Gas powers upstream drive

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As the only Asian member of OPEC until it suspended membership of the oil producers' organisation in 2005, Indonesia has been a dominant presence in Southeast Asia's hydrocarbons sector for the past 50 years. But where the world's largest Muslim economy's position was once solidly founded on its status as a prominent exporter of crude oil, the country's energy profile is shifting.

Just over ten years ago, Jakarta was pumping more than 1.3 million barrels a day (b/d) of oil, but since then its output has been in decline, shedding an average 4 per cent a year to reach just 902,000 b/d in 2011 – a drop of more than one-third since 2011. Since 2004 Indonesia has been a net importer of oil.

Compensating for the decline is a marked shift from oil to gas. And it is this migration in activity that is generating rising interest and investment in Indonesia's hydrocarbons sector.

Situated slap-bang in the middle of the world's most gas-hungry energy market, Indonesia remains a major hydrocarbons centre by any standards, with a multiplicity of unexplored basins offering robust growth potential.

Despite the decline in its oil exports and a growing domestic demand profile, Indonesia will remain a prominent supplier of the Asian market. Oil and gas play a critical role in the economy, generating US$35bn in revenues which accounts for one-quarter of the total government budget in 2011.

Globally, Indonesia ranks as the eighth-largest gas producer, with proven reserves of 108 trillion cubic feet (tcf). And as an exporter of liquefied natural gas (LNG) – the supercooled form of gas that is fuelling the fastest-growing Asian economies – Indonesia ranks second only to Qatar globally.

In recent years, Indonesia has been an active exploration and production market. Over the 2005 to 2010 period, Indonesia reported a 100 per cent reserves replacement ratio, with the industry responding favourably to an environment of high prices.

The result has been a steady increase in gas production, given an uplift in 2009 with the coming on stream of Tangguh LNG plant as Indonesia' third LNG export facility. Natural gas output has crept up from 6.3 billion cubic feet (bcf) in 2001 to 8.4 bcf in 2011.

The other two LNG plants are at Arun in Aceh and Bontang in East Kalimantan. The Bontang LNG complex in east Kalimantan is one of the world's largest LNG plants, with a nominal capacity of 22 million tonnes a year (t/y) and average production of 15 milion t/y. New LNG projects promise to extend Indonesia's customer base, though it will have to compete with Australian production in the prized Asian marketplace from 2016 onwards, when major Australian LNG projects start-up.

Indonesia lost its crown as the largest LNG exporter in 2005 as the government shifted policy to focus supply on meeting growing domestic needs. From now on, serving the local market remains a guiding principle of state energy policy.

Around 38 per cent of Indonesia's gas is sold to the domestic market, with the remainder being exported as either piped gas – to Singapore and Malaysia – or as LNG cargoes to Japan, South Korea, Taiwan, Mexico and China. These LNG exports account for 11 per cent of the world's total. With GDP growth remaining strong at around 6 per cent this year, energy consumption is set to double in the next 10 years and gas is primed to meet this demand.

Once Indonesia's current LNG contracts with Japan end, much of the gas will be directed inwards, says Hun Sung Yen, consultant at Singapore-based Facts Global Energy. Already there is a 25 per cent domestic market obligation (DMO). "Some exports will still occur, of course, but the government views that natural gas should be a domestic priority and directed to domestic use. There are five LNG receiving terminals planned now (including modifying the Arun LNG plant into a regas plant) and several mini-receiving terminals in the eastern part to receive and regas LNG liquefied in other parts of Indonesia."

As well as remaining an exporter of LNG, Indonesia is to begin importing international LNG volumes over the next few years. That will not prevent the authorities from seeking to boost production.

Despite the large scale of its gas reserves, there are numerous untapped fields. And though this brings opportunity, it also means overcoming some challenges, says Chris Newton, director of Singapore-based investment firm Risco Energy. Many Indonesian fields are undeveloped and distant from the major markets in Java, with supply constrained by a lack of transport infrastructure.

