market price in US dollars and the averaged price using an established Platts and Oilgram formula.

(c) The gain to Pertamina in buying oil through the DMO was therefore US\$1.554 billion, or (a) x (b).

In conclusion, the oil DMO provides a subsidy to Pertamina for its refining activities, although further analysis of the impacts of this subsidy is outside the scope of this study. The oil DMO fee is, in effect, a de facto tax to the PSCos. The question then is whether the “exemption” from this de facto tax, which oil producers now receive during the first five years of production of “new oil,” constitutes a subsidy. It has been concluded this should not be seen as a subsidy, since an investor in an oil project (such as a PSCo) would normally expect to be able to receive market price for oil produced, and the exemption from the discounted oil DMO fee (for the first 5 years) allows an investor to obtain this market price.

3.4.1.3 GAS DMO

Background

In the early days of Indonesia’s oil industry, the international gas market was not as economically attractive as oil. Trade in gas was sparse and an international price of gas was hard to identify. The use of gas as a feedstock, which usually required large investments, obliged investors to demand a long-term contract as security for their investment. One way the government dealt with this issue was to fix the price of gas sold into the domestic market using an alternative fuel price as a reference. This internal price did not necessarily follow an international market formula.

The gas DMO was introduced in the 2001 Oil and Gas Law. The gas DMO obligates PSCos producing gas to sell 25 per cent (or more) of their gas production into the domestic market. The DMO rate is stated in the PSC model contract available to all tender participants whenever the GOI issues a PSC WA bidding round.

The DMO rate and conditions are the same for all PSCs. It is possible that the GOI may decide to increase the minimum DMO percentage in the future, however, before doing so, the GOI will have to consider the impact this may have on future investment in gas exploration and production.

Assessment of subsidy

There is anecdotal evidence that over the past 15 years or so, that is both before as well as after the gas DMO was introduced, that PSCos have sold gas to some local gas consumers at prices far below international gas price levels, sales to fertilizer plants being one example of this. Detailed research would be needed to identify the magnitude of this. Today, it is still evident that the average price of gas sold into the domestic market is significantly below the average level of export gas prices, but the gap has narrowed (see Chapter 2 for further details).

What has increased substantially is the volume of gas that is being sold into the domestic market, which is partly a result of the gas DMO. The sale of gas into the domestic market at prices below the international market is certainly an opportunity loss, rather than a subsidy, for gas producers, but may well represent a subsidy for the gas buyer, and this may need to be identified if it has not already been (though it does not fall within the scope of this study). It is difficult to estimate the size of this subsidy because domestic gas prices vary contract by contract and there is no reliable price reference to refer to for the weighted average of gas sold domestically.

The question may be asked: Has the GOI enabled PSCs to be recompensed in some form for the costs they have incurred in selling gas into the domestic market at prices significantly below international prices? This might happen by making some terms and conditions in the PSC more favourable than they would otherwise be, which would mean that part of the subsidy enjoyed by gas users is in fact granted to the gas producers. Based on research conducted for this study, we have not found any evidence of this. Of course it could be argued that the GOI's objective in granting some of the subsidies identified in this study has been also been in part to compensate the oil and gas producers for this gas DMO, but the GOI has never stated this explicitly (and the same would apply to the oil DMO referred to in Section 3.4.1.3)

4 SUMMARY OVERVIEW OF INDONESIA'S PRODUCER SUBSIDIES

4.1 SUMMARY OF SUBSIDY IDENTIFICATION

Figure 4.1 provides a summary of the identification and estimation of subsidies conducted in Chapter 3.

