ISSN: 2087-1392

RIEBS

Review of Indonesian Economic and Business Studies

June 2012, Vol 3 No. 1

Economic Research Center
LIPI

TABLE OF CONTENTS Page

EFFECT OF FISCAL INCENTIVES ON COAL BED METHANE PRICE: A HYPOTHETICAL ANALYSIS

Makmun
Principal Researcher at the Fiscal Policy Office, Ministry of Finance, Republic of Indonesia
E-mail: syadullah@yahoo.com

Eddy Mayor Putra Sitepu
Researcher at the Fiscal Policy Office, Ministry of Finance, Republic of Indonesia.
E-mail: eddy.sitepu@gmail.com

ABSTRACT

Fossil fuel reserves are diminishing and coal bed methane (CBM) has been regarded as a potential replacement energy source because Indonesia's CBM reserves are enormous, up to 453 trillion cubic feet. To boost investment in CBM development in Indonesia, support in the form of fiscal incentives is needed. By analysing the effects of incentives on CBM's selling price this study assesses whether the forms of incentives provided by the government so far have been appropriate and sufficient. This study uses economic modelling to calculate the effect of incentives on the economics of CBM development in Indonesia. The results of this study show that incentives will have a significant effect on CBM's economic price if there is a composite of different forms of incentive. Nevertheless, in implementing an incentives policy it is important to consider the effect fiscal incentives will have on the reduction of the subsidy for electricity.

Keywords: *CBM, Fiscal incentive, Economic price*

JEL Classification: H32, Q42

I. INTRODUCTION

Coal bed methane (CBM) is another energy resource to meet Indonesia's need for energy in the future. CBM reserves are abundant and have not yet been exploited to any great extent. Indonesia's potential CBM resources are approximately 300 to 450 trillion cubic feet (TCF). These enormous CBM reserves are scattered over eleven coal basins in several areas of Indonesia (Ditjen Migas, 2011).

CBM is expected to contribute 3.3 per cent of Indonesia's primary energy consumption by 2025. In the endeavour to meet ever increasing energy needs, Indonesia faces a number of challenges; infrastructure development for an archipelagic country, maintaining oil and gas production levels, accelerating the development of non-fossil-fuel energy sources and improving efficiency in energy utilisation (which includes conservation and diversification) and the setting of fair energy prices. To achieve these goals, the government is willing to increase the help it gives to the CBM industry.

To foster the development of CBM resources, the government is also preparing some incentives. As a start, the government has just reviewed the possibility of incentives in the form of tax allowances during the period of exploration before a CBM well comes into production. To extract CBM, water must first be removed from the coal layers before the gas can flow and this can take several years. Special incentives are necessary to encourage investment in the development of this industry because there are huge setup costs to be met before the gas can be extracted.

In line with the high commercial risks faced by those who invest in CBM operations, the development of this energy resource requires incentives. The question is, what forms of incentives will be the most effective? In addressing this problem, it is necessary to study the effect of fiscal incentives on coal bed methane pricing.

This paper analyses the effect of incentives on CBM's selling price and will provide policy recommendation for the form of incentives required to achieve an economic price for a CBM project. This paper comprises an introduction, conceptual framework, research methods, review of CBM developments in Indonesia, fiscal incentives and CBM model simulation, and it closes with a conclusion and recommendations.

II. CONCEPTUAL FRAMEWORK

Fiscal policies are economic policies to guide improvements to the economy by making changes to government revenues and expenditures. Instruments of fiscal policy are closely related to taxes; if taxes are reduced, the purchasing power of the people will rise and industry will be able to increase its output. On the other hand, a tax increase will reduce purchasing power and lower industrial output in general.

In economic theory, the concept of incentives has positive connotations (rewards) or negative connotation (costs and penalties). Incentives can affect how people conduct their activities as economic actors as well as how they manage the effect and consequences of their behaviour. Decisions by economic actors in general are determined by the net expected incentives to be received, material and non-material. Thus, the decisions of economic actors may change if there is a change in incentives.

In the context of exploration for, and exploitation of, CBM, large investment is needed and there is a high risk of failure. Therefore, government intervention is needed to support the utilisation of CBM and to encourage investment in its development. The intervention may take the form of government incentives or other facilitation. Incentives might be in the form of changes to regulations, or financial and fiscal incentives. It is expected that by providing various incentives and facilities, such schemes will lower the costs of exploration and exploitation of CBM, and this, in turn, will lead to lower production costs.

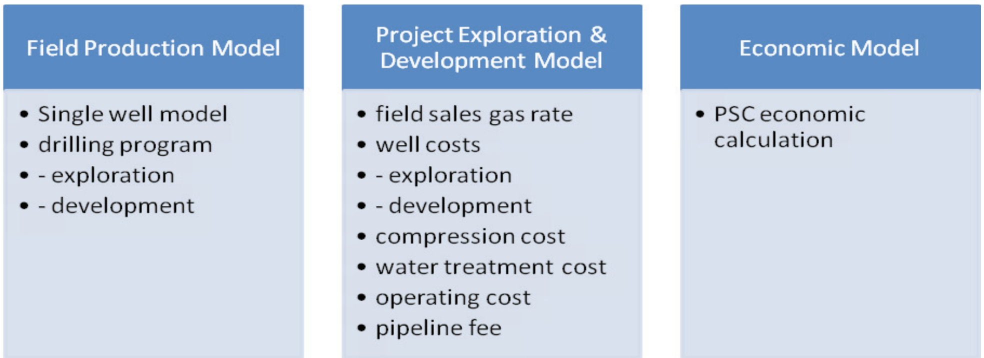
The government has made plans for CBM development in Indonesia until 2025. It is expected that in the immediate future, CBM production is to be used for electricity generation. One problem is that, of those companies that have won tenders to explore for and exploit the possibilities of CBM, most have not conducted exploration because of the high risks of failure and financial uncertainty entailed. CBM exploration and exploitation requires large areas and large numbers of wells to be drilled.

