EXECUTIVE SUMMARY

Indonesia ranks seventeenth among world oil producers, with approximately 1.8 percent of the world's production. At an unofficial 1.01 million barrels of oil per day (b/d) by the end of 2003, Indonesia's production of crude oil and condensate continued a gradual decline from 1.25 million b/d in 2002, 1.34 million b/d in 2001, and 1.41 million b/d in 2000. Indonesia's oil reserves are approximately 9.7 billion barrels.

The country ranks sixth in world gas production, with proven and potential reserves between 170-180 trillion cubic feet (TCF). Indonesia produced 3.04 TCF of gas in 2002, rising unofficially to about 3.08 TCF in 2003. Indonesia also remained the world's largest exporter of liquefied natural gas (LNG) in 2002 at 26.2 million metric tons (MT). Although it enjoys a 22.9 world market share, this dominance is under threat from newer producers in Qatar, Australia and Russia.

Despite the gradual decline in oil production, the industry remains a key sector that generates strong cash flows. In 2002, oil and gas contributed $12.1 billion or 21.2 percent of total export earnings and about 25 percent of government budget. Though significant, this is in stark contrast from 1990, when the oil and gas sector contributed 43% of export earnings and 45% of government revenues.

The 2004 budget assumes crude oil production of 1.15 million b/d, a target that will be difficult to meet unless production levels improve. That budget also assumes an exchange rate of Rp 8,700/US$ and an oil price of $21/barrel. Actual crude oil prices for SLC during August 2003 were $28.03 per barrel.

With substantial reserves of natural gas, coal and geothermal, Indonesia could remain a net energy exporter for a longer period than current forecasts. To do so, the government must implement legislation and policies that will attract new private direct investment and rationalize use of Indonesia's energy resources. Energy policy reform is necessary in order to maintain Indonesia's status as a net oil exporter and enhance efficient use of energy resources.

In line with its former International Monetary Fund (IMF) commitments, the government continued to hike domestic fuel prices in 2002 by eliminating subsidies. Fuel prices were raised across the board first in October 2000, in June 2001 and again in January/March 2002 to reduce the GOI's fuel subsidy burden to Rp 30.3 trillion in 2002. The GOI increased fuel prices again in January 2003; however, it later reversed much of the increase due to widespread public protest. This, combined with high international oil prices, raised the actual 2003 fuel subsidy to Rp 30 trillion. The government is unlikely to raise fuel prices again until after the 2004 elections.

2002-2003 were important transition years for Indonesia's oil and gas industry, following passage of a new oil and gas law in October 2001. Law 22/2001, which replaced the 1960 Oil and Gas Law and Law for Pertamina 8/1971, required the upstream and downstream sectors to deregulate within two years and four years, respectively. The law also mandated the end of Pertamina's monopoly over downstream oil distribution and marketing of fuel products. Pertamina's upstream responsibilities to manage the Production Sharing Contracts (PSCs) also shifted to the central government.

The new law created two new governmental bodies: the Executive Body that takes over Pertamina's upstream functions and the Regulatory Body that supervises downstream operations. The Executive Body, BP Migas, was established in July 2002. It took over Pertamina's upstream regulatory functions and management of oil and gas contractors. The downstream regulatory body (BPH Migas) was established in December 2002. When fully operational, it will license downstream operators to assure sufficient natural gas and domestic fuel supplies and the safe operation of refining, storing, transport and distribution of petroleum products.

The government has not yet completed its implementing regulations for the upstream and downstream sectors, which were due by the end of 2003. The industry continues to work with the GOI on the draft regulations in an effort to improve the sector's investment climate. At the time of this report, the industry had serious concerns about the draft regulations in a few key areas, including:

- Sanctity of contract for existing PSCs (grandfathering provisions);
- Requirement for PSCs to first offer any sale or transfer of its participating interest to a national company;
- Lack of clarity on the oil and gas domestic market obligation (DMO);
- Potential overlapping responsibilities between the upstream and downstream authorities BP Migas and BPH Migas, including natural gas transportation via pipeline.

In 2002

- The dollar value of oil and gas exports declined to $12.1 billion in 2002, compared with $12.6 billion in 2001.

- Oil and gas imports increased in 2002 to $6.5 billion, compared with $5.5 billion a year earlier.

Crude Oil

Reserves: 9.7 billion barrels.

Gross Production: 1.01 million barrels per day (2003, unofficial).

Export revenue: $6.2 billion in 2002.

In 2002, Indonesia produced an average of 1.252 million b/d, down 6.9 percent over the previous year level of 1.344 million b/d. Unofficially, the country's production continued to decline in 2003 to an average 1.01 million b/d. Most of the country's major producers were responsible for the 92,700 b/d production drop in 2002. Foreign PSCs accounted for 85% of Indonesia's crude output in 2002.

Expenditures by petroleum companies declined 18.7 percent in 2002 to $3.42 billion from $4.2 billion in 2001.

The number of new exploration and appraisal wells drilled in 2002 up slightly 88 wells from 79 wells in 2001 after peaking up at 145 wells in 1998.