FIGURE 4.1: SUMMARY OF THE IDENTIFICATION AND ESTIMATION OF SUBSIDIES CONDUCTED IN CHAPTER 3

Primary Category	Secondary Category	Subsidy Identified	Estimated Annual Value (US\$ millions)	
			2007	2008
Direct and indirect transfer of funds or liabilities	Government ownership of energy-related enterprises	Pertamina Work Agreement compared with Standard PSC (3.1.1.1)	Possible subsidy of marginal value; difficult to quantify	
	Direct spending	Recovery of Operating Costs (3.1.2.1)	No subsidy	
		R&D support to industry (3.1.2.2)	Further detailed research needed to see if subsidy exists (e.g. LEMIGAS)	
		Restoration and rehabilitation (3.1.2.3)	No subsidy	
Credit support		Investment credit allowance (3.1.3.1)	87	115
		Bank financing support (3.1.3.2)	Further detailed research needed to quantify subsidy (in case of projects below standard IRR)	
Government revenue foregone	Tax breaks and special taxes	Tax incentives for imported goods and services (3.2.1.1)	98	130
Provision goods or services below market value	Government-owned energy minerals	Application of royalty (3.3.1.1)	Further details research needed to conduct international comparison	
		Equity shares (3.3.1.2)	No subsidy	
		Year end reconciliation of overlifting and underlifting (3.3.1.3)	No subsidy	
		Access to new acreage (3.3.1.4)	No subsidy	
		Access to expired PSCs (3.3.1.5)	Further detailed research needed to quantify subsidy (e.g., Central Sumatra PSC)	
	Bonuses paid by industry (3.3.1.6)	No subsidy, but recommend further research on selection criteria for new acreage		
	Government-owned infrastructure and land	Government provided infrastructure and support services, preferential access to land (3.3.2.1)	Further detailed research needed to identify full value of forested area	

FIGURE 4.1: CONTINUED

Primary Category	Secondary Category	Subsidy Identified	Estimated Annual Value (US\$ millions)	
			2007	2008
Income or price support	Market price support and regulation	Farm in to existing PSC (3.4.1.1)	No subsidy	
		Oil DMO subsidy to Pertamina (3.4.1.2)	No subsidy to oil producers (but there is a subsidy to Pertamina refining worth US\$1.554 billion in 2008)	
		Gas DMO subsidy to gas consumers (3.4.1.3)	No subsidy to gas producers (but there is subsidy to gas consumers)	

As can be seen in Figure 4.1, further detailed research is needed in several cases to determine whether a subsidy exists and, if so, to quantify it.

4.2 WHICH ACTIVITIES ARE MOST SUBSIDISED AND WHO BENEFITS FROM THEM

Based on the research, it is apparent that the main areas where subsidies exist and the parties that benefit from them are as follows:

(a) **The development of marginal and new oilfields**

- Investment Credit: the beneficiary being PSCos and Pertamina that participate in developing “new” oil and gas fields.
- Bank financing support: the beneficiary being PSCos and Pertamina that participate in developing oil and gas fields that generate below-standard IRRs.

(b) **Importation of goods and services needed for oil and gas exploration and production**

- VAT exemption: the beneficiary being all PSCos and Pertamina.
- Import Duty exemption: the beneficiary being all PSCos and Pertamina.

(c) **National Institutions: Pertamina and BUMDs**

A subsidy may exist, but it has not yet been quantified; based on initial assessment, it appears to be of marginal value in the case of:

- Access to expired PSCs: the beneficiary being Pertamina and BUMD's.
- Offering out farm-in opportunities: the beneficiary being Pertamina.

(d) **Access to forested areas**

Further research is needed, but a subsidy may exist

- Access to forested areas: the beneficiary being all PSCos and Pertamina.

(e) **Consumer subsidies**

While this study focuses on producer subsidies, the research conducted has identified that consumer subsidies are generated from two upstream activities.

- Selling crude oil for domestic use at below market price: the beneficiary being Pertamina's refineries.
- Selling gas for domestic use at below market prices: the beneficiaries being certain gas users.

5 CONCLUSIONS AND NEXT STEPS

Overview of the study

This study analyzed Indonesia's fiscal framework for oil and gas exploration and production to determine whether the government grants subsidies for upstream oil and gas activities, and if so, to estimate their value. It is the first of its kind to be undertaken in Indonesia, with previous studies in Indonesia primarily focusing on the downstream consumer subsidies. Indeed, it is one of very few studies worldwide to look at the issue of producer subsidies, and it is the first in the GSI's series⁴ of country case studies to identify and quantify subsidies for fossil-fuel producers. This study not only provides useful insights into Indonesia's rather opaque system of PSCs, but it also establishes a framework that can be consistently used for undertaking similar research in other countries.

