Asia-Pacific
Economic Cooperation

APEC
ENERGY OVERVIEW
2004

Energy Working Group

December 2004

Prepared By
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FOREWORD

The recent recovery of the world economy in the aftermath of the Asian financial crisis has accompanied strong demand growth in energy worldwide. In no small part, the strong and robust energy consumption growth engenders volatile energy prices, especially oil and coal. Rather an unexpected surge in demand for energy has put a strain on energy markets as energy supply is constrained by upstream and transportation infrastructure.

Most APEC economies are increasingly concerned with energy security and the development of new and renewable technologies to reduce its dependence on conventional, imported energy. The high cost of these new types of energy is the major stumbling block for their deployment and is still waiting to be resolved.

Individual APEC economy energy policy initiatives and notable developments particularly on energy security, upstream and downstream development, transformation and transportation, market reform, efficiency and conservation, alternative energy development, renewable energy deployment, environmental protection, and international/regional cooperation are compiled in this report.

We extend our special thanks to the efforts of APEC member economies in improving the accuracy and currency of the information provided. We also would like to acknowledge the expert contributions of the APERC researchers to this report and a special note of gratitude to the guidance and provision of the basic energy statistics of the EGEDA members. We sincerely hope that this report would help deepen the mutual understanding among the member economies on current energy issues in the region.

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President,
Asia Pacific Energy Research Centre

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Expert Group on Energy Data and Analysis

December 2004

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LIST OF ABBREVIATIONS

ABARE	Australia Bureau of Agriculture and Resource Economics
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
bbl/d	Barrels per day
BCM	Billion cubic metres
BFOE	Barrels of Fuel Oil Equivalent
Bt	Billion tonnes (Thousand Mt)
CO_2	Carbon dioxide
DOE	Departmnt of Energy (USA)
EDMC	Energy Data and Modelling Center (Japan)
EIA	Energy Information Administration (USA)
EVN	Electricity of Viet Nam
EWG	Energy Working Group (APEC)
GDP	Gross domestic product
GHG	Greenhouse gases
GW	Gigawatts (Thousand MW or Million kW)
GWh	Gigawatt-hours (Million kWh)
HKC	Hong Kong, China
IPP	Independent Power Producer
ktoe	Kilotonnes (thousand tonnes) of oil equivalent
kW	Kilowatts
kWh	Kilowatt-hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane)
MCM	Million cubic metres
Mt	Megatonnes (Million tonnes)
mtpa	Million tonnes per annum
MW	Megawatts (Thousand kW)
NZ	New Zealand
PDOE	Department of Energy (the Philippines)
PNG	Papua New Guinea (or pipeline natural gas, depending on context)
PPP	Purchasing Power Parity
R&D	Research and development
SDPC	State Development and Planning Commission (China)
TFEC	Total final energy consumption
TPES	Total primary energy supply
toe	Tonnes of oil equivalent
TWh	Terawatt-hours (Billion kWh)
US or USA	United States of America
VND	Viet Nam Dong

AUSTRALIA

INTRODUCTION

Australia is the sixth largest country and smallest continent in the world. It is the only continent that is its own country and lies between the Indian and South Pacific Oceans. Its dry flat continent spans approximately 7.6 million square kilometres, mostly plateaus, deserts, and fertile plains and is divided into six states and two territories. Its population of about 19.66 million (in 2002) live mostly in cities or major regional centres in the eastern and southeastern seaboard. Australia is abundant in minerals, fossil fuels and other energy resources. It is famous for its Great Barrier Reef, the largest coral reef in the world, located along its northeastern coast.

For more than two decades, from 1980 to 2002, Australia's economy grew by an average rate of 3.3 percent per year. In 2002, GDP reached US$497.15 billion from US$ 483.91 billion (1995 US$ at PPP) in 2001, further reducing its unemployment rate to 6 percent from 6.3 percent the previous year. The Australian economy has remained relatively robust despite the global economic slowdown, owing much to the buoyant property market and strong domestic demand. It has steered clear of economic recession, and is expected to continue to outperform most of the developed economies in the coming years. Over 70 percent of Australia's international trade is with APEC economies and Asia accounts for around 60 percent of Australian trade.

Australia is a major exporter of coal, LNG and uranium. The resource sector is the largest exporting sector of the Australian economy and covers over 35 percent of Australia's export earnings. This has made the Australian economy very sensitive to changes in foreign earnings, arising from fluctuations in international market prices.

Table 1 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	7,600,000	Oil (MCM)	556
Population (million)	19.66	Gas (BCM)	2,550
GDP Billion US$ (1995 US$ at PPP)	497.15	Coal (Mt)	82,090
GDP per capita (1995 US$ at PPP)	25,283		

Source: Energy Data and Modelling Centre, IEEJ. * Proved reserves at the end of 2002 from BP Statistical Review of World Energy 2003.

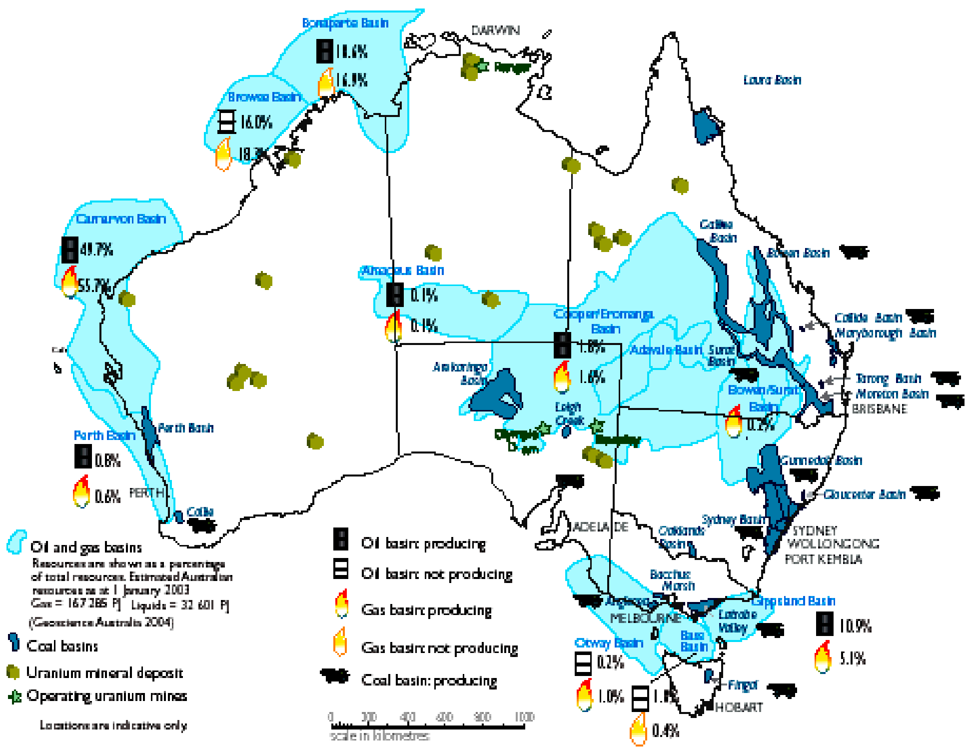
ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

The production of primary fuels in Australia has continued to grow since 1980. In 2002, the total supply of primary energy net of trade in Australia reached 123,172 ktoe. Significant increases have occurred in coal, which contributed the largest share of about 41 percent, followed by oil at 29 percent, and natural gas at 24 percent. Since 1980, supply from gas exhibited the greatest growth at 6.2 percent, followed by coal 3 percent, and oil (the least) at 0.7 percent per annum. Supply from other sources (i.e. wood, bagasse, hydro, geothermal, solar, etc.) has been fairly stable at about 2.4 percent per year during the same period.

Australia is the world's largest exporter of coal and the fourth largest producer behind China, USA and India. Australia produces high quality coking and steaming coals that are high in energy content, low in sulphur, ash and other contaminants. In 2002, total coal production reached 178,868 ktoe, 70 percent (or 124,706 ktoe) of which was exported to other Asian economies. Coal plays a central role in the Australian economy, accounting for approximately 10 percent of Australia's total export income and accounting for over 80 percent of all electricity produced in Australia. Over the past few years, Australia's production and exports of coal have grown, with exports increasing by approximately 6 percent a year. In 2004/05 black coal production is expected to reach over 300 million tonnes of which 77 percent, or approximately 218 million tonnes, will be exported overseas to the value of $[1]16 billion. Although it remains the biggest exporter of black coal, Australia has the highest reserve-to-production ratio of all seaborne-coal trading countries.

Figure 1 Australia's Energy Resource Map 2002



Source: ABARE 2004

In 2002, Australia's natural gas reserves reached 2,550 BCM, an almost four fold increase over the past two decades. Most of the increase came from the western and northwestern areas. Total supply from natural gas in 2003 reached 26,505 ktoe. About half of this, or 15,013 ktoe was consumed domestically, while the rest was exported, as liquefied natural gas (LNG), almost entirely to Japan. At current production levels, Australia's natural gas reserves should last around 90 years. Australia began exporting LNG to the Asia Pacific region in the late 1980s. These exports initially grew rapidly but levelled off after the 1997 Asian financial crisis.

Australia is a net importer of oil and petroleum products. Despite its 30,401 ktoe crude oil and condensate production in 2002, its total demand exceeded domestic supply. In 2002, import

[1] Currency is in Australian Dollar unless specified.

dependency was around 52 percent. Oil reserves in 2002 stood at 556 million cubic metres (MCM), up from 254 MCM in 1990. The reserve to production ratio is around 14 years.

About 222,183 GWh of electricity was generated in 2002, mostly from thermal sources (92 percent) with a modest amount (about 7 percent) from hydro sources. Most of the fuel used in thermal plants came from coal, while the rest was fed from oil and gas. Electricity demand has been growing at about 3.4 percent per year during the last two decades.

Table 2 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	258,208	Industry Sector	31,124	Total	222,183
Net Imports & Other	-135,037	Transport Sector	26,585	Thermal	204,206
Total PES	123,172	Other Sectors	19,745	Hydro	16,031
Coal	50,205	Total FEC	77,454	Nuclear	-
Oil	35,683	Coal	5,110	Others	1,947
Gas	29,505	Oil	35,744		
Others	7,779	Gas	15,088		
		Electricity & Others	21,512		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

FINAL ENERGY CONSUMPTION

In 2002, the total energy consumption in Australia reached 77,454 ktoe. Total energy consumption was dominated by industry and transport. Industry consumed 40 percent of energy, the transport sector 34 percent, and other sectors (including residential and commercial) 25 percent. Strong growth in energy consumption is attributed to the increased electrification in all end use sectors, rapid growth in a number of industries where electricity is the primary resource, such as the commercial and non-ferrous metal sectors, and manufacturing of new appliances. By fuel source, petroleum products accounted for 46 percent of consumption, natural gas for 19 percent, and coal 7 percent. Electricity accounted for 28 percent of consumption.

Since 1980, consumption of natural gas has grown at an annual rate of 4 percent, much faster than any other energy type.

Impediments to the widespread use of gas domestically are large distances between main sources of supply in the far west of the continent and centres of demand on the eastern seaboard, and the very competitive price of steam coal for power generation. Despite this, it is expected that extensions of the natural gas pipeline network will be built in response to strong demand, particularly from the mining, manufacturing and electricity generation sectors. Domestic natural gas consumption is projected to grow at around 5 percent per annum over the next decade.

POLICY OVERVIEW

NATIONAL ENERGY SECURITY[2]

Australia enjoys a high level of energy security characterised by relatively low-priced reliable energy supplies and a significant natural endowment of energy resources including coal, natural gas, liquid petroleum and a significant potential for renewable energy. Underpinning Australia's natural energy endowments are extensive infrastructure and well-functioning domestic and international energy markets.

Notwithstanding its current energy security position, the Australian Government undertook a wide-ranging review of Australia's energy policy. This culminated in the release of the Energy White Paper Securing Australia's Energy Future in June 2004 (available from http://www.pmc.gov.au/energy_future/).

The Energy White Paper provides the policy context for Australia's energy policy as well as Australia's energy security policy. The Australian Government's energy objectives consist of:

- prosperity – that the value of energy resources is optimised;
- security - that Australians have reliable access to competitively priced energy; and
- sustainability – that environmental issues are well managed.

Within these broad energy policy objectives, the Energy White Paper establishes an energy security policy to address both short-term and long-term energy security challenges. The policy is characterised by a focus on well-functioning national and international energy markets, minimum effective regulation, meaningful public-private partnerships, and practical, intra-regional dialogue on energy security rather than viewing self-sufficiency in energy resources as synonymous with energy security.

The main short-term threat to national energy security identified by the Energy White Paper is temporary disruptions to energy production and distribution. These disruptions can result from natural phenomena, human interaction, geo-political issues, and/or systems or equipment failure.

Australia's arrangements for handling such disruptions involve Federal, State and Territory governments, the private sector and international cooperation. Various measures exist to assist governments at the Federal, State and Territory level to manage electricity, liquid fuels and natural gas related emergencies. The Ministerial Council on Energy is considering options for a National Gas Emergency Response Protocol to facilitate communications and coordination of activities in the event of a major gas supply disruption. An inter-jurisdictional Gas Emergency Protocol Working Group has been established to manage development of the Protocol. Similarly, electricity and oil related emergencies are addressed via the National Electricity Market Management Company and the National Oil Supplies Emergency Committee respectively. Australia's energy supplies are further assured through participation in international energy security arrangements including the IEA's emergency arrangements as well as activities of the Asia Pacific Economic Cooperation Forum's Energy Working Group.

As part of Australia's critical infrastructure protection activities, the Energy Infrastructure Assurance Advisory Group (the Energy Group) will assess medium to long-term vulnerabilities in the protection of energy infrastructure in Australia. The Energy Group, as part of the Australian Government's Trusted Information Sharing Network, facilitates the owners/operators of energy infrastructure sharing information on issues relating to generic threats to, and vulnerabilities in, critical infrastructure and appropriate measures and strategies to mitigate risk. The Energy Group comprises representatives from the private sector and state and territory governments.

[2] http://www.pmc.gov.au/publications/energy_future/docs/energy.pdf

The Energy White Paper identifies the main long-term energy security challenge as that of attracting timely large-scale investment in sustainable supply systems to meet the growing demand for energy. Accordingly, the Energy White Paper recommended that the Government undertake a biennial review of the national energy security outlook, to consider the adequacy of existing policy and Australia's international commitments and obligations. Consequently, the review, being undertaken by the Australian Government Department of Industry, Tourism and Resources, will analyse energy security from the perspective of the domestic stationary and non-stationary energy sectors, providing information on short and long-term issues that may impact on the security of Australia's energy supplies, thereby facilitating informed policy-development.

UPSTREAM ENERGY DEVELOPMENT

To maximise the value of Australia's energy resources, the Australian government aims to provide consumers with reliable supplies of competitively priced energy, ensure an appropriate return to the community for the development of its depletable resources, and meet environmental and social objectives.

The Australian government's approach in developing the economy's energy resources is guided by the following basic principles:

1. Private decision makers should be allowed to manage risk in a regulatory framework that is predictable, transparent, equitable and timely
2. Energy resource development should be required to comply with standards of environmental performance which are commensurate with those imposed on other sectors of the economy
3. Commercial decisions should determine the nature and timing of energy resource development, with government interventions being transparent and allowing commercial interests to seek least-cost solutions to government objectives (e.g. environment, safety or good resource management objectives)
4. Government objectives should generally be driven by sector-wide policy mechanisms rather than impose inconsistent requirements on individual projects/private investors

Australia is proven to be highly prospective for many of its resources, particularly for coal, uranium and gas. Large oil resources, such as the giant Bass Strait oil fields, have been found. Australia also has some 40 offshore basins of petroleum potential, but half of these remain unexplored because of the cost and high-risk nature of exploration in frontier areas. Encouraging further exploration in these areas is one of the Australian government's priorities.

The Australian government provides for pre-competitive geoscience data to attract exploration investments and is currently spending more than $90 million annually on the data (i.e. both for mineral and energy resources) (Geoscience Australia 2003). The 2003-04 Budget included around $25 million to generate new geoscience data in offshore frontier areas. The government-generated geoscientific maps and data sets, company reports of previous exploration and other open-file databases, and geographic information systems are now available either free of charge or at minimal cost.

Geoscience Australia and the state geological survey organisations provide quality services to private investors. In a 2003 report prepared by the House of Representatives Standing Committee on Industry and Resources which inquired about the impediments to increasing investments in mineral and petroleum exploration in Australia, a number of recommendations were made to improve both the availability and quality of geoscientific data. The recommendations were further validated by the efforts made by the Minerals Exploration Action Agenda (MEAA 2004), which also validated the need to improve the availability of pre-competitive geoscience data. The Australian government has viewed this to be an important step in bringing all jurisdictions to work together and improve coverage, accessibility and quality of data and information under nationwide protocols, standards and systems.

FISCAL REGIME AND INCENTIVES

Determining the relative attractiveness of energy resource projects depends for the most part on Australia's taxation requirements. The large-scale nature of energy projects and its consequent need for international capital support has made the energy sector most sensitive to the international competitiveness of Australia's fiscal regime than in many other sectors.

The attractiveness of Australia's fiscal regime is based on two areas: 1) general taxation regime that applies to all projects; and 2) secondary taxation system that applies to the use of community-owned underground resources. In principle, energy sector investments are treated equally with other large investments in the general taxation system. The Australian government has implemented major reforms to business taxation to improve the economy's international competitiveness, including the reduction of company tax rate from 36 to 30 percent from 2001-2002. Secondary taxes, on the other hand, apply to underground mineral and energy resources, and are applied by both the Australian (offshore) and state (onshore) governments. The taxes are designed to compensate the community for allowing the private extraction of Australia's depletable resources.

The secondary tax system, which applies to coal, uranium, gas and liquid petroleum vary across Australia. State and territory royalties apply to energy resources in those jurisdictions and are generally 'ad valorem'. Australian government jurisdictions (e.g. beyond coastal waters to the outer limits of Australia's continental shelf), Petroleum Resource Rent Tax (PRRT) applies in all areas except the North-West Shelf; where the excise and royalty regimes have been maintained to keep up with government's long standing assurances that the fiscal regime for the North West Shelf project would remain stable.

The PRRT is a profit-based tax that automatically adjusts to changes in prices and costs. The regime has performed well, owing to its international competitiveness and efficiency.

NATIONAL ELECTRICITY MARKET REFORM

Like many industries around the world, the Australian electricity industry has had substantial changes, both in its structure and institutions. In the early 1900s, the electricity supply industry consisted of a mixture of both private and public enterprises. By late 1940s, it was predominantly government owned. State governments have chosen to organize the delivery of electricity through state owned, vertically integrated monopolies with small interconnection links between states.

Restructuring of the Australian electricity industry (which actually started as early as 1900) consisted of vertical disaggregation of the vertically integrated, state-owned utilities into separate: generation, transmission, distribution, and retail supply components; corporations, privatization of electricity businesses; horizontal separation of generation sector into numerous competing businesses; separation and regulation of transmission and distribution functions; introduction of retail competition; and others.

One important element of reform was the establishment of the 'national electricity market' (NEM) in December 1998. NEM is composed of the Australian Capital Territory, New South Wales, Victoria, South Australia and Queensland. NEM is basically made up of the electricity generators, a competitive retail sector, and the regulated network sectors. It was created to promote competition and efficiency, both in production and consumption of electricity, and its associated services. It should also allow customers some flexibility and choice of supplier, without room for discrimination against technology, location of customers and suppliers.

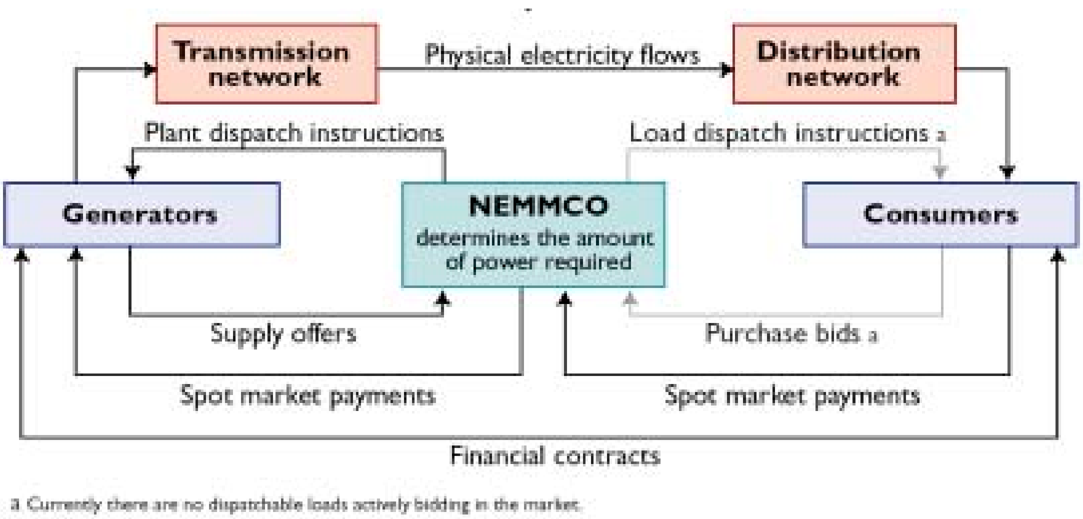
In 2003, about 43 different companies bidded their generation output into the NEM with approximately eight major large retailers. Most network service providers (i.e. transmission and distribution networks operating as regional monopolies) are regulated through various Commonwealth and state economic regulatory bodies. Merchant transmission development was allowed under certain conditions.

A single National Energy Regulator will be established, which will be responsible for transmission and market monitoring. At the end of the decade, it is expected to be the only regulatory body for the electricity industry.

The National Electricity Market Management Company (NEMMCO), on the other hand, will be responsible for the management of the spot market and the central coordination of the dispatch of electricity from all generators to ensure sufficiency of supply to meet the demand. NEMMCO will also be responsible for maintaining power system security.

The NEM spot market is the mechanism for balancing electricity supply and demand. Generators with a capacity greater than 30 MW are required to sell all electricity through the spot market. NEM's operations are governed by a set of rules and regulations contained in the National Electricity Code. The code should allow participants maximum level of commercial freedom, in a market that is transparent and efficient. Trading risks are hedged via financial contracts managed in secondary markets.

Figure 2 Structure of the 'National Electricity Market'



Source: ABARE 2004

NATIONAL ENERGY POLICY FRAMEWORK

In 2001, Australian governments agreed to establish a national energy policy framework to guide future energy policy decision making by jurisdictions and to provide increased policy certainty for energy users, including households and small businesses.

The Council of Australian Governments (COAG) has agreed on the following national energy policy objectives:

- Encouraging efficient provision of reliable competitively priced energy services to Australians, underpinning wealth and job creation and improve quality of life, taking into account the needs of regional, rural and other remote areas.
- Encouraging responsible development of Australia's energy resources, technology and expertise, their efficient use by industries and households and their exploitation in export markets.
- Mitigating local and global environmental impacts, notably greenhouse gas emission impacts of energy production, transformation, supply and use.

Consistent with the above policy objectives, and in the light of their responsibilities under the constitution, all Australian governments have agreed that their energy policies will:

- Recognise the importance of competitive and sustainable energy markets in achieving these objectives
- Continuously improve Australia's national energy markets, in particular, between and among jurisdictions and recognising the growing convergence between energy markets, energy resources and supply and demand side opportunities
- Enhance the security and reliability of energy supply, encompassing resource availability, conversion, transportation and distribution, and recognising the impact of government policy and the regulatory environment on private sector investment and operation
- Stimulate sustained energy efficiency improvements to technologies, systems and management proficiency across production, conversion, transmission, distribution and use
- Encourage the efficient economic development and increased application of less carbon-intensive (including renewable) energy resources and technologies, including exploring opportunities for appropriate inter-fuel substitution
- Recognise that Australia's energy markets operate in the context of world energy markets and seek to enhance Australia's international competitiveness in these markets
- In view of the importance of long-term investment in the energy sector, provide the degree of transparency and clarity in governmental decision-making that is required to achieve confidence in current and future investment decisions
- Carefully consider the social and economic impacts on regional and remote areas, with particular regard to business, industries and communities
- Facilitate constructive, effective inter-jurisdictional cooperation and productive international collaboration on energy markets

COAG also commissioned a wide-ranging review of the strategic direction of stationary energy markets in Australia. The review, which was published at the end of 2002, recommended an ambitious programme of reform. Measures included significant changes to improve and streamline governance and regulation, a market oriented approach to transmission, and new demand-side proposals. The projected impact on GDP of the review's reform programme was estimated at nearly $7 billion in net present value terms over the period 2005-2010.

The Ministerial Council on Energy (MCE) responded substantively to the COAG review proposals in December 2003 in their report to COAG on *Reform of Energy Markets.* This was followed by an Expanded Gas Program in April 2004. The energy market reform program was formalised in the *Australian Energy Market Agreement*, which was endorsed by the Prime Minister and all Premiers and Chief Ministers on 30 June 2004. The program consists of the following elements:

Governance and Institutions:

- The Ministerial Council on Energy as the single national energy market governance body, supported by a national legislative framework (effective 1 July 2004).
- Two new national institutions, the Australian Energy Market Commission and the Australian Energy Regulator will be established. These bodies will undertake market development functions and economic regulation, respectively.

Economic Regulation:

- National approaches to energy access and distribution and retail regulation for electricity and gas will be developed.

Electricity Transmission:

- Improve the market orientation of electricity transmission arrangements through market-based incentives for transmission performance, improved assessment of regional boundaries and transmission planning, and a new regulatory test for transmission investments.

User Participation:

- Encourage increased end-user participation in the energy market through various means including enhanced demand-side response mechanisms and interval metering.

Gas Market Development:

- Improve gas access arrangements through the Ministerial Council on Energy's response to the Productivity Commission's 2004 Review of the Gas Access Regime.
- Develop principles to underpin future gas market development.

Further information on the MCE's energy market reform program can be found at www.mce.gov.au.

RENEWABLES

Australia's renewable energy currently accounts to less than 5 percent or 244 petajoules of total energy consumption. The decline is mainly from low biomass production, which was affected by its low energy content and high handling and processing costs. Hydro is largely used for electricity generation and accounts for about 95 percent of the total share of renewable electricity generated. Despite hydro's strong contribution, it is projected to grow by about 0.6 percent per year, reaching about 18 TWh by 2019 – 2020. By contrast, wind power is expected to grow from 1 TWh to 4 TWh over the same period.

Australian authorities have introduced a range of policy measures to support the development of renewable energy. Among these measures are the: 1) Mandatory Renewable Energy Target (MRET) scheme and 2) New South Wales Government's greenhouse gas emissions benchmark scheme. MRET requires the generation of 9,500 GWh of extra renewable electricity per year by 2010. Certificates are issued to the electricity generated from eligible technologies. Purchasers of electricity, on the other hand, are required to surrender a specified number of certificates for the electricity they require during the year.

NOTABLE ENERGY DEVELOPMENTS

In June 2004, the Australian Government has released its Energy White Paper, 'Securing Australia's Energy Future'. It was the first national energy statement, which has set out a comprehensive, integrated, and long-term framework for the development and implementation of energy policies and approaches. It is based on the three key energy objectives: prosperity, security and sustainability.

The succeeding discussions embody the whole paper:

NATIONAL ENERGY SECURITY OUTLOOK

Through its industry, tourism and resources departments, the Australian government proposes to undertake a biennial review of the national energy security outlook by considering existing policy and international obligations. It will try to analyse energy security in the context of domestic stationary and non-stationary energy sectors, and provide information about the short and long-term issues that may impact on the security of Australia's energy supply. Through the Ministerial Council on Energy (MCE), Australia hopes to address its concern over energy production and distribution. MCE will complement the arrangements already in place that handle oil supply disruptions.

CRITICAL INFRASTRUCTURE PROTECTION

The Australian government has also established the Energy Infrastructure Assurance Advisory Group (the Energy Group). It is within the Trusted Information Sharing Network (TISN), which comprises a number of groups from different sectors involving business and governments across Australia. TISN facilitates the sharing of information on issues, which relate to generic threats, vulnerabilities, critical infrastructure, and the development of measures and strategies necessary to mitigate risks. The Energy Group, on the other hand, will be comprised of representatives from the private sector, including state and territory governments, and will facilitate information sharing among owners and operators of critical infrastructures, on critical energy infrastructure security issues.

LOW EMISSION ENERGY TECHNOLOGIES

The Australian government has outlined the following measures to support its thrust towards the development and adoption of low emission technologies:

- $500 million (US$355 million) Low Emission Technology Demonstration Fund. This would leverage at least $1 billion in private sector investments in new technologies to demonstrate low emission technologies like renewable energy and some significant long-term abatement potentials.
- $75 million (US$52 million) Solar Cities trial. This would demonstrate the economic benefits of solar technologies and demand side management in reducing GHG.
- $100 million (US$70 million) Renewable Energy Development Initiative (REDI). REDI will support the development of renewable energy technologies with strong commercial potential.
- $20 million (US$14 million) Advanced Electricity Storage Technologies initiative. The initiative will support energy storage for intermittent renewable technologies, such as wind and solar.
- Up to $14 million (US$10 million) to develop a wind forecasting capability.

Likewise, the Australian government will work with states and territories, through the MCE, to identify and overcome energy market rules that provide impediments to the uptake of smaller-scale renewable and distributed generation.

MANDATORY RENEWABLE ENERGY TARGET

The Australian government has renewed its commitment to the Mandatory Renewable Energy Target (MRET) at its current level of 9,500 GWh by 2010, and maintaining until 2020. MRET is a key element of the Australian government's greenhouse response strategy and underpins the strategic development of the Australian renewable energy industry. MRET also creates a guaranteed 20-year market, backed by legislation and utilises a system of tradeable certificates.

A recent review (in 2003) of the MRET operation found that the scheme was successful in increasing the amount of renewable energy in Australia and will continue to do so in the future. MRET has stimulated over $1 billion in renewable energy investment and $1 billion more, as either committed or planned.

To improve the operational and administrative efficiency of the measure, the Australian government, has agreed to introduce changes which would include enhancing market transparency (by establishing time limits in creating Renewable Energy Certificates (REC)), increasing opportunities for bioenergy (by reducing the compliance burden), extending the deeming period for solar technologies, improving business certainty, and encouraging innovation through the recognition of emerging renewable electricity generation technologies.

NATIONAL ENERGY MARKET REFORM

Significant progress has been made in implementing Australia's energy market reform programme. It involved coordinated efforts among federal and state government agencies through the MCE. MCE was tasked to, among others, develop a truly national and efficient energy market for electricity and gas.

Australian governments have agreed to a number of reform initiatives in the key areas of governance, economic regulation, electricity transmission, user participation, and gas market development. The following is an update of such initiatives:

- Endorsement of the Australian Energy Market Agreement on 20 June 2004 by the First Ministers of all Australian States and Territories and the Prime Minister.
- Establishment, under Commonwealth legislation in June 2004, of the Australian Energy Regulator (AER). AER is responsible for market regulation.
- Establishment, under the South Australian legislation in June 2004, of the Australian Energy Market Commission (AEMC). AEMC is responsible for rule-making and market development.

Further work is in progress in the following:

- Development of the national approach for energy access
- Establishment of agreed national framework for distribution and retailing
- Improvement of the planning and development of electricity transmission networks that will create a stable framework for efficient investment in new generation and transmission
    - A new NEM transmission planning function was developed, including an Annual National Transmission Statement (released in July 2004).
- Enhancement of user participation in energy markets through full retail contestability, demand-side response and interval metering
- Increased penetration of natural gas:
    - MCE has agreed to accelerate the development of reliable, competitive and secure natural gas market starting April 2004
    - MCE to respond to the Productivity Commission's Review of the Gas Access Regime in 2004
    - Consideration of joint marketing provisions with MCMPR
    - Consideration of access to upstream facilities with MCMPR

OFFSHORE PETROLEUM EXPLORATION ACREAGE RELEASE

In March 2004, the Australian government made available a number of new offshore petroleum areas for exploration. Thirty-one (31) areas in Commonwealth waters (i.e. between 3 nautical mile territorial limit and limit of Australian jurisdiction) around Australia remained opened for bidding (in the form of work programs) until March 2005.

Since the Australian government does not undertake or finance petroleum exploration, it relies on the annual acreage releases in order to create opportunities for exploration investment. Details of such releases are contained in a comprehensive information package, which is widely distributed in Australia and overseas.

OFFSHORE PETROLEUM EXPLORATION INCENTIVE

In May 2004, the Australian government announced the introduction of a taxation incentive that will encourage petroleum exploration in Australia's remote offshore areas. The measure would allow an immediate increase of up to 150 percent in petroleum resource rent tax (PRRT) deductions for pre-appraisal exploration expenditures during the initial term of the exploration permit, granted for a designated offshore frontier area. The measure was applied to offshore acreage releases in 2004 and will continue to be applied until 2008. By lowering the cost of petroleum exploration in frontier areas, the measure should then be able to provide an incentive to explore in Australia's offshore remote areas and increase the probability of discovering a new oil province.

ESTABLISHMENT OF THE NATIONAL OFFSHORE PETROLEUM SAFETY AUTHORITY

In September 2002, the Ministry Council on Mineral and Petroleum Resources (MCMPR) has reaffirmed its priority to improve safety in Australia's offshore petroleum industry and has endorsed the formation of the National Offshore Petroleum Safety Authority (NOPSA). NOPSA, which is to commence operations in January 2005, is tasked to regulate petroleum safety in Federal, State and Northern Territory (NT) waters. The establishment of NOPSA will ensure the consistent regulatory approach for the industry across all jurisdictions.

CARBON SEQUESTRATION LEADERSHIP FORUM

The Australian government hosted the second Carbon Sequestration Leadership Forum (CSLF) in September 2004. The CSLF is an international climate change initiative, which focuses on the development of carbon dioxide capture, and storage technologies for long-term stabilization of GHG levels. The Forum also provides a mechanism to form bilateral and multilateral partnerships, facilitate coordination of carbon sequestration activities, strengthen international collaboration on technology development, and mobilization of international resources.

The Forum focused mainly on the CSLF charter, which is to facilitate the development of improved cost-effective technologies for the sequestration and capture of carbon dioxide, for its transport and long-term safe storage, and to make technologies broadly available internationally.

As outlined in the Policy Overview, the Ministerial Council on Energy agreed to the following reforms to Australia's energy market on 1 August 2003:

- The Ministerial Council on Energy to be the single energy policy forum from 1 July 2004, with the Australian Government and Tasmania to join the National Electricity Market Ministerial Forum as full members in the interim;
- A national energy legislative framework to be agreed and developed on a collaborative basis;
- The establishment of two new statutory bodies - an Australian Energy Market Commission (AEMC) as a separate statutory rule-making body for market development purposes; an Australian Energy Regulator (AER) to enforce regulations across the sector; and
- Agreement to the objective of a national regulatory framework for distribution and retailing (other than retail pricing) under the Australian Energy Regulator, for implementation in 2006; and
- Ministers to take decision by year-end on significant initiatives to improve the framework for electricity transmission planning and investment, including on a national approach to transmission.

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BRUNEI DARUSSALAM

INTRODUCTION

Brunei Darussalam (the Abode of Peace) is located on the northwest side of the island of Borneo. It has a total land area of about 5,765 square km and a 161 km coastline along the South China Sea. It is bounded on the north by the South China Sea and all other sides by the Malaysian state of Sarawak; which divides Brunei Darussalam into two parts. The eastern part is the Temburong District, and the western part consists of Brunei-Muara, Tutong and Belait Districts. In 2002, the population of Brunei Darussalam was about 0.35 million.

The real gross domestic product (GDP) at current price in 2002 was recorded at US$6,350 million and the GDP per capita was at US$18,091, an increase of 2.8 percent compared to the previous year, mainly attributed to oil and gas sector.

The steady political situation and excellent vision of His Majesty the Sultan and Yang DiPertuan have made it possible for Brunei Darussalam to achieve sustainable economic prosperity and stability. Brunei Darussalam's economy has been heavily relying on oil and gas since its discovery in 1929. The oil and gas sector is the main source of the economy's revenue which constitutes about 90 percent of Brunei Darussalam's exports and about 37 percent of its GDP. To further sustain and strengthen the oil and gas industry, his Majesty's Government is promoting and pursuing an economic diversification policy thus actively pursuing the development of the new upstream and downstream activities.

Brunei Darussalam's crude oil and condensate production in 2002 averaged 193 thousand barrels per day. The gas production for 2002 was about 32 million cubic metres per day, which were mostly exported to Japan and South Korea as liquefied natural gas (LNG).

Table 3 Key data and economic profile (2002)

Key data		Energy reserves**	
Area (sq. km)	5,765	Oil (MCM)	223
Population (million)	0.35	Gas (BCM)	350
GDP at current prices (Million US$)*	6,350	Coal (Mt)	-
GDP per capita (US$)*	18,091		

Source: Energy Data and Modelling Center, IEEJ. * Brunei Darussalam Key Indicators 2003.

** Proved reserves, end of 2001, BP Statistical Review.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Brunei Darussalam is the third-largest oil producer in Southeast Asia. It is also the fourth largest producer of liquefied natural gas in the world. In 2002, the total primary energy supply of Brunei Darussalam reached 3,320 ktoe, increasing by 37 percent compared to 2001. Brunei's oil and gas production was 20,769 ktoe, an improvement of 18 percent from its 2001 production of 17,519 ktoe, and 89 percent of which was exported. Natural gas represents 77 percent of the total energy supply while oil represents 23 percent.

Total proven crude oil reserves are 223 MCM. Oil is exported mostly to Japan, Korea, Singapore, Chinese Taipei and Thailand. Brunei Darussalam has natural gas reserves of 350 BCM, and the long-term prospects for its production is thought to be excellent. Most of Brunei's LNG is exported to Japan, with a small amount going to South Korea. Despite the good prospects for the growth of oil and gas exports, Brunei Darussalam's economy is still vulnerable to movements in global oil prices. The drop in global oil and gas prices (as was experienced in the past) have continued to weighed down on Brunei Darussalam's economy, including that of its trading partners, which resulted to reduced energy demands.

However, Brunei Darussalam's economy is expected to remain strong with the implementation of the 8th National Development Plan (NDP 2001-2005). With the US$4 billion budget allocated for the implementation of the 8th NDP, the economy is optimistic that its targeted growth rate of 5-6 percent will be achieved.

In 2002, the economy's total installed generating capacity under the Department of Electrical Services (DES) and the Independent Power Utility namely the Berakas Power Company (BPC), reached 810.1 MW. DES and BPC each have an installed capacity of 552.5 MW and 257.6 MW respectively. Almost all, or 99.7 percent of the total electricity generated was supplied by natural gas. Total generation for 2002 was 3,017 GWh, about 3.6 percent higher than 2,910 GWh in 2001.

FINAL ENERGY CONSUMPTION

In 2002, the total final energy consumption of 689 ktoe went up by 8 percent from 635 ktoe in 2001. The shares of the three sectors remain unchanged. The transportation sector consumed 52 percent of the total amount, followed by other sectors (residential, commercial and non-energy) at 34 percent and industrial sector at 14 percent. By source, petroleum products contributed the largest share with 63 percent of consumption, followed by electricity at 33 percent and gas at 4 percent.

Table 4 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	20,769	Industry Sector	93	Total	3,017
Net Imports & Other	-17,448	Transport Sector	360	Thermal	3,017
Total PES	3,320	Other Sectors	236	Hydro	-
Coal	-	Total FEC	689	Nuclear	-
Oil	661	Coal	-	Others	-
Gas	2,660	Oil	434		
Others	-	Gas	30		
		Electricity & Others	225		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

POLICY OVERVIEW

Brunei Darussalam has so far implemented seven National Development Plans (NDPs). The long-term objectives outlined in these NDPs, particularly the current 8th NDP, place specific emphasis on programmes to strengthen and expand the oil and gas industry, economic diversification through non-oil industries, maximum economic utilisation of national resources, improvements in the quality of life of the people, and promotion of a clean and healthy environment. In pursuing these objectives, development plans will continue to focus on strategies and programmes that will expedite the process of industrialisation with the end in view of achieving more balanced socio-economic development. The government is also working on improving the economy's investment climate to attract and encourage the private sector to play a more active and important role in the development of the economy.

OIL AND GAS

Prior to 1963, all mining activities (including petroleum) were regulated by the Mining Act. In 1963, the Government has introduced the Petroleum Mining Act to cover all petroleum mining activities. The latter came with its own model of concessionary agreements where most exploration and production operations in the economy were carried out. Under the Petroleum Mining Agreement between His Majesty's Government and the concessionaires, His Majesty's Government reserves the right to participate in the petroleum field upon declaration of commerciality.

In 1992, the Petroleum Mining Act was amended with all its schedules (including the Second and the Third Schedules) repealed. The move is partly due to the government's desire to introduce other forms of agreements (non-concessionary) for future petroleum mining activities. The amended act provides for procedures where the government may invite persons to bid for a petroleum mining agreement with respect to any onshore state land or offshore state land for purposes of exploring or mining petroleum. Any person interested to bid shall therefore conform to such terms and conditions, imposed by the Government, in the invitation to bid.

Amendments to the Petroleum Mining Act, made in January 2002, recognise the formation of Brunei National Petroleum Company Sdn Bhd (Petroleum Brunei). The company has the right to perform both commercial and regulatory functions. One of its regulatory functions is to act as a state party in the negotiation, conclusion and implementation of Petroleum Mining Agreements. New petroleum areas such as the deepwater Blocks J and K are to be awarded under Production Sharing Contract (PSC) with Petroleum Brunei's participation.

To extend Brunei Darussalam's oil reserves, the Brunei Oil Conservation Policy was introduced in 1980. It came into effect in 1981 and has resulted in oil production of around 150,000 barrels per day. Since November 1990, the government has given flexibility to the Conservation Policy, which further increased production availability.

In 2000, the Brunei Natural Gas Policy (Production and Utilisation) was introduced. It seeks to sustain gas production levels in order to adequately satisfy current obligations. It also seeks to open new areas and encourage more exploration activities by new and existing operators. It provides that priority shall always be given to domestic utilisation of gas, especially for power generation.

NOTABLE ENERGY DEVELOPMENTS

DEVELOPMENT OF DOWNSTREAM OIL AND GAS INDUSTRY

In an effort to diversify Brunei Darussalam's oil and gas based economy, the government commissioned an international consultant to conduct the Brunei Darussalam Master Plan Study on Downstream Oil and Gas Industry. The study was completed in 2001 and has identified the following potential industries to be developed in Brunei Darussalam:

- Gas based industry such as ammonia, urea and methanol;
- Derivatives of olefins and aromatics from naphtha cracker with the possibility of integration with a refinery; and
- Energy intensive industry such as aluminium smelters.

In 2002, Petroleum Brunei called for expressions of interest for investment in the petrochemical projects to be located at the Sg. Liang Industrial site in the Belait District from which investors were short listed to conduct their Detailed Feasibility Study (DFS) on their proposals.

The DFS reports were submitted in the third quarter of 2003 from which selection for project implementation will be by first half 2004.

In January 2003, the Brunei Economic Development Board (BEDB) has announced it's "two-pronged strategy" that included plans for the development of Sungai Liang, Pulau Muara Besar and the identification of other industry clusters for FDI, as well as for local investment. BEDB has reviewed one of its current policies and procedures that an approval has been granted by His Majesty's Government for the change of policy on the ownership and lending of industrial land. This would enable BEDB to lease, sublease or sublet industrial lands and buildings to investors and for the assets involved to be changed as collateral for bank financing.

LNG SIXTH TRAIN EXPANSION OPPORTUNITY

Brunei LNG has embarked on a program to expand its present capacity of 7.2 million tonnes per year to 11.2 million tonnes per year by 2010. Brunei LNG will also refurbish existing capacity to extend its operating life to 20 years, or up to 2033. It is also aiming for continued LNG sales beyond 2013. Around B$2.4 billion is earmarked for investment over the next 13 years to support such activities. The feasibility study will begin early 2003, and a final investment decision is expected in 2005.

OPENING OF NEW PETROLEUM AREAS

In the new petroleum areas, two consortia bid for Block J (5,020 sq km), and one for Block K (4,944 sq km) were received. Both blocks are located offshore in the deep water Exclusive Economic Zone (EEZ). There was no bid for the onshore Block L (2,254 sq km), which is still under review to develop strategies for re-offer, possibly with supplementary seismic data and revised fiscal terms.

On 29 January 2002, the government awarded Block J to a joint venture of TotalFinaElf, BHP Billiton, and Amerada Hess Corporation. TotalFinaElf (the designated operator) holds a 60 percent interest, while BHP Billiton and Amerada Hess hold the remaining 25 percent and 15 percent respectively. The government has also awarded exploration rights to Block K to a joint venture led by Shell International (the designated operator) owning 50 percent interest, including Conoco and Mitsubishi with 25 percent interest each.

POWER SECTOR

An assessment of the current situation of the electricity sector revealed that the Brunei Darussalam electricity industry faces a major challenge of an increasing electricity demand due to its economic activities and to attract direct foreign investment.

The existence of another power utility (Berakas Power Company Private Limited) has actually relieved the Department of Electrical Services of the administrative and financial burden of supplying power to several strategic loading (areas). BPC today supplies about 40 percent of the total loads in Brunei Darussalam.

In 2002 the maximum demand recorded by DES and BPS were about 246 MW and 174 MW respectively, an increase of about 4 percent of the total load demand compared to previous year. Almost 100 percent of the population today are being provided with the electricity supply from the grid. However, the peak demand will increase substantially if the various projects being considered by BEDB are materialised.

The Department of Electrical Services has formulated plans to fulfil the increasing energy demands in line with the economic development. To accomplish its mission to provide electricity supply in an efficient, reliable, safe, as well as economical manner to upgrade the standard of living of the people and for the development of the country, the Department has embarked on several major projects in its power development plan in the current 8th NDP

(2001-2005). In this 8th NDP, the electricity sector has been allocated B$529.7 million or 7.3 percent of total development funds.

The collective factors from the natural demand growth and scheduled retirement of generating machines, necessitates the Department to undertake the construction of various planting up program so as to uphold the supply and demand profile in the best secure and effective manner. In 2001, two units 3 MW diesel-generating sets were installed and commissioned in the Temburong District. Ninety-nine (99) MW of additional generation capacity in Gadong I Power Station were commissioned in 2002. In addition, the construction of a 110 MW at Bukit Panggal Combined Cycle Power Plant – Phase I has been tendered and expected to be commissioned in 2006.

Years 1998 to 2003 also witnessed the implementation and completion of various projects in the transmission system such as construction and completion of several major 66KV substations including the completion and commissioning of the new 275KV rated transmission line designated as Gadong Feeder 7 & 8 from Katok 66KV substation which is located in the Brunei Muara District to the new Pasir Putih 66KV substation in Tutong District. This 275KV transmission line is at the moment energized at 66KV voltage level. These lines are to be extended towards the Lumut Cogeneration Plant in the west in the future National Development Plan.

REDUCING THE OIL AND GAS INDUSTRY'S CONTRIBUTION TO GLOBAL WARMING

The oil and gas industry is one of the major contributors to global warming through the emission of methane and carbon dioxide (CO_2). The main sources of methane emissions are process venting, instrument gas and fugitives. Major sources of CO_2 emissions include process flaring, atmospheric gas flaring (where recovery is uneconomic), fuel gas combustion (gas turbines and other prime mover exhausts), and transport.

As part of their environmental initiatives, major oil and gas producers in Brunei Darussalam plan to reduce the disposal of gas by continuous venting and flaring by 2003 and 2008 respectively. Projects undertaken to reduce venting include:

- Simplifying and rationalising old facilities, centralising processes at main complex facilities, and improving operations to reduce venting from compressor trips, fugitive losses, atmospheric gas disposal and from use of instrument gas;
- Converting existing vent stacks to flare stacks; and
- Simplifying and rationalising facilities to recover and recompress vented flash gas from surge vessels and to reduce instrument gas consumption.

Realising that fuel gas combustion contributes to a large percentage of CO_2 emissions, companies intend to focus more on improving the energy efficiency of gas turbines. Furthermore, new facilities will not be designed to continuously vent and flare gas for disposal, and instrument gas in new projects will not be allowed unless it is recovered. However, venting and flaring cannot be totally phased out. Venting and flaring will be limited only to atmospheric gas disposal, instrument gas in old facilities, fugitives (minimised), safeguarding measures (purge and pilot gas, and emergency relief) and process deviations (like compressor trips, or oil production during plant shutdown and maintenance), and it will take place under strict controls.

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CANADA

INTRODUCTION

Canada covers the northern part of North America and is second only to Russia in geographic size. Its small population of around 31 million, of which two-fifths is concentrated in the province of Ontario, is spread over 10 million square kilometres of territory. Canada is known for its wealth of energy and other natural resources. In 2002, its GDP accounted to roughly US$832 billion (in 1995 US$ at PPP), or US$26,553 per capita. Due to this high standard of living, cold climate, long distances between major cities, and many energy intensive and bulk goods industries, Canadians are heavy energy consumers. Canada's final energy consumption per capita in 2002 was 6.2 toe or about four times the APEC average.

Canada's economic picture has generally been very positive in recent years. Real GDP grew an average of 3.5 percent per annum in the late 1990s. The economy slowed substantially in 2003 due to the effects of SARS, restrictions on beef exports, appreciation of Canadian dollar, and the August blackout. Canada's real GDP increased by only 2 percent compared with 3.3 percent in 2002. Inflation remained low, with consumer prices increasing 2.2 percent in 2002 and 2.8 percent in 2003. Unemployment averaged 7.7 percent in 2002 and 7.6 percent in 2003.

Canada is the fifth largest energy producer in the world (behind the United States, Russia, China and Saudi Arabia) and is a major energy exporter. It has abundant reserves of oil, natural gas, coal and uranium in its western provinces and enormous hydropower resources in Quebec, Newfoundland, Manitoba and British Columbia. It also has significant offshore oil and gas deposits near Nova Scotia and Newfoundland. At the end of 2002, energy reserves included 688 MCM of conventional crude oil, 27,730 MCM of oil in oil sands, 1,599 BCM of natural gas, 6,578 Mt of coal, and 439 kt of uranium. Installed electric generating capacity amounted to some 111 GW. Energy production is very important to the Canadian economy, accounting for 6 percent of GDP and 300,000 jobs in upstream and downstream operations, representing 1.7 percent of the Canadian labour force, in 2003. The gross export revenues from natural gas, petroleum, electricity and coal in 2003 were about 27 percent higher than 2002 levels.

Table 5 Key data and economic profile (2002)

Key data		**Energy Reserves****	
Area (square km)*	9,984,670	Oil (MCM)***	688
Population (million)	31.36	Gas (BCM)***	1,599
GDP Billion US$ (1995 US$ at PPP)	832.76	Coal (Mt) - Recoverable	6,578
GDP per capita (1995 US$ at PPP)	26,553	Oil Sands (MCM)***	27,730

Source: Energy Data and Modelling Center, IEEJ. * Statistics Canada. ** National Energy Board.

*** Established reserves of oil, gas and oil sands are equal to the sum of all proven reserves and half of probable reserves.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, Canada's energy production exceeded 388 Mtoe. Natural gas accounted for most of the supply at 40 percent, crude oil 35 percent, coal 9 percent, hydropower 8 percent, nuclear power 5 percent and other sources 4 percent. Gross energy exports, primarily crude oil and natural gas from the western provinces, reached nearly 212 Mtoe or 55 percent of energy produced. But there were also substantial energy imports of some 73 Mtoe, mostly crude oil by eastern provinces, so net exports were just 36 percent of total production.

Taking into account the amount of exports, imports and stock changes, Canada's domestic primary energy demand in 2002 reached a total of 256 Mtoe or 66 percent of production. Exploration for oil and gas increased in 2003, in response to higher commodity price and low storage levels. At the same time, about 19,957 wells were drilled, exceeding that of 2002 by 40 percent or 5,399 wells. Because of the strong natural gas prices in 2003, exploration activities focused on gas; reaching about 70 percent of all wells drilled. Producers have expanded their drilling programs in northeastern British Columbia, the Alberta Foothills, southeast Alberta and southwest Saskatchewan. Production from oil also increased in 2003 by 8 percent as gas production declined. Generation from hydro plants experienced modest decreases due mainly to poor water conditions and were partially offset by increases in nuclear generation in Ontario. Production of coal also declines as some coal facilities shutdown as a result of industry restructuring and consolidation of operations in 2003. High commodity export prices pulled up the total gross export earnings for natural gas, petroleum, coal and electricity, increasing it from a record CAN$43 billion in 2002 to CAN$62 billion in 2003.

The largest source of crude production is the Western Canadian Sedimentary Basin (WCSB). Declining WCSB reserves were nearly offset by reserve additions from the East Coast offshore and oil sands. Recent declines in light crude production have been offset by additional production of heavy crude. Conventional crude oil and natural gas liquids made up the bulk of oil production, but 33 percent of production in 2003 came in the unconventional forms of bitumen, synthetic crude and pentanes plus. Synthetic crude from oil sands in Alberta, which had a supply cost of some CAN$22 per barrel in the 1990s, is expected to grow in importance as technology lowers costs to CAN$15-$18 per barrel.

Exports account for a large portion of Canada's oil and gas production. In 2002, crude oil production exceeded 136 Mtoe, where 75 percent was exported mainly from western Canada. Meanwhile, nearly 54 Mtoe of oil was imported into eastern Canada, so that net oil exports were equivalent to just 36 percent of production. Gas production in 2002 totalled more than 154 Mtoe, of which net gas exports of around 88 Mtoe were equivalent to 57 percent. The 1990s saw average annual growth of 3.6 percent in net oil exports and 9.2 percent in net gas exports. In 2003, net export volumes on natural gas decreased by 11.5 percent from 2002 while total gross exports went down 7.6 percent from the previous year because of lower production and higher demand in the US; primary reduction in the industrial and electric power sectors. But the long-term prospects for oil and gas exports remain bright due to the robust demand in the US, expanding pipeline capacity, and continued discoveries. Net export on natural gas accounted for 52 percent of total Canadian production in 2003, lower than that of 55.5 percent in 2002.

Table 6 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	388,533	Industry Sector	74,669	Total	600,443
Net Imports & Other	-132,081	Transport Sector	53,843	Thermal	174,331
Total PES	256,452	Other Sectors	65,797	Hydro	350,386
Coal	29,113	Total FEC	194,309	Nuclear	75,526
Oil	92,940	Coal	4,080	Others	200
Gas	75,276	Oil	80,838		
Others	59,123	Gas	53,890		
		Electricity & Others	55,501		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

Canada generated about 600 TWh of electricity in 2002, nearly 2 percent higher than in 2001. Hydropower dominated with a 58 percent share, followed by thermal plants with 29 percent and nuclear power at 13 percent. Natural gas is increasingly favoured over coal for incremental thermal generation, owing to its reputation as a cleaner fuel and the availability of cost-effective combined-cycle generators. There is a substantial two-way electricity trade with the western United States mostly among hydropower facilities. Net electricity exports to the US in 2002 accounted to roughly 6 percent of production. The Canadian electric power generation, transmission and distribution sector accounts for 2.4 percent for total Canadian GDP.

Canada coal production in 2003 reached 62.2Mt, down by about 6.7 percent from 66.6Mt in 2002. The decline came from the bituminous coal production, while the sub-bituminous, and lignite coal production remained unaffected. Due to the rising demand for coking coal in the world market, Canada's coal exports increased by 10 percent to 28.3Mt in 2003. This finally put a stop to the downward trend since 1997. Such an increase on coal exports occurred in Europe and Latin America. Exports to the Middle East and North America had a moderate increase. However, exports to Asia was down from 64 percent in 2002 to 57 percent in 2003, even with the new demand from China. The only significant import of coal is for thermal requirements and cement industry in Ontario, New Brunswick and Nova Scotia, and for steel industry in Ontario. Canada imported 22.4Mt of coal in 2003, almost the same level as in 2002. Finally, Canada remains the world's leading producer and exporter of uranium, of which it accounts for about 32 percent of 2002 global mine production.

