NATURAL GAS

Indonesia's natural gas industry is changing, affected by more competitive LNG markets, new pipeline exports, and increasing domestic gas demand. Rising power demands, fuel subsidy removals, and gas incentives in the 2001 Oil and Gas Law will drive increased use of gas domestically. Infrastructure limitations, financing issues, and regulatory uncertainty constrain gas development, however. Overcoming these constraints is necessary in order to balance Indonesia's gas use, lower the cost of domestic energy, and maintain a stable power supply. Indonesia's overall investment climate will determine the pace of future development.

Indonesia has between 170 and 180 trillion cubic feet (TCF) of natural gas reserves (proven and probable), the twelfth largest in the world. In 2002, the country produced 3.04 trillion cubic feet (TCF) of gas, number six in world gas production. Gas reserves are equivalent to three times Indonesia's oil reserves and can supply the country for 50 years at current production rates. According to the GOI, over 71 percent of natural gas reserves are located offshore, with the largest reserves found off Natuna Island (34.4 percent), East Kalimantan (30.2 percent), Irian Jaya (15.1 percent), Aceh (6.8 percent) and South Sumatra (6.4 percent). However, not all of these reserves are commercially viable, due to both the quality of the gas as well as its distance to market.

Indonesia currently supplies 26 percent of the world's LNG. LNG accounts for 54 percent of the country's total natural gas production and is exported to Japan, South Korea and Taiwan. Pipeline gas exports to Singapore began in 2001, reaching 82 BCF last year, with a new Sumatra-Singapore pipeline inaugurated in late 2003. Revenues from gas exports are substantial -- $5.6 billion in 2002, or about 10 percent of Indonesia's total export revenues. Domestically, gas demand comes primarily from fertilizer and petrochemical plants (34 percent) and the power industry (25 percent). Most of Indonesia's gas comes from East Kalimantan (33 TCF in reserves) and Sumatra (29 TCF in reserves), but there are large uncommitted reserves in Papua (18 TCF) and other areas in the archipelago (46 TCF). The industry is dominated by six major companies, which account for 90 percent of all production.

Gross Natural Gas Production by Major Producers (MMSCF)

Producers	2000	2001	2002	% Change
Total Ind.	841,419	880,237	835,031	-5.1
Exxon	458,929	268,109	557,873	108.1
Vico	452,456	464,049	438,982	-5.4
BP	293,034	294,972	272,113	-7.7
Pertamina	285,692	276,791	258,012	-6.8
Gulf Res.	165,226	163,751	162,638	-0.7
Unocal	166,316	159,313	149,317	-6.3
Others	238,230	299,928	367,877	25.9
Total	**2,901,302**	**2,807,150**	**3,041,87**	**8.4**

Roughly 55 percent of Indonesia's natural gas was marketed as LNG or liquefied petroleum gas (LPG) for export, 7.7 percent for electricity, 7.4 percent for fertilizer and 2.2 percent for city gas. Less than six percent was flared.

The nature of Indonesia's gas industry is changing, however. New LNG producers in Qatar, Australia, Russia, along with Malaysia, now challenge Indonesia's leadership in the LNG market. At the same time, a regional gas transmission network is developing, creating new gas markets and sources of revenue.

Domestically, the reduction of fuel subsidies ease fuel price distortions, making natural gas more competitive as a fuel alternative. Gas should also play a significant role in meeting the country's growing power demands. Finally, the Oil and Gas Law of 2001 has streamlined the process for domestic gas supply sales and created a new domestic market obligation (DMO) for gas. These changes create new opportunities in the domestic gas market, even as the global LNG market becomes more diversified.

Pipeline exports of natural gas have offset in part the greater competition in LNG markets. In 2001, Indonesia began exporting 325 mmcfd to Singapore via subsea pipeline from West Natuna under a 22-year contract. Deliveries of natural gas to Malaysia's Duyong gas platform began in August 2002, under a 20-year contract for 250 million cubic feet per day (mmcfd). Gas sale revenues will likely total $14.2 billion over the life of both contracts. In August 2003, the South Sumatra-Singapore gas pipeline was completed; it will eventually supply 350 mmcfd over a 20-year contract. Pipeline gas exports increased nearly 160 percent between 2001 and 2002, reaching 82 BCF and accounting for 5 percent of gas export volume.

