ASIA PACIFIC ENERGY RESEARCH CENTRE

ENERGY INVESTMENT OUTLOOK FOR THE APEC REGION

2003

Published by

Asia Pacific Energy Research Centre
Institute of Energy Economics, Japan
Inui Bldg.-Kachidoki 16F, 1-13-1 Kachidoki
Chuo-ku, Tokyo 104-0054 Japan
Tel: (813) 5144-8551
Fax: (813) 5144-8555
Email: apercadmin@aperc.ieej.or.jp (administration)

APEC#203-RE-01.5
ISBN 4-931482-24-4

Printed in Japan

FOREWORD

APEC economies are increasingly concerned about the adequacy and reliability of energy supplies as their needs for energy expands. Timely investment in energy production facilities and transportation infrastructure is essential to ensure that energy remains steadily available to fuel economic growth. Thus, a study of energy investment requirements, the ability of economies to meet these requirements and policies to promote required investment should be of broad interest across the APEC region.

This report estimates future investment requirements for each major energy sector and every APEC economy, building upon information developed in the *APEC Energy Demand and Supply Outlook 2002.* It also assesses the burden of energy investment relative to economic output over time as economies develop. Further, it examines the principal factors affecting the adequacy of energy investment and suggests ways for APEC members to ensure that energy investment requirements continue to be met.

This report is published by APERC as an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or individual member economies. But we hope that it will serve as a useful basis for discussion and analysis both within and among APEC member economies for the promotion of investment in the energy sector.

Masaharu Fujitomi
President
Asia Pacific Energy Research Centre

ACKNOWLEDGEMENTS

Juan Ramón Mota Aguilar and Naoko Doi were the project co-leaders: the former was responsible for estimation of energy investment requirements including modelling, while the latter was responsible for analysis on issues relevant to energy investment including historical trends and financing. Yonghun Jung provided overall guidance and valuable insights on the study directions. Jeffrey Skeer greatly contributed to writing of the draft report.

We would like to thank all of those who contributed to this study, which could not have been successfully completed without the hard work and inspiration of many individuals.

Especially valuable advice and insights were received from a number of energy experts worldwide, including J. Phil Prince (Canadian Energy Research Institute), Aya Yamazaki (Japan Bank for International Cooperation), Fatih Birol (International Energy Agency), Neil Davis (Energy Information Administration, US Department of Energy) and Gordon Kwan (HSBC Securities).

We would also like to thank members of the APEC Energy Working Group (EWG), APEC Expert Group on Energy Data and Analysis (EGEDA), and APERC Advisory Board, along with a list of experts in the APEC region, including Edito S. Barcelona (The Philippines Department of Energy), Keii Cho (Institute of Energy Economics, Japan), Jesus T. Tamang (The Philippines Department of Energy), Vu Van Thai (Ministry of Industry, Viet Nam) and Zhongan Wang (China National Offshore Oil Corp.) for their stimulating comments and current information.

APERC CONTRIBUTORS

PROJECT CO-LEADERS

Naoko Doi (Japan)

Juan Ramón Mota Aguilar (Mexico)

MAIN CONTRIBUTORS:

I Gusti Suarnaya Sidemen (Indonesia)

Yonghun Jung (Korea)

Desiderio Añora Fuerte, Jr (Philippines)

Jeffrey Skeer (USA)

Binh Nguyen (Viet Nam)

OTHER CONTRIBUTORS:

Iván Jaques (Chile)

Yanjia Wang (China)

Jaya Singam Rajoo (Malaysia)

Gary Eng (New Zealand)

Vichien Tantiwisarn (Thailand)

ADMINISTRATIVE SUPPORT

Sutemi Arikawa, Shohei Okano, Sachi Goto, Mizuho Fueta and Chie Koshino.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

Following are a few abbreviations used in this report, most of which are of a technical nature. Abbreviations of most institutions and organisations in APEC economies are defined in the text.

APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
Bcf	billion cubic feet (one thousand Mcf)
Bcm	billion cubic metres (one thousand Mcm)
Btu	British thermal unit
CHP	combined heat and power
GDP	gross domestic product
GJ	gigajoule (one billion joules or one thousand MJ)
GW	gigawatt (one billion watts or one million kW)
GWh	gigawatt hour (one billion watt-hours or one million kWh)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IPP	independent power producer
kcal	kilocalories
km	kilometres
kW	kilowatt (one thousand watts)
kWh	kilowatt hour (one thousand watt-hours)
LA	Latin America
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MBtu	million British thermal units
Mcf	million cubic feet
Mcfd	million cubic feet per day
Mcm	million cubic metres (35.3147 Mcf)
MJ	megajoule (one million joules)
Mtoe	million tonnes of oil equivalent
MW	megawatt (one thousand kW)
MWh	megawatt hour (one thousand kWh)
NA	North America
NEA	Northeast Asia
SEA	Southeast Asia
Tcal	teracalories (one billion kcal or 100 toe)
Tcf	trillion cubic feet (one million Mcf)
toe	tonne oil equivalent (ten million kcal or 39.68 MBtu)
TPES	total primary energy supply
TWh	terawatt hour (one trillion watt-hours or one billion kWh)

EXECUTIVE SUMMARY

STUDY OBJECTIVES

Economic growth across the APEC region will mean steady growth in energy demand over the next two decades, with substantial requirements for new investment in the energy sector. This study assesses the magnitude of future energy investment requirements, the burden they are likely to place on APEC economies relative to their growing output, factors which affect the amounts of investment required and the ability to attract it, and the role of member governments in enhancing the ability of the energy sector to attract the large amounts of investment it will need.

These issues are addressed in successive chapters as follows:

5. *Risks and Returns as Drivers of Energy Investment:* How the ability to attract investment is affected by regulatory environment and the balance between risks and returns.
6. *Economic Factors Affecting Energy Investment Decisions:* How investments are affected by the cost of capital, rate of economic growth, exchange rates and tax regimes.
7. *Overview of APEC Energy Investment Requirements:* The projected amount of energy investment needed, how future investment needs compare with past needs, and the burden of investment needs compared with the size of growing economies.
8. *APEC Energy Investment Requirements by Infrastructure Type:* Projected energy investment requirements in key supply sectors for selected individual APEC economies.
9. *Energy Investment for Environmental Projection:* Projected investment required to limit atmospheric emissions of pollutants and carbon dioxide from energy facilities.
10. *Financing Energy Projects in Developing and Transitional Economies:* Special issues encountered by developing and transitional economies in financing investment.
11. *The Role of Governments in Energy Investment:* How governments in APEC economies at different levels of development can improve conditions for investment in the energy sector.
12. *Case Studies:* Energy investment in China, Indonesia, Philippines and Viet Nam.

RISKS AND RETURNS AS DRIVERS OF ENERGY INVESTMENT

In competitive markets for oil and gas production and electricity generation, the pace of investment can be expected to vary as demand requirements affect the balance between risks and expected returns. An example is the market for electric generating capacity in the United States. In the 1980s and early 1990s, reserve margins of capacity over peak demand were ample, so potential returns on new facilities were low and few capacity additions were made. In the late 1990s, as reserves margins tightened and wholesale prices rose, a lot of new capacity was built.

