Recent Developments in the Oil and Gas Industry in Indonesia

April 2009

Introduction

In recent times, Indonesia's oil and gas industry has had a chequered history. Last September Indonesia voluntarily suspended its OPEC membership in the face of declining oil production, having become a net importer of crude oil in 2006 as production declined from a peak of 1.5 million barrels per day ("**bpd**") in the mid-1990s to about 860,000 bpd in 2008. In addition, images of the uncontrollable mudflow allegedly triggered by the drilling of a well by a subsidiary of the Bakrie Group in East Java in September 2006 were beamed across the world. However, the Government has not been complacent and has actively sought to stimulate exploration in a number of frontier areas, and offered attractive fiscal terms to encourage international E&P players to return to the country that was the birthplace of Royal Dutch Shell more than 100 years ago. The Duri Field in Sumatra is undergoing one of the most advanced steamflood and enhanced recovery operations in the world under the operatorship of Chevron, and the super giant multi-billion barrel Minas Field (also operated by Chevron) which has produced 11 billion barrels, is scheduled to undergo advanced chemical recovery operations to assist in recovery of estimated oil in place of four billion barrels, and increase production which is well down from its historical highs of over 400,000 bpd to approximately 150,000 bpd.

The Government has set itself an ambitious oil production target of 1.1 million bpd for 2010.[1] In order to reach this target, the Government realises that the key to maintaining production levels is the discovery of new fields through exploration, and its first petroleum bidding round of 2008 resulted in the award of thirty-three new Production Sharing Contracts ("**PSCs**"). The bid round was a success, and attracted over US$600 million in firm investment commitments and approximately US$110 million in direct bonuses. Following the success of the first petroleum bidding round, the Indonesian regulatory authorities announced a second bidding round which opened on 16 December 2008, which released a further 31 blocks for tender. The Government is currently evaluating bids for this round but has scheduled a further bid round this year for 24 blocks, 17 of which are to be regular tender blocks.

However, there have been recent political tensions that threaten to impede the goal of the Government to encourage exploration and development, as a number of critics have drawn attention to the cost recovery regime in the face of declining production and abuses have been widely publicised in the media, including some egregious claims such as dancing courses and sponsorship of movie festivals. In 2005, the Supreme Audit Agency ("**BPK**") found that oil and gas contractors were abusing the cost recovery system, and claimed US$1.5 billion in potential losses had resulted from such abuses.[2]

Consequently, the revised form of PSC in the 2008 bid round included a number of modifications designed to reduce cost recovery expenditures. In addition, the Ministry of Energy and Mineral Resources ("**MEMR**") introduced Regulation No. 22 of 2008 ("**Regulation 22/2008**") which reduces the type of expenses that contractors can claim as reimbursable costs under the cost recovery scheme. The Minister of Energy and Mineral Resources, Purnomo Yusgiantoro, stated: "Now there is a demand from the public such as the House or others stating that the Government should control cost recovery."[3]

Despite these changes, foreign investors have not been deterred from the recent bid rounds, and some of the world's largest E&P companies have obtained acreage, including, ExxonMobil, Eni, Chevron, Total, StatoilHydro, Hess Corporation, Murphy Oil and ConocoPhillips, although the first petroleum bidding round was not without controversy. The Government awarded the Semai V offshore oil and gas block in Papua (the most contested regular tender block with a potential resource of 8 trillion cubic feet ("**tcf**") of natural gas) to US independent Hess, ahead of a consortium of State owned oil and gas company, PT. Pertamina (Persero) ("**Pertamina**") and Shell, as well as several other major companies. Pertamina lodged an official complaint on the basis that it had offered a larger work commitment for the development of the block. Pertamina offered an investment commitment of US$252.26 million plus a signature bonus of US$15 million. Hess had pledged to invest US$143 million but, significantly, provided a signature bonus of US$40 million (reportedly the largest ever paid in Indonesia). The Government has stood by its decision following the public protest.