Lower Subsidies, New Laws Stimulate Domestic Demand

Given the increasingly competitive LNG market, both government and industry recognize the need to develop Indonesia's potentially large domestic gas market. Indonesia's low utilization (compared with other developing countries), in part is due to reserves being located far from the demand centers in Java and Bali and the limited infrastructure. However, fuel subsidy reductions and legislative changes should stimulate domestic gas demand. The GOI slashed fuel subsidies from $7.6 billion in 2001 to a projected $1.6 billion in 2003, a 78 percent reduction. (Note: this reduction is probably closer to 70 percent, following a partial rollback on fuel price hikes in January 2003). According to Pertamina's published fuel prices, this makes natural gas, at $2.50-$3.00/mmbtu, much more attractive than fuel oil ($4.85/mmbtu) and diesel ($5.53/mmbtu).

The Oil and Gas Law of 2001 introduced other changes that will encourage domestic gas use. The new law permits direct "free market" negotiations of gas contracts between buyer and seller, endorsed by the government. In the past, production sharing contractors (PSCs) had to sell their gas to the state-owned petroleum company, Pertamina, which in turn sold the gas to the final buyer. Several PSCs report that the GOI's new direct negotiation mechanism is working well and that upstream authority BP Migas has generally stayed out of the negotiations, except in cases where either the buyer or seller requested its participation.

Growing Power Needs Will Drive Gas Demand

Power generation needs in Java and Bali will also spur growing domestic gas demand. Over the last several years, peak power demand grew by an average of eight percent annually, while power capacity did not increase. As a result, the actual reserve margin has declined from 16 percent in 2001 to a razor-thin 6 percent in 2003 (Note: desired reserve margins are normally between 25 and 30 percent). According to a Cambridge

Energy Research Associates (CERA) study, Indonesia needs over 10,000 megawatts of new capacity between 2008 and 2015 in order to prevent a long-term power crisis. Much of that new capacity will be fueled by gas. PLN plans to raise natural gas use by the power sector from 21 percent in 2002 to 40 percent by 2015. By volume, this means an increase from 450 mmcfd last year to 1.7 billion cubic feet per day (bcfd) in 2015.

Increasing gas consumption in the energy mix makes strong economic sense. About 2700 MW of PLN's gas turbine combined cycle (GTCC) plants in Java are running on fuel oil because of declining gas supply and transmission problems in East Java. Petroleum fuels are expensive – about 6.2 cents per kilowatt hour (kwH), or 2.5 times more costly than gas. PLN spends about $1.7 billion annually on oil-based fuels and estimates it can save up to $1 billion per year by switching to gas. The switch, when coupled with the power utility's plans to raise electricity tariffs to 7 cents/kwH, is an important element in restoring the financial health of Indonesia's power industry.

These incentives have raised domestic demand estimates and led to a number of new gas sales agreements. In December 2002, PSCs and gas buyers signed 14 gas and LPG agreements under the direct gas marketing mechanism. In December 2003, gas producers signed 13 agreements worth $14 billion that will supply a total of 1.3 bcf/d to power and petrochemical buyers. PGN projects conservatively that between now and 2015, Indonesia's domestic gas demand will increase by as much as 60 percent to 3.7 bcf/d.

Impediments to Domestic Gas Growth

Despite these changes spurring gas demand, impediments limit domestic gas growth. The primary obstacles include a limited transmission and distribution system, financing limitations, and continued regulatory uncertainty. Because Indonesia has an inadequate gas transmission and distribution network, state-owned gas utility PGN plans three more transmission projects to meet rising power sector demands for gas, as follows:

Projects	Length Km	Capacity mmscfd	Comp letion
Grissik-Jakarta	606	400	2006
Kalimantan-Java	1,620	1,500	2008/ 2010
E.Java-W.Java	680	350	2008/ 2010

In addition to these projects, the GOI may also build an LNG receiving terminal in West Java, to process and distribute gas from existing LNG plants (Bontang), as well as future plants in Papua (Tangguh) and South Sulawesi (Donggi). PGN is also investigating the feasibility of shipping compressed natural gas (CNG) over short to medium distances.