In regulated portions of competitive markets, such as gas pipelines and electric transmission lines, it is important that regulated returns reflect the average weighted market cost of capital in order for returns on regulated facilities to attract needed investment.

Investors in oil and gas exploration and development assess the balance of risks and returns on the basis of both above-ground and below-ground conditions. Above-ground conditions include political stability, fair and transparent laws and regulations, the attractiveness and stability of the tax regime on investment, and openness towards investors. Below-ground conditions include the size and location of reserves and the cost of technology to exploit them. Oil and gas exploration and development projects may be less attractive in APEC economies than they are elsewhere due to the relatively small size of potential reserves. In this context, host economies of APEC will face significant challenges in attracting and retaining investor interest in such projects.

ECONOMIC FACTORS AFFECTING ENERGY INVESTMENT DECISIONS

The timing, location and type of energy investment are significantly affected by the cost of capital. Economies with a lower real cost of capital, reflecting lower political and economic risks, are more likely to attract investment than economies with a higher real cost of capital. In the electric power sector, low discount rates favour capital-intensive nuclear power plants, while high discount rates favour fuel-intensive coal-fired power plants.

The timing and location of energy investment are also affected by the pace of demand growth, the stability of exchange rates, and the attractiveness of tax regimes. The faster the pace of demand growth, the more readily new investments to meet demand can generate financial returns. The more stable exchange rates are, the less risk that projects will have difficulty repaying loans or bonds denominated in foreign currency. The lower the effective tax rate on profits, the greater the expected returns on investment and the greater the incentive to make it.

OVERVIEW OF APEC ENERGY INVESTMENT REQUIREMENTS

Energy investments of US$3.4 trillion to US$4.4 trillion will be needed in the APEC region over the 20-year period through 2020. Nearly half the total, $1.9 trillion to $2.2 trillion, will be required for generating and transmission capacity in the electric power sector. About a fifth of the total, or $0.7 trillion to $1.0 trillion, will be needed for oil and gas production facilities. In addition, roughly $0.5 trillion to $0.7 trillion will be needed for domestic oil and gas pipelines, $0.3 trillion to $0.4 trillion for international oil and gas trade, and $0.1 trillion for the coal industry.

Future APEC energy investment requirements will be dominated by China, the United States and Russia, accounting for over three-fifths of energy investment in the 20-year period. Another fifth of projected APEC energy investment will occur in Canada, Mexico, Korea and Japan. The final fifth of projected energy investment will occur in the other fourteen APEC economies.

In the APEC region as a whole, energy investment over the two decades through 2020 should take up less than one percent of gross domestic product, but the burden of energy investment will be much higher in some developing economies of the region. Energy investment is projected to represent 0.8 percent of the GDP of all APEC economies combined. For six industrialised economies (Japan, Hong Kong China, New Zealand, United States, Chinese Taipei and Australia), the burden of energy investment relative to GDP will fall below this average. For nine economies, mostly at lower or middle levels of income per capita (Thailand, Chile, China, Indonesia, Malaysia, Brunei Darussalam, Russia, Viet Nam and Papua New Guinea), the burden of energy investment will exceed 2 percent of GDP, but many of these economies have substantial energy resources whose revenues can be used to help finance the investment required.

Investments in new petroleum refinery capacity over the two-decade projection period should be about half of those during the previous two decades in 18 APEC economies analysed. In five economies (United States, Chinese Taipei, Japan, New Zealand and Brunei Darussalam), refinery capacity needs in the projection period are expected to be less than in the historical period. But the future burden is projected to be about four times as heavy as the historical burden in Chile, three times as heavy in Viet Nam and Peru, and twice as heavy in China, Malaysia and Philippines.

Total investment in new electric generating capacity over the projection period should be about the same as over the historical period in 15 APEC economies analysed. All higher-income APEC economies (New Zealand, United States, Hong Kong China, Japan, Canada, Brunei, Darussalam, Australia and Chinese Taipei) are projected to require less investment in generating capacity from 2001 through 2020 than they required from 1981 through 2000. But at least three developing APEC economies (Mexico, Chile and China) are projected to require more than twice as much investment in generating capacity through 2020 than they did in the previous 20 years.

The burden of investment in electric power plants as a share of GDP should continue to decline in most APEC economies, as it has historically, as economic output grows.

ENERGY INVESTMENT FOR ENVIRONMENTAL PROTECTION

Investments required to meet stricter environmental regulations could account for a significant share of APEC energy sector investment through 2020. About US$42 billion could be needed to produce and transport cleaner highway diesel fuels, accounting for more than 2 percent of total projected investment in the oil and gas sector. Roughly US$205 billion could be needed to install equipment for controlling sulphur dioxide and nitrogen oxide emissions in coal-fired power plants, accounting for about 10 percent of projected investment in the power sector.

Demand side measures to promote energy efficiency and fuel switching could reduce annual growth in APEC electricity demand by 0.6 percent, reducing needs for investment in new electricity generating capacity by 20 percent over the 20-year analysis period.

FINANCING ENERGY PROJECTS IN DEVELOPING AND TRANSITIONAL ECONOMIES

Developing economies of APEC can enhance the availability of investment funds for energy projects by developing domestic capital markets, especially bond markets. Bonds can provide long-term capital for energy projects at lower interest rates than bank loans. Bonds can also limit the amount of energy investment financed by foreign borrowing, reducing the mismatch between domestic currency assets and foreign currency liabilities that contributes to project risk.

Sponsors of energy projects, whether governments or private firms, should choose a mix of bank loans, bonds and equity financing that will minimize costs of financing.

Host governments, export credit agencies and multilateral financial institutions can help mitigate project risks by issuing guarantees for repayment of loans and equity.

THE ROLE OF GOVERNMENTS IN ENERGY INVESTMENT

Governments face challenges in balancing the need to attract energy sector investment with the need to provide energy at reasonable cost, as well as in balancing the desire for predictable regulation with the desire to introduce competition in energy markets. By preserving contract provisions for existing energy facilities as competition for new facilities is introduced, governments can reassure investors about the financial viability of new energy projects.

The non-binding investment principles agreed by APEC leaders are vital to healthy investment climate in the energy sector. The principles regarding a transparent legal and regulatory framework, expropriation, repatriation and capital exports are of particular importance.

Sound macroeconomic management by governments can boost investment in capital-intensive energy projects by helping to keep the real cost of capital to reasonable levels.

Asset privatisation and reduced restrictions on private ownership, entry, management and operation of energy facilities can boost the availability of capital for such facilities.

Market-based prices, reflecting environmental costs, can help ensure that energy investments take place where they are most needed and economically justified.

By providing for fair competition, governments can help ensure that the most cost-effective energy projects are financed in competitive markets. Fair competition requires transparent rules and regulations, competitive bidding procedures, independent regulatory authorities, non-discriminatory energy transportation, and prohibition of anticompetitive practices.

Industrialised APEC economies with mature capital markets can take several steps to ensure that regulation is predictable, markets are transparent and competition is fair. Regulatory processes can be streamlined, information firewalls can be put in place between bond rating and investment banking divisions of financial firms, and competing energy firms can be given access to oil and gas pipelines, LNG terminals and electric transmission lines on similar terms.