To minimise risks and to make CBM development more attractive for business, the government needs to give incentives. However, such incentives need to be tailored such that the government will not lose potential revenue on one side and, on the other, CBM development will not be hampered. For this reason, it is necessary to strike a balance between the government's potential loss of revenue caused by the incentives given and the potential gain of a decrease in subsidy for electricity as an effect of CBM development.

If the amount of the decrease in subsidy for electricity resulting from CBM development is bigger than the potential loss of revenue (that is, the cost of the incentives), then it can be concluded that the incentives are cost effective for CBM development. On the contrary, if the decrease in the subsidy is smaller than the government's potential loss, the incentives given are deemed to be ineffective.

III. RESEARCH METHODS

The research method used in this study is economic analysis using economic models to calculate the effect of incentives on the economics of CBM development in Indonesia. Basically, the CBM economic modelling used for analysis in this paper comprises of three models, described in Figure 1.



Source: ARI, MIGAS Technical Report, 2004
Figure 1. Fiscal incentive analysis

The field production model (Model 1) is used to simulate a CBM production profile (production rate) using geological data inputs and drilling program assumptions. A production profile produced by Model 1 is used as input for the project exploration and development model (Model 2). Assumptions about types and capacity of production facilities, technical calculations (fuel demand, efficiency, etc.), and calculation of estimated costs (exploration, development and operating) are set and calculated in this model. Output from this model is in the form of a gas sales rate (in terms of MMSCFD [million standard cubic feet per day]) and costs, which are used as inputs for the economic model (Model 3). The economic model is used to calculate the commercial viability of the project (internal rate of return [IRR], net present value [NPV], etc.). In principle, Model 3 is to calculate a contractor's cash flow based on accounting formulae that are regulated in a production sharing contract (PSC).

Production revenue is estimated by multiplying gas price by gas sales rate from Model 2. The contractor take (net profit of the contractor's share) is then calculated by using the aforementioned formula. The contractor's annual cash flow is calculated from contractor take from which are deducted annual costs incurred by the contractor. From annual cash flow, the contractor's IRR can be calculated. The threshold of the project's feasibility, the IRR, is set at 15 per cent. The economic gas price is then calculated by iteration (using the 'goal seek' tool in a Microsoft Excel spreadsheet) by changing assumptions of gas price to achieve a 15 per cent IRR.

To research and devise a set of incentives for CBM projects, we utilised a hypothetical case study called the CBM field simulation model. This simulation model has three main components.

1. An individual CBM well model to calculate production flow for a single CBM well.
2. A CBM field development model (using input from an individual CBM well model) to calculate the number of CBM wells, processing facilities, production flows for the whole field and to give an estimate of development costs.
3. A CBM production sharing contract economic model, to calculate the economics of CBM projects based on the PSC mechanism and input from a CBM field development model.

The analysis is conducted by comparing the economic prices of CBM fields to obtain an internal rate of return (IRR) of 15 per cent, which is appropriate for the minimum target of plan of development (POD) approval requirement in general.

However, because there are many variations in the features of the CBM fields and CBM projects in Indonesia, a number of assumptions are used in the analysis.

First, the geological parameters of CBM reservoirs that are used as input for individual CBM well models are based on work done by Stevens and Hadiyanto (2004). Using data from several CBM basins in Indonesia, we choose parameters that can be applied generally to all basins in Indonesia.

Table 1. Geological parameter assumptions of CBM wells for simulation

	South Sumatra	Central Sumatra	Barito Basin	Kutei Basin	Berau Basin	Hypothetical Well/Project
Area (km^2)	18,800	13,350	16,000	15,600	7,000	1,500
Thickness (m)	36.6	15	30	21	15	20
Depth (m)	762	750	800	900	700	700
Ash content (%)	10	10	5	5	5	5
Permeability (mD)						5
Density (tons/acre-ft)	1.46	1.46	1.46	1.46	1.46	1.46
CO_2 (%)	3	2		1	1	1
CH_4 (m^3/t)	7	4.5	4.7	4.5	4.5	5
R_0 (%)	0.47	0.45	0.45	0.45	0.45	0.45
Saturation (%)						65

Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

The summary of some selected parameters can be seen in Table 1.

Second, assumptions of field development costs are based on inputs from some current CBM operators in Indonesia and compared with costs in other countries that have developed CBM earlier. Based on infrastructure conditions and CBM field development facilities in Indonesia, it is expected that CBM development costs in Indonesia will be similar to those of Australia. The references to cost components in the United States and Canada are difficult to apply in the context of Indonesia because of the vast differences in infrastructure availability and supporting service industries. The areas of CBM development in the United States and Canada, in general, have well developed supporting infrastructure and pipelines, backed by a good availability of CBM rigs. The assumption of cost components used in the simulation models can be viewed in Table 2.

Third, assumptions of economic parameters used in this model, among others, are reference year, 2011; annual discount rate, 10 per cent; annual increase in gas price, 2.5 per cent; exploration price increase 2.5 per cent; development cost escalation 0 per cent (assuming that optimisation from year to year will reduce development costs and will compensate for an annual increase in development costs); operational cost escalation, 2.5 per cent; and an internal rate of return (IRR) of 15 per cent. These assumptions are based on the general economic experience of oil and gas operators.