In 2003, alternative and renewable energy production increased by about 2 percent over 2002 and accounted for nearly four percent of total energy consumption in Canada.

FINAL ENERGY CONSUMPTION

In 2002, total end use energy consumption in Canada reached more than 194 Mtoe. Industry accounted for 39 percent of energy use, residential and commercial buildings 31 percent, transport 28 percent, and agriculture 3 percent. By fuel source, petroleum products accounted for 41 percent, natural gas 28 percent, electricity 23 percent, coal 2 percent and the remaining 6 percent by other fuels.

In the residential and commercial sectors, space and water heating account for about 72 percent of energy use while lighting, air conditioning and electronic equipment account for the other 28 percent. Growth in consumption has been slow, averaging just 1.4 percent per annum in the 1990s. Significant improvements in the energy efficiency of buildings, HVAC (heating, ventilation and air conditioning) and electronic equipment have occurred. But these efficiency gains have been offset by demand growth associated with increases in population and GDP, by greater market penetration of household appliances and office equipment and by a strong preference for larger homes.

Three industries - pulp & paper, petroleum refining and iron & steel - account for approximately 6 percent of Canada's GDP, yet are responsible for around 46 percent of industrial energy consumption. Energy is used to power equipment, generate process heat, and provide raw material in production processes. Energy consumption in the industrial sector grew on average 1.3 percent per annum during the 1990s. Growth in energy consumption was boosted by strong economic growth but moderated by efficiency improvements in some key industrial sub-sectors.

With the strength in both passenger and freight traffic, energy use grew faster in the transportation sector than in any other sector during the 1990s, at an average of 1.8 percent per annum. Petroleum products dominated the sector, accounting for 90 percent of its energy consumption in 2003. Four-fifths of transport demand, in terms of distance travelled, is met by road transport. Light trucks, including sport utility vehicles and minivans, which consume far more fuel per kilometre than cars, continue to be popular for passenger transport. Modest fuel efficiency improvements in new vehicles, strong market preferences for enhanced performance and significant increases in average distance travelled per vehicle have contributed to energy consumption growth. In freight transport, energy use has been boosted by growing demand and a shift away from railways towards more energy-intensive truck transport.

The National Energy Board (NEB) was tasked to monitor the energy market in Canada and inform Canadians about energy trends and issues. In July 2003, the NEB published *Canada's Energy*

Future: Scenarios for Supply and Demand to 2025 to show the long-term energy outlook. It also issued three energy market assessment reports related to electricity exports and imports, the Maritimes natural gas market and short-term natural gas deliverability from the Western Canada Sedimentary Basin (WCSB) in 2003.

POLICY OVERVIEW

In Canada, jurisdiction over energy matters is shared between the provincial and federal governments. The constitution gives the provinces ownership of natural resources, which thus have authority over the conservation, and management of these resources within their borders. But jurisdiction over international and inter-provincial trade is a federal responsibility. The division of power outlined by the constitution requires the different levels of government to cooperate in important policy areas such as climate change, environmental protection and regulation of gas and electricity grids. Through Natural Resources Canada (NRCan) and other government departments including Environment Canada, the Department of Fisheries and Oceans, and Indian and Northern Affairs Canada, the federal government works with provincial governments to implement national development strategies and to honour international agreements.

Energy policy in Canada is market-based. Due to its huge and diverse resource base, physical energy security is not an issue in Canada. However, sustainable development of existing resources to ensure adequate supplies for the future is a key priority. Policies are therefore aimed at promoting economic growth while encouraging the sustainable development of resources and limiting environmental impacts. NRCan intervenes in areas where the market does not adequately support these policy objectives. NRCan implements policies and programmes which encourage scientific and technological research, promote energy efficiency and assist the development of renewable and alternative energy sources.

OIL AND GAS MARKETS

Wellhead oil and natural gas prices in Canada have been fully deregulated since the Western Accord between the federal government and energy-producing provinces was reached in 1985. The Accord opened up the gas market to greater competition by permitting more exports, allowing users to buy directly from producers and unbundling production and marketing from transportation services. Oil and gas pipeline networks, over which competing oil and gas supplies are transported, continue to be regulated as natural monopolies. Federal authorities have the main responsibility for regulating long-distance, high-pressure transport networks, as well as exports. Provincial authorities have the main responsibility for regulating local and regional distribution networks.

The National Energy Board (NEB), a federal regulatory body under the Minister of Natural Resources, regulates oil and gas pipelines that cross international and inter-provincial borders and approves exports of oil, gas and electricity. In 1987, the NEB adopted a "market-based procedure" for approving export licenses essentially leaving it to the market to satisfy legal requirements for natural gas to be provided at fair market prices. To improve market functioning, the NEB holds public hearings on applications to build or expand pipelines and establishes inter-provincial transportation rates, conditions of access and terms of service. To limit costly hearings, the NEB encourages large groups of shippers to negotiate pipeline rates directly with pipeline companies, subject to Board approval.

The NEB *Processing Plant Regulations* came into effect in January 2003. This regulation is established based on a goal-oriented approach. It also deals with the design, construction, operation and abandonment of federally-regulated gas process plants. With the help of goal-oriented approach, three further sets of regulations are being developed including the *Damage Prevention Regulations*, the *Canada Oil and Gas Diving Regulations*, and the *Canada Oil and Gas Drilling and Production Regulations*.

In April 2003, the NEB published an annual performance report, called *Focus on Safety – A Comparative Analysis of Pipeline Safety Performance*, on the safety of the companies they regulated. It is aimed at providing a clear understanding of the safety performance of the NEB-regulated oil and gas pipeline industry.

ELECTRICITY MARKETS

Electricity markets in Canada are organised along provincial lines and regulated by provincial governments. In most provinces, the power industry has been highly integrated, with the bulk of generation, transmission and distribution provided by a few publicly owned utilities. But since the mid-1990s, driven in part by restructuring efforts in the United States, several provinces have taken measures to make electricity markets more competitive. Such measures include the unbundling of major utility functions into transmission, generation, distribution and marketing segments, with provisions for fair access of competing generators and suppliers to the transmission grid.

To maintain access to US export markets, British Columbia, Manitoba, Alberta, Quebec and Ontario have complied with rules of the US Federal Energy Regulatory Commission (FERC) and have opened up their transmission systems to competition. Several Canadian utilities have taken steps to coordinate their operations with regional transmission organisations (RTOs) being set up under FERC proposals for standardised market design. Manitoba Hydro has participated in the first RTO approved by FERC and signed a coordination agreement with the Midwest Independent Transmission System Operation, Inc. (MISO). Alberta is also considering participation in the RTO West. Ontario has been assessing the merits of alternative options for joining RTOs in adjacent US markets as well.

Alberta was the first province to reform its power markets. In 1996, it introduced a competitive wholesale market, including location-based rates and a power pool. In 2000, it compelled electricity producers to sell their electricity output at auction to wholesalers. Since the start of 2001, it has allowed large and small electricity customers to choose among competing retail suppliers. But reform has not been without challenges. Rapid economic growth in the late 1990s sharply increased demand while uncertainty over rules for deregulation discouraged investment in power plants and curtailed supply. Because of this supply shortfall, consumers have sometimes faced price hikes of 80 percent or more since retail competition was introduced. But due to low reserve margins at the time that competition was introduced, it is likely that significant price hikes would have occurred under traditional cost-of-service regulation as well. As new supply is added, it is expected that prices will come down. Meanwhile, temporary price rebates have offered customers some relief on power bills. To protect the Alberta consumer, retailers marketing electrical services to home, farm, eligible small commercial and industrial consumers are licensed by Alberta Government Services. In addition, Alberta Government Services has enforcement powers to deter dishonest marketing practices. The Market Surveillance Administrator is responsible to monitor, investigate and enforce market rules, and the Alberta Energy and Utilities Board is responsible to review most regulated energy and delivery charges through open and transparent hearings. The *Electric Utilities Act* (EUA 2003) came into force in June 2003. It legislates changes that will help deliver the benefits of deregulation to Albertans faster and ensures the electricity marketplace continuous to operate efficiently.

In November 1997, the Province of Ontario released a policy setting out a restructuring plan for electricity industry in Ontario. The market restructuring legislation, the *Energy Competition Act* 1998, was enacted in 1999. The wholesale and retail electricity markets were opened to competition in May 2002. There were significant changes on the electricity market in the way the electricity industry operates after the market opened. Generators currently compete to sell electricity through the Independent Electricity Market Operator (IMO)-administered spot market. Local distribution companies and large industrial facilities directly connected to the transmission system, other large industrial and commercial customers connected to the distribution system who opt to be wholesale market participants and retailers. The generation company, Ontario Power Generation, must compete with other power producers and has until 2010 to reduce its share of the provincial electricity market to 35 percent from the 85 percent share it held when the Act was signed. The transmission entity, Hydro One, remains publicly owned and provides access on non-discriminatory terms to all competing suppliers. Distribution companies, most of which are municipal electric utilities, were required by the Act to separate their wires businesses, which remain regulated as natural monopolies, from their retail supply businesses, which are competitive. The competitive operation of Ontario's power market is overseen by an Independent Electricity Market Operator (IMO). In December 2002, the Province modified the legislation governing the Ontario electricity market by enacting the *Electricity Price, Conservation and Supply Act*, 2002. The Province expanded the availability of the fixed price to include additional consumers when it announced a business protection plan for large electricity consumers in Ontario in March 2003. The Ontario government introduced a new pricing plan for electricity taking into effect on 01 April 2004. This replaces the price cap of 4.3 cents per kWh that most Hydro One customers had paid. Under the new plan, the first 750 kWh of electricity consumer used each month will be priced at 4.7 cents per kWh. Each kWh a consumer use above 750 kWh per month will be priced at 5.5 cents.

Restructuring has not advanced as quickly in other provinces and may be subject to further reviews given the experience of Ontario, California and the August 2003 power blackout. As noted below, several provinces - British Columbia, Nova Scotia and New Brunswick have initiated some steps toward restructuring.

ENERGY END USE MARKETS

To promote energy efficiency and conservation in end use markets, the Government of Canada relies on a variety of policy instruments. These include leadership by example, voluntary measures, equipment and product labelling, financial incentives for certain types of investments, and energy efficiency standards for household appliances, office equipment and industrial motors. In 1998, NRCan established the Office of Energy Efficiency (OEE) with a mandate to strengthen and expand Canada's commitment to energy efficiency. OEE manages energy efficiency measures in all energy end-use sectors and alternative fuel initiatives in transport to overcome barriers of inadequate information and knowledge, institutional deterrents, and financial and economic constraints in the energy end-use market. The OEE developed a set of progress indicators to track the impact of these measures.

Programmes aimed at improving energy efficiency are sponsored not only by the Government of Canada but also by provincial and territorial governments, municipalities, utilities and some non-governmental organisations. Over the period from 1990 through 2002, the OEE Index has indicated an overall energy efficiency improvement of about 13 percent, which translates into energy savings of 880.7 petajoules in 2002 and reducing annual greenhouse gas emissions by 49.9 megatonnes. An annual assessment of trends in energy use are published in a technical report entitled *Energy Efficiency Trends in Canada*.

ENERGY AND ENVIRONMENT

Canada was one of the 160 countries that negotiated the Kyoto Protocol in December 1997 under the United Nations Framework Convention on Climate Change. Under this Protocol, Canada's target is to reduce its greenhouse gas emissions to 6 percent below their 1990 levels by the first commitment period of 2008-2012. This is a challenging target for Canada; being a cold-climate economy with long distances and energy-intensive industries. According to business-as-usual scenarios, emissions in Canada should rise significantly between 1990 and 2010, fuelled by economic and population growth. To achieve its Kyoto target, Canada will have to reduce its 'business-as-usual' emissions by 29 percent or 240 million tonnes.

From 1998 through 2002, intense discussions took place between the federal government and its provincial and territorial counterparts. Stakeholders were also actively engaged under this National Climate Change Process to identify best options to reduce emissions in the various sectors of Canadian society. Discussions and consultations led governments to take some initial actions on climate change. For instance, a *First National Climate Change Business Plan* was released in October 2000 and identified emissions reduction actions to be undertaken by federal, provincial and territorial governments. The federal component of this Business Plan was the *Government of Canada*

Action Plan 2000 on Climate Change, which represented a financial commitment of CAN$500 million. Overall, federal financial commitments during the period 1998 to 2002 amounted to CAN$1.7 billion for investments in climate science, mitigation, and the development of new long-term technologies. As of March 2002, the Government of Canada had reduced its GHG emissions by 24 percent.

In December 2002, the Government of Canada officially ratified the Kyoto Protocol. This decision reconfirmed Canada's strong commitment to addressing climate change and to working with the international community in dealing with this global problem. To support its ratification decision, the Government of Canada released the *Climate Change Plan for Canada*, which is a road map for Canada to follow in order to achieve its Kyoto target. The Plan established that measures underway at the time of its release were expected to achieve 80 Mt of emissions reductions. These included carbon sinks of 30 Mt from existing forestry and agricultural practices. As a second step, the Plan highlighted measures to reduce emissions by an additional 100 Mt. At the heart of this second step are the negotiations of covenants with large final emitters to reduce industrial emissions by 55 Mt. Also proposed was a series of measures targeted at sectors non-covered under the covenant approach. As a third step, the Plan suggests further emissions reductions of 60 Mt from various sources such as new technologies and initiatives by provincial and territorial governments.

In addition to the CAN$1.7 billion in climate change investments announced by the Government of Canada in 1997, the federal budget of February 2003 provided new funding of CAN$2 billion over five years to support climate change initiatives.

NOTABLE ENERGY DEVELOPMENTS

CARBON SEQUESTRATION

Canada is part of an international effort to address climate change. In 1997, Canada signed the Kyoto Protocol and committed to reduce greenhouse gas (GHG) emissions to 6 percent below 1990 levels by the commitment period 2008-2012. A two-year initiative was announced in February 2004 to help develop a market for carbon dioxide (CO_2) capture and storage in Canada, as well as innovation new uses of CO_2 from industrial emitters. Incentive funding will be used to support projects that demonstrate CO_2-based enhanced resource recovery in small-scale commercial settings, to help abate the costs of CO_2 capture and storage. Potential applicants for this incentive include any for-profit firm that will operate a project that injects CO_2 from a Canadian industrial source into a geological formation for storage, enhanced oil and gas recovery, and/or disposal in Canada. A CAN$15 million investment in CO_2 capture and storage builds on the unique expertise Canada has developed from the Weyburn CO_2 Monitoring Project and offers significant long-term potential for addressing GHG emissions, while continuing the pursuit of industrial economic objectives.

Carbon dioxide is collected during processes such as oil sands recovery, electricity generation and cement, petrochemical and fertilizer production. The captured CO_2 can then be processed, compressed, transported and injected into geological sites, such as oil and natural gas reservoirs, deep coal beds or deep saline aquifers. The Western Canada Sedimentary Basin, which covers large portions of Alberta, Saskatchewan, Manitoba and the Northwest Territories, is believed to be the most promising location for such projects.

ETHANOL EXPANSION PROGRAM

As part of the Climate Change Plan for Canada, as announced on August 2003, the Ethanol Expansion Program will provide up to CAN$100 million in contributions over the next three years toward the construction of fuel ethanol production facilities in Canada. It is intended to expand fuel ethanol production and use and reduce transportation-related greenhouse gas (GHG) emissions that contribute to climate change. The first round of the Ethanol Expansion Program has a total allocation of CAN$78 million. Funding for this program is part of the CAN$2 billion commitment to climate change action made in Budget 2003. The Government of Canada has committed more than CAN$3.7 billion to climate change programs and to the development of leading-edge technologies over the past five years.

The funding under the Ethanol Expansion Program is part of a larger bio-fuels strategy that also includes the extension of the National Biomass Ethanol Program, research and development under the biotechnology component of the Technology and Innovation Strategy, and an investment in biodiesel. The Government of Canada is also promoting greater use of ethanol through consumer-awareness campaigns and ongoing education initiatives.

The Government of Canada selected seven project proposals for construction of new fuel ethanol facilities as part of a competitive process under the Ethanol Expansion Program. The 750 million litres of annual fuel ethanol capacity planned by these projects will more than quadruple Canadian production (currently about 200 million litres per year), increasing supply to almost 1 billion litres. There are currently more than 1,000 retail locations selling ethanol-blended gasoline in Canada.

The seven projects will produce fuel ethanol from grain (corn or wheat) using proven technology. The Government of Canada is also actively working with industry to research and develop new technology that would produce ethanol from agricultural residues (including straw and corn stalks) and forestry byproducts. Ethanol produced with this technology is expected to result in even greater GHG reductions – from 60 to 80 percent compared to gasoline.

ENERGY EFFICIENCY

Government and industry established energy efficiency ratings for gas fireplaces in March 2004. Natural Resources Canada (NRC), the Heating, Refrigeration and Air Conditioning Institute of Canada (HRAI), and the Hearth, Patio and Barbecue Association of Canada (HPBAC) announced the new rating program for natural gas fireplaces based on the well-known EnerGuide program. NRCan has worked with manufacturers and dealers in the gas fireplace industry to develop the EnerGuide Fireplace Efficiency Rating for Gas Fireplaces.

The ratings are based on test results under the new Canadian Standards Association P.4.1-02 standard, introduced in Canada in 2003. This standard is the first in North America for testing and validating the energy efficiency of gas fireplaces, and is a more accurate way to determine how a gas fireplace works in a house than previous methods.

The manufacturers representing these industry groups produce approximately 80 percent of all fireplaces sold in Canada. Consumers will be able to find EnerGuide ratings on the back of manufacturers' brochures. The list of products and their ratings can be found from the website of www.oee.nrcan.gc.ca/equipment/english/gas_fireplaces.cfm. The list will be updated frequently as new models are rated.

CLIMATE CHANGE

The Government of Canada established the Climate Change Action Fund (CCAF) in the 1998 federal budget as it recognised that climate change is among the most serious environmental challenges. The federal budget of February 2003 announced new climate change investments of CAN$2 billion over five years, of which CAN$300 million was allocated to specific programmes in the budget itself and another CAN$1 billion was allocated by the government in August. Negotiations of covenants with large final emitters also proceeded in 2003. The climate change strategy included achieving a 25 percent improvement in new vehicle fuel efficiency by 2010, an increase in the use of ethanol in the gasoline supply, development of fuelling technologies and infrastructure for commercialisation of fuel cell vehicles, urban transportation initiatives, and negotiation of voluntary agreements to improve fuel efficiency of good transportation.

In October 2003, the Government of Canada launched several additional climate-change programmes including a public investment to extend Canadian leadership in the emerging hydrogen economy. A financial incentive for energy-efficiency retrofits of houses was initiated as well.

The first climate change Memorandum of Understanding (MOU) signed with the Government of Canada was Nunavut on 31 October 2003, followed by Prince Edward Island on 7 November 2003. On 6 November 2003, the Government of Canada signed an MOU with the pulp and paper industry, the first such agreement concluded in the context of negotiating covenants with large final emitters. The Government of Manitoba signed an MOU for Co-operation on Addressing Climate Change with the Government of Canada on 19 March 2004. They agreed to explore cooperation on renewable energy development opportunities. In October 2002, the Government of Manitoba released "Manitoba's Climate Change Action Plan – 2002: Kyoto and Beyond" – a plan of action to meet and exceed Manitoba Kyoto target. On 21 May 2004, the Government of Canada and the Government of Ontario signed an MOU to work together on climate change. They have agreed to explore cooperation on the areas of electricity supply and renewables, energy efficiency, conservation and fuels, environmental management, innovation and technology, land resources and agriculture, impacts and adaptation, and public awareness and education.

For the period of 2001-2004, the CCAF basically underscore the components of building for the future, international policy and related activities, public education and outreach, science, impacts and adaptation, and Technology Early Action Measures (TEAM). In addition to the five components, the CCAF Reserve will be used to fund projects that fall beyond the scope or budgets of the five core areas.

As part of the Government of Canada's Action Plan 2000, the Freight Efficiency and Technology Initiative is expected to result in approximately 2 mega tonne reduction of greenhouse gas emission by 2010. On 23 April 2004, the Government of Canada announced a four-year, CAN$11 million Freight Efficiency Program, which is part of CAN$32.3 million allocated for the Commercial Transportation Energy Efficiency and Fuels Initiative. One of the key components under the Freight Efficiency Program is a CAN$5-million Freight Incentives Program, which the Government of Canada announced on 20 October 2004. The Freight Incentives Program provides funding to eligible applicants to purchase and install efficiency-enhancing technologies.

ALTERNATIVE AND RENEWABLE ENERGY

In 2002, the CAN$260 million *Wind Power Production Incentive* was launched to assist in the development of wind energy projects across Canada. In 2003, Canada's first urban wind turbine was installed in Toronto, and its largest wind farm to date, with CAN$100 million invested in 114 turbines, opened in Alberta. Saskatchewan, Quebec and Prince Edward Island also have wind farms. The installation of wind power facilities increased capacity by 81,240kW to a total of 316,270kW for this type of generation.

Between 2001 and 2003, less than 200 hybrid electric vehicles were sold in Canada. The interest in these vehicles has been limited but it is expected that over time they will gain greater consumer acceptance.

POWER BLACKOUT IN ONTARIO

On 14 August 2003, a cascading power outage caused the largest blackout in history, affecting some 50 million people and nearly 62 GW of generating capacity in Ontario and the northeastern United States. In some parts of Ontario, rolling blackouts continued for ten days before full power was restored and the entire system was back to normal. In response to the blackout, Prime Minister Jean Chrétien and President George Bush established the Joint Canada - U.S. Power System Outage Task Force to identify the causes of the outage and recommend actions to prevent future outages. Canadian energy ministers established a Federal-Provincial-Territorial Electricity Working Group in September 2003. The objectives of this group are to exchange information on the August power outage, work towards reducing constraints on investment in electricity infrastructure and assess initiatives to implement mandatory electricity reliability standards.

The Power System Outage Task Force issued an interim report in November 2003 on the causes of the blackout. It assessed the conditions on the transmission grid that contributed to the blackout, outlines the physical causes of the outage, and discussed events and conditions that allowed the blackout to spread. The report assigned primary responsibility for the blackout to the actions of one utility company and one independent system operator, noting specific ways in which they violated operating procedures established by the North American Electric Reliability Council. Key factors identified in the Task Force's Interim Report were a lack of training, a lack of communication with other regions, and improper maintenance plans. The Final Report of the Task Force presented 46 recommendations for action on 5th April 2004. After the issuance of the Final Report, the mandate of the U.S. – Canada Power System Outage Task Force was extended for a year to ensure that the recommendations would be implemented. Government agencies, North American Electric Reliability Council (NERC), and the electricity industry have continued to pursue a wide array of initiatives to reduce the risk of future blackouts since the release of the report. Some actions have already been completed. Other actions launched analyses or processes that will not be completed for several months or even longer.

ELECTRICITY MARKET REFORM

In 2003, Canadian electricity markets featured continuing efforts to restructure the industry. The extent of restructuring varied widely across the country because regulation of the electricity industry is generally a responsibility of the provinces and territories.

In British Columbia, the vertically-integrated BC Hydro and Power Authority is to have its transmission assets unbundled into a new BC Hydro Transmission Corporation by 2004, according to a new energy policy announced in November 2002. This should reinforce the ability of competing electricity generators to obtain fair access to the provincial transmission grid. But the energy policy also provides that consumers should continue to share the rents from existing hydro generating assets, which are low in cost because they are almost completely depreciated, through a ten-year extendable "heritage contract" on the output from these assets to ensure low electricity rates. In addition, the policy ended a seven-year rate freeze in 2003 and established that rates would once again be regulated by the BC Utilities Commission. The policy envision some rate increases to attract investment in new generation and transmission facilities, but would limit the increases through shared rents from hydro assets, competition among generators, and performance-based regulation. British Columbia, Saskatchewan, Manitoba, and Quebec will offer wholesale access to transmission.

In New Brunswick, competition in wholesale was introduced in April 2003. In the wholesale market, competing generators can obtain access to the transmission grid according to an open access transmission tariff filed by New Brunswick Power in June 2002. Even through New Brunswick was introduced wholesale access, it has no plans to open the retail market to competition. In the retail market, 40 large industrial customers will be allowed to choose their power suppliers.

Nova Scotia announced plans for a competitive electricity market in December 2001 and set up an Electricity Market Governance Committee in May 2002 to implement them. Under these plans, utilities and independent generators would be able to access the transmission system on equal terms. Competition is to be introduced in stages, starting with the province's six municipal utilities. Nova Soctia's Electricity Marketplace Governance Committee released its final report in October 2003 recommending introduction of limited competition in the province's electricity marketplace with the wholesale market expected to open in 2005.

In May 2002, the Ontario market opened to wholesale and retail competition with little or no immediate impact on consumers. The government introduced proposed legislation, the *Ontario Energy Board Amendment Act, 2003*, which outlines an interim pricing plan in November 2003. Under the proposed legislation, it is expected that electricity prices would more accurately reflect the cost of electricity and provide incentives for conservation.

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CHILE

INTRODUCTION

Chile is one of the two APEC economies in South America. Located in the southern South America, it is bordered by the South Pacific Ocean between Argentina and Peru, and stretches along a coastline of 6,435 km. It's area covers nearly 757,000 square kilometres. Most of its 15.9 million population (as of December 2003 estimates) live in urban areas, with nearly one-third residing in Santiago, the capital city. Chile is a major producer and exporter of copper.

Chile's GDP in 2003 reached nearly US$140 billion, and US$8,805 per capita, both in terms of purchasing power parity, PPP, in 1995 US$. The economy grew at an average annual rate of 3.5 percent a year during 2000-2003. The global economy recovery has helped boost export demand, particularly copper, the price of which has nearly doubled since end 2002. In 2003, Korea and Chile ratified a Free Trade Agreement (FTA) between both governments, becoming the first FTA agreement in place between an Asian and an American country. It expects to sign similar agreements with China and Japan in the near future.

Chile has very limited indigenous energy resources and has to rely on imports to meet all of its needs. In 2003, its energy reserves consisted of 23.8 MCM of oil, 99 MCM of natural gas and 1,302 Mt of coal. In 2003, roughly two-fifths of its total primary energy supply was produced indigenously. Natural gas is the main import fuel for electricity production, which comes entirely from Argentina through pipelines (located in north, central and south parts of frontier) connecting both countries.

Table 7 Key data and economic profile (2003)

Key data		Energy reserves*	
Area (sq. km)	757 000	Oil (MCM) - Proven	23.8
Population (million)	15.90	Gas (BCM)	99
GDP Billion US$ (1995 US$ at PPP)	140	Coal (Mt)	1,302
GDP per capita (1995 US$ at PPP)	8,805		

Source: Banco Central de Chile, Energy Data and Modelling Center, IEEJ.

*2003 figures from Energy Information Administration, USA.

Chile's main concern in 2003 was Argentina's decision to reduce its natural gas exports. Such a decision has forced some weeks of its domestic electricity generation to switch from a relatively cheap natural gas to a more costly diesel-generated power. In addition, plans for an LNG port are being studied in order to stabilize the supply of this fuel in the near future. The economy is currently pursuing preliminary LNG agreements with Indonesia and other economies of APEC region.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Chile's total primary energy supply (TPES) grew at an average annual growth rate of 4.9 percent from 1990 to 2002. In 2002, TPES reached 25,274 ktoe, approximately 40 percent of which comes from crude oil, 25 percent from natural gas, 10 percent from coal and 25 percent from other sources, mainly biomass and hydropower. Natural gas and other sources (i.e., renewable energy - hydropower and biomass) together contributed half of the TPES, with each sharing 25 percent. The introduction of natural gas from Argentina in 1997 has led to a slight change in Chile's TPES mix (i.e. more gas use). Oil however remained a major energy source, 40 percent of share in 2002 compared to 44 percent in 1990. The change took its toll on coal, causing a drop on its share from 18 percent in 1990 to 9.9 percent in 2002.

Chile's dependence on imported energy had been increasing for many years. In 1980, approximately 64 percent of TPES was contributed by indigenous production and 36 percent from net imports. However in 2002, this proportion was reversed, 58 percent from imports and the rest from indigenous production. The change is caused mainly by an increase in gas and oil imports.

For the past two decades, imports have increased for several reasons. One is the dwindling of oil reserves. Crude oil production peaked at 32 percent of domestic supply in 1982, and later declined to only 3 percent of total oil supply in 2002. The lack of competitiveness of the domestic coal industry has also led to an increase in coal imports. Domestic coal production has accounted for only 10 percent of Chile's consumption in 2002, down from nearly 70 percent in 1980. The gas market reform (which started in 1997) has also increased imports from Argentina to the most populated regions in north and central parts of Chile while previously, due to infrastructure constraints, gas was only available in the south. However in April 2004, Argentina began curbing natural gas imports to almost half of the contracted volumes on some occasions.

Empresa Nacional del Petróleo (ENAP), a state-owned enterprise, is the major oil producer and refiner in Chile. Because of decreasing domestic energy resources, ENAP has increased its exploration and production operations abroad, mainly in Latin America and North Africa, through its international subsidiary, SIPETROL. ENAP is working towards supplying at least 30 percent of Chile's total oil demand, which comes mostly from Argentina, Ecuador, Nigeria, and Venezuela. Both the retail and wholesale markets of petroleum products trade at competitive basis. There are three refineries in Chile: Petrox Talcahuano (100,640 bbl/d throughput capacity, scheduled to increase 25 percent by the first quarter of 2002), Refinería de Petróleo de Concón (94,350 bbl/d) and Gregorio Magallanes (9,859 bbl/d).

In 2002, Chile's power generation was 43,670 GWh. During the period 1980 to 2002, the generation increased consistently around 6.2 percent per annum. Over the last two decades hydropower has accounted for most of the installed capacity. However, thermal is getting more significant, and in 2002, the thermal installed capacity reached 20,483 GWh, or 47 percent of the total installed capacity. The introduction of natural gas from Argentina has boosted the use of combined cycle plants. Thermal relies mainly on natural gas and coal, 24.1 and 22,5 percent of total, respectively. In addition, there are some production from fuel oil, biomass, and other fuels (6 percent) as well. The use of petroleum coke (petcoke) is allowed in some plants, but under restrictions for environmental control.

Table 8 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	10,558	Industry Sector	5,540	Total	43,670
Net Imports & Other	14,716	Transport Sector	5,619	Thermal	20,483
Total PES	25,274	Other Sectors	8,376	Hydro	23,187
Coal	2,484	Total FEC	19,536	Nuclear	0
Oil	10,165	Coal	814	Others	0
Gas	6,203	Oil	9,943		
Others	6,422	Gas	1,338		
		Electricity & Others	7,442		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

There are four separate power grids in Chile: Sistema Interconectado Central (SIC), Sistema Interconectado del Norte Grande (SING), Sistema Aysen and Sistema Magallanes. Sistema Interconectado Central (SIC – Central Interconnected System) is the most important. It serves over 90 percent of the population and more than 40 percent of the land area. Its installed capacity as of December 2002 was 6,732 MW, of which 61 percent was hydro. Sistema Interconectado del Norte Grande (SING – Great North Interconnected System), on the other hand, serves mainly mining consumers. It has an installed capacity of 3,645 MW (including 643 MW in Argentina), almost entirely thermal, in 2002. Sistema Aysén and Sistema Magallanes, the other two grids, represent only a small portion of installed capacity.

FINAL ENERGY CONSUMPTION

Chile's total final energy consumption (TFEC) grew at an average annual rate of 4 percent from 1980 to 2002 and reached 19,536 ktoe in 2002. It accounts for a 1.2 percent increase in growth rate as compared to 2001. The main energy consuming sectors were transport (29 percent) and industry (28 percent); with residential, commercial and public sectors consuming 43 percent. By energy source, oil products have accounted for 51 percent of final consumption, with electricity and "other" sources, gas and coal at 38 percent, 7 percent, and 4 percent, respectively.

Chile is the largest producer of copper in the world. Its copper production is expected to grow to nearly 40 percent of world production in the medium term. The copper industry is by far the most important industrial energy consumer in Chile. In 2002, the total consumption was 13.5 GWh, which is nearly 48 percent of the total energy consumption in the industrial sector.

Other important sectors are pulp and paper and iron and steel industries, each consuming 15 percent and 8 percent respectively. In the 1990s, most of the 6.6 percent annual growth in industrial energy use was driven by non-energy-intensive industries, which grew at 9.1 percent annually. For the total industrial energy consumption by fuel type, oil products account for 28 percent, electricity for 35 percent, biomass for 15 percent, coal and coke for 10 percent and natural gas for 12 percent. Gas has been replacing petroleum products, especially heavy fuel oil and coal in the industrial sector due to the introduction of Argentinean gas in the northern and central Chile.

Transportation has recently been the fastest growing end-use sector, with an average increase of about 4.2 percent per annum over the last 10 years. In 2002, road transport was responsible for 88 percent of energy consumption. Petroleum products have accounted for 99.3 percent, electricity 0.2 percent and natural gas 0.5 percent.

In the residential, commercial and public sectors, growth in energy use is similar to transportation, averaging about 4.5 percent per annum between 1990 and 2002. The residential sector accounted for 30 percent of energy consumption in 2002. In 2002, biomass (mostly firewood) was the most important fuel in this sector, which accounted for 59 percent, followed by petroleum products at 20 percent, electricity at 13 percent and natural gas at 7 percent.

POLICY OVERVIEW

Energy policy in Chile aims to promote dynamic development in the energy sector, overall economic growth and a better quality of life for its people. To achieve such goals, government has set out to develop its energy sector, based on the following principles:

- To promote free competitive market in the energy sector. The role of government is to regulate the market in order to avoid market distortions, especially in those areas where natural monopolies arise;
- Improvement of energy supply conditions as well as the quality and security of energy products and services;
- Reduction in the prices of energy products and services, within reason, in order to reflect technological and managerial advances, improve the economy's international

competitiveness, maintain incentives for investment, and offer consumption opportunities to the poorest segments of the population;

- Protection of energy consumers by minimising abnormal fluctuations in prices of key products, especially those caused by temporary distortions in markets;
- Focused and transparent support, through efficient and effective mechanisms, to sectors that do not have access to key energy resources, where providing such access has a high social priority or social return;
- Development of and compliance with regulations that protect the environment.

In other words, the main objective of Chile's energy policy is to achieve strong energy supply and economic growth, without compromising the welfare of energy consumers, key industries or the environment. The general guidelines for achieving this objective are as follows:

- Assure an adequate degree of regulatory stability to minimise risks to investment, while upgrading and improving the regulatory framework with prudence and timeliness;
- Strengthen local competition, increase participation in international markets, and increase energy diversification;
- Create conditions where the prices and quality of energy products and services approach those theoretically obtainable in perfectly competitive markets;
- Foster sustainable development and efficient use of energy;
- Contribute to social equity using economically transparent mechanisms;
- Monitor energy security;
- Take advantage of international opportunities and anticipate potential problems.

An example of a policy supporting these objectives is energy sector privatisation. Chile was the first economy in the world to restructure its power sector in the 1980s, almost a decade before the United Kingdom. The market reform strategy that Chile developed twenty years ago has served as a model for other economies in South America.

NOTABLE ENERGY DEVELOPMENTS

INTERNATIONAL ENERGY INTEGRATION

Chile is engaged with other South American economies in a process to diversify its energy matrix and strengthen bilateral relations to ensure adequate energy supply.

ARGENTINA

Although energy integration with Argentina has progressed more than with any other economy, shortages of natural gas from Argentina has prompted problems for the electricity sector in Chile. As combined cycle units are an important source of energy for electricity production (nearly 24 percent in 2002), the impact of natural gas reduction has affected the Chilean policy for this fuel. On one hand, a bilateral agreement regarding shortages is under development between Chile and Argentina. The aim of this agreement is to ensure crisis management and to allocate appropriate compensation schemes. On the other, Chile is planning to build an LNG port to accommodate additional supply sources from other economies.

LNG TERMINAL FOR PACIFIC LNG GAS

In 2004, Chile has confronted a restriction of natural gas import from Argentina that almost reached to 45 percent of the total volume previously supplied.

This situation left in evidence that it is not possible to access new natural gas supply contracts from Argentina, which generates difficulties for companies that use natural gas within their production processes, as well as for electricity generation and distribution.

Facing this situation, on May 6th, the President of the Republic, publicly recommended the National Oil Company, ENAP, to head a project in order to develop an LNG re-gasification terminal and, to provide the country with a new source of natural gas. Currently ENAP is leading and coordinating the project in order to receive, store and re-gasify natural gas in Chile starting in 2008.

The rationale behind the project is two-fold. Firstly, ENAP is a major consumer of natural gas, and the demand is projected to exceed 1.5 million cubic meters per day by 2008. At the same time, the facility will diversify the country's sources of energy, stabilizing it against future supply fluctuations. Thus, this project has a strategic interest in securing a reliable supply, at competitive prices for the Chilean energy demand.

The project aims to construct, by the end of 2008, a plant capable of accepting, storing and re-gasifying liquefied natural gas. Liquefied natural gas will be imported by sea from parts of the world where supplies are readily available.

In addition to the re-gasification plant itself, the full installation will include a docking bay for off loading liquid natural gas, storage tanks and ducting into the existing gas network. The most likely location will be Quintero Bay in the 5th Region, close to the main distribution and consumption centres.

In this line, preliminary contacts with Indonesia, Algeria and other nations are under way in order to seek proper partners for the construction of the LNG port.

MODIFICATIONS TO THE ELECTRICITY LAW

The Chilean government passed a bill to change the General Law of Electrical Services of 1982, which was approved in March 2003. The goal of the proposed changes is to improve economic incentives and encourage efficiency in the competitive segments of the electricity market, particularly in the small-scale production segment. Where market intervention by regulatory agencies is necessary, this intervention should increase sectoral efficiency, economic equality and the active participation of energy consumers in the market. In achieving these goals, environmental law and regulations will play an important role. The main points included in the approved law are:

- Incorporation of low scale producers into the market;
- Tariffication in medium-sized systems;
- Reduction of the price band used in the determination of node prices; and
- Basic procedure to calculate distribution tolls.

The House of Congress approved the law in March 2003 and currently the corresponding regulatory instruments and norms are being developed. It is expected that the new law, along with all the regulatory instruments, will be in place in 2004. A key point in this law is the incorporation of small power generating units in the market, which will open the possibilities for NRE proliferation in the Chilean market. In fact, due to its longitudinal structure, NRE resources are economically competitive in several parts of the economy, and clear rules for their commercialization are the only true barrier for their deployment.

HYDROCARBONS

Regulations are being revised to improve the requirements regarding emissions for new fuels and ENAP will be mostly affected. ENAP will also be influenced by a National Energy Commission (CNE) study on the impacts of current gas regulation on different energy market participants.

RURAL ELECTRIFICATION

Within the framework of the National Rural Electrification Program of Chile, which is coordinated by CNE, the Government of Chile aims to reach a goal of 90 percent of rural households electrification coverage in the year 2006, as well as, to improve the electric generation systems for isolated rural communities. In this line, a project for the Implementation and eventually Operation of a Hybrid Electric Generation System, Wind-Diesel, in the Robinson Crusöe Island, of the Archipelago of Juan Fernández, in Valparaíso Region is currently under way.

RENEWABLE ENERGY

A strong boost to renewable energy technologies came with the modification of the law for the electricity sector, which has incorporated small-scale power production as a specific segment in the supply market. The streamline of the law has been a key issue in the policy of the National Energy Commission to allow competition for wind, biomass, PV and geothermal power sources, which are typically in the range of 100kW to 10 MW.

ENVIRONMENT

Chile ratified the Kyoto Protocol on 9 July 2002. It is expected that the National Commission for the Environment (CONAMA) will have measures in place to use the Clean Development Mechanism (CDM) by 2003. CNE will help implement these measures.

The first approved CDM project in Latin America, the Chacabuquito Hydro Project, started producing energy in July 2002. The 25MW run-of-the-river power plant is located some 100km northeast of Santiago, Chile's capital. The project obtained support from the Carbon Prototype Fund of the World Bank. It is expected to reduce emissions by approximately 6.9 Mt of CO_2 during its lifetime. An agreement to buy 11,000 tonnes of its emissions reduction has been reached between the Chilean company Hidroeléctrica Guardia Vieja S.A. and Mitsubishi of Japan.

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CHINA

INTRODUCTION

China is the fourth largest economy in the world, next to Russia, Canada and the United States. It is located in East Asia, and bordered by the East China Sea, Korea Bay, and South China Sea. It lies between North Korea and Viet Nam. Its population of 1.3 billion is roughly one fifth of the world's population. Its diverse landscape consists mainly of mountains, deserts, and river basins and covers around 9.6 million square kilometres.

Currently, China is the world's second largest energy consumer (next to the United States) and the third largest energy producer (after the United States and Russia). However, its per capita primary energy consumption (at 0.6 toe) is by far lower than in many developed economies and the world's average.

China has sustained high rates of economic growth, just under 10 percent, for more than 20 years. However, in the late 1990s, growth slowed slightly to about 8 percent per year. Energy demand resumed to grow rapidly through most of the 1990s but has dropped off since 1997. GDP per capita is still quite low, at US$4,075 (1995 US$ at PPP) in 2002.

China is rich in energy resources, particularly coal. It is the largest producer and consumer of coal in the world, as well as the fifth largest producer and third largest consumer of oil in 2002. However, after a long history of being a net oil exporter, China finally became a net oil importer in 1993. According to recent estimates, China has recoverable coal reserves of some 114.5 Gt, proven oil reserves of 2,910 MCM[3] and proven natural gas reserves of 1,510 BCM. In addition, China is endowed with 676 GW of hydro potential, more than any other economy in the world. For power generation and industrial development purposes, coal and oil resources have been utilised more extensively than reserves of gas and hydro potential.

Table 9 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	9,600,000	Oil (MCM)	2,910
Population (million)	1,280.40	Gas (BCM)	1,510
GDP, Billion US$ (1995 US$ at PPP)	5,217.45	Coal (Gt) - Recoverable	114.5
GDP per capita (1995 US$ at PPP)	4,075	Hydro (GW) - Potential)**	676

Sources: Energy Data and Modelling Center, IEEJ. *Proved reserves, end of 2002, *BP Statistical Review*.
**China Energy Annual Review 1997.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

China's primary energy supply has expanded sharply since 2001, driven mainly by the rapid growth in energy consumption. In the recent two years, although China's economy has kept growing steadily, energy consumption went up even strongly. In 2002, the total primary energy supply (TPES) reached 898.2 Mtoe. Of this total, coal has accounted for 67.3 percent, oil for 26.2

[3] BP revised the oil reserve data in 2002. This data is much less that it was a year before.

percent, and natural gas for 3 percent, while hydropower, nuclear power and other sources accounted for the remaining 3.5 percent.

China has since given much political and financial support for the development of its abundant indigenous coal reserves to ensure the security of its energy supply. As early as the 1990s, Chinese authorities have been encouraging the switching of fuels (e.g. from coal to cleaner fuels), introduced energy efficiency initiatives (to reduce pollution and emissions from energy use) and optimise existing energy structure. The use for coal reached its peak in 1996, then experienced a significant decline between 1997 and 2000. It did however recover in 2001, followed by strong growths in 2002, 2003, and 2004. In 2003, coal production reached 832[4]Mtoe.

The supply of petroleum products grew by about 7.4 percent compared with the preceding year while domestic oil output also slightly increased to about 168.9 million tons. China has imported approximately 72 Mtoe[5] of petroleum. Import dependence on oil reached around a third of total oil consumption. Most of China's oil production comes from onshore, mainly from its largest production fields in the northeast at Daqing and Liaohe. Oil production from the west and offshore in recent years has also increased rapidly with a growth rate of 9.3 percent and 8 percent respectively from 2000 to 2002. Primary natural gas supply totalled 27.4 Mtoe in 2002 while its share in the total primary energy supply remained at 3 percent. Although its proportion in the total primary energy supply is still quite small, primary natural gas supply increased very rapidly at a rate of 7 percent in the last five years along with the construction of natural gas pipelines and increase in gas reserves. The demand for gas is expected to more than double by 2010. This will involve increases in domestic production, and imports, by pipeline and in the form of liquefied natural gas (LNG).

Table 10 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	872,855	Industry Sector	323,676	Total	1,640,477
Net Imports & Other	25,317	Transport Sector	66,014	Thermal	1,327,376
Total PES	898,173	Other Sectors	242,775	Hydro	287,974
Coal	604,712	Total FEC	632,465	Nuclear	25,127
Oil	235,408	Coal	274,341	Others	-
Gas	27,367	Oil	190,608		
Others	30,686	Gas	28,949		
		Electricity & Others	138,566		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

The installed generation capacity increased at an average annual rate of 8.4 percent from 1990 to 2002. It reached 357GW at the end of 2002 with a corresponding growth in power generation to 1640 TWh. By type of fuel, 74.5 percent of the total installed capacity was from thermal plants, 24.1 percent hydro, and 1.3 percent nuclear. The corresponding shares of power generation were 80.9 percent for thermal power, 17.5 percent for hydropower, and 1.6 percent for nuclear power. China's electric power industry experienced a serious oversupply problem in the late 1990s, due to a reduction in demand resulting from closures of inefficient state-owned industrial units, which were major consumers of electricity.

[4] China Statistical Yearbook, 2004

[5] International Petroleum Economics, 2004(3)

FINAL ENERGY CONSUMPTION

Final energy consumption in China reached 632.5 Mtoe in 2002, or 11.2 percent higher than the previous year. Industry was the largest user accounting for 51.2 percent of energy consumption. Transportation sector accounted for 10.4 percent of energy use and other sectors 38.4 percent. In terms of fuels, coal (43 percent) still was the most important fuel in 2002, followed by oil (30 percent), electricity, heat and other fuel (22 percent), and gas (5 percent).

China has consumed 235.4 million tons of petroleum in 2002. In 2003, China has overtaken Japan to become the second-biggest oil consumer behind the United States for the first time, with total demand of 246.9Mtoe[6].

Coal consumption in 2002 reached 694.2 Mtoe[7], exceeding its peak for the first time in 1996 (at 681.6 Mtoe). In 2003, coal consumption grew to about 788[8] Mtoe, along with the recent increase in economic activity.

The market for gas is mainly in the southeastern area, accounting for a third of total natural gas consumption. At present, the chemical industry is the biggest gas user, accounting for about 36 percent of the total, followed by industrial feedstock (30 percent), city gas (20 percent) and power generation (14 percent). City gas use has increased faster in recent years as a result of accompanying construction of city gas pipeline network.

POLICY OVERVIEW

The Energy Bureau of National Development and Reform Commission (NDRC) is responsible for: the formulation of China's energy development strategy and main energy policy, creation of energy development plan and suggestions on energy industry reform, implementation and management of China's oil, natural gas, coal and power resources, including the establishment of policies and measures on energy conservation and new and renewable energy development. National Oil Stockpiling Office (NOS) is now under the leadership of the Energy Bureau of NDRC. The office is responsible for managing state oil strategy stockpiling.

The fundamental objective of China's energy policy in the Tenth Five Year Plan for the period is to diversify the energy mix, ensure the overall security of energy supply, improve energy efficiency, and protect the environment.

The 16th National Congress of the Communist Party of China has seen the quadrupling of GDP by 2020. It was also referred to as the "Building a well-off society in an all-round fashion". NDRC is formulating the Eleventh Five Year Plan and medium- & long-term energy development strategy in order to implement the government's goal.

POWER SECTOR REFORM

Over the past decades, China's power sector has grown rapidly to become the second largest in the world. The growth is the result of far reaching reforms that have transformed the centrally and administratively run government of the early 1980s into corporatized and business oriented power companies at the national, regional, provincial level. Nevertheless, the sector faces both structural and operational problems those which includes increasing prices due to untapped efficiency and inter-provincial and inter-regional trade potential; discrimination between generators due to monopoly and monopoly power; and unnecessary impacts on the environment due to the proliferation of small and high polluting units.

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[6] BP Statistical Review of World Energy 2004

[7] BP Statistical Review of World Energy 2004

[8] China Statistical Yearbook, 2004

In April 2002, the Chinese government ratified the National Power Sector Framework Reform Plan with the objective of fostering competition and ensuring environmentally sustainable development of the sector.

Since its implementation, the power sector reform has experienced some important progress in reforming China's power market. The separation of generation from transmission and distribution has been basically fulfilled and the monopoly of power market by state-owned power companies has been broken and competition in the power market is gradually coming into play. The system of investment incentives in power generation has also started to take shape. Regional power grid companies have been established and put into operation in order to create a healthy system environment for the full-scale optimization of power resources and development of regional power markets.

In 2004, the State Power Regulatory Commission has set up the six regional power regulatory bureaus: North China, Northeast China, Northwest China, East China, Central China, and South China. The regional power regulatory bureaus are directly under the leadership of the State Power Regulatory Commission and its major responsibilities are:

- To supervise and regulate the operation of regional power market and to maintain its equity competition in accordance with authorization of the State Power Regulatory Commission;
- To supervise regional power companies and regional power distribution and exchange organization; and
- To be responsible for the execution of the electric power law and the administration of punishment, as well as administration of litigation in its region.

The establishment of regional power regulatory bureaus is another substantial progress of the China power reform. At present, the State Power Regulatory Commission is conducting a pilot power scheme "power pooling system" in two pilot regions of North China and Northeast China, while the provincial power grid and provincial power market are undergoing reform.

ENERGY SECURITY

The Chinese government has decided to establish a state strategy for oil stockpiling and included it in the Tenth-Five Year Energy Plan in order to ensure the nation's energy supply security (especially oil). The Plan has pointed out the need to strive and complete the construction of a state strategic oil stockpile (in certain scale) during the Tenth-Five Year Plan period and to encourage enterprises to expand the capacity of their own oil stockpiling. At present, the first stage facilities of state oil stockpiling have been under construction and the relevant laws and management measures for the state strategy oil stockpiling are underway. The Chinese government expects the facilities in Dalian of Liaoning Province, Huangdao of Shandong province, Zhenghai and Zhoushan of Zhejiang province to be completed by end of 2008. Aside from the establishment of state strategy oil stockpiles, Chinese government has also adopted other measures to ensure energy/oil supply security such as accelerating the exploitation and development of domestic oil reserves to increase indigenous oil production, decrease oil consumption of industrial and civil vehicles by utilizing alternative fuels and enhancing the standards of fuel economy, utilizing natural gas resource in large scale, and encouraging oil exploitation overseas to Chinese oil companies.

INVESTMENT SYSTEM REFORM

The State Council has promulgated the decision to reform the investment system (hereinafter referred to as Decision) on July 17, 2004. The core of the reform is to give a full play to the market in terms of resources allocation by relieving enterprises of intervention from the government. It is the enterprises that should play the leading role in investment activities. The government, on the other hand, should make more scientific investment decisions in a more democratic way through an optimized decision making process, for government investment projects.

The reform is focused on the following points:

- To transform the function of the investment management system. Investment decisions should be made by investors. Businesses will never have to go through any approving process for non-government sponsored projects. Instead, they will be subject to a confirmation system or a registration system. Large enterprises will be freer to make investment decisions and companies will have more channels to fund their projects. The government will encourage the social capital to step into industries and fields as long as laws and regulations do not deny them to enter into these areas. Financial institutions should improve their fixed asset loans system and sharpen their ability of loans check-up to ward off financial risks.
- To consummate the government investment mechanism. The government investments are mainly channelled to social and economic fields that concern the national security (and where the market does not work well). Decisions should be made scientifically and democratically. Responsibilities for a project should be defined well and the process of approving should be streamlined. The capital should be put under proper control and the way of construction should be optimized. The operation system for non-profit government investment projects should be in place as early as possible. Local governments should attract social capital into utilities and infrastructure projects.
- To strengthen and improve the macro-control on investment and achieve a balanced aggregate and better structure. Legal, economic and administrative measures should be combined with economic tools including market access, prices, interest rates and taxation to leverage the investment of the whole society. The government should navigate the social investment through planning, policies, information disclosure, and market access control.
- The supervision of investment to secure the market order of investment and construction. Corporate investment, government investment and investment intermediaries will be put under the watch of a comprehensive supervision system. Various investors should act within the legal framework that is expected to be in place as early as possible and carried out carefully.

The Decision has published the catalogue of investment projects confirmed by the government (2004 version). The catalogue covers the fields of farming, forestry, water conservancy, energy, transportation, information industry, materials (raw material, machinery, tobacco processing), high-tech industry, city construction, finance, foreign investment, etc.

IMPROVING ENERGY EFFICIENCY

Over the last two decades, China has greatly reduced the energy intensity of its economy through energy conservation measures and economic structure optimisation, from 0.57 toe per thousand 1995 US$ of GDP (PPP) in 1980 to 0.16 toe per thousand 1995 US$ of GDP (PPP) in 2001.

Over the last two years, tensions of energy supply disruptions have promoted the implementation of some measures to encourage energy conservation. In 2003, the National Development and Reform Commission has issued the Tenth Five-Year Plan for Oil Saving and Fuel Oil Substitution, Special Development Plan for Fuel Alcohol and Grain Alcohol Used in Vehicles. The key aims of the two plans are to strengthen the guidance of oil conservation for oil consumers and producers, study new technologies and processes of oil substitution and oil saving, and develop pilot projects of fuel alcohol and grain alcohol used in vehicles. Voluntary Agreements (VAs) are considered as a policy for increasing industry energy efficiency in China. The agreement of the first VAs pilot project was signed in Jinan Iron and Steel Company and Laiyang Iron and Steel Company in April of 2003. Energy conservation mechanism of Energy Management

Company (EMC) has been applied in more enterprises. By now, more than 60 EMCs have been established in China. An EMC industry association is expected to be established soon.

ENERGY CONSERVATION

In November 2004 the National Development and Reform Commission issued China's first medium and long-term plan for energy conservation. The directive idea, principles and targets of energy conservation are given in the Plan. Under the Plan, China will aim to burn 2.3 tonnes of coal for every 10,000 yuan (US$1,200) of GDP by 2010, down from 2.7 tonnes per 10,000 yuan of GDP in 2002. By 2020, the level should reach 1.5 tonnes of coal per 10,000 yuan of GDP while energy conservation is expected to reach 1.4 billion tons of coal equivalent and a corresponding reduction of sulphur dioxide of about 21 million tons. To implement the Plan's objective, the Chinese government outlined ten measures: 1) prioritization of energy conservation, 2) consolidation of energy and environment polices on promoting energy conservation, 3) industrial polices on strengthening energy conservation, 4) implementation of incentive policies on strengthening energy conservation, 5) the speeding up of the development, demonstration and dissemination of energy conservation technologies, 6) strengthening the enforcement in implementing energy conservation management, 7) promoting new energy conservation mechanism based on market mechanism, 8) enhancing energy conservation management of key and large energy consumers, 9) expanding energy conservation awareness, education and training and 10) concretizing organization and leadership to realize energy conservation program.

ENVIRONMENTAL PROTECTION

While becoming the second-biggest energy consumer and third-biggest energy producer in the world, China has also become the first-biggest sulphur dioxide and second-biggest carbon dioxide emitting economy in the world. In 2002, the total sulphur dioxide emission in China reached 21.6 million tons[9], while the total emission of carbon dioxide reached 840.5 million tons-C. To fulfil the sustainable development objective of the economy, through adequate resources utilization and environmental protection, the Chinese government is undertaking efforts to lessen emissions of pollutants such as sulphur dioxide and nitrogen oxide, through improved pollution controls on power plants as well as policies designed to increase the share of natural gas in the country's fuel mix. After issuing a new version of the regulation for charging pollutant emissions in January 2003 (which took effect in July 2003), the Chinese government has promulgated a new version of air pollutant emission standards on power sector in 2004. In the version, pollution emission standards for thermal power plants, which refer to internationally advanced standards to be issued in 2003, will greatly enhance sulphur dioxide emission. New building thermal power plants have to desulphurize coal without consideration of the sulphur content in coal while older thermal power plants have to desulphurize, after a grace period, and conform to the same emission standards. NOx alleviation is also required for thermal power plants. In addition, technological policy for prevention of pollution from vehicles has been made. It is mandated that emission level of: 1) car should meet the Euro I standard in 2000; 2) other light vehicle except car should meet the Euro I standard after 2000; 3) all light vehicle including car and diesel vehicle should meet the Euro II standard in 2004 and meet the international level in 2010; and 4) heavy vehicle should meet the Euro II standard in 2005 and meet the international level in 2010. In Beijing, light vehicles including diesel and gasoline vehicles and heavy diesel vehicles have started to implement the emission level of the Euro II standard in 2003 and will implement emission level of the Euro III standard in 2005.