[1] Antara News, 18 August 2008: "Govt's oil price assumption at US$100 seen as too low"; http://www.antara.co.id/en/arc/2008/8/18/govts-oil-price-assumption-at-u100-seen-as-too-low/.

[2] The Jakarta Post, 3 July 2008, "Commentary: Enforcing budgetary discipline for oil contractors. "The BPK found that in 2005, oil and gas contractors claimed expenses for goods and services such as DVDs, parties, dance courses, charities and haj pilgrimages to Saudi Arabia": The Jakarta Post, 3 July 2008, "Commentary: Enforcing budgetary discipline for oil contractors". See also The Jakarta Post, 1 September 2007, "Oil cost-recovery rules 'need changes'".

[3] MIGAS website press release dated 21 April 2009: http://www.migas.esdm.go.id

The 2008 revised PSC

Principal Changes in the 2008 PSC

- Liability of contractor
- Commerciality procedure
- Cost recovery
- Bonus payments
- Assignment and change of control
- Pertamina back-in right

In the first petroleum bid round of 2008, investors were introduced to a revised form of production sharing contract (the "**2008 PSC**"), which had not been materially altered since its inception in 1961.

The principal changes in the 2008 PSC are:

- **Liability of contractor**. Although an Operator shall be responsible to BPMIGAS (the Indonesian regulatory authority) in assuming the responsibilities and liabilities of the other Participating Interest holders,[4] BPMIGAS now has the right to directly communicate with, and enforce the obligations, responsibilities and liabilities of, any Participating Interest holder on a joint and several basis.[5] As the PSC previously referred to the Contractor as a single entity, this clarification has made it clear that the Government can seek redress from any single member of the Contractor Group, and speculation exists that this change was in part motivated by the concerns regarding the Lapindo mudflow, and the lack of recourse potentially available to the Government against the other contractors.

- **Commerciality procedure**. The 2008 PSC specifies in greater detail the procedure for assessing and developing the commerciality of a contract area. A Contractor must report a petroleum discovery made during the exploration period to BPMIGAS and the Government. The Contractor then has 2 years from receipt of BPMIGAS acknowledgment to submit a proposed Plan of Development for the relevant field for Ministerial approval (which may be extended subject to the availability of commercial gas sales commitments and BPMIGAS approval). Approval of the Plan of Development without material condition shall constitute a declaration of commerciality.

  If, prior to expiration of the exploration period, BPMIGAS does not issue an acknowledgment of discovery or the Minister does not approve the Plan of Development, then the PSC shall automatically terminate after a notification from BPMIGAS. In addition, the PSC shall automatically terminate if the Contractor does not conduct petroleum operations within five consecutive Contract Years after approval of the Plan of Development. The effect of these provisions is to improve the previous terms of the model PSC that were somewhat vague as to the steps to be taken to achieve commerciality.

- **Cost recovery**. Previously, in Indonesia's PSCs, fields were not segregated for cost recovery purposes; cost recovery was available for all Operating Costs incurred in respect of the entire PSC block. However, the 2008 PSC only permits Operating Costs to be recovered out of Petroleum produced from the particular field in respect of which the costs have been incurred based on the Plan of Development approved for that field. This "field ring-fencing", which prevents Contractors claiming recovery for dry hole costs and other expenditures from producing fields, is a direct response to the public pressure to reduce the level of cost recovery. It is highly controversial and was unsuccessfully lobbied against by industry participants.

  The 2008 PSC also expressly limits what costs may be cost recovered, increasing the range of costs which must be borne solely by the Contractor.

  - Any exploratory expenditures corresponding to any portion of the Contract Area outside the field that has been relinquished prior to the receipt of Plan of Development approval may not be recovered as Operating Costs.
  - Interest on loans obtained by the Contractor shall not be recoverable as Operating Costs.
  - Costs and expenses relating to the acquisition of a Participating Interest shall not be recoverable as Operating Costs.
  - Costs and expenses incurred to conduct community development programmes relating to the community surrounding and/or adjacent to the Contract Area after the Exploration Period shall not be regarded as Operating Costs.