IV. REVIEW ON CBM DEVELOPMENT IN INDONESIA

4.1 Economic risks of CBM

Technological developments in methane gas drilling from reservoirs have been proven to have brought about more economic efficiency, typically shown by general changes in energy prices. This ongoing development of technology will become the lever for the continuing development of coal bed methane (CBM) production in Indonesia. Currently, the concept of fiscal policy being used to encourage CBM development in Indonesia is modelled on the example of those fiscal policies applied to the oil and gas sector, which, by most CBM investors, are viewed as less attractive than those of neighbouring countries. Therefore, for the continuation of CBM development in Indonesia, what comes after improved regulations for CBM development is an effective fiscal policy for the industry. The profitability of CBM development, whicheis classified as marginal, should be supported by an innovative fiscal policy to make CBM production a more attractive investment in comparison with conventional gas drilling or to make it competitive with other countries' investment policies in regard to CBM development.

Table 2. Assumption of unit cost in CBM development

Item	Unit	Indonesia (model assumption)	BP Migas estimation	Australia (2010)	Remarks
Exploration Coring Pilot	USD/well ('000,000)	4 6	0.6 1.3	1.4 1.9	Continuous coring CBM rig limitation Well control – casing size Stimulation cost Initial access Data acquisition
Development, drill and completion	USD/well ('000,000)	1.6	0.88	1.6	
Lease (pad, road, etc.)	USD/well ('000,000)	0.4	0.12	0.4	
Separator	USD/well ('000,000)	0.3		0.1	Local supplier limitation for CBM
Gathering system and trunk lines	USD/well ('000,000)	0.5	0.1	0.6	Limitation of field infrastructure, roads and pipelines. Slow land acquisition processing because of data mix-up and slow bureaucratic practices.
Water storage	USD/well ('000,000)	0.2	0.03	0.1	
Compression and processing	USD/ MMSCFD	900,000	900,000	900,000	
General operating expenses (opex)	USD/ MMSCF ('000,000)	1.3	0.25	1.3	Lift cost Lowest opex found in dry CBM field (does not contain much water) is 0.95/MMSCF
Water treatment operating expenses	USD/barrel	0.25	0.3	0.3	

Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

Technical aspects that, among others, need to be taken into account by operators in calculating the economics of CBM are as follows. First,

CBM development projects need quite large areas to enable them to acquire reserves in economic amounts that will ensure the longevity of the project. Drilling and completion costs vary significantly. Costs tend to be higher when searching for coal at deeper levels and with lower permeability.

Initially CBM wells generally produce water only, especially during the preliminary dewatering phase. Delays in CBM production caused by the time taken for dewatering have negative effects on the calculation of economic cash flow.

CBM production wells are characterised by relatively low gas pressures and require the construction of large-diameter gathering lines as well as the use of compressors to lift the gas to pipelines. As with oil and gas projects, environmental-impact studies can cause delays in getting licences, and pipeline and other problems can also affect the economics of CBM development.

Other factors that can potentially lower the economic value of CBM development is the absence of special regulations for CBM well drilling. If there are no regulations, operators must use the current regulations that apply to conventional gas drilling. CBM drilling does not require as many types of equipment as does drilling for high-pressure gas and this lowers the drilling costs for CBM. In principle, the economic value of CBM development will be improved if the drilling cost per well is at its minimum.

Higher capital costs (compared with conventional gas exploration) at the initial (exploration) stage of the project should be compensated by financially equivalent incentives. The incentives can be in the form of bonuses, though lower than those for conventional gas exploration (Law 22 of 2001); or full cost recovery for activities during the pilot projects in the first phase. At the production phase, the incentives can be in the form of a more generous profit sharing than the current ratio of 55 to 45, tax holidays or investment credits (or both), and a longer development life cycle. Currently, the fiscal terms and rules of the game for CBM development in Indonesia are not considered attractive by CBM investor candidates.

Some technical aspects that potentially can improve the economic value of a CBM field are the utilisation of field data and the sharing of facilities for processing, storing, and sales with operators who have been working in the one area. This can be realised considering that the facilities are state owned and were, until 13 November 2012, maintained by Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Buma (BP Migas), the Upstream Oil and Gas Executive Agency.

4.2 Patterns of CBM development

Production sharing contract

The regulation of CBM development in Indonesia is based on the same assumptions that apply to the regulation of the development of upstream oil and gas. Upstream oil and gas development and production are arranged and controlled by using production sharing contract (PSC) regulations.[1]

The PSC, as a minimum should cover:

1. The ownership of the natural resources remaining in the hands of

[1] A production sharing contract (PSC) is a form of contract in exploration and exploitation that benefits the state more and the revenue is used for the people's welfare.

the government up to the handover point.

2. The operation's management control being with the implementing agency.
3. The capital and all other risks are borne by the business entity or permanent establishment.

A PSC is a mechanism for cooperation on oil and gas management between the government and a contractor based on article 1 (19) of Law 22 of 2001. According to this law, a PSC is a contract or other form of cooperation for exploration and exploitation that should give a financial benefit to the state for the improvement of people's welfare.

The substance of a PSC system is totally different from concession systems and joint contracts. In a concession system, the oil and gas produced belongs to the contractor, the state only receives cash in the form of royalty payments (approximately four per cent of gross production), income tax, land tax and specified bonuses.