[9] China Environment Statistical Yearbook, 2004

WORK SAFETY LAW

The Law of the People's Republic of China on Work Safety became effective on 01 November 2002. The law has requested all production and business units to redouble their efforts to ensure work safety by setting up and improving the responsibility system for work safety, thus improving the conditions for it to guarantee work safety.

The recent increases in serious accidents at coalmines, as well as other production and traffic accidents have raised concerns from the highest government officials. The government, therefore, has resolved to close those coalmines that cannot meet the national standards or industrial specifications for work safety, as formulated by law. China plans to restructure its mining industry, forcing small coalmines to merge together or join syndicates in an effort to improve safety conditions.

NOTABLE ENERGY DEVELOPMENTS

TAKING MEASURES TO EASE POWER SHORTAGE

In 2004, China faced the greatest scarcity of power since the 1980s. The power shortage caused brownouts in most of China's provinces (24/27) and municipalities during the summer of this same year. The nationwide power outage, as estimated by State Grid Corporation of China, has exceeded 30 GW in 2004[10]. China's recent power-intensive industrial growth, inadequate construction of power resources in the past two or three years and the unbalanced power structure, over-high proportion of thermal power plus coal inadequacy and limited railway transportation were the main reasons for the power shortage this year. Limitation and shortages in the electricity are having a negative impact on the economy's future growth. Recently, the Chinese government has taken some emergency measures to ease the power shortage, including redistribution of power supplies among different regions, adjusting electricity consumption through price controls, establishment of more power plants, curb blind investments and wasteful duplications in some industries and cut irrational demand, improving coal supply for areas suffering from power shortage, accelerating construction of energy and transport projects to expand supply, improving efficiency of energy consumption, stepping up planning for construction of energy and transport facilities, and ensuring safety and security of energy production, supply and transport. It is estimated that China's power shortage situation will be fundamentally altered by 2006[11].

ACCELERATING NUCLEAR POWER CONSTRUCTION

From the standpoint of energy supply security, energy mix optimization, environmental protection and keeping the national nuclear technique advance ability, the Chinese government plans to build nuclear power plants with 30 GW of generation capacity over the next 16 years. The plan would increase the share of nuclear power capacity to 4 percent from its current 1.6 percent. In the past several decades, China has built a complete nuclear fuel system from resources exploitation to disposal of spent fuel. China now has the ability to build 300,000 kilowatt-level and 600,000 kilowatt-level nuclear power stations. It can also manufacture key equipment for one million kilowatt-level nuclear power stations. In addition, the country has already established a rapid response system conforming to international norms to deal with nuclear safety and nuclear accidents. Therefore, China has all the conditions required in accelerating the development of its nuclear power capacity.

[10] Xinhu(2004)

[11]People Daily (2004) "Power shortage problem to be solved by 2006: official "http://english.peopledaily.com.cn/200403/31/eng20040331_139071.shtml

PRIORITY GIVEN TO EFFICIENT HYDROPOWER

China has prioritised its hydropower projects as part of its sustainable development strategy to meet the needs of China's developing economy in the next 20 years and to reduce pollution resulting from burning coal. China has a huge hydropower potential, 676 GW. Although its hydropower exploitation potential ranks the first in the world, China's utilization ratio is still very low, which varies in different areas. If converted to electricity, the development ratio would be about 10 percent, ranking 80th in the world (since the average world level is 18.4 percent). This ratio is far less than that of developed countries (50~100 percent), and would even rank behind some of the developing economies, such as India, Vietnam, Thailand and Brazil etc., where power supplies, especially hydropower, are developed very rapidly. Based on China's economic and social development plan, the total installed hydropower capacity will reach 125 GW[12] in 2010 and 150 GW in 2015, respectively. In addition, the Department of Water Resources has formulated a new development strategy for mini-hydro power in the next 16 years.

WEST TO EAST NATURAL GAS PIPELINE

China's long-distance west to east natural gas pipeline started its full operation on 01 October 2004, with gas from the Tarim and Changqing gas fields in western Xinjiang and Shaanxi provinces being pumped across the country to Shanghai. The pipeline, which was started in 2002, with an investment exceeding 140 billion yuan (16.9 billion US dollars), is expected to transport 12 billion cubic meters of gas a year, running through Xinjiang, Gansu, Ningxia, Shaanxi, Shanxi, Henan, Anhui, Jiangsu, Shanghai and Zhejiang. The eastern section of the pipeline, linking Shaanxi and Shanghai, was completed and started trial operations in October 2003. It has already supplied 700 million cubic meters of gas to 21 gas users in the eastern part of China. The western section, from Lunnan of Xinjiang to Jiangsu, has started gas transmission on 06 September 2004. The whole gas pipeline is expected to start supplying gas commercially by 01 January 2005. The completion and operation of the gas pipeline project will increase China's gas yield by nearly 50 percent and increase the gas share in China's energy consumption structure by one to two percentage points.

OIL TRADING CENTRE TO REOPEN DOORS

China has re-launched its oil futures in Shanghai on 25 August 2004, after a long period of debate and research. Fuel oil, the most liberalized oil product with the least control by the government, was the first to hit the board. China opened oil futures exchanges in 1993 in Beijing and Shanghai, trading crude oil, gasoline, diesel and fuel oil. They were closed two years later due to an industry overhaul and partly because of rampant speculation. The resumption of fuel oil futures was a test mechanism for the launch of futures trading of more important oil products such as gasoline, diesel and crude oil. The futures contract would increase China's say in determining price, and offer Chinese players a yuan-denominated tool to guard against price volatility as the world's second-largest oil consumer becomes increasingly dependent on foreign oil, and be helpful to establish modern oil circulation system as well as increase the flexibility of micro-control on oil market by the government.

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HONG KONG, CHINA

INTRODUCTION

Hong Kong, China is a world-class financial, trading and business centre of some 6.7 million people situated at the southeastern tip of China. Since 1997, it has been a Special Administrative Region (SAR) of the People's Republic of China. All of the energy consumed in Hong Kong, China is imported, as it has no natural resources, except one of the finest deep-water ports in the world. The energy sector consists of investor-owned electricity and gas utility services.

Hong Kong, China is a modern economy with a high GDP per capita of US$23,904 (1995 US$ at PPP) in 2002. The service sector is responsible for 85 percent of GDP. Hong Kong, China's economy went through a sharp gyration during the course of 2003. Even with the profound setback caused by Severe Acute Respiratory Syndrome (SARS) during the year, the economy still attained an appreciable growth of 3.3 percent in real terms for 2003, better than that of 2.3 percent in 2002. In terms of gross domestic fixed capital formation, overall investment spending declined only marginally by 0.1 percent in 2003, a visible improvement from a 4.3 percent dip in 2002. Hong Kong, China was ranked the 11th largest trading entity in the world in 2002. The Composite Consumer Price Index (CPI) continued to decline in 2003, as domestic consumer prices were kept down by the slack demand and profit margin squeeze especially during the course of the SARS threat, as well as by lower wages and rentals. In 2003, CPI fell by 2.6 percent, modestly smaller than the 3.0 percent decline in 2002. Average unemployment rate reached 7.9 percent in 2003, higher that the 2002 average of 7.3 percent.

In recent years, Hong Kong, China's relationship with China has strengthened in terms of business ties, the extent of government contacts, and flow of people. To stay competitive and attain sustainable growth, Hong Kong, China needs to restructure and re-position itself to face-up with the challenges posed by globalisation and closer integration with China. The Government's strategy is to go up the value chain by; speeding up structural transformation to a high-value, knowledge-based, and skill-intensive economy; pursuing reforms in education and population policy to amass the pool of talent; as well as leveraging on the immense business opportunities in China. Financial services, logistics, tourism, professional, and producer services are the four high value added sectors in the economy, which Hong Kong, China possess as a competitive advantage.

Table 11 Key data and economic profile (2002)

Key data		Energy reserves	
Area (sq. km)	1,103	Oil (MCM)	-
Population (million)	6.79	Gas (BCM)	-
GDP Billion US$ (1995 US$ at PPP)	162.24	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	23,904		

Source: Energy Data and Modelling Centre, IEEJ.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, total primary energy supply in Hong Kong, China was 15,323 ktoe. Of this total, 50 percent was oil, 33 percent coal and 13 percent gas. Electricity imports from China accounted for the remaining 4 percent. Hong Kong, China has no domestic energy reserves or petroleum refineries and therefore imports all of its primary energy needs. It however generates some electricity.

Hong Kong, China had a total installed electricity generating capacity of 12,203MW in 2002. Electricity is supplied by CLP Power Hong Kong Limited (CLP Power) and The Hong Kong Electric Company Limited (HEC). CLP Power supplies electricity from its Black Point (1,875MW), Castle Peak (4,108MW) and Penny's Bay (300MW) power stations. Natural gas is currently used for power generation at the Black Point and Castle Peak power stations. It is imported from the Yacheng 13-1 gas field off Hainan Island in southern China via a 780-kilometre high-pressure submarine pipeline. Two more 312.5MW generators, which are also fuelled by natural gas, are scheduled for commissioning at the Black Point power station between 2005 and 2006. CLP Power has contracted to purchase about 70 percent of the power generated at the two 984MW pressurised water reactors at the Guangdong Daya Bay Nuclear Power Station to help meet the long term demand for electricity in its supply area. It also has the right to use 50 percent of the 1,200MW capacity of Phase 1 of the Guangzhou Pumped Storage Power Station at Conghua. Electricity for HEC is supplied from the Lamma Power Station and its total installed capacity was 3,420MW. In May 2000, the Government has approved HEC's new power station at the Lamma Extension and the installation of the first 300MW gas combined-cycle generator. The unit is scheduled for commissioning in 2006. All locally generated power is thermally fired.

Towngas and liquefied petroleum gas (LPG) are the two main types of fuel gas used throughout Hong Kong, China. Towngas is distributed by the Hong Kong and China Gas Company Limited. It is manufactured at plants in Tai Po and Ma Tau Kok, both using naphtha as feedstock. LPG, on the other hand, is supplied by oil companies and imported into Hong Kong, China by sea and stored at the five terminals in Tsing Yi Island.

FINAL ENERGY CONSUMPTION

Total final energy consumption in Hong Kong, China reached 10,805 ktoe in 2002. The bulk of energy was used in the transportation sector (55 percent), followed by the residential/commercial sector (34 percent) and the industrial sector (11 percent). With the dominance of transport, the most important end use fuel was petroleum, accounting for 65 percent of energy use. Electricity and others made up 30 percent of end-use consumption, while gas accounted for only 5 percent.

As mentioned earlier, gas is supplied for domestic, commercial and industrial uses in two main forms. In addition, LPG is used as a fuel for LPG taxi and light buses, and natural gas is used for electricity generation. In energy terms, town gas accounted for 80 percent of gas use in these sectors in 2002.

Table 12 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)*	
Indigenous Production	-	Industry Sector	1,235	Total*	34,312
Net Imports & Other	15,323	Transport Sector	5,967	Thermal	34,312
Total PES	15,323	Other Sectors	3,604	Hydro	-
Coal	5,069	Total FEC	10,805	Nuclear	-
Oil	7,642	Coal	5	Others	-
Gas	1,924	Oil	6,953		
Others	688	Gas	573		
		Electricity & Others	3,275		

Source: Energy Data and Modelling Centre, IEEJ. (See http://www.ieej.or.jp/egeda/database/database-top.html)

* Total does not include electricity generated by hydro and nuclear facilities located in China.

POLICY OVERVIEW

The Government of the Hong Kong Special Administrative Region (SAR) pursues two key energy policy objectives. The first is to ensure that the energy needs of the community are met safely, efficiently, and at reasonable prices. The second is to minimise the environmental impact of energy production and promote the efficient use and conservation of energy.

In keeping with Hong Kong, China's free market economic philosophy, the Government intervenes only when necessary to safeguard the interests of consumers, ensure public safety, and protect the environment. The Government works with the power, oil and gas companies to maintain strategic reserves of coal, diesel and naphtha. It monitors the performance of the power companies through the Scheme of Control Agreements. It has entered into an Information and Consultation Agreement with the Hong Kong and the China Gas Company Ltd to make the town gas tariff adjustment mechanism more transparent. In consultation with the power companies, the Government also promotes energy efficiency and energy saving measures.

To help monitor the energy situation, Hong Kong, China has developed an energy end-use database and forecasting model. The database will provide useful insight into the energy supply and demand situation, including energy consumption patterns and trends, and energy use characteristics of the individual sectors and sub-sectors. A basic data set is publicly available on the Internet.

In 1997, the Government has carried out a study of Introducing Common Carrier System for Gas Supply in Hong Kong. Following the consultant report's recommendations, the Government has set out its policy position in a statement in June 1998. It was set to closely monitor the potential development of natural gas from China.

Another study (on the interconnection and competition in the electricity supply sector in Hong Kong, China) has concluded that increasing the HEC-CLP interconnection capacity would be a necessary pre-condition for the introduction of generation-level competition in the future. The study has recommended that the Government immediately develops a long-term strategy for the Hong Kong, China electricity sector by describing the long-term goal for the industry structure, the transition path and planned time-line to move from the current structure to the long-term industry structure, and specifying the relationship between the time-line and external developments, over which Hong Kong, China does not have direct control, particularly in the Southern China electricity sector.

The Hong Kong, China Government is also currently studying an electricity market review to map out the broad framework for the development of the electricity market, once the Scheme of Control Agreements expires in 2008.

The Electricity Ordinance and the Gas Safety Ordinance regulate the safe supply of electricity and gas. Among other things, these ordinances cover the registration of generating facilities, workers and contractors for electrical and gas installations, wiring and gas installation standards and safe distribution and use of electricity and gas. Most provisions of the Electrical Product (Safety) Regulation, which regulates the safety of household electrical products, came into effect in May 1998. To regulate the import, supply and installation of domestic gas appliances for use in Hong Kong, China, the Gas Safety (Installation and Use) Regulation and the Gas Safety (Miscellaneous) Regulation were amended in 2002.

NOTABLE ENERGY DEVELOPMENTS

COMPREHENSIVE BUILDING ENERGY CODES

The Hong Kong, China Government has promulgated Building Energy Codes (BECs) through its 1998 Hong Kong Energy Efficiency Registration Scheme for Buildings. The scheme covered lighting, air-conditioning, electrical, lift & escalator installations, and overall thermal transfer value of buildings. The codes are prescriptive in nature. To provide for an alternative path for compliance with the existing codes and to encourage innovative energy-efficient building design features, a performance-based building energy code was published in April 2003. The code uses total energy-budget approach to assess the building performance. As of August 2004, about 269 buildings and 597 installations have been registered in the scheme.2002.

APPLIANCE ENERGY EFFICIENCY LABELS

As of end August 2004, the Government has issued labels for more than 2,200 appliance models including refrigerators, room coolers, washing machines, electric clothes dryers, compact fluorescent lamps, electric storage water heaters, electric rice-cookers, dehumidifiers, televisions multifunction devices, photocopiers, laser printers, and LCD monitors under voluntary Energy Efficiency Labelling Scheme. The scheme has extended to cover electronic ballasts, computers and domestic gas instantaneous water heaters in late 2004.

The voluntary Energy Efficiency Labelling Scheme has also been extended to cover Petrol Passenger Cars in February 2002, to raise the level of public awareness in the energy efficiency of vehicles. This was the first labelling scheme for vehicles in Hong Kong, China.

ENERGY AUDIT PROGRAMME

The Hong Kong, China Government has since 1993 been implementing Energy Audit Programmes in selected government buildings. As of March 2004, energy audits and re-audits had been performed in 181 major government energy-consuming buildings. With the help of these audits, the top electricity consuming Government departments were able to conduct various energy saving measures, thereby successfully reducing their annual electricity consumption by some 4.5 percent. More promotional activities will be carried out in the succeeding years to encourage the public and private sectors to adopt energy audit to reduce energy consumption in existing buildings.

Pilot tests on EMO using innovative energy efficient equipment related to lighting, air conditioning and vertical transportation have also been carried out to achieve energy savings in government buildings since 1999. The tests have been very successful and substantial energy savings were achieved. The Government has also published reports and application guidelines to promulgate the use of the EMOs. The studies included application of electronic ballasts, T5 lamps, variable speed drives and others.

ENERGY END-USE DATABASE

The Government has continuously maintained and updated the energy end-use database. The database provides useful insight into energy consumption patterns of different sectors, sub-sectors and the end uses in Hong Kong, China. A basic data set (Year 2002 basic data) from the database was published in December 2004 and is made available for public access at the EMSD website (http://www.emsd.gov.hk).

ALTERNATIVE FUEL VEHICLES

The Government has provided an incentive scheme to encourage owners of existing diesel taxi to replace their vehicles early with LPG. The program target, to replace all diesel taxis in the Territory with LPG taxis, has now been achieved. Almost all (99.8 percent), of the 18,138 diesel taxis were replaced with LPG. With the successful implementation of the trial run of LPG and electric light buses, the Government launched a voluntary incentive scheme in August 2002, to encourage owners of existing diesel public and private light buses to replace their vehicles with LPG or electric models. As a result, more than 1,400 diesel light buses, representing over 75 percent of the newly registered light buses were replaced with LPG light buses. The Electrical and Mechanical Services Department (EMSD) advises Government on incentives to motivate the switch to vehicles that use clean alternative fuels, as well as on how to develop supporting infrastructure for the use of such fuels. It is closely involved in the safety control and approval of the LPG vehicles, LPG filling stations, LPG vehicle workshops, as well as establishing and maintaining a registry of competently trained LPG mechanics. EMSD will also continue to play its role in the gas safety and advisory aspect.

RENEWABLE AND CLEAN ENERGY

Several local institutions have received both direct and indirect funding from the Government to support their research projects on the utilisation of renewable energy resources. The scope of research projects varies from the theoretical study of solar irradiation to the applications of both photovoltaic and fuel cell technologies.

In late 2000, the Government commissioned a two-stage consultancy study to investigate the viability of using new and renewable energy technologies in Hong Kong, China, including a review of the associated institutional, legal, regulatory and financial issues. The first stage of the study was completed and identified a number of new and renewable technologies as likely options for wide scale local adoption. These new and renewable energy technologies, include solar power, wind power, energy from waste and building integrated fuel cells. The second stage was also completed in late 2002, and installed building-integrated photovoltaic panels in existing high-rise buildings. The performance of the photovoltaic panels installation was monitored over a 12-month period. The data collected were assessed to check the effectiveness of the installation. The whole consultancy study was completed in late 2004.

More demonstration projects on renewable energy power systems are also being initiated by the Government to promote public awareness on renewable energy. Aside from solar energy, two micro wind-turbines will also be installed on top of the new EMSD Headquarters building. Such installation would then allow studies on the application of wind power system in an urban environment to be carried out. Furthermore, two power companies in Hong Kong, China have already agreed to set up two pilot commercial scale wind turbine projects for public demonstration and evaluation purposes, subject to detailed feasibility studies.

CONSULTANCY STUDIES ON WIDER USE OF:

WATER-COOLED AIR CONDITIONING SYSTEM (WACS)

The Government is conducting three consultancy studies in order to recognise the energy saving potential of WACS. One is on the territory-wide implementation of WACS and the other two are on the implementation of district cooling system in a new development area and an existing developed area. The first two studies were completed in 2003 and the Government is currently following up on its recommendations. The Government expects to complete the last study, on the existing developed area, in 2004.

ENERGY CONSUMPTON INDICATORS AND BENCHMARKS

The consultancy study on the development of energy consumption indicators and benchmarks has been completed. The study covered hospitals, clinics, universities, schools, hotels and boarding houses, private offices and commercial outlets in the commercial sector, as well as medium and heavy goods vehicles, private cars and light goods vehicles in the transport sectors. The study established energy consumption indicators and benchmarks that enabled targeted groups to set its own improvement targets, and identify and implement improvement measures. On-line benchmarking tools were also made available at the EMSD website, where individual operators could benchmark their energy consumption with others in the same group.

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INDONESIA

INTRODUCTION

Indonesia is an archipelago comprised of 17,508 large and small islands near the equator, with a total land area of about 2 million square kilometres. The population in 2002 is about 212 million, the majority of whom reside in Java, one of the five main islands.

In 2002, real gross domestic product (GDP) was US$593.03 billion and per capita GDP was about US$2,801 (both in 1995 US$ at PPP). Since 1991, manufacturing was the major contributor, to Indonesian economy. In 2002 it accounted for 25 percent of the real GDP, while agriculture, livestock, forestry and fishery contributed 17.47 percent. Trade, hotel and restaurant contributed around 16.07 percent. Mining and quarrying contributed about 11.91 percent, transport and communication 6.0 percent, financial ownership & business services 6.56 percent, services 9.37 percent and construction 5.7 percent. Electricity, gas and water supply contributed the least at 1.81 percent.

In 2002, Indonesia's economy grew by an average of 3.7, a slight improvement from its 3.1 percent growth in 2001.

Mining activities, especially of petroleum and tin, have expanded since 1970. Fossil energy resources, such as oil, natural gas and coal, played important roles in the economy both as industrial raw materials and foreign exchange earners. Oil and gas contributed US$12.1 billion or 21.2 percent of total export earnings and about 25 percent of government budget in 2002. Mining contributed US$4.2 billion to export earning, solely from coal export at US$1,762.4 million.

In 2002, Indonesia's oil and natural gas reserves slightly decreased to around 747.3 MCM and 2,560 BCM respectively, while that of coal remained at 5,370 Mt.

Table 13 Key data and economic profile (2002)

Key data		**Energy reserves***	
Area (sq. km)	1,937,179	Oil (MCM)	747.3
Population (million)	211.72	Gas (BCM)	2,560
GDP Billion US$ (1995 US$ at PPP)	593.03	Coal (Mt)	5,370
GDP per capita (1995 US$ at PPP)	2,801		

Source: Energy Data and Modelling Centre, IEEJ.

* Proved reserves at the end of 2002 from the BP Statistical Review.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, total primary energy supply was 100,796 ktoe. Of this total, 50 percent was oil, 27 percent gas, 16 percent coal, and 6.5 percent for other energy such as geothermal, hydro and new and renewable energy resources.

Most of Indonesia's proven oil reserve base is located onshore in the Duri and Minas fields in central Sumatra. Other significant production fields are located in offshore northwestern Java, East Kalimantan and the Natuna Sea. During the last decade, crude oil production in Indonesia ranged between 1.3 and 1.4 million bbl/d. But as fields were continually developed and reserves were depleted, crude oil production started to decline in the recent years. Thus, in 2003, Indonesia was only able to produce crude oil at a rate of 1.1 million bbl/d. Production further declined in

September 2004 to only 966,466 barrel per day. Aside from oil, Indonesia also produces around 131,000 bbl/d of natural gas liquids and lease condensate.

Besides relying on its domestic oil production, Indonesia also imports crude oil and refinery products to support its domestic oil requirements. Prior to 2002, Indonesia has been an energy exporter, exporting oil, gas, and coal. But in 2002, because of increased demand and depleting reserves, Indonesia (for the first time) became a "net oil importer". It has exported 185.9 million barrels of crude oil and 42 million barrels of refinery products, but imported 124 million barrels of crude oil and 106.9 million barrels of fuel oil. In total, Indonesia's net oil imports reached 3 million barrels in 2002.

Indonesia is however optimistic that it will immediately recover and get out of its current status as a "net oil importer" when new oil resources are discovered and developed in the next few years.

In 2002, Indonesia's natural gas production reached around 79,089 ktoe, an increase of 5 percent from its 2001 production of 75,000 ktoe, or about 30 percent from 2000 at 60,500 ktoe. More than half (57 percent) of Indonesia's natural gas production was used to supply the economy's domestic demand, while the rest (43 percent) was exported. 42 percent are utilized by industry and electricity, while 31 percent are used for gas injection and fuel on the field. The rest of the domestic supply is utilized either as chemical feedstock (for fertilizer) 17 percent, city gas 7 percent, or in refineries 3 percent.

About 90 percent of the gas is exported as LNG, 4 percent as LPG and 6 percent as piped gas. Of the exported LNG, around 69 percent went to Japan, 19 percent to Korea and 12 percent to Chinese Taipei. Despite however the availability of natural gas in Indonesia, its domestic use is relatively under-developed.

More than half of Indonesia's total recoverable coal reserve is lignite (about 57 percent), 27 percent is sub-bituminous, 14 percent bituminous and less than 0.5 percent anthracite. Based on a recent assessment of Indonesia's coal reserves, 10 more coal basins were identified which contain 336 tcf of Coal Bed Methane (CBM). The major coal reserves in Indonesia are located in the islands of Sumatra, and Kalimantan, while some reserves are also found in West Java and Sulawesi. Indonesian coal generally has a heating value ranging between 5,000 - 7,000 kcal/kg, with low ash and sulphur levels. The sulphur content of Indonesia coal is below 1 percent.

In 2002, Indonesia has produced about 104 million tonnes of coal and has exported most or about 70 percent to Japan, South Korea and Chinese Taipei. Indonesia plans to double its coal production, eyeing other economies in East Asia and India as potential markets.

Indonesia has 24,048 GW of installed generating capacity in 2002, of which it has generated about 108,043 GWh of electricity. Most of the electricity generated came from thermal (85 percent), while the rest were supplied by hydro (9.2 percent) and geothermal and others (5.8 percent).

Table 14 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	175,743	Industry Sector	21,863	Total	108,043
Net Imports & Other	-74,946	Transport Sector	22,085	Thermal	91,866
Total PES	100,796	Other Sectors	23,469	Hydro	9,940
Coal	15,873	Total FEC	67,418	Nuclear	-
Oil	50,841	Coal	5,020	Others	6,238
Gas	27,483	Oil	44,999		
Others	6,599	Gas	9,529		
		Electricity & Others	7,870		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

FINAL ENERGY CONSUMPTION

Indonesia's final energy consumption slightly increased to 67,418 ktoe in 2002 from 65,861 ktoe in 2001. The most important end use fuel was oil, accounting for 67 percent of consumption, followed by gas at 14 percent, electricity at 11.6 percent and coal at 7.4 percent. There was however a slight change in the domestic use of gas in 2002. Despite the significant growth in domestic consumption (about 28 percent from 2000 to 2001), the lack of supply and infrastructure has slowed down domestic consumption from 10,345 ktoe in 2001 to 9,528 ktoe in 2002. This has resulted to a negative growth rate of almost 8 percent.

Coal consumption, on the other hand, has continuously increased in 2002. After almost doubling from 2000 to 2001, coal consumption has increased by almost 18 percent from 2001, and to about 5,020 ktoe in 2002. Coal consumption from the power stations in Sumatra contributed much to the increase in coal consumption in 2001 and 2002.

Electricity consumption also picked up in 2002, achieving a higher growth of about 8 percent after it suffered a big drop (39 percent) from 2000 to 2001 at 11,878 ktoe and 7,269 ktoe respectively. The current consumption pattern sent a cautious signal to Indonesian energy policy. Indonesia's policy of promoting the domestic use of gas seemed to have not achieved its goal because of the limited supply availability as a result of declining gas production from gas fields, especially in East Java and Arun. Indonesia seemed to have not recovered from its declining gas production. Due to the lack of available feedstock for its fertilizer plant, Indonesia was forced to temporarily shutdown its fertilizer production operations.

Increased tariff and subsidy removal also affected the sector's energy consumption. In 2002, transport surpassed industry as the largest consuming end-use sector, and accounted for 33 percent of final energy consumption. Industry sector and other sectors (household and commercial) accounted for the rest of the final energy consumption, at 32 percent and 35 percent respectively. Industrial sector's final energy consumption dropped to 7 percent from 25,170 ktoe in 2000 to 23,468 ktoe in 2001. The industrial sector also suffered the downtrend with consumption dropping to 21,863 ktoe in 2002 to about 7 percent from 2001. In contrast, the Others sector's (household and commercial) consumption grew by 7 percent from 19,459 ktoe in 2000 to 20,855 ktoe in 2001. From 2001 to 2002 household and commercial sectors experienced higher growths of 13 percent. The transportation sector's consumption grew by about 3 percent from 2001 to 2002. Considering the industrial sector's continuous growth, it would seem that increases in energy prices has motivated the industries to implement energy saving and increase its energy efficiency, which resulted to significant reduction in final energy consumption. The increase in energy use in the other sector (household and commercial sectors), on the other hand was mainly due to increased demand as a result of growth in the sector during the period.

Non-commercial biomass, an important source of energy in the residential sector, is not currently taken into account due to difficulties in measuring consumption levels.

POLICY OVERVIEW

Indonesian energy policy is collaboratively formulated by inter-ministerial bodies; the BAKOREN (Badan Koordinasi Energy Nasional) the National Energy Coordinating Board. BAKOREN is a cabinet level inter-ministerial body, created in 1980 to formulate government policies on the development and utilization of national energy resources and to coordinate the implementation of the policy. The membership consist of Minister of Energy and Mineral Resources, Public Works, Industry, Agriculture, Forestry, Environment, Defense, Research and Technology and Head of Nuclear Agency and Pertamina Director.

In the executive level, the Ministry of Mines and Energy has overall responsibility for the development of mining, oil, natural, electricity and new and renewable energy. The line supervision and regulation of Indonesian energy sector falls under three Directorate General of the Ministry.

The Directorate General of Oil and Gas (MIGAS) covers regulation and supervision of the upstream and downstream oil and gas industry. MIGAS is also responsible for offering oil and gas acreages to oil and gas companies. Under the Oil and Gas Law, promulgated in 2001, MIGAS is supported by two independent bodies; BP Migas and BPH Migas. BP MIGAS (Badan Pelaksana Minyak dan Gas Bumi) is an upstream implementing body responsible for managing oil and gas contractors. BPH Migas (Badan Pengatur Hilir Minyak dan Gas Bumi), on the other hand, is responsible for controlling downstrean activities, such as regulating and determining the supply and distribution of oil based fuel, regulating the transmission and distribution of natural gas, allocating fuel to meet national oil fuel reserves, the use of oil and gas transportation and storage facilities, setting tariff for gas pipelines use, and the price setting of natural gas for household and and small consumers.

Directorate General Geology and Mineral Resources (DJGSM) handles the promotion and supervision of the mining industry, including coal and geothermal.

The Directorate General Electricity and Energy Development (DJEED) is responsible for policy planning and supervision of electricity industry and new and renewable energy development.

The Indonesian energy policy was launched in 1990 and amended in 1991, 1998 and 2004. The 1998 Indonesian Energy Policy consists of five major policies objectives, namely: 1) diversification of energy resources, 2) intensification of searching for new reserves, 3) energy conservation 4) implementation of market economy for energy and 5) promoting environment as an important part of energy related decision making. The major policy is supported by nine supporting policies: 1) promotion private sector investment, 2) appropriate taxation, incentives and dis-incentive, 3) standardization and certification, 4) energy infrastructure development to reduce disparity among regions, 5) human resources development, 6) dissemination energy information, and 7) research and development.

DIVERSIFICATION OF ENERGY SOURCES

The main objective of the policy for the diversification of energy resources is to shift the dominant share of oil in domestic energy supply. Oil share in the final energy use has been constantly high, about 95 percent as early as the 1970's. It has decreased to around 70 percent only in 2003. At the other end, oil production is in continuously declining, from 1.5 million barrel per day in early 1980's to below one million barrel/day in 2004. Indonesia has explored most of its energy resources including coal, natural gas, hydro, geothermal, new and renewable energy. Until recently, Indonesia has seriously considered studying the possibility of developing its coal bed methane (CBM). However, aside from coal, natural gas, hydro and geothermal have contributed quite a significant share in the energy mix. Coal share in primary energy supply has increased from 0.4 percent in 1980's to 19.7 percent in 2002. While gas share increased from 6 percent in 1970's to 22.6 percent in 2002, hydro remained constant to about 4 percent. Despite huge potential for geothermal resources (about 19,658 MW), geothermal share in energy supply only increased from 0.1 percent in 1980's to 1.6 percent in 2002.

In 2002, out of the total 102.9 million metric ton (MT) of coal produced, 72.5 million MT was exported. The power sector dominated domestic use of coal, which accounted for 29 million MT or 65 percent of total domestic use. The rest was utilized by industries, cement, pulp and paper, metallurgy and small industry. Although there are policies in place to expand the utilisation of coal briquettes to replace subsidized kerosene, it seems that the progress is not significant.

The Domestic Gas Obligation in Oil and Gas Law 2001, supports the policies on domestic gas utilization. The companies producing gas are required to supply to domestic demand a maximum level of about 25 percent of its production. In 2004, Indonesia Constitutional Court amended ceiling obligation.

In 2002, 55 percent of Indonesia's natural gas was exported as LNG, LPG and pipelines, 7.7 percent for electricity generation, 2.2 percent for city gas, less than one percent for fuelling taxi and bus and about 6 percent was flared.

In response to the financial crisis, where gas prices too expensive for domestic companies; Indonesia issued a Domestic Gas Incentive. The government lowered the price of the gas to around 20 to 55 cents per MMBTU, depending on utilisation, for a period of 3 years. The incentives ended in 2003. No data was however available that will show that the policy contributed to recent domestic gas shortages.

The promotion of new and renewable energy started as early as 1980's, when stand-alone wind energy generation and solar home system were installed. The economy initiated the world largest decentralized rural electrification program with photovoltaic system with total installation of 50 MWp solar house systems in 1990's. The program did not however materialise because of the financial crisis in 1997. There are currently about 0.5 MW wind power and about 5 MW photovoltaic in operation, which provide electricity to remote villages. Mini and micro hydro utilisation are more prospective. From its 460 MW capacity potential, around 64 MW have been developed mainly for rural electrification. Indonesia also promotes electricity from biomass. In 2002 the economy has installed 302.5 MW plants using biomass as fuel. To increase the rate of new and renewable energy development in 2002, Indonesia issued a policy that obligated the State Electricity Company to buy power from small power producer which generate electricity from wind, solar, mini-micro hydro, agricultural and industrial wastes, municipal solid wastes, dendro thermal and geothermal. Furthermore, in early 2004, Indonesia has introduced another new policy on renewable energy development and energy conservation. Under the policy, Indonesian utility companies are required to generate 5 percent of produced electricity from renewable energy. With that obligation, Indonesia is expected to utilize 78,800 BOE of renewable energy by 2010.

For decades, the diversification of energy resources only come with marginal result as indicated that oil is still dominant for Indonesia's energy supply. Geographical mismatch between location of energy resources and energy demand, unfavourable policy, and price subsidy are among the major hindrances for diversification. It is imperative for the Indonesian government to make a stronger effort for diversification of energy resources as the oil production continuously declining.

INTENSIFICATION OF THE SEARCH FOR NEW ENERGY RESERVES

New resources are important to replace the exploited resources. The policies encourage the exploration of energy resources such as oil, coal and new and renewable energy. Explorations of energy resources need significant investment. To invite investment in exploration of energy resources, favourable business environment is necessary.

Although such policies have been in place since the 1990's, its effectiveness has been questioned. Oil exploration, for over 10 years, has not yielded significant discoveries. More than 80 percent of Indonesia's commercial reserves came from oil blocks signed before 1971, and only five percent of the oil reserves found from the work area were signed after 1990.

Gas exploration, on the other hand had shown better prospects. However, only 60 percent of Indonesia commercial gas reserves come from gas block signed before 1971. While, blocks signed after 1990 accounted for only 14 percent of the commercial reserves. With only 38 out of 60 basins explored, Indonesia's failure to find significant additional oil and gas reserves strongly indicate under-investment.

In 2003 and 2004 the Ministry of Energy and Mineral Resources has initiated measures to try and improve the investment climate in oil and gas sector by simplifying procedures for exploration and production contract and increasing the profit shares for companies. Previously, oil and gas companies could only receive working areas through official tenders. By simplifying procedures, company can apply for working areas without waiting for a formal bidding session. Upon receipt of application, Government invites other bidders to participate. If there are no other bidders within a prescribed time, the sole bidder will be awarded the block. The new fiscal system will allow an increase in production shares for companies from 15 percent to 25 percent for oil, and from 30 percent to between 35 percent and 40 percent for gas.

The Ministry of Finance imposed a new tax on equipment for oil exploration. For more than three decades, the oil industry had been exempted from taxes on imported equipment used in exploration. The tax used to be imposed after commercial production. New tax system would likely create a drawback for oil investment despite the efforts made by Ministry of Energy and Mineral Resources.

The coal sector also encountered a similar problem as with the oil and gas sectors. The continuous increase in production and rate of exports has caused a declining trend on investment for finding additional reserves. Investment in the coal sector dropped significantly from US$778 million in 1997 to US$61 million in 2002. Government tax policy, which abolished the Value Added Tax (VAT) of imported capital goods and serviced reimbursement from production, reduced company's income by 8-10 percent. New Forest law promulgated in 1999 characterized 50 mining areas (some are coal mining) as conservation area although the company granted the area before the promulgation of the law. With long negotiation 13 or 22 mining companies may proceed with their activities.

Exploration on new and renewable energy have located potential resources for development of mini and micro hydro, wind power, solar energy. However, more intensive exploration is likely needed to develop resources commercially.

There will always be competition between government and companies to maximise benefit from energy resources or other natural resources projects. However, government should be able to provide and maintain transparent, stable and neutral regulation and taxation system. Inter-ministerial conflict of interest should never bring the companies as a victim of contradictory policies. It has become imperative to build better coordination among Indonesia ministries as indicated by Indonesia Energy Policy spirit.

ENERGY CONSERVATION

Institutionally, Indonesia's energy conservation program started in 1991, by the issuance Presidential Decree No. 43 on energy conservation. The decree led to the National Master Plan for Energy Conservation in 1995. The plan included programmes for training, efficiency award, energy management, and industrial energy audit. It also outlined fiscal incentive such as tax reduction and soft loans for energy conservation projects. The plan has set a target for 15 percent energy saving by 1999, which was not achieved. In 2000, a more realistic target was set, to reduce energy intensity by 1 percent per year.

Along with all ASEAN members, except Brunei, Indonesia adopted voluntary building energy codes in 1992. Full adoption of the codes estimates 20 percent energy savings in the long term.

In 2000, Indonesia promulgated mandatory standard for compact fluorescent lamps (CFLs). Refrigerators will be subject to mandatory standard by 2005, with maximum allowable consumption of 250 kWh per year. Standard for other electrical equipment such as air conditioner, flat iron, TV and freezers has been in effect since 1992.

To boost energy conservation program, Indonesia also introduced Demand Side Management Program (DSM) in 1992. The program focused on introduction of more efficient lighting, time of use tariff and motor efficiency improvement. Revised program in 2002, expected in 2005, will bring 1,555.4 MW peak load reduction.

To support energy conservation program, Indonesia created energy service companies PT Konservasi Energy Abadi (KONEBA). The company performed industrial energy audit, energy conservation planning, database development, training, information dissemination and the procurement and installation of energy saving equipment.

Despite having the conservation program in place for quite a long time, Indonesia's energy conservation have been limited by subsidised energy prices which limit incentive to use energy efficiently, lack of mandatory minimum energy performance standard and weak institutional support.

IMPLEMENTATION OF MARKET ECONOMY FOR ENERGY

The policy directed the establishment of appropriate energy pricing, the main objective of which is to provide affordable energy price and stimulate investment in energy sector. Market based pricing is considered as the optimal pricing mechanism. The pricing policy imperatively also suggested the internalisation of external cost and the introduction depletion premium for fossil energy as it is an exhaustible resources. In addition, the policy also mandated price discrimination between productive and consumptive use of energy.

In practice, however, Indonesia has for long a period subsidised the end use energy price. There were several attempts to abolish subsidy from energy price. In 2003, Indonesia has removed subsidy on oil fuel almost entirely, except kerosene for household use. The total subsidy removal was planned by 2004. However, political situation, where Indonesia held general election postponed the plan. Furthermore, high oil price in the last quarter of 2004 brought the consequence to subsidize all fuel prices, as it was not politically sound to pass the high oil price to consumers. The consequence is a significant increase in government spending for fuel subsidy. Originally, government proposed to spend only 14 trillion rupiah in 2004. High oil prices have pushed the government spending on fuel subsidy to more than four fold to 63 trillion rupiah, equivalent to 1.5 percent of GPD for the year.

Price discrimination applied to kerosene where subsidy provided for kerosene consumed by household also found to be un-effective. The price difference increases demand for kerosene and lead to shortage of supply. Where, in fact the subsidized kerosene was consumed by industry, while the poor households pay higher than the posted kerosene price due to additional distribution fee imposed by local distributors.

PROMOTING ENVIRONMENT AS AN IMPORTANT PART OF ENERGY RELATED DECISION MAKING.

The policy mandated that environmental aspects should be considered on every stage of energy development, from exploration to final use. This policy is supported by policy that required environmental impact assessment for energy projects, promotion of low emission fuel for transportation, abolishment leaded gasoline, and development clean coal technology for power generation.

In addition Indonesia also adopted the Convention on green house gases. In 2004, Indonesia ratified the Kyoto Protocol. Although, Indonesia is not on the Annex I list of the Protocol, the ratification could provide positive contribution to meet Kyoto requirements by participating in projects aimed to support Kyoto Protocol such as Clean Development Mechanism and Joint Implementation.

No principal change was made in the revision of energy policy in 2004, except for its title and the awareness of a possibility to become an energy importer in the near future. The title of energy policy was change to National Energy Policy 2003 – 2020. The awareness of the possibility of Indonesia to be energy importer in the near future lead to the promotion of a policy to build access to energy resources in a foreign economy.

NOTABLE ENERGY DEVELOPMENTS

OIL

In the last three years Indonesia has continued its oil industry reform process as well as inviting investors to conduct oil and gas exploration activities in order to increase the economy's oil reserves. The reform continued the development of several instruments to support the operationalisation and implementation of the new oil and gas law. Efforts were likewise focused on inviting more investor by offering new areas for bid and improvements in the petroleum fiscal system. Indonesia also continues its programs of abolishing the oil subsidy that placed a burden on the state budget for along time.

REFORMS

The promulgation of the New Oil and Gas Law, Law No. 22/2001 abolished the mining rights of Pertamina over oil and gas resources. The mining right therefore was returned to the state, and to administer the exploration and exploitation of oil and gas resources Government of Indonesia established the executing body called Badan Pelaksana Kegiatan Hulu Migas (Upstream Oil and Gas Executing Body) called BP-Migas in 2002. BP-Migas signed the cooperation contract on behalf of Government of Indonesia with Oil Company awarded prospective acreage. The prospective acreage is offered to oil companies through a competitive bidding mechanism. To supervise the downstream sector in December 2002 Indonesia has established a Regulating Body to supervise the supply and distribution of fuel oil and the transmission/distribution gas through pipelines. To proceed with the oil sector reform, Indonesia has reduced Pertamina's status to a limited liability company in 2003. Within a period four years, Pertamina's sole right to distribute petroleum products will finally be eliminated.

After almost a year of delay, in October 2004, Indonesia issued two implementing regulations of Law No. 22/2001 regarding Oil and Gas Law. Government regulation No. 35/2004 provides the basic framework for upstream oil business, and Government regulation No. 36 provides business framework for downstream oil and gas sector. However, despite the issuance of the implementing regulation, Indonesia postponed the liberalisation of fuel price to 2010. It was expected that liberalisation of fuel price will take effect in 2005 upon the removal of Pertamina's obligation to supply fuel for the entire economy.

Despite the postponement of liberalisation of fuel price, Indonesian Government has awarded licenses to retail petroleum products to 6 companies namely PT Krida Petra Graha (Shell), Petronas of Malaysia, BP, PT Sigma Rancang Perdana, PT Pandu Selaras, PT Elnusa Petropine, PT Elnusa Harapan, and PT Raven Sejahtera. Singapore Petroleum Company (SPC) recently also raises the interest to involve in retail business in Indonesia. Other nine companies were given permit to distribute natural gas.

After two years in place it was reported by industry that BP MIGAS more inefficient than Pertamina. The staffing increase fourth-fold than it was planned, and the decision making process was found to be slow. Frustrated companies said that Indonesia oil reform stalled in the transition.

The Oil and Gas law 2001 mandate the application of market price for petroleum product pricing in domestic market. However, in 2004 Indonesian Constitutional Court rejected the provision and returned the power to set up tariff to Government.

NEW BIDDING ROUND

In 2002, Indonesia has not been very successful in inviting investors for the prospective areas offered. Out of the 14 working areas tendered, only one investor came to bid. The rigid fiscal system, wherein the government takes too much from the produced oil, is believed to be the main barrier or serious hurdle for prospective and future investors. In order to improve its investment climate, the government of Indonesia has introduced a new fiscal system in 2003. The new fiscal system will allow an increase in production shares for companies from 15 percent to 25 percent for oil and from 30 percent to between 35 percent and 40 percent for gas.

The new fiscal system seemed encouragingly attractive to investors. For the 11 oil and gas working areas offered by Indonesian in July 2003, 36 investors came to bid, and 9 companies then were awarded the Production Sharing Contracts, with a total value of US$170 million. The government expects that from the new working areas opened for bid, 8 more contracts will be signed, which will bring the total contracts signed to 17 in 2003. This is a big improvement from 2002 where only one contract was signed. In 2004 Indonesia offered 20 more new blocks for oil and gas exploration.

NEW PRODUCING FIELD

Belanak field in Natuna Sea operated by ConocoPhilips started the production in October 2004. The expected full operation of the field will bring 100,000-barrel oil per day to Indonesia.

OIL IMPORT FROM RUSSIA

Indonesia is considering importing diesel fuel from Russia. Pertamina will import 600,000 barrels of diesel during a trial period. If the first shipment goes smoothly, it will probably continue with a three year long-term contract. Economically it is expected that by importing diesel from Russia, Indonesia will save around US$109 million per year.

IMPACT OF OIL PRICE

High oil price, which started in July 2004, is widening the Government's budget deficit, due to the increase in subsidy. Although theoretically, GOI only subsidized kerosene, high crude oil price in practice make government subsidize all fuel product. Political situation where Indonesia face general election in 2004 bring unfavourable climate for government to increase fuel price or pass down the additional crude oil price to consumer. As a result, Indonesian Government who originally plans to spend 14 trillion rupiah on fuel subsidies in 2004 has to increase the budget for subsidy to 63 trillion rupiah, equal to 1.5 percent of the GDP in 2004.

NATURAL GAS

In 2002 and 2003 Indonesia took serious efforts to, among others, market LNG from Tangguh plant, encourage domestic gas utilisation and restructure its natural gas industry. China, Japan, Republic of Korea, Mexico, the Philippines, Chinese Taipei, and USA are considered potential buyers for the Tangguh LNG. On the domestic front, Indonesia enhanced gas utilisation for power generation and petrochemical plant (fertiliser). Pertamina, Amerada Hess and Santos with their working area adjacent to BP Kangean field will serve as alternative sources of gas to meet the gas demand, which BP Kangean has recently been unable to supply due declining reserves. Pertamina will supply gas for power generation in East Kalimantan and Central Java. PT Expand Nusantara, on the other hand, will supply gas for power plants in South Sumatra and East Kalimantan.

After the Share Sale of the PT PGN, which established the transportation company, PT Transportasi Gas Indonesia (Transgass Indo) in 2002, Indonesia opened Initial Public Offering of PT PGN stakes in November 2003. Government sold the PGN stakes at up to 30 percent in December 2003.

GAS SUPPLY DEAL

Indonesia achieved some success in marketing gas both for the domestic and export market. In 2003 gas producers in Indonesia have signed 13 agreements to supply gas worth of US$14 billion to state-owned electricity company PT PLN, state-owned fertiliser company PT Petrokimia, Gresik and Singapore's utility Island Power.

Indonesia has also signed LNG contracts that started the development of the two trains LNG Tangguh with a production capacity of 7 million ton per year. BP Indonesia has signed a contract with Fujian province to supply 2.5 million ton LNG per year to the province starting in 2007. In addition BP also signed an MOU with SK Corporation and Posco of South Korea to supply both companies with an average of 1.1 to 1.5 million tons of LNG per year for 20 years. The MOU was followed by selling contract in July 2004. BP Indonesia has also signed a contract to supply LNG to the Philippines in 2006. In October 2004, Indonesia with its partner BP has signed a long-term sales and purchase agreement with Sempra Energy LNG to supply up to 3.7 mtpa from Indonesia to markets in Mexico and the US. Delivery will start in 2008 to Sempra Energy purpose terminal in Ensenada in Baja California, Mexico. As the amount of sales and purchase contract required for the LNG Tangguh's to proceed to construction achieved, the plant construction seems to be started soon. Indonesia government started negotiation with BP for expansion of LNG Tangguh.

PGN has considered building a gas-receiving terminal in West Java and East Java to ensure uninterrupted gas supplies to the island by utilising liquefied natural gas from Tangguh LNG plant in Papua and Donggi in South Sulawesi.

PNG DEVELOPMENT

As early as 2001, Indonesia has continuously increased its gas export through pipelines. In 2002 Indonesia has exported about 226,5 MMSCFD (million standard cubic feet per day) of gas through 2 pipelines to Singapore and Malaysia. The first pipeline delivered gas from three production blocks - Block A, Block B and Kakap in Natuna sea to SembGas facilities at Jurong Island at the rate of 126,5 MMSCFD. The 656 kilometer pipeline which has a capacity of 700 million standard cubic feet per day were jointly developed by Conoco, Gulf and Premier. The second pipeline delivered gas from Block B West Natuna to Petronas Carigali Duyong gas facility. The delivery started in August 2002 at the rate of 100 MMSCFD, and is expected to increase at a rate of 250 MMSCFD in 2007.

The third export pipeline was commissioned in August 2003. The 470-kilometre pipeline delivered gas from Grissik Field in South Sumatra to Singapore's Sakra island via Sakerman in Jambi and Batam Island with an initial flow rate of 150 MMSCFD. The capacity will be increased to 350 MMSCFD by 2009. The pipelines will also supply gas at a rate of 50 MMSCFD to Batam island. Gas delivery started in October 2004 to PLN Batam, at 12.5 MMSCFD. However, there is no tentative schedule for gas delivery to other industry in Batam.

In addition to its export gas pipelines, Indonesia also plans to build the Indonesian Integrated Transmission Pipelines, which is aimed at meeting the economy's domestic gas demand. The plan includes the development of a pipeline from Sumatra and Kalimantan to Java. A section of the gas grid, the 399 kilometer pipeline linking Grissik to Jakarta via Pagardewa in South Sumatra and Cilegon in West Java with capacity of 550 MMSCFD, already went on stream in 2002.

East Kalimantan - Java pipelines consist of 600 kilometer pipelines from Samarinda (Bontang)-Balikpapan-Banjarmasin and 500 kilometer pipeline from Banjarmasin to Surabaya. The pipelines are expected to deliver 700 MMSCFD of gas by 2005. The inter-Java pipeline linking east-center and west of Java are projected to be completed in 2004 - 2007.

LNG IMPORT

Declining gas production in Arun field and some problems in Bontang LNG plant have caused Indonesia's inability meet its supply obligation from her own production in 2004. To fulfil supply requirements, Indonesia bought 7 cargoes of LNG in the spot market to be diverted to the contracted buyer.

GTL PLANT

Rentech (Matindok) has conducted a feasibility study to build a 16,000 barrel/day gas to liquids plant. Using Fischer-Tropsch technology, the plant is expected to be on stream in 2007. Shell is also examining the possibility of building a GTL plant with a capacity to produce diesel at 75,000 barrel per day and other middle distillates using the same process proposed by Rentech.

POWER SECTOR

Indonesia's electricity generation capacity is estimated at 23.4 GW, of which 84 percent is thermal, 14 percent hydropower, and 2 percent geothermal. Indonesia is still struggling to overcome the shortage of power, in the main island of Java-Madura Bali and outer islands. Lack of generating capacity and transmission has placed several areas in high risk of having a power shortage. To address this problem GOI has renegotiated the 27 postponed IPPs. In the first quarter of 2003, PLN and the government has thus far resolved price disputes with 20 of the 27 independent power producers that were licensed in the early 1990s. From 26 IPP projects negotiated, 14 projects have proceeded for construction, 7 projects were closed and 5 projects were acquisitioned by State Power Company. However, most of the projects will come on stream only within the next 3 to 4 years. PLN itself is building a new power station with a capacity of 850 MW at Muara Tawar in West Java but this one too is only expected to come on line next year.

The power-capacity level will thus remain dangerously low, making industrial users in Java and Bali highly vulnerable to supply disruptions. It is therefore more imperative than ever for PLN to improve its peak load management, maintenance system and cooperation with captive power suppliers to avert major power blackouts during this critical period until enough additional capacity comes on stream to increase the power reserve margin much higher than the minimum 30 percent, a standard recommended by World Bank.

After struggling to maintain reserve capacity during peak loads for several years, PT PLN, in 2004 could maintain a 600 MW reserve capacity in Jawa-Bali during peak load. This capacity expected could be maintained until dry season next year before other plant put on line. However, for Sumatera and Kalimantan islands available capacity could not meet peak demand. As a result, both of the two islands will remain vurnerable to electricity shortage, especially for areas such as North Sumatra and Aceh, Jambi, Riau and Rengat, and the southern part of Sumatra and Singkawang for Kalimantan island.

With the implementation of the new electricity law, passed by Parliament in 2002, PLN will gradually loose monopoly in power generation, transmission and distribution, and the private investors will be allowed to enter the electricity sector. Indonesia plans to liberalise the electricity market by 2007. To supervise the electricity market, the Government of Indonesia has established a Power Market Supervisory Agency called BAPETAL (Badan Pengatur Tariff Listrik). The power industry watchdog will determine which province in the economy is ready for market competition, and which will remain under government control. The supervisory body will be in charge of ensuring fair market competition for mid sized and large consumer and determining power prices for small users. Java, Madura, Bali (Jamali) and Batam islands will become the first areas were open market competition will be applied.

However, further development in power deregulation will stall for uncertain time now as Indonesian Constitutional Court annulled the Electricity Law No. 20/2002 in December 2004. The court considered that electricity is commodity vital to the lives of many citizens and should therefore remain under Government control. The Ministry of Energy and Mineral Resources propose to submit new draft electricity law with a softer approach to liberalizing the power sector.

GEOTHERMAL

Indonesia is estimated to own 40 percent of the world's geothermal resources, an equivalent 20,000 MW electricity capacity. However, only about 4.3 percent or 860 MW of this huge resource have been utilised. To enhance the utilisation of its geothermal resources, Indonesia has promulgated the Geothermal Law in 2003. The law provides legal certainty and security to investors, establishes the regulating body and transparent business procedures.

COAL

PT Tambang Batu Bara Bukit Asam (PTBA), the state owned company, discovered around 200 million tons of new coal reserves at Ombilin in West Sumatra in 2003. To develop the resource Indonesia has established it ties with the Japan Energy Coal Center (JCOAL).

ENVIRONMENT

In the last 3 years Indonesia has made several efforts to reduce the environmental impact of energy use, most important of which are the ratification of the Kyoto Protocol, and the issuance of policy to reduce emission.

KYOTO PROTOCOL RATIFICATION

On 28 June 2004, the House of Representatives of Indonesia ratified the Kyoto Protocol. The establishment of a Designated National Authority followed the ratification. Indonesia's ratification of the Kyoto Protocol has indicated its willingness to work together to reduce the impact of carbon emission. As a non-annex I economy, Indonesia could support the carbon reduction by participating in CDM. With CDM Indonesia could benefit in financing sources, technology and sustainable development benefit.

NEW EMMISSION STANDARD

Transport sector contribute significantly to Indonesian air quality. In 2003 there were 32.8 million vehicles in Indonesia. Among those vehicles, 23.3 million were motorcycles, 5.1 million passenger cars, 1.3 million buses and 3.1 million trucks. To reduce emission from transportation sector, Indonesia has imposed a new mandatory standard emission. For all new vehicles, manufactured in Indonesia from 1 January 2005, should meet Euro 2 emission standard. For vehicles being produced the requirement will be in force from 1 January 2007. Indonesia will stop the production of motorcycles with two stroke engines by 1 January 2007.