Many producers require explicit financial guarantees. The government's reluctance to provide such guarantees poses another obstacle to domestic gas growth, according to industry observers. In the power industry, a number of PSCs have requested that PLN provide standby letters of credit (SBLC) before investing in long-term gas supply agreements. According to industry analysts, PLN's credit availability with government-linked banks is limited. PLN has asked Bank Indonesia to exclude SBLCs from the legal lending limit in order to get around this obstacle. (Note: some power analysts suggest that if PLN would permit higher returns on investment, companies would be willing to assume more of this risk themselves).

A recent Wood Mackenzie gas and power study concurs that financing limits growth in the domestic gas market. According to the study, most export credit agencies (ECAs) remain wary of large, domestic-oriented projects in Indonesia. Future financing will be easier for offshore-structured, export-oriented projects that minimize political risk and generate dollar revenues. Financing will also be more likely if companies like Pertamina, with hard currency offshore accounts, participate.

Regulations Are Still Undefined

The current uncertain regulatory environment also limits domestic gas growth, because it inhibits the exploration and development of potential gas reserves. Despite the DMO provisions in the 2001 Oil and Gas law to promote gas use, no accompanying upstream or downstream regulations have been issued to define the "rules of the game." Nor do current regulations clearly define Pertamina's new oil and gas role. In addition to the regulatory uncertainty, doubts about contract sanctity, contract extensions, security, and taxation hurt the gas investment climate.

As mentioned previously, this uncertainty has affected the amount of new gas exploration. According to the American Chamber of Commerce, gas blocks signed before 1971 still account for nearly 60 percent of Indonesia's commercial reserves. Blocks signed after 1990 account for only 14 percent of commercial reserves.

A Trans-ASEAN Gas Pipeline?

ASEAN's Energy ministers signed a memorandum of understanding on July 5, 2002 to push ahead with a $7 billion natural gas pipeline project in a bid to alleviate concerns over oil supply shortages and to improve economic development. Minister of Energy and Mineral Resources Purnomo Yusgiantoro said the project's masterplan has been completed, and a council will soon be established to oversee the completion of the gas grid. Purnomo said more than 1,000 kilometers of the grid has already been constructed. ASEAN has identified the need for 4,500 kilometers of pipeline to complete the project, which might reach 6,000 kilometers, if the necessary new Indonesian domestic pipelines are included.

Purnomo said Indonesia will be a major player in the trans-ASEAN gas pipeline project because of its enormous gas reserves. ASEAN members have previously said that a regional natural gas pipeline, as well as an electricity grid, is the most efficient way for ASEAN countries to prevent a future energy crisis. Indonesia has already developed several pipelines - from West Natuna to Singapore, West Natuna to Malaysia, and from South Sumatra to Singapore. It is also studying a possible pipeline from West Natuna to Thailand.

ASEAN members will develop regulations and frameworks for the cross-border supply, transportation and distribution of natural gas throughout the region. This will be supervised by a future ASEAN Gas Consultative Council. The key reason behind the gas grid is the need to reduce the consumption of oil and to provide backup energy sources for ASEAN members. ASEAN members hope to complete the gas grid by 2020.

Expanding Future Production

Indonesia has significant gas reserves but much of the gas is non-exportable. There is also a geographical mismatch between location of gas reserves and energy needs. In addition to geographical constraints, other disincentives to developing Indonesia's gas resources include the availability of financing, long project lead-time, and the lack of incentives to explore and exploit gas reserves. With more competitive fiscal terms and a market-based pricing system, there would be an incentive to exploit more of Indonesia's natural gas reserves. Four key areas have been identified by the private sector to increase gas development in Indonesia:

- Increase incentives to find and produce natural gas;
- Promote private investment and ownership, as well as stability and cost recovery for those firms that invest in major gas facilities;
- Encourage multi-buyer and multi-seller gas marketing; and
- Establish incentives for domestic gas usage.

Domestic Gas Usage

PGN estimated that current domestic demand is about 20 percent of the energy mix.

The World Bank and the Asian Development Bank (ADB) have urged Indonesia to adopt a pricing regime more conducive to providing companies with an incentive to find and produce gas. If gas were able to compete on price with alternative energy forms in the market place, the full value and potential of Indonesia's gas reserves would be realized. Without pricing changes, the domestic gas market is constrained by the lack of incentives for exploration and development of gas fields too small to support LNG but large enough for domestic gas supplies. A second, major constraint is the absence of a predictable basis for forecasting the future value of gas, such as an indexed price formula. A final constraint has been the subsidy provided for alternative fuels.