In a joint contract system, the contactor is only given authority to mine, and thus oil and gas produced does not belong to the contractor. The contractor is not even given rights to develop the surface land of a mining area. Rather, they only run the management of the operation under a profit-sharing system with the state.

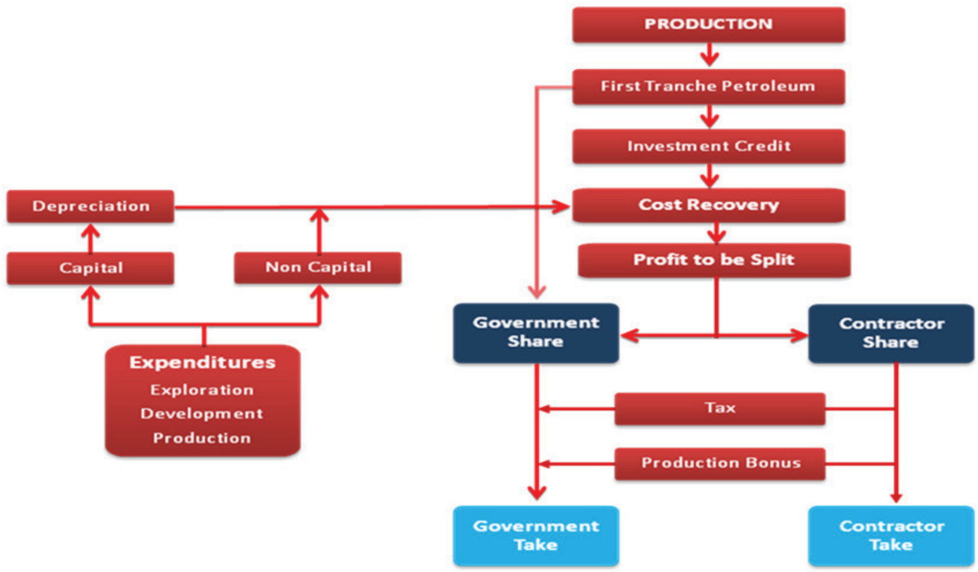
With a PSC system, the oil and gas that is produced belongs to the state, which also acts as the mining authority. The contractor only has the right to enjoy the economic benefits through production sharing. If in a joint contract it is profit that is to be shared (profit sharing), with a PSC it is oil or gas production that is to be shared (production sharing).

The scheme of a production sharing contract is described in Figure 2.

CBM development begins with exploration activities (a geological and geophysical study, core hole, exploratory well and pilot project) over six years, which is in two stages; the first stage of three years is to engage in mining exploration and the next three years are to bring the well into production. The exploration period can be extended once to four years.

Through a pilot project, it can be discovered whether the CBM field development can lead to commercial production and in what scale (commercial field development). The CBM production is conducted by decreasing the reservoir pressure, which is followed by extensive dewatering from coal layers.

The production of CBM requires a large number of wells (because of the low gas production flow) and considerable financial investment. Therefore, the returns for investors will not be sufficient if the production period is shorter..To improve the economic viability and efficiency of production wells that have an expected life of



Source: FGD with Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, 5 July 2011

Figure 2. Production sharing contract scheme

more than thirty years, the contract period must be specified to ensure consistent returns in the long term.

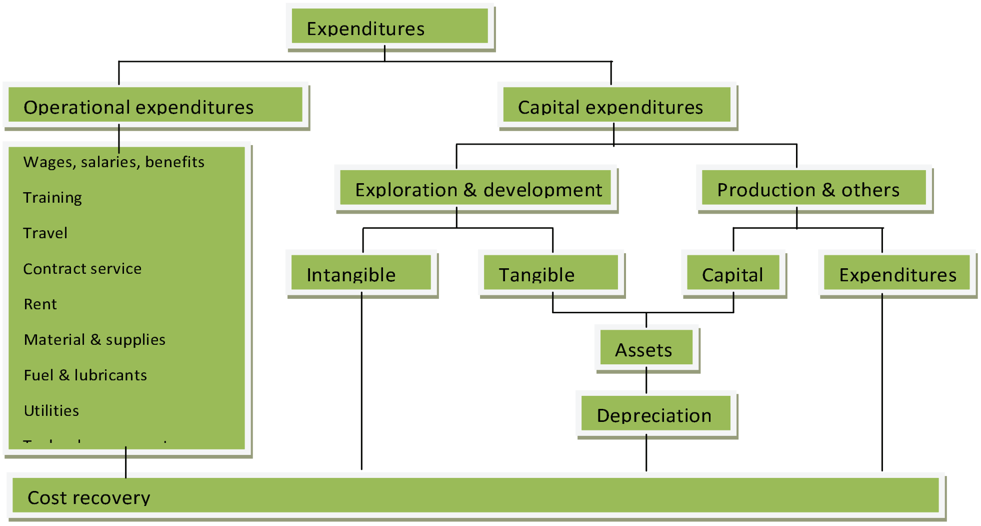
Cost recovery scheme

According to the Upstream Oil and Gas Executive Agency (BP Migas), cost recovery is for reimbursement of costs that are already expended (recoverable costs) by contractors under a production sharing contract for oil and gas production. According to article 1 (6) of Law 41 of 2008 (State Revenue and Expenditure Budget, Fiscal Year 2009) as amended by Law 26 of 2009, cost recovery is reimbursement of all costs that have been incurred by contractors (if they are successful in producing oil and gas), before the production is split between the government and contractor.