Price terms are being addressed. "A long history of low domestic gas prices, certainly lower than export prices, is one of the reasons behind the current domestic supply constraints," says Newton. "Upstream gas prices, as measured by new domestic gas contract signings have been trending strongly upward for a number of years, as oil prices (and upstream costs) have also trended upward and supply constraints increased."

Years of low, long, flat nominal pricing has been replaced by higher starter prices with some form of indexation now the norm. Oil linked prices paid by some customers deliver prices in excess of US$10/MMbtu (million British thermal units) at current oil prices – "a good deal for both producers and customers," says Newton.

Indonesia state gas distribution company PT Perusahaan Gas Negara (PGN) has this autumn agreed to pay higher gas prices to ConocoPhillips and state oil company Pertamina. PGN is committed to paying US$5.60/MMBtu to Conoco – three times the current price – rising to US$6.50/MMBtu in 2014.

The readiness to pay higher gas prices is seen as a positive for the sector's prospects. "A number of gas contracts have been renegotiated in the past 12-18 months, especially in the likes of Java where we've seen gas prices increase by 200 per cent," says Jamie Taylor, a Southeast Asian oil and gas analyst at consultants Wood Mackenzie. "Legacy contracts have been renegotiated to obtain prices upwards of US$6/mcf , so if there are marginal projects onshore Java or Sumatra or in shallow waters, that could incentive companies to develop these projects knowing there's a chance they could obtain higher prices."

The biggest field developments underway are the new projects that will feed into a proposed expansion of the Bontang LNG plant, which in recent years has been undersupplied. Though feedgas into Bontang is expected to fall through to 2015, new supply sources should reverse the decline thereafter. These are dominated by two major new supply projects due over the next five years: Chevron's Indonesia Deepwater Development and the Eni-operated Muara Bakau, both planned for 2015 (though delays are possible) and which could produce a combined 1,100 mmcfd by 2022.

According to Wood Mackenzie there is a challenge in that the nature of these new reserves, largely coalbed methane (CBM) or in deep water, provide for technical and financial uncertainties. "There are a number of PSCs in the Bontang area, both deep-water and onshore, and also a number of CBM blocks being awarded. With supply from existing sources declining, it opens up potential for exploration blocks to supply into Bontang," says Taylor.

CBM is seen as revolutionising Indonesia's gas sector, in freeing up more reserves. The country's CBM reserves are estimated to be 453 tcf, which puts it in the very top rank of global reserve holders. The first CBM contract was signed in 2008 and by April 2012 some 50 contracts were in place. The government is targeting 500 million cf/d in CBM production by 2015, rising to 1,500 by 2025.

Several CBM blocks were auctioned off in the past year, so E&P work is underway. Four CBM exploration blocks were awarded in a bid round in March. "Certainly the in-place volumes appear to be

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Night view of a Pertamina oil refinery, Java, Indonesia

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there, although the challenge will be in extracting significant volumes. The quality of the coal in terms of gas content appears to be very good, but a lot will depend on gaining approval to go out there and drill the hundreds/thousands of production wells that will be required to produce large volumes," says Taylor.

However, fiscal terms still have to streamlined and made more attractive to attract more international players into the market. "Pertamina and the other domestic players can't do it alone, they don't have the technology," says Yen. " Any large scale of CBM will have to occur post-2018, and even then I don't think it will be as significant as some players are painting it to be."

Though terms across Southeast Asia generally are viewed as challenging, Indonesia has managed to attract IOCs with some flexible terms – helped along by the improved domestic pricing framework.

Some big international fish continue to be attracted to Indonesia's upstream, with France's Total announcing two PSCs in Indonesia in October, for two offshore gas exploration blocks.

Oil major Royal Dutch Shell has an extensive presence going back more a century – indeed Indonesia is the birthplace of the Anglo-Dutch giant's upstream business. Shell has re-entered Indonesia's upstream with the signing of an agreement in 2011 with Japanese operator Inpex, as a strategic partner to develop the Abadi gas field. In 2006, Shell augmented its downstream presence with the establishment of a Commercial Fuels business in Indonesia, providing bulk fuels and related technical support to the industrial and mining sector.