Major APEC oil and gas producers with high investment requirements can take several steps to make more funds available for public purposes. Private firms can be allowed to bid competitively on production sharing contracts, assets of state-owned energy firms can be partially divested, and private firms can be allowed to produce energy in competition with state firms.

Developing APEC economies can take several steps to strengthen their ability to finance energy projects. They can ensure that competing energy firms have comparable access to energy transportation infrastructure. They can also streamline and clarify rules so that returns on regulated energy projects are high enough and predictable enough to attract investment.

Transitional APEC economies, namely China and Russia, can strengthen their financial and regulatory institutions to attract the energy-sector investment they need. They can strengthen legal enforcement of contracts, follow the rule of law in awarding and monitoring contracts, and avoid restrictions on foreign investment and repatriation of investment returns. They can also allow end-use prices to fully reflect the costs of investment in energy transportation facilities, including a fair return on investment. Further, they can allow new energy projects to compete on fair terms with established projects, promote joint ventures with foreign partners to obtain their capital and expertise, and provide government guarantees on a portion of the debt issued by newly established firms to limit the risk premiums that rating agencies assess.

CASE STUDIES

China's success in mobilizing needed energy investment funds will depend upon the pace and scope of energy sector reforms it has started to implement. A weak domestic capital market makes it difficult to fully mobilise domestic savings, boosting reliance on private and international capital flows to finance massive energy investment needs. Unpredictable laws, rules and regulations and inconsistent enforcement of contracts remain investment hurdles. These hurdles must be surmounted to sustain investment inflows at the high rate the economy requires.

Indonesia needs to reform its energy pricing regime, which has held domestic prices well below export prices, to attract investment in domestic energy facilities. As a major producer and exporter of oil, gas and coal, the economy needs not only to find and exploit more reserves of these fuels, but also to transport them to domestic and foreign markets. The government has periodically modified the profit split with firms on upstream projects in order to attract more investment, especially as exploration moves to more critical hard-to-mine areas. But domestic transportation infrastructure will suffer if domestic prices remain below export prices.

The Philippines can enhance energy sector investment by developing institutional capacities and refraining from market intervention. Private investment has been attracted to the energy sector through build-operate-transfer contracts, advantageous terms for exploration and development of oil and gas resources, competitive bidding for oil and gas contracts, and streamlined regulations. But private capital flows have been limited by institutional factors such as regulatory delays, some incidents of corruption, and the limited capacity of government agencies to absorb project assistance and undertake development projects. In addition, the government has sometimes intervened to limit prices when demand pressures cause prices to rise, which acts to limit the profit incentive for investors to satisfy demand through investment in supply facilities.

Viet Nam should build on the steps it has taken to attract the foreign investment that is needed to develop its energy resources and expand its electricity grid. Laws on investment, adopted as early as 1987, have allowed joint ventures, complete foreign ownership of enterprises, business cooperation contract, and build-operate-transfer (BOT) project financing schemes. BOT projects have taken advantage of a number of incentives, such as exemption from or reduction of certain taxes, and government guarantees on foreign exchange. The government is restructuring the power sector to make it more competitive, with generation unbundled from transmission and distribution. As a result, more private and foreign investment has flowed to generation and distribution projects. However, state-owned Electricity of Viet Nam (EVN) remains the majority shareholder in power plant projects, restricting the contribution of foreign investment.

INTRODUCTION

STUDY OBJECTIVES AND SCOPE

Energy is an integral part of economic activity, and investment in energy facilities is therefore essential to support economic growth in the APEC region. Increased energy use underpins industrialisation, boosts the mobility of people and the goods they consume, improves living standards, and enhances the quality of life. Thus, there can be little doubt that investment in the energy sector is a matter of abiding interest to all APEC economies.

Failure to make timely energy investments can have serious socio-economic consequences. During the 1980s, inadequate power supplies kept a fifth of China's industrial capacity idling.[1] In 2001, power shortages in California caused economic losses of 40 billion dollars.[2] Costly incidents such as these have raised growing concerns over how to secure timely supply of energy resources. These concerns are greater in those APEC economies whose energy demand is growing faster.

In the APEC region as a whole, energy demand is expected to continue growing steadily, at an average rate of roughly 2.1 percent per annum through 2020.[3] Steady demand growth will mean substantial investment requirements to find and develop energy resources and build the transportation infrastructure to deliver energy to users. Upstream investment will be needed in oil and gas production facilities, as well as in electric power plants. Midstream investment will be needed in oil and gas pipelines, tankers, LNG facilities and electric transmission lines. Downstream investment will be needed in petroleum service stations and gas and electric distribution lines.

Financing the required investments in energy projects will present major challenges to both policy makers and energy industries. Governments are increasingly relying on private financing for energy projects, as public budgets are limited and are called upon to serve social purposes like health and education for which private funding is normally not available. In Asian economies, the shift to private financing was accelerated by the financial crisis of the late 1990s, which reduced the public funds available for energy projects and led many state-owned energy assets to be privatised.

APEC economies need to mobilise private financial sources domestically and internationally. But developing economies lack well-developed domestic capital markets, making financing more costly and difficult to obtain.[4] Moreover, their laws and regulations are often inadequate to protect foreign investment and hence to attract it. Developed economies, meanwhile, may have difficulties financing large-scale energy investments in the wake of recent financial scandals. The bankruptcy of Enron and subsequent liquidity problems for energy merchant companies show that unless companies maintain transparent balance sheets, attracting capital will not always be easy.

While an attempt was made to estimate energy investment requirements through 2020 in *APEC Energy Demand and Supply Outlook 2002*, the estimates made in that document were in some ways incomplete. This report improves the estimates with better methods for estimating certain types of investment needs, the addition of estimated investment requirements for domestic oil and gas pipelines, and the inclusion of newly announced projects. It also compares future energy investment needs with historical energy investment needs, and assesses the burden of energy investment needs relative to the size of growing economies. Further, it estimates investment requirements for environmental control measures in petroleum refining and electricity generation.

Beyond evaluating the magnitude of energy investment requirements and their economic burden, the present study examines how energy investment requirements can best be met. The regulatory and economic factors affecting the ability to attract investment to the energy sector are

1 Xu (2002).

2 Weare (2003).

3 APERC (2002a).

4 Petroleum Economist (2003).

described in some detail, including government regulation, the cost of capital, economic growth rates, currency exchange rates, and tax regimes. Case studies of the energy investment environment in specific economies are used to highlight some of the difficult issues that are encountered. Practical suggestions are made as well for how governments might foster investment going forward.

OUTLINE OF THE REPORT

The next two chapters of this report review key factors that affect the location, timing and amount of energy sector investment in the APEC region. The first of these looks at risks and returns as drivers of energy investment, examining how the regulatory environment in member economies affects risks and returns and therefore the ability to attract investment. The second looks at how energy investments are affected by economic factors such as the cost of capital, rate of economic growth, currency exchange rates, and the tax regime that applies to investments.

The following three chapters, which form the core of the report, give a quantitative assessment of projected energy investment requirements in APEC economies. The first of these is an overview of energy investment requirements throughout the region, including the total amounts required over the twenty-year period through 2020, how those amounts compare with requirements in the previous twenty years, and the burden of past and future energy investment as a share of economic output (GDP). The second offers some more detailed assessments of energy investment requirements in selected individual APEC economies. The third focuses on the portion of energy investment that is needed to preserve the environment, by limiting atmospheric emissions of pollutants and carbon dioxide.