The following describes the scheme of cost recovery, starting from expenditure in terms of operational and capital costs, and then followed by details of each class of cost and the flows to cover the complete cost recovery.

From the chart, it can be seen that cost recovery is indemnity or compensation for all costs incurred by contractors, either capital or non-capital. Capital costs are charged through depreciation but non-capital costs can be directly expensed (reimbursed). If there are costs that have not been recovered in a particular year, they may be recovered in the following year.

The cost recovery schemes for CBM bring benefits and risks if they are applied for development. The



Source: FGD with Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, 5 July 2011

Figure 3. Cost recovery

cost profile of CBM field development shows that most of the costs are incurred during the development and production phases and these will be recovered through the cost recovery scheme. Thus, the operator's cash flow will not be burdened by the high initial costs and may focus on production expansion.

4.3 Taxation

Provisions in a PSC are regarded as *lex specialis* (article 33A (4) of the income tax law). However, contractors are still obliged to obey regulations set down in law and in the PSC's operational ordinance, particularly those related to lodging tax forms, tax calculation and payment, accounting and record keeping. In addition, contractors are also obliged to withhold income tax by as much as 20 per cent of profit after deducting income tax (known as branch profit tax).

Taxation regulations for PSCs have changed over time along with the changes in tax laws, but the current regulations are those that came into operation after 1994. For PSCs signed *before* 1 January 1995, the tax regulation at the time of contract signing is applied. In article 33A (4) of the income tax law of 1994, it is stipulated that taxpayers who run a business in oil and gas mining based on a production sharing contract that is still current at the time when this law is in effect, then the tax is calculated according to provisions in the production sharing contract and until termination of the contract. For PSCs signed *after* 1 January 1995, the income tax law of 1994 is applied. Income tax is payable at 30 per cent and branch profit tax at 20 per cent or 44 per cent effectively.

V. FISCAL INCENTIVES AND CBM MODEL SIMULATION

5.1 Feasibility analysis of fiscal incentives

Fiscal incentives are specifically to attract further investment in CBM development. This is to ensure that CBM development will increase not only gas reserves but also increase the utilisation of environmentally friendly sources of energy and employment.

According to article 1 (4) of Law 30 of 2007 on energy, new energy sources are those that can be produced by new technology, either derived from renewable or non-renewable sources, of which one is coal bed methane. Further, in article 20 (5) it is stipulated that energy supplied from new and renewable energy sources by a business entity, a permanent industry establishment or individuals may be granted facilities or incentives (or both) from the central government or from a regional government (or both) according to their authority for a period of time until the economic viability of the project is achieved.

Moreover, in the elucidation of the above-mentioned law, it is explained that the economic value is the value formed from the balance of supply and demand maintenance. Incentives can be in the form of capital support, taxation relief and fiscal incentives. Facilities can be in the form of simplification of licensing procedures and requirements for CBM development.

Some arguments to be considered for giving incentives for CBM are that: CBM development requires high capital investment at the beginning. Compared with conventional gas, costs for CBM development, especially at the initial stages, are substantially higher. Therefore, CBM development projects require policies that provide support, such as subsidies and tax allowances, to enable them to achieve economies of scale. This has been shown to be effective in the United States, Canada and Australia in the development of their CBM industries.

A CBM production period is longer than for conventional gas. In general, CBM development needs around three years for exploration, and after that there is piloting and multi-piloting for about three years more. CBM might only be produced in the seventh year. Commonly, the peak production is achieved from the second until the seventh year of production although the full production period ranges from ten to twenty years.

CBM has produced benefits for coal mining in terms of advances in the application of deep-mining techniques. Knowledge and experience gained and techniques developed for CBM operations can be applied to underground coal mining to reduce the hazards from methane that is found in coal seam cleats.

The occurrence of CBM in coal seams has become a problem for underground coal mining. A concentration of methane gas higher than four per cent has a high potential to cause an explosion. Commonly, CBM is found in basins at a depth of 500 to 600 metres and, at this depth, coal cannot be mined using open-pit techniques; underground mining must be used. If CBM mining techniques are utilised for underground coal mining it will be safer.

5.2 CBM simulation model

Figure 4 shows a production sharing contract (PSC) mechanism for CBM according to a version released in 2011 by the Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources.

In brief, the steps in the accounting mechanism of PSC for CBM can be explained as follows: Gross revenue from gas production sales is subject to first tranche petroleum (FTP), an amount of 10 per cent, which is deposited with the government.

The remaining proceeds (after FTP) are then adjusted for cost recovery to achieve gross profit. Cost recovery is calculated every year and it contains components of production costs and depreciation of capital equipment incurred by the contractor. If the remainder of the year's production is not sufficient to cover all of the cost recovery as calculated, then the rest of cost recovery unpaid will be added to next year's cost recovery. Gross profit is shared in the proportion of 25 per cent for the government and 75 per cent for the contractor.

The contractor's share is subject to 25 per cent income tax and 20 per cent branch profit tax; if added together, the total amount of tax paid by contractor is 40 per cent. Gross profit after tax is deducted gives net profit. If tax is put into the equation, the production shares (setting aside FTP and bonus) become 55 per cent for the government and 45 per cent for contractor. As with the standard PSC for oil and conventional gas production, the life of a CBM PSC is 30 years.