INVESTMENT

In 2004, Indonesia recorded a significant investment in the energy sector. Upstream oil sector successfully invited US$7.5 billion investment, the highest investment achieved so far in the last 8 years. The investment was made in 27 working areas for exploration, development, production and administration.

In the downstream sector, the total investment in 2004 reached US$112.6 million, consisting of US$51 million investment in gas transportation and refinery and US$61.6 million private investment on LPG plants. As the result of deregulation in oil and gas sector, private companies have made some investment in downstream gas sector, which was previously monopolized by Pertamina the state owned company. PT Bhakti Minggas Utama invested US$41.1 million to build LPG plant in West Java. PT Titis Sampurna and PT Musi Banyuasin, both domestic companies, invested US$31 million and US$20 million respectively in LPG plant construction in Sumatra. Other local companies also invested in gas distribution systems with a total investment of US$8.6 million. It was reported that there were 35 more companies waiting approval to make business in downstream sector.

PGN IPO

As part of divestment program, PGN, the state gas pipeline company, was listed on the Jakarta Stock Exchange on 15 December 2003, offering totally 1.3 billion shares (30 percent of paid up capital) and consisting of 475 million share previously owned by Government and 821 million new shares with an offering price Rp. 1500 per share. The IPO raised US$300 million, where PGN received about US$147 million to fund its expansion program.

ISLAMIC FINANCE DEAL

Indonesia state oil company Pertamina signed a deal with HSBC Amanah, an HBSC’s Islamic banking subsidiary, to secure up to US$250 million in Islamic trade financing and fund the purchase of crude oil from the Middle East in December 2004. The deal involved Dubai Islamic Bank, Kuwait Finance House and Egypt’s Faisal Islamic Bank. Pertamina’s deal was the first international Islamic facility transaction in Indonesia. The Islamic finance market could be a good alternative financing resource for Indonesia’s energy sector. However, as the Islamic finance market is still very young in Indonesia, it is still difficult to predict its contribution to investment in energy sector.

NEW SECTOR OPENED FOR FDI

Onshore drilling and radioactive mining was released from the investment negative list. Indonesia expects that such a development would bring more foreign direct investment to the energy sector.

PERTAMINA INVESTMENT IN IRAQ

Pertamina signed a service agreement with the Iraqi Oil Exploration Company to conduct oil exploration in Block 3 Western Desert and negotiated investment in Tuba field. Although Pertamina has invested more than US$ 25 million, future prospect of Pertamina in Iraq is still uncertain. Concerns on security led to Pertamina's temporary suspension of all activities in Block 3 Western desert field.

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JAPAN

INTRODUCTION

Japan is a small island nation in Eastern Asia. It consists of several thousand islands, the largest of which are Honshu, Hokkaido, Kyushu and Shikoku. It spans across a land area of approximately 377,800 square kilometres and most of its land area is mountainous and thickly forested.

Japan is the world's second largest economy after the USA. Japan's real gross domestic product (GDP) in 2002 was about US$3,060 billion (1995 US$ at PPP). With a population of 127 million people, per capita income was high at US$ 24,065.

Up to the early 1990s, Japan enjoyed a long period of rapid socio-economic development. In 1992, however, Japan's economy entered a decade of stagnation. GDP grew only 0.3 percent in 2002 compared to 0.4 percent in 2001. The unemployment rate reached 5.4 percent in 2002[13].

Japan possesses a modest amount of indigenous energy resources and imports almost all of its crude oil, coal and natural gas requirements to sustain economic activity. In 2002, proven energy reserves included around 9 MCM of oil, 40 BCM of natural gas and 773 Mt of coal.

Table 15 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	377,800	Oil (MCM) – Proven	9.3
Population (million)	127.15	Gas (BCM)	40
GDP Billion US$ (1995 US$ at PPP)	3,059.91	Coal (Mt) – Recoverable**	773
GDP per capita (1995 US$ at PPP)	24,065		

Source: Energy Data and Modelling Center, IEEJ. *Oil & Gas Journal. ** World Energy Council.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Japan's total primary energy supply (TPES) was 501 Mtoe in 2002. By fuel, oil represented the largest share at 49 percent; coal was second at 19 percent, followed by natural gas at 13 percent, nuclear at 13 percent, hydro at 4 percent and NRE, including geothermal, wind and others at 1 percent. In 2002, 80 percent of the total primary energy was imported. Imports account for almost 100 percent of oil consumption, 99 percent of coal demand and 97 percent of gas use. Total primary energy supply fell by 1.4 percent in 2002.

In 2002, Japan was the world's second largest oil consumer after the United States[14], and almost all of the oil was imported. The bulk of these imports (85 percent in 2002) came from economies in the Middle East such as the United Arab Emirates (UAE), Saudi Arabia, Iran, Qatar

[13] Japanese economy showed signs of recovery in 2003, with the annual GDP growth rate at 2.7 percent (2002-2003). The recovery was driven by exports, mainly to China, and strengthened domestic capital investment. Unemployment rate has fallen down to 4.6 percent in 2003 from 5.4 percent in previous year.

[14] In 2003, China overtook Japan to become the second largest consumer of oil in the world.

and Kuwait. In 2002, the primary oil supply was 244 Mtoe, a decline of 1.5 percent from the previous year.

Japan is endowed with only limited coal reserves at 773 million tonnes. The small amount of coal production had been heavily subsidised until January 2002 when Japan's last coal mine in Kushiro eastern Hokkaido was closed. Japan is the world's largest coal importer of steam coal for power generation, pulp and paper and cement production and coking coal for steel production. Japan's main steam coal suppliers are Australia, China, Indonesia, Russia, the United States, South Africa and Canada. Coking coal is imported from Australia, Indonesia, Canada, China, Russia, the United States and South Africa. In 2002 primary coal supply was 95 Mtoe or 1.2 percent higher than the previous year due mainly to the increase in demand for power sector.

Natural gas resources are also scarce in Japan. Domestic reserves stand at 40 BCM, located in Niigata, Chiba and Fukushima prefectures. Domestic demand is met almost entirely by imports of LNG[15], which come mostly from Indonesia (28 percent of imports in 2002), Malaysia (21 percent) and Australia. Natural gas is mainly used for electricity generation, followed by reticulated city gas and industrial fuels. In 2002, primary natural gas supply was 64 Mtoe, down 4.3 percent from the previous year.

Japan has 266 GW of installed generating capacity and generated about 1,069 TWh of electricity in 2002. The fuel generation is broken-down as: thermal (coal, natural gas and oil) at 60 percent, nuclear at 29 percent, hydro at 8 percent and geothermal, solar and wind taking up the remainder.

Table 16 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		**Final Energy Consumption (ktoe)**		**Power Generation (GWh)**	
Indigenous Production	99,600	Industry Sector	154,374	Total	1,069,252
Net Imports & Other	401,078	Transport Sector	86,373	Thermal	644,078
Total PES	500,678	Other Sectors	112,724	Hydro	86,751
Coal	95,866	Total FEC	353,470	Nuclear	314,934
Oil	244,404	Coal	37,815	Others	23,488
Gas	64,395	Oil	206,636		
Others	96,013	Gas	22,233		
		Electricity & Others	86,786		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

After the first oil crisis in 1973, Japan invested heavily in nuclear power generation to reduce its reliance on oil. Despite Japan's desire to increase the reliance on nuclear, Japanese nuclear power industry was forced to face several challenges in recent years. In 2002, Tokyo Electric Power Company (TEPCO) was found to have falsified their safety reports in the later half of 1980s and during 1990s. This led to the closure and inspection of all 17 nuclear units belonging to TEPCO for several months[16]. In early August 2004, another incident occurred in one of the Kansai Electric Power Company's nuclear reactors. The accident was caused by a fracture on the secondary piping system at the Mihama Unit 3[17]. As a result of these incidents, public opposition against nuclear power generation has increased.

[15] In 2002, LNG imports to Japan comprised 61 percent of total world LNG trade.

[16] To make up for nuclear capacity shortages, TEPCO had to increase its generation from crude oil, diesel, coal, and LNG.

[17] Five workers were killed by the release of steam into the plant.

FINAL ENERGY CONSUMPTION

In 2002, Japan's total final energy consumption was 353 Mtoe, or 0.01 percent lower than the previous year. The industrial sector consumed 44 percent of the total, followed by the other sectors mainly residential/commercial at 32 percent and the transportation sector at 24 percent. By fuel source, petroleum products accounted for 58 percent of the total final energy consumption, followed by electricity and others at 25 percent, coal at 11 percent and city gas at 6 percent.

Energy consumption for the industrial sector showed a slight increase by 0.75 percent in 2002, compared to a decline by 4.7 percent in 2001. The upturn of industrial energy consumption in 2002 reflects the increase in production for energy intensive industries such as iron and steel, and petrochemicals.

The energy consumption of the residential/commercial sector in 2002 showed modest decline by 0.2 percent. In 2002, the structure of energy consumption in the residential/commercial sector remained almost the same with the previous years, with electricity taking the largest share at 47 percent of total energy consumed, followed by petroleum products at 36 percent, city gas at 15 percent, solar heat at 1 percent and coal at 1 percent. .

In the transportation sector, the passenger sector accounted for 65 percent of the total energy consumption while the remaining 35 percent went to the freight sector in 2002. In 2002, the passenger sector's energy consumption increased steadily with the growing number of passenger-cars, while freight sector's energy consumption decreased, for the same time period, reflecting slow economic activities. As a result, total transportation sector energy demand has declined by 0.3 percent in 2002.

POLICY OVERVIEW

The Ministry of Economy, Trade and Industry (METI) is responsible for formulating Japan's energy policy. Within METI, the Agency for Natural Resources and Energy (ANRE) is responsible for the rational development of mineral resources, securing stable supply of energy, promoting efficient energy use, and regulating electricity and other energy industries. The Nuclear and Industrial Safety Agency (NISA) is responsible for the safety of energy facilities and industrial activities while the Ministry of Foreign Affairs formulates international policies.

The fundamental goal of the Japanese energy policy is to achieve a stable energy supply while meeting the demands for environmental conservation and efficiency improvement.

Japan is faced with the following energy challenges. First is securing a stable energy supply at reasonable prices, despite the 82 percent reliance on imports for its total energy supply. Second is in meeting its Kyoto Protocol commitment to reduce greenhouse gas (GHG) emissions to 6 percent below the 1990 levels between 2008 and 2012. Lastly, on how best to improve the Japanese industries' (including the energy sector's) economic efficiency which thereby increases its domestic and global competitiveness.

OIL

Japan aims to decrease its dependency on oil due to past experiences of the oil crises. However, oil still accounts for around 49 percent of Japan's total primary energy supply and oil is expected to take the dominant share of Japan's future energy supply. Securing stable supply of oil will continue to be one of Japan's major energy policy concerns.

Japan's oil supply structure is vulnerable to incidents of supply disruption since Japan imports almost all of its crude oil. Middle East dependency in 2002 was high at 85 percent. In preparation for any incident of supply disruption, Japan has been pursuing emergency measures by: 1) holding emergency oil stockpiling, and 2) conducting independent development of resources and promoting cooperation with oil producing economies for emergency situations.

The Japan National Oil Corporation (JNOC) had carried out the national stockpile business until 2003. JNOC provided financial and technical assistance to the Japanese oil industries for their oil and natural gas exploration and development both domestically and abroad. In 2004, functions of the national stockpile business were transferred to Japan Oil, Gas and Metals National Corporation (JOGMEC), which was established in February 2004. Following the Specially Designated Public Corporation Rationalisation Plan, JOGMEC was established through mergers of JNOC and the Metal Mining Agency of Japan.

The oil industries have been making every effort for rationalisation with huge cost reduction, like downsizing and tie-up with distributors. The reorganisation of the structure and consolidation of the groups are still ongoing. Making a strong oil industry through the promotion of rationalisation and efficiency is also important for the energy security in Japan.

NATURAL GAS

Demand for natural gas has been increasing rapidly over the last two decades. Between 1980 and 2002, natural gas demand grew at an annual growth rate of 5.1 percent – the fastest growth rate in all primary energy sources. The robust growth in natural gas demand is expected to continue because of environmental reason and ease of use factor.

Japan has undergone natural gas market reform since 1995 in an attempt to lower the cost of gas supply and increase the industrial competitiveness in the global market. To date, Japan has taken three steps to liberalise gas market:

- The Gas Utilities Industry Law was amended in 1995. The Law allowed industrial customers with contracted amounts of more than 2 million m^3 per year to directly negotiate prices with suppliers.
- The Gas Utilities Industry Law was further amended in 1999. The scope of deregulation for large volume supply was extended by lowering the annual contract volume to 1 million m^3 per year and over. Regulations for third-party access for large-volume supply were also established.
- In June 2004, the Diet passed the amended Law on the Gas Utilities Industry. The amendment in 2004 stipulated that customers with the contracted amount of 0.5 million m^3 could freely choose suppliers. The Law has set a timetable for those customers with contracted amount of 0.1 million m^3 to be allowed to choose their suppliers by 2007.

Natural gas is supplied almost entirely by imports in the form of LNG from Indonesia, Malaysia, Brunei Darussalam and Australia. Since Japan has taken priority on their stable and secure supply of LNG, Japanese LNG buyers have been paying a higher price than buyers in Europe or in USA under a long-term "take or pay" contract with rigid terms on volume and price.

Now Japanese gas and electric utilities are faced with mounting pressure to reduce cost because of the deregulation of gas and electricity markets. Japanese gas and electric utilities have been making efforts to secure LNG supply at flexible terms that enable them to quickly respond to the change in market situation and to supply gas at lower cost. For example, the agreement reached by Tokyo Electric Power Company (TEPCO) and Tokyo Gas for their purchase on LNG from Malaysia's MLNG Tiga project includes outstanding features: (1) some of the LNG will be shipped on FOB, rather than Ex-Ship, and (2) agreement increased both the upward quantity tolerance and downward quantity tolerance.

COAL

In 2002, coal accounted for 19 percent of the total primary energy supply. Coal will continue to play an important role in Japan's energy sector mainly for power generation, iron and steel, cement and paper and pulp. Coal mines in Japan have become increasingly deeper and remoter and the mining costs are approximately three times that of imported coal. The government has since then subsidised the coal mining industry and has achieved structural adjustments by reducing coal production gradually. The domestic production of commercial coal substantially ended at the end of fiscal year (FY) 2001.

Japan is the biggest importer of coal, with imports reaching over 20 percent of the total imported coal in the world. From its standpoint, it is essential therefore, to promote the development of overseas coal for energy security in Asia, to address its growing coal demand. To secure a stable supply of overseas coal, Japan is implementing a five-year plan to transfer coal-mining technologies overseas in economies that still have abundant coal resources. Some of the concrete measures to support overseas coal development include, subsidies for investigations prior to mine exploration and development and loans for mine exploration, technology cooperation with coal producing economies and for environmental concerns, development of technology to improve heat efficiency such as technologies of pressurised fluidised-bed combustion, coal gasification combined power generation and coal gas production for fuel cells, support to introduction of high efficiency coal boilers and development and diffusion of Clean Coal Technologies (CCT).

ELECTRICITY

Electricity is an important source of energy that took the second largest position in the total final energy consumption in 2002. Increased usage of electric appliances at home, wide spread use of personal computers and related information technology in offices, and shift in industry structure to services sector, combined to give an upward pressure on future electricity demand.

Despite Japan's heavy reliance on electricity, its electricity price is among the highest in developed economies. To lower electricity price and increase industrial competitiveness, Japan has undergone a programme to reform electricity sector.

The Electricity Utilities Industry Law, the main legislation covering the electricity industry, was amended in 1995 to address global energy sector reform, comparatively high electricity tariffs in Japan and deteriorating load factors. The amendments permitted the entry of independent power producers (IPPs) into the Japanese electricity market. The 10 major electric utilities, each of which holds a regional monopoly, were given the right to accept tenders for IPP investment in generation to cover short-term thermal power requirements.

Subsequent amendment in 1999, allowed the partial liberalisation of retail sales starting in March 2000. Eligible customers, either high voltage users (20kV) or users with contracted demand over 2,000 kW, can now freely enter into contracts with power suppliers, including IPPs.

In June 2004, the Japanese Diet passed an amendment on the Electricity Utilities Industry Law. The amendment includes plan to permit more eligible customers that can choose electricity supplier. According to the law, customers with 500kW of consumption can directly negotiate with suppliers. This is followed by a plan to open market in 2005 for those customers with 50kW. Discussion has started to consider the total opening of retail market for the introduction of full competition in 2007.

NUCLEAR ENERGY

Nuclear energy is perceived to address two key energy issues: supply stability and the environment (no CO_2 emissions). It has now become a major source for electric power generation and will most likely play a big role in the future. To achieve its goal of supply stability and environmental sustainability, Japan is expected to install an additional 10 to 13 nuclear power stations by 2010 (according to the Long-term Energy Supply-Demand Outlook (July 2001)). However, it is deemed necessary that significant and sufficient dissemination of information about the safety and necessity of nuclear power in order to get the national and regional support. The government has undertaken several promotion measures for the siting of the future nuclear power stations.

To ensure efficient use of nuclear resources, it is essential to work out countermeasures to establish the nuclear fuel cycle. In May 2000, the "Specified Radioactive Waste Disposal Act" was approved to ensure the planned, and most importantly reliable execution of high-level radioactive waste disposal. In October 2000, authorisation was granted by METI to establish the Nuclear Waste Management Organisation of Japan (NUMO). NUMO is responsible for identification of the disposal site, construction, operation and maintenance of the repository, closure of the facility and post-closure institutional control. The Low-level Radioactive Waste Disposal Center of the Japan Nuclear Fuel Limited (JNFL) has been in operation at Rokkasho-mura in Aomori Prefecture since 1992.

ENERGY CONSERVATION

In order to achieve its target set forth at the Kyoto conference on climate change (COP 3), Japan formulated its energy efficiency measures in 1998. In 2000, the Advisory Committee for Natural Resources and Energy started the total review of energy policy and the Energy Efficiency and Conservation subcommittee has re-evaluated the energy efficiency measures set in 1998 and has added measures for the industrial, residential/commercial and transportation sectors.

The current energy efficiency measures include, measures for factories based on Law Concerning the Rational Use of Energy, a follow-up of the Keidanren environmental voluntary action plan in the industry sector, strengthening efficiency improvement of equipment and improvement of energy efficiency performance of houses in the residential/commercial sector, strengthening fuel efficiency improvements in cars and acceleration of the popularisation of clean-energy motor vehicles in the transportation sector.

NOTABLE ENERGY DEVELOPMENTS

ESTABLISHMENT OF JOGMEC

On 29th February 2004, JOGMEC (Japan Oil, Gas and Metals National Corporation) was established. JOGMEC takes over major functions from JNOC (Japan National Oil Company) and MMAJ (Metal Mining Agency of Japan). This reorganisation was conducted as part of the Japanese government's administrative reform.

As a result of this reorganisation, JOGMEC has become responsible for providing financial and technical assistance to the Japanese companies in their oil and gas exploration and production (E&P) activities. It has also become responsible for management and operation of national crude oil stockpile and the national stockpile bases.

STRENGTHENING ENERGY COOPERATION IN ASIA

At the 1st ASEAN+3 Energy Ministers Meeting, held in Manila, the Philippines, on 9th June, 2004, Energy Ministers agreed to achieve greater energy security and sustainable development through the effective use of programmes under ASEAN+3 Energy Partnership.

Subsequent to the agreement in Manila, the Advisory Committee on Natural Resources and Energy under METI recognised the importance of strengthening existing framework of cooperation among Asian economies for the establishment of shared prosperity. The Advisory Committee proposed to conduct the following activities:

- Introduction or strengthening of emergency oil stockpiling in Asian economies,
- Creation of market for regional trade on crude oil, petroleum products and natural gas in the Asia-Pacific region, and
- Improvement of energy efficiency and environmental quality in Asian economies.

To facilitate these activities, METI has established the "Study Group on International Business Activities of Energy Related Industries for the Asian Energy Partnership. Members of the study group include representatives of electric companies, gas companies, trading firms, and oil companies. The first meeting was held on 13th October 2004 and an interim report is scheduled to be published by March 2005.

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KOREA

INTRODUCTION

Korea is located in Northeast Asia between China and Japan. It has an area of about 99,601 square kilometres and a population of around 48 million. Approximately 21 percent of the population lives in Seoul, Korea's largest city and capital.

In the last few decades, Korea has been one of Asia's fastest growing and most dynamic economies. Its GDP has increased at an unprecedented growth rate of 7.1 percent per year over the period 1980 to 2002, reaching US$717.6 billion (1995 US$ at PPP) in 2002. Its per capita income in 2002 reached US$15,063, more than 3.6 times higher than its 1980 level. Its major industries include semi-conductor, electronics, shipbuilding, automobile, steel and chemicals.

Korea has very few indigenous energy resources. It is completely without oil resources, and at the end of 2002, there were only 340 Mt of recoverable coal reserves and 250 BCM of gas at a recently discovered small natural gas field. To sustain its high level of economic growth, Korea imports large quantities of energy products. In 2002, Korea was the fourth-largest importer of oil and the second-largest importer of both coal and liquefied natural gas in the world.

Table 17 Key data and economic profile (2002)

Key data		**Energy reserves***	
Area (sq. km)	99,538	Oil (MCM)	-
Population (million)	47.64	Gas (BCM) - Recoverable	250
GDP Billion US$ (1995 US$ at PPP)	717. 61	Coal (Mt) - Recoverable	340
GDP per capita (1995 US$ at PPP)	15,063		

Source: Energy Data and Modelling Center, IEEJ.

* Korea Ministry of Commerce, Industry and Energy and Korea Energy Economics Institute (2003), *Yearbook of Energy Statistics*.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply increased 5.2 fold from 38 Mtoe in 1980 to 199 Mtoe in 2002. In particular, energy supply from 1990 to 2000 increased by an annual average growth rate of 7.7 percent, far exceeding the economic growth rate of 6.2 percent for the same period. Likewise, per capita primary energy supply grew from 1.0 toe in 1980 to 4.2 toe in 2002. This is a level similar to that of Japan and most European economies.

In 2002, Korea's total primary energy supply was 199 Mtoe, 4.9 percent increase from the previous year. By fuel type, oil represented the largest share at 50 percent, coal at 22 percent, nuclear at 15 percent and gas at 10 percent. The remaining 2 percent of primary energy came from hydro and other fuels. Korea imported around 82 percent of its total energy needs in 2002, including all of its oil and gas requirements and 95 percent of its coal supply.

The total primary oil supply in 2002 was 100 Mtoe, a 2.8 percent increase from 97 Mtoe in 2001. The share of oil in total primary energy supply declined by 50 percent, as the fuel switching from oil to LNG and other energy sources is taking place. In 2002, the amount of imported crude oil decreased to 791 MB from 859 MB in 2001 due to increase in import of petroleum products.

The economy imported about 73 percent of its crude oil from the Middle East. Korea was the world's sixth-largest consumer of oil (sharing 3 percent of world oil consumption) in 2002.

Coal use in 2002 totalled 44 Mtoe, 5.0 percent higher than the previous year, reflecting the rapid growth of steam coal demand for power generation. The power sector's share of coal consumption reached 59 percent in 2002, from 26 percent in 1990. Korea has modest reserves of low-quality, high-ash anthracite coal that is not sufficient to meet its demand. Almost all of Korea's coal demand, therefore, is met by imports. Korea is the world's second-largest importer of both steam and coking coal after Japan. Coal imports come from China, Australia, Indonesia, Canada, Russia, and the US.

Korea introduced natural gas in the form of LNG in 1986. Since then, gas use has grown rapidly, reaching up to 21 Mtoe in 2002, increasing to 10 percent, its share in the primary energy supply mix. Korea imports the bulk of its LNG from Qatar, Indonesia, Oman, Malaysia, and Brunei Darussalam. Recently, a small quantity of natural gas, with 250 BCM of recoverable reserves, was discovered in the Donghae-1 offshore field, southeast of the economy.

Korea's electricity generation in 2002 was 306 TWh, 7.4 percent more than in 2001. Nuclear produced 38.9 percent of the total electricity generation, followed by coal at 38.5 percent, gas at 12.7 percent, oil at 7.9 percent and hydro at 1.7 percent. The installed capacity in 2002 reached 53.8 GW. There are currently 20 nuclear power plants with a total installed capacity of about 17.7 GW.

Table 18 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	35,839	Industry Sector	78,238	Total	306,473
Net Imports & Other	163,606	Transport Sector	32,081	Thermal	182,062
Total PES	199,445	Other Sectors	42,931	Hydro	5,309
Coal	44,369	Total FEC	153,250	Nuclear	119,102
Oil	99,850	Coal	20,548	Others	-
Gas	20,805	Oil	91,496		
Others	34,421	Gas	13,110		
		Electricity & Others	28,096		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html).

FINAL ENERGY CONSUMPTION

Korea's total final energy consumption in 2002 was 153 Mtoe, a 5.0 percent increase from the previous year. By sector, industry accounted for the largest share at 51 percent, followed by residential and commercial sector at 28 percent and transport at 21 percent. In general, demand growth in the industry has weakened since the late 1990s, while the rate of demand growth in the transport and commercial sector has increased.

By fuel source, petroleum products were the most important energy source, accounting for 60 percent of total demand. Electricity was responsible for 18 percent, coal for 13 percent and gas for 9 percent of end use. Due to strong policy measures, gas consumption has increased particularly in the residential and commercial sectors, from a small amount in 1990 to 9 percent of final energy consumption in 2002.

POLICY OVERVIEW

The Korean government has traditionally intervened heavily in the energy sector. Supporting high levels of economic growth despite inadequate indigenous energy resources has been the key driver of Korea's energy policy platform. The Ministry of Commerce, Industry and Energy (MOCIE) is responsible for developing and implementing energy policies and programmes, maintaining energy security, administrating the energy industry, supporting research and development of new energy technologies and formulating international cooperation on energy-related matters.

In December 2002, the Korean government announced "The 2nd National Basic Plan for Energy Policy". According to the Plan, "Sustainable Development" has been set as the new goal of Korea's energy policy. In the past, the primary goal of Korea's energy policy has focused on ensuring a stable energy supply to sustain economic growth. However, the new and changing environments have induced the government to seek a new direction in energy policy that supports sustainable development in full consideration of the 3E (Energy, Economy, and Environment).

In terms of the operation of energy market, Korea is undergoing a shift from government-controlled system into market-oriented system in due consideration of the recent world trend of efficiency and privatisation. In addition, since world energy market has rapidly been integrated, Korea is now pursuing an active international role in regional energy cooperation with an open energy system. Korea is set to put more resources in new energy technology development.

In summary, the following four dimensions comprise Korea's energy policy:

- Goal - sustainable development;
- Energy industry - from government-controlled system to market-oriented system;
- International relations - open to outside markets and regional cooperation; and
- Activity - support to technological innovations.

OIL

Due to Korea's complete dependence on oil imports, the government has been trying to secure supplies in the short and long term. To smooth short-term supply disruptions and to meet its obligations to the International Energy Agency, of which Korea became an official member in March 2002, the Korean government plans to increase its strategic oil stocks from 74.6 million barrels (51 days of net imports) in December 2003 to 141 million barrels (72 days of net imports) by 2008. Public and private oil inventories combined could replace about 106 days of net imports, which substantially exceeds the International Energy Agency's requirement of 90 days.

In the longer term, to increase energy security, the Korea National Oil Corporation (KNOC) has been active in exploring and developing oil and gas at home and abroad. To encourage private companies to invest in the development project of overseas resources, the Korean government has expanded its policy of supplying long-term low-interest loans through the Special Account of Energy and Resources. As of the end of 2003, Korea had equity stakes in 55 overseas exploration and production projects in 22 economies including Indonesia, Vietnam, and Peru.

In addition, Korea has been trying to diversify supply channels for crude oil. The number of sourcing economies increased up to 33 in 2002 from 9 in 1980, but the import dependency of crude oil on the Middle East is still high at 73 percent in 2002. Korea is also active in strengthening bilateral cooperation with oil-producing economies as well as multilateral cooperation through the IEA, APEC, ASEAN+3, IEF and ECT, so as to enhance crisis management capabilities. In particular, the government plans to play a leading role in energy resource development and trades in Northeast Asia by creating the collaborative framework on energy cooperation in Northeast Asia.

NATURAL GAS

To reduce the economy's dependence on imported oil, Korea has introduced natural gas-based city gas to the residential sector in the 1980s. Since then, gas use has grown rapidly, replacing coal and oil in the residential sector, to reach 10 percent share of primary energy supply in 2002. Korea Gas Corporation (KOGAS) has monopoly over Korea's natural gas industry including import, storage, transport and wholesale businesses. 32 city gas companies monopolize the gas retail business in each region of the country.

According to "The 6th Plan of Long Term Natural Gas Supply and Demand," which was finalised by MOCIE in November 2002, it is projected that natural gas demand would grow by 4.3 percent per annum from 2002 to 2015. To ensure a stable supply base for gas, KOGAS plans to expand LNG storage capacity to 7.4 MCM (55 units) in 2015 from 3.4 MCM (29 units) in 2003.

The first success story with respect to domestic exploration efforts was the discovery of a commercially viable gas reserve in the Donghae-1 offshore field, southeast of the economy. The field is estimated to hold about 250 BCM of recoverable gas. It plans to provide Ulsan with an annual 400,000 tons until 2018, accounting for 2.2 percent of annual demand in Korea.

ELECTRICITY

Demand for electricity has gone up quite substantially for the last few decades, marking 9.5 percent average annual growth through the 1990s. The installed capacity in 2003 reached 56.1 GW from 21 GW in 1990, more than two and half-fold increase. According to "The 1st Basic Plan of Long Term Electricity Supply and Demand," which was finalised by MOCIE in August 2002, it is projected that electricity demand would grow by 3.3 percent per annum from 2001 to 2015 and a total of 32.7 GW in capacities will be added by 2015. Taking decommissioning into account, it translates into 77 GW of total generation capacity for that year.

In order to rectify an energy supply and demand structure that was overly dependent on oil, construction of oil-fired power plants was strictly controlled and the development of non-oil power sources such as nuclear, coal and gas was promoted. Gas-fired power plants were introduced in 1986 and now account for more electricity production than oil-fuelled plants, with capacity shares being around 26 percent and 8 percent, respectively. While the gas-fired share of generating capacity is expected to stabilise at around the current level, the oil-fired share is expected to decline substantially to under 3 percent during the next 15 years.

Korea has been building nuclear power plants since the 1970s, and nuclear power now accounts for around 40 percent of electricity production. The capacity share of nuclear is envisaged to increase to 34.6 percent in 2015 from 29.2 percent in 2002, surpassing the traditionally largest share of coal-fired capacity. Eight additional nuclear power plants (currently 20 plants) will be built by 2015, including the four currently under construction.

ENERGY MARKET RESTRUCTURING

Since the late 1990s, restructuring of the energy sector has been pursued with the introduction of the principle of free competition to such utility industries as electricity and gas that had been considered natural monopolies. In a move to introduce competition to the electricity industry, the government announced "The Basic Plan for Restructuring the Electricity Industry" in January 1999. Main points of the basic plan include unbundling and privatisation of the Korea Electric Power Corporation (KEPCO), which is the state-owned monopoly company.

Part of the plan has been implemented, including the establishment of the Korea Power Exchange and the Korea Power Commission in April 2001. The power generation part of KEPCO was split into six companies (five thermal generation companies and Korea Hydro & Nuclear Power Co., Ltd.). The five thermal generation companies that split from KEPCO will be privatised in stages. Currently, privatisation is in progress for the first of the five companies, Korea South-East Power.

Along with electricity market restructuring, the Korean government developed "The Basic Plan for Restructuring the Gas Industry" in November 1999. The plan outlines a scheme to introduce competition into the import and wholesale gas business. The government plans to enact the relevant law on restructuring based on agreement by labor, management and government.

With regard to introducing competition into KOGAS's import/wholesale sectors, the final decision will be made on whether to split the sectors from KOGAS or to introduce new companies, following sufficient discussion among interested parties. Given the strong public interest on this sector, the existing public utility system will be maintained. As for the retail sector, which is currently operated under a monopoly system by each region, competition will be introduced in stages, in consideration of the progress made in the wholesale sector.

ENERGY CONSERVATION AND EFFICIENCY PROMOTION

To establish a low energy-consuming economy, the Korean government has promoted energy conservation and enhanced efficiency at the consumption stage. In the industrial sector, in order to minimise energy losses and to achieve an energy-saving industry structure, the Korean government enforced stringent administrative regulations on energy management in combination with provision of free consulting services to small enterprises. In addition, the government has been developing voluntary agreements on energy saving with large energy-consuming enterprises that consume more than 2 ktoe. The number of such agreements increased to 699 in 2003 from 67 in 1999.

In the transport sector, tax and fee incentives are provided to purchasing small cars less than 800 CC to increase the use of low energy-consuming vehicles. The government enforced the regulation that automobile industries should improve the energy efficiency of vehicles by 20 percent from the 1999 levels by 2009. In the public sector, all agencies have to reduce 3 percent of energy consumption by 2006, from the 2003 levels. Adding to this, newly constructed public buildings are obliged to adopt the High Efficiency Energy-Using Appliance certified by MOCIE.

Korea has recently launched several conservation programmes aimed at the residential and commercial sectors. At present there are three major energy efficiency programmes in operation: 1) the Energy Efficiency Standards and Labelling Programme which began in 1992 and targets some household appliances, lighting and automobiles; 2) the Certification of High Efficiency Energy-Using Appliance Programme implemented in December 1996; and 3) the Energy-Saving Office Equipment and Home Electronics Programme which began in April 1999. One key objective of these programmes is to give incentives to manufacturers to improve the energy efficiency of their products. Another key objective is to induce consumers to purchase more energy efficient products among those available in the marketplace.

District heating and cogeneration for industrial parks, factories and large buildings were also encouraged. As of the end of 2003, 9.5 percent of total households, or 1.2 million households, were supplied by district heating. Further, more rational energy price structure has continuously been developed and implemented to facilitate the efficient use of energy. Aided by these policies, the GDP elasticity of energy consumption has declined from 1.32 on average in the 1990s to 0.83 in 2002.

NEW AND RENEWABLE ENERGY

To establish an environment-friendly energy system, the Korean government plans to increase the share of new and renewable energy to 5 percent in total primary energy consumption by 2011. As of 2002, the share stood at approximately 1.4 percent, which is quite low compared to that of other advanced countries. To develop new and renewable energy technologies, the government has selected three major areas, which have viable market potentials, such as hydrogen fuel cell, photovoltaic, and wind power, and plans to concentrate support in these areas.

To disseminate new and renewable energy, the government also plans to strengthen its support for this energy source. As of the end of 2003, the number of Green Villages that are energy self-sufficient thanks to new and renewable energy has been increased to five. Since May 2002, MOCIE has implemented the price support program to compensate the difference between power generation cost and selling price of new and renewable energy. In addition, the government made it mandatory for the installation of new and renewable energy facilities in March 2004, for all new public buildings that exceed a certain size.

NOTABLE ENERGY DEVELOPMENTS

KOREA BEGAN ITS 1ST COMMERCIAL PRODUCTION OF GAS

Korea's dream of becoming an oil and natural-gas-producing country was finally realized on 5 November 2004, with the first commercial production of natural gas at the Donghae-1 field. This marks a successful outcome of 40 years of attempts to produce gas on its own since 1964. With the gas development, Korea has become one of the 95 oil-producing economies. Donghae-1 gas field is located in the East Sea about 58 km off Ulsan on the southeast coast and is 150 meters deep. It is estimated to hold about 250 BCM of recoverable gas, which is about 5 million metric tons when converted into liquefied natural gas.

KNOC detected the potential for natural gas in the East Sea in 1998 and established a production plant in 2002. It plans to provide Ulsan with an annual 400,000 tons until 2018, which accounts for 2.2 percent of annual demand in Korea. According to KNOC, 400,000 tons is enough to power about 340,000 household units annually. More than anything, the field proves that Korea is equipped with the technology to detect and produce gas on its own, not to mention that it can help secure supply amid the growing demand.

PRIVATE COMPANIES TO DIRECTLY IMPORT LNG FOR THEIR OWN USE

Pohang Iron and Steel Company (POSCO), the leading steel company in Korea, has become the first local private company to obtain a contract for direct LNG importation with an overseas supplier. In July 2004 POSCO signed a contract with the Tangguh LNG consortium led by BP for importing 550,000 tons of LNG per annum for the next 20 years starting from 2005. The LNG will be supplied to POSCO’s power plants and steel mills at Pohang and Gwangyang. POSCO expects that the deal will result in a reduction of about 60 billion won (US$55 million) in LNG costs for the company per annum. The contract stipulated the ceiling for LNG prices in order to evade possible price hikes resulting from rising oil prices in the future.

LNG supply to the domestic market has been monopolized by state-run KOGAS. In 2001, however, entities other than KOGAS were allowed to import LNG for their own use provided they own LNG storage facilities of over 100,000 cubic metres or obtain LNG storage rights from others. In order to take advantage of this opportunity, POSCO began building an LNG terminal at Gwangyang in 2002. The LNG terminal will be able to store 1.7 million tons of LNG, and its construction is to be completed by June 2005. In addition, MOCIE has allowed the power generation companies of KEPCO to bid for LNG supplies of their own use in November 2004.

ESTABLISHMENT OF THE PROJECT GROUPS TO DEVELOP NRE TECHNOLOGIES

In May 2004, Korea established the project groups to develop hydrogen fuel cell, photovoltaic, and wind power among new and renewable energy sources. They are comprised of 1,000 experts from industries, universities, research institutes, and NGO. The Korean government announced its plans to operate the project groups by investing approximately US$227 million by 2008 in developing hydrogen fuel cell, photovoltaic, and wind power. This is the largest single project for a government research and development project.

Through such support, the government plans by 2012 to distribute 3,200 automobiles that run on hydrogen fuel cell, to distribute 100,000 photovoltaic generation systems in households, and to establish wind power generation systems with a total capacity of 2,250 MW.

SPLITTING DISTRIBUTION SECTOR FROM KEPCO SUSPENDED

The Korean government on June 17, 2004 decided to discard a plan to divide the power distribution part of KEPCO into six companies. The decision was made after the Tripartite Commission recommended that the distribution sector remain a part of the national utility. Instead, the government will operate power distribution division of KEPCO as an independent unit and promote internal competition among its operational units in a bid to ensure the efficiency of the power industry. However, MOCIE stated that it would continue to push for the ongoing privatisation of KEPCO's thermal generation companies.

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MALAYSIA

INTRODUCTION

Malaysia is located in Southeast Asia. Its 330,242 square kilometres of territory consist of Peninsular Malaysia and the Sabah and Sarawak states on the island of Borneo. The total population of Malaysia was 24.3 million in 2002 with an average annual growth of 2.1 percent.

GDP grew at an average of 7 percent per year from 1990 to 2000. After experiencing a sluggish growth in 2001, the Malaysian economy rebounded with a strong 5.2 percent growth in 2003[18]. Prospects for a higher growth were affected by a slower GDP growth in the US, the largest trading partner. Global events such as tension in the Middle East and the slump in equity markets following revelation of accounting malpractices in several corporate giants had also eroded investors' confidence and contributed to a slower growth in 2002. The growth, which is largely driven by better demand for housing, motor vehicles as well as increased public spending on defense reached US$191 billion or US$7,898 per capita (both in 1995 US$ at PPP).

Malaysia is well endowed with conventional energy resources such as oil, gas and coal, as well as renewables such as hydro, biomass and solar energy. As of December 2002, reserves included 4.23 billion barrels of oil, 87.3 tscf of gas, 1,483.06 million tons of coal, and 29,000 MW of hydropower capacity. Malaysia is a net energy exporter. Crude oil, LNG and petroleum products contributed 10.5 percent of the economy's export earnings in 2004.[19]

Table 19 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	330,242	Oil (Bbl) - Proven	4.23
Population (million)	24.31	Gas (Tscf) - Proven	87.30
GDP Billion US$ (1995 US$ at PPP)	191.97	Coal (Mt) -Recoverable	1,483.06
GDP per capita (1995 US$ at PPP)	7,898		

Source: Energy Data and Modelling Centre, IEEJ. *National Energy Balance Malaysia, 2002

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary supply in 2002 was 52,995 ktoe. Gas accounted for 49 percent of total primary supply, while oil, coal and others accounted for 42 percent, 8 percent and 1 percent respectively. Most of the coal used in Malaysia was imported.

Malaysia produced 37 million tonnes of crude oil in 2002. Almost 87 percent of oil produced was exported to markets in Japan, Thailand, Korea, and Singapore. Most of Malaysia's oil fields are located offshore near Peninsular Malaysia. The Tapis field is the source of more than half of Malaysian production. In view of the declining domestic reserves, Petronas, the state oil and gas company, is investing in exploration and production projects outside of Malaysia. At the end of March 2003, Petronas had set up operations in 34 countries with 39 exploration and production

[18] The Malaysian Economy in Figures 2004, Economic Planning Unit, Malaysia

[19] Department of Statistics Malaysia, http://www.statistics.gov.my/English/rpm/rpmnovember04.htm

ventures in 21 countries. During the same period, Petronas had also signed 17 new production-sharing-contracts, bringing the current total to 57 ventures in 25 countries. Petronas' international operations contributed 75 percent of the company's group revenue for financial year 2002/2003.

Gas production in Malaysia reached about 45.2 Mtoe in 2002, an increase of 183 percent from 1990. Forty one percent of this gas was exported, usually in the form of liquefied natural gas (LNG), to Japan, Korea and Chinese Taipei. A small percentage of the gas is exported to Singapore by pipeline. Gas is used domestically for electricity generation and as a feedstock in the petrochemicals industry.

In 2002, total electricity generation was 74,196 GWh. Thermal generation, mostly from natural gas, accounted for 92 percent of production and hydropower for the remaining 8 percent.

Table 20 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	80,519	Industry Sector	12,853	Total	74,196
Net Imports & Other	(27,524)	Transport Sector	13,441	Thermal	68,897
Total PES	52,995	Other Sectors	6,995	Hydro	5,300
Coal	4,133	Total FEC	33,289	Nuclear	0
Oil	22,308	Coal	1,086	Others	0
Gas	26,101	Oil	20,638		
Others	453	Gas	5,643		
		Electricity & Others	5,922		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

FINAL ENERGY CONSUMPTION

In 2002, total final energy consumption in Malaysia was about 33 Mtoe. The transport sector consumed 40 percent of this total, followed by the industrial sector at 38 percent and other sectors (agriculture, residential/commercial and non-energy) at 21 percent. By fuel source, petroleum products contributed the largest share with 64 percent of consumption followed by electricity (18 percent), gas (15 percent) and coal and coke (3 percent).

POLICY OVERVIEW

The Prime Minister's Department, the Ministry of Energy, Water and Communications and the Energy Commission are responsible for formulating Malaysia's Energy Policy and for regulating the quality of energy service. The Ministry of International Trade and Industry (MITI) and the Ministry of Domestic Trade and Consumers Affairs (MDTCA), through the Petroleum Regulations of 1974 (amended in 1975 and 1981), are vested with powers to regulate downstream petroleum activities. MITI, through the Malaysia Industrial Development Authority (MIDA), issues licences for the processing and refining of petroleum and the manufacture of petrochemical products. MDTCA issues licences for the marketing and distribution of petroleum products.

Malaysia's energy policies took shape during the early 1970s after the 1973 world oil crisis. The cornerstones of Malaysian petroleum policy were fleshed out in the Petroleum Development Act (PDA) of 1974 and the National Petroleum Policy of 1975. This legislation aims to regulate the oil and gas industry to achieve economic development needs. It outlines the following policy goals:

- Making sure adequate energy supplies at reasonable prices are available to support national economic development objectives;

- Promoting greater Malaysian ownership and providing a favourable investment climate, including creating opportunities for downstream industries; and
- Developing oil and gas resources at a socially and economically optimal pace, while conserving these non-renewable assets and protecting the environment.

The PDA established Petronas as a state-owned enterprise with exclusive ownership, exploration and production rights. It comes under the direct purview of the Prime Minister and is responsible for planning, investment and regulation of all up-stream activities. The PDA also introduced a system of production sharing contracts (PSCs) to replace the previous system of concessions. In these ways, the oil and gas sector was streamlined to ensure greater Malaysian participation in the ownership, management and control of oil and gas resources and activities.

NATIONAL ENERGY POLICY OBJECTIVES

In 1979, Malaysia's energy policy principles were broadly defined in terms of three policy objectives. These policy objectives are instrumental in guiding the formulation of five-year development plans. They are:

- *The Supply Objective:* To ensure the provision of adequate, secure and cost-effective energy supplies by developing indigenous energy resources, both non-renewable and renewable, using least-cost options, and diversifying supply sources both within and outside the economy;
- *The Utilisation Objective:* To promote the efficient utilisation of energy and the elimination of wasteful and non-productive patterns of energy consumption; and
- *The Environment Objective:* To minimise the negative impacts of energy production, transportation, conversion, utilisation and consumption on the environment.

THE SUPPLY OBJECTIVE

In pursuing the supply objective, Malaysia has implemented polices to extend the life of non-renewable energy resources such as oil and gas and to reduce dependence on oil by encouraging the use of other energy forms.

The National Depletion Policy of 1980 was developed to preserve declining oil reserves. The policy, aimed at major oil fields of over 400 million barrels of oil initially in place (OIIP), restricted production to 1.75 percent of OIIP. However, the initial restriction proved too conservative, and in 1985, the ceiling was raised to 3 percent of OIIP. Due to this policy, total production of crude oil is limited to about 650,000 barrels per day. At the current production rate, proven oil reserves are expected to last another 18 years. The National Depletion Policy was later extended from crude oil to include natural gas reserves. An upper limit of 56.6 MCM per day (2,000 million standard cubic feet per day) has been imposed in Peninsular Malaysia. At the current rate of production, known natural gas reserves are expected to last for about 35 years.

In 1981, to complement the National Depletion Policy and ensure the reliability of supply, the government adopted the Four-Fuel Strategy. This strategy was designed to reduce the economy's dependence on oil, and its goal is to achieve a balanced energy supply mix of oil, gas, hydropower and coal. As much as possible, development of domestic resources is encouraged to enhance security of supply. Under this initiative, oil share has fallen significantly. Consumers, particularly the power sector, have substituted away from oil towards natural gas, which is available domestically and is environmentally-friendly compared with other fossil fuels. In June 1999, the Prime Minister announced that the Four-Fuel Strategy would be revised to become a Five-Fuel Strategy. Recognising the potential for renewable energy resources and emphasising its commitment to promote renewables and preserve the environment, Malaysia adopted renewables as its "fifth fuel."

THE UTILISATION OBJECTIVE

There have been limited initiatives to pursue the utilisation objective. Demand side management initiatives by the utilities, particularly through tariff incentives, have encouraged more efficient use of energy. Most energy efficiency initiatives are aimed at large energy consumers such as industry. The Malaysian Industrial Energy Efficiency Improvement Programme launched in July 1999 is a collaborative effort between the government of Malaysia and the United Nation Development Programme (UNDP)/Global Environmental Facility (GEF). This 4-year project aims to remove energy efficiency barriers, encourage rational use and improve energy efficiency in Malaysian industries. Other industrial energy efficiency initiatives currently being planned include an energy auditing programme, an energy service companies support programme and a technology demonstration programme.

In 1998 the Malaysia Energy Centre (MEC) was established as an independent non-profit entity to formulate, coordinate and manage energy-related research and development programmes and promote the development of indigenous technologies. Officially launched by the Prime Minister during the World Renewable Energy Congress in June 1999, in Kuala Lumpur, one important role of MEC is to promote renewable energy and energy efficiency programmes in Malaysia and to formulate innovative financing mechanisms to make these projects commercially viable.

THE ENVIRONMENT OBJECTIVE

In support of the environment objective, all major energy development projects are subjected to a mandatory environmental impact assessment (EIA) requirement. Recently, Malaysia was evaluated to be the third cleanest economy in Asia behind Japan and Singapore.

OIL AND GAS SECTOR

The outlook for the oil and gas sector in Malaysia remains positive despite predictions from many experts that there will be very few major oil discoveries. In July 2002, Murphy Oil declared the discovery of deepwater oil off the coast of Sabah state in the Kikeh prospect (Block K) indicating an estimated reserve of between 400 and 700 million barrels[20]. This is also Malaysia's first deepwater oil discovery and will prove to be a significant boost to the declining oil reserve of the economy. The Malaysian government has also stated that it will continue its policy of developing the economy's hydrocarbon resources, with particular emphasis on the development of gas fields.

Malaysia has the 24th largest crude oil reserves and the 13th largest gas reserves in the world[21]. Combined, Malaysia has total domestic reserves of 19.345 billion barrels of oil equivalent (boe): 75 percent gas and 25 percent oil. As at 1 January 2004, Malaysia's crude oil reserves (including condensates) stood at 4.841 billion barrels and natural gas reserves stood at 87 tcf[22] (14,504 million barrels of oil equivalent). Gas reserves remain three times the size of oil reserves.

Malaysia's total oil and gas production for the year ending March 2004 was 576.9 million barrels of oil equivalent: 47.6 percent oil and condensate and 52.4 percent gas. Total crude oil and condensate production was 274.6 million barrels and total gas production was 1.81 tcf (302.3 million barrels of oil equivalent). Average daily production rates were 750,200 bpd and 4,944 mmscfd of gas. At the current rates of production, Malaysia's oil and gas reserves are expected to last for another 18 and 35 years respectively.

Malaysia has 494,183km² of acreage available for oil and gas exploration: 337,167km² in offshore continental shelf areas; 63,968km² in deepwater; and 93,048km² onshore. This acreage has

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[20] UK Trade & Investment, 2004, http://www.trade.uktradeinvest.gov.uk/oilandgas/malaysia/profile/overview.shtml

[21] PETRONAS, http://www.petronas.com.my/internet/corp/centralrep2.nsf/f0d5fd0d9c25fbdd48256ae90025ee04/2b3caac313db597148256be60015256c/$FILE/Financial%20Highlights%202004.pdf

[22] UK Trade & Investment, 2004

traditionally been split into 54 blocks, but recently some of the deepwater blocks have been sub-divided - into deepwater and ultra-deepwater blocks - to create a present total of 65 blocks. Of these 65 blocks, 30 are currently operated or being developed by Petronas Carigali (the E&P arm of the national oil company, PETRONAS) and 11 other oil companies/consortiums. One more block is under a Technical Evaluation Agreement. In percentage terms, approximately 38 percent of Malaysia's acreage is under PSC terms, while the remaining 62 percent of acreage is open.

Until 1993, exploration and production activities took place in the broad continental shelf offshore of the states of Sabah and Sarawak in East Malaysia and offshore of the state of Terengganu on the East Coast of Peninsular Malaysia. The economy's deeper offshore areas, with water depths of 200 metres or more, have only recently been opened to oil and gas exploration. Within the continental shelf, five major sedimentary basins in Malaysia have been identified as petroleum bearing. The water depth of these areas is 25 to 200 metres. To date, exploration activities in the continental shelf have resulted in discoveries of 323 oil and gas fields. At present, 70 oil and gas fields are in production, with several other fields (oil and gas) under development and/or due to begin operations in the near future.

Petronas carries out exploration, development and production activities in Malaysia through production sharing contracts (PSCs) with international oil and gas companies. Current PSCs are based on the "revenue over cost" concept (R/C PSC) to encourage additional investment in Malaysia's upstream sector. The R/C PSC allows PSC Contractors to accelerate their cost recovery if they perform within certain cost targets. The underlying principle is to allow the PSC Contractor a higher share of production when the Contractor's profitability is low and to increase Petronas' share of production when the Contractor's profitability improves. The contractor's profitability at any time, is measured by the "R/C Index" (ratio of the contractor's cumulative revenue over the contractor's cumulative costs).

There are a total of 11 oil and gas companies/consortia (those that are undertaking exploration work or producing) active in the Malaysian oil and gas industry. The six producing oil and gas companies in Malaysia are Petronas Carigali, ExxonMobil, Shell, Murphy Oil, Talisman Energy and Nippon Oil. The five other companies and consortiums that are in the exploration phase of their PSC licences are Amerada Hess, CTOC (a joint-venture between Petronas Carigali and Amerada Hess (formerly Triton Oil)), CS Mutiara Petroleum (a joint-venture between Petronas Carigali and Shell), PCPP Operating Company (a joint-venture between Petronas Carigali, Pertamina and PetroVietnam) and Newfield Exploration Company. Newfield have only recently entered the upstream Malaysian oil and gas sector when they signed a PSC with Petronas in May 2004.

ExxonMobil is the largest crude oil producer in Malaysia producing nearly half of Malaysia's crude oil. Their current daily production stands at 280,000 barrels of crude oil, 15,000 barrels of condensate and 1.4 billion cubic feet of gas (70 percent of Peninsular Malaysia's daily natural gas needs). ExxonMobil Exploration and Production Malaysia Inc. (EMEPMI) has 16 producing fields offshore Terengganu with 36 oil and gas platforms. The Tapis oilfield is the largest in Malaysia. A further third of its production comes from the Seligi field.

ExxonMobil's most recent developments have been the Bintang Field development in February 2003 and the Tapis F satellite platform in February 2004. The Bintang Field is expected to produce approximately 1 tcf of gas with a peak production rate of 355 million cubic feet per day. The total project development costs for Bintang are estimated at US$80 million excluding drilling costs. Tapis F is the seventh facility in the Tapis field, located 200km offshore Peninsular Malaysia. Tapis F is tied-in to Tapis A and Tapis B and will produce approximately 8 million barrels of oil. Crude oil production is expected to peak at around 6,000 bpd. Total project development costs were US$24 million excluding drilling costs.

Shell has 18 PSCs, of which 14 of these are operated, and 1 Technical Evaluation Agreement (with Petronas Carigali for block SK303). Their current oil and liquids production is approximately 228,000 barrels per day and gas production is approximately 2.5 billion cubic feet per day. Most of Shell's operations are in East Malaysia: Sarawak for gas and Sabah for oil. In Sarawak, Shell operates the Balingian field for crude oil, the M1 and M3 fields for gas (for MLNG2) and the

Central Luconia fields (F6, F23 & E11) for unassociated gas. In Sabah, Shell operates the Kinabalu field for both oil and gas, and the St Joseph, South Furious, SF30 and Barton fields for oil.

Shell has signed a PSC with Petronas for Block PM303 (offshore Terengganu), which marks their entry into E & P offshore Peninsular Malaysia. They have also invested with Petronas Carigali on a 50/50 basis in a new operating company, CS Mutiara Petroleum, which operates Blocks PM301 and PM302, offshore Peninsular Malaysia. Unlike ExxonMobil, Shell is actively undertaking exploration in Malaysia.

Shell's most recent upstream project in Malaysia was the B11 P-A project, which delivered its first gas in November 2003. The 600 mmscfd capacity production platform will supply gas to MLNG2 at Bintulu. The B11 gas field was discovered in 1980 and is located 170km north of Bintulu, offshore Sarawak. Shell Malaysia is the operator and holds 50 percent equity. Petronas Carigali holds the remaining 50 percent.

MAJOR DISCOVERIES

In deepwater, in July 2002, Murphy Oil announced they had drilled a significant oil discovery in the Kikeh prospect (Block K). The well encountered several hundred feet of high quality oil reservoirs and reserves are estimated to be between 400 and 700 million barrels. Murphy Oil is currently moving through the development phase and hopes to bring the Kikeh field into production in 2007. Located in almost 1300 metres of water, the Kikeh discovery lies in the southern part of Block K and is the first major deepwater oil discovery made in Malaysia. Since the Kikeh discovery, several other deepwater fields (both oil and gas) have been discovered with recoverable reserves estimated at approximately 500 million barrels of oil and 5 tcf of gas. The deepwater fields have been drilled in water depths of 200 to 1300 metres.