The two succeeding chapters examine particular issues related to financing energy projects in developing and transitional economies, and how governments in APEC economies at different levels of development can improve conditions for investment in the energy sector. How can developing economies benefit from development of domestic capital markets? How can the need to attract investment be reconciled with the need to provide energy at reasonable cost? How does macroeconomic policy relate to the cost of capital and energy investment? How can needed energy investment be elicited in increasingly competitive gas and electricity markets? Questions such as these, of keen policy interest, are the focus of these two chapters.

Finally, the report presents detailed case studies of the energy investment environment in selected APEC economies. The economies covered are China, Indonesia, the Philippines and Viet Nam. China is of course of great interest due to its size and rapid economic growth. Indonesia is of interest as a key energy producer and exporter. The Philippines and Viet Nam are economies that have substantial energy resources but are not entirely self-sufficient in energy supply. Together, these cases offer illustrations of interest to a broad range of economies in the APEC region.

.

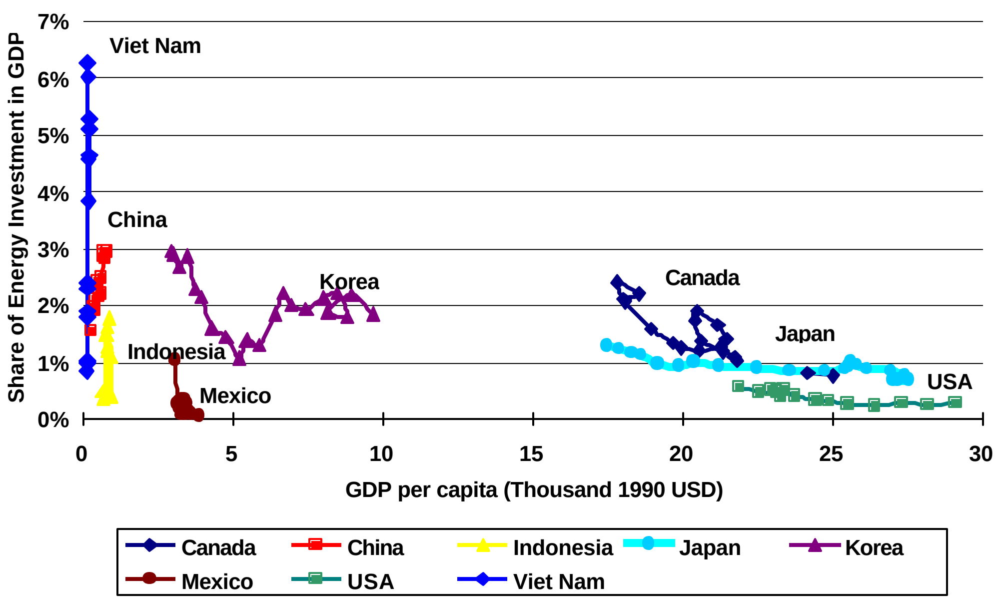
RISKS AND RETURNS AS DRIVERS OF ENERGY INVESTMENT

AN OVERVIEW OF ENERGY INVESTMENT IN APEC

The fundamental driver for energy investment is economic activity and the resulting demand for energy services. Thus, requirements for investment in energy infrastructure may be particularly large in economies that are at an early stage of development and growing rapidly.

Figure 1 compares the share of gross domestic product that is taken up by investment for energy utilities with gross domestic product per capita in several APEC economies for the period from 1980 through 2001. The comparison clearly shows that the burden of investment, relative to GDP, often declines as GDP per capita increases, both *between* economies and over time *within* economies. The most developed economies, with highest GDP per capita, have relatively low investment burdens, as shown by Canada, Japan and the United States. The least developed economies, with lowest GDP per capita, have relatively high investment burdens, as shown by China and Viet Nam.

Figure 1 Investment by Energy Utilities as Share of Gross Domestic Product, Compared with GDP per Capita, in Selected APEC Economies, 1980-2001



Source: APERC analysis based on the data from China Statistical Yearbook, DRI-WEFA, EDMC Database, National Accounts of OECD Countries, PLN, US Department of Commerce and Statistical Yearbook of Viet Nam

Less developed economies may tend to exhibit relatively high investment requirements for energy infrastructure because such economies are in the midst of a transition from reliance on non-commercial energy sources, like biomass, which require little infrastructure, to commercial fuels like coal, oil, gas and hydropower, which require substantial infrastructure. In Viet Nam, for instance, just 40 percent of total primary energy supply comes from commercial fuels, and a three-quarter of households do not have access to the national electricity grid. Development of commercial energy sources and expansion of the power grid will entail substantial new investment.

In middle-income economies, requirements for new energy infrastructure are likely to continue to exert a considerable burden. In Korea, for example, the share of energy utility investment in GDP declined roughly from 3 percent in 1980 to 1 percent in 1988 but grew again to around 2 percent during most of the 1990s. Increased investment for the last decade has been largely driven by natural gas infrastructure development. Since the introduction of LNG in 1986 to supply natural gas to power generation and a subsequent policy for the economy-wide introduction of natural gas, substantial investment has been needed to develop gas trunk lines and distribution networks. Such downstream networks often have greater investment requirements than upstream gas development.

Higher-income economies like Canada, Japan and the United States have smaller energy utility investment requirement than other economies even though their absolute level of energy utility investment is higher since their GDPs are large. The main reason for their smaller energy utility burdens is that they have a substantial capital stock of energy infrastructure already in place. One of their main challenges is how best to replace obsolete facilities in a deregulated environment for gas and power production where utilities are faced with the competitive pressure to reduce costs.

Energy investment is a key component of industrialisation and improvement of living standards. At earlier stages of economic development, energy sector investment requirements tend to be large relative to economic output as economies shift toward commercial energy sources and experience rapid growth. As economies become industrialised, their growth is increasingly driven by the less energy-intensive services sector, their energy investment needs relative to economic output tend to decrease.

ENERGY SECTOR REFORM AND INVESTMENT

Energy investment is also influenced by institutional factors such as government rules and regulations, and by industrial structure. Many APEC economies are considering or have already taken market reforms and restructuring of energy sector. Such reform efforts are designed to encourage competition from additional energy producers and lower energy costs to consumers by ensuring that all energy suppliers have a fair opportunity to obtain access to customers and for consumers to have a choice of suppliers.