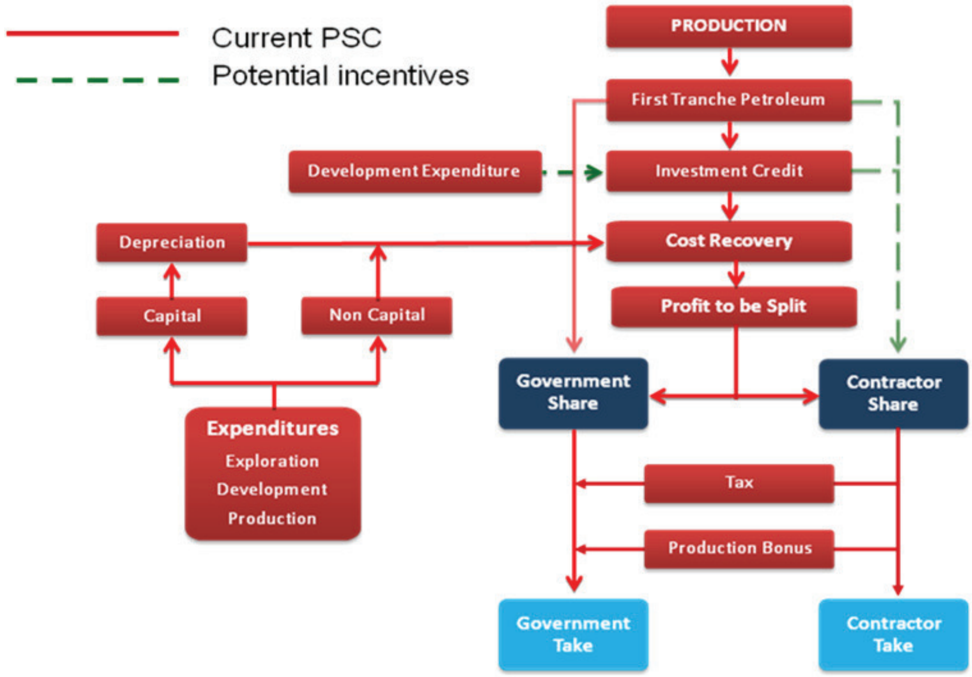
5.3 SIMULATION RESULTS

Individual CBM well production flow

According to results using simulation models and assuming 80-acre well spacing, a hypothetical CBM well production profile in Indonesia in general is described in Figure 5. [2]

Maximum production flow is estimated to be 250 MMSCFD, which is reached in the third year, after which it

[2] A CBM project needs a large number of drilling wells. The well density of a CBM field is often higher than a conventional natural gas field. One section (640 acres or one square mile) typically contains eight CBM wells, compared to just one conventional gas well per section. (Source: http://www.oilandgasbmps.org/resources/cbm.php, accessed 6 August 2012)



Source: FGD with Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, 5 July 2011

Figure 4. PSC scheme for CBM

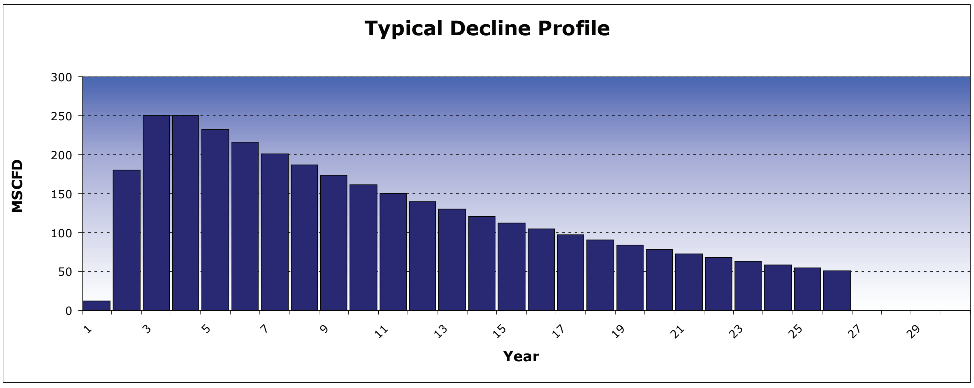
starts to decrease gradually over time. The production profile in Figure 5 is hypothetical and describes a CBM well production flow profile in Indonesia in general. As cited earlier in Table 1, there are six basins of CBM reserves across Indonesia with varied geological and reservoir conditions. The hypothetical individual well production is based on features in those six basins and, consequently, the real CBM well production flow profile in Indonesia is very likely to be far higher or far lower. Thus, this hypothetical pattern of production flow might not represent all CBM projects in Indonesia.

CBM field development model

A summary of the concept and assumptions used in the CBM field development model is in Table 3.

The CBM field development model assumes that there is no limitation of CBM rig availability to hamper drilling. The concept also assumes that all exploration activities, which comprise data study, coring, dewatering and pilot testing, can be completed in six years and all processes regarding licences and POD approval run quickly and do not affect a project's execution.

With these assumptions of development, a CBM production profile is attained for the whole field and is



Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

Figure 5. Hypothetical individual CBM well production-flow profile in Indonesia

described in Figure 6. It is important to notice that there is still a significant volume of gas in place (GIP) after the PSC period ends. An extension of the PSC period for a CBM contractor will help to improve the profitability of CBM projects.

By using the development concept described in Table 3 and the unit cost assumptions in Table 2, a profile of CBM development costs is acquired, which can be seen in Figure 7.

The result of economic model simulation using a standard fiscal mechanism stated in PSC (base case)

From the CBM field production flow and cost profile, either for development or for operation, the project cash flow is shown in Figure 8.