As expected, identifying and quantifying subsidies proved to be a complex undertaking, requiring detailed analysis of the fiscal and regulatory framework and its practical application. The study was only possible due to the CMS consulting group's significant expertise and working knowledge of Indonesia's fiscal and regulatory regime for the oil and gas industry; aided by their access to, and detailed practical knowledge of, commercially sensitive documents. The researchers have noted in the conclusions and next steps below where further research could advance this work. This study is an initial piece of research that lays out the essential information needed to inform a public debate on what subsidies exist and how big they could be.

The conclusions can be considered in three parts. First, there are those activities where it was found subsidies do exist and could be estimated. Second, there are those activities where it was found subsidies might exist but further detailed research is required to form a definitive view, and to quantify this subsidy, if it is concluded a subsidy does indeed exist. Third, the study identified those activities where it is judged no subsidies exist.

Subsidies identified and their scale

Three types of subsidies were clearly identified and estimated.

Subsidy	Estimated value in 2008
Investment Credit Allowance	US\$115 million
Tax incentives for imported goods and services	US\$130 million
Oil DMO (subsidy from industry to Pertamina's refineries)	US\$1,554 million
Total	US\$1.799 billion

The three subsidies identified provide a minimum total of US\$1.799 billion in 2008. It should be noted that oil DMO is a subsidy regulated by the GOI but the cost is borne by industry. Other potential subsidies identified below, which we were unable to quantify in this study, could raise total value of subsidies provided to industry.

⁴The second country study in the series analyzes federal and provincial subsidies for oil exploration and production in Canada, and will be published in November 2010.

Potential subsidies identified but further research required

The following areas were identified as potentially giving rise to subsidies, but further research is required to clarify whether a subsidy actually exists and, if so, to estimate the value.

- **Pertamina Work Agreement compared with standard PSC:** Further research is required to determine the impact of Pertamina's greater flexibility in "farming out" some of its acreage.
- **R&D support to industry:** Further research is needed to determine whether the fees paid by industry to access R&D services cover the full cost of providing those services borne by the GOI.
- **Bank finance support:** This is likely a subsidy, but further research is needed to quantify the value of the benefit. The value of the subsidy is the difference between the free cost of capital that some PSCos receive, where the IRR is shown to be below the IRR for standard petroleum investment, and the internally set rate of return that PSCos must achieve when projects are financed internally. Some further research would be needed to calculate this difference.
- **Access to expired PSCs:** The preferential right to an expired PSC, which has been granted to Pertamina and a BUMD, could be considered a subsidy. But in order to quantify this subsidy, it will be necessary to obtain detailed information about the return the BUMD and Pertamina have obtained from operating the field and comparing this with an assumed standard return for the industry.
- **Access to forested areas:** The amount of subsidy, in terms of its financial value, requires further research to determine the value of the forest (including its environmental value), which is being replaced by the oil and gas operations, and to identify if this value is being reflected in the land acquisition costs.
- **Application of royalties and equity shares:** Further analysis is required to compare the Indonesian PSC terms and conditions with equivalent terms and conditions applied to oil and gas producers in other countries.
- **Gas Domestic Market Obligation:** Subsidies may exist for gas consumers, but to estimate the size of the subsidy would require detailed analysis of gas prices on a contract-by-contract basis. It may also be difficult to identify a reliable reference price, which may require a weighted average of gas sold domestically.

Activities that are not subsidized

The study concluded that the following upstream activities are not subsidized by the GOI:

- Restoration and rehabilitation of depleted oil and gas fields,
- Year-end reconciliation of overliftings and underliftings,
- Access to new acreage,
- Farm-in to existing PSCs, and
- Bonuses paid by industry.

Impacts of subsidies and next steps

For those subsidies that were identified, the researchers looked at the direct impacts of the subsidies in achieving their policy objectives. This study found that both the investment credit allowance and tax incentives for imported goods and services positively contribute to the GOI's stated objectives of increasing exploration activities and, in particular, encouraging investments in new geological plays. However, the study has not established how efficient the subsidies are in achieving these objectives or whether the aims would be better met by alternatives.

Nor does the study assess the indirect impacts of the subsidies on the wider economy, which was outside the terms of reference for this study. Further work could usefully undertake a full assessment of the economic, environmental and social impact of these subsidies in order to further inform a public debate on whether the subsidies should be kept or considered for reform.