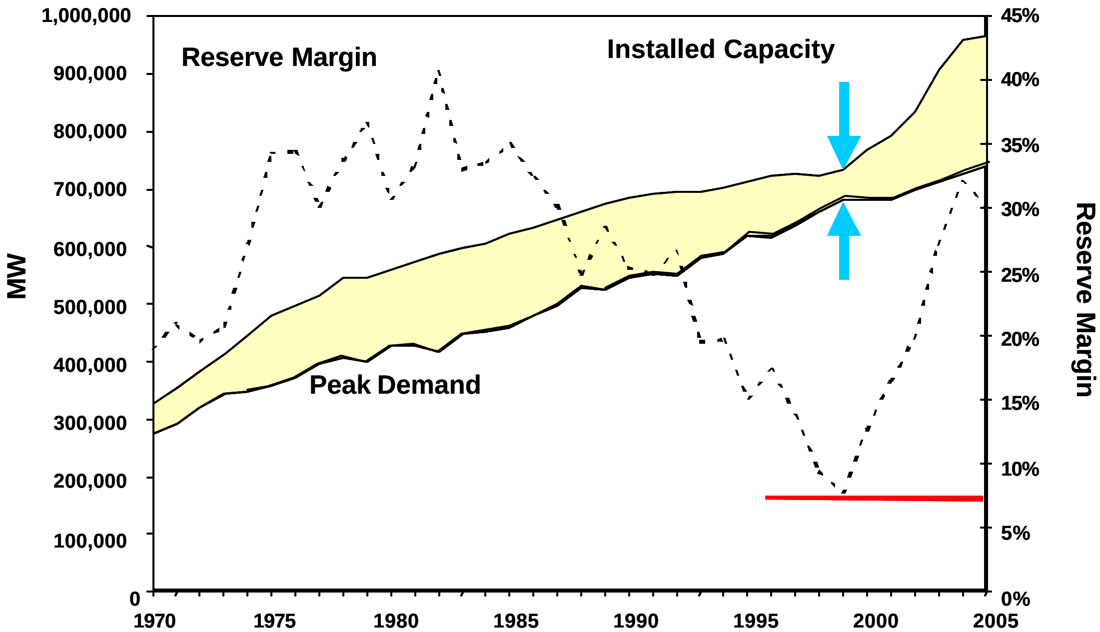
Fair access to consumers means non-discriminatory access to transmission and distribution networks, which typically remain regulated as natural monopolies. The construction of transmission and distribution lines for natural gas and electricity as well as terminal facilities for receipt and processing of liquefied natural gas (LNG) in some places is usually subject to rate-of-return regulations. Under such regulations, regulators allow investors at least a market-based rate of return on investment in "used and useful" facilities, based on the weighted average cost of debt and equity capital.

Regulators may also provide investors with additional incentives to improve productive efficiency and lower costs on gas and electric networks. For example, under "RPI – X" regulation, rates are allowed to increase by the rate of price inflation (RPI) less a specified target rate of efficiency improvement (X). If investors are able to improve efficiency by more than X each year, they are allowed to retain all or part of the additional resulting cost reductions in their operating profits.

If regulators fail to sanction a market-based rate of return on investment in transmission and distribution facilities, such facilities will not be constructed. Regulatory failure of this sort is by no means confined to markets in which regulatory reforms have allowed competition among gas producers and electricity generators over the regulated transmission and distribution lines.

An interesting illustration is offered by the United States. The entire economy has deregulated the wholesale market for power sales, and more than half of the states have also deregulated retail electricity sales from competing power suppliers to final customers. During the 1980s and early 1990s, there were limited new capacity additions because of ample reserve margins. Then, a large amount of new generating capacity was built in the late 1990s, as the reserve margins tightened, prices rose and anticipated returns on investment jumped sharply (Please see the Figure 2).

Figure 2 Reserve Margins and Installed Generating Capacity in the United States



Source: Tucker (2003).

INVESTMENT IN TRANSMISSION

Maintaining stable as well as reliable electricity supply is essential for the growth of economy. In order to ensure reliable supply, transmission forms a key part, although it accounts for only 6 percent of the total retail cost of electricity.[5] There should be enough transmission capacity to move electricity from power plants to the distribution system and to deliver electricity to customers at the end of the chain. Under deregulated markets, enhancing a comprehensive regional interconnected transmission system is of vital importance because it increases the potential for competition by allowing customers to purchase less expensive power from distant suppliers.[6]

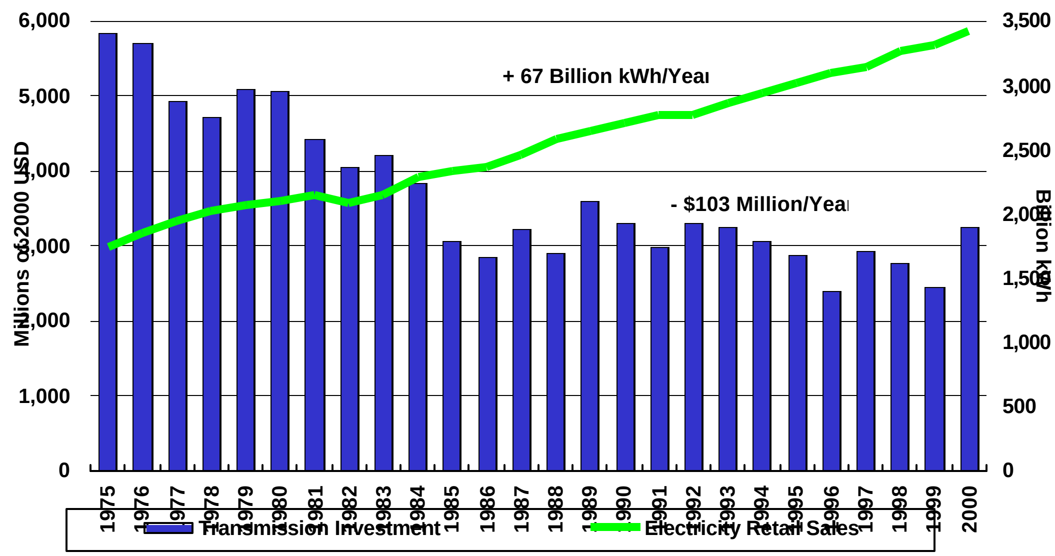
Again, an interesting illustration concerning investment under deregulated environment is provided by the United States. As shown in Figure 3, US transmission investments have been declining by an average of $103 million per year for the last 25 years. By the late 1990s, annual investment outlays for transmission facilities were around half of what they were in 1975. One could argue that the use of transmission is getting more efficient, moving more electricity per unit of transmission capacity. This could be due in part to the growing use of combined-cycle gas-fired power plants, which are often located close to demand centres.

On the other hand, as shown in Figure 4, the transmission grid is becoming more congested, with incidents requiring transmission loading relief becoming much more frequent since 1998. This can be attributed to increased electricity generation to meet growing demand, combined with vigorous trading in the wholesale market for generation. The blackouts experienced in the Northeast in 2003, which affected 80 million people and were thus the most extensive in history, also suggest that the grid may be strained beyond its capacity. Together, the growing congestion and recent blackouts strongly indicate the need for additional transmission capacity to be built if market competition is to keep growing and the supply of electricity is to remain reliable.