Under the historic system for determining gas prices, price in supply contracts is reached through negotiations on a field-by-field basis between Pertamina and individual producers after the discovery of the gas field. Prices are fixed for a designated supply for the duration of the contract. Hence, the producer price for gas is different for each PSC. Consumer prices are set on a cost-plus basis.

Domestic Gas Pricing
(Per MMBTU)

I. FUEL	
1. Fertilizer Plant	$1.00 – 2.00
2. Steel Industry	$2.00
3. Electricity	$2.45 - 3.00
4. Cement Industry	$2.70 - 3.00
5. Paper Industry	$1.30
6. Refinery	$1.49
7. Plywood	$0.97
8. City Gas	Rp 2,500 - 4,150
II. FEEDSTOCK	
1. Fertilizer	$1.00 – 2.00
2. Steel Industries	$0.65
3. Methanol Plant	$1.42 – 2.00

Integrated Transmission System

The South Sumatra pipeline is part of a state gas company Perusahaan Gas Negara (PGN) plan for an integrated gas transmission pipeline system, known as the Integrated Transmission System (ITS). The ITS will eventually link the islands of Sumatra, Java and Kalimantan via a 3,588-kilometer integrated gas pipeline. Reputed to be Southeast Asia's longest, the pipeline is being funded by the World Bank, ADB and other institutions. PGN's network will flow 2.2 BCFD of natural gas after its scheduled completion in 2010.

Project One: Grissik-Duri Pipeline: Phase One became operational in 1998. The 544-kilometer Grissik/Duri gas transmission pipeline transports 310 mmscf/d of natural gas from the Grissik gas plant in ConocoPhillips Indonesia's Corridor PSC in South Sumatra. The project will supply Caltex's Duri Steam Flood Project in Central Sumatra for 15 years. ConocoPhillips is the gas producer, Caltex is the gas buyer and PGN is the owner of the pipeline network.

The Grissik/Duri pipeline project is the first part of a 850-kilometer gas transmission pipeline to link South Sumatra to Singapore. Phase Two, which covers a 530-kilometer leg from Grissik to Singapore by way of Batam Island was completed in August 2003. Both the Grissik/Duri pipeline and the Grissik/Singapore pipeline have been included in the TransgasIndo pipeline consortium, jointly owned and operated by PGN and a joint venture with ConocoPhillips, Petronas, Talisman, and Singapore Petroleum.

Project Two: South Sumatra–West Java Pipeline: This 606-kilometer pipeline project will provide gas from ConocoPhillips and Pertamina fields to West Java power plants and industrial users. The pipeline will be funded by a combination of JBIC loans and proceeds from PGN bond and IPO offerings. All parties hope to complete the project and have first gas in 2006. One part of the project will provide 220 mmcfd of gas (ramping up to 400 mmcfd) from ConocoPhillips' prospective Suban II facility with the Muara Tawar, Tanjung Priok and Muara Karang gas-fired power plants in Jakarta. In July 2003, ConocoPhillips and PLN signed a HOA to supply gas to the plants.

Another part of the pipeline will be a loop from Maringgai in South Sumatra to Cilegon and Cimanggis in West Java. This pipeline will supply natural gas from Pertamina's gas fields in Prabumulih to West Java industrial users. Pertamina and PGN have already agreed to provide 250 mmcfd to West Java once the pipeline becomes operational. The two companies are presently negotiating to increase the gas transmission volume by an additional 250 mmcfd.

Project Three: East Kalimantan-Java: The most ambitious of the four projects, the 1,600-kilometer East Kalimantan-Java pipeline would transport up to 1.5 bcfd of gas from Bontang in East Kalimantan to Central and West Java through a still-undetermined location on the coast of Java. PGN would partially fund the project from its bond and IPO offering, but will need substantial outside financing. Timing of the project depends on a number of factors, including Java gas demand increases and a proposed LNG regasification facility in West Java. Presently, PGN plans project construction in 2008 and first gas in 2010.

Project Four: East/West Java Pipeline: This proposed project consists of two phases, the 292-kilometer Cirebon (West Java) to Semarang (Central Java) pipeline and the 388-kilometer Semarang to Surabaya link. The project will transport about 700 mmcfd of natural gas. There is no set timeframe for project completion yet.