- **Bonus payments**. Previously, a Contractor was entitled to use bonus payments in order to reduce its taxable income. However, subsection 8.6 of the 2008 PSC expressly states that "bonus payments (including all production bonuses)" will not be used as a reduction of the Contractor's taxable income.

---

[4] See sub-section 1.1.6 of the 2008 PSC.

[5] See sub-section 1.1.6(e) of the 2008 PSC.

- **Assignment and change of control**. A Contractor's right to sell or assign all or part of its Participating Interest to an Affiliated Company is no longer restricted by a requirement that the Contractor remain the majority Participating Interest holder during the first three Contract Years. However, a Contractor is now required to obtain the consent of BPMIGAS and the Government in order to assign to an Affiliated Company (as well as to a Non-Affiliated Company), which will prevent inter-affiliate transfers followed by share sales which had previously been used to circumvent approvals process.

  In addition, BPMIGAS and Government consent is required for a direct or indirect change in the ownership of at least 50% of the voting stock of a Contractor. Although the 2008 PSC does not specify how far up the corporate chain requires approval for a change in control, some of the draft PSCs negotiated following the 2008 petroleum bid round define a "Change of Control" to relate to transactions in which the Participating Interest is the "only substantive asset".

- **Pertamina back-in right**. In the Bid Documents issued for the 2008 bid round, the Tender Procedures stipulated that Pertamina has the right to acquire a 15% interest in the relevant PSC negotiated with the winning bidder(s) on a "business to business" basis, provided Pertamina submits a letter of intent to the winning bidder within 14 days of the announcement of the winning bidder. Significantly, this 15% participation right is in addition to the Indonesian Participant provisions in the PSC, which entitle a Local Government Owned Company or Indonesian National Company to take a 10% Participating Interest following Government approval of the first Plan of Development.

  Many industry observers were surprised at the inclusion of this directive and it is not clear how this right will work in practice. If a winning bidder is obligated to transfer a 15% interest to Pertamina "at cost" (i.e., without any premium or promote) then this requirement promises to be of great assistance and competitive advantage to Pertamina. Many would argue that this is another example of a policy change that could be questioned, but it must be said that it still falls short of the requirements of many other countries where contractors are required to deal with the host country's national E&P company as a partner.

Scrutiny of cost recovery

Cost recovery limits have changed dramatically in Indonesia since the inception of the PSC. The first generation PSC contracts contained a cost recovery limit of 40%, whilst the second generation contracts from 1978 – 1987 did not contain a cost recovery cap at all. The third generation contracts introduced the concept of *first tranche petroleum*, which required 20% of total production to be shared between the Government and the Contractor before the Contractor could recover its costs. Therefore, first tranche petroleum worked effectively as a cost recovery limit. The 2008 PSC provides that 10% of first production shall be allocated to BPMIGAS before any deduction for the recovery of Operating Costs, thereby acting as a 90% cost recovery limit.

The Government implemented Regulation 22/2008 on 30 June 2008, which lists 17 items that relate to upstream oil and natural gas activities that shall not be considered as Operating Costs and, therefore, shall not be recoverable from the Government including:

- Costs related to the personal interests of employees of the Contractor, including personal income tax, losses incurred in the sale of property and personal automobiles.
- Long term incentive plans or any other type of incentive plans for the Contractor's employees.
- The cost of hiring legal counsel for matters outside PSC operations.
- Marketing costs in relation to the Contractor's share of oil and gas, and other costs arising as a result of Contractor's wilful misconduct in its marketing activities.
- Environmental and community development costs during the exploitation period (i.e., after the exploration period).
- Technical training costs for foreign employees.
- Costs relating to mergers and acquisitions.
- The cost of procuring goods and services or any other activities in excess of the approved Authorization for Financial Expenditure by more than 10%, without clear justification.
- The costs of surplus materials due to improper or mistaken planning and purchasing.
- Transactions with affiliates which adversely cause losses to the Government, without going through a tender process, or in conflict with Law Number 5 of 1999 concerning Anti-Monopoly Practices and Unfair Business Competition or any other tax regulations.