5 Hirst (2000).

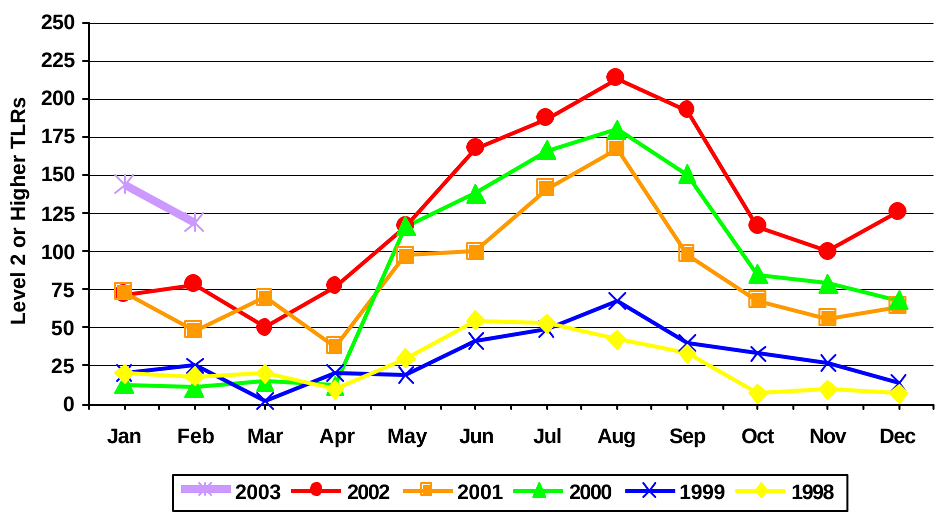
6 APERC (2000).

Figure 3 Transmission Investment and Electricity Retail Sales in the United States



Source: Edison Electric Institute (2001).

Figure 4 Growing Transmission Line Congestion in the United States, 1998-2003



Source: North American Electric Reliability Council (2003).

The question then is: What are the barriers to additional investment in transmission lines? One of the most intractable obstacles relates to difficulties in siting. Transmission networks increase the options for customers to buy less expensive electricity from more distant sources. But siting new transmission facilities is difficult due to the complexity of environmental and land use regulations, as well as the NIMBY or "not in my backyard" syndrome. Regulations may require that before a construction permit is granted, environmental impact assessments must be performed and transmission investments must be shown to be the least-cost alternatives. NIMBY may be particularly pronounced where new lines are proposed in what might be called "transit" areas that contain neither major power plants (whose owners would profit from increased sales) nor major load centres (whose consumers would benefit from competition among more generators).

Another critical obstacle for transmission investment in the United States is that owners of transmission facilities often have little incentive to invest in new facilities. Current regulatory frameworks do not provide a mechanism for transmission owners to share the benefits that accrue to power plant owners and electricity customers from competition, even though transmission lines are what make the competition possible. Hence, returns on investment in transmission facilities may often be inadequate to attract such investment. According to a study by Hyman, transmission owners can earn an after-tax return on investment of 9 percent per annum over a 40-year period, which is less attractive than returns on other investments in the energy sector and elsewhere.[7]

Investment in new transmission facilities may also be discouraged by regulatory uncertainty over transmission pricing, for which there are many different methodologies. For example, PJM is using license-place rates, charging an access price based on the location of the load. The New England Power Pool applies region-wide postage-stamp rates for transmission access which are the same regardless of where the load is located. Under these circumstances, transmission owners have little incentive to invest in the transmission facilities unless they are absolutely necessary.

In the process of deregulating electricity markets in the US, discussion seems to have focused on the importance of non-discriminatory access to the transmission infrastructure. Recognising the benefits obtainable from competition between the generators, the complementary role played by transmission facilities to enable access to less expensive sources of generation, deregulated electricity markets need careful designing to facilitate investment in transmission lines in a manner that keeps pace with rising demand.

To this end, there are at least two important requirements for enhancing transmission network investment. One is to ensure the long-term regulatory framework and the second is to provide incentives for transmission owners in a manner so that they can recover costs and earn a competitive return on transmission investments. Transmission pricing should include economically efficient signals to transmission users. One option may be nodal pricing, through which the adequacy of transmission capacity could be reflected to the price of transmission access.

7 Hyman (1999).

THE OIL PRICE AND INVESTMENT FOR OIL AND GAS EXPLORATION AND DEVELOPMENT

Oil and gas production is sustained by continued investment in order to add proved reserves to replace production. However, the investment environment for oil and gas upstream exploration and development has not always been favourable to investors. For one thing, investors have to deal with the risks arising from the geological conditions in finding profitable wells because exploration wells are mostly dry holes[8]. Thus, a small number of successful wells are required to cover the costs of unsuccessful field exploration.

In addition, investors, in particular foreign investors, must cope with further difficulties caused by the interaction with host governments. One of the difficulties lies in the fiscal policies of the host governments. Generally, underground mineral resources like oil and gas belong to sovereign states. Therefore, investors are subject to the payment of taxes, royalties and surcharges to the host government. Sometimes the fiscal framework is either unattractive or inadequate in view of the potential risks involved. The fiscal regime may also be subject to frequent revision, which may deter investors out of fear that the terms of deals will be altered once they are in place or out of hope that better deals can be secured at a later date. Legal issues and political stability are additional hurdles as far as foreign investment in oil and gas field development is concerned.

Then the question posed is: What is the main driver of investment for oil and gas exploration and development (E&D)? More specifically, the question can be focused on whether investment activities are driven by economic activities or oil price movements.

APERC conducted econometric tests[9] to statistically identify the drivers for oil investment activities, using world crude oil price and real global GDP as the independent variables. Table 1 shows the results of the econometric analyses, which have two major implications.

Table 1 Econometric Results: Capital Expenditures vs Crude Prices and World GDP

Dependent Variable	Independent Variable	Statistics	DF test
CAPEX 1977 – 2001 (n=25)	= 15727.1 + 134.9397 PCRUDE T = 7.70 T = 2.61	R^2 = .23 DW = 1.17	DF=-4.18 (95% DF statistics = -3.6)
CAPEX 1973 – 2001 (n=29)	= 13933.6 + 145.7352 PCRUDE T = 5.93 T = 2.41	R^2 = .18 DW = 0.68	DF=-2.40 (95% DF statistics = -3.7)
CAPEX 1973 – 2001 (n=29)	= 11007.6 + 0.33179 WRGDP T = 2.00 T= 1.44	R^2 = .08 DW = 0.70	DF=-3.02 (95% DF statistics = -3.8)

APERC Analysis (2003) Note 1: CAPEX = Capital expenditure by oil majors on upstream E&D (ExxonMobil, Shell, BP and Shevron), PCRUDE = World crude oil price (2001 Prices), WRGDP = World real GDP (2001 Prices). Three variables were tested as non-stationary time series. Note 2: * Co-integration relationship. In absolute terms, if the computed DF value exceeds that of critical DF value, the two values share long-term common trend. In other words, they are co-integrated time series.

One of the implications of the analyses is that world oil price is a key driver for upstream E&D whereas world GDP has a statistically insignificant impact on investment in upstream E&D. In other words, higher oil prices mean higher investment on upstream oil and gas E&D.