GAS DEVELOPMENT AND UTILISATION

Development and utilisation of gas continues to be the main thrust of Petronas' activities to exploit the economy's substantial gas reserves through value-adding projects. Completion of Gas Processing Plant 6 has expanded the capacity of the Peninsular Gas Utilisation (PGU) system by one third, to 2,000 million standard cubic feet per day.

To ensure the sufficiency of Malaysia's natural gas supply and prolong the economic life of domestic gas reserves, Petronas has signed an agreement with Pertamina to purchase gas from Indonesia's West Natuna Sea area amounting to 1.5 TCF over a 20-year period. The first gas delivery was received via a pipeline to Petronas' Duyong Gas Field facilities located offshore Terengganu on 8 August 2002. The 100-km pipeline is the latest component of the growing interconnection of cross-border gas infrastructure in ASEAN and charts another important step towards the realisation of the Trans-ASEAN Gas Pipeline (TAGP). Interconnection with existing and future infrastructure in the gas-prolific areas of ASEAN will enhance security of gas supply to meet the region's increasing energy requirements.

Petronas and Pertamina signed a Memorandum of Understanding (MoU) on 8 August 2002 to facilitate a Gas Sales Agreement (GSA) from South Sumatra to Malaysia. The GSA, which is expected to be concluded by end 2002, will result in the supply of 300 million standard cubic feet of gas per day to Malaysia for 20 years. Delivery of the gas is scheduled to commence in early 2005. Work is also progressing to link the PGU system to the Trans-Thailand Malaysia Pipeline project. The project will add another building block to the emerging Trans-ASEAN Gas grid.

Petronas' international gas production comes from Myanmar (Yetagun field Blocks M12, M13 and M14) and Iran (South Pars Phases 2 and 3). Currently, the interests of the parties in the Yetagun field and the gas pipeline consist of Petronas International Capital Ltd (PICL, 30 percent), Premier Petroleum Myanmar (27 percent), Nippon Oil (14 percent), PTTEPI (14 percent) and MOGE (15 percent). In September 2002, PICL entered into an agreement to relinquish its 25 percent share of Premier's stock and pay Premier US$359 million in cash and debt in return for Premier's stake in Yetagun and Premier's 15 percent interest in Natuna Sea Block A in Indonesia.

NATURAL GAS VEHICLE (NGV) PROGRAMME

Petronas introduced a natural gas vehicle (NGV) programme in 1986 as part of its efforts to add value to the economy's abundant natural resources. Today, the company has close to 4,000 NGVs, including 1,000 units of Enviro 2000, in and around Kuala Lumpur (capital city). These are served by 21 NGV refuelling stations, which receive gas through pipeline or trailer systems. Exhaust emissions from these NGVs is well below EURO II limits on carbon monoxide, hydrocarbon and nitrogen oxide. The NGVs can travel up to 480 km on a full tank of natural gas, so its range is equivalent to that of a petrol powered vehicle. More importantly, these NGVs significantly lower fuel expense.

Petronas' subsidiary, Petronas NGV Sdn. Bhd., signed a three-year MoU with the Petroleum Authority of Thailand (PTT) on 1 June 2001 to introduce the Enviro 2000 natural gas-powered vehicle in Thailand. The MoU is part of a long-term approach to be undertaken by both parties to promote NGV businesses in Thailand. Under the MoU, Petronas NGV will embark upon a six-month field demonstration on the roads in Bangkok involving five Enviro 2000 NGVs like those that have served as taxis in Kuala Lumpur since 1998. The vehicles are expected to be used both by the riding public and government officials in Thailand. The field demonstration will contribute to Petronas' plans to promote and create market awareness of NGVs and Enviro 2000 outside Malaysia, in line with its continuous efforts to increase the use of gas as a cleaner, cheaper and environment-friendly alternative fuel.

The terms of the MoU also call for both parties to undertake a joint feasibility study on the development of other related NGV businesses in Thailand. These would include areas like NGV refuelling station construction and operation, promotion and marketing of NGV and production of bi-fuel and monofuel NGV vehicles in Thailand. Upon request, Petronas NGV will provide technical assistance and expertise to PTT in relation to the development of regulations and safety standards for NGV vehicles, refuelling stations and other related matters.

RENEWABLE ENERGY (RE)

To enhance excessive dependency on natural gas, which today accounts for 80 percent of the fuel used for power generation, the government has set an objective to make renewable energy (RE) account for 5 percent of power supply or some 600 MW of generating capacity by 2005. Ways are being studied to efficiently utilise the abundant RE resources available locally such as the biomass technology for transformation of oil palm wastes to fuel. These steps are in line with the government's decision to intensify development of RE as the fifth fuel resources under the economy's Fuel Diversification Policy as stipulated in the Eighth Malaysia Plan, in addition to gas, oil, hydropower and coal. A special committee has been established in the Ministry of Energy, Communications and Multimedia to coordinate implementation of the RE intensification strategy.

SMALL RENEWABLE ENERGY POWER PROGRAMME

To further support the efforts to diversify energy sources, the Small Renewable Energy Power (SREP) Programme was launched in May 2001 to gain first hand experience of feeding renewable energy-based electricity into the national grid. This programme was initiated with the objective of promoting the wider use of the huge amount of RE resources available in Malaysia particularly biomass (oil palm and wood wastes). A secretariat for the programme has been set up at the Ministry's Department of Electricity and Gas Supply to facilitate industry participation.

SREP projects are defined as power generating projects that are capable of converting RE resources into electricity. The utilisation of all types of RE including biomass, biogas, municipal waste, solar, mini hydro and wind is allowed under this programme. The size of a power plant can be greater than 10 MW, but the maximum capacity allowed for power export to the distribution grid must not exceed 10 MW. Small power generation plants that utilise RE can apply to sell to the utility through a distribution grid. Project developers are required to negotiate directly with the relevant utility on all aspects of the Renewable Electricity Purchase Agreement, including the selling price on a willing-seller, willing buyer and take-and-pay basis.

EDUCATION AND TRAINING IN RENEWABLE ENERGY AND ENERGY EFFICIENCY

Malaysia has established the Centre for Education and Training in Renewable Energy and Energy Efficiency (CETREE) aimed at increasing public awareness of the positive attributes of RE and energy efficiency measures. Under the Eighth Malaysia Plan, CETREE had been recognised as a centre to assist the school and university education sectors in upgrading knowledge and awareness of renewable energy and energy efficiency.

ELECTRICITY

In anticipation of the increase in demand for power resulting in the need for additional capacity from 2008 onwards, the government revived the Bakun Hydroelectric Project in early 2002, albeit at a smaller scale than originally planned. Sarawak Hidro Sdn Bhd, a company under the Ministry of Finance Incorporated, has been designated as the project implementing agency. Thirteen consortia have been short listed for the pre-qualified tender for the civil works of the RM9 billion dam project. When completed, Bakun will have a total capacity of 2,400MW for use in Sabah, Sarawak, Brunei Darussalam and possibly also Kalimantan.

As a first step in the Bakun hydro project, Sarawak Hidro has awarded a contract for construction of a coffer dam to Global Upline Sdn Bhd. The coffer dam will create a dry area across the river so that the main dam can be built. The project's civil works, estimated to cost between RM2 billion and RM3 billion, will also include the main dam, spillway, power tunnel, power tower and ancillary roads. Construction of the Bakun dam is expected to commence in the third quarter of 2003, following announcement of a winning bid by the Ministry of Finance.

Agreements were signed by TNB in July 2001 for construction of coal-fired power plants by two independent power producers, Jimah Power Sdn Bhd and SKS Ventures Sdn Bhd. These coal-fired power plants are in line with the economy's efforts to reduce reliance on natural gas. The development of the two power plants will be staggered, with some units coming on stream in 2006 and others in 2007. Jimah's power plants will have a final capacity of 1400 MW to be built in Mukim Jimah, Negeri Sembilan. SKS Ventures' power plants will have a final capacity of 2100 MW to be built in Pulau Bunting, Kedah. TNB has paved the way for detailed negotiations on the power purchasing agreement (PPA) with the companies. TNB has also signed a PPA with Panglima Power Sdn Bhd for the installation of a plant in Teluk Gong, Malacca.

NOTABLE ENERGY DEVELOPMENTS[23]

The peak electricity demand in Malaysia grew at a rate of 5.8 percent per year, reaching 12,637MW in 2003. In line with the positive outlook of the national economy, peak demand for electricity is expected to grow at a rate of 7.2 percent annually, to reach 14,531MW in 2005. The electricity generation installed capacity in December 2003 was 19,253.8MW, with the bulk of capacity expansion taking place in Peninsular Malaysia, at 17,596.4MW.

In the key sectors of Malaysian economy, oil and gas make up to 80 percent of the primary energy supply. The economy has an ample reserve margin of about 30 percent currently, to guarantee sufficient supply of electricity. This reserve capacity is expected to be reduced in the future. Malaysia has been fortunate in that it possesses an abundant energy resource base in the form of oil and natural gas. However, these being fossil fuels have a life span and therefore Malaysia has given importance to implementing Energy Efficiency measures and developing Renewable Energy resources. By applying energy conservation, the economy could save about

[23] MALAYSIA, Statement on Notable Energy Development since EWG 25 (June 2003)

RM1.6 billion[24] or 10 percent of total energy consumption. The Government is encouraging the use of renewable energy such as solar power, hydro, geothermal and agricultural biomass to ensure the sustainability of energy resources. The target is 5 percent of energy generated through renewable energy by 2005.

FIVE FUEL POLICY

Malaysia has a Five-Fuel Diversification Policy of gas, hydro, coal, oil and renewable with emphasis given to biomass, biogas, municipal waste, solar and mini hydro. The National Energy Diversification Policy makes it incumbent to diversify its energy resources to avoid over dependence on one type of fuel. In the past there were over-dependent on oil with almost 80 percent of it being used in power generation. Presently around 70 percent of power generation is fuelled by gas. This over-dependence on gas may be reduced in the future and the share of coal in power generation is expected to increase.

RENEWABLE ENERGY INITIATIVES

In Malaysia, biomass together with solar (thermal) energy account for more than 90 percent of the RE potential. It is estimated that by achieving a 5 percent share of renewable energy (RE) in electricity generation by 2005, Malaysia can save RM2.8 billion over a 20-year period just by reducing coal imports. From an environmental perspective, the utilization of RE would result in a net reduction of 70 million tonnes of carbon dioxide by 2020 if RE-generated electricity can sustain a 5 percent share from 2005.

SMALL RENEWABLE ENERGY PROJECT (SREP)

The Small Renewable Energy Project (SREP) program was launched on 11 May 2001 aimed at fast-tracking small-scale power plant projects utilising renewable sources such as wood based residues, palm oil biomass, mill residues and hydropower as fuels in power generation. A SREP developer can apply to sell electricity to the utility company through the distribution grid system and are allowed to export up to a maximum of 10MW. As of December 2003, 53 applications were approved with a capacity of 283.9MW.

GRID CONNECTED PALM OIL BIOMASS POWER GENERATION AND COGENERATION

A national programme on grid-connected Palm Oil Biomass Power Generation and co-generation was launched in October 2002. The goal of this project is to reduce the rate of greenhouse gas emissions from fossil fuel-fired combustion processes via the utilisation of palm oil waste. To develop energy potentials from biomass waste, the program envisages a two-stage implementation covering five project components over a five-year period (2002-2007): These components are information services and awareness enhancement, policy studies and capacity building, financial assistance for biomass energy projects, demonstration projects and biomass energy technology development. A website is currently being developed. The site for the first demonstration project is also being identified.

FISCAL INCENTIVES FOR RENEWABLE ENERGY

Fiscal incentives were given in the 2003 Budget for the development of renewable energy resources, which include palm oil mill or estate wastes, rice mill wastes, sugar cane mill wastes, timber/sawmill wastes, paper recycling mill wastes, municipal wastes and biogas (from landfill, palm oil mill effluent, animal waste and others). The above incentives also apply to the use of small hydropower not exceeding 10MW and solar power. The incentives are up to 2005.

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[24] US$1 = RM3.80

ENERGY EFFICIENCY (EE) INITIATIVES

ENERGY EFFICIENCY FISCAL INCENTIVES

Fiscal incentives for energy efficiency (EE) initiatives were also provided for in the 2003 National Budget. The incentives would be up to the year 2005.

MALAYSIAN INDUSTRIAL ENERGY EFFICIENCY IMPROVEMENT PROGRAMME (MIEEIP)

The MIEEIP project is a major national EE programme and is co-funded by the Government of Malaysia, UNDP-Global Environment Facility (GEF) and the private sector in Malaysia with a total cost of US$20.8 million. Its main goal is to remove barriers to efficient energy use in the industrial sector in Malaysia. The focus of MIEEIP is on 8 energy-intensive manufacturing sub-sectors namely wood, food, glass, cement, rubber, pulp & paper, iron & steel, and ceramic.

An Energy Efficiency Project Lending Scheme (EEPLS) has also been established with GEF contributing RM4 million and the government of Malaysia another RM4 million. The EEPLS is to provide soft loans to energy service companies (ESCOs) and industries to implement EE projects.

The Master Services Agreement (MESA) for the first demonstration project was signed on 7 April 2003 between a wood-based factory and an ESCO. It is expected to reduce the company's energy bill by 90 percent by changing the oil-based boiler to a wood waste boiler. The factory could use its wood dust as a fuel source. The second project between a cement company and an ESCO was signed in April 2004.

ENERGY EFFICIENCY IN BUILDINGS

The new office premises of the Ministry of Energy, Communications and Multimedia (MECM) in Putrajaya, was completed in February 2004.

It has been designed as an EE or "Low Energy Office (LEO) Building" and is the first, large Government building to be specifically designed with the EE, and cost-effective features. It is to be a showcase building to demonstrate that EE buildings can be built without incurring excessive construction costs. It is hoped that other public and private sector buildings replicate such EE measures in their buildings.

The design of the LEO building predicts an economically viable, low energy use building, using proven technology, with a cost premium that permits capital outlay recovery within 10 years, and without affecting the project construction schedule target. The design concept translates to reduce the MECM building's energy use from a typical value of about 250 kilowatt-hour per square meter per annum, for air conditioned buildings in Malaysia, to less than 135 kilowatt-hour per square meter a year. This is in line with the proposed National Building Code, which forms a part of the revised National Uniform Building By-Laws (UBBL). A more detailed analysis indicates that energy use could be reduced even further, to about 100 kilowatt-hour per square meter per annum. The incremental cost of the EE features is estimated to be not more than 10 percent of the base capital cost. An energy management guidebook for the LEO building has also been published. Information on the LEO building can be accessed at www.mecm.leo.gov.my. A Malaysian version of the modelling tool E-10 is currently being developed.

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MEXICO

INTRODUCTION

Mexico is located in North America, bordering the United States to the north and Belize and Guatemala to the south. Mexico is one of the most populous economies in Latin America, with a total population of about 100.82 million people that grew by 1.4 percent between 2001 and 2002. As a result of urbanisation in the last part of the 20th Century, 67 percent of the population now lives in urban areas. Thirty four percent of the population is concentrated in nine metropolitan areas, the largest of which is Mexico City, serving as home to 19 million people in 2003.[25]

Real GDP growth rate at purchasing power parity averaged 2.4 percent between 1980 and 2002. The slow growth resulted from various episodes of economic downturn, the most recent of which has persisted for the last 4 years due mostly to the economic situation worldwide and particularly in the United States, Mexico's largest trading partner. GDP per capita actually *decreased* in terms of Purchasing Power Parity between 2001 and 2002 by 0.54 percent. The first three trimesters of 2004 have shown signs of imminent growth with an increase in productive activities driven by trade. In the first quarter of 2004, exports of manufactured goods and imports of intermediate products recorded annual growth rates exceeding 10 percent for the first time in several years, stimulating other areas of commercial activity and resulting in an annualised growth in the 3rd quarter of 2004 of 4 percent for the overall economy. [26]

Table 21 Key data and economic profile (2002)

Key data		Energy reserves	
Area (sq. km)	1,964,375*	Oil (MCM) – Proven**	2,550
Population (million)	100.82	Gas (BCM) – Proven**	457
GDP Billion US$ (1995 US$ at PPP)	823.98	Coal (Mt) –Recoverable***	1,211
GDP per capita (1995 US$ at PPP)	8,173		

Sources: Energy Data and Modelling Center, IEEJ

* INEGI, Información geográfica. 2003.

** As of January 2004. Anuario Estadístico PEMEX 2004.

*** As of January 2003. Handbook of Energy & Economic Statistics in Japan 2004. EDMC.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary energy supply in Mexico was 150 Mtoe in 2002. Oil and gas (with contributions of 53 percent and 29 percent respectively) dominate primary energy supply with a combined share of 82 percent. The remaining fuel sources are biomass (6 percent), coal (5 percent), hydro (4 percent), nuclear (2 percent), and geothermal (1 percent). Included in biomass is firewood, which

[25] La Situación Demográfica de México 2003. CONAPO.

[26] INEGI (2005), Secretaría de Hacienda y Crédito Publico, México, 2005.

continues to be an important source of energy in rural households and contributes 5 percent to the total primary energy supply.[27]

OIL

The oil industry plays a crucial role in the economy, accounting for about one third of government revenue. Proven oil reserves in January 2004 were the 13th largest in the world, totalling 2,550 MCM (including condensates and plant liquids). PEMEX, Mexico's state oil company, was the second largest crude oil producer in the world in 2002 after Saudi Aramco. In 2002, total Mexican oil production was 179 Mtoe, 0.7 percent more than the previous year. PEMEX was also the 7th largest oil company in the world in terms of revenue in 2002, and by law is the sole provider of oil services in Mexico from upstream exploration to final distribution.[28]

In 2002 Mexico was the world's 7th largest crude oil exporter. In that year 1.72 million barrels per day of crude were exported, or around 48 percent of its total production. Seventy eight percent of exports in the same year were directed to the United States. Average export levels in 2002 were 0.3 percent higher than in 2001.[29]

PEMEX owns six major refineries that in 2002 had a total processing capacity of 1,540 thousand barrels per day. Most refineries are currently being upgraded to increase output volume and improve the quality of gasoline and distillate production. In 2002 Mexico produced 1,276 thousand barrels per day of oil products and imported an additional 244 thousand barrels per day, which was 27 percent less than the previous year.[30]

NATURAL GAS

Mexico's proven natural gas reserves in January 2004 were 457 billion cubic metres. Indigenous production of natural gas in Mexico was 4.4 Bcfd in 2002, 2 percent less than the year before. Mexico both imports and exports natural gas along its northern border with the United States. Exports continued decreasing and in 2002 they amounted to 4 Mcfd, or 84 percent less than the previous year. Imports on the other hand continued increasing and in 2002 they almost doubled with respect to the previous year to 592 Mcfd.[31]

Natural gas consumption is expected to grow substantially in the coming years driven mostly by electricity generation. According to the Mexican Energy Secretariat total gas consumption will grow annually at a rate of 5.8 percent in average between 2004 and 2013, with the demand from the power sector growing at a rate of 10 percent annually in the same period.[32] In anticipation of this growth, plans are underway to increase domestic supply by focusing investments on gas exploration and production activities and on transportation infrastructure. More immediate are the plans for several LNG importing facilities to be located both on the Gulf of Mexico and Pacific coasts, with the one closest to completion scheduled to start operations by 2006 in Altamira, on the Gulf coast. Still, the large amount of investments required and budget restrictions in PEMEX mean that in the medium term domestic natural gas demand will continue to grow more quickly than production, and imports are expected to account for as much as 41 percent of domestic demand in 2013.[33]

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[27] National Energy Balance 2003. Secretariat of Energy, Mexico.

[28] Anuario Estadistico PEMEX 2004.

[29] Anuario Estadistico PEMEX 2004.

[30] Anuario Estadistico PEMEX 2004.

[31] Anuario Estadistico PEMEX 2004.

[32] Prospectiva del Sector Electrico 2004-2013. Secretaria de Energia, Mexico. 2004.

[33] Prospectiva de gas natural 2004-2013. Secretaria de Energia, Mexico. 2004.

COAL

The total coal supply in 2002 was 8.26 Mtoe and accounted for around 5.5 percent of total primary energy in the same year. Coal resources total 1,211 Mt and are mostly located in the northern part of Mexico. Around 70 percent of recoverable reserves are anthracite and bituminous, while 30 percent are lignite and sub-bituminous.

Coal in Mexico is mostly used for steel production and electricity generation, and imports from United States, Canada and Colombia are needed to complement domestic demand. The largest coal producer in Mexico is Minera Carbonífera Rio Escondido (MICARE), now owned by U.S.-based Mission Energy.[34]

ELECTRICITY

Electricity generation capacity in Mexico in 2002 was 45,674 MW, 7.6 percent more than in 2001. Eighty-three percent of the generating capacity is owned by the two state electric utilities CFE and LFC; 7.6 percent is owned by IPPs; 6.1 percent by auto-producers; 2.6 percent by co-generators; and 1.2 percent by small own-users.[35]

Electricity generation has increased rapidly over the past decade at an annual average rate of 5.1 percent. Electricity generation in 2002 in the national interconnected grid reached 201 TWh, but the total electricity generated including auto-producers equalled 214 TWh. Of this total 83.6 percent came from Mexico's two public utilities, 10.6 percent from IPPs and 5.8 percent from the various types of auto-producers. In 2002 fuel oil contributed 50 percent to the electricity produced within the interconnected grid, while natural gas combined cycle units contributed 22 percent, hydropower 12 percent, coal 8 percent, nuclear power 5 percent and geothermal and wind power 3 percent.[36] For the next 10 years (2004-2013), Mexico has plans to base between 52 and 79 percent of its future additional generation capacity on natural gas combined cycles. In the government's latest plans, coal has an almost imperceptible participation in future additional capacity.[37]

Mexico has large potential reserves of renewable resources, although at present only hydropower and geothermal energy have been widely developed for a total of 9,608 MW of hydropower and 843 MW of geothermal energy in 2002. The government has a policy of renewable energy promotion that includes continued support for research and the introduction of favourable conditions for generators using these resources. Attention will be given to biomass and wind plants, and plans are underway to develop wind farms along the southern Pacific coast in the State of Oaxaca. Solar energy in combination with other renewable sources including wind and biomass are currently being promoted as a power source for isolated rural communities, where extending the national grid would prove too costly due to terrain conditions.

As much as 17,000 MW of capacity are believed to be readily available in wind, mini-hydro and solar resources. In the next ten years 3,200 MW of new hydropower plants will be added to the generation pool along with 405 MW of wind plants.[38]

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[34] Country Analysis Briefs Mexico. EIA/USDOE. 2003.

[35] Prospectiva del Sector Electrico 2003-2012. Secretaria de Energia, Mexico. 2003.

[36] Prospectiva del Sector Electrico 2003-2012. Secretaria de Energia, Mexico. 2003.

[37] Prospectiva del Sector Electrico 2004-2013. Secretaria de Energia, Mexico. 2004.

[38] Prospectiva del Sector Electrico 2004-2013. Secretaria de Energia, Mexico. 2004.

Table 22 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	229,119	Industry Sector	28,456	Total	201,252
Net Imports & Other	-79,357	Transport Sector	39,019	Thermal	161,238
Total PES	149,762	Other Sectors	28,052	Hydro	24,862
Coal	8,259	Total FEC	95,527	Nuclear	9,747
Oil	79,458	Coal	1,715	Others	5,405
Gas	44,523	Oil	59,522		
Others	17,523	Gas	12,174		
		Electricity & Others	22,116		

Source: Energy Data and Modelling Center, IEEJ.

For full details of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

FINAL ENERGY CONSUMPTION

As a result of the periodic economic downturns, energy consumption has fluctuated significantly over the last twenty years. However, the average growth rate in energy demand was 2 percent over the period between 1980 and 2002. Total energy consumption in 2002 was 95.5 Mtoe, an increase of 1.2 percent relative to the previous year. The transportation sector accounted for 41 percent of consumption in 2002, industry for 30 percent, the residential and commercial sectors for 21 percent, agriculture for 3 percent, and non-energy uses for 5 percent.

POLICY OVERVIEW

In Mexico, the State's ownership of natural resources including oil, and its control over the oil and electricity industries, are principles embedded in the Political Constitution. The Constitution defines "strategic" areas that are the exclusive responsibility of the State and include: the ownership and production of radioactive minerals, oil and all other hydrocarbons, basic petrochemical processes, electricity and nuclear power generation.

This legal framework has historically restricted the participation of private investors in the energy sector. However, in the interests of modernisation of the national infrastructure and increased productivity the government in its "Energy Sector Program 2001-2006" recognises the need to liberalise energy markets to augment investment capacity, foster competition and to enhance energy quality and supply.

Modifications to the legal framework have now made the participation of private and foreign investors possible in the electricity industry, albeit in a limited fashion. Changes to the "Public Service Electric Energy Law" of 1992 opened the door to private investment in the form of Independent Power Producers, co-generators, auto-producers and small (less than 30 MW) generators. Independent Power Producers sell their energy to the State monopoly through power purchase agreement schemes. Since 1998, every new power generation facility has been constructed following this model.

In 1995, the Oil Regulatory Law was reformed to open the possibility to investors to construct, own and operate natural gas transportation, distribution and storage systems. The modifications have also made it possible for private entities to import, export and commercialise natural gas to final consumers.

Another modification to the Oil Regulatory Law in 1996 defined "basic" and "non-basic petrochemical compounds" and allowed private investment and participation of up to 100 percent in new plants for the production of non-basic petrochemicals.

In the Liquefied Petroleum Gas (LPG) market, private participation had been allowed since the 1950's, but a new "LPG Regulation" published in June 1999 reorganised the industry into four areas and defined the participants allowed in each. Under the terms of this regulation, PEMEX continues to be responsible for first hand sales (sale of the original product), transportation by pipeline, and the operation of its production and supply plants. National and foreign private participation was allowed in transportation and storage, while final distribution and commercialisation was established as an exclusive area for national private investors.

Mexico is a major non-OPEC oil producer, and together with that organisation and other independent producers, has contributed to the stabilisation of crude oil market prices.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS SECTOR DEVELOPMENTS

The increase in oil prices in 2004 has underscored the importance of expanding investment in exploration and production. Mexico has made a determined effort to increase investment in exploration and production by allocating US$ 10.6 billion in 2004, up from US$ 5.4 billion in 2000. Plans are to increase investments in the future, as well.

In 2003, the construction of exploration and development wells was higher than in any previous year. During 2004, the government projects a further 71 percent increase, or a total of 1,018 additional wells. In 2003, 13 new oil fields and 24 new gas fields were discovered, allowing the reserve restitution rate to reach 44.7 percent, as compared with an average rate of 26 percent in the last decade. The new discoveries added 708 Mboe of oil and gas to existing reserves.

Optimisation techniques applied to the Cantarell Complex oil fields in the State of Campeche allowed the production of 2.5 million barrels per day of Maya crude, the highest in the history of PEMEX. This complex produced between January and October 2004, 63 percent of the total national production of crude oil.

To aid in the stabilisation of prices, Mexican oil exports have been on the increase for the last 4 years as Mexico's production capacity slowly expands. The level of exports averaged 1.85 million barrels per day in the first 10 months of 2004, which represents an increase of 15 percent over the volume in 2000.

In 2003 and the first 10 months of 2004 natural gas production reached record levels and reversed the decreasing tendency existing since 1998. Between January and October of 2004 natural gas production averaged 4.58 Bcfd. However, Mexico continues to import natural gas from the United States and the price increases to US$6.33/Mill. BTU (Henry Hub price) in October 2004, negatively impacted the nation's natural gas trade balance. Natural gas imports between January and October 2004 averaged 758 Mcfd, decreasing by 1.9 percent compared to the same period in the previous year as a result of increased domestic production.

PEMEX is investigating the use of "multiple services contracts" to manoeuvre around constitutional limitations and allow private parties to participate in exploration activities for oil and natural gas. In these contracts, PEMEX pays a set fee for services provided and retains ownership of the energy resources produced. The scheme has been used on a few occasions since 2003 and recently in 2004 two new contracts were awarded to Lewis Energy Group from Texas and to a Mexican consortium. In total, 6 contracts have been awarded up to now amounting to a total production volume of 681 Mcfd of gas; despite doubts raised in Congress about their legitimacy under the present constitutional legal framework.[39]

[39] Secretaria de Energia, Mexico. 2004.

LNG FACILITIES

The rapid growth expected of natural gas consumption in the mid-term future will represent a challenge for PEMEX. PEMEX' plans a natural gas supply annual average growth rate in the next 10 years of 2.5 percent compared to a growth of 5.8 percent for consumption, resulting in a deficit of 3.784 Bcfd of the fuel in 2013 or 41 percent of domestic demand.[40] Restrictions on the availability of funds for reinvestment on the required schedule means that alternative supply sources have to be found. PEMEX' strategy to cover the expected demand at present is based on focusing funds to the exploration of new resources and to promote the construction of importing LNG facilities.

Four permits for LNG regasification and storage facilities have been granted by the Energy Regulatory Commission, one to be located on the Gulf of Mexico coast and three on the Pacific coast in Baja California near the border with the United States. The capacity of these terminals total 2.25 Bcfd at an estimated investment of US$ 2 billion, and are scheduled to be online between 2006 and 2007. Four other terminals are being proposed on the Pacific coast for an additional 3.9 Bcfd of capacity to fuel electric power plants in the western and southern regions of the nation. The scheduled dates for the initial operation of these new units is 2008.[41]

RENEWABLE ENERGIES

During the present administration, 8 MW of mini hydro and 8 MW of biomass electricity generating units have been installed. In addition to these, there are as much as 3,600 MW of capacity (including large hydro) planned both by the state electricity utility CFE, and by private investors.

The Federal Electricity Commission (CFE) has plans for 2,600 MW of additional large hydro plants, 217 MW of geothermal capacity, and 450 MW of windmills. Private projects include 120 MW of wind power, 160 MW of small hydro, 40 MW of landfill biogas, and 14 MW of animal-origin biogas for industrial auto consumption and for public lighting projects.

At least two other large projects are being investigated in collaboration with the Global Environmental Facility (GEF).[42]

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[40] Prospectiva del mercado de gas natural 2004-2013. Secretaria de Energia, Mexico. 2004.

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NEW ZEALAND

INTRODUCTION

New Zealand is a small island nation in the southern Pacific with a population of approximately 3.94 million in 2002. GDP has grown by an average of around 3 percent per annum (1990-2002), reaching about US$76.6 billion in 2002.

New Zealand had modest energy resources including 12.7 MCM of oil, 48 BCM of natural gas, and 8,600 Mt of coal. Hydro and geothermal resources currently meet around 65 percent of electricity demand. New Zealand is self-sufficient in all energy forms apart from oil.

Table 23 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	268,680	Oil (MCM)	12.7
Population (million)	3.94	Gas (BCM)	48
GDP Billion US$ (1995 US$ at PPP)	76.66	Coal (Mt) - Recoverable	8,600
GDP per capita (1995 US$ at PPP)	19,461		

Source: Energy Data and Modelling Center, IEEJ.

*Ministry of Economic Development (New Zealand) as at 31 December 2001.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

New Zealand's total primary energy supply in 2002 was 19,484 ktoe. A variety of energy sources are used to meet these needs comprising of oil (34 percent), gas (26 percent), geothermal (13 percent), hydro (12 percent), coal (7 percent) and others (8 percent). Self-sufficiency in 2002 was just over 81 percent.

New Zealand was over 50 percent self-sufficient in oil in 1986. By 1995, with demand having increased faster than production, this figure declined to 36 percent. By 2003, self-sufficiency had continued to decline to 23 percent due to a decline in production from the Ngatoto, Waihapa/Ngaere, Maui, Maui F Sands, Moturoa, Tariki/Ahuroa, Mangahewa, Kapuni and McKee fields. In 2004, self-sufficiency was expected to fall to 20 percent with a decrease in production from most of the energy fields.

Domestic transport is the main consumer and energy user of petroleum products, accounting for 85 percent of the total oil consumption in 2002. The other consumption was shared by agriculture (6 percent), industrial (6 percent), commercial (2 percent) and residential (1 percent).

In 2002, New Zealand generated 39,494 GWh of electricity. Around 72 percent of generation was from hydro and renewable resources. Hydro at 62 percent was the most important source of generation. The thermal share was consequentially high at around 28 percent, geothermal and others were around 10 percent. Around 70 percent of hydro electricity is generated in the South Island, and all geothermal electricity is generated in the North Island. The balance, almost all of which is generated in the North Island, is generated by natural gas, coal, wind and landfill gas. The largest electricity-using sector is industry (chiefly an aluminium smelter, iron and steel works, several pulp and paper mills and large dairy factories), which accounted for 43.8 percent of electricity demand in 2002. The residential sector consumed around 35.2 percent with the commercial sector consuming the balance of 21 percent.

Table 24 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	15,848	Industry Sector	3,512	Total	39,494
Net Imports & Other	3,636	Transport Sector	5,349	Thermal	11,082
Total PES	19,484	Other Sectors	5,355	Hydro	24,303
Coal	1,381	Total FEC	14,216	Nuclear	0
Oil	6,669	Coal	884	Others	4,109
Gas	5,058	Oil*	6,368		
Others	6,376	Gas*	2,997		
		Electricity & Others	3,967		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

*The figure had included with non-energy use

FINAL ENERGY CONSUMPTION

New Zealand's final energy consumption grew by 6.34 percent in 2002 to 14,216 ktoe. The industrial sector consumed 24.7 percent of energy used, the transportation sector 37.6 percent and other sectors 37.7 percent. Consumer energy is dominated by oil, comprising 6,368 ktoe per annum (45 percent), gas 2,997 ktoe (21 percent), coal 884 ktoe (6 percent) and 3,967 ktoe for electricity (21 percent) and renewables (7 percent) such as geothermal, wastes and wood.

Transportation (domestic) is the largest end use accounting for 37.6 percent of final consumption. The bulk of petroleum products used in New Zealand are consumed by this sector. The industrial sector is next with 24.7 percent and others which comprises of residential /commercial sector, non-energy sector, and agricultures sector consumes the remaining 37.7 percent.

POLICY OVERVIEW

New Zealand's energy sector has experienced a period of significant change and reform over the past 10-15 years, in particular, quite dramatic change in the structure of the electricity industry. Former government-owned and -operated electricity and gas monopolies have been either corporatised or sold to the private sector. The former vertical integration in both gas and electricity sectors has been dismantled to separate natural monopoly elements from those that are competitive, and a wholesale electricity market has been established.

Recently it has become apparent that New Zealand faces some challenge to ensure security of supply in gas and electricity sectors at the best price. These include the depletion of the Maui gas field, the vulnerability of hydro to dry year and growth in demand for electricity.

The electricity and gas industries bill will set the legal framework for next phase in the development of New Zealand's electricity and gas industries. The Bill updates the electricity act to reflect the establishment of electricity commission and provides enhanced powers for ensuring security of electricity supply. In addition, The Bill provides further electricity regulation relating to consumer protection and promotion of retail competition.

OIL

Deregulation of the oil industry in the late 1980s removed price control, government involvement in the refinery, licensing of wholesalers and retailers and restriction on imports of refined products. In 2003, most oil was produced from the Maui field (77 percent), McKee (6 percent), Kapuni (5 percent), Tariki/Ahuroa, Waihapa/Ngaere, Kaimiro, Ngatoro, Moturoa and

Rimu (12 percent). New Zealand has one oil refinery, at Marsden Point in Northland. It is jointly owned by the four major oil companies (BP, Shell, Mobil and Caltex). There are six petrol retailers: BP, Caltex, Challenge (now owned by Caltex), Gull, Mobil and Shell.

New Zealand's primary self-sufficiency in oil depends on both indigenous oil production and production demand. Over the period of 1974 to 1986 self-sufficiency increased dramatically from under 5 percent to over 50 percent. By 1995, with demand having increased faster than production, this figure declined to 36 percent. By 2002, self-sufficiency had continued to decline to 30 percent. This was due to a decline in production from most of the fields. In the year ended September 2003, with a decrease in production, self-sufficiency fell to 23 percent. In August 2002, twenty-one new petroleum exploration permit issued following a competitive bidding will boost New Zealand's oil exploration effort and indicate a strong interest in New Zealand's oil and gas prospects.

The Ministry of Economic Development is also leading work with New Zealand's major oil companies to investigate how best to increase the economy's stockpiling of crude oil and oil products, including petrol and diesel. The project follows a review and recalculation of industry data on oil stock to meet International Energy Agency's obligation to maintain 90-days of stocks of oil products as a buffer against disruptions to global oil supplies.

NATURAL GAS

The gas sector has a critical role to play in achieving the government's objective of sustainable and efficient energy future and higher economic growth rates.

The Government initiated a wide-ranging review of the gas sector in February 2001. A draft Government Policy Statement was released in November 2002, and after a period of consultation and comment, the final Statement "Development of New Zealand's Gas Industry" was released on 28 March 2003. The package of changes contained in the Statement is designed to enhance efficiency and reliability in gas production and transportation, and improve fairness for gas customers. Exploration for new gas reserves will be encouraged through a suite of measures announced in 2004. With the depletion of Maui gas reserve, new fields are critical to meet future energy needs.

ELECTRICITY

In 2003 New Zealand experienced electricity shortages caused by low rainfall that in turn affected generation from its hydroelectric plants, the principal source of electricity generation. The threat of shortages resulted in high and volatile (spot) prices to the consternation of consumers, notably some industrial users who curtailed production when high power prices made production unprofitable.

On 20 May 2003, the Government announced that an Electricity Commission would be established to govern the electricity industry. There was also concern that the existing market arrangements did not ensure security of supply in dry years. The Commission is responsible for managing the electricity sector so that electricity demand can be met even in a 1 in 60 dry year. The key tasks of The Commission include ensuring New Zealand's electricity supply is secure with adequate reserve generation for dry years, establishing transmission pricing methodology for investment in the natural grid and improving demand-side participation in the wholesale market.

Electricity sold by generators and purchased by retailers and large industrial users is subject to the Electricity Governance Regulations and Rules 2003 that came into force on 1 March 2004. This replaced two multi-lateral industry contracts related to the operation of the New Zealand Electricity Market (NZEM) and the Metering and Reconciliation Information Agreement (MARIA).

RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable energy sources are already making a significant contribution to New Zealand's total energy, especially now that Maui gas is near the end of its production life. Hydro and Geothermal are the main renewable energy sources in New Zealand.

In the government's 2003 Budget presented in May, small amounts of funding, also to be managed by EECA, have been allocated to accelerate the uptake of (non-traditional) renewable energy and improve energy efficiency. NZ$1.2 million has been allocated for providing insulation in low-income homes, NZ$200,000 has been committed to the Solar Hot Water Grants scheme and the NZ$1 million Crown Energy Efficiency Loan scheme has been doubled to fund public sector organisation's energy efficiency projects with the loans being repaid from energy costs savings.

The New Zealand government's sustainable development programme of action, released in January 2003, aims to put sustainable development principles at the heart of national policy-making. The program of action identifies four key action area as significant: water quality and allocation, energy, sustainable cities, and child and youth development.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY AND GAS INDUSTRIES BILL

To establish a new legal framework for the electricity and gas industries, the Bill on Electricity and Gas Industry was passed on 13 October 2004. The major features of the Bill include:

- Update the Electricity Act and Regulation to enable the Electricity Commission to take over the responsibility for gas industry governance if the gas industry's arrangements fails to deliver government policy objectives;
- Provide further regulation to enhance consumer protection, promotion of retail competition, information for market participants and development of distributed generation;
- To ensure security of electricity supply, the Electricity Commission is authorised to contract for reserve energy supplies; and
- Amend the Commerce Act to clarify the roles of the Commerce Commission and the Electricity Commission in regulating electricity distribution companies.

The Bill also allows for the establishment of a co-regulatory governance body for the gas industry and backstop powers for the establishment of an Energy Commission. Other changes include enabling electricity lines companies to own generation equivalent to the higher of 50MW or 20 percent of their network load, allowing Transpower to contract for generation to manage grid reliability and delaying the transfer of jurisdiction for the lines targeted price control regime from the Commerce Commission to the Electricity Commission until after 31 March 2009.

FACILITAION OF DISTRIBUTED GENERATION

In New Zealand, around 15 to 20 percent of electricity comes from smaller plants connected to local distribution networks. This distributed generation includes small local hydro, landfill gas, small geothermal, diesel, gas, wind, solar and co-generation from wood processing residues.

The proposed regulation is to regulate the distribution companies' terms and conditions for connecting electricity generators to their distribution networks. The small-scale electricity generation of up to 10kW will be allowed to connect to local lines without any charges. For generation above 10Kw, distribution companies are allowed to impose a reasonable connecting charge. It is anticipated to help the expansion of renewable generation and to make it viable.

OIL AND GAS EXPLORATION

Research by New Zealand's Institute of Geological and Nuclear Science showed that there are good potentials for developing oil and gas fields. Exploration for new gas reserves will be encouraged through a suite of measures announced in June 2004. With the depletion of Maui gas reserve, new fields are critical to meet future energy needs.

In Feb 2004, the award of 13 explorations permits involving over $130 million in new investment in Taranaki region of New Zealand was announced. The permits have been awarded to a combination of new and local companies ranging from explorers to multinational companies.

Two power companies are promoting the establishment of a gas exploration fund designed to accelerate gas exploration activities in New Zealand. The objectives of the fund are to broaden the range of gas supply options for New Zealand and ensure that potential sites with attractive opportunities that might be overlooked is developed in a timely manner. A major benefit of the fund is that it will facilitate a co-ordinated drilling programme across a range of prospects. This reduces the costs and allows a larger programme to be undertaken for the same expenditure.

SUSTAINABLE DEVELOPMENT PROGRAM

In order to establish sustainable development and values, the Sustainable Development Programme of Action (SDPOA) was released in January 2003. The SDPOA calls on government agencies to take a wider, more integrated approach to policy development.

The three desired outcomes for the SDPOA are:

- Energy use in New Zealand becomes more efficient and less wasteful;
- Renewable sources of energy are developed and maximised; and
- New Zealand consumers have a secure supply of electricity.

A discussion document "Sustainable Energy – Creating a Sustainable Energy System" was released in October 2004 (by the Ministry of Economic Development) which identifies the energy challenges and opportunities facing New Zealand, explains Government's strategic direction in energy policy and outlines possible future directions for policy development.

SOLAR WATER HEATING GRANT

Under the 2003/4 Budget, the government committed $200,000 to EnergyWise Solar Water Heating Grants. The grant will put more than 400 solar water heater on New Zealand homes by 30 June 2004.

In addition to the grants, the government also work with the Solar Industries Association to get industry training, improve the quality of installation, establish a testing regime for solar systems and market the benefits of solar water heating.

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PAPUA NEW GUINEA

INTRODUCTION

Papua New Guinea (PNG), an island nation in the South Pacific, is geographically located north of Australia and is comprised of more than 600 islands, several habitable ones including half of the main island of New Guinea with West Papua, Indonesia. PNG has a population of more than five million people, spread across its total area of 462,840 square kilometres.

The PNG economy is slowly recovering from the current global economic slowdown. Current per capita GDP (US$ 2,005) is 5.8 percent lower than 2001 level (US$2,063). In 2002, real GDP at 1995 US dollars at PPP was estimated at US$ 10.78 billion, which declined by 0.54 percent from 2001 level. Inflation in 2002 was around 12 percent.

Energy use per capita in PNG at 0.1 toe is far below the APEC average of 1.5 toe per capita. Energy resources exports are very important for earning foreign exchange and national revenue. In 2002, the energy industry accounted for approximately 14 percent of the economy's GDP, about 20 percent of total exports and employed about 1000 Papua New Guineans in both upstream and downstream operations.

Table 25 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	462,840	Oil (MCM) - Proven	63.6
Population (million)	5.38	Gas (BCM)	430
GDP Billion US$ (1995 US$ at PPP)	10.78	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	2,005		

Source: Energy Data and Modelling Center, IEEJ, WDI 2004 and BP 2004 Statistical Review of World Energy.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2002, PNG's net primary energy supply was 1394 ktoe, a seven percent increase from 2001. Light crude oil and petroleum products accounted for 84 percent, gas for 10 percent while hydro and other fuels comprised the remaining 6 percent. Around 50 percent or 1,382 ktoe of indigenous energy production is exported to other economies. An annual budget of US$ 20 million supports oil and gas exploration in PNG.

PNG has a small oil field, which has been producing 100,000 bbl/day of light crude since 1992. As the field matures, production levels have begun to decline. The light crude is mainly for export. In September 2000, the government approved a Petroleum Development Licence for Moran Oil to begin production of 13,000 bbl/day by the end of 2000, to supplement the Kutubu project. In the period of January to August 2004 six well had been drilled in the Moran field. An additional 10 million barrels of oil reserves have been found from the 'wildcat drilling.'

To attract more investment, PNG introduced new incentive rate for petroleum operations in 2003. The incentive provides 20 percent tax relief for new investment in petroleum sector, compared to the previous taxation system

PNG also has a natural gas field with an estimated reserve of 430 BCM. In 2001, a small amount of gas was produced (144 ktoe) for electricity generation – mainly for the gold mine at

Porgera. PNG is still negotiating to sell this gas to Australia with approximately 100 –150 Petajoules per year as a base load.

In 2004, the owner of the Highland Gas Project have reached conditional agreement with Queensland Alumina Limited (QAL) and CS Energy Limited on commercial term of the sale of gas. QAL will buy 12-13 petajoules of gas per year for a 20-year period to QAL's refinery at Gladstone. CS energy had agreed to buy 10 petajoules of gas per year for 20 years, to be used for power generation in Brisbane. In 2002, a conditional agreement was also signed with TXU Electricity Ltd. to supply between 20 – 35 petajoules per year, also for 20 years.

The project participants Exxon Mobil (Esso Highland Limited as a project coordinator), Oil Search, Chevron Texaco, MRDC (a PNG company representing landowner interest and JPP (Japan PNG Petroleum) have decided to move the Highland Gas Project to the Front End Engineering and Design (FEED) phase of its development, having secured their customer.

To bring the gas to Australia the Highland Gas Project Owner signed a Letter of Intent (LOI) with APC (a consortium led by AGL and Petronas). Under the LOI, APC will be responsible for designing, owning and operating the pipeline that brings the gas to Australia. Total investment for the project is estimated at US$ 1,500 million.

Considering the relatively low domestic demand for gas , PNG plans to build a LPG plant to produce 600,000 ton per annum of LPG for South East Asian growing market. In addition, a consortium consisting of Niugini Gas and Chemical of Papua New Guinea, I&G Venture Capital, South Korea and Rentech of USA have all signed an MOU with the Ministry of Petroleum and Energy for the development of natural gas at Wewak, in northern Papua New Guinea. This development consists of the construction of a LNG Plant, a compressed natural gas production facility, an ammonia and urea production facility as well as a 15,000 bpd gas to liquid (GTL) facility.

Table 26 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	2,776	Industry Sector	552	Total	2,884
Net Imports & Other	-1,382	Transport Sector	344	Thermal	1,954
Total PES	1,394	Other Sectors	112	Hydro	930
Coal	-	Total FEC	1,008	Nuclear	-
Oil	1,170	Coal	-	Others	-
Gas	144	Oil	774		
Others	80	Gas	-		
		Electricity & Others	234		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

As of 2002, the total installed power capacity was 451.3 MW. PNG produced 2,884 GWh of electricity in 2002 (a 7 percent increase from 2001). The sources of generation were hydro at 32 percent and thermal (gas and fuel oil) at 68 percent (an increase of 11 percent to meet demand as the share of hydro has remained steady over the last 3 years). There is little economic potential for the expansion of large hydro, due to the lack of substantive demand near supply sources. However, there is a greater potential for developing smaller hydro schemes. Most power stations, thermal and hydro are owned and operated by the government owned monopoly, the PNG Electricity Commission.

FINAL ENERGY CONSUMPTION

In 2002, the total end use energy consumption in PNG was 1008 ktoe (an increase of 6 percent from 2001 or 14 percent from 2000). The industrial sector, accounting for 55 percent (an increase of 7 percent over 2001) is the largest end user, followed by transport at 34 percent (an increase of 5 percent over 2001), and other sectors include agriculture and residential/commercial at 11 percent (an increase of 7 percent over 2001). Petroleum products accounted for 78 percent of total consumption (an increase of 6 percent over 2001), electricity and others for 22 percent (an increase of 7 percent over 2001) and natural gas accounted for less than 1 percent.

In PNG about 85 percent of the population live in rural areas and electrification rates remain low. Petroleum products such as diesel or petrol are used in the transport sector and for the generation of electricity. PNG Electricity Commission is continuously extending rural distribution network throughout the economy. In 2002, more than 4 million Kina was spent to construct 125 km of 22 kV and low voltage line to Gumine and Gembogl in Simbu Province, and to Lufa and Okapa in the Eastern Highlands Province.

Renewable energies such as small hydro, wind power and solar energy are not widely used, as they are expensive to install for general electricity use. In recent years, however, solar water heating equipment has been installed in more new buildings. Organisations such as Telikom PNG and the Civil Aviation Authority also use solar photovoltaics for power supply to telecommunication and navigational aids equipments.

POLICY OVERVIEW

In PNG, the national government has jurisdiction over energy matters including overall energy policy. The PNG Electricity Commission controls the generation and distribution of electricity, energy policy matters are determined by the Ministry of Energy Department, while the Department of Petroleum and Energy oversees the exploration and development of petroleum resources.

The Department of Finance and Treasury is responsible for setting prices or tariffs for electricity and petroleum products. The provincial governments work with the PNG Electricity Commission, the Energy Division of Department of Petroleum and Energy and/or private companies to organise new projects such as grid extensions or the development of small hydro and other renewable energy resources.

The PNG National Energy Policy Statement and Policy document has been referred back to the drawing board. Previous Acts of Parliament such as the Electricity Commission Act, gave authority to the PNG Electricity Commission for the generation, distribution and sale of electricity. The Petroleum Act of 1972 and the Oil and Gas Act of 1998 gave the Ministry and Department of Petroleum and Energy authority over the licensing and development of petroleum resources. The Price Control Act authorises the Ministry and Department of Finance and Treasury to set fuel prices and electricity tariffs.

The Energy Division of the Department of Petroleum and Energy implements policies and programmes, which are aimed at encouraging the diffusion of new and affordable renewable energy technologies. It also works closely with the PNG Electricity Commission to increase the available amount of electricity capacity as and when demand growth justifies it.

NOTABLE ENERGY DEVELOPMENTS

- In April 2003, Papua New Guinea commissioned its first geothermal power station. The gold company, Lihir Gold Limited commissioned a 6MW geothermal power station on Lihir Island in New Ireland Province; the first in PNG to use natural geothermal energy for the generation of electricity. The Lihir power plant requires over 100 tonnes of steam per hour to operate at maximum capacity, while the 6MW produced represents about 10 percent of the gold mine operations' total power requirement. Lihir is only one of 40 identified geothermal fields in PNG; the others still remain untouched and undeveloped.

- Highland Gas Project to sell gas to Queensland (Australia) has achieved the required customers and the project owner decided to proceed to FEED stage for both plant and pipeline.
- A 32,500-barrel per day nameplate capacity refinery built by Canadian independent, InterOil at Port Moresby (Napa Napa) was commissioned on May 2004. First sale of refinery product occurred on 10 August 2004. A first sale of the refined product was dispatched on 7 September 2004. The operation of the refinery has transformed PNG from importer to exporter of refined product.
- In view of the declining exploration activities, PNG introduced a new incentive rate for petroleum operations in 2003. The incentive is a decrease in company income tax to 30 percent from the current rate of 50 percent imposed prior to 1 January 2001 and 45 percent for projects thereafter.

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PERU

INTRODUCTION

Peru is located on the Pacific Ocean coast of South America. It shares borders with Chile to the south, Ecuador and Colombia to the north, and Brazil and Bolivia to the east. Its nearly 27 million people are spread over 1,285,216 square kilometres, but 73 percent live in urban areas. It has three main regions and climates: the western desert coastal plains, the cold central Andes mountains, and the tropical eastern Amazon jungle. Geographically, approximately 53 percent of the population live in the coastal region, 37 percent in the mountainous region and 10 percent in the Amazonian region. Peru is a major exporter of metals; it is the world's second largest silver exporter after Mexico and is also among the top five exporting economies for copper, zinc, tin and lead.

Peru's GDP in 2002 was US$119.5 billion while GDP per capita was US$4,468 (both in 1995 US$ at PPP). In 2003, Peru experienced (an estimated) real gross domestic product (GDP) growth of 4 percent, down from the previous year's rate of 4.9 percent. Overall, real GDP growth is projected to remain favourable in 2004, at around 4 percent, with mineral exports, construction, and the long-expected Camisea energy project driving Peru's economy.

Peru is now a net importer of energy. Of the total energy imported, more than 90 percent is crude oil used as refinery feedstock; domestic crude is not of adequate quality for such feedstock. The remainder of Peru's energy imports consist of coal. Its energy reserves in 2003 included approximately 53.2 MCM of oil, 245.1 BCM of gas and 1059 Mt of recoverable coal.

Table 27 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	1,285,216*	Oil (MCM) – Proven	53.2
Population (million)	26,750**	Gas (BCM) – Proven	245.1
GDP Billion US$ (1995 US$ at PPP)	119.5	Coal (Mt) - Recoverable	1059.59
GDP per capita (1995 US$ at PPP)	4,468		

Source: Energy Data and Modelling Center, IEEJ.

*January 2003 data from Ministry of Energy and Mines, Peru.

** Estimated 2003

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply (TPES) in 2002 was 10,757 ktoe, nearly the same as in 2000, which was 10,653 ktoe. Oil still comprised the biggest share of TPES (62.4 percent), although its share decreased by 4.8 percent from its share in 2000. The share of natural gas in 2002 reached 15.4 percent, a minor increase from its 14 percent share in 2000. Favourable weather condition and the completion of the Machu Picchu hydro plant increased the share of hydro from 13 percent in 2000 to 15 percent in 2002. Coal's share increased slightly from 6 percent in 2000 to 7.3 percent in 2002.

Peru imported about 2,788 ktoe or 26 percent of its energy requirements (mostly oil from Colombia, Ecuador and Venezuela) in 2002, similar to previous year import of 2,753 ktoe.

In the absence of new oil discoveries, production of crude oil declined by 7 percent in 2000 and 3 percent in 2001 to an average of 96,000 barrels per day (bbl/d). In 2002, Peru increased the production slightly, to about 97,666 bbl/d. In 2003, Peru produced 95,000 bbl/d of oil (including crude and NGLs), a decrease of 2.7 percent year-on-year, while consuming 163,000 bbl/d. Peru's total proven oil reserve was 285 million barrels, as of January 2004. Current production areas are located in the northern jungle along the Ecuador border, north eastern and central Peru and offshore. The total number of wells drilled by oil companies decreased significantly from around 30 wells in 2000 and 2001 to only 10 in 2002. President Toledo's administration had taken several measures to attract more investors, however, the economy's political situation remains unstable.

The Norperuano pipeline from the Amazon to the Pacific Ocean is being used to meet domestic oil demand. The pipeline has a capacity of 200,000 bbl/d, but only 30 percent is being used. In 2001, Ecuador utilised the line to export oil. Oil is sent via river barge to existing Peru's pipeline currently, however, there are plans to build a connecting pipeline to Norperuano.

Peru's average annual gas production increased significantly from about 5 percent in 2000, to 18.8 percent, or nearly 2 BCM in 2002. Peru has the potential to produce far more gas than it does today as domestic gas demand and gas export markets grow. Upstream operations recently began at the Camisea field, one of the largest in South America, which was first discovered in Peru's southern jungle in the early 1980s. The field is expected to produce 10 MCM/d of gas and 0.004 MCM/d of condensate once fully operational. The revenue from royalties and taxes over the next 30 years is expected to reach US$ 5-6 billion. . The two reservoirs in this area are estimated to contain 245 BCM of gas and over 90 MCM of condensate. The power generation and industrial sectors are expected to be major gas consumers.