Regulation 22/2008 has proven to be controversial. Many have also complained that the focus on cost recovery has obscured the bigger issue that has caused delay and inefficiency, namely, the approval and budgetary procedures administered by BPMIGAS and MIGAS, which many complain are cumbersome and lead to delays in both exploration and production.

While the clamp down on cost recovery "abuses" resonates with the public, the reality is that more attention needs to be focused on improving the time taken to approve AFEs and budgets. It would be regrettable if these new measures create further bottlenecks as administrators control cost but slow efforts to explore and develop fields.

Brad Roach, partner

Coal bed methane

In another important development in 2008, BPMIGAS entered into six Coal Bed Methane ("**CBM**") PSCs; the first PSCs for CBM awarded in the history of the country. BPMIGAS concluded its first CBM PSC with domestic gas companies PT. Medco Energi Internasional Tbk. ("**Medco**") and PT. Energi Pasir Hitam ("**Ephindo**") in May 2008 to develop a deposit in South Sumatra. Earlier this year, Medco and Ephindo separately reached agreement with Arrow Energy, an Australian based emerging global leader in coal seam gas development, to cooperate in the joint exploration and development of CBM in their respective CBM PSC working areas.

It is estimated that total CBM reserves in Indonesia are approximately 450 tcf – the world's second largest CBM reserves after China – with at least 10% of those reserves being capable of economic extraction. However, in spite of its abundance, and in comparison to more mature CBM markets, such as the United States, Canada and Australia, the commercial production of CBM is in its infancy in Indonesia.

Indonesian legislation classifies CBM as a natural gas, largely adopting the legislative regime applicable to upstream oil and natural gas activities. More recently, the MEMR introduced Regulation No. 36 of 2008 on the Operation of Coal Bed Methane ("**Regulation 36/2008**"), which entered into force on 12 November 2008, replacing MEMR Regulation No. 33 of 2006 on Business Undertakings of Coal Bed Methane ("**Regulation 33/2006**").

PROCEDURES FOR OFFERING AND AWARDING CBM WORKING AREAS

Offering and awarding CBM working areas located in CBM open areas

The offering and award of CBM working areas in CBM open areas or the so-called available working area (i.e., areas in the Indonesian territory that have not yet been determined as a CBM working area, oil and natural gas working areas and/or coal mine, either in the form of mining authorization ("**KP**") or coal contract of work ("**PKP2B**"), working areas) follows the procedures for the offering and award of oil and natural gas blocks under MEMR Regulation No. 35 of 2008 on Procedures for Oil and Gas Blocks Allocation and Offering.

Offering and awarding CBM working areas located in oil and natural gas or coal mine working areas

Under Regulation 33/2006, if CBM was located in an existing oil and natural gas PSC contract area, the PSC contractor would be given the first opportunity to exploit the CBM, provided that the PSC contract area did not overlap with a KP working area or a PKP2B working area. Similarly, if CBM was located in a working area which was subject to a KP or a PKP2B, the KP contractor or, if relevant, the PKP2B contractor would be given the first opportunity to exploit the CBM in exactly the same way that a PSC contractor would have priority in the PSC contract area.

Regulation 36/2008 now allows new investors to submit a direct offer proposal for CBM operation rights through Joint Study methods in the CBM open areas to the Director General of Oil and Gas ('**MIGAS**"). Oil and gas contractors who have fulfilled their "Firm Commitment" for the first three years of the exploration period under the relevant PSC, and KP contractors or PKP2B contractors who have been conducting coal exploitation activities for at least three years, in the particular working area in which CBM is located shall be given first opportunity to submit a direct offer proposal through a Joint Evaluation of the CBM in that working area to MIGAS. However, if a Joint Study for the development of CBM in a working area has been submitted by a third party prior to the signing of the PSC or PKP2B or the issuance of the KP that relates to that working area, then the oil and gas contractor, KP contractor or PKP2B contractor (as applicable) shall not have such first opportunity right.