Secondly, the results show that major oil companies' investment activities share a common trend with oil price movements over the period between 1977 and 2001, while they do not share

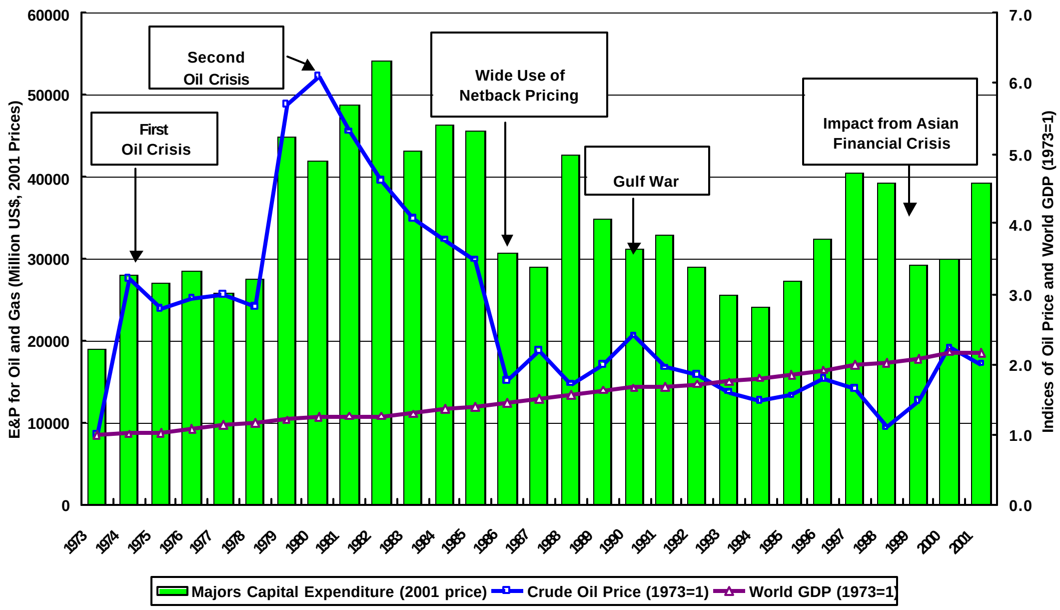
[8] Adelman (2002).

[9] Two steps were taken to identify the underlying factors. First, a unit root test was conducted to determine whether the variables are stationary time series. Second, regressions are run to determine the statistical significance of the independent variables. When both independent and dependent variables are non-stationary, a technique called the Dickey-Fuller test is used to determine whether the investment activities share a long-term common relationship with any independent variable.

any common trend if the data is taken between 1973 and 2001. These results coincide with the timing when investment of oil major companies changed. In the early 1970s, investment activities were led by political considerations to enhance security of oil supply, while since the end of 1970s, investment activities have been more driven by the commercial viability of investment in E&D, for which crude oil prices have played the key role as a determinant.

Figure 5 shows the historical trend of capital expenditure for exploration and development of oil and gas reserves by four major oil companies (BP Amoco, ExxonMobil, Royal Dutch Shell and ChevronTexaco), along with indices of world crude oil prices and real world GDP. One could understand the estimated impact of the oil price on investment for oil and gas E&D from the figure.

Figure 5 Oil Price, World GDP and Investment in Oil and Gas E&D, 1973-2001



Source: APERC analysis based on the data from EDMC database (2003).

FINDING COSTS OF OIL AND GAS

Declining exploration and development costs for finding new oil and gas reserves have significantly reduced the overall investment requirements for bringing oil and gas to market. As shown in Figure 6, finding costs for oil and gas in 2001 US dollars per barrel of oil equivalent (boe), exclusive of tax, have been declining since 1980.[10] World average finding costs peaked in the mid-1980s and have since exhibited a general downward trend. Finding costs declined by two thirds from around US$18 per boe in the mid 1980s to around US$6 per boe in the late 1990s.

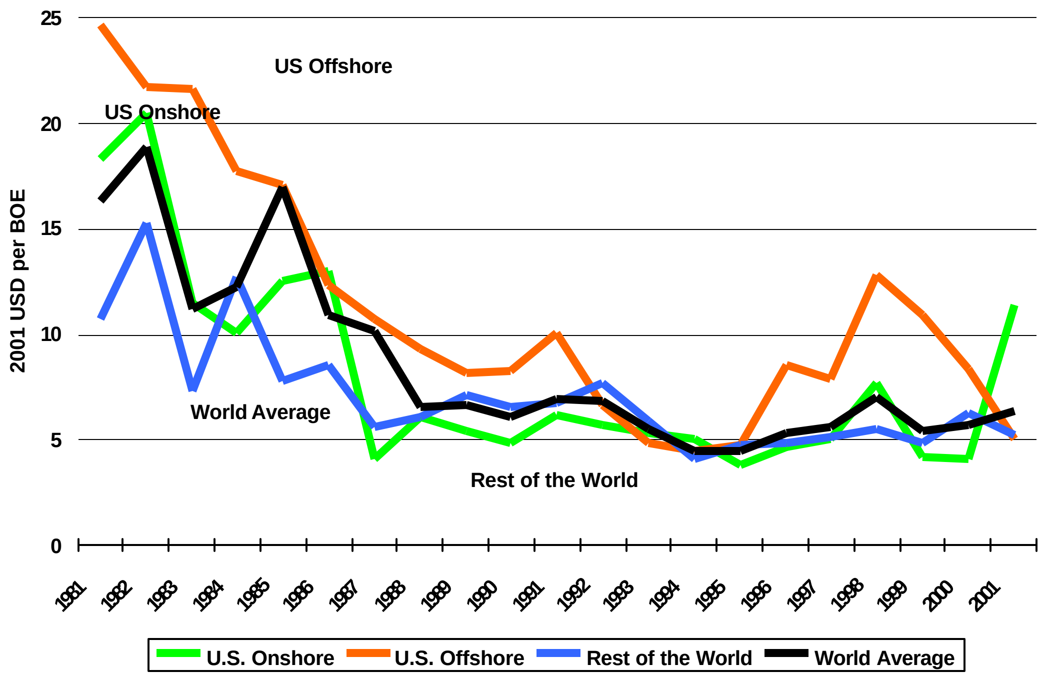
The rise of US onshore finding costs in 2001 runs counter to the long-term general downward trend. At around US$11 per boe, the onshore finding costs that year were the highest since the late 1980s, apparently due to the start up of many new projects. At the initial stage of projects, finding costs tend to be higher because of lags between the time when expenditures are made and the time when resulting reserve additions are made. Projects started up in 2001 include BP's oil projects in Alaska, the Hugoston field in Western Kansas, and Occidental Petroleum's gas projects at Elk Hills. Most of these drilling activities were undertaken to take advantage of high oil and gas prices.

The impact of technology improvements on the costs of finding oil and gas has been remarkable. Three-dimensional and four-dimensional seismic technologies have made it less costly to locate oil and gas reserves before attempting to drill for them. Horizontal drilling technologies

10 EIA (2001).

have made it possible to drill for oil in multiple locations within the same field through just a single rig. This reduces drilling costs once promising areas are located and makes it technically feasible to drill in areas that had previously been inaccessible.

Figure 6 Finding Costs of Oil and Gas in the United States and the Rest of the World



Source: EIA, "Financial Reporting System"

Taking the finding ratio of oil and gas (the ratio of new reserve additions against the total numbers of new wells), one can understand the impact of technology improvements. The world average finding ratio of oil and gas has increased from 0.34 million barrels per well in 1980 to 0.72 million barrels per well in 1999, more than doubling over the last two decades.

Along with improved technology, cost-cutting efforts by the oil companies have contributed to lower the finding costs. World average E&D expenditures per well, which may be considered an inverse proxy for the productivity of companies' operation, declined (in 2001 US dollars) from around $6.2 million in the early 1980s to around $4.26 million at the end of 1990s.