Unocal continued its ambitious drilling program in the deepwater, offshore East Kalimantan blocks.

ExxonMobil continued efforts with Pertamina, without success, to extend its contract for the Cepu block in East Java.

The government awarded 15 new production sharing contracts in 2003, compared with 1 in 2002, and 6 in 2001, down from a record 29 contracts in 1997. Major international and U.S. companies were largely absent from the bidding on these new exploration blocks. The GOI will offer another 10 blocks in 2004. Ten contracts were relinquished between January 2002 and September 2003.

Indonesian crude production profited from high world oil prices, averaging $25.11/barrel for Sumatran Light Crude (SLC) in 2002 and $29.02 for the first eight months of 2003. As a result of OPEC decisions to reduce oil production, Indonesia received four quota declines, 77,600 b/d in February 2001, 52,000 b/d in April, 42,000 b/b in September and a further 78,000 b/d in January 2002. OPEC's quota reductions had no impact on Indonesia as the country produced well under its quota throughout this period.

Indonesia's major crude oil customers (in rank order) were Japan, South Korea, Australia, Singapore, China and the United States. Indonesia's overseas markets generally showed a decline in sales in 2002 with the exception of China, USA and Thailand.

Natural Gas

Reserves: 176.6 trillion standard cubic feet (TSCF).

Gross Production: 3,036 billion cubic feet (BCF).

Export revenue from LNG and LPG:
$5.9 billion in 2002.

Indonesia has natural gas reserves of over 176.6 TSCF – 90.3 TSCF proven and 86.3 TSCF probable/possible. Indonesia's largest producers are ExxonMobil, Total, Vico, BP and Unocal operating under production sharing contracts.

Indonesia, which traditionally exports gas in the form of LNG, started natural gas pipeline exports to Singapore in January 2001, totaling 32 billion cubic feet (BCF) from fields within 3 PSCs in West Natuna operated by ConocoPhillips Indonesia, Star Energy and Premier. The PSCs deliver 325 million cubic feet per day (mmcfd) from Indonesia to Singapore (Sakra Island) via a 650-kilometer sub-sea pipeline. The gas is used by power generating companies and petroleum and petrochemical plants. Revenues from the gas sales are projected to reach $8 billion over the life of the 22-year contract.

The government inaugurated a second gas transmission pipeline to Singapore in August, 2003. The 477-km pipeline links the Grissik gas plant in the Corridor PSC in South Sumatra with Sakra Island, Singapore. The gas supply volume from South Sumatra fields operated by ConocoPhillips and PetroChina to Singapore will eventually reach 350 mmcfd. The pipeline was built for $420 million and should generate $9 billion in revenues to Indonesia over 20years.

Indonesia celebrated the first delivery of natural gas to the Duyong gas platform offshore Peninsular Malaysia from Indonesia's South Natuna Sea Block B PSC (operated by ConocoPhillips) in August 2002. Pertamina supplies 100 mmcfd of natural gas (increasing to 250 mmcfd by 2007) to Petronas for 20 years from South Natuna Sea Block B. Revenues from the gas sales are projected to reach $6.2 billion over the life of the contract.

LNG and LPG

Most of Indonesia's natural gas is processed into LNG and LPG, followed by domestic power generation and petrochemical production. LNG production at Arun and Badak (Bontang) was 26.2 million metric tons (MT) in 2002, an increase from 2001's production of 24.3 MT. Japan, South Korea and Taiwan were the key markets for LNG.

LPG production declined slightly to 2.1 MT in 2002 from 2.2 MT in 2000, while exports to the four top customers -- Japan, Hong Kong, Taiwan and Australia -- dropped to 1.27 MT.

In 2002 and 2003, there was mixed news for Indonesia's LNG producers:

In August 2002, Indonesia lost a bid to supply $10 billion in LNG to China's first LNG receiving terminal at Guangdong. However, Indonesia's Tangguh LNG project won a separate contract to sell 2.6 MT/year of LNG to a prospective LNG terminal in Fujian for 25 years, worth about $8.5 billion. Tangguh also won a preliminary contract to supply 1.35 MT/year of LNG to South Korea's K Power and POSCO for a 20-year term starting in 2005.

In July 2003, Qatar beat Indonesia in a bid to supply 1.7 MT of LNG per year to Taiwan's planned Ta-Tan LNG terminal.

During 2003, Indonesia began lobbying Japan to extend 12 MT worth of LNG contracts set to expire in 2010. In August and December 2003, BP Migas signed an MOU with Marathon Corporation for 6 MT per year and a Heads of Agreement (HOA) with Sempra Energy for 3.7 MT per year beginning in 2007 to supply LNG to a proposed LNG receiving terminal in Baja California.

In October 2003, ChevronTexaco unveiled its project to erect a storage and regasification LNG terminal 13 miles offshore Baja California. ChevronTexaco is currently holding possible partnership discussions with Pertamina in the Donggi-Matindok area of Central Sulawesi.

Tight production levels and desired new gas for fertilizer plants may cause the GOI and some PSCs to meet a portion of their LNG export quantities by purchasing LNG cargoes abroad in 2004.