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APPENDIX: 1

Acts and Regulations

Regulation of the Minister of Finance Number 24/PMK.011/2010 Regarding Government-Borne Value Added [05/05/2010]

Regulation Minister Energy & Mineral Resources No. 6 Year 2010 on Policy Guidelines To Increase Oil and Gas Production [16/02/2010]

Government Regulation No.22/2008 – Regulation Minister of Energy & Mineral Resources [06/10/2009]

Law No.30/2007 – Energy [29/06/2009]

Minister of Finance Decree No. 177/2007 – Keputusan Menteri Keuangan Republik Indonesia tentang pembebasan pajak pertambahan nilai selama masa eksplorasi [Minister of Finance Decree on VAT Exemption During the Exploration Phase]

Government Regulation No.34/2005 – Oil and Natural Gas Upstream Business Activities [02/09/2005]

Government Regulation No.42/2002 – The Implementing Body for Upstream Crude Oil and Natural Gas Business Activities [02/09/2002]

Law No.22/2001 – Petroleum and Natural Gas [02/09/2001]

Law No. 8/1971 – Undang-undang tentang pendirian perusahaan pertambangan minyak dan bumi nasional [Law on the Establishment of State-Owned National Oil and Gas Enterprise]

Government Regulation No. 27, 1968 – Peraturan Pemerintah tentang pendirian perusahaan negara pertambangan minyak dan gas bumi [Government Decree on the Establishment of State-Owned Oil and Gas Enterprise]

Law No. 44/1960 – Peraturan Pemerintah Pengganti Undang-undang tentang pertambangan minyak dan gas bumi [Government Decree in lieu of Law on Oil and Gas Mining]

APPENDIX – 2

INDONESIA PSC – GENERATION 1 PSC, SIGNED 1965–1975

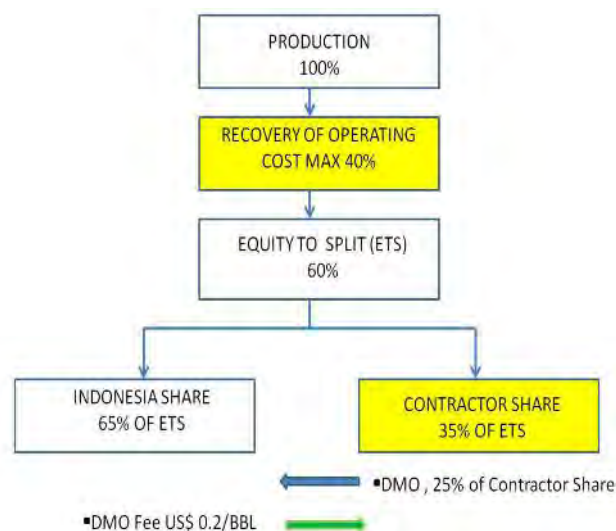
TERMS AND CONDITIONS OF AGREEMENT

- Pertamina holds the management of operation
- All capital and risk shall be borne by the contractor
- Recovery of Operating Cost in any year should be maximum 40% of produced and saved oil (40% cap) and if there is any excess of operating cost, then the unrecovered excess shall be recovered in succeeding years.
- Split sharing of production after cost recovery is:
 - 65% Indonesia share
 - 35% contractor share, including income tax.
- 25% of the contractor share is for oil DMO, valued at US\$0.20/bbl.
- All physical assets landing in Indonesia acquired by contractor become Pertamina's property.
- 10% of participating interests is available for an Indonesian company in the early commercial field development.

Remark: "Operating cost" refers to expenditures made and obligation incurred in carrying out petroleum operating hereunder, determined in accordance with the accounting procedure attached in such PSC agreement.

Expenditures incurred in the abandonment of exploratory wells and the restoration of their drill-sites shall be charged as operating cost in accordance with Article II of exhibit "C" of Accounting Procedure.