Table 28 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	7,968	Industry Sector	3,336	Total	21,982
Net Imports & Other	2,788	Transport Sector	2,998	Thermal	3,942
Total PES	10,757	Other Sectors	2,310	Hydro	18,040
Coal	783	Total FEC	8,644	Nuclear	0
Oil	6,707	Coal	483	Others	0
Gas	1,660	Oil	6,438		
Others	1,606	Gas	5		
		Electricity & Others	1,717		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

The installed electricity generation capacity in Peru increased from 5,907 MW in December 2001, to 5,936 MW in 2002. 75.3 percent of the population had access to electricity. Hydropower and thermal share equally the electric generating capacity. However, hydropower produced 82 percent of the electricity in 2002 and thermal plants produced the remaining 18 percent. Thermal power is generated from residual fuel oil, diesel, natural gas and coal.

Peru has an interconnected national system (SICN) and southern (SIS) grids to form the National Interconnected Electrical System (SEIN). In 2002, of the 21,982 GWh of electricity generated in the economy, 98 percent was delivered through the SEIN and the remaining 2 percent was delivered through several smaller isolated systems (SSAA). Of all electricity traded in 2002, 52 percent was traded in regulated market and 48 percent in free trade. With the privatisation of Peru's electricity sector in June 2002, the government awarded Red de Energía del Perú (REP), a consortium comprising of Colombian companies Empresa de Energía de Bogotá (EBB), Isaperu, and ISA subsidiary Transelca, a 30-year concession to own and operate Peru's two main transmission companies, Empresa de Transmision Centro Norte (Etecen) and Empresa de Transmision del Sur (Etesur). EBB is the largest shareholder of REP, with a 40 percent stake. Isaperu and Transelca each hold 30 percent. In order to regulate the operation of the market, the Peruvian government created Osinerg (Organismo Supervisor de la Inversion en Energía), which is currently Peru's energy regulator.

FINAL ENERGY CONSUMPTION

Between 1980 and 2002, final energy consumption in Peru increased by 39 percent while energy production fell by 25 percent. In 2002, final energy consumption in Peru amounted to 8,644 ktoe, of which, the transport sector consumed 35 percent, industry sector 39 percent and other sectors 26 percent. Petroleum products dominated end use consumption, accounting for 75 percent of demand in 2002, a decrease of 1 percent from its share in 2001. The share of electricity from final energy consumption was 20 percent. Coal accounted for 5 percent while gas was less than 1 percent.

POLICY OVERVIEW

In 2002 Peru amended the constitution and began to decentralise the structure of Government. The amendment mandated the creation of three levels of government (National, regional and local), with political and economics autonomy. Regional elections were held in November 2002 and the new administration took office on 1 January 2003. The decentralisation of government structure will be followed by a decentralised neutral fiscal system.

In order to improve neutrality tax and increase tax base in 2002, Peru also reformed the tax policy and tax administration measures. Reform includes the removal of some VAT exemptions, an increase in kerosene tax by 80 percent to partially reduce the differential with the tax on diesel, intensifying the control of tax collection and improve the administration.

Peru's economy is becoming more market-oriented. Virtually all trade, investment and foreign exchange controls were eliminated in 1990. The mining, electricity, hydrocarbons and telecommunication industries have been partially privatised. In particular, the state oil company, Petroperu, was partially privatised in 1993. In the same year, Perupetro, State Company, was created by law to be responsible for promoting the investment of hydrocarbon exploration and exploitation activities. Several laws affirm that "national and foreign investment are subject to the same terms" and have permitted foreign companies to participate in almost all economic sectors.

The Electricity Concessions Law, passed in 1992, allows private firms to invest in power generation, transmission and distribution. The state utility ElectroLima and the bulk of state utility ElectroPerú were privatised soon after the law was implemented. Another law, passed in 1997, promotes competition in the power sector by prohibiting control of more than 15 percent of power generation, transmission or distribution by any one firm. The government can block acquisitions to ensure that private companies do not gain excessive market power. The private sector, including foreign companies, today controls about 65 percent of generating capacity and 72 percent of the distribution system. The government retains ownership of key hydroelectric plants.

Peru is a member of the Andean Community, set up in March 1996 by leaders of Bolivia, Colombia, Ecuador, Peru, and Venezuela. Currently, the Community is working towards integrating energy sectors, particularly electricity and natural gas markets, through physical networks and harmonised regulatory frameworks. In November 1997, Peru joined the Asia Pacific Economic Cooperation (APEC) forum. Peru has also been participating in the Free Trade Area of the Americas negotiations.

As a part of Peru's effort to reduce air pollution in major cities and monetise stranded natural gas fields, Peru is considering to develop a Gas to Liquid (GTL) plant to exploit Talara and Northwest gas fields. With the support from Syntroleum, Peru's GTL project will be developed in two stages. Phase I would consist of the construction of a GTL plant with a capacity of 5,000 barrels per day near Talara. The output will be expanded to between 20,000 and 40,000 barrels per day. The development of this plant would also reduce sulphur dioxide emission from diesel combustion considerably, and support the proposed Clean Air Initiative for Lima-Callao.

NOTABLE ENERGY DEVELOPMENTS

PRIVATISATION PROGRAMME

The government that took office in July 2001 stepped up privatisation activities in the energy sector that had slowed under the two previous governments. While opponents claim that privatisation contributes to unemployment and high-energy tariffs, the government believes that it increases investment and lowers prices. Active promotion of private investment helped to bring about the July 2001 sale of the Electroandes Power Company to PSEG Global of the US. The Talara oil refinery and the Mantaro hydroelectric plant are also being considered for privatisation. However, violent demonstrations and riots in June 2002 in the cities of Arequipa and Tacna, which followed the government's announcement of the sale of the Egasa and Egesur electric utilities to Belgium's Tractebel, have delayed privatisation plans. In January 2003, the Government also postponed the privatisation of Yuncan hydro, as it failed to gain support from local government.

The private company with the largest presence in Peru is Spain's Endesa, which manages 1.5 GW of installed capacity. As of December 2003, Endesa held 60 percent of generators Etevensa (340 MW) and Empresa Eléctrica de Piura (Eepsa) (148 MW), as well as a controlling interest of 63.3 percent of Edegel (970 MW), through its subsidiary Enersis. Endesa, in conjunction with Enersis, also holds a 60 percent interest in electricity distributor Edelnor, the largest of Peru's 21 distributors. Some other international companies include Belgium's Tractebel, which holds 78.95 percent stake in Enersur (362 MW); Duke Energy International, which owns 100 percent of Egenor (529 MW); and PSEG Global, which owns 100 percent of Empresa de Electricidad de los Andes (ElectroAndes). Electroandes's main assets are four hydroelectric plants: Yaupi (108 MW); Malpaso (54 MW); Pachachaca (12 MW); and Oroya (9 MW). PSEG Global, along with Sempra Energy, jointly own 84.05 percent of Luz del Sur, (previously Edelsur), the second-largest electricity distributor in Peru

ADVANCES IN THE CAMISEA GAS PROJECT

Camisea gas was discovered by Shell in 1986, however, its development only started in 2000 with the establishment of the Special Committee of Camisea Project (CECAM). CECAM had divided the Camisea development into two projects, upstream and downstream. A consortium led by Argentina's Pluspetrol SA and consisting of Hunt Oil, SK Group and Tecpetrol, was awarded the 40-year contract to develop the upstream project. A 33-year contract for the downstream project consisting of transportation of the gas from Camisea to Lima, transportation of liquid gas (condensate) to coat and distribution of gas in Lima and Callao was awarded to Traportadora de Gas del Peru (TGP). TGP, a consortium made-up of Techhint, Pluspetrol, Hunt Oil, Sonatrach, SK Corporation and Tractebel will build two pipelines, one for natural gas (714 kilometres) and another for condensate (540 kilometres). The pipelines are expected to deliver 250 mmscfd of natural gas expandable to 729 mmscfd by 2015 and 70,000 bpd of condensate, with the first delivery beginning in August 2004.

In 2002 an additional downstream project, a 30-year concession for the construction and operation of gas distribution network in Lima and adjacent port Callo was awarded to Tractebel. The distribution network spans 37 miles to deliver gas to industries and power generators around Lima.

The total investment required for developing the Camisea project is estimated at US$1.6 billion. The Peruvian Government and the Camisea Company had attempted to secure financing from US Exim Bank and Inter-American Bank (IDB). Due to strong pressures from environmental groups, the US Exim Bank had rejected the US$ 214 million loan application on 28 August 2003. However, on 10 September 2003 IDB approved $ 135 million loan for the project. The loans consist of a US$ 75 million loan from ordinary capital and a US$ 60 million syndicated loan. TGP intends to issue US$ 200 million bond for additional funding.

Figure 1 Peru Gas Pipelines Development

Source: Ministry of Energy and Mines (2003)

Pluspetrol believes that Camisea could yield as much gas as fields in neighbouring Bolivia, where recent exploration and development activities have uncovered reserves of 3.68 BCM of natural gas and 95 MCM of condensate. Techint SA, also from Argentina, operates a transportation concession to deliver gas from Camisea to the city of Lima, and Belgium's Tractebel SA heads the consortium that will handle distribution in Lima. Additional reserves could make Peru a regional gas exporter, with potential customers in Mexico, the western United States and Brazil.

The government, in cooperation with the private sector, is carrying out an aggressive plan to expand gas utilisation in Peru that could lead to a gas grid linking all communities with more than 5,000 inhabitants and help reduce the dependence on oil imports nationwide. Also envisioned is a greater use of compressed natural gas (CNG) in transportation, along the lines of Argentina's programme that has yielded a fleet of 800,000 CNG vehicles.

Pluspetrol has drilled its first well, San Martin 1, which was tested in November 2002. A second well was also completed (?) in 2002, and three more wells are planned in the same area. Pluspetrol had wanted to start commercial operations in April 2004 even though the original concession contract calls for operations to begin in August of that year.

Work has also started on the construction of a gas pipeline that would distribute gas from the Camisea project to the major Peruvian cities of Lima and Callao. This would serve as a trunk line for distribution to other areas in the future. The government estimates that electricity tariffs could decrease by 30 percent within 10 years as a result of increased gas availability in the economy.

PERU LNG PORT

The huge reserves of natural gas discovered in Camisea, besides the reserves discovered at less than 20 kilometres in the Pagoreni Field, which together made an estimated 15 TCF of proven and probable reserves, had arisen the interest of two of the enterprises integrating the consortium in charge of the Camisea Project. Hunt and SK (Korean Enterprise) had established the LNG Peru

Consortium in order to export liquefied natural gas, for which they have signed an agreement with Tractebel, an enterprise with vast experience in commercialising liquefied natural gas. In virtue of this Agreement, Tractebel will purchase and export 2.7 million tones per year of liquefied natural gas (LNG) for 18 years. Potential markets for these exports will be Mexico and the State of California in United States of America. The initial investment to build a plant to liquefy natural gas will be within 900 and 1000 million dollars. The total investment of the project includes a reception terminal (possibly in Mexico) where the re-gasification plant and the tankers for LNG transport will be located, making a total estimated investment of 2,000 million dollars. Peruvian gas market demand will always be guaranteed.

In addition, the recent natural gas shortage experienced by Chile, due to supply problems in the Argentinean gas industry, has fostered the possibilities for gas trade between Chile and Peru. In fact, Chile is currently embarking on an LNG port project to receive gas from exporting economies, where Peru has clear advantages due to its proximity and competitive prices from Camisea gas resources.

POWER GRID

Peru has been in the process of integrating its power grid with Colombia and Ecuador. Those three economies signed the agreement in September 2001 and April 2002. The integration will possibly be expanded to Andean Community common electricity market, which will increase the efficiency of the market. The first inter-country electricity sales began in 2005, when Peru started exporting electricity to Ecuador. Currently, a $15 million 35 miles transmission line and a $1 million continuous AC substation that allows the transmission line to transport 150 MW of electricity in both directions is being built. The capacity of the lines will be increased to 250 MW. The facilities will enable Peru to sell excess hydropower during its rainy seasons to Ecuador.

ENCOURAGING NEW EXPLORATION

The participation of E&P contractors in exploration activities has been discouraging recently. The Government of Peru has introduced a more attractive fiscal term in May 2003 to address this problem. This new fiscal term offers two options; the first being, royalty based on production level that ranges from 5 to 20 percent and the second with a royalty based on a fixed component (5 percent) and a variable component (up to 20 percent) and are dependent on the profit margin. The new scheme also reduces payable royalty by up to 30 percent from the previous scheme. In addition, the government also offers other incentives such as the right to market hydrocarbon freely, allow free capital flow both within and outside the economy, a more flexible work programme and international arbitration on resolving disputes.

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THE PHILIPPINES

INTRODUCTION

The Philippines is located in the western rim of the Pacific Ocean. It is domicile to 79.94 million (2002 estimate) Filipinos of various ethnic origins that are spread over about 300,000 square kilometres of land, carved out into an archipelago of 7,107 islands and islets. Luzon is the largest among the three major island groups and accounts for more than half of the population. North of the Philippines is Chinese Taipei and in the south, the Indonesian archipelago.

Despite the global and local security threats and political uncertainties, the domestic economy still managed to overcome these difficulties. Gross Domestic Product (GDP) in 2002 grew by 4.43 percent at US$306.52 billion {1995 US$ at 1995 purchasing power parity (PPP)}. Its GDP per capita likewise posted an improvement of 2.3 percent at US$3,834 (1995 US$ at PPP). However, its energy consumption per capita of 0.2 toe, remains the lowest in the APEC region.

The resilience of the Philippine economy plays an important role in the world energy market as it is eyed by many as a growing consumer (a net importer) of energy, particularly for oil, coal and natural gas in the power and transport sectors. It has been considered a promising market for foreign energy companies.[43] In the long term, it may turn out either as a significant natural gas producer (with more gas discoveries) or an LNG importer (with increased gas demand).

The Philippines' indigenous energy reserves are relatively small with only about 24 million cubic metres (MCM) of crude oil, 107 billion cubic metres (BCM) of natural gas and 399 million metric tonnes of coal, mainly lignite. It however boasts of a geothermal resource that could make the economy the world's largest producer and user of geothermal energy for power generation. Other renewable energy resources (solar, wind, biomass and ocean) are theoretically estimated to have a power generation potential of more than 250,000 MW.

An effort to limit oil and coal imports to reduce the economy's dependence on imported energy has led to the prioritised and expanded use of natural gas for power generation.

Table 29 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	300,000	Oil (MCM) - Proven	24
Population (million)	79.94	Gas (BCM) - Proven	107
GDP Billion US$ (1995 US$ at PPP)	306.52	Coal (Mt) - Recoverable	399
GDP per capita (1995 US$ at PPP)	3,834		

Source: Energy Data and Modelling Centre, IEEJ. *Philippine Department of Energy (DOE)

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2002, the total primary energy supply (TPES), excluding traditional fuels, accounted to 32.3 Mtoe. The economy imports more than half (or 55.5 percent) of the total energy supply; the remainder was supplied through domestic production of indigenous resources, at 14.4 Mtoe. The main energy sources were oil (47 percent), geothermal and others (35 percent), coal (13 percent),

[43] Philippines Country Analysis Brief, Energy Information Administration (EIA), 2002

and gas (5 percent). Because of the coming on-stream of the Malampaya gas field in October 2001, gas production increased considerably in 2002 (by about 1,973 percent). Oil production likewise increased 20-fold due to the development of the deep-sea condensate deposit in the oil and gas rich Malampaya field, although this production is still only around 5 percent of the current demand, of about 356,000 bpd. APERC projected that oil consumption will increase annually by about 4.1 percent as demand in most sectors increase due to the economy's robust growth.

Most of the economy's total coal requirement is supplied through imports. However because of the lower demand for coal both for power and industry, coal imports decreased by about 9 percent, to 3,310 Ktoe from 3,644 Ktoe in 2001. Indigenous production, however, improved slightly to 798 Ktoe in 2002 from 590 Ktoe in 2001. Bulk of these imports came from China (41.2 percent) and Indonesia (41 percent), while the rest were supplied from Australia (14 percent) and Viet Nam (3.7 percent).

The Philippines' coal industry has since been heavily backed by regulations, imposing import restrictions on coal. When the World Trade Organization (WTO) regulations finally lifted such restrictions, it pulled down further the economy's crippling domestic coal production. This and other factors, including a switch (away from coal) to gas for electricity generation and opposition from pressure groups, are seen to have likely affected the decline in the importance of the domestic coal sector.

The government has announced that many coal-fired power plants will be converted to natural gas, including the 600 MW Calaca plant located south of Manila. To cushion its impact on the sector, government has introduced and encouraged several alternative uses of the domestically produced coal. According to the DOE, plans are underway for three new smaller-scale "clean coal" power plants (about 50 MW each). The DOE expects these plants completed by 2005.

The commissioning of the natural gas fired power plants in October has pushed upward the economy's natural gas production more than a thousand times, from 0.087 Mtoe in 2000 to 1.7 Mtoe in 2002. Following the success of the Malampaya project, more natural gas supply is expected as more areas are opened for prospective oil and gas developers.

In 2002, electricity production reached about 55,953 GWh. Bulk of this electricity generated came from thermal power plants, mostly run on coal and fuel oil (56 percent), geothermal and others (32 percent), and hydro (13 percent). The total installed electricity generating capacity is 14,702 MW. APERC predicts that electricity demand would grow to about 6 percent per annum to 2020: this implies that significant additional generation capacity will be required in the future.

The Philippines Energy Plan indicates that between 2004-2007, the economy's total energy demand will grow at 3.7 percent per year but will slow down a little to 3.5 percent between 2007-2013[44].

FINAL ENERGY CONSUMPTION

Final energy consumption was about 17.3 Mtoe in 2002. Half of the economy's energy supply was consumed by the transport sector, due mainly to oil, which made up more than 77 percent of the final energy demand. The residential, commercial and other sectors consumed about 28 percent mostly for electricity use while the remaining 20 percent was taken up by the industrial sector: utilising coal for power generation, industrial direct process, small end-use household fuel and briquetting.

[44] Philippine Energy Plan 2004-2013

Table 30 Energy supply & consumption for 2002

Primary Energy Supply Ktoe		Final Energy Consumption Ktoe		Power Generation GWh	
Indigenous Production	14,359	Industry Sector	3,487	Total	55,953
Net Imports & Other	17,914	Transport Sector	8,897	Thermal	31,192
Total PES	32,273	Other Sectors	4,910	Hydro	7,033
Coal	4,051	Total FEC	17,294	Nuclear	-
Oil	15,266	Coal	739	Others	17,728
Gas	1,724	Oil	13,401		
Others	11,232	Gas	-		
		Electricity & Others	3,154		

Source: Energy Data and Modelling Centre, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

ENERGY POLICY OVERVIEW

Over the last 10 years the Philippines has carried out and pursued reforms in the energy sector. Major reforms include; the reduction of the economy's dependence on imported energy (oil and coal), restructuring and deregulation of the electricity sector to improve efficiency (and attain the highest quality of service), provide fair and reasonable energy prices, and wider access to electricity supply.

The Philippines Energy Plan (PEP) 2004-2013, an annual update of the Philippines energy sector's plans and programmes, is set to achieve the energy sector's continuing commitment to promote a balanced economic growth, alleviate poverty and foster a market-based industry. The PEP targets to maintain 50 percent average energy self-sufficiency level in the next 10 years and raise this up to 55 percent by 2013. To achieve this target, it plans to intensify the development, exploration and use of the economy's indigenous energy resources and diversify its use in the power, industrial and transport sectors. The PEP also plans for the full implementation of the provisions of RA 9136 or the Electric Power Industry Reform Act of 2001, monitor and review sector pricing policies to ensure transparency and improve system efficiency. It plans to fully energise all the remaining un-electrified villages by 2006.

The government has issued a natural gas policy framework for its emerging gas industry. As facilitator, the government shall see through the development of the domestic natural gas resource and ensure its competition with imported gas. Natural gas prices will however remain regulated in areas where there are no competitive fuels.

STABLE AND SECURE ENERGY SUPPLY[45]

The commercial entry of indigenous natural gas into the economy's list of energy resources has enabled the economy to achieve a significant increase in self-sufficiency, both in the primary energy and power generation mixes. In 2002, the economy's primary energy consumption exhibited a marked reduction on imported fuels. The introduction of natural gas and subsequent emergence of the natural gas industry further reduced importations of oil and coal to 40 percent and 8 percent respectively. The commercial operation of the 3 natural gas fired power plants, enhanced utilization of renewable energy, retirement of 400 MW of oil-based power plants and extended non-operation of several coal-fired power plants further reduced the economy's dependence on

[45] 2002 Energy Sector Accomplishment Report, Philippine Department of Energy, 2003

imported oil and coal. The combined share of imported oil and coal declined from 54.5 percent in 2001 to 48 percent in 2002.

DIVERSIFICATION AND MAXIMIZATION OF RESOURCE POTENTIAL

Upstream Exploration

The development of the economy's domestic oil supply depends heavily on the international oil companies' willingness to invest in high-risk ventures like oil exploration and development. To further encourage investment in the oil sub-sector, the government has undertaken a resource assessment study, Philippine Petroleum Resource Assessment (PhilPRA), and complemented this with a promotions project, Philippine Petroleum Exploration Investment Promotion (PhilPRO) to publicise PhilPRA's results through international campaigns or road shows. The Department of Energy (DOE) has successfully initiated a "bidding round system" to award exploration contracts to the applicant with the best work program proposal including its technical and financial capability. It also envisions to review its current service contract system, improving and adding more incentives to investments, to draw more prospectors in petroleum exploration. The study produced an updated map of the 16 sedimentary basins in the economy. PhilPRA also established an inventory of the economy's petroleum resources – oil, natural gas and condensate – which totalled to about 8.9 BFOE.

Two Geophysical Survey and Exploration Contracts (GSECS) were awarded in June 2002. The contracts covers a geophysical survey program which includes slick mapping; geological survey and sampling analysis; and reprocessing and interpretation of a minimum of 740 line kilometres of seismic data.

Downstream Natural Gas Industry

The downstream natural gas sector received its initial push with the promulgation of the Executive Order (EO) No. 66 on 18 January 2002. EO 66 mandates DOE to act as the lead government agency in ensuring a coordinated effort towards the establishment of a successful natural gas industry. The DOE was vested with powers to draft the appropriate policy statements, industry rules and guidelines and issuances that would facilitate and encourage investments from the private sector. A Natural Gas Policy and Regulatory Framework was later issued to promote further investments and entry of other stakeholders in the industry.

In August 2002, the Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas was promulgated. The Circular provides the key elements (including technical and economic guidelines) for the various infrastructure projects. It also prescribes the process which relates to construction of transmission and distribution pipelines (and other related facilities). The DOE has also started with Congress, House Bill 4754, a bill which aims to institutionalise the regulatory mechanisms for the development of a downstream natural gas industry.

PROMOTION OF RENEWABLE ENERGY

Renewable Energy Policy Framework

The DOE has initiated the formulation of the Renewable Energy Policy Framework (REPF). REPF is intended to revisit the economy's existing renewable energy policies and programs, evaluate the current and future supply-demand outlook, and identify gaps and policy issues that need to be addressed for renewable energy's full deployment. It also lists steps and strategies to be undertaken that would ensure the market for renewable energy. Some of the policy initiatives include: a) diversification of energy mix in favour of indigenous RE resources; b) promotion of the wide-scale use of RE as alternative fuels and technologies; and c) encourage greater private sector investments and participation in RE development through market-based incentives.

Renewable Energy Bill

A renewable energy bill was filed in Congress that aims to promote the development, utilization and commercialisation of renewable energy sources. The bill provides for a framework for implementing renewable energy programs, including support to renewable energy systems' non-power uses. Among the salient features of the bill include: a) the setting of a minimum amount of generation capacity from renewable energy; b) establishment of a green electricity pricing program to promote the choice of power supply; c) conduct of sustained information dissemination on renewable energy development; and d) provision of additional fiscal and financial incentives to developers and implementers of renewable energy projects.

WIDER ACCESS TO ENERGY SUPPLY

The provision of wider access to energy supply is the primal responsibility of government. Such a task requires accelerated establishment of critical infrastructure, vigorous rural electrification program and prudent decentralization of various energy facilities.

ENHANCED INFRASTRUCTURE

Power Infrastructure

In 2002, the economy has an installed generating capacity of 14,702 MW. The commissioning of the 1,200 MW Ilijan and 500 MW San Lorenzo natural gas-fired power plants in June and October 2002, respectively, and the retirement of the 400 MW Sucat power plants, led to a net capacity addition of 1,300 MW: a 9.7 percent increase from its 2001 installed capacity level of 13,402 MW.

The National Transmission Corporation (TransCo), which administers about 24,738.6 circuit-kilometres (ckt-kms) of transmission and sub-transmission lines and about 23,062.9 megavolt-ampere (MVA) of substation capacity, has added to the system: 388 ctt-kms of transmission lines and 1,990 MV of substation capacity in 2002.

In August 2002, TransCo's Transmission Development Plan (TDP) was finalised. The Plan is viewed to provide an adequate and more efficient delivery of electricity to end-users and support the expected capacity build-up outlined in the Power Development Plan (PDP). The TDP has identified a total of 11,172 ckt-kms of transmission and sub-transmission lines and 20,980 MVA of substation capacity that need to be built within the next 10 years.

Distribution facilities were also built to enhance systems reliability and dependability. A total of 1,645 ck-kms of distribution lines were constructed while about 745 ckt-kms were rehabilitated. Thirteen substations with a total capacity of 102.5 MVA were installed at recipient villages within the electric cooperative's coverage areas.

OTHER INFRASTRUCTURE

The DOE has identified and established a pipeline infrastructure network that will include among others, high pressure natural gas transmission pipelines from Batangas to Manila and from Bataan to Manila, and spurlines to other locations to ensure the availability of natural gas to other potential users, particularly anchor loads identified in Sucat, Parañaque and Pililia, Rizal and Limay, Bataan.

Downstream Oil Industry

The deregulation of the oil industry resulted to the interplay of market forces in the local market particularly on supply sourcing and pricing of petroleum products, both in bulk and retail. This paved the way for the new players to participate in a more liberal investment environment, thus increasing the degree of competitive pressure and eventually improve efficiency resulting in better quality of products and services and market-driven oil prices. As of December 2002, a total of 84 players were engaged in various activities in the oil industry such as marketing, distribution and storage of petroleum products.

The DOE has endorsed the registration of more companies to the Board of Investments, and some expansion projects' application for incentives in the importation of capital equipment. The projects include facility expansion and establishment of terminals and the construction of new service stations in various parts of the economy.

The industry received a further boost with the issuance of Department Circular No. 2002-05-001 prescribing the rules and guidelines for the implementation of the Gasoline Station Lending and Financial Assistance Program. The program provides beneficiaries technical and financial assistance to establish and operate their own gasoline stations. Individuals, partnerships, cooperatives, associations, non-government organizations and corporations may enter into joint venture supply agreements with the new players for the establishment, management and operation of gasoline stations, including LPG retailing.

Rural Electrification

As of December 2002, the economy's electrification level stands at 87.1 percent. About 36,590 villages were energized, an increase of 4.8 percent from the previous year's total. The dramatic increase could be attributed to the creation of a working manual for the remaining un-energized villages, implementation of an accelerated sectoral approach among the "O Ilaw" team members and the full participation of the private sector; particularly the independent power producers (IPPs) thru advanced payments of missionary electrification fund from the Energy Regulations (ER) 1-94 and the "Adopt a Barangay" scheme. The DOE has also energised 134 villages through its Locally-Funded Project, using solar photovoltaic (PV) battery charging stations and 4 more villages through micro hydro systems in various parts of the economy.

FAIR AND REASONABLE ENERGY PRICES THROUGH POWER SECTOR REFORM

On 27 February 2002, the Joint Congressional Power Commission (JCPC) approved the Implementing Rules and Regulations (IRR) of the Electric Power Industry Reform Act (EPIRA), which was formulated by the DOE. The IRR is critical because the envisioned reforms in the power sector (under EPIRA) cover the intra- and inter- relationships of all the industry stakeholders. Likewise the reforms are expected to be implemented over an extended period and their impact on the industry's performance is anticipated to be gradual and incremental.

The following are some of the activities undertaken in implementing the provisions of the EPIRA:

CREATION OF THE ENERGY REGULATORY COMMISSION (ERC)

The ERC was created to replace the Energy Regulatory Board. ERC is an independent quasi-judicial body tasked to promote competition, encourage market development, ensure customer choice and penalise abuse of market power in the restructured electricity industry. It is also responsible for the issuance of rules including: a) follow-up rules and regulations implementing the de-monopolisation and shareholdings dispersal of distribution utilities issued on 13 March 2002; b) guidelines for the issuance of Certificate of Compliance to generation companies/facilities issued on 26 June 2002; and c) guidelines to govern the imposition of administrative sanctions in the forms of fines and penalties issued on 17 May 2002.

NPC PRIVATIZATION PLAN

On 4 October 2002, the Privatization Plan of TransCo and NPC, which was prepared by the Power Sector Assets and Liabilities Management Corporation (PSALM), was approved by President Gloria Macapagal Arroyo. The Privatization Plan encompasses the privatization of NPC transmission, generation and other disposable assets. The generation assets are to be sold through competitive bidding, which would then result to the formation of several generating companies (called GENCOs). The privatization of the transmission assets shall be made through the awarding of a concession agreement, likewise through a competitive bidding process.

ESTABLISHMENT OF THE WESM

On 28 June 2002, the DOE issued Department Circular No. 2002-06-003 which adopted the detailed rules for the wholesale electricity spot market (WESM), a mechanism critical for a successful electric power industry restructuring. WESM will facilitate competition in the production and supply of electricity thereby leading to more efficient and reliable power sector, and is thus expected to provide a competitive and reasonable electricity prices. The WESM rules will govern the operation of the spot market and provide the device that will identify and set the price of electricity between sellers and buyers of power.

The WESM website, www.wesm.ph, was launched on 11 November 2002. The site will be host to various WESM materials, frequently asked questions (FAQs), including questions and discussions, and serve as opinion site for information exchange.

CLEAN AND EFFICIENT ENERGY FUELS AND INFRASTRUCTURES

DEVELOPMENT OF CLEAN AND ALTERNATIVE FUELS FOR TRANSPORTATION

The following are several of the initiatives the DOE has undertaken to develop, promote and utilize alternative clean fuels and technologies:

- A 1,000 km on-road performance of a converted DOE compressed natural gas (CNG)-bus.
- Conversion and performance testing of a DOE utility vehicle to run on a bi-fuel (natural gas or gasoline) system.
- Launching of the Natural Gas Vehicle Programme for Public Transport (NGVPPT) on 16 October 2002. The programme aims to promote the use of natural gas as a clean alternative fuel for public transport. 100 natural gas are set to ply the major road networks starting 2003. Also unveiled during the programme launch was the package of fiscal and non-fiscal incentives to encourage public transport companies to use CNG as alternative fuel. Incentives include among others; financing schemes, tariff reductions, and franchise grants.
- Initiated the conduct of a joint feasibility study with Shell for a pilot project on the establishment of a CNG mother-daughter refueling station system. The proposed mother station will be sited at the Malampaya Onshore Gas Plant (MOGP) in Tabangao, Batangas. Calamba, Laguna is selected as the proposed site for the daughter station.
- Launching of the first public commercial autogas dispensing station by Petron Gasul in December 2002.
- Initiated the conduct of a pilot study to convert 10 service vehicles of the Development Bank of the Philippines (DBP) to run on gasoline and autogas.
- Conduct of a collaborative study entitled “Utilization of Coconut-Methyl Ether (CME) as Diesel Fuel Quality Enhancer” with the Philippine Coconut Authority (PCA) and the Technological University of the Philippines (TUP) to establish the benefits of CME for transport. Some benefits include reduction of air pollution and improved engine performance. The quality standards for CME was developed to facilitate its introduction as a potential blending component for conventional diesel fuels.

PROMOTION OF ENERGY EFFICIENCY

The Philippines entry to the 2002 ASEAN Energy Efficiency and Conservation Best Practice Buildings Awards received special citations for the Enterprise Centre and the Tower One and Exchange Plaza buildings in Makati City. Savings were achieved through strict compliance and implementation of energy efficiency and conservation projects and measures. With respect to the operation of commercial, industrial and the economic zones, the Partnership for Energy Responsive Economic Zones (PEREZ) and Partnership for Energy Responsive Companies (PERCs) were re-launched on 26 March 2002. The programmes are aimed at: a) assisting government offices and private companies to identify, install, operate and monitor energy conservation and efficiency programs, b) facilitating voluntary actions with regards to monitoring and reporting of energy consumption and adoption of energy efficient technologies by locators within and outside the ecozones, c) conducting information campaigns on the energy services that the government and private sector's Energy Service Companies (ESCOs) could provide.

NOTABLE ENERGY DEVELOPMENTS

In pursuing energy policy focussed on sustainable development and global competitiveness, the Philippines has been actively reviewing existing policies and carrying out reforms particularly in the power and downstream oil and gas sectors. The following embodies the economy's statements of recent and notable energy developments[46].

INSTITUTIONAL REFORMS

RENEWABLE ENERGY

With the government's formulation of the Renewable Energy Policy Framework (REPF) in 2003, the Philippine Department of Energy (DOE) is aggressively pushing for the passage of a law that will provide for a comprehensive and responsive framework for the implementation of its renewable energy program.

The law, otherwise known as "Renewable Energy Bill", will seek to support the development of new and renewable energy (NRE) resources that include among others; geothermal, hydro, wind, solar, ocean, biomass, and hybrid power system. Under the bill, participants in the development of NREs will enjoy, aside from other incentives; unregulated tariff, income tax holiday, tax and duty-free importation of equipment, tax credit on locally-sourced material, and exemptions from the value-added and real estate taxes.

Meanwhile, the Philippine government is actively pursuing its renewable energy development program through the following:

Solar Energy

1. In March 2004, a solar wafer fabrication facility was inaugurated at the Laguna Technopark in Sta. Rosa, Laguna, Philippines, signaling the start of its commercial operations. The company has successfully produced and commercially shipped its first PV wafer production in August 2004. The company is upbeat on the attainment of its 150 MW plant capacity by 2008.
2. The 990 kWp Centralised PV of Cagayan Electric Power and Light Co. (CEPALCO) in Cagayan de Oro City, Philippines, was completed and turned over by the contractor in July 2004. The plant's pre-commissioning test (dry-run) are being conducted by CEPALCO and they are just waiting for the issuance of the Energy Regulatory Commission's (ERC) Certificate of Compliance before they could start their commercial operation.
3. The Solar Power Technology Support (SPOTS) Project-Phase I of the Philippine Department of Agrarian Reform (DAR) started its actual installation of various solar PV systems package to the beneficiaries in April 2004. The project is an integrated social and agricultural program that will benefit 40 agrarian reform communities (ARCs) in Mindanao. The SPOTS Phase I has been extended and scheduled to be completed by December 2004.

[46] Statement of Notable Energy Developments, Philippines, Since EWG 27 (March 2004)

Wind Energy

1. The groundbreaking of the 25 MW Bangui Bay Wind Farm Project of Northwind Power Corporation in Bangui, Ilocos Norte on 24 April 2004 signaled the start of the project implementation. The project proponent has increased the capacity to 40 MW and targets to complete it by December 2004.
2. The 1st Phase of the 1.1 MW Batanes Wind-Diesel Hybrid Project was inaugurated on 7 August 2004. This signaled the start of commercial operation of the Philippines' 1st wind-diesel hybrid system.
3. The project will provide 24-hour electricity supply to 4 municipalities in Basco, Ivana, Mahatao, and Uyugan in Batan Island, in coordination with the provincial government of Batanes, the National Power Corporation (NPC) – Small Power Utilities Group (SPUG), First Philippine Energy Corporation, the Office of the Representative of Batanes, and the DOE.
4. A Philippine Wind Power Investment Kit was launched by the DOE on 28 June 2004 where 16 areas with an average capacity of 345 MWe was offered for investment by the private sector to develop and implement wind projects in the economy.

   As a result, the DOE received expressions of interest from Trans Asia Renewable Corporation and Powergen Inc., to study sites in Sual, Pangasinan; San Remigio and Pandan, Antique; Manoc-Manoc, Aklan; and Caliraya, Laguna. The Philippine National Oil Company – Energy Development Corporation (PNOC-EDC) will undertake other areas for study.

Hydropower

1. The DOE awarded the operating contracts for the development and implementation of the following mini-hydro projects: a) 2.5 MW Sevilla mini-hydro by Bohol 1 Electric Cooperative (BOHECO) in Sevilla, Bohol; b) 960 kW Catingas mini-hydro by Romblon Electric Cooperative Inc., in Sibuyan Island, Romblon; and c) 350-kW Hinubasan mini-hydro by the local government unit (LGU) of Loreto in Dinagat Island, Surigao Norte.
2. Funding for the conduct of feasibility studies for the following projects have been approved by the Japanese government: a) Sicopong Small Hydropower Project in Negros Oriental (September 2004), to be handled by WestJEC with PNOC; b) Talubin River in Mt. Province (September 2004), to be handled by TEPSCO with DOE; and c) Conservation of the Ifugao Rice Terraces through the Development of Hydropower Resources (April 2004), to be handled by TEPSCO with the DOE.
3. The 18-kW Pantikian micro-hydro was completed in August 2004. The project will provide electricity to small villages in Pantikian in Balbalan, Kalinga Province; benefiting 120 households.

Biomass

1. A Memorandum of Understanding (MOU) between the Talisay Bioenergy Inc. (TBI) and the PNOC was signed on 23 April 2004; PNOC acquired an equity in the project. TBI is the proponent of the 30 MW Bagasse Co-generation Project in Talisay City. TBI has already signed a Power Supply Agreement with a local distribution cooperative (CENECO).
2. Financing for the 1 MW Rice Husk fired co-generation project of La Suerte Rice Mill (LSRM) in San Manual, Isabela was approved by the Development Bank of the Philippines. The project is supported by the EC-ASEAN Cogen 3 Programme as a full-scale demonstration project.

3. The DOE completed the evaluation of the feasibility study of the proposed 5 MW Rice Husk Fired Power Plant in Bocaue, Bulacan. DOE now awaits the submission of a waste disposal plan from its project proponent, INTERCO.

DOWNSTREAM OIL INDUSTRY DEREGULATION

The downstream sector remains to be an attractive area for investments. To date, the Philippines has attracted the entry of 87 new players. More investments are expected through the incentives provided in the Republic Act (RA) 8479 or the “Downstream Oil Industry Deregulation Act of 1998”, particularly in the areas of storage, marketing, retailing, and distribution activities. These incentives include income tax holiday, additional deduction for labour expenses, minimum tax and duty of 3.0 percent and value-added tax (VAT) on imported capital equipment, exemption from real property tax on production equipment/machinery and exemption from taxes and duties on imported spare parts.

Likewise, as Section 14 of R.A. 8479 clearly provided for the promotion of retail competition, it stipulates the implementation of a Gasoline Station Lending and Financial Assistance Programme by government through the DOE. The programme is so designed to provide credit assistance to New Industry Participants (Borrowers) who have successfully completed the two-fold program on management and skills training in the retailing of petroleum products for the establishment, operation, improvement, management, and maintenance of gasoline stations under a deregulated environment. The financial assistance covers the retailing of all petroleum products sold in gasoline stations, including LPG.

Copies of the Department Circular 2003-06-007 or the guidelines for availment of the said financial assistance program are available at the Oil Industry Management Bureau of the DOE.

POWER SECTOR REFORMS

In the three years from the passage of Republic Act No. 9136 or the Electric Power Industry Reform Act of 2001 (EPIRA), the DOE has continued its mandate to oversee the planning, monitoring and assessment of the electricity industry reforms. The DOE has been working towards the implementation of the various reforms embodied in the EPIRA in collaboration with concerned government agencies and the private sector.

The electric power rate is considered as the most sensitive issue in the economy. The government remains focused in assuring a competitive environment that would ensure efficiency, reliability, transparency in the charges of electricity rates, and creation of a competitive market for the supply of electricity.

POWER GENERATION SECTOR

Privatization

Privatization of the generation assets of the National Power Corporation (NPC) shall be conducted through the following:

- Sale of generation assets shall be pursued parallel to the privatization by either through concession or partial sale of the National Transmission Corporation (TransCo);
- The sale sequence will consider the bidding out of the generation assets which do not require “assigned supply contract”;
- Assets will be grouped according to a set of criteria that shall consider, among other, investor interest and maximum return to government;
- An appropriate dispatch protocol will be put in place to address the requirements of a pre-spot market, post-privatization scenario.

The latest estimate on the proceeds of the sale of generation assets is US$2 billion. In the mean time that the selling is ongoing, NPC shall remain as the operation and maintenance of the generation assets. It continues to act as the leading government body in meeting generation demand where needed.

The first sale of the generation asset was accomplished in March 2004 with the successful bidding of the 3.5 MW Talomo Hydroelectric Plant in the southern city of Davao. A bigger plant, the 210 MW Navotas Power Plant in Metro Manila is set for bidding this first meeting semester of 2004.

Likewise, 3 diesel/bunker plants with a total of 168.5 MW capacity, 4 mini-hydro plants having a total capacity of 5.2 MW, and 4 decommissioned plants across the archipelago are scheduled for privatization by the second quarter of 2004. Fifteen generating assets with a total capacity of 2,774.9 MW are set to be offered to the private sector in 2003.

Privatization of NPC assets are being handled by the Power Sector Assets and Liabilities Management Corporation (PSALM), a government-owned and controlled corporation whose main function is to manage the orderly sale, disposition and privatization of NPC generation assets, real estate and other disposable assets and IPP contracts.

Tariff

In order to ensure transparent and reasonable prices of electricity in a regime of free and fair competition, the unbundling of electric power rates has been enforced. With the unbundled rate structure, power customers are now cognizant of the cost components of the electricity they are producing.

Independent Power Producers

NPC's contract agreements with IPPs total about 7.3 GW, or 65 percent of the total generation of NPC plants and NPC-IPPs. These contracts are to be assigned to Administrators who shall administer, conserve and manage the contracted energy output.

Missionary Electrification and Watershed Management

The missionary electrification function has remained with the NPC, through its Small Power Utilities Group (SPUG). It is responsible for providing power generation and its associated power delivery systems in areas that are not connected to the grid.

The recently-initiated campaign for private sector participation conducted by the DOE is envisioned to pave the way for the inflow of private capital into missionary areas. It provides for the transfer of SPUG's generation function to the private sector through a competitive process.

SPUG is set to adopt a Bid Supply with Financing Scheme for its upcoming projects for 21 areas with a total capacity of 32 MW. The scheme requires bidders to offer sources of financing along with their equipment. Advertised for bidding in March 2004, the new capacities are targeted for commissioning in the year 2005.

A second batch of capacity additions for 57 areas involving a total of 15.76 MW will also be bidded out within the year. For new area, SPUG will implement solar photovoltaic systems for 100 villages and mini-grid systems for 16 other villages.

Another vital function to remain with the NPC is the management of the watershed areas where the generating assets are located.

TRANSMISSION SECTOR

TransCo's transmission assets primarily consist of a network of overhead high voltage transmission lines and associated substations. As of August 2004, the total substation capacity owned and managed by TransCo reached 24,274 MVA. The length of the transmission lines totalled 21,106 circuit kilometres.

TRANSMISSION DEVELOPMENT PLAN (TDP)

The Transmission Development Plan (TDP) is a 10-year development that envisions a unified transmission system for the entire country. As a continuing effort towards interconnecting the major grids, the interconnection of Mindanao island with the presently interconnected island of Luzon, Leyte-Samar, Cebu, Negros, Panay, and Bohol by 2011 will be pursued, given a favourable result of feasibility study.

The TDP of 2004, covering the period 2004 to 2013, envisions the addition of around 11, 815 circuit-kilometres of transmission lines and 26,565 MVA of substation capacity.

OPEN ACCESS TRANSMISSION SERVICE

The National Power Corporation (NPC) has been implementing open access to its transmission facilities to allow the entry of private generating facilities into the major grid even before the enactment of the Electric Power Industry Reform Act (EPIRA). With the implementation of the EPIRA, TransCo has been mandated to provide all electric power industry participants open and non-discriminatory access to transmission system. The comprehensive policies on open access is contained in the Open Access Transmission Service (OATS Rules) approved by the Energy Regulatory Commission (ERC) on 11 February 2004. The OATS Rules serve as the framework of TransCo's open access mandate.

TRANSMISSION ASSETS PRIVATIZATION

R.A. 9136 provides that TransCo's facilities, including grid interconnections and ancillary services, shall be privatized with the objective of maximizing the present value of the proceeds to the government while attracting qualified investors.

The approved privatization plan for TansCo is in the form of a concession, which is effectively a 25-year lease of the transmission and automatically renewable for another 25 years provided that concessionaire is not in the breach of the concession agreement.

Both the first and second rounds of public bidding were declared failure by the Pre-qualification Bids and Awards Committee (PBAC) in July and August 2003. After two failed bids, PSALM Board has authorized the PSALM management to initiate negotiation with qualified interested parties.

To date, PSALM is evaluating the term sheets submitted by five interested proponents. Upon evaluation, PSALM will issue a short list and proceed with the negotiations. The government plans to put out a concessionaire in place by end 2005.

WHOLESALE ELECTRICITY SPOT MARKET (WESM)

The key feature of the power industry restructuring is the introduction of a competition in generation that will change the landscape of the current tariff practice from a regulated regime to a competitive one. To make this work, the Wholesale Spot Market (WESM) for electricity was established, and the Philippine WESM Infrastructure Site is already all set for the forthcoming delivery and installation of the Market Management System's (MMS) hardware and software components.

Preparations for the registration of the WESM participants are ongoing, and registration itself will commence in December 2004. The market trial operation of the WESM in Luzon is set in June 2005. This will test the rules, systems and procedures of the WESM as well as ensure the market participants' readiness. Commercial operation of WESM will take place by end 2005.

POWER SECTOR ASSETS AND LIABILITIES MANAGEMENT CORPORATION (PSALM)

The PSALM is mandated under R.A. 9136 primarily to manage the orderly sale, disposition and privatization of the National Power Corporation's (NPC) generation assets, real estates and other disposable assets, and Independent Power Producers (IPP) contracts, as well as transmission assets and facilities and sub-transmission functions and assets of the TransCo, with the purpose of liquidating all NPC financial obligations and stranded contract costs in an optimal manner.

Likewise, additional tasks are continuously being performed by PSALM, such as:

1. The assumption of the electric cooperatives' (ECs) financial obligation to the National Electrification Administration (NEA) and initiated the loan condonation of electric cooperatives owed to other government entities;
2. Administration of universal charge collection, deciding which fund is to be discharged in an open and transparent manner;
3. Filing of rate petitions, together with NPC, for a generation rate adjustment, to reflect the actual cost of generating capacity;
4. Simulation and eventual trading of electricity generated by the NPC and IPP Plants prior to its privatization;
5. Privatization of NPC;
6. Review and renegotiation of IPP contracts that are expected to continue and be finalized by 2005.

NATURAL GAS

Natural Gas for Power Sector

A total of 2,700 MW of installed capacity of gas-fired power plants make use of the natural gas produced from the offshore Malampaya gas field in the island province of Palawan. Likewise a 3 MW installed capacity of gas-fired power plant is also supplied by the onshore San Antonio gas field in Isabela Province. Together, cumulative gas production from both gas fields reached 56,565 MMSCF from January-July 2004, and it continued to contribute to the country's total primary energy mix by 6.5 percent.

From January to July this year, natural gas consumption of gas-fired power plants, namely: the 1,200 MW Ilijan, 1,000 MW Sta. Rita and the 500 MW San Lorenzo gas-fired plants in Batangas, including the San Antonio field in Isabela reached a total of 53, 587 MMSCF to generate 20,732 GWh of electric power.

As of 2003, natural gas continued to contribute to the country's total primary energy mix by 6.5 percent while the share of natural gas in the total generation is about 25.4 percent.

Non-Power Application of Natural Gas

Executive Order (EO) 290, entitled "Implementing the Natural Gas Vehicle Program for Public Transport", was issued by President Gloria Macapagal Arroyo in support to the Natural Gas Vehicle Program for Public Transport (NGVPPT). The EO provides for a package of fiscal and non-fiscal privileges and incentives that can be availed of by the NGVPPT participants, particularly bus operators and equipment/spare parts suppliers.

Department Circular 2004-04-004 was issued in April 2004 that provides the guidelines on the issuance of Certificate of Accreditation (CA) and Certificate of Authority to import (CAI).

A public hearing on the reduction of tariffs from 1 percent to 0 percent on NGV industry-related equipment, facilities, parts, and components was conducted on 23 September 2004.

To facilitate the implementation of the CNG Pilot Project under the NGVPPT through the acquisition of CNG, a MOA was signed among the DOE, DOTC, LTO, LTFRB and 4 other bus operators (HM Transport Inc., NGV Adbus Inc., De Guia Enterprises, Inc. and First CNG). Another development on the program was the contract signing between the bus operators and

Cummins Westport Asia in Beijing, China for the purchase of 100 units of CNG buses. The event was witnessed by President Arroyo during her state visit on 03 September 2004.

On 17 May 2004, the government launched the Libreng Sakay (Free Ride) sa NGV Program. This was conducted for the commuting public together with the drivers of various bus operators in order to test and drive the demo CNG buses along major thoroughfares in Metro Manila; Calamba, Laguna; Batangas: and Cavite. The program also serves as an information, education and communication (IEC) campaign to the commuting public on the environmental benefits as well as a demonstration of the CNG vehicles for local adaptability.

A CNG three-wheeler was also looked at for demonstration under the NGVVT Program. On 25 February 2004, the DOE signed a MOA with Bajaj Auto Limited (India) for the provision of two units bi-fuel CNG three wheelers that was delivered to the DOE in May 2004 for testing and demonstration to local government to local government units in Metro Manila. Part of the donation was the conduct of technical briefing and training on the technology to DOE technical staff and NGV technical working group by Bajaj representative. Demonstration activities on the three- wheeler vehicles were conducted to the Tricycle Group in Makati, Pateros and Taguig.

As regards to the CNG program implemented by PNOC, there is on going conducdt of field demonstration of the Enviro-taxis and orientation on NGV development in the Philippine in schools located in Southern Luzon.

An ecozone profiling to determine the energy profile of the ecozones in the economy in terms of consumption, source of power, installed capacity and potential for natural gas use is being conducted. First phase of the study is ongoing.

Ongoing Infrastructure Program for the Development of the Natural Gas Industry

The development of gas transmission and distribution pipeline networks, including their related facilities, such as CNG/LNG, is critical activity to the successful development of the downstream natural gas industry.

The Batangas to Manila (BATMAN 1) gas transmission pipeline project, spearheaded by the PNOC-EC, is targeted to be operational by year 2007. In April 2004, the Front End Engineering Design (FEED) contract was bidded out. Technical bids were opened on 12 August 2004 while the financial bid is scheduled on 12 November 2004.

The Bataan to Manila Pipeline, otherwise known as BATMAN 2 is part of the Philippine government's over-all natural gas development program that aims to expand natural gas utilization from Bataan to other areas in Luzon.

The DOE is also evaluating new technologies to be able to transport natural gas to island provinces in central and southern parts of the economy.

Natural Gas Bill

One of the top five priority bills of the present administration filed in Congress is House Bill No. 1533 entitled "An Act Ordaining the Development of the Downstream Natural Gas Industry, consolidating for the Purpose all Laws relating to the Transmission, Distribution and Supply of Natural Gas and for other purpose", was filed on 30 June 2004.

Likewise, Senate Bill No. 8 entitled "An Act ordaining the Development of the Downstream Natural Gas Industry, consolidating for the Purpose all Laws relating to the Transmission, Distribution and Supply of Natural Gas and for other purpose", was filed on 30 June 2004.

ENERGY EFFICIENCY AND CONSERVATION

In line with its mandate to promote judicious conservation and efficient utilization of energy, the DOE continues to pursue an aggressive energy efficiency program. The aim of the Program is to improve energy use in major energy-consuming sectors, and reducing greenhouse gas emissions and other pollutants resulting from energy production and utilization.

ENERGY LABELING AND EFFICIENCY STANDARDS

The Philippines is among the many economies that implement energy standards and labelling program for household appliances and lighting products as a strategy to reduce energy consumption.

Launched in 2003, the program currently covers room air conditioners (mandatory standards and labelling), compact fluorescent lamps (CFLs) (voluntary labelling by 2004) and fluorescent lamp ballast (voluntary labelling by 2004).

The energy labels show the product's capacity and energy ratings such as energy consumption and efficiency. Thus consumers would be able to choose just the right size or capacity for their particular requirements and thus, save on what cold have been excess power consumption. On the other hand, the information on energy ratings of the product empowers the consumer in choosing the more energy efficient brand and model.

To effectively carry out the standards and labelling program, the Philippine DOE established the Lighting and Appliance Testing Laboratory (LATL) to verify the claimed product ratings as indicated in the energy label.

During the third quarter of 1994, the government launched the National Energy Efficiency and Conservation Program (NEECP) that includes, among others, the continued implementation of energy standards and labelling. Pursuant to this, the DOE shall implement the following activities:

1. Develop a financing scheme for consumers who want to convert from incandescent bulbs to CFLs which are far more expensive but more energy efficient;
2. Fast track the development of the national standard for energy labeling of linear fluorescent lamps;
3. Develop a consumer guide pamphlet that would show the list of certified brands and models of products covered by the energy-labeling program.

OTHERS

The Philippine government, through the PNOC-EC has signed an agreement in September 2004 with the China National Offshore Oil Company (CNOOC) to undertake a joint study of the resource potential of certain areas of the South China Sea.

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RUSSIA

INTRODUCTION

Russia is the largest economy in the world in terms of land area (about 17 million square kilometres). It is located in East Europe and Northern Asia, bordering the Arctic Ocean, between Central Europe and the North Pacific Ocean. Broad plains with low hills west of Urals, vast coniferous forests and tundra in Siberia, and uplands and mountains along the southern border regions, characterise its terrain. It has a vast natural resource base which includes major deposits of oil, natural gas, coal and other minerals. Despite the land area advantage, it is unfavourably located in relation to major sea lanes of the world. Likewise, it lacks the proper climate (either too cold or too dry) for agriculture. The overall population density is low - less then 9 persons per square kilometre, with its northern and eastern regions very sparsely populated. Since 1990 the population declined from 148.4 million into 144.2 million in 2004.

After a decade of economic contraction, of about 40 percent compared to the 1990 GDP level, the Russian economy began to grow again at the beginning of 1999, boosted by the stimulating effect of the 1998 ruble devaluation and higher oil prices. Russia's economy is continuing its strong development and achieving the 4th year of positive economic recovery. GDP declined from 6.4 percent in 1999 to 4.3 percent in 2002. The industrial production grew 4.9 percent and investment in fixed capital was up 8.7 percent. GDP in 2002 was estimated US$1,045 billion (at 1995 purchasing power parity dollars) and the inflation, which remains under the control of the government, was 15.1 percent. The official unemployment rate is about 8.5 percent.

Russia has abundant natural energy resources, possessing the world's largest proven reserves of gas, 6 percent of the world's proven oil reserves and 15.9 percent of the world's coal reserves. However, formidable obstacles of climate, terrain, and distance have hindered exploitation of these natural resources. The economic potential of hydropower is estimated at 852 TWh per year, only 20 percent of which has been developed. Economic reserves of uranium ore comprise about 14 percent of the world total.

Russia is the world's largest exporter of energy, largest exporter of natural gas, the second largest oil exporter (behind the Saudi Arabia), the second largest primary energy producer (behind the United States) and the third largest energy consumer (behind the United States and China).

The energy sector is very important to the Russian economic development. In 2002, it accounted for 25 percent of GDP and approximately 50 percent of the economy's export including oil, natural gas and petroleum products.