Offering and awarding CBM working areas located in both oil and gas and coal mine working areas

Under Regulation 33/2006, the first opportunity to exploit CBM in an area where a PSC contract area overlaps with a KP area or PKP2B area (an "**Overlapping Area**") was given to the PSC contractor and the KP contractor or PKP2B contractor (together, the "**Contractor Parties**") based on written agreement among the Contractor Parties. If the Contractor Parties wished to exploit CBM in an Overlapping Area, exploitation was to be undertaken by a separate legal entity, which was set up by the Contractor Parties, on the basis of a written agreement.

The position under Regulation 36/2008 is different. The first opportunity right to submit a direct offer proposal through Joint Evaluation to MIGAS for CBM operation rights in an Overlapping Area belongs to the oil and gas contractor. A KP contractor or PKP2B contractor must submit a proposal to MIGAS if it wishes to exploit CBM in such Overlapping Area, and MIGAS will open discussions with the oil and gas contractor as to its intention. If, within 6 months thereafter, the oil and gas contractor has not submitted a proposal to MIGAS, its first opportunity right will be deemed invalid and MIGAS may grant the KP contractor or PKP2B contractor such right.

CBM COOPERATION CONTRACTS

Regulation 36/2008 provides for the exploitation of CBM to be undertaken in accordance with a separate Cooperation Contract to be entered into by the CBM contractor with BPMIGAS, even if the relevant working area is already subject to an oil and natural gas PSC, a KP or a coal mining concession.

Regulation 36/2008 sets out the basic provisions which, as a minimum, shall be contained in a CBM Cooperation Contract. These provisions are consistent with the basic provisions for a Cooperation Contract required by Article 11 of Law No. 22/2001 for Oil and Natural Gas (the "**2001 Oil and Gas Law**") and the basic provisions for an oil and natural gas Cooperation Contract required by Article 26 of Governmental Regulation No. 35 of 2004 on Upstream Oil and Gas Activities. They include, among others, provisions for state revenues, description of the CBM working area and its relinquishment, the CBM contractor's expenditure obligations, the transfer of the ownership in the CBM that is produced, dispute resolution, domestic allocation, and environmental management. The current draft CBM Cooperation Contract released by BPMIGAS last year is closely modelled on the 2008 PSC, but the profit splits are reportedly much more favourable to Contractors than existing fiscal terms for natural gas and crude oil, recognising the capital intensive nature of CBM operations.

Currently, a number of major E&P companies are actively pursuing CBM transactions, including Shell/Arrow, Chevron, Vico Indonesia and Marathon, and the new regulation should assist its development as there were widespread problems with competing KP claims and studies in the past. It is to be hoped that the development of a transparent tender system will facilitate the expansion of the industry, as in the past the process to obtain a right to conduct a joint study to evaluate CBM prospectivity from the authorities was not public.

Major projects in Indonesia

Since its transition from a regulatory body to a limited liability company in July 2006, Pertamina has been under pressure to increase production levels in order to boost state revenues. In order to do so in the face of declining reserves, Pertamina has been expanding its production base to sites outside Indonesia. Pertamina's senior-vice president referred to his company's desire to "secur[e] oil in regions far from here, including the Middle East".[6] In addition to its interests in Malaysia, Iraq, Libya and Sudan, Pertamina more recently acquired exploration rights over an onshore oil block in Qatar.[7] Pertamina is also planning to participate in several blocks, including Total's Mahakam block in East Kalimantan and Chevron's deepwater fields off East Kalimantan, and to upgrade assets and increase production in its existing acreage, including its Limau oil fields in South Sumatra and Tambun gas fields in Bekasi, West Java.[8]