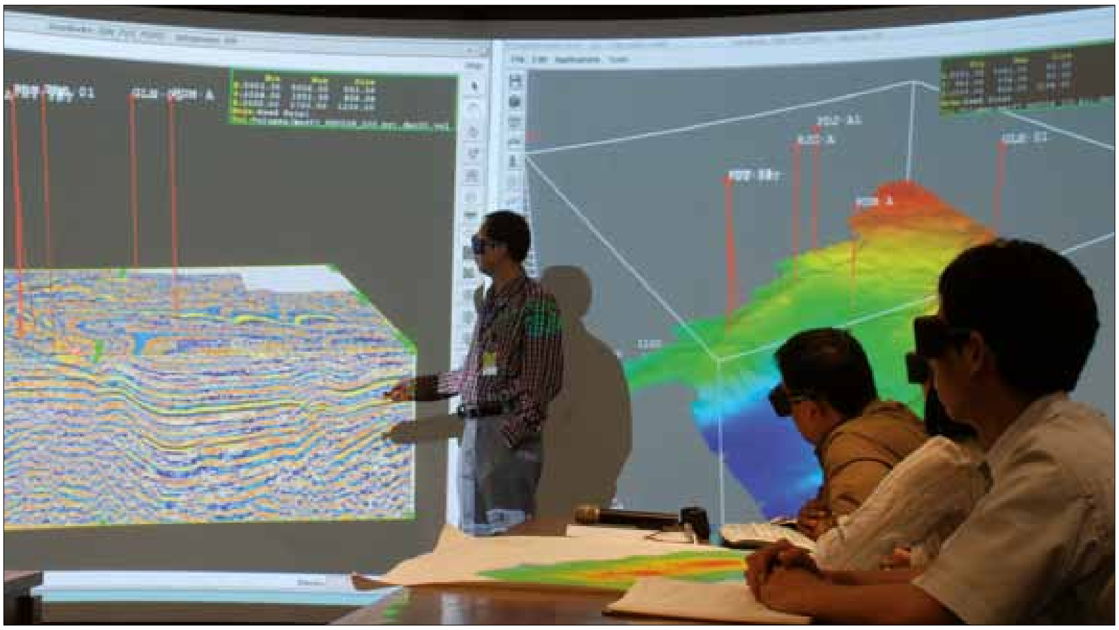
"Shell sees Indonesia as a key growth country in Asia and important to the Shell's long term global strategy," Shell chief executive Peter Voser said in June 2012 after a meeting with Indonesia's president, Susilo Bambang Yudhoyono in Jakarta.

The government is keen to focus investment on the local market. "Recently they've been trying to get upstream players to contribute more gas supply to the domestic market, above and beyond the 25 per cent DMO. BP Migas and Ditjen Migas are trying to streamline the terms to attract more players, but that's going to take a while and they have domestic obligations to consider," says Yen.

Little can realistically be done to halt the decline in older fields like Duri and Cepu, despite renewed enhanced oil recovery (EOR) activities. According to Yen, there aren't enough new fields coming on to offset those losses. Maintaining crude oil production at around 900,000 b/d looks the best bet for now.

The bottom line though for Indonesia, says Newton, is that net energy exports remain strongly positive with the industry's historic export status being driven successively by oil, then gas and now coal. Unconventional could also play a major future role, with demand projections identifying a supply shortfall by 2025 of 26 million b/d. Indeed a combination of EOR projects, rising conventional and unconventional exploration, will all play a critical role in evolving Indonesia's increasingly diverse energy mix.

Like many growing Asian economies, Indonesia has to carry off a careful balancing act, setting off sharp rises in the domestic demand outlook with a need to continue revenue-generating exports of gas to its main customers. The willingness to address fiscal terms should assure the participation of foreign players, keeping Jakarta in with a shouting chance of meeting that formidable long-term challenge. F



3D visual dome modelling of geologic structures