Table 31 Key data and economic profile (2002)

Key data		**Energy reserves***	
Area (sq. km)	17,075,200	Oil (MCM) - Proven	10,986
Population (million)	145.1	Gas (BCM) - Proven	47,000
GDP Billion $ (1995 $ at PPP)	1044.6	Coal (Mt) - Recoverable	157,010
GDP per capita (1995 US$ at PPP)	7,200		

Source: Energy Data and Modelling Center, IEEJ. * The BP Statistical Review of World Energy, 2004.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Russia's total primary energy supply in the year 2002 was 648.5 Mtoe. This total comprised 55.8 percent of natural gas, 19.8 percent of crude oil and petroleum products, 15.6 percent of coal and 8.8 percent others including nuclear and hydro. Russia was the largest net exporter of energy in the world in 2002 with 40 percent of energy production has been exported. Western and Eastern Europe including Commonwealth of Independent States accounted to 98 percent of Russia's total energy export destinations. Currently, Russia is developing new energy export routes aiming to markets in such APEC economies as USA, China, Japan, South Korea, Canada and other.

OIL

In 2002, Russia produced 377.6 Mt of crude oil and gas condensate. The net exports of crude and petroleum products totalled 255.4 Mtoe, or 66 percent of production, while the annual average refinery capacity was 256.9 Mt.

Currently, the oil industry is highly profitable because of high world oil prices. The main oil province of West Siberia produces some 70 percent of total crude oil and NGL. New prospective oil provinces are located in the Timano-Pechora region, East Siberia, the Far East and North Caspian offshore.

NATURAL GAS

Natural gas production in 2002 reached 532.8 Mtoe. Net exports accounted for 160 Mtoe or 30 percent of production. About all of natural gas exports are destined to Europe, including Turkey, with small amount pumped to Transkaukasian states - Armenia, Azerbaijan and Georgia.

Since the 1990s natural gas production has exceeded the rate at which reserves are discovered. This is mainly due to insufficient investment in exploration. New resource bases are located in remote regions without the necessary infrastructure to start upstream operations. Such areas are the Barents Sea offshore (Schtokman field), East Siberia (Kovykta), Yakutia (Chayanda) and Sakhalin offshore.

The East Siberian and Yakutia gas fields belong to the ancient sediments and characterised by high helium contents. Along with central US this region contain the largest world reserves of helium in natural gases.

COAL

In 2002, Russia produced 112.2 Mtoe of coal, a decline of 6 percent than in the previous year. Hard coal contributed most of the production (about 75 percent of total production), with lignite filled the balance. Net export of coal in 2002 amounted to 12.4 Mtoe, or 11 percent of production.

The main coal production areas are located in the Asian Part of Russia - the Kuznetsk and Kansk-Achinsk regions. Perspective coal basins have been found in more remote areas of Eastern Siberia, South Yakutia and the Far East. The government envisions a greater role of coal in national energy balance, particularly in power generation.

ELECTRICITY

Russia produced 896 GWh of electricity in 2002, of which 65.3 percent was produced from fossil fuels (gas, coal and fuel oil), 18.5 percent by hydro and 15.9 percent by nuclear.

There is significant untapped hydro energy potential in the Asian part of Russia. Hydropower performs an important function to regulate peak loads in the unified power grid. The largest stations and the most prospective resources are located in southern Siberia; however, the capital costs of new hydro are prohibitively high. Russia hopes to complete construction of some of the large hydros in the next 10 years namely: the Boguchanskaya station in East Siberia; Bureya, Ust'-Srednekanskaya; and Vilyi stations in the Far East.

In 2002 Russia operated 30 nuclear reactors with an installed capacity of about 21.2 GW. Most of these reactors are located in the European part of Russia.

Table 32 Energy consumption & supply for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	1 080,798	Industry Sector	152,277	Total	896,042
Net Imports & Other	-432,331	Transport Sector	87,382	Thermal	585,287
Total PES	648,467	Other Sectors	189,646	Hydro	166,163
Coal	101,304	Total FEC	429,305	Nuclear	141,629
Oil	128,194	Coal	19,609	Others	2,963
Gas	361,841	Oil	89.366		
Others	57,129	Gas	128,605		
		Electricity & Others	191,725		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

FINAL ENERGY CONSUMPTION

In 2002, total final energy consumption in Russia was 429.3 Mtoe, an increase of about 3.3 percent compared with the previous year. By sector, industry had accounted for 35.5 percent share, transport for 20.4 percent and other sectors for 44.1 percent. By fuel shares, coal accounted for 4.6 percent, petroleum products 20.8 percent, natural gas 29.9 percent and electricity, heat & others 44.7 percent. The most important energy use is for space heating, comprising about 40 percent of total final consumption due to the extreme cold climate.

Russia's final energy intensity is the highest among APEC economies, a clear sign of inefficient energy use in the national economy. The traditional energy intensive industrial structure with its aging capital stock has not changed greatly, due to the lack of investment. Structural shifts to less energy intensive services and high technology industries are considered as a major policy direction to encourage energy savings, along with energy efficiency measures in existing industries. According to various estimates, Russia has an untapped energy savings technical potential of 35 - 45 percent of total energy consumption

POLICY OVERVIEW

ENERGY STRATEGY UP TO YEAR 2020 ADOPTED

One of the milestones in Russia's energy sector development is the adoption of the Energy Strategy of Russia to 2020, which was approved by the Federal Government in August 2003. The document identifies the main directives of the country's long-term energy policy. As stated in the Strategy, "the natural fuel and energy resources and industrial, scientific, technological and human resources potential of the energy sector is Russia's national wealth. Its effective use should create necessary conditions for sustainable economic development of the country improving the welfare and living standards of the people". The Energy Strategy of the Russian Federation to the year 2020 is the main document which contains the system of scientifically-justified principles on priorities of long-term state energy policy and mechanisms of it's realization.

The Energy Strategy was destined for Governmental Agencies, Joint-Stock Companies and Public Organizations for determining priorities, directions and means of structural, regional, scientific, technical and environmental policies in energy supplies.

Main Priority of Energy Strategy of Russia is to improve energy efficiency using state interference on the energy market. Some of these interferences include among others: pricing policy, tax and customs policy. In addition Russia also perform institutional and organizational reforms in the fuel and energy sector by improving its legislative and regulatory policies.

Main pricing policy include:

- Gradual expansion of the application of market pricing for fuel and energy in the internal market
- Provision for financial stability and investment attractiveness of fuel and energy enterprises
- Removal of existing disproportion between prices of main types of energy resources
- deepening price (tariffs) differentiation for different categories of consumers
- gradual removal of all forms of energy subsidy

Based on a business as usual scenario the GDP of Russia in 2010 will increase to 1.73 times, and about 3.34 times in 2020 from its GDP in 2000. The reorganization of the economic structure and the application of technological innovations for expected energy savings will reduce power consumption by about 26-27 percent in 2010 and 45-55 percent by end 2020. About half of projected economic growth could be achieved by structural reorganization without any increase in energy costs. Energy saving measures expected will contribute to 20 percent and only about one third of GDP growth will demand an increase in energy consumption.

Another key factor in Russia's energy policy is its participation, as the large supplier of energy resources, in improving the international energy security. To achieve these objectives, Russia has adopted the following strategic initiatives:

- modernization and construction of port terminals to enhance export shipments of energy resources
- development of the trunk oil pipelines system
- development of oil and gas resources of Eastern Siberia, Republic of Sakha (Yakutia) and Sakhalin Island offshore, and
- creation of bulk oil and gas export routes to the economies in the Asia-Pacific region.

Development of a transport infrastructure in Russia is a necessary step towards having its own export terminals. This would secure export deliveries of oil and petroleum products, including the formation of new export routes. Some of the on going projects are: Baltic Pipeline System with export capacity of 62 Mt of oil per year, the new pipeline on the Kola peninsula with capacity up to 120 Mt oil per year, capacity expansion of Black sea oil terminals on to 59 Mt of oil per year, and the construction of the first ever oil export pipeline from East Siberia to the Pacific coast on Russian Far East with branches to Daquing in Northern China.

The market of hydrocarbons in the Western and Central Europe, which serves as the main destination of Russia's energy export (reaching 98 percent), will remain as Russia's largest market until the next 20 years. At the same time, Russia energy export to the economies in the Asia-Pacific Region will increase up to 30 percent in 2020. Exports to APEC economies such as USA, Canada, Japan and China, have become one of Russia's recent priority. Another priority is to increase oil and gas production in the Russian Far East and in Eastern Siberia. Yamal peninsula and Arctic shelf could become Russia's important sources of hydrocarbons in the future. About 25 percent of oil and up to about 35 percent of gas production in Russia in 2020 could be produced from this fields.

MARKET LIBERALISATION

Oil and coal markets in Russia have been deregulated since the 1990s. Oil industry consists of 11 vertically integrated companies that produce about 90 percent of crude oil in Russia, some 240 small-scale enterprises produced the remaining 10 percent. There is no state control on petroleum prices except under the Federal Antimonopoly Supervision Agency.

During the transition period, the government is keeping control over the tariff-setting policy for natural monopolies services. The Federal Tariff Service is authorised to set maximum allowable regional natural gas, electricity and centralized heat tariffs. At the end of 2004 correlation for per energy unit producer's price for oil, fuel oil, steam coal and natural gas will be 1-0.5-0.1-0.3 respectively.

The coal sector has been restructured since 1996, when Rosugol (the state coal monopoly) was privatised. Quantitative export restrictions have been removed and no export quotas exist. Coal is the single largest commodity transported by Russia's railway network, accounting for over 27 percent of the country's rail freight. The geographical size of Russia's vast country requires the haulage of coal over long distances; therefore, it is extremely important to set up freight rates that are competitive to allow coal to maintain its proportionate share in the energy mix. In the past rail tariffs were relatively cheap, however, there has been a significant increase in rail freight rates due to the restructuring in the railway industry.

Although domestic price controls have been removed, many coal producers find it difficult to compete with alternative fuels such as oil and gas whose prices are still regulated by the government. Consequently, coal producers will often quote domestic coal at prices that are below production cost.

Created in 2000, MDM Group controls roughly 70 percent of Russia's coal production. Foreign ownership in the Russian coal sector is practically nonexistent.

Market liberalisation is a strategic direction for power industry development. One of the main issues is a gradual move from state-regulated energy pricing to free market pricing. For domestic energy markets as a whole, the urgent problem to resolve is the elimination of price distortions between oil products, coal and artificially low state-regulated gas prices.

In March 2003, Russian President Vladimir Putin signed 6 bills into law to substantially reform the power industry. By this law, tariff rates on the domestic market could be liberalised by 01 July 2005 and Unified Energy System should be liquidated in 2006. Electricity generation and distribution networks are expected to be privatised, while the economy's transmission grid will remain under the control of the Government.

Free electricity trade market was launched on 1 November 2003 within the framework of the Federal Wholesale Electricity Market (FOREM). One year later there were already 106 players on the market, and the free trade volume exceed 4.2 percent of total electricity generation. Russian free trade electricity market stands 5th in Europe and 9th in the world for volume of electricity traded.

Starting from 1 April 2005, Siberia would join free electricity market with 5-15 formulation, while in European part formulation would change to 15-30, which means that 5 (15) percent of electricity generated producers *could* sell, and 15 (30) percent of the demand consumers *could* purchase on responding regional free electricity market.

Electricity free trade applied on the European part of Russia, except for the Arkhangelsk Oblast and Komi Republic. In free market, new pricing mechanism was introduced, where the prices are established as a result of an equilibration of demand and supply on electricity and completely depend on price preferences of the market participants.

Government is the main shareholder of Gazprom with a stake of 38.4 percent. The consolidation of the company's shares was completed in 2003, in which the government controls more then 51 percent of shares of company and its subsidiaries. Along with Gazprom who produce some 90 percent of natural gas there are independent gas producing companies. Access for independent producers to Gazprom's gas transportation system as well as wholesale gas prices is regulated by a special Governmental Decree.

ENVIRONMENTAL POLICY

Russian President V.V.Putin has signed into law the bill ratifying Russia's acceptance of the Kyoto Protocol to the UN Framework Convention on Climate Change on 5 November 2004, effectively enforcing the Protocol in Russia. This decision reconfirmed Russia's strong commitment in addressing climate change and to working with the international community in dealing with this global problem. It was announced by the UN Secretary General that the Protocol will become legally binding on its 128 Parties on 16 February 2005.

One of great issue for world energy development is nuclear safety. Some countries have no large-scale plans for development of national nuclear energy and, accordingly, do not require new energy fuel - recycled products of spend nuclear fuel (SNF) processing. However the Russian Federation, as the USSR before, uses other approach, based on the so-called "Fast Breeder Reactor" technology.

Russia adopted the concept of "the closed fuel cycle" with SNF processing and obligatory return of fission nuclear materials to a fuel cycle. That concept improved the technological side, global environment protection and safety. The adoption of closed fuel cycle was announced in the initiative of the President of the Russian Federation at "Summit of Millenium" in the United Nations, in September 2000. To provide legal framework in managing nuclear wastes, amendments to the Environment Protection Law and Nuclear Energy Utilization Law were made in June 2001. The amendment allows treatment of other country's SNF and permanent storage of nuclear waste in Russia.

NOTABLE ENERGY DEVELOPMENTS

CONOCOPHILLIPS DEAL WITH LUKOIL

In September 2004 Houston-based ConocoPhillips, the No. 3 U.S. integrated oil company behind ExxonMobil and ChevronTexaco paid some US$2 billion for a 7.6 percent stake in Lukoil and signed an agreement that could increase its interest in the Russian oil giant to 20 percent. This deal got the nod from both the Kremlin and the White House.

Lukoil is the second largest oil and gas company in Russia behind Gazprom. The company produces about 1.7 million barrels-of-oil-equivalent a day and had 20 billion barrels of proved reserves at year-end 2003. Comparatively, ConocoPhillips produces 1.6 million barrels a day and had 7.85 billion barrels of proved reserves at year-end 2003.

As of October 2004 ConocoPhillips has finished the share in the capital of Lukoil with 10 percent. The largest Russian oil company already declared that extraordinary assembly of shareholders which will enter ConocoPhillips representative into Board of Directors will be held in January 2005 in Moscow.

GAZPROM ADSORBING STATE OIL COMPANY

In September 2004 Gazprom, the Russian state-controlled natural gas company, announced that it will take over Rosneft, the state oil firm. By executing the stock swap, the state increases its ownership percentage in Gazprom from 38 percent to 50 percent and transforms what is already the world's largest natural gas producer (20 percent of world gas production) into a significant oil producer as well. The combined company would hold oil and gas reserves of about 117.7 billion barrels-of-oil-equivalent.

It is planned that Rosneft activities will be included in the structure of the company within the framework of the Government–Gazprom transaction as a result of which 50 percent + 1 action of

Gazprom would appear in the state property, and Rosneft will be part of Gazprom. The merger will lead to the lifting restrictions of foreign ownership of Gazprom shares.

GAZPROM PLANS TO ENTER NORTH AMERICA LNG MARKET

Russian gas monopoly Gazprom has intensified efforts to break into the fast-growing North America's LNG market with leading Western oil majors.

The Russian company said the operation would allow it to learn more about the industry before it starts producing its own LNG next decade from the giant Shtokman field in the Barents Sea with gas reserves of 3.2 trillion cubic metres. The monopoly hopes that, using a subsea production solution with Western participation, will allow it to produce its first commercial gas by 2010 at an initial investment cost of US$7 billion. The declaration of Gazprom's liquefied natural gas ambitions came as executive chairman Alexei Miller visited the US for talks with ExxonMobil, ChevronTexaco and ConocoPhillips about their possible involvement in the Shtokman project. Gazprom will retain its control over all gas supplies through the monopoly-owned pipeline to traditional Russian and European markets. Gazprom had earlier signed a memorandum of understanding with Norway's Norsk Hydro and Statoil on its potential participation in Shtokman.

Canada's PetroCanada has also emerged as a competitor. The company may invest around US$2.8 billion in Shtokman field in exchange for a 10 percent interest in the development. PetroCanada is also proposing that Gazprom builds a smaller LNG plant near St. Petersburg at a cost of US$1.3 billion to gain experience and start testing LNG shipments to North America. Feedstock for the plant would be delivered almost 3000 kilometres from West Siberia through Gazprom's trunk pipeline network.

Gazprom is also pursuing an LNG project on the Yamal peninsula, but seems to be prioritising Shtokman at this point.

SAKHALIN ISLAND OIL AND GAS FIELDS DEVELOPMENT

The Sakhalin 2 project being developed by Shell, Mitsubishi and Mitsui is now the most dynamically developing oil-and-gas project in Russian Far East region. During the first five production seasons it has shipped about 6.7 million tons of high-quality oil to Japan, China, South Korea, Taiwan, USA and Philippines. Oil deliveries by Sakhalin 2 from non-frozen port Korsakov on south coast of Sakhalin Island are expected to begin in 2006. Maximum volume of oil production could reach 8.75 million tonnes per annum (mtpa). Expected cost of the project already exceeded US$17 billion.

Shell is currently building the world's largest LNG liquefaction plant with a capacity of 9.6 mtpa on the island. It is also the first Russian LNG facility, targeting its first exports to Japan in 2007. In October 2004 Sakhalin Energy Investment Company Ltd. (Sakhalin Energy) announced the signing of a sell and purchase agreement (SPA) to supply 37 million tones of LNG over a 20 year period to Shell Eastern Trading Ltd. (Shell) for the North American natural gas market. This represents the first sales of Russian natural gas to North America. The agreement will bring the total long-term sales deals for Sakhalin Energy LNG to 5 mtpa. Sakhalin Energy in November 2004 has awarded contracts for the long-term charter of three new-built 147,200 m^3 LNG ships. The three ships will have ice strengthening and will be designed to operate at low temperatures to allow them to make deliveries from Sakhalin Energy's LNG Plant all year round.

The Sakhalin 1 project is being led by Exxon Neftegaz in cooperation with SODECO, ONGC Videsh, Sakhalinmorneftegaz and Astra. The project started drilling in May 2003 and expected to start oil production in 2005. The largest world oil company ExxonMobil is going to construct the pipeline between Sakhalin Island and Japan for deliveries of the Sakhalin gas, instead of transporting the liquefied natural gas through tankers. Exxon Neftegaz finds it most suitable (both in the aspect of technical and commercial) to use a pipeline for gas transport.

BALTIC PIPELINE SYSTEM EMERGING

The Baltic Pipeline System (BPS) came online in December 2001, and carries crude oil from Russia's West Siberian and Timan-Pechora oil provinces westward to the newly completed port of Primorsk in the easternmost arm of the Baltic Sea. The BPS annual capacity reached 47.5 million tons per year in 2004. Russian Industry and Energy Minister Viktor Khristenko reported in October 2004 that decision on expanding the BPS to 62 million tons per year has been submitted to Government.

The BPS gives Russia a direct outlet to northern European markets, allowing the country to reduce its dependence on transit routes through Baltic States - Estonia, Latvia, and Lithuania.

INTERNATIONAL FEASIBILITY REPORT PREPARED FOR KOVIKTA GASFIELD

In October 2003 Russian RUSIA Petroleum, Chinese CNPC and Korean Kogas have ratified in Moscow the international feasibility study (IFS) of gas trunk pipeline construction from giant Kovikta gasfield. Yet the participants of the US$17 billion project have not agreed upon the price of the Russian gas, and also the pipeline should pass next to south cost of Baikal lake – the route on which environment approval for oil pipeline Angarsk - Daquin has drawn the negative conclusion.

Three more companies have ratified IFS and have signed the MoU on the sale and purchase of the Russian gas. Deliveries of gas are planned to start in 2008 while reaching plate level in 2017. About 20 BCM is scheduled for Northern China and 10 BCM to the Republic of Korea.

EAST OIL PIPELINE PROJECT

The final decision of the Russian Government on the construction of an oil pipeline to the Russian Far East was accepted at the very end of year 2004, sealing Transneft investment proposal for Eastern Siberia – Pacific Ocean rout. In November 2004 Transneft CEO S.Vainshtock sent a letter to the Prime Minister with offer of stage-by-stage implementation of the project wherein the course of the first stage is expected to construct the pipeline up to Skovorodino on Baikal-Amur railway. In May next year Government should adopt time schedule for each stage of the project.

Transneft has defined the cost of oil transportation to a route Eastern Siberia – Pacific Ocean for the first time. Originally it will make US$47 per ton (US$47 per bbl) and after repayment of credits could decrease twice. The project provides construction of an oil pipeline Taishet – Kazachinskoye – Skovorodino – Khabarovsk – Perevoznaya harbor. It's total length will make 4,130 km. Capacity of system could reach up to 80 mtpa with total investment expenses estimated at US$16 billion. The raw-material base of the project is Western Siberia oil (24 million tonnes) and the rest should come from yet to be developed deposits of Eastern Siberia and Republics of Sakha (Yakutia).

NEW HYDRO FACILITIES

In June 2003 the first unit of Bureya dam on the Amur river in Russia's Far East began producing power. This is one of the largest hydroelectric dams to come on line in the past 15 years. In November 2004 the third unit was commissioned which almost doubled the hydro station's current capacity to 670 MW. After completing in 2007 with its full 2,000-megawatt capacity, Bureya dam could supply Russian Far East regions cheaper and environmentally friendly electricity with gradual increase in electricity export expected for this region.

NUCLEAR FACILITIES IMPROVED

Russia's Kursk nuclear power plant reached its design power of 4 million kilowatts on 4th November 2004 for the first time in 14 years – since 1990, when power limitations were placed on Kursk-1 and -2 units by former regulatory body Gosatomnadzor. Reaching the design capacity became possible after a series of safety improvement measures which included an in-depth safety assessment for the modernization and reconstruction of Kursk's first-generation power units were made.

Located 40 kilometres south-west of the city of Kursk, the four-unit Kursk nuclear plant supplies electricity mainly to central Russia. Kursk-1 and -2 are first-generation RBMK-1000 channel-type reactor units, which first provided power to the grid in 1976 and 1979, respectively. Kursk-3 and -4 are second-generation RBMK-1000 units, which first provided power to the grid in 1983 and 1985, respectively.

The lifting of the power limitations on units one and two increases the operating capacity of the entire Kursk plant by 600 megawatts.

Loading of the first fuel assemblies into the reactor core marked the physical start of unit three of Russia's Kalinin nuclear power plant on 02 October 2004. It is expected that the loading process and tests will take about one month and the unit will be connected to the grid by the end of 2004. Hot tests started at Kalinin-3, a VVER-1000 reactor unit with a net electrical capacity of 950 MW earlier this year. The currently operational Kalinin-1 and -2 are also 950MW units.

Modernization of Kola NPP was completed in 18 September 2004, when unit two was connected to the grid and extended its service lifetime by 15 years. A year earlier, modernization of the Kola's nuclear power unit 1 has also been completed which allowed the extension of its operational life by 15 years. For the next year, preparation to modernization of the 3rd and 4th units is planned.

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SINGAPORE

INTRODUCTION

Singapore is a small island economy located between Malaysia and Indonesia. The Johore Strait separates it from Malaysia. Singapore has a total land area of 682.3 square kilometres and a population of about 4.16 million (2002 est.). Despite its small size and population, Singapore is one of the more highly industrialised and urbanised economies in the Southeast Asian region. It has a highly developed and successful free market economy and enjoys an open and corruption-free environment, stable prices, and a high per capita GDP.

In 2002, real gross domestic product (GDP) was US$ 85.2 billion and per capita GDP was US$ 20,476 (both in 1995 US$ at PPP). The economy depends heavily on exports, particularly electronics and manufacturing (including consumer goods, chemicals and mineral fuels). Major industries include electronics, chemicals, financial services, oil drilling equipment, petroleum refining, rubber processing and rubber products, processed food and beverages, ship repair, offshore platform construction, life sciences, entrepot trade, etc. Its export partners are: Malaysia 15.8 percent, USA 14.3 percent, Hong Kong, China 10 percent, China 7 percent, Japan 6.7 percent, Chinese Taipei 4.7 percent, Thailand 4.3 percent, and South Korea 4.2 percent[47] Because of its strategic location on the Straits of Malacca, Singapore serves as an important shipping centre and host to a large petroleum refining industry. Singapore however does not have its own energy resources and relies entirely on imports to meet its energy requirements.

Table 33 Key data and economic profile (2002)

Key data		Energy reserves	
Area (sq. km)*	682.3	Oil (MCM)	-
Population (million)	4.16	Gas (BCM)	-
GDP Billion US$ (1995 US$ at PPP)	85.26	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	20,476		

Source: Energy Data and Modelling Center, IEEJ. * Singapore Department of Statistics.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Singapore is a net energy importer. Its domestic energy supply depends on imported oil and gas. In 2002 Singapore imported 26,073 of energy, mostly oil. More than half of the oil imports was re-exported as refinery products, while the other half was retained for domestic use. Oil accounted for 80 percent of the domestic supply, the remainder was gas. The four-fold increase of gas share in energy supply, from 2 percent in 2000 to 8 percent in 2001 was mainly due to gas imports through pipeline from Indonesia.

Singapore's electricity demand grew at an average of 6.4 percent per annum from 1996 to 2002 and is expected to grow from 3 to 5 percent per annum from 2003 through 2013. The amount of electricity consumed in 2002 was 34,665 GWh. The electricity was produced from 8,919 MW installed thermal generation capacity using heavy fuel oil and gas. By plant types, in 2002, Singapore installed generation capacity consists of 57.8 percent steam plant, 23.7 percent combined cycle plant, 11.1 percent cogeneration plant, 5.7 percent gas turbine and 1.7 percent incineration

[47] World Factbook 2004, http//www.cia.gov/cia/publications/factbook

plant. At the end of 2002, gas contributed to almost 43.5 percent of Singapore electricity production. Gas share expected increase to 60 percent of total fuel used in electricity generation.

FINAL ENERGY CONSUMPTION

In rough terms, the industrial and transport sectors each account for about two-fifths of final energy consumption, while the residential and commercial sectors account for somewhat less than one-fifth. About three-quarters of final consumption are in the form of oil fuel, mostly for transport and industry, while about a quarter is in the form of electricity.

Singapore's final energy consumption increased by 28 percent from 10,186 ktoe in 2001 to 13,081 ktoe in 2002, at its economy recovered after financial crisis and SARS.

Table 34 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)*		Final Energy Consumption (ktoe)**		Power Generation (GWh)	
Indigenous Production	-	Industry Sector	5,326	Total	34,665
Net Imports & Other	26,073	Transport Sector	4,974	Thermal	34,665
Total PES	26,073	Other Sectors	2,781	Hydro	-
Coal	7	Total FEC	13,081	Nuclear	-
Oil	26,046	Coal	-	Others	-
Gas	20	Oil	10,300		
Others	-	Gas	107		
		Electricity & Others	2,674		

Source: * Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)
** Data obtained from International Energy Agency (IEA).

POLICY OVERVIEW

PRICING

There are no energy subsidies in Singapore. Allowing energy prices to reflect international market prices for fuel ensures that energy is used efficiently. Electricity tariffs are reviewed periodically to ensure that they reflect true costs. Prices for other forms of energy, such as the piped gas supplied by PowerGas Ltd and petroleum products supplied by oil companies, are set by the individual private suppliers and reflect international market prices of fuel. Many reforms have been introduced to increase competition in the natural gas and electricity markets.

NATURAL GAS

The government is actively working to reduce Singapore's dependence on oil. Since January 1992, natural gas from Malaysia has been used for electricity generation as a first step towards energy supply diversification. Gas imports from Indonesia were introduced in 2001.

The gas industry has been restructured by separating the ownership of the gas transportation business, which is a natural monopoly, from the contestable functions of importing, trading and retailing. The gas distribution and transmission network will be owned by a gas grid company, PowerGas Ltd, which will allow players open and non-discriminatory access to the network.

ELECTRICITY

The vertically integrated electricity industry was restructured in 1995 to introduce competition in electricity generation and supply. Two generation companies (PowerSenoko Ltd and PowerSeraya Ltd), a transmission and distribution company (PowerGrid Ltd) and a supply company (Power Supply Ltd) were formed under Singapore Power Ltd. The third generation company, Tuas Power, took over the development and operation of the Tuas Power Station. The Public Utilities Board, which had been supplying power to the entire economy since 1963, was reorganised in October 1995 to take on a new role of regulating the power and piped gas industries.

The Singapore Electricity Pool (SEP), a wholesale electricity market, began operation on 1 April 1998. This pool facilitates the trade of wholesale electricity in a competitive environment. Generation companies compete to sell electricity through the Pool. Electricity suppliers then purchase electricity at competitive prices from the Pool for retail sale to consumers. As competition in electricity generation and supply develops, there will be less reliance on regulation.

In September 1999, the government of Singapore carried out a comprehensive review of the electricity industry. The review's key objective was to implement an electricity market structure and regulatory framework that would support a competitive electricity industry while maintaining the reliability and security of power supply. Based on the review, the government decided in March 2000 to further reform the industry and obtain the full benefits of competition. It decided to introduce wholesale competition in generation and retail competition for large industrial and commercial consumers, with retail choice for smaller customers to be introduced later. It decided as well to establish an independent system operator. PowerGrid remained subject to performance-based regulation since its transmission and distribution business is a natural monopoly.

In the restructured electricity industry, contestable functions like generation and retailing will be separated from non-contestable functions like transmission and distribution at the ownership level. To this end, Singapore Power divested two generation companies, PowerSenoko and PowerSeraya, to Temasek Holdings on 1 April 2001. On the same date, The Energy Market Authority of Singapore (EMA) was established to replace the PUB as the regulator of electricity and gas industries and to take on the system operator functions that had been performed by PowerGrid. The Energy Market Company Pte Ltd was formed as an EMA subsidiary to operate the SEP.

As of 1 July 2001, consumers with a maximum power requirement (contracted capacity) of 2 megawatts (MW) and above have been able to buy electricity from competitive retailers apart from Power Supply Ltd, Singapore Power's retail arm. The electricity retail market will be further liberalised to allow more consumers to choose the retailer from whom they buy electricity.

ENERGY DIVERSIFICATION, ENERGY EFFICIENCY AND CONSERVATION

To encourage the use of natural gas, owners of natural gas buses and passenger cars (including taxis) have been given rebates from October 2001. Such owners receive a rebate equivalent to 5 percent and 20 percent of the vehicle's open market value for buses and passenger cars (including taxis) respectively that can be used to offset the fees and taxes payable at registration. They also receive a road tax rebate of 20 percent. The rebates will be in place till after 31 December 2003 and reviewed for their relevance thereafter.

Upgrading of power stations with newer and bigger machines to generate electricity has improved Singapore's overall system thermal efficiency, which reached 38 percent in 2001. The five petroleum refineries also continually upgrade their operations with sophisticated value-added processes and employ stringent energy conservation practises.

Energy conservation has been actively promoted and pursued at a national level through a series of fiscal and non-fiscal policies with the objective of improving overall system efficiency through better load management. The EMA provides advisory services in efficient use of electricity to consumers in the industrial and commercial sectors. A set of energy conservation standards for building design has been incorporated into the building regulations administered by the Building and Construction Authority. A multi-agency committee is continuously looking into ways to increase energy efficiency and conservation in various areas, such as its land transport system.

A National Energy Efficiency Committee (NEEC) was set up in 2001 to promote energy conservation through the efficient use of energy in the industrial, building and transportation sectors and promote the use of cleaner energy sources such as natural gas and renewable energy sources. A labelling scheme that differentiates energy-efficient electrical appliances from less energy-efficient ones has been introduced to help consumers make better-informed choices. Examples of other programmes are energy-efficient building award scheme and energy audit scheme for large energy consumers.

NOTABLE ENERGY DEVELOPMENTS

LNG IMPORT PLAN

The Energy Market Authority (EMA) is considering importing LNG to meet expected high gas demand growth. LNG expected could provide greater supply security compare with a sole reliance on gas pipelines import. EMA has invited consultants to perform feasibility study in 2004. Considering the size of the economy, Singapore likely will not build a big LNG terminal. A receiving terminal with capacity to handle 500,000 to 1 million ton per year most likely will be adequate for the beginning.

ELECTRICITY BLACK OUT

Singapore experienced massive black out on 29 June 2004 for two hours due to failure in gas receiving terminal at Sakra Jurong island. Malfunction of pressure regulating valve in receiving terminal disrupted gas flow to all gas turbines of three power station Seraya, Tuas and SembCogen and cause shutdown. The shutdown of power plant led to a loss of about 30 percent of online generation capacity and affecting about 300,000 consumer. Power successfully restored within 2 hours.

A NEW COMPETITIVE POWER MARKET

Singapore commenced a new competitive market called The National Electricity Market of Singapore (NEMS) on 1 January 2003. The new market aimed to bring competition in the electricity market to higher level. The new market enable the price of electricity in the wholesale market to respond the change in market condition in every half-our. The new market system provided better ability to the market to observes the demand, result in less volatile price and the price more reflective of the demand. This is mainly because the generation companies are able to adjust their offers up to four hours before real-time dispatch in the NEMS, whereas in the previous Singapore electricity pool the generation company required to predict demand over 24 hours. The new market reduced reserve cost by an average of 89.1 percent in 2003 and helped keep the price of electricity low.

VESTING CONTRACT

The Singapore electricity generation market is dominated by three large generation companies namely Senoko Power Ltd., Power Seraya Ltd and Tuas Power Ltd, with together hold 90 percent of total installed capacity in Singapore. EMA introduced Vesting Contract in order to prevent the generation companies from abusing their market power. The vesting contract replaced previous price cap regulation. In principle vesting contracts, introduced on 1 January 2004, require the generation companies to sell a specified quantity of electricity at a specified price (vesting price). The vesting price is set at the Long-Run Marginal Cost (LRMC) of the most efficient generation technology, which is currently combined cycle gas turbine. The allocation of vesting contract is in proportion with installed capacity. With application vesting contract, about 65 percent of demand was set up at the vesting price and the remaining 35% had been opened to competition in the wholesale market. The application of vesting contract reported has reduced wholesale electricity price by an average 10 percent.

COMPETITION IN GAS MARKET

Currently EMA is restructuring gas industry. Regulatory instruments that govern the restructured industry such as the Gas Supply Code and Gas Network Code, were being finalized in consultation with industry players. To promote a level playing field, the gas transportation activity will be completely separated from other activities in the gas industry such as gas shipping, retail, trading or importing. Under the new gas industry framework, pipe line infrastructure owned and operated by Power Gas Ltd. The company mandated to offer fair and open access to all shipper and retailers.

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CHINESE TAIPEI

INTRODUCTION

Chinese Taipei is an isolated island off the southeast coast of China with an area of some 36,000 square kilometres and a population of 22.45 million. It is an important trading centre with one of the world's busiest ports, Kaohsiung. Its main industries are electronics and petrochemicals.

Chinese Taipei sustained high levels of economic growth, averaging 7.2 percent per year, between 1980 and 2000. The economy slowed substantially in 2001, but real GDP growth recovered to 3.6 percent in 2002 and 3.2percent in 2003. GDP per capita was US$15,337 in 2002 (in 1995 US$). Unemployment averaged 5.2 percent in 2002 and 5.0 percent in 2003.

Chinese Taipei has very limited domestic energy resources and relies on imports for most of its energy requirements. Oil reserves are less than 1 MCM and coal reserves are 1 Mt. Gas reserves are larger at around 76.5 BCM. In 2002, electricity generation capacity totalled 31,915 MW.

Table 35 Key data and economic profile (2002)

Key data		Energy reserves**	
Area (sq. km)	36,000	Oil (MCM) – Proven	0.64
Population (million)	22.45	Gas (BCM)	76.5
GDP Billion US$ (1995 US$*)	344.36	Coal (Mt) - Recoverable	1.0
GDP per capita*	15,337		

Source: Energy Data and Modelling Centre, IEEJ. *Purchasing power parity (PPP) figures not available.
**US EIA.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary energy supply in Chinese Taipei was 89,273 ktoe in 2002, of which 45 percent was provided by oil, 35 percent by coal, 12 percent by nuclear power and 8 percent by natural gas. Around 98 percent of energy needs were imported, including most of the natural gas and nearly all of the oil and coal.

Chinese Petroleum Corporation (CPC), the state oil company, is the dominant player at all stages of Chinese Taipei's petroleum industry, including exploration, importation, refining, storage, transportation, and marketing. The main supplier of crude oil to Chinese Taipei is the Middle East. In 1999, the domestic oil market was liberalised by freeing up import regulations for fuel oil, jet fuel, and LPG. Significant competition began in August 2000 when commercial production began at the economy's first private refinery, the facility in Mailiao owned by Formosa Petrochemical Corporation.

CPC also is responsible for domestic exploration, production and imports of natural gas. CPC operates Chinese Taipei's only liquefied natural gas (LNG) receiving terminal at Yungan, Kaohsiung. In anticipation of growing gas demand for power generation and in light of gas market liberalisation, the government has granted permits to import LNG to companies other than CPC and is accepting bids to build additional LNG terminals from both CPC and private firms. Chinese Taipei has imported LNG from Indonesia since 1990 and from Malaysia since 1995.

Almost all of Chinese Taipei's coal is imported, primarily from Australia, China and Indonesia. Coal is used for power generation as well as in the steel, cement and petrochemical industries.

In 2002, Chinese Taipei produced 198,820 GWh of electricity, of which 77 percent came from thermal power plants, 20 percent from nuclear plants, and 3 percent from hydropower plants. Taiwan Electric Power Company (Taipower), a state-owned utility, currently dominates the electricity sector, but the role of independent power producers (IPPs) has expanded rapidly since the wholesale electricity market was opened to competition in 1995.

Table 36 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	11,608	Industry Sector	36,640	Total	198,820
Net Imports & Other	77,665	Transport Sector	12,892	Thermal	152,908
Total PES	89,273	Other Sectors	12,634	Hydro	6,360
Coal	31,266	Total FEC	62,167	Nuclear	39,553
Oil	40,136	Coal	9,179	Others	-
Gas	7,018	Oil	36,496		
Others	10,854	Gas	1,707		
		Electricity & Others	14,784		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)

FINAL ENERGY CONSUMPTION

Chinese Taipei's final energy consumption grew by 4.9 percent in 2002 to 62,167 ktoe. The industrial sector consumed 59 percent of energy used, the transportation sector 21 percent and other sectors 20 percent. Oil is the dominant fuel, accounting for 58 percent of energy consumption. Electricity accounted for 24 percent of energy use, coal for 15 percent and gas for just 3 percent.

POLICY OVERVIEW

The Energy Commission, which was established in 1979 under the Ministry of Economic Affairs (MOEA) was legalized and became an Energy Bureau as Constituent Act of the Energy Bureau promulgated in January 2004. The Bureau took over the role of Energy Commission to formulate and implement national energy policy. It is also charged with carrying out the Energy Management Law and the Electricity Law. It regulates natural gas utilities, petroleum and LPG filling stations, and the importation, exportation, production and sale of petroleum products. It maintains an energy database, evaluates energy demand and supply requirements, and promotes energy conservation. Further, it implements research and development programmes and promotes international energy cooperation.

The ultimate goal of the Chinese Taipei Energy Policy is to promote energy security, supported by secure import of oil, gas and coal as well as the development of domestic energy resources, nuclear, fossil fuel and new and renewable energy. For environmental reason Chinese Taipei plans to triple LNG consumption by 2010. To increase efficiency of its energy sector, Chinese Taipei promotes privatisation of energy market.

The liberalisation and privatisation of energy-related enterprises has been promoted in recent years to let the private sector build power plants and oil refineries, promote transparency in domestic fuel prices and electricity rate adjustments, strengthen the management of energy supply and demand, and address energy-related environmental impacts.

In electric power markets, wholesale competition was established in 1995, when independent power producers were allowed to invest in generating facilities and sell their output to Taipower, the integrated state electric utility. Retail competition and unbundling of Taipower's generating assets from its transmission and distribution assets are proposed in a new electricity law. Oil markets were fully opened to retail and wholesale competition in 2001.

COAL

Coal production totalled more than five million metric tons annually from 1964 to 1968. Thereafter, production tapered off due to increasing competition from imported coal and spiraling local production cost that were the result of increasingly difficult mining condition. Coal has been totally imported from foreign countries since 2001, mainly from China, Indonesia and Australia.

To meet the future requirements of power generation and industry, a diversification of procurement is taken. In addition, in order to secure a stable supply of coal, exploration and development overseas on a joint venture are being pursued.

OIL

Chinese Taipei's oil market was fully liberalised by the Petroleum Administrative Law that was promulgated on 11 October 2001 and became effective on 26 December 2001. All varieties of petroleum products allowed to be imported into Taiwan.

The Chinese Petroleum Corporation (CPC) operates three oil refineries with a total refining capacity of 770,000 barrels per day. In addition, the private Formosa Petroleum Coporation (FPCC) operates an oil refinery with a refining capacity of 45,000 barrels per day. Total refining capability has reached 1,220,000 barrels per day, exceeding the local demand of petroleum product. Both of them will export their surplus oil to adjust the market situation.

The Middle East remained the major source of crude oil for Chinese Taipei in 2003. The remaining came from other sources.

NATURAL GAS

Chinese Taipei has limited natural gas production capacities and has been importing LNG since 1990. Since then, the total consumption of natural gas has increased significantly, from 1.8 BCM in 1990 to 8.03 BCM in 2003. The use of gas for electricity generation has grown especially fast, now comprising two-thirds of total gas consumption.

The demand for natural gas is expected to increase further. To enhance the stability of natural gas supply, the CPC is now planning the construction of a second LNG receiving terminal in the Port of Taichung. The imported LNG was accounting for 90% of the total amount of nature gas supply in 2003. Mainly 61% came from Indonesia and the other 39% from Malaysia.

ELECTRICITY

In order to maintain a stable electricity supply, the Ministry of Economic Affairs (MOEA) has promoted the opening of the market to independent power producers (IPPs) in three stages: the first in Jan 1995, the second in Aug 1995 and the third in Jan 1999.

To expand foreign participation, the government decided in Jan 2002 that foreign investors permitted to own up to 100% of an IPP. The MOEA reviews applications on case by case basis.

By late 2003, the amount of electric generating capacity provided by independent power producers in Chinese Taipei had reached 4,600 MW. The Kuokuang power plant (480 MW) and Chiahui power plant (670 MW) started commercial operation in 2003, following the Mailiao plant (3x600 MW) , the Ever plant (2x450 MW), the Ho-Ping plant (2x650 MW) and Hsintao plant (600 MW). Another two IPP plants, with a total capacity of 1,470 MW, should enter service in 2004.

NEW AND RENEWABLE ENERGY

Chinese Taipei intends to create a sustainable environment that harmonizes environment protection, energy security and economic development by enforcing the bill. It is also hoped that electricity from renewable resources will be able to make up over 10% of the total electricity generation capacity.

The renewable energy development plan, which was approved by the executive Yuan on Jan 1, 2002, will lead to concerted efforts by all levels of the government as well as the general public to develop renewable energy and to aggressively adopt its use. Taipower plans to install 60 units with a total capacity of 100.8 MW. This wind power project will be implemented from 2004 to 2005.

In order to effectively promote renewable energy and respond to the requirements of the private sector for institutionalised incentive measures, Chinese Taipei has proposed a "renewable Energy Development Bill" .The bill has gone through the deliberation of the Executive Yuan and has been delivered to the Legislative Yuan. The legislation of renewable energy-related laws is also one of key items in "Challenging 2008: The Six-Year National Development Plan".

NUCLEAR

On 13 February 2001, Chinese Taipei's legislative and executive departments signed an agreement, publicly proclaiming that the future planning of the country's overall energy development should, on the premise of maintaining a constant and sufficient supply of energy, take into account such relevant factors as national economy, social development, world trends, and the spirit of international trends, so as to achieve the country's ultimate goal of building a "Non-Nuclear Homeland".

The Executive Yuan announced the resumption of construction of the Fourth Nuclear Power Plant on Feb 14, 2001 after the ruling of council of Grand Justice over the constitutionality of the decision and negotiations between the Executive Yuan and Legislative Yuan.

Two advanced light water reactors in the Fourth Nuclear Power Project, 1350 MW each, are scheduled for commercial operation in July 2006 and 2007, respectively.

NOTABLE ENERGY DEVELOPMENTS

CONSTITUENT ACT OF THE ENERGY BUREAU

Chinese Taipei has passed the " Constituent Act of the Energy Bureau, MOEA" in January 2004 in cope with the liberation of energy enterprises and effectively speeding up implementation on the energy policy.

The Act finalized the legalization process as supervision bureau of the overall energy affairs , which had been existed as "commission" status for years before the legislation. It is significant that the Act provides Legal Framework for the liberalization on petroleum, natural gas and electric power industries, which has been regulated as overall status and the implementation on codes in regulating energy industries become current issues in meeting with global situation.

As usual, policy on "Bureau of Energy, BOE" will continuously lead to exertion on promoting energy saving, upgrading energy efficiency and developing renewable energy. The major responsibilities of BOE include: drafting of energy policies and legislation, planning of energy supply and demand and reviewing activities related to the exploration, production, storage, conversion, distribution and marketing of energy resources.

MAJOR NATURAL GAS CONTRACT

The petroleum company CPC has won a bid to supply natural gas to Tatan Power Plant of Taiwan Power Co. for twenty-five years. CPC won over three other contenders with a lowest bidding price of NT$298.2 billion, equivalent to near US$9 billion. CPC has signed SPA with Qatar's Ras Lafan Liquefied Natural Gas Co.(Ras Lafan) to secure the gas supply. This procurement signifies a long-term stable energy source through a new diversified fuel sources after the operation of Tatan Power Plant in 2008. It is also expected to comparatively reduce carbon dioxide emissions.

PURCHASE CONTRACT FOR WIND POWER

In Dec 2003, Taipower signed Sales and Purchase Contract with InfraVest windpower Co. for 22,100 kW wind power electricity. InfraVest windpower Co has been known as a newly established German firm planning to invest NT$13 billion to install wind power generators at ten different coastal locations along the western coast.

Another two local companies will also sign the contract with Taipower shortly in supplying wind power electricity. These procurements have been qualified through the "MOEA Operation Guidelines of Evaluation on Renewable Energy Electric Power Providers" as the first phase suppliers. It is considered a significant new step of adopting renewable energy in coping with the energy policy

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THAILAND

INTRODUCTION

Thailand is located in Southeast Asia and shares borders with Malaysia to the south and Myanmar, Laos and Cambodia to the north and the east. It has an area of 513,115 square kilometres and a population of about 61.6 million at the end of 2002.

Over the past two decades, engendered by strong economic growth that was temporarily interrupted by the 1997-98 financial crisis, Thailand has not only significantly increased its energy consumption but has also developed its energy sector to the extent that import dependency has been declining throughout the period. In 1997, an economic recession in Thailand caused by the Asian financial crisis, resulted in negative economic growth and a decline in energy demand for the first time in 30 years. Two of the effects of the crisis were the depreciation of the currency and higher inflation and up until the first half of 1999, the resulting recession weakened domestic purchasing power; notably in the prices of imported energy such as oil. However, by the second half of 1999, economic countermeasures taken by the government began to take effect and a gradual recovery, particularly in the industrial export sector, has since taken hold. Currency levels stabilised and the inflation rate declined. However, in 2002, GDP was US$ 382.5 billion (at US$ 1995 at PPP), an increase of 5.4 percent compared with 2001.

Thailand is highly dependent on energy imports, particularly oil. In 2002, net energy imports accounted for 57.2 percent of energy supply in the economy; down significantly from 96 percent in 1980.

Table 35 Key data and economic profile (2002)

Key data		**Energy reserves***	
Area (sq. km)	513,115	Oil (MCM)	52
Population (million)	61.61	Condensate (MCM)	41
GDP Billion US$ (1995 US$ at PPP)	382.47	Gas (BCM)	378
GDP per capita (1995 US$ at PPP)	6,208	Coal (Mt) - Recoverable	1,354

Source: Energy Data and Modelling Centre, IEEJ. * Proved reserves, Department of Mineral Fuels, Ministry of Energy.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, the primary energy supply was 71,677 ktoe. Oil comprised 51.6 percent of primary supply, gas 34.2 percent, coal 13.0 percent and others 1.2 percent. Energy imports accounted for 57.2 percent of primary energy supply in 2002, slightly higher than 0.3 percent in 2001. The supply of oil and natural gas were slightly increased compared to 2001, at 0.2 percent and 0.1 percent increase in primary energy supply, respectively.

In 2002, Thailand produced only 6,280 ktoe of crude oil, while imported more than 88 percent of its oil requirements or 41,897 ktoe. A high level of import dependence is expected to continue in the foreseeable future. The major sources of crude oil imported are the Middle East at 74.3 percent of total oil imported, following ASEAN 19.2 percent, Asia Pacific 1 percent (excluding ASEAN Economies), Africa 5.2 percent and Europe 0.2 percent. At the end of 2002, Thailand's total proven reserves of crude oil were around 52 MCM. Onshore reserves are located in the Sirikit field (17.5 MCM) while offshore reserves (33.6 MCM) are mainly in the Benchamas, Jarmjuree, and

Maliwan fields. For condensate, total proven reserves are 41 MCM. All deposits are located offshore with major pools in the Bongkot, Pailin, JDA and Erawan areas.

Due to the lingering effects of the financial crisis and high oil prices, domestic petroleum product consumption in 2002 was lower than might otherwise have been the case meaning that domestic refineries were not required to operate at full capacity. Its capacity utilisation in 2002 was around 88 percent. To mitigate losses, Thai refineries were exported some of their output. Exports of petroleum products were 5,512 ktoe in 2002, decreased 1.7 percent from 2001, and imports were 793 ktoe, rose 102 percent compared to the previous year. Thailand has a combined refinery capacity of 817,000 barrels per day.

Thailand is more self-sufficient with respect to natural gas. Imports, from Myanmar, are around 27 percent of demand. Gas production was around 4.7 percent higher in 2002 compared with 2001. Natural gas is used largely for electricity generation.

Coal in Thailand is used for electricity generation and in the industrial sector. Most of Thailand's proven coal reserves are lignite, coal of low calorific value. The total volume of recoverable reserves is 1,354 Mt, most of which is located in the Mae Moh basin. Around a third of coal requirements are imported.

Total electricity generation in 2002 was 109,013 GWh, 6.4 percent more than in 2001. Almost domestic production was thermal generation (93 percent). The remaining 7 percent was supplied by hydro, geothermal, solar and wind turbine energy. Natural gas is the most important thermal fuel source for electricity generation, accounting for around 60 percent of thermal consumption. Other important thermal fuels were fuel oil and lignite coal. To supplement domestic production and balance peak loads, Thailand imports electricity from the Lao Peoples Democratic Republic. Imports are typically 3 percent or 2,812 GWh of requirements.

Table 36 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	30,679	Industry Sector	15,064	Total	109,013
Net Imports & Other	40,998	Transport Sector	19,819	Thermal	101,540
Total PES	71,677	Other Sectors	11,981	Hydro	7,471
Coal	9,305	Total FEC	46,865	Nuclear	-
Oil	36,972	Coal	4,930	Others	2
Gas	24,537	Oil	31,553		
Others	863	Gas	1,767		
		Electricity & Others	8,615		

Source: Energy Data and Modelling Centre, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/egeda/database/database-top.html

FINAL ENERGY CONSUMPTION

Thailand's total final energy consumption for 2002 was 46,865 ktoe, an increase of 6.3 percent over the previous year. Petroleum products account for the highest proportion of secondary demand (67.3 percent), followed by electricity (18.4 percent), lignite coal (10.5 percent) and gas (3.8 percent). Demand for coal was highest at 34.5 percent then natural gas 27.3 percent and electricity 14 percent respectively from 2001. On the other hand, petroleum demand grew by 14 percent.

The transportation sector was the largest energy consuming sector and accounted for 42.3 percent of total final energy consumption at 19,819 ktoe . This was only 0.4 percent less than its consumption in 2001. The industry sector consumed 15,064 ktoe in 2002, an increase of 9.5

percent from the previous year. Energy consumption in the residential and commercial sectors decreased to 4.2 percent in 2002 from 16 percent in 2001.

Electricity demand was 100,173 GWh increased by 8.5 percent in 2002, it was higher than 5 percent in 2001. Although hydro generation was near 18.5 percent in 2002 higher than in 2001, Thailand still depended on fossil fuels for around 93 percent of generation. Industrial sector consumed highest electricity proportion of 45.7 percent, following commercial sector at 31.6 percent, residential sector at 22.1 percent, transportation sector at 0.04 percent and the rest of 0.61 percent for others.

Natural gas increased up 7.8 percent over the previous year of that 7.4 percent increased in power sector, 12.2 percent increased in manufacturing sector, and in transportation sector increased by 2 folds. LPG was mainly consumed in residential and commercial sector and it accounted for 70 percent. Following 19 percent, 10.9 percent and 0.1 percent by manufacturing sector, transportation sector and agricultural sector, respectively.

POLICY OVERVIEW

DEREGULATION, PRIVATISATION AND RESTRUCTURING

Thailand has been deregulating its energy sector for around a decade with a primary objective of creating a more competitive energy market. The oil and gas industries, both upstream and downstream, were completely de-regulated and liberalised in 1996. Deregulation of the electricity and gas sectors is less advanced although significant progress is being made in both.

ENERGY SECURITY

As a significant energy importer, especially of oil, Thailand is concerned about energy security. This concern applies to both the security of supply and volatile oil prices. To insulate the economy from oil supply and price shocks it is considering several different strategies. On the demand side, the government is promoting energy conservation and the efficient use of energy. It also advocates diversifying energy use away from oil towards less volatile energy markets such as natural gas, orimulsion, coal and renewable sources. Recognising the importance of emergency preparedness in the case of an oil shortage or crisis, Thailand is also considering establishing strategic oil stockpiles. The National Energy Policy Office (NEPO) is studying the national oil stockpiling strategy and is considering stockpiling options for Thailand. In addition, NEPO closely cooperates with other ASEAN economies to improve the ASEAN Petroleum Security Agreement (APSA) and to strengthen energy security in Asia.

Energy security is also focused on electricity balance between power generation and consumption, to ensure sufficient of supply to consumption without blackout and to minimize the power reserve margin. The electricity price should reflect to the real cost, reasonable price, which is subjected to increase quality of life in society and environmental concerns and friendly to local areas and society as a whole. Electricity Generation Authority of Thailand (EGAT) will set up funding to compensate the local area and to improve quality of life in society, whose receive an impact from the environment damage.

Today, Natural Gas in Thailand is estimated to be self-sufficient for 30 years, based on 5 percent increase per annum for Natural Gas consumption. Thailand attempts to ensure its self-sufficiency from 30 years to 50 years. The strategic of this is to increase closer cooperation with its neighbouring economies and to increase more effort in investment in Natural Gas, such as Trans ASEAN Gas Pipeline.

ENERGY EFFICIENCY

TRANSPORTATION SECTOR

Thailand aims to improve the energy efficiency, by reducing Energy Elasticity from 1.4:1 to 1:1 by 2007. Thailand will achieve this plan by focusing on the reduction energy consumption in transportation and industrial sectors. For the transportation sector, Thailand has been invested in mass transit and attempted to reduce road traffic, especially in metropolitan areas, Bangkok and Chaingmai. Today Thailand has the mass transit, rail network and subways, only in Bangkok area for 44 km in total and plans to expand the network up to 291 km within 2009. Furthermore, Thailand will promote multimode transport, road-rail and land-water. Tax incentive will be one of the major instruments for introducing this plan.

INDUSTRIAL SECTOR

For industrial sector, Thailand mandates energy conservation certification for factories and buildings. Tax incentive and energy saving standardization for electric appliances and fuel consumption of car are implemented.

ELECTRICITY GENERATION SECTOR

In power supply system, EGAT has adjusted its strategic plan and implementation to enhance sustainable development by a) improving efficiency of existing power system as well as expanding generation capacity by advanced technology project development; b) developing only power projects which could prove to be economically affordable, environmental sound and provide social profits; c) Maximizing use of clean fuels such as natural gas and renewable energy resources, and d) minimizing electricity loss of the transmission system by upgrading existing transmission line to the high voltage lines of 500KV and 115 KV.

DMS PROGRAMME

In 2002, the DMS program has implemented since 1992 has proven a real achievement in potential peak load reductions and energy savings. As result of the program, EGAT estimated the cumulative peak demand reductions of 736 MW, energy saving of 4,164 million KWh and emission reductions of 3.1 million tons of carbon dioxide. To ensure the stable success of DMS, EGAT has formulated a master plan for the second phase DMS program during 2002-2006 for residential, commercial and industry sectors included the campaigns to promote the use of high efficiency electrical appliances like efficiency program of thin tube fluorescent lamps, refrigerators etc. The DMS program's target will be 632MW of peak load reductions and 2,508 KWh of energy savings in these sectors.