Pertamina's production targets have also received a significant boost since it was granted the right to develop the Natuna D-Alpha block in the Riau Islands in February 2008, after the production sharing contract held by ExxonMobil was terminated by the Government in 2005. Following a selection process, the Malaysian Prime Minister announced on 23 April 2009, that Pertamina had selected Petronas as its partner to develop Natuna D-Alpha. The Natuna D-Alpha block is Asia's largest undeveloped gas block which holds an estimated 222 tcf, of which 46 tcf is estimated to be recoverable. However, the field has an extremely high level of carbon dioxide (approximately 70%), so the development costs are likely to be several billion dollars. Given the deepening global financial crisis and the significant drop in energy prices, Pertamina's ambitions in the forthcoming years may not be easily achieved as it may be forced to cut back on its spending and delay certain projects, particularly given difficulties obtaining external financing.[9]

In recent times, Indonesia has been plagued by delays between discoveries and development, and the Banyu Urip oil field in the Cepu Block in Java is a case in point. The field was initially discovered in 2000 by ExxonMobil but as the terms of the Technical Assistance Contract with Pertamina were due to expire in 2010, the field was not developed as an extension was required. Initially, the field was touted as a billion barrel discovery (it has since been downgraded to 350 million barrels), and Pertamina and ExxonMobil clashed over operatorship. Eventually, a compromise involving joint operation by both companies was reached and a new PSC was awarded in 2006, involving an innovative differential equity split linked to oil prices. Despite earlier predictions that development would commence in 2003, full commercial production of around 165,000 bpd has been delayed and early production of 20,000 bpd is planned this year,[10] in part due to delays in accessing the contract area and over the proposal for an offshore FSO rather than an onshore facility.

Several major oil and gas projects are currently in development in Indonesia and are expected to commence within the next couple of years. Until 2006, Indonesia was the world's largest exporter of liquefied natural gas ("**LNG**") from the Bontang LNG facility in Badak, East Kalimantan and the Arun plant in North Sumatra, but these projects have suffered from declining feedstock supplies. The BP-operated, Tangguh LNG project is scheduled to commence first deliveries later this year, and its production of 7.6 million tonnes per year will be delivered to buyers in China, South Korea and Mexico (although the diversion of certain cargoes initially earmarked for Mexico is currently under discussion by the sponsors and the LNG purchaser).

Currently, the two main LNG projects under development in Indonesia are the Donggi–Senoro LNG Project in Sulawesi and the Masela LNG Project in the Timor Sea, although both of these projects face challenges in the current economic environment. Foreign investors will also be keeping an eye on what proportion of gas produced from these projects will be required to be allocated to the domestic market. Although the Government has set a priority to supply gas for domestic consumption rather than for overseas buyers, many existing contracts do not allocate a proportion of production to the market. On February 5 2008, the MEMR introduced Regulation No. 2 of 2008 on the domestic market obligation ("**DMO**") for upstream oil and gas contractors ("**Regulation 2/2008**"), which mandates that a PSC Contractor allocate 25% of its share of oil and gas production to be supplied to the domestic market. The Government has also hinted that Chevron's proposed Gehem and Gendalo deepwater gas field development off East Kalimantan may receive dispensation from the DMO due to the costs involved in the project.[11] Chevron has signalled that the project may be on-stream by 2011, but it is believed that BPMIGAS has yet to receive any proposals concerning the development of the project.

[6] The Financial Times, 1 June 2008, "Scramble for Asian resources raises fears".

[7] Oil & Gas Journal, 22 December 2008, "PT Pertamina to invest $1 billion on production": http://www.ogj.com/articles/article_display.cfm?ARTICLE_ID=348796&p=7; http://online.wsj.com/article/BT-CO-20081201-709470.html.

[8] Oil & Gas Journal, 22 December 2008, "PT Pertamina to invest $1 billion on production": http://www.ogj.com/articles/article_display.cfm?ARTICLE_ID=348796&p=7.