PRODUCTION SHARING ARRAGEMENT



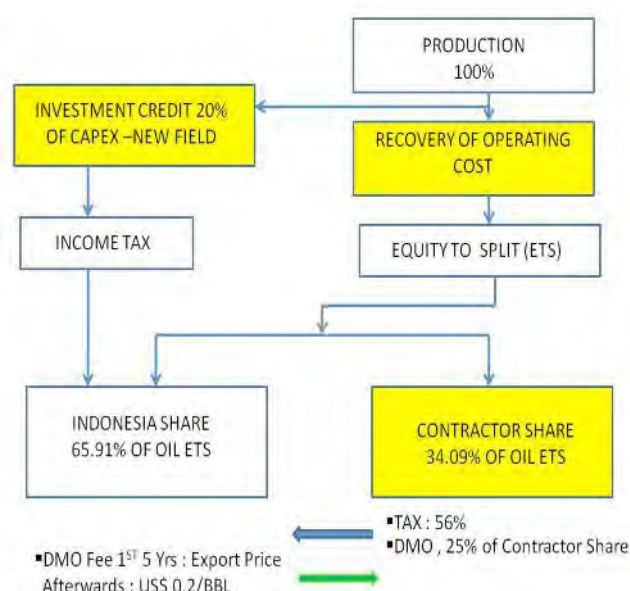
APPENDIX – 3

INDONESIA PSC – GENERATION 2 PSC, SIGNED 1976–1987

TERMS AND CONDITIONS OF AGREEMENT

- Pertamina holds the management of operation
- All capital and risk shall be borne by the contractor
- Contractor will recover all operating costs out of the produced and saved oil (no cap) and if there is any excess of operating cost, then the unrecovered excess shall be recovered in succeeding years.
- Split Sharing of production after cost recovery is:
 - OIL:**
 - 65.91% for Indonesia
 - 34.09% for contractor, pays 56% tax
 - GAS:**
 - 31.80% for Indonesia
 - 68.20% for contractor, pays 56% tax
- Split Sharing for the agreement signed in 1984 and onwards is:
 - OIL:**
 - 71.15% for Indonesia
 - 28.85% for contractor, pays 48% tax
 - GAS:**
 - 42.31% for Indonesia
 - 57.69% for contractor, pays 48% tax
- 25% of the contractor share is for DMO for the first of 5 years valued at export price, afterwards at US\$ 0.20/bbl.
- All physical assets landing in Indonesia acquired by contractor become PERTAMINA's property.
- 10% of participating interest in a working is available for an Indonesian company.

PRODUCTION SHARING ARRANGEMENT



APPENDIX – 4

INDONESIA PSC – GENERATION 3 PSC, SIGNED 1988–CURRENT

TERMS AND CONDITIONS OF AGREEMENT

- Pertamina holds the management of operation
- All capital and risk shall be borne by the contractor
- First Tranche Petroleum (FTP), 20% of production is taken before the deduction of operating cost and will be split between Indonesia and the contractor.
- No cost recovery cap; 100 % of the proceeds after FTP
- Split of production after recovery of operating costs:

OIL:

- 71.15 % for Indonesia
- 28.85 % for contractor, pays 48% tax

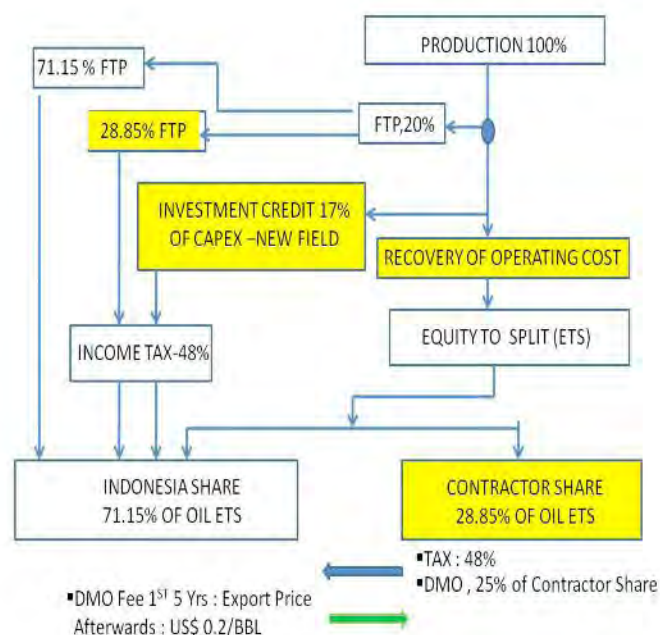
GAS :

- 42.31 % for Indonesia
- 57.69 % for contractor, pays 48% tax

- 25% of the contractor share is for DMO for the first of 5 years valued at export price, afterwards at US\$0.20/bbl.
- All physical assets landing in Indonesia acquired by contractor become PERTAMINA's property.
- 10% of participating interest in a working area is available for an Indonesian company in the early commercial field development.