NEW AND RENEWABLE

Thailand sets the Renewable Portfolio Standard (RPS) for 8 percent, or equal to 6,540 thousand toe, within FY 2011. In 2002, Thailand had commercial NRE consumption in a proportion of 0.5 percent of total energy consumption, or 265 thousand toe. The target of 8 percent RPS in 2011 will be mandated in power generation for 4 percent in every new power plant. These 4 percent NRE will be from PV, wind, biomass and geothermal. Thailand will promote more in research and development of NRE, PV, small hydro, wind and biomass, and promote and support private-own power plant to use NRE.

ENVIRONMENT

Current energy policies in Thailand also focus on conservation and environment. A range of policies have been implemented or being considered to mitigate the environmental effects of energy production and use. Policy measures include the substitution of natural gas for coal and fuel oil in electricity generation, increasing the use of renewable electricity technologies, promoting clean coal technologies, implementing higher emissions standards for power plants (for example, SO_2

emissions have been reduced by more than 75 percent since 1996), and implementing emissions controls and higher fuel quality for motor vehicles.

NOTABLE ENERGY DEVELOPMENTS

PETROLEUM TRADING CENTRE

Thailand will develop Sriracha, an island in Chonburi province approximately 140-km away from Bangkok to the east, as The Thailand and Region Petroleum Trading Centre. Sriracha is expected to have investment in Petroleum facilities, to be ready to accommodate 350,000 dead-weight-ton tankers, and tax incentives as "Tax Free Zones". A one Stop Service has been established to facilitate all transaction concerning the this region. The corporate income tax in this area on oil-trading profit has been reduced from 30 percent to 10 percent and 5 percent for high-volume trader. Customs duties and formalities in Sriracha are waived as well. Sriracha are surrounded by country oil facilities, such as oil storage and refinery. Thailand expects that this development will benefit to every corner of the regions of Indochina, Southern China and the others of Far East, with this superior location, facilities and better tax incentives.

ELECTRICITY

NEW HYDROELECTRIC TURBINES

EGAT has a plan to install small turbines of total capacity of 40 MW in 14 irrigation dams. The cost of all turbines is about US$7.0 million –19.0 million, which would put in Pa Sak, Klong Tha Dan, Chao Phraya and Naresuan dams. Electricity from these dams will supply to local use to reduce the dependency of imported electricity from neighbouring countries and mitigate environmental impacts due to using fossil fuels. The Private Electricity Generating Holding Plc will provide the said investment cost above of these hydroelectric turbines.

POSTPONED ELECTRICITY GENERATION PLANTS

The two coal-fired power plant project in southern Thailand at Bo Nok and Hin Krut have been postponed at least two years. By the schedule these two coal–fired power plants should completed in 2002. The reason made the two plants have to delay was the opposition from local communities and environmentalists. The Thailand government also have a plan to move the two plant projects to other location and switch to natural gas as a fuel. The question of possible overdependence on natural gas is a growing concern for the Thai government.

ELECTRICITY TRANSMISSION EXPANSION

In 2002, Thailand's the TS No. 10 transmission project has continuously expanded to increase transmission capacity, maintain continuity and reliability of supply service in order to meet the growth electricity demand of the country currently and in the future. The 13,600 million baht transmission line included the construction of 230KV and 115 KV transmission lines with 975 circuit- kilometres and two substations of 230KV, purchase of additional tie transformers totalling 1,600 MVA. This transmission system has implemented in provincial areas countrywide including the Greater Bangkok area.

ENERGY CONSERVATION

Thailand is attempting to improve the efficiency of the electricity market by a process of de-regulation and promoting competition. According to the master plan, during 2003-2004, three state own enterprises, the Electricity Generation Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA), will be privatised in the same way as PTT. A regulatory authority will be established, and a power pool will be set up. Consumers will be able to choose their own supplier(s).

With a view to decreasing the growth of energy consumption in the 2002-2011 periods, the Strategic Plan for Energy Conservation was developed and approved by the National Energy Policy Council in April 2002. The four main prongs of the strategy are energy conservation, renewable energy utilisation, human resources development and public awareness campaigns. Thailand targeted to reduce its energy consumption by 6.6 percent or 4,823 ktoe in 2006 and 8.5 percent or 9,306 ktoe by 2011.

ENERGY COOPERATION

ENERGY SUPPLY RELATION

The regional energy project is to make use of Thailand's geographical advantage as energy-supply link between main producers in Middle East and major consumers in Far East Asia, like China, Japan, Korea and Chinese Taipei. With this development, Thailand expects time and cost savings for the trade between these two regions. Thailand has put high effort in the project with these five major measures: 1. Taxation, Customs Free Zone, 2. Transmission network of NG pipeline, 3. The north and northeast oil pipeline transmission systems and support intra-regional connection of various transport modes from east to west and south to north of the economies, Thailand-Burma, Indochina and south of China, 4. Energy Land Bridge in the south of Thailand, a link between two seas, India Ocean and Pacific, 5. Encourage of integration, synergies and merger among producers for a large-scale petrochemical.

ENERGY LAND BRIDGE

Thailand plans Two-Year Energy Land Bridge project to link Andaman Sea, India Ocean, to Gulf of Thailand, Pacific Ocean, with energy facilities, highway, pipeline, oil depot and oil refinery. The 230-km highway system and a Trans-isthmus pipeline will create a short cut of the energy trade route between Middle East-major suppliers, and Far East-consumers. This project is expected to help enhance the oil supply security and safety in region and to help increase oil-transportation efficiency.

ELECTRICITY TRANSFER AGREEMENT

During 2004-2007, Thailand has a high electricity demand as the result EGAT and TNB have made an agreement for transfer of 300MW of power electricity from Malaysia to Thailand through the high voltage system in 6 May 2004. With power purchase from TBN, Thailand's EGAT could strengthen the its stability of power generation system in the South region of the country, reduce higher generation cost using fuel oil and diesel during the construction of natural gas pipeline system.

NEW AND RENEWABLE ENERGY

PROMOTION OF BIOFUELS

To reduce dependency on fossil fuels in the future, Thailand has a priority plan to develop new and renewable energy resources. Among the measures initiated is the biofuel program including ethanol and biodiesel.

Thailand has a strategy plan to utilize 3.0 million tons of ethanol per day to blend with gasoline at 10 percent ratio by 2006. A pilot product of gasohol 95 which is the mixture of ethanol and Octane 91 gasoline at ratio of 1 to 9, has been introduced in domestic use. To promote development and use of ethanol, the government of Thailand has exempted the excise tax imposed on the 10 percent ethanol mixed with gasoline, making the price of gasohol cheaper than price of Octane 95 gasoline. This will be an incentive measure for consumers to use more gasohol instead of gasoline.

For biodiesel, the target of Thailand is a replacement of 3 percent of diesel consumption in 2011 by biodiesel. It accounts for 2.4 million litres of biodiesel per day. From 2006 onwards, biodiesel will be blended as an additive in diesel at 2 percent ration, as the result, it requires about

1.6 million litres of biodiesel per day mainly for transportation sector. From 2011, this program will be enforced nationwide.

RATIFICATION OF THE KYOTO PROTOCOL

After the Asian financial crisis 1997-1998, energy consumption in Thailand has grown up fast. Thailand's carbon dioxide emissions discharged from industrial sectors were doubled between 1990 and 2002. Thailand in a non-Annex I country of the Kyoto Protocol, so it is not required to reduce carbon dioxide emissions below 1990 levels by 2012, but with its concern to climate change, Thailand government ratified the agreement in August 2002.

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UNITED STATES

INTRODUCTION

The United States (US) is the world's largest and most influential economy, with a GDP of US$ 9.2 trillion (in 1995 US$ at PPP) in 2002. The US is located in North America between Canada and Mexico. It has a population of 288 million people (2002), and spans 9.3 million square kilometres.

The United States enjoyed a lengthy economic expansion from 1991 through 2000. Growth was particularly robust from 1995 to 2000, averaging 3.8 percent per annum. A brief recession slowed growth to 0.3 percent in 2001, recovering to 1.9 percent in 2002 and 3.0 percent in 2003. Unemployment rate rose from 4.0 percent at the end of 2000 to 6.3 percent in June 2003 before subsiding to 5.5 percent in the third quarter of 2004 as the recovery gathered steam.

The United States is the largest producer, consumer, and importer of energy in the world. It is also rich in energy resources. At the start of 2003, there were 3,609 MCM of proven oil reserves and 5,292 BCM of natural gas reserves. In 1999, there were some 275.1 billion tonnes of recoverable coal reserves, up 10 percent from two years earlier. There were over 948 GW of electricity generating capacity in summer 2003, of which 30 GW was owned by commercial or industrial firms. Of the remaining 918 GW, in the electric power sector, 40 percent was owned by independent power producers. Due to a large, wealthy population and broad industrial base, the economy consumed 5.5 toe (FEC) per capita in 2002, nearly four times the APEC average and far in excess of production.

Table 37 Key Data and Economic Profile (2002)

Key Data		Energy Reserves*	
Area (square km)	9,372,610*	Oil (MCM) – Proven**	3,609
Population (million)	288.37	Gas (BCM) **	5,292
GDP Billion US$ (1995 US$ at PPP)	9,231	Coal (Bt) - Recoverable ***	275.1
GDP per capita (1995 US$ at PPP)	32,014		

Source: Energy Data and Modelling Center, IEEJ.
* US Energy Information Administration.
** Oil and gas reserves as of 1 January 2003.
*** Coal reserves as of January 1, 1997.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, net primary energy supply in the United States was about 2,148 Mtoe. By fuel type, 39 percent of supply came from crude oil and petroleum products, 25 percent from coal, 25 percent from natural gas and 11 percent from nuclear, hydro, geothermal and other fuels. The United States imported about 26 percent of its energy requirements in 2002.

In 2002, the United States used approximately 826 Mtoe of petroleum. Petroleum product supply grew 1.5 percent per annum during the 1990s, but domestic crude oil production levels declined by 2.2 percent per year as oil exploration and production companies turned their attention to cheaper, less mature basins in Africa, Asia and the Middle East. While 47 percent of crude oil and products demand was met by imports in 1990, the import share had climbed to 58 percent by 2002. Almost half (40 percent in 2002) of imported oil comes from OPEC economies. Neighbouring Canada and Mexico are the largest non-OPEC suppliers. Growth in the transportation and industrial sectors has been driving demand for petroleum products. Four-fifths of the economy's oil reserves are located in Texas, Alaska, Louisiana and California, which are the four largest states in terms of current oil production.

The United States contains about 3.3 percent of the world's natural gas reserves. Primary natural gas supply totalled 535 Mtoe in 2002, exceeding domestic production by 15 percent. Most of the production shortfall was met by imports from Canada through an extensive network of pipelines. Gas use by industry and power generators has grown because gas is a clean fuel that favours environ-mental approvals. Its growth was assisted by a period of falling wellhead gas prices following their deregulation in the 1980s and by an expanding pipeline network that made gas more widely available.

Strong demand and other factors have led to higher natural gas prices in recent years. During the winter of 2000-2001, average wellhead prices more than doubled from those of the previous winter. While spot prices at the Henry Hub reference had fallen by August 2001 to half the winter's peak, they were still well above those two years earlier. In March 2003, city gate gas prices and delivered gas prices to electricity producers and industry were roughly double those a year before. Average wellhead gas prices per thousand cubic feet doubled from $1.96 in 1998 to $4.02 in 2001, fell by a fourth to $2.95 in 2002, surged by two-thirds to nearly $4.98 in 2003, and were projected to subside by a fifth to around $4 in 2004 – similar to prices in 2001 but double those in 1998. Market mechanisms are working to meet gas needs reliably, albeit at prices on a jagged upward trend.

Table 38 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation GWh)	
Indigenous Production	1,593,149	Industry Sector	503,340	Total	3,858,996
Net Imports & Other	554,534	Transport Sector	635,175	Thermal	2,729,959
Total PES	2,147,683	Other Sectors	440,272	Hydro	255,586
Coal	531,733	Total FEC	1,578,787	Nuclear	780,064
Oil	835,071	Coal	66,816	Others	93,387
Gas	535,341	Oil	825,623		
Others	245,539	Gas	395,903		
		Electricity & Others	290,445		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/egeda/database/database-top.html)
Note: Source figures are derived from official US Energy Information Administration data, but differ due to adjustments, combinations and reallocations by IEEJ for various fuels and end-use sectors which arise from definitional differences.

Coal use in the United States totalled 532 Mtoe in 2002. US coal reserves are concentrated in Appalachia and key western states. Appalachian coal, which accounted for 36 percent of production in 2002, is mainly higher-sulphur coal from underground mines. Western coal, which accounted for most other production, is mainly low-sulphur coal from surface mines. Western coal production, which first surpassed that of Appalachian coal in 1998, was given a major boost by the Clean Air Act Amendments of 1990, which have required reduced sulphur emissions from coal combustion since 1995. During 2003, production declined in Appalachia but grew in the West.

The United States is the fifth largest coal exporter in the world behind Australia, South Africa, Indonesia and China. Since 1998, US coal exports have fallen sharply due to lower world coal prices, increased competition among coal-producing economies, and substitution of natural gas for coal in power production. In 2001, US coal exports fell to their lowest level since 1978, as a strong dollar made coal from elsewhere cheaper and high spot prices for domestic coal made it attractive for producers to sell at home, and they fell still further in 2002 to a level not seen since 1961. By the first half of 2003, US coal exports to Asia (mainly Japan and Korea) had virtually evaporated, and total US coal exports were down 1.6 percent from 2002, with a 7 percent (or 3 percent at year end 2003) decline in exports to Europe offset by increases of 15 percent to North America, 17 percent to South America and 74 percent to Africa.

The United States produced 3.86 million GWh of electricity in 2002 with 71 percent coming from thermal plants, 20 percent from nuclear power, 7 percent from hydropower, and 2 percent from other sources. Of the thermal generation, roughly three-quarters was fuelled by coal and one-quarter by natural gas, with small amounts produced from oil and other fuels. Average electricity prices per kWh fell every year between 1993 and 1999 but rose to 6.9 cents in 2000, 7.3 cents in 2001, and increasing further to 7.4 cents in 2002 and 2003, largely because of higher gas prices.

The United States generates more nuclear power than any other economy in the world but has not had any new nuclear power plants built since 1977. The Three Mile Island accident in 1979 raised concerns about nuclear power plant safety while ad-hoc regulatory responses to these concerns made some new plants very expensive; both factors deterred further expansion. But the average utilisation rate of 103 commercial nuclear plants has risen steadily to over 90 percent in 2002. Moreover, many nuclear plants have applied to the Nuclear Regulatory Commission (NRC) for 20-year extensions of their operating licenses, to 60 years. As of October 2004, the NRC had approved license extensions for 26 nuclear units and had applications for another 20 extensions under review, while more than 20 other units had informed the agency of their intent to seek extensions by 2012.

FINAL ENERGY CONSUMPTION

In 2002, end use energy consumption in the United States totalled 1,579 Mtoe. Broken down by sector, transport consumed 40 percent, industry accounted for 32 percent, and residential and commercial buildings used 28 percent. By fuel, petroleum accounted for 52 percent of consumption, natural gas for 25 percent, coal for 4 percent, and electricity and other fuels for 18 percent.

POLICY OVERVIEW

Energy policy in the United States is very supportive of market mechanisms. The Department of Energy (DOE) is responsible for implementing energy policies and programmes initiated by the Congress, monitoring the state of energy markets, maintaining energy security, and supporting research and development of new energy technologies. The Federal Energy Regulatory Commission (FERC) and various state public utility commissions share responsibility for regulating gas and electricity markets and promoting competition in those markets.

STRATEGIC PETROLEUM RESERVE

The United States imports more than half of its oil requirements, and its heavy dependence on oil imports is expected to continue. A vital policy instrument in this context is the Strategic Petroleum Reserve (SPR), established in 1975. With a stock exceeding 670 million barrels in late 2004, the SPR is the largest emergency oil stockpile in the world. The government intends to fill the SPR to its 700 million barrel capacity by 2005 through a “royalty-in-kind” exchange program whereby oil produced from federal leases in the Gulf of Mexico is exchanged for oil going into the SPR. In the late 1990s, the SPR was upgraded to ensure its full and safe operation until at least 2025.

The SPR represents a total investment of more than US$20 billion with an annual requirement in the range of US$158 million for maintenance and operation. The average price paid for oil in the reserve is about US$27 per barrel. Crude oil is stored mainly in four underground salt caverns on the Gulf Coast in Texas and Louisiana, with a distribution system in place for the oil’s use. DOE manages the SPR facilities and periodically conducts test sales and releases. The current SPR inventory could replace roughly 53 days of imports, down from a peak of 118 days in 1985. Public and private oil inventories combined could replace about 150 days of imports, which substantially exceeds the International Energy Agency’s requirement of 90 days. Upon order of the President, oil can be delivered to the US market within 13 days at a maximum rate of 4.3 million barrels per day.

TECHNOLOGIES AND POLICIES TO LIMIT ENVIRONMENTAL IMPACTS

The United States has made substantial progress in reducing environmental impacts of energy use. Sulphur dioxide and nitrogen oxide emissions from coal plants have been cut dramatically through a combination of plant-specific requirements for emissions limits and a system of emissions trading. The acid rain programme established by the Clean Air Act Amendments of 1990 is expected to reduce yearly SO_2 emissions by 10 million tons or about half from 1980 levels by 2010. Phase II of the programme began in 2000, setting a nationwide cap of 9.2 Mt through 2009 and 8.95 Mt thereafter for all power plants with a capacity of 25 MW or greater and all new utility-owned plants. A trading system for SO_2 emissions permits, in place since 1995, has reduced emissions to 29 percent below legally required levels and has limited the cost of reducing emissions to about US$ 200 per ton. Since 1970, despite a doubling of coal use, aggregate emissions of key air pollutants (SO_2, nitrogen oxides, mercury, carbon monoxide and volatile organic compounds) have declined by 31 percent.

To extend this progress, objectives for further reducing emissions of sulphur dioxide, nitrogen oxides, and mercury were announced by the government in 2002. Annual SO_2 emissions would decline from 11 million tons in 2000 to 4.5 million tons by 2008 and 3.0 million tons by 2018. Yearly NOx emissions would decline from 5 million tons in 2000 to 2.1 million tons by 2008 and 1.7 million tons by 2018. The Environmental Protection Agency (EPA) is pursuing these goals through an Interstate Air Quality Rule and Utility Mercury Reductions Rule which were announced in late 2003 and were close to being finalised in late 2004. Relative to 2002 levels, annual SO2 emissions would decline 3.6 Mt or some 40 percent by 2010 and 5.6 Mt or some 70 percent lower several years later. Annual NOx emissions would fall 1.5 Mt or 55 percent by 2010 and 1.8 Mt or 65 percent by 2015. Mercury emissions would be cut 14 tonnes or 30 percent by 2008, 33 tonnes or 70 percent by 2008.

In addition, it was proposed to reduce the carbon intensity of the economy, or ratio of carbon emissions to GDP, by 18 percent by 2012. This goal has been vigorously pursued through nearly 60 federal programmes. On example is DOE's Climate VISION programme of voluntary industry-wide commitments to reduce emissions in 12 energy-intensive sectors. Another is the Climate Leaders programme, run by EPA, involving 50 major companies that have developed comprehensive climate change strategies with corporate emissions reduction goals. Still another example is the modification of farm conservation programmes to encourage the set-aside of farmland for carbon sequestration.

CLEAN COAL TECHNOLOGY

Since the United States obtains over half of its electricity from coal, major emphasis has been placed on the development of technologies for limiting environmental emissions from coal-fired power plants. The Clean Coal Power Initiative, begun in 2002, pledges US$2 billion in federal cost sharing over a ten-year period to advance such technologies, with at least half the funding for each project coming from private sources. Since earlier efforts have already made a great deal of progress in reducing traditional air pollutants such as particulates, SOx, and NOx, current efforts are increasingly focused on reducing greenhouse gas emissions. A FutureGen demonstration plant is being designed to separate carbon and hydrogen streams from coal so that all the carbon can be sequestered without entering the atmosphere. If the costs are not too high, carbon separation and sequestration could point the way to a hydrogen economy in which continued use of coal is environmentally sustainable. In 2004, $378 million was budgeted for coal R&D, with $179 million for the Clean Coal Power Initiative, $90 million for innovative power plant designs, $38 million for advanced research, $31 million for improved fuels and $40 million for carbon sequestration.

NUCLEAR POWER TECHNOLOGY

Nearly one-fifth of electricity in the United States is generated by nuclear power, from which atmospheric pollution and carbon dioxide emissions are close to zero. The US is an active participant, along with Japan and others, in development of Generation IV technologies with enhanced passive safety features and more standardised designs to limit costs. These hold the promise of retaining nuclear power as a major option after the current generation of plants is retired.

The Congress has approved development of Yucc a Mountain, in Nevada, as a permanent geologic repository for high-level nuclear waste. This will be the first such repository in the US, relying on more than twenty years and US$4 billion of scientific study which demonstrates that Yucca Mountain is scientifically and technically suitable for development. Energy security, homeland security and environmental protection will all be enhanced by sitting a single nuclear waste repository at Yucca Mountain rather than leaving nuclear waste stranded in temporary storage locations at 131 sites in 39 states. Independent experts at the Nuclear Regulatory Commission (NRC) are reviewing the scientific study of Yucca Mountain and will later consider the site for a license.

RENEWABLE ENERGY TECHNOLOGY

"New" renewable energy sources (other than hydropower) have continued to make inroads from a small base. The trend has been encouraged by a tax credit, currently 1.8 cents per kWh, for the first ten years of electricity production from new wind and closed-loop biomass. The credit was established by the Energy Policy Act of 1992, briefly lapsed for new facilities in 2000 before being extended through 2001 and later through 2003, and again lapsed for new facilities for most of 2004 before being extended through the end of 2005. Periodic lapses in the credit have led to an uneven pattern of wind power capacity additions, which plummeted from 732 MW in 1999 to 53 MW in 2000, soared to a record of 1,696 MW in 2001, crashed to 410 MW in 2002, rebounded to 1,687 MW in 2003, and seemed likely to fall off sharply in 2004. But installed wind capacity grew an average of 28 percent per annum over the five years through the end of 2003, when it totalled 6,374 MW. The Wind Powering America initiative at the Department of Energy has set an ambitious goal of having 80 GW of wind turbines in place by 2020 which could be achieved if such rapid growth persists.

Other renewable technologies have received substantial attention as well. The photovoltaic systems programme aims by 2005 to cut the cost of highly reliable PV modules to $1.85 per watt and lower the overall cost of photovoltaic electricity to 18 cents per kilowatt-hour. By 2020, it is anticipated that PV systems could be cost-competitive on the electric grid and that installed PV capacity could total 30 GW. The geothermal programme at DOE aims to reduce costs of geothermal power from 5 to 8 cents per kWh in 2000 to a range of 3 to 5 cents per kWh by 2007. DOE's bio-power programme aims to increase generating capacity from energy crops, agricultural residues, wood and wood residues from 3 GW in 2000 to 10 GW by 2010, while its biofuels programme aims at 2.2 billion gallons of cellulosic ethanol production by 2010, versus zero in 2000. Renewables R&D received about US$242 million in federal government funding in 2004, of which $86 million went to biomass and biorefinery technology, $83 million to solar technology, $41 million to wind R&D, $26 million to geothermal systems, and $5 million to hydropower.

About sixteen states have implemented renewable energy goals or portfolio standards, including such large states as California and Texas. The Energy Information Administration has estimated that a 20 percent renewable energy portfolio standard for the year 2020 would, if implemented through a system of tradable credits, yield a market value for credits on the order of 5 cents per kilowatt-hour. While that would imply a first-order price increase of 1 cent per kWh (5 cents per kWh applied to 20 percent of the generating mix), the EIA found that consequent easing of natural gas demand would limit the net effect on electricity prices, after considering reduced costs of gas input to power production, of just 0.4 cents per kWh, or about 5 percent of the average electricity price.

ENERGY CONSERVATION

FUEL EFFICIENCY STANDARDS AND TRANSPORTATION TECHNOLOGY

Corporate Average Fuel Efficiency (CAFE) standards, in place since 1978, require that light trucks and automobiles sold by each vehicle manufacturer attain a certain average level of fuel economy, with sales in excess of this standard subject to fines. Historically, CAFE standards helped to bring about and sustain a huge improvement in the efficiency of the vehicle fleet, despite relatively low gasoline prices. But the fuel economy standard has been static at 27.5 miles per gallon (mpg) for cars since 1985 and 20.7 mpg for light trucks since 1996. Due to increased sales of sport utility vehicles and minivans, which fall within the light truck category, average fleet efficiencies have even declined slightly in recent years, reaching a 20-year low of 24.4 mpg by 2001. However, a statutory prohibition on examination of fuel efficiency standards by the Department of Transportation (DOT) was lifted in December 2001. In April 2003, DOT issued a final rule raising fuel economy standards for light trucks by a total of 7 percent to 21.0 mpg in 2005, 21.6 mpg in 2006 and 22.2 mpg in 2007.

In addition to fuel economy standards, several other policies are proposed or in place to raise the efficiency and limit the environmental impacts of transport. The Department of Energy has invested heavily over the last decade, with major US automakers, in the Partnership for the Next Generation of Vehicles and then the Freedom CAR initiative, to support research and development of gasoline hybrid and fuel cell vehicles that could ultimately triple the efficiency of vehicles on the road. It has also supported the Hydrogen Fuel Initiative to develop technologies for vehicle use of hydrogen. DOE expects to invest $1.7 million over the five years through 2008 on research and development of advanced hybrid vehicle components, fuel cells, and hydrogen infrastructure technologies. It is anticipated that with improved technology for electrolysis, hydrogen might be produced from renewable energy sources at a delivered cost of $2.25 per gallon of gasoline equivalent by 2015.

BUILDING AND APPLIANCE STANDARDS

The Department of Energy has energy efficiency standards in place for all major types of energy-using appliances, including air conditioners, clothes washers and dryers, space and water heaters, kitchen ranges and ovens, refrigerators and freezers, and lighting. In 2001, new minimum efficiency standards were issued for central air conditioners and heat pumps, water heaters, clothes washers, and some types of commercial heating and cooling equipment. The National Energy Plan called for appliance standards to be strengthened for products already covered and extended to additional products where technologically feasible and economically justified.

The highly successful Energy Star labelling programme clearly signals high efficiency in office buildings and appliances to consumers. The NEP recommended that the program be expanded from office buildings to include schools, stores, homes, and health care facilities. It also recommended that Energy Star labels be extended to additional products, appliances, and services. Further, the NEP recommended doubling expenditure on weatherisation of houses for low-income households, as well as support for educational programs related to energy development and use.

ELECTRICITY MARKET REFORM

The United States has achieved a high degree of competition in its electric power markets. Roughly one-fourth of all electricity generated in the United States in 2002 was provided by independent, non-utility generators. Seventeen states, with nearly half the US population, allow consumers to choose their electricity supplier. Virtually all new electric generating capacity which is planned or under construction is being financed and built by independent power producers; very little new capacity is being provided by traditional vertically integrated utilities.

The competitive power market came about as a result of initiatives by the Federal Energy Regulatory Commission (FERC). FERC orders 888 and 889, issued in 1996, required investor-owned utilities to open up their transmission systems to competing power providers on a non-discriminatory basis. Order 2000, issued in 1999, encouraged transmission-owning utilities to cede operational control of their high-voltage power lines to independent Regional Transmission Organisations (RTOs), while retaining ownership of these lines and revenue streams from their use. FERC's authority to issue these orders was upheld by the Supreme Court in 2001.

In July 2002, FERC issued a Standard Market Design proposal to govern the structure and operation of wholesale US power markets. FERC's idea is that all utilities that own, operate or control interstate transmission should conform to this standard design. Key elements include stronger inducements to participation in RTOs, active monitoring and mitigation measures to prevent market abuses, a centralised spot-power market to complement decentralised bilateral contracts for power, steps to enhance price and market transparency, and measures to encourage construction of needed power plants and transmission infrastructure.

RTOs: Under the Standard Market Design, all transmission owners and operators would have to join an RTO or contract with another independent transmission provider (ITP) to operate their transmission facilities. It is anticipated that if utilities have to cede operational control of their transmission in any case, they are likely to opt for the operational advantages of an RTO. RTOs and other ITPs would help FERC monitor the market for potential anticompetitive actions by market participants. Each RTO would also provide for seamless trading within the market it serves, so that transmission customers can avoid "pancaked" rates in which fees are paid to each utility that owns transmission assets needed to carry out a power transaction. Electricity sellers would pay a single access fee and a region-wide transmission rate which better reflects the true (lower) cost of transmission service and will therefore promote additional cost-saving transactions. RTOs would be overseen by a governing board of directors completely independent of market participants, as well as by an advisory committee of market participants and state government officials.

Bilateral Contracts: For the vast majority of power transactions which are made under bilateral contracts between buyers and sellers, the Standard Market Design provides for physical delivery of power through Congestion Revenue Rights, or CRRs. These are tradable financial rights for transmission between two points on the grid over a particular period of time. A secondary market would be created for such rights so that congested transmission pathways can be used by electricity suppliers who value the pathways the most. In addition, a new "network" transmission tariff would allow all transmission users to schedule power deliveries using multiple receipt and delivery points, with the same operational flexibility enjoyed by transmission owners.

Spot Market: To complement bilateral contracts, RTOs and other ITPs would administer voluntary markets for short-term transactions: spot markets for wholesale power, ancillary services and transmission congestion rights; a real-time "balancing" market to maintain reliable operations of the power grid; and a separate "day-ahead" market. The centralised spot-power markets would be "security-constrained" with measures to ensure grid reliability and "bid-based" with buyers and sellers bidding the price at which they are willing to buy or sell power during any day or hour. This would ensure that electricity trade is not pursued at the expense of reliability. Market-clearing prices would be provided transparently to all supply and demand-reduction sources to encourage efficient short- and long-run operations. A "circuit breaker" provision, to help prevent short-term price spikes, would bar bids above US$1,000 per megawatt-hour. The length and severity of price spikes would also be limited by allowing demand reduction measures to be bid into the spot market.

Investment: Several aspects of the Standard Market Design would promote required investment in new transmission capacity, generating plants and conservation. The market for CRRs would allow suppliers to hedge transmission cost uncertainty and would assign values to congestion that could signal the need for investment to relieve transmission bottlenecks. Locational marginal pricing at each point on the grid would potentially signal where investment in generation and transmission is needed to improve grid operations. Companies that invest in new transmission would be allowed to retain rights to the added power-transfer capacity. A generation adequacy requirement would compel companies serving retail customers to arrange sufficient supplies and demand reductions to meet peak demand plus a 12 percent reserve margin. Infrastructure needs would be identified by RTOs through a planning process in each region that includes state regulators and local zoning authorities, so that projects meeting these needs could more readily obtain financing on the basis of anticipated returns. Such incentives and procedures should strengthen competition, limit tight supply situations that lead to short-run price spikes, and enhance the reliability of service.

NOTABLE ENERGY DEVELOPMENTS

ALASKA NATURAL GAS PIPELINE

The Congress has approved a package of measures to facilitate construction of a natural gas pipeline from Alaska to the lower 48 states. Most of these measures were taken from the proposed Energy Policy Act of 2003, which did not pass, and included in either the military construction appropriations bill for 2004 or the American Jobs Creation Act of 2004. The package includes a federal government loan guarantee for 80 percent of the first $18 billion spent on the project if for some reason it should not be completed. It creates an Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects to streamline the process for obtaining regulatory permits and to expedite judicial review. It affirms the validity of rights-of-way and permits granted for an Alaska pipeline under the 1976 Alaska Natural Gas Transportation Act, providing that any complaints be heard in an expedited process by the U.S. Court of Appeals. It requires FERC to complete an environmental review of the pipeline within 18 months of receiving an application to build it and to issue a construction permit within 60 days of the review's completion. It provides for non-discriminatory access so that competing producers can get their gas through the pipeline to market. For tax purposes, investors will be able to depreciate the pipeline over 7 years instead of the usual 15.

RENEWABLE ENERGY TAX INCENTIVES

Several tax measures, originally included in the Energy Policy Act of 2003, were passed by Congress to promote renewable energy. The Working Families Tax Relief Act of 2004 extends through the end of 2005 an existing tax credit of 1.8 cent per kWh for electricity produced from wind, closed-loop biomass and chicken waste. The American Jobs Creation Act of 2004 provides, for the first time, a 1.8 cent per kWh credit for solar and geothermal electricity and a 0.9 cent per kWh credit for open loop-biomass including agricultural livestock waste, municipal biosolids and sludge, and municipal solid waste (including landfill gas). It promotes alcohol and biodiesel fuels, extending an existing income tax credit for alcohol fuels through the end of 2010, providing a new income tax credit for biodiesel ($0.50 per gallon for business use, $1.00 per gallon for agricultural use), and creating new excise tax credits for alcohol and biodiesel fuel mixtures. It establishes a new category of tax-exempt bonds called qualified green bonds, up to $2 billion of which can be issued to finance commercial projects on brownfield sites that incorporate state-of-the-art renewable or energy efficiency features and create at least 1,500 permanent full-time jobs and 1,000 construction jobs.

OIL AND GAS PRODUCTION INCENTIVES

A few tax measures, originally part of the Energy Policy Act of 2003, were enacted during 2004 to encourage production of oil and gas from marginal wells. The American Jobs Creation Act creates production tax credits of $3 per barrel for crude oil and $0.50 per thousand cubic feet of gas from such wells, which apply at oil prices below $18 per barrel and gas prices under $2 per thousand cubic feet. With respect to such wells, the Working Families Tax Relief Act extends by two years, through the end of 2005, a suspension tax rules that normally limit deductions for depletion of oil and gas reserves to 100 percent of net income in any given year.

PENDING LEGISLATIVE ISSUES

Several further provisions of the Energy Policy Act of 2003, which passed the House but not the Senate, could well be introduced by other legislation. There could be a renewed move to repeal the Public Utility Holding Company Act (PUHCA) of 1935, which somewhat restricts the entry of competitive generators into the electricity market. There could also be a renewed effort to require that all users, owners and operators of transmission or generating facilities on the power grid comply with reliability standards set by the North American Electric Reliability Council (NERC). Further, Congress may try again to extend the Price-Anderson Act, which indemnifies nuclear power plant licensees against potential damage from nuclear accidents, while raising liability limits on licensees.

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VIET NAM

INTRODUCTION

Viet Nam is located in South East Asia and shares borders with Cambodia, Laos and China. It has an area of 331,111 square kilometres and a population of about 80.42 million (2002). With the start of reform policies for an open market-oriented economy in 1986, the economy of Vietnam has developed considerably. GDP grew at an annual average rate of 7 percent from 1991 to 2002. In 2002, its GDP reached US$166 billion (in 1995 US$ at 1995 PPP), and its unemployment rate returned to the level of 6.0 percent as recorded before the Asian financial crisis in 1997. However, Vietnam's income per capita is still low at US$2,064 (in 1995 US$ at 1995 PPP). The government has set-up a target to double the income per capita by maintaining a GDP annual growth rate of 7.2 to 8.0 percent and controlling the population growth under 1.5 percent for the period up to 2010.

Vietnam is endowed with diverse primary energy resources including oil, gas, coal and new and renewable energy, such as hydropower, biomass, solar, wind, geothermal. Since 1990, Vietnam has been a net energy exporter, and mainly exports crude oil and coal.

Table 39 Key data and economic profile (2002)

Key data		Energy reserves*	
Area (sq. km)	331,111	Oil (MCM) - proven	397.5
Population (million)	80.42	Gas (BCM) - proven	230
GDP Billion US$ (1995 US$ at PPP)	165.99	Coal (Mt)	3,972
GDP per capita (1995 US$ at PPP)	2,064		

Source: Energy Data and Modelling Center, IEEJ.

* Ministry of Industry, Viet Nam. Oil, gas and coal reserves as of end 2003.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2002, Viet Nam's total primary energy supply reached 19,419 ktoe, or an increase of 16.91 percent from 2001 or about 3.6 times that of TPES in 1991. By fuel type, 48.9 percent of supply came from petroleum products, 28.4 percent from coal, 14.6 percent from natural gas and 8.1 percent from hydro and other fuels.

As of end 2003, Vietnam's proven oil reserves were reported at 347 Mtoe. From 1991-2003, Vietnam's oil production grew significantly at 16.2 percent per annum. Current oil developments are in offshore areas, particularly in Cuu Long, Nam Con Son and Malay-Tho Chu Basins. In 2003, Viet Nam produced over 17,930 ktoe of crude oil, most of which were exported mainly to Japan, Singapore, the US and South Korea. All of the crude oil extracted from oil fields in Vietnam are "light" and "sweet" and hence command a premium price over benchmark Brent crude in the world market.

Currently, Vietnam has to import petroleum products for 98 percent of its domestic needs. Its first major refinery should be commissioned by mid 2008.

Vietnam's gas industry is in its early stage of development. Current gas proven reserves of 207 Mtoe are expected to increase because of several significant gas discoveries during the last 5 years on its continental shelf. Gas supply experienced a strong growth of 47.6 percent per annum (on the average) since 1995, to 2,845 ktoe in 2002. Growths in industrial and especially the power sectors have driven the demand for natural gas. Up to mid 2004, Vietnam has invested and completed two gas pipelines with combined transport capacity of 9 BCM per year and related facilities, six gas-fired power plants with about 3,400 MW capacity and one 0.8 tone per year-capacity fertilizer plant, supporting its gas production.

Compared to oil and gas, Vietnam coal production grew more gradually during the period 1991-2003. Coal production reached 8,904 ktoe in 2002 and 10,700 ktoe in 2003, about more than 3.8 times of the level in 1991. As the economy has had the tendency of consuming less coal in preference to electricity and oil, coal export has been fostered for the last years. In 1991, exports stood at 657 ktoe and accounted for 23 percent of total production; in 2002, this number increased to 3,387 ktoe, occupying 38 percent of total output. Vietnam exported coal to more than 30 economies. Its main importers are China (35 percent), Japan (30 percent), Thailand, South Korea, and India. As of end 2003, coal reserves were estimated 3,972 Mt, excluding the recent discovery of a potential 210 billion tones in the Red River Delta. The production is forecasted to have steady growths in the next years, and the supply proportion to the national market will be re-enlarged.

As of end 2003, Vietnam's economic and technical potential of hydropower was estimated at 87 billion KWh or 21,750 MW. In 2002, with a total power plant available capacity of 8,500 MW, Vietnam produced 35,795 GWh (or 3,078 ktoe), up 17 percent from the level in 2001. 51 percent of electricity output came from hydro power plants, 23 percent from gas, 14 percent from coal and 12 percent from oil-fired power plants. Distribution loss was on downward trend since 1990 at an average rate of 1.5 percent per annum but still considerable as 16 percent in 2002. The Vietnam's electricity elasticity coefficient has been always over 1 and is forecasted to be under 1 only beyond 2010.

Table 40 Energy supply & consumption for 2002

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	30,213	Industry Sector	6,001	Total	35,795
Net Imports & Other	-10,794	Transport Sector	4,969	Thermal	17,597
Total PES	19,419	Other Sectors	4,413	Hydro	18,198
Coal	5,517	Total FEC	15,383	Nuclear	-
Oil	9,493	Coal	4,017	Others	-
Gas	2,845	Oil	8,761		
Others	1,565	Gas	19		
		Electricity & Others	2,586		

Source: Energy Data and Modelling Center, IEEJ. See http://www.ieej.or.jp/egeda/database/database-top.html

FINAL ENERGY CONSUMPTION

Vietnam's final commercial energy consumption (TFEC) enjoyed a steady growth of 11.9 percent per annum from 1991 to 2002. In 2002, the economy consumed 15,383 ktoe, up 14.6 percent from that of 2001. However, its number per capita of 0.19 toe is very low in comparison to the APEC average (1.48 toe) as a large proportion of the Vietnamese population still relies heavily on non-commercial biomass energy sources. In 2002, although gas demand recorded the highest growth (23.5 percent) among fuels, it was still very marginal in non-power sector. Oil, electricity and coal continued to contribute major increments of the total demand, at 67 percent, 19 percent and 14 percent respectively. And in the energy consumption mix, oil accounted for 57 percent, coal 26 percent, electricity 16.8 percent, and gas 0.2 percent.

Industry as the driver sector in the GDP growth had the biggest demand, about 39 percent of TFEC. This sector consumed mainly coal at 49 percent, then petroleum products 32 percent, electricity 18 percent, and natural gas 1 percent. Transport ranked the second accounting for 32.3 percent of TFEC. It remained as the main consumer of oil at 56 percent of the economy's total oil requirement. Residential and commercial consumption represented 25 percent of TFEC. In this sector, electricity accounted for 37.8 percent, oil 34.5 percent, and coal 27.7 percent. Demand on electricity was on the strongest upward trend. This reflects the improvement of household income, which brings about an increase in electric appliance use, and of power supply quality. However, in remote and rural areas, non-commercial energy such as wood and agricultural by-products was still main source of households.

POLICY OVERVIEW

Vietnam aims to achieve "rapid, efficient and sustainable development, economic growth in combination with social progress, equity and environmental protection". For the period of 2001-2010, priority activities in the energy sector posted in The Vietnam Agenda 21 are as follows:

- Strengthen legal bases for energy production and consumption activities and environmental protection. Thoroughly improve system of energy management agencies, enhancing energy development plan formulation.
- Select techniques for using and producing energy of all types, choose policy instruments, formulate development programs to implement sustainable development strategy.
- Support research and development, transfer and application of energy systems, which do not harm the environment, including new energy sources and renewable energy. Encourage the application of technology that consumes less energy and actively implement energy saving programs. Priority is given to developing renewable energy sources via financial incentives and market mechanisms in the national energy development strategy.
- Apply specific measures on technology and the organizational management of each energy sub-industry to implement programs and projects on reducing negative environmental impacts in production activities and energy use.
- Actively engage in international cooperation and exchange activities under the Frame Agreement on Climate Changes of which Vietnam has been a participant since 1994. Import and apply foreign advanced techniques to coal mining, washing and processing. Renovate techniques in coal industry with foreign capital and techniques.

The Ministry of Industry (MOI) is responsible for the state management of whole energy industries, namely electricity, new and renewable energy, coal, and oil and gas industries. MOI is in charge of presiding over the formulation of law, policies, development strategies, master plans and annual plans with respect to these sectors, and submitting to the Government and Prime Minister for issuance or approval. Also, MOI is responsible for directing, supervising development of energy sectors and reporting to the Prime Minister.

The national energy policy will be submitted by MOI to the Prime Minister for approval by early 2005. It aims to respond to questions on: national energy security, efficient use and preservation of energy resources, environmental protection, reforms in the energy structure and organization, establishment of energy market, increase in investment capital resources for energy sectors, market-oriented energy pricing, NRE and new energy technology development, enhancement of energy technology-related studies, and expansion of global integration and external trade on energy products.

OIL AND GAS SECTOR

Participants in the oil and gas sector belong to different private and public organizations and ministries. Among them, only the Vietnam Oil and Gas Corporation (PETROVIETNAM), which was established in 1975 and supervised by the Ministry of Industry since July 2003 (instead of the Prime Minister) is vested the entire oil and gas resources in Vietnam. PETROVIETNAM is entrusted with the responsibility of developing and adding value to these resources. Its business activities cover all the operations from oil and gas exploration and production to storage, processing, transportation, distribution and services. In the downstream operation, the Vietnam National Petroleum Corporation (PETROLIMEX), which was established in 1956 by the Ministry of Trade and re-established in 1995 by the Prime Minister) is always known as the main supplier, regulating, stabilizing and developing the fuel and petrochemical markets all over the country. This state-owned corporation currently ensures import, storage and distribution of petroleum products for 60 percent of national market.

UPSTREAM

Considered as one of the key measures to ensure the nation's energy security, the Vietnamese government has prioritised the importance of increasing oil and gas proven reserves, and accelerating its oil and gas field development plans. In June 2000, the Petroleum Law of Vietnam was amended to conform more to international practices in petroleum industry, and encouraging foreign and Vietnamese organisations, as well as individuals to invest their capital into the petroleum industry of Vietnam. PetroVietnam has been entrusted to push plans of exploring and exploiting oil and gas in advance over Vietnam's continental shelf through strengthening international cooperation. Likewise, since 2001, the Government has encouraged PetroVietnam to expand its oil and gas exploration and exploitation activities overseas to find additional oil sources for the national market. Vietnam has set up a target to increase national production to 18-20 Mtoe of crude oil and 11-13 Mtoe of natural gas in 2010.

DOWNSTREAM

Vietnam is reforming its policies on oil downstream operations. On 15th September 2003, the Prime Minister signed the decision number 187/QD-TTg permitting all economic components to participate in petroleum products business over the country market as agent of state-owned import-export firms. The government has also encouraged PetroVietnam, Petrolimex to restructure and equitize their state companies, which operate in oil and gas storage, distribution and services.

Vietnam is accelerating its plan for building up two refineries with total capacity of 13.5 Mt per year in order to be 50-60 percent self-sufficient in oil by 2010. PetroVietnam should participate as major stakeholder in both projects, according to government-level approved feasibility studies.

In the gas sector, Vietnam has facilitated contractors having gas fields under development to expand their business in downstream projects such as gas pipeline, gas-fired power plant and services. BP is the briskest contractor snatching this open policy by investing huge amounts since 2000 in the Nam Con Son pipeline project – the world's longest two-phase pipeline to-date with a carrying capacity of 7 BCM per year, and in a 720 MW capacity gas-fired power plant - the Phu My 3. Both projects started operation in 2003. Currently, UNOCAL and KNOC are also considering their projects on downstream.

Aiming at quadrupling gas use to 12-14 BCM in 2010, the government is encouraging Petrovietnam to strengthen cooperation with gas-field contractors to accelerate transportation plans in parallel with field developments. Beside two existing pipeline systems and the one of 2-Bcm capacity from PM3 field in Malay-Thochu basin to Ca Mau power plants under investment, Vietnam also intends to push up the collaboration with ASEAN countries to build the Asia's largest 5,000-kilometer natural gas pipeline linking Vietnam with Thailand, Malaysia, Indonesia and China. This is considered as an important solution favouring Vietnam's gas exploitation, import and export.

COAL SECTOR

Profound reforms have occurred in the coal sector since 1999. The National Coal Corporation (VINACOAL), the leadership state-owned coal corporation, established in 1994, has been restructured and reorganized. Its companies are specialised in business segments and operate under market orientation. Since 2002, coal is produced and traded under contracts signed between Vinacoal and independent companies.

Vinacoal focuses on increasing proven reserves, production capacities and coal quality through use of modern equipments for deep underground exploration, exploitation and transportation, and discovering new domestic and international niche markets for their products. In 2003, it spent US$111 million (VND1,729 billion) renewing mining technology and facilities in order to increase productivity, reduce labour accidents and improve the environment in coal mining regions. Also, Vinacoal currently participates actively in international collaborations through projects on training and transfer of coal clean technologies with Japan, Germany, Russia, etc.

Considering coal as an important energy source of the economy especially beyond the next ten years, the Vietnamese government is now promoting the construction of coal-fired power plants. Beside EVN, Vinacoal is investing on three plants, namely Na Duong, Cao Ngan and Cam Pha with total capacity of 500 MW, accounting for 15.6 percent of the total 3,200 MW additional coal-fired power capacity between 2005-2010. It is estimated that domestic demand on coal will increase to 20-23 Mt by 2010. The power sector with a capacity as high as 4,450 MW in 2010 (or 3.6 times from now) will use about 10 Mt.

POWER SECTOR

The power sector leads the reform process in Vietnam's energy industry. Since 2001, the Electricity of Vietnam (EVN- the leadership state-owned corporations operating from production to transmission and distribution, established in 1995) has conducted necessary changes in financial and operational management to actively prepare for a power competitive market in future. The investment in power sources has been more and more opened to domestic and foreign investors.

The Government has approved in March 2003 the Revised Electricity Master Plan 5 for the period of 2001-2010. Accordingly, the power sector will grow with an annual growth rate of 13-14 percent and will generate 48.5-53 TWh by 2005, and 88.5-93 TWh by 2010 to meet the expected demand. The sector is planned to supply power to 90 percent of the rural households in mountainous regions by 2010. Also, EVN has aimed to improve the quality of service and reduce transmission loss to 10 percent by 2010. Electricity price is being regulated to match the long-run marginal cost of US$7 cents per KWh in 2005.

To realise this target, total power installed capacity required is 21.5 GW by 2010, so 57 new power plants with a combined capacity of 13 GW need to be installed between 2003-2010. Hydropower will continue to be given the priority, especially for projects that could combine goals of generating power, regulating water for agricultural production and flood and drought prevention. Investment of 4.81 GW hydropower has been scheduled in order to raise its total installed capacity to 8.9 GW (42 percent) in national system by 2010. Coal and gas power is promoting to gain share of 21 percent and 33 percent respectively by the end of the term. From 2008, electricity imports through the National Interconnected System will be initiated with an amount of 100MW per year from Laos. Vietnam also planned to develop transmission and distribution systems, as much as 2300 km of 500 kV lines and 7400 km of 220 kV lines between 2002-2010. New investments were assessed US$14 billion for the next five years.

NOTABLE ENERGY DEVELOPMENTS

NEW ELECTRICITY LAW

On 10th November 2004 the National Assembly passed the electricity law with 10 chapters and 70 articles, which will come into effect on July 1st, 2005. Electricity law contains stipulations to promote investment from domestic and foreign investors, to facilitate international integration of Vietnam's electricity, while contribute to improving state management efficiency, and effectively meet energy demand for the country's socio-economic, security and defense development.

The law stipulates for improving electricity quality and services, facilitating a fair competition in electricity business in a market economy, clarifying rights and duties of electricity buyer and seller, and also confirming regulator role of the government on electricity pricing.

According to the law, electricity market will be established and gradually developed through three competition levels, from power generation, then wholesale and retail business. The Prime Minister is responsible for issuing regulations of itinerary and conditions for forming and developing power market levels. Power price will be set appropriately to market development levels and in the manner facilitating investors to achieve their reasonable profit, encouraging energy saving, protecting lawful rights and benefits of electricity companies as well as consumers. As for rural, mountainous and island regions, the government will reserve supports on investment capital, operational expenses, and favour conditions for loan and taxes to projects invested in the areas, especially to projects of electricity grids and generating stations which use local energy resources and NRE.

CREATION OF A COMPETITIVE POWER MARKET

The Electricity of Vietnam (EVN) opened to competition its power generation in July 2004. For the first phase, 14 EVN subsidy power plants have participated in a pilot scheme for creating a power market. EVN announces each day the expected power demand and the plants will offer their selling prices, and EVN will then make its purchasing decision. The scheme aims currently only to help participating plants determine their cost and prices, get used to a competitive environment, and therefore, does not yet make impact on selling electricity prices to consumers. The scheme will be, step by step, opened to whole 32 power plants. Plants not owned by EVN currently account to 10 percent of the total power sales. It has been also scheduled that from 2005, EVN-owned power plants would be split into independent companies. EVN will keep only its monopoly in the 500-110kV transmission line.

RESTRUCTURING STATE COMPANIES IN POWER SECTOR

On 28th October 2003, the Prime Minister signed Decision number 219/2003/Qd-TTg to approve the project of restructuring and renovating state companies under EVN up to 2005. Accordingly, 34 companies and organisations will maintain 100 percent of state investment in their charter capital and keep unchanged their legal entity, 2 electricity companies in Ninh Binh and Hai Duong will be restructured to sole proprietorship limited liability companies in 2003-2004, 11 companies will be equitized within 3 years 2003-2005, of which 8 have the government's major stake, The Information Technology Center of EVN and Can Tho electricity company will be reorganised in 2004 and 2005 respectively by merging other local organisations which have close specialities.

PRICE AND TAX ADJUSTMENTS FOR OIL PRODUCTS

Under impacts of persistent soaring world prices of petroleum products, import tax and retail price of gasoline, diesel, kerosene, and mazut were many times adjusted by the Vietnamese government. By end 2004, import taxes on fuel have been reduced to zero percent. Retail ceiling price of gasoline RON 90 and 92, after adjusting three times in February 22nd, June 19th, and November 1st, 2004, grew by 35 percent from the levels at the end 2003 to VND 7,300 per liter and VND 7,500 per liter respectively, diesel went up 10 percent to VND 4,850 per liter and kerosene 12 percent higher to VND 4,800 per liter. However, this price levels are still low in comparison to other ASEAN countries such as Campuchia, Thailand, Malaysia, and China, and lower than real import prices of petroleum companies. Currently, the government gives a subsidy of about VND1,000 to petroleum companies for each liter of gasoline they sell and VND1,200 for each liter of diesel, kerosene.

ENVIRONMENT

Energy saving: Vietnam is implementing a US$29 million project funded by the Global Environment Fund (GEF) with the aim at saving 90,000 tonnes of oil and reduce energy costs by at least 10-15 percent as well as reduce carbon dioxide emissions by more than 1 million tonnes each year. A total of 500 small- and medium- sized enterprises making bricks, ceramics and paper, weaving and food processing will be assisted in reducing production cost and product prices by 2009 by raising their energy resource efficiency. The enterprises will be given free training on energy management, update information on new business support policies as well as assistance in devising schemes to reduce energy costs. In addition, they will receive a guarantee when borrowing loans from the Industrial and Commercial Bank and other sources from the Development Assistance Fund, the Vietnam Environment Protection Fund, and the Science and Technology Fund.

First appearance of LPG-fuelled taxis in Hanoi: since the last 6 years, organizations and institutes of Petrovietnam, Petrolimex and The Da Nang Technology University have carried out many research studies and pilot projects for using LPG and CNG for transport to replace conventional fuels. And recently, research results have been applied in the business life with the appearance on 17th November 2004 of the Hanoi Petrolimex Gas Taxi Company with its 50 first liquefied petroleum gas taxis operating. The company plans to quickly increase the number of LPG-fuelled taxis operating in Hanoi to 100 and expand its operation network in Ho Chi Minh City and other localities in the next years.

NEW AND RENEWABLE ENERGY

Solar power: In September 2004, five solar power systems with a combined capacity of about 3 kW have been put into operation on Quan Lan island, the northern coastal province of Quang Ninh, marked the first phase completion of the Vietnam-Germany cooperation program in developing NRE energy in Vietnam. These solar power systems were funded by the Germany Business Association of Sachsen-Anhalt State and installed by Germany's Teutloff GmbH and Spicher GmbH companies in coordination with the Centre for New Energy Research of the Ha Noi Technology University. The project enabled residents on the island to access electricity.

Wind power: As part of the plan to develop NRE in remote and island areas, the first wind power generating station of Vietnam was inaugurated and put on operation on Bach Long Vi island, Hai Phong province on 31st October 2004. This US$1 million station has a capacity of 8 MW, and has been equipped by modern technology imported from Spain. The station will ensure the electricity supply to productive units and households on the island for 24/24 hours instead of 20 hours a day as before.

EVN has also set up a project costing about VND140 billion to harness wind power on Phu Quy island in the central coastal province of Binh Thuan. It is planned to build up five wind power generating stations on this island of 20,000 people, which is more than 80 nautical miles away from the mainland. The first station is scheduled to be completed in 2005, and the rest will be built from 2006-2008. Once completed, the project is expected to supply 70 percent of electricity for the island, helping reduce power production from diesel generators.

COOPERATION WITH JAPAN FOR COAL EXPLORATION AND EXPLOITATION

Vietnam and Japan will cooperate to explore deep underground coal deposits in southern Quang Ninh province, where 80 percent of current Vietnam coal reserves are located. A memorandum of understanding to this effect was signed on 21st October 2004 by General Director of VINACOAL and senior counsellor of the Chairman of the Japanese New Energy and Industrial Technology Development Organisation (NEDO). Head of Vinacoal's Geodesic Geology Department and Head of NEDO's Committee for Coal Projects also signed a masterplan on implementation of the first year of the project to explore coal deposits deep underground in Quang Ninh.

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