Refining and Imports

Installed capacity: approximately 1.057 million b/d at nine state-run refineries.

Capacity utilization: 96.8 percent.

Growing domestic consumption and limited capacity at Indonesia's nine refineries account for the increase in crude oil and fuel product imports. Domestic fuel consumption increased to 57.8 million kiloliters in 2002, about 7.5 million kiloliters higher than pre-crisis levels. In 2002, Indonesia's crude oil imports rose to 124.1 million barrels, largely from Saudi Arabia and Nigeria. Fuel product imports rose to 106.9 million barrels from 89.6 million barrels in 2001.

Petrochemicals

The petrochemical industry was again stagnant in 2002, with no new plants completed. In the wake of the financial and economic crisis that erupted in mid-1997, projects under construction remained in limbo. However, in July

2003, the government announced the impending resumption of 14 large strategic projects, valued at $9.3 billion, which were suspended in 1998. These projects include the $290 million ammonia/urea fertilizer plant in Kujang, West Java, the $360 million Unit 5 Kaltim fertilizer plant, the $35 million hydrogen plant at AAF/Aceh, a $256 million fertilizer plant in East Kalimantan, a $310 million urea fertilizer plant at PIM/Aceh and a $900 million aromatic plant in Tuban, East Java. These projects are still pending international financing, however.

Regional Autonomy/Decentralization

On January 1, 2001, Regional Autonomy Law 22/1999 and Fiscal Decentralization Law 25/1999 came into effect. Law 25/1999 contains formulas for sharing revenue between the central government and various regional authorities. Local misunderstanding of the oil and gas revenue allocations continues, raising expectations and causing regional administrations and the public to overestimate future transfers. By definition, the "government share" is tax revenues plus its portion of oil and gas profits after the PSC share and cost recovery are deducted. However, the central, provincial and regional government revenue splits shown in the table below only apply to oil and gas profits after cost recovery. Therefore, depending on the amount of cost recovery, provincial and regional oil and gas income can be significantly different than the reported gross oil/gas revenues.

Shares of state revenue* before and after Law No. 25/1999

Type of revenue	Central Govt.	Province	Regencies
Before (%):			
- Oil	100	-	-
- Natural gas	100	-	-
- Mining land rent	20	16	64
- Mining royalties	20	16	64
- Land/building tax	10	16.2	64.8
- Duties on land/ building acquisition	20	16	64
After (%):			
- Oil	85	3	12
- Natural gas	70	6	24
- Mining land rent	20	16	64
- Mining royalties	20	16	64
- Land/building tax	-	16.2	64.8 (+)
- Duties on land/ building acquisition	-	16	64 (+)

* State revenue refers to net oil and gas profits after PSC share and cost recovery are deducted. Special autonomy provisions for Aceh and Papua give those provinces 70 % of net oil and gas profits after PSC share and cost recovery, with the remaining 30% to the government.

In an attempt to clarify the ongoing debate over the regions' share of oil and gas revenues, the Ministry of Finance issued Decree 237/2003 in June 2003. The decree estimates the allocation of oil and gas revenues to the provinces, regencies and cities for 2003, as shown below:

Province	Est. Allocation (Rp millions)	Est. Allocation ($US)
Aceh	2,102, 082	253,250,000
N. Sumatra	56,721	6,830,000
Riau	3,218,702	387,800,000
Jambi	31,008	3,735,000
S. Sumatra	639,342	77,030,000
Lampung	199,638	24,050,000
Bangka Belitung	711	85,600
DKI Jakarta	60,134	7,245,000
W. Java	481,061	58,000,000
C. Java	602	72,500
E. Java	29,425	3,545,000
E. Kalimantan	3,873,452	466,680,000
C. Sulawesi	416	50,120
Maluku	4,372	526,700
Papua	71,639	8,630,000

Rp 8300 = $1US

The estimated allocations are based on expected oil and gas production for the year. Further study is needed to determine the actual amount of oil and gas revenues flowing to the regions and whether these proceeds have improved the quality of life in those areas.

Major Events for Oil in Indonesia

Year	Events
1890	Telaga Said production field sold to a company that later merged to form Royal Dutch Shell. First production was in 1892.
1912	Standard Oil of New Jersey through its Dutch subsidiary received permission to explore for oil in South Sumatra.
1921	The Talang Akar field discovered, which proved to be the biggest find before WWII.
1942	Japanese took over most oil fields during WWII and slow production
1944	Caltex' Minas field discovered. Largest oil field in Southeast Asia
1945	Indonesia declared independence from The Netherlands
1961	Government signs first PSC, with Asamera for the Block A PSC in Aceh.
1962	Pan American Oil Company signed the first contract of work with Pertamina.
1962	Indonesia joined OPEC
1968	National oil companies Permina and Pertamin merged to form Pertamina
1978	First LNG plant entered production
2001	The Government revised Oil and Gas Law
2002	Upstream/downstream bodies formed.
2003	Pertamina becomes a limited liability company.