According to the development concept, and by using the standard fiscal mechanism stated in a PSC, we can know that to get an IRR of 15 per cent, the CBM price required is USD13.7 per MMBTU.[3] In other words, the price of CBM at the well head must be USD13.7 per MMBTU or higher to achieve an IRR of 15 per cent. This price is called the economic price of the project. At this price, the project will be sustainable over its lifetime and, overall, either the government or the contractor will get a profit of 26 per cent and 28 per cent respectively. Other than the profit, the government share also includes 19 per cent tax, which makes up the total 45 per cent share for the government. The remaining 55 per cent becomes the contractor's share. This ratio of 45 to 55 sharing for government and contractor is based on the production sharing contract for CBM projects.

5.4 CBM project economic analysis

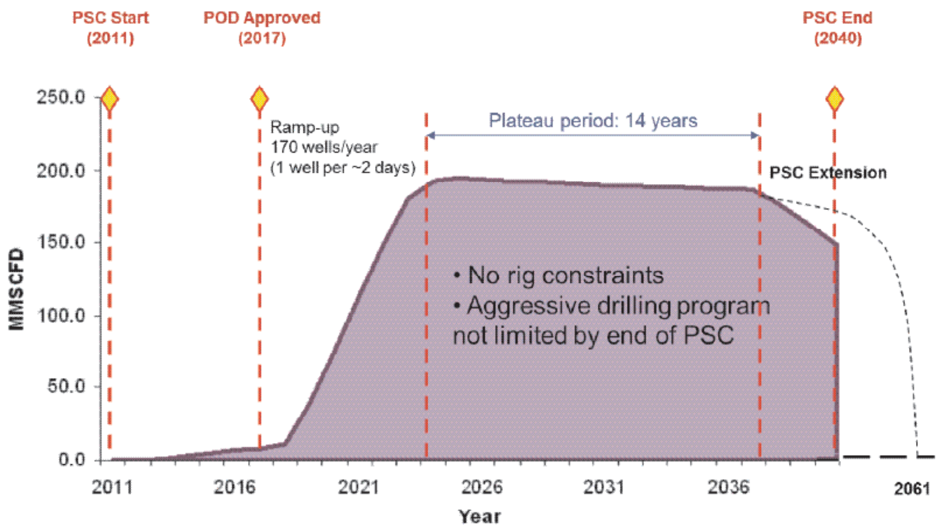
According to the CBM field production profile presented in Figure 9, it

[3] MMBTU is an abbreviation for a million British thermal units.

Table 3. Summary of concept for CBM field development model

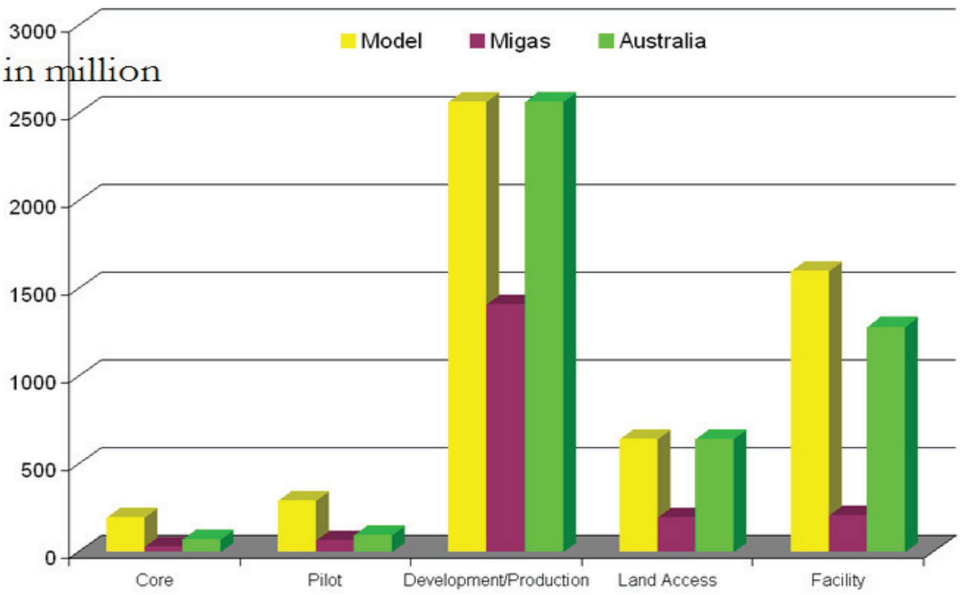
Item	Description
PSC surface area	1500 km^2
Exploration and exploitation period	6 years and 24 years
PSC award year	2011
POD approval year	2017
Full field development area	520 km^2 (35% effective working area)
Well spacing	80 acres (600 m)
Well count (not limited by end of PSC)	1600 wells (no rig constraint assumed) 950 wells to reach plateau 650 wells to maintain production
Gas production	170 MMSCFD plateau, 14 years
Water removal	30.5 Ml/day at peak
Wellsite capex	Well and completion Separator Gas gathering system Site construction, roads Water storage
CO_2 content	<2% (no CO_2 treatment costs included)
Compression and processing	Compression, dehydration, power generation
Water treatment	Gathering, transport, disposal or beneficial use

Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011



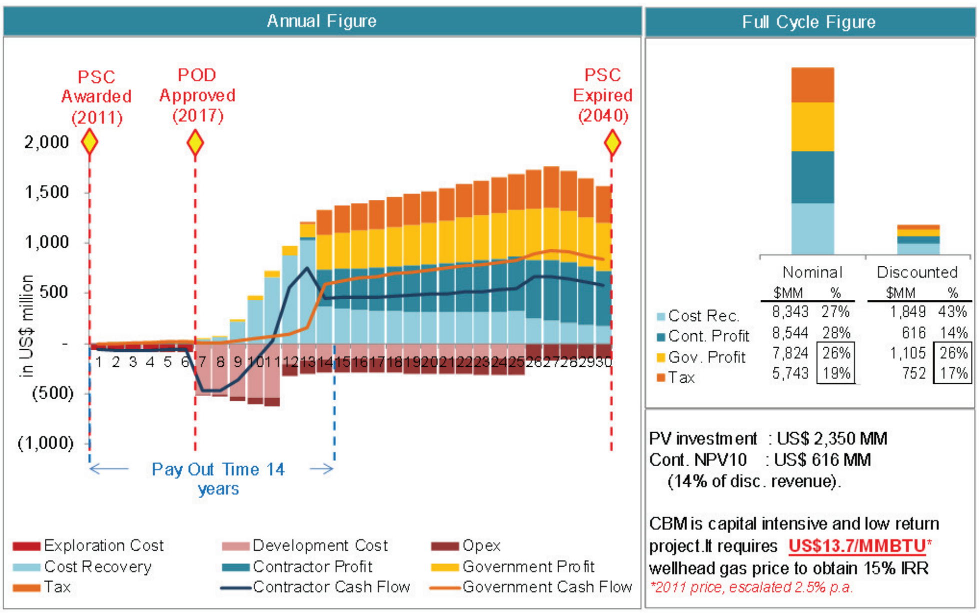
Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

Figure 6. CBM production profile for the whole field



Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

Figure 7. CBM field development cost profile



Source: FGD with Indonesian Petroleum Association (IPA), 10 October 2011

Figure 8. The project cash flow

is clear that even though the model assumes that the well-drilling program is conducted highly aggressively and without any bureaucratic obstacles, a CBM project still needs at least seven years to reach peak production after plan of development (POD) approval. This results in the flow of returns to capital investment in CBM projects being slow, especially when compared with conventional oil and gas projects, which take three to four years only to reach peak production.

Another significant difference is that in CBM projects a contractor must continue to make significant investments throughout the project to continue drilling to maintain constant production, as can be seen in Figure 8. The slow return of capital flows is also reflected in the pay-out time for a project that may take approximately fourteen years after the approval of its PSC on CBM exploration.

With such characteristics, CBM projects require high gas prices and supporting fiscal mechanisms to make them economically feasible.

5.5 Analysis of the effect of incentives on a project's economics

To select the most effective incentives for the development of CBM, it is necessary to make an analysis of several other forms of incentives that can be applied to production sharing contracts. Simulation is conducted for each possible incentive to calculate the economic price of CBM, which is the price necessary to achieve an IRR of 15 per cent.

The summary of simulation results of the effect of incentives on the economic price of CBM are in Figure 9.

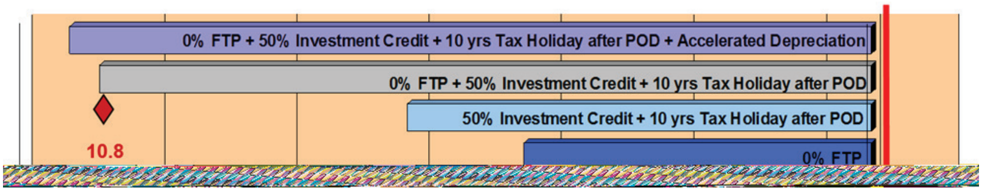
More detailed explanations and analyses of the incentive options in Figure 9, from the smallest effect on price to the largest, are set out below.

100 per cent pre-POD contractor share

Mechanism: all of the income received by the contractor from the sale of gas produced before POD (through pilot wells and dewatering tests) belongs to the contractor (the government does not have a share) and are taxed in accordance with prevailing regulations.

Result: the economic price of CBM can be reduced by 0.7 per cent to USD13.6 per MMBTU.

Underlying consideration: to support a CBM pilot-to-power program, contractors need to be encouraged to use gas produced from pilot tests to produce electricity. On the other hand, using gas from pilot tests cannot be assured to be the most economic option for a contractor. The most common CBM pilot test method is by flaring the gas produced. Additional investment that is required for generating electricity has high risks for contractors because the volume of gas is uncertain, not to mention the possibility of failure. Therefore, the incentive provided is expected to stimulate a



contractor to make the additional investment needed to support CBM pilot-to-power program.

Deficiency: the benefit of this incentive to the economics of the project as a whole is very minor because the sales volume during the period before full production in general is small, so the effect on CBM development in the long run is very small.

Pre-POD tax holiday

Mechanism: profit for a contractor from gas sales produced before POD (through pilot wells and dewatering test wells) is not subject to tax (income tax and branch profit tax).

Result: the economic price of CBM can be reduced by 1.5 per cent to USD13.5 per MMBTU.

Underlying consideration: because the costs of investment and costs of production during pre-POD gas sales can only be included in cost recovery after POD approval, all revenue gained by a contractor during the pre-POD period is regarded as profit; consequently, in fact tax is overpaid, which will be compensated on cost recovery after POD approval. On the other hand, a contractor must bear all costs of investment and production in advance.

Deficiency: the benefit of this incentive to the economics of the project as a whole is very minor because the sales volume during pre-POD period in general is small, so the effect on CBM development in the long run is very small.

ERROR: ioerror
OFFENDING COMMAND: image

STACK:

-mark-
-savelevel-