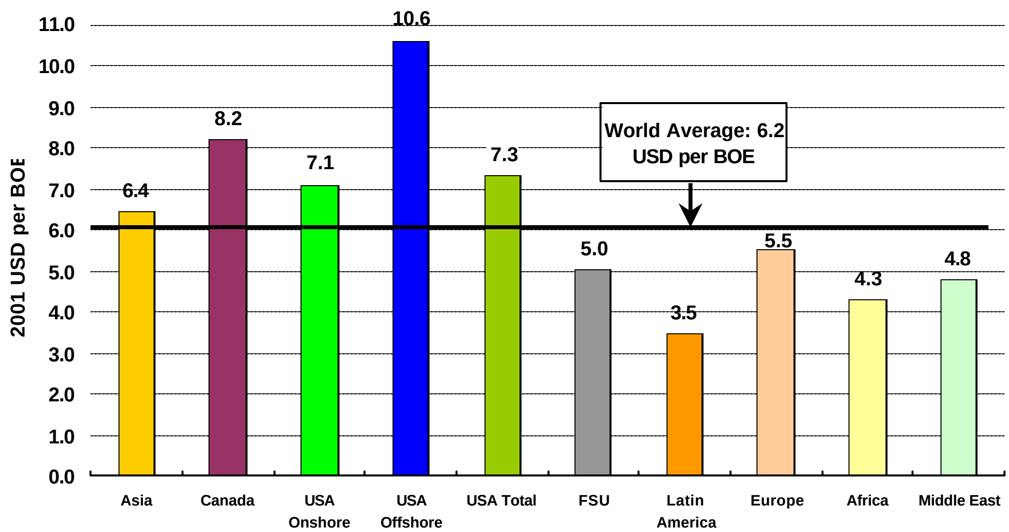
Despite the general downward trend in finding costs, there persist regional differences as shown in Figure 7. Geological conditions such as size of reserves, depth of well, and whether the field is offshore or onshore are the most important factors that affect the level of finding costs. In theory, the newly found deposits are getting smaller, deeper, more remote and harder to reach.

Between 1998 and 2001, as seen in Figure 7, projects implemented in the sub-regions of APEC show higher finding costs than the world average of US$6.20 per boe. For example, the average finding costs of US offshore reserves between 1998 and 2001 was the highest in the world at US$10.60 per boe. The major factor driving finding costs of offshore US higher than other areas relates to the project costs incurred in developing the areas of deepwater Gulf of Mexico, with water depths exceeding a thousand feet. Investment activities have been boosted significantly since the issuance of the Deepwater Relief Act in 1996 that provided royalty relief to the projects in deepwater Gulf of Mexico.[11] The finding costs for Canada were the second highest in the world

[11] Deepwater relief act issued in 1996 enhanced investment climate for the deepwater project by eliminating the royalty requirements.

averaging around US$8.20 per boe, although those of between 1990 and 1997 showed much a lower average at around US$5.50 per boe. The steep rise results from increased expenditures for the acquisition and exploration of unproved acreages in 2001 by the reporting companies.[12]

Figure 7 Finding Costs for Oil and Gas Around the World (Average 1998-2001)



Source: APERC analysis of data from EIA, "Financial Reporting System".

FOR THE FUTURE

Investors in oil and gas E&D need to analyse the balance between risks and returns arising from the interaction of different factors. In addition to oil prices movement, a key driver for oil and gas E&D investment, investors take account of host economies' investment conditions. Examples include the adequacy and robustness of the fiscal framework and stability of the tax regime. Stability and political openness towards foreign investors are also important drivers for investment.

Both "above ground" and "below ground" conditions affect investment decisions. The cost of finding new reserves depends on geological conditions like the size of reserves, whether reserves are onshore or offshore and resource depth. Given the same geological conditions, the level of technology applied to drilling activities can influence the costs and probability of finding new reserves, which also affect the overall investment requirements for bringing oil and gas to market.

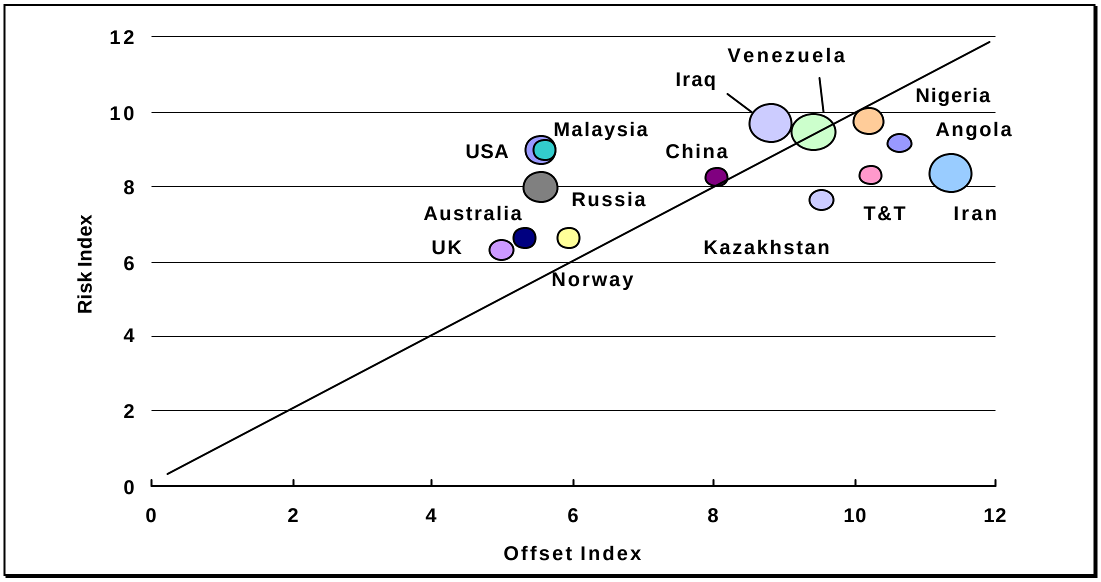
A study by Sandrea attempts to evaluate opportunities for investment in upstream oil and gas exploration and development, taking account of both risks (political, fiscal and environmental) and rewards or offsets (high potential reserves, low finding costs). The study indicates that conditions for such investment may not be as attractive in some APEC economies as they are elsewhere. Perhaps what makes projects in APEC less attractive is the relatively small size of potential reserves. As shown in Figure 8, all the economies in the analysis have a risk index between 6 and 10, while the offset index varies more widely, ranging from 5 for the United Kingdom to nearly 12 for Iran. The study assumes the potential size of reserves would be the most important factor offsetting the risks arising from the inadequacy of institutional factors.[13]

---

[12] According to EIA (2002), E&D expenditures increased by 70 percent, while reserve additions were increased only by 9 percent between 1998 and 2001.

[13] Sandrea, R. (2003).

Figure 8 Opportunity and Risk in Oil and Gas Exploration and Development Investment



Source: Sandrea (2003)

The host economies of APEC are faced with the challenge of how they can best create attractive conditions for investors in recognition of the relative small size of potential reserves compared with those of non-APEC economies.

One of the interesting emerging trends in this context is the progress of sub-regional cooperation in the exploration and development of oil and gas fields. The ASEAN Council on Petroleum (ASCOPE), for example, is a framework under which national oil companies and governments of Southeast Asian economies share information and work together to secure upstream oil and gas stakes