[9] Pertamina will rely on internal revenues to fund the Cepu project in East Java following its inability to secure loans from foreign banks: The Jakarta Post, 23 September 2008, "Pertamina to invest $500 million on Cepu project". However, Pertamina received a US$225 million financing commitment from a foreign bank consortium to build a polypropylene unit at its refinery in Balongan, West Java: The Jakarta Post, 12 January 2009, "Pertamina gets $225 million loan for Balongan".

[10] Upstream Online, 11 December 2008, "ExxonMobil opens Cepu taps".

[11] The Jakarta Post, 18 February 2009, "Chevron to decide big investment in 2011".

DONGGI-SENORO LNG PROJECT

The Donggi-Senoro LNG project will be the fourth largest LNG production base project in Indonesia, and is expected to produce approximately 2.1 million tonnes of LNG per year. It will be the first LNG project in Indonesia to be structured as a downstream project where the LNG plant owner/operator, PT. Donggi-Senoro LNG – which is 51% owned by Mitsubishi Corporation, 20% by PT. Medco LNG Indonesia (a subsidiary of PT. Medco Energi Internasional Tbk.) and 29% by Pertamina – will purchase natural gas from Medco and Pertamina's upstream entities, operate the LNG plant and sell LNG to international buyers.

The gas to supply the LNG plant is being provided principally by the Senoro gas field located in the north-eastern region of Sulawesi, which was discovered in April 1999 and has approximately 1.4 tcf of proven gas reserves. The owners of the Senoro gas field, PT. PHE Tomori Sulawesi and PT. Medco E&P Tomori Sulawesi, signed a gas sales agreement on 22 January 2009 to supply gas amounting to 250 million standard cubic feet ("**mmscf**") per day for a period of 15 years to PT. Donggi-Senoro LNG.

Gas will also be supplied from the Pertamina-operated Donggi, Matindok, Maleo-Raj and Minahaki fields, which contain in aggregate 0.7 tcf of proven reserves. The gas sales agreement (also signed on 22 January 2009) is for the supply of 85 mmscf of gas per day, also for a term of 15 years.

The total price of the gas sales is expected to reach over US$16 billion.[12] The final investment decision for the project, which was scheduled for 2008, is expected this year; and the project is scheduled to commence commercial operations in 2012. However, due to the decline in oil prices, the project has been criticised by legislators because the price at which the natural gas will be sold to the LNG plant is considered to be low, notwithstanding the absence of any domestic gas demand in Sulawesi.

MASELA LNG

INPEX Masela Ltd. ("**INPEX**"), a subsidiary of Japan's INPEX CORPORATION looks set to build the world's first floating LNG plant in the Abadi field in the Masela block, the Timor Sea, following the Government's "in principle" approval of its plan of development earlier this year.[13] INPEX may soon have partners to assist in funding the estimated US$19.6 billion project given comments from the Chairman, Kunihiko Matsuo, that INPEX may sell part of its interest in order to curb funding options in the current world financial crisis.[14]

INPEX discovered a large-scale gas structure, the Abadi Field, in December 2000; the first discovery of natural gas in the Indonesian Arafura Sea. INPEX estimates there are more than 10 tcf of natural gas reserves in the Abadi Field.[15] However, monetisation of the project has proved challenging given the isolated location of the gas field. INPEX had been studying building a pipeline to Australia to ship the gas to the Ichthys onshore liquefaction plant in Darwin, but that development method was shelved for technical and economic reasons.

The floating LNG plant will have an annual LNG production capacity of 4.5 million tonnes per year.

LNG RECEIVING TERMINAL IN JAVA

A consortium of Pertamina, Indonesia's gas distribution company, PT Perusahaan Gas Negara ("**PGN**") and State owned electricity firm PT Perusahaan Listrik Negara ("**PLN**") is planning to build Indonesia's first LNG receiving terminal in Bojonegara, West Java.

PLN's interest in the terminal is to secure gas supplies for its gas-fired and combined cycle power plants located in Jakarta.