Incentive Package August 1988 was launched to promote field development, including deregulation in procurement procedures, then a series of incentive packages were introduced in February 1989, August 1989, August 1992 and January 1994 to boost the level of oil/gas activities in the eastern part of Indonesia and higher risk/more remote areas.

PRODUCTION SHARING ARRAGEMENT



APPENDIX – 5

INDONESIA PSC – GENERATION 3, SIGNED 1988 – CURRENT

INCENTIVE PACKAGE AUGUST 31ST 1988

ELEMENT	DESCRIPTION
INVESTMENT CREDIT	Investment credit amounting to 17% of the capital investment of new fields
COMMERCIALITY	Condition that the government has to obtain a minimum of 49% of gross revenue no longer valid. The minimum guarantee is 25% of the gross revenue for the government.
DMO PRICE	10% of export price after the first five years production
PROCUREMENT	Deregulation measures are applied to procurement procedures
FIRST TRANCHE PETROLEUM (FTP)	20% of production taken before deduction of recovery of operating cost and will be split between government and contractor.

APPENDIX – 6

INDONESIA PSC – GENERATION 3, SIGNED 1988 – CURRENT

INCENTIVE PACKAGE FEBRUARY 1989

ELEMENT	DESCRIPTION
SPLIT SHARE FOR TERTIARY EOR FIELDS	Conventional area and frontier area: 80%–20%
SPLIT SHARE FOR MARGINAL FIELDS	Frontier area : 75%–25%
SPLIT SHARE FOR PRE TERTIARY	Conventional area, deep sea over 600 feet and new contract frontier : <ul style="list-style-type: none"> • For production < 50 MBOPD: Split share 80%–20% • For production 50 M – 150 MBOPD: Split share 85%–15% • For production > 150 MBOPD: Split share 90%–10% Frontier Area : <ul style="list-style-type: none"> • For production < 50 MBOPD: Split share 75%–25% • For production 50 M – 150 MBOPD: Split share 80%–20% • For production > 150 MBOPD: Split share 85%–15%
INVESTMENT CREDIT FOR DEEP SEA AREA	For oil – 110% For gas – 55%
EXTENSION TO 6 YEARS EXPLORATION	Exploration period to become 10 years
GAS PRICE	Base on field development economics (economic price)
ACCESS TO FIELD DATA ACQUISITION	Prepared by Pertamina and will be available to contractor for bidding

APPENDIX – 7

INDONESIA PSC – GENERATION 3, SIGNED 1988 – CURRENT

INCENTIVE PACKAGE AUGUST 1992

ELEMENT	DESCRIPTION
SPLIT SHARE FOR DEEP SEA, 600–4,500 FEET AND OVER 4,500 FEET	<ul style="list-style-type: none"> • For production < 50 MBOPD: Split share 75%–25% • For production 50 M – 150 MBOPD: Split share 80%–20% • For production > 150 MBOPD: Split share 85%–15%
SPLIT SHARE FOR NEW CONTRACT	Frontier area : Single split 75%–25%
INVESTMENT CREDIT NEW FIELDS	<ul style="list-style-type: none"> • Pre-tertiary reservoir rock: 110% for oil and gas • Water depth 200–1,500m: 110% for oil and gas • Water depth below 1,500m: 125% for oil and gas
DMO PRICE	15% of export price after the first five years
SPLIT GAS	For water depth below 1,500m: Split share 60%–40% For new contract in conventional area: Split share 65%–15% For new contract in Frontier area: Split share 60%–40% For new contract in depths below sea level of 1500m: Split share 55%–45%

Note: Split Share ratio: GOI/PSC

APPENDIX – 8

INDONESIA PSC – GENERATION 3, SIGNED 1988 – CURRENT

INCENTIVE PACKAGE JANUARY 1994

ELEMENT	DESCRIPTION
APPLIED TO	Eastern Indonesia areas and part of western Indonesia areas having similar geological and geographical condition.
SPLIT SHARE OF OIL FOR FRONTIER AND SEA DEPTH BELOW 1,500 M	65%–35%, with out investment credit
SPLIT SHARE OF GAS FOR FRONTIER AND DEPTH SEA BELOW 1,500 M	60%–40%, with out investment credit
INVESTMENT CREDIT NEW FIELDS	<ul style="list-style-type: none"> • Pre Tertiary reservoir rock: 110% for oil and gas • Water depth 200–1,500m: 110% for oil and gas • Water depth below 1,500m: 125% for oil and gas
DMO PRICE	25% of export price after the first five years
FIRST TRANCHE PETROLEUM (FTP)	15% of production taken before deduction of recovery of operating cost and will be split between government and contractor.

Note: Split share ratio: GOI/PSC

ABOUT THE AUTHORS

David Braithwaite is a senior executive with 35 years experience in the international energy industry working for a major international oil company (BP plc), as an advisor to ministerial-level officials in the Indonesian energy sector, and running a management consultancy focused on the energy sector in Indonesia. David's extensive experience includes 19 years in South East Asia (Indonesia and Philippines).

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Sutadi Pudjo Utomo has expertise in taxes and financial economics, particularly relating to the implementation of Production Sharing Contracts and investment economics. He worked at Pertamina for 27 years, during which he was assigned various roles, including Senior Manager of Finance, Vice-President of Financial and Economics, Vice-President Corporate Finance, and Director of Finance of Pertamina's Geothermal Development Project in West Java. Since retiring from Pertamina in 2003, he started his own business lectures in Financial Economics.

Pri Agung Rakhmanto is a graduate of Institut Teknologi Bandung (Bandung Institute of Technology) in Petroleum Engineering. Agung who also holds a Masters Degree in Mineral Economics from Colorado School of Mines United States and a PhD from Twente University of The Netherlands. Pak Agung is an energy analyst and lecturer in Petroleum Economics at Petroleum Engineering Department of University of Trisakti, Jakarta. He is the founder of a research-based NGO focusing in Energy and Mining Economics, ReforMiner Institute, and is now the executive director of the Institute.

THE GLOBAL SUBSIDIES INITIATIVE (GSI) OF THE INTERNATIONAL INSTITUTE FOR SUSTAINABLE DEVELOPMENT (IISD)

The International Institute for Sustainable Development (IISD) launched the Global Subsidies Initiative (GSI) in December 2005 to put a spotlight on subsidies – transfers of public money to private interests – and how they undermine efforts to put the world economy on a path toward sustainable development.

Subsidies are powerful instruments. They can play a legitimate role in securing public goods that would otherwise remain beyond reach. But they can also be easily subverted. The interests of lobbyists and the electoral ambitions of officeholders can hijack public policy. Therefore, the GSI starts from the premise that full transparency and public accountability for the stated aims of public expenditure must be the cornerstones of any subsidy program.

But the case for scrutiny goes further. Even when subsidies are legitimate instruments of public policy, their efficacy – their fitness for purpose – must still be demonstrated. All too often, the unintended and unforeseen consequences of poorly designed subsidies overwhelm the benefits claimed for these programs. Meanwhile, the citizens who foot the bills remain in the dark.

When subsidies are the principal cause of the perpetuation of a fundamentally unfair trading system, and lie at the root of serious environmental degradation, the questions have to be asked: Is this how taxpayers want their money spent? And should they, through their taxes, support such counterproductive outcomes?

Eliminating harmful subsidies would free up scarce funds to support more worthy causes. The GSI's challenge to those who advocate creating or maintaining particular subsidies is that they should be able to demonstrate that the subsidies are environmentally, socially and economically sustainable – and that they do not undermine the development chances of some of the poorest producers in the world.

To encourage this, the GSI, in cooperation with a growing international network of research and media partners, seeks to lay bare just what good or harm public subsidies are doing; to encourage public debate and awareness of the options that are available; and to help provide policy-makers with the tools they need to secure sustainable outcomes for our societies and our planet

www.globalsubsidies.org

The GSI is an initiative of the International Institute for Sustainable Development (IISD). Established in 1990, the IISD is a Canadian-based not-for-profit organization with a diverse team of more than 150 people located in more than 30 countries. The GSI is headquartered in Geneva, Switzerland and works with partners located around the world. Its principal funders have included the governments of Denmark, the Netherlands, New Zealand, Norway, Sweden and the United Kingdom. The William and Flora Hewlett Foundation have also contributed to funding GSI research and communications activities.

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