The consortium signed a memorandum of understanding in July 2008 with Total and INPEX to supply 1.5 million tonnes per year of LNG to the receiving terminal from East Kalimantan's Mahakam block from 2012 for 11 years.[16]

[12] Antara News, 29 August 2008, "Pertamina, Medco agree on US$16 billion gas sales deal": www.antara.co.id/en/arc/2008/8/29/pertamina-medco-agree-on-us16-billion-gas-sales-deal/.

[13] Oil & Gas Journal, 11 January 2009, "Indonesia approves INPEX floating LNG plant plan".

[14] The Jakarta Post, 17 December 2008, "INPEX to sell stakes in Indonesia LNG project".

[15] Upstream Online, 9 June 2008, "INPEX submits $19.6bn floating LNG plan": www.upstreamonline.com/live/article156695.ece.

[16] Platts, 18 December 2008, "PLN says may pull out of west Java LNG project if plans change": http://www.platts.com/Natural%20Gas/News/8244857.xml?src=Natural%20Gasrssheadlines1.

Conclusion

Since cost recovery expenditures amounted to US$8.3 billion in 2008, aside from specific changes to the regulations and the terms of the model PSC, the Government is reported to be investigating the adoption of an entirely different form of concession that would eliminate cost recovery. However, there are mixed views even within the Government on this issue, although in an election year (as 2009 is) it will be interesting to see which view ultimately prevails. For the sake of the development of the E&P industry in Indonesia, it is hoped that the right balance is struck, and that short term solutions that focus on curtailing cost recovery do not result in more harm than good, especially in the radically different economic conditions that prevail today.

The untold riches of the CBM bonanza have attracted some of the world's largest E&P companies, but it remains to be seen whether the fiscal terms will strike the right balance. At a glance, the CBM PSC has not adequately taken into account the unique characteristics of developing CBM, and the absence of globally competitive local gas markets may dissuade foreign investors from participating in the sector. However, it is likely that CBM may one day form the basis for major gas developments. The recent activity in Queensland, Australia in the CBM/LNG sector will no doubt be watched closely by industry observers. As ever, Indonesia has the resources so it remains a case of ensuring that the Government can strike the right balance to lead to the monetisation of these reserves.

One thing is clear, and that is that foreign and domestic investors will require certainty in order for them to make their investment decisions, so the see-sawing in recent times on cost recovery and amendments to the PSC are not conducive to the considerable financial commitments that are needed to open up the remaining deepwater basins in Indonesia and to develop CBM resources. An increase in cost recovery restrictions (including an increase in the number of taxes that are no longer cost recoverable), overlapping laws and regulations issued by the central and local governments, and difficulties in contractors acquiring land for E&P activities, are among the issues discouraging investors from investing in the oil and gas sector in Indonesia.[17] There is a lot at stake in today's competitive world for E&P dollars, so for the sake of Indonesia, it is to be hoped that the authorities strike the right balance.

[17] The Jakarta Post, 1 April 2009, "Attracting investment in oil and gas in Indonesia amid global recession."

Acknowledgement
We thank PT Medco Energi Internasional Tbk. for providing and granting us the permission to reproduce the pictures in this client note.

Further information
If you would like further information on any aspect of this client note please contact a person mentioned below.

Contact
Brad Roach
Partner
T +65 6302 2556
brad.roach@lovellsleenlee.com

Janine Gill
Associate
T +65 6302 2434
janine.gill@lovellsleenlee.com

Andi Haryanto
Legal Executive
T +65 6302 2564
andi.haryanto@lovellsleenlee.com

April 2009

www.lovellsleenlee.com

Lovells LLP and its affiliated businesses have offices in:

Alicante	Madrid
Amsterdam	Milan
Beijing	Moscow
Brussels	Munich
Budapest*	New York
Chicago	Paris
Dubai	Prague
Dusseldorf	Rome
Frankfurt	Shanghai
Hamburg	Singapore
Hanoi	Tokyo
Ho Chi Minh City	Warsaw
Hong Kong	Zagreb*
London	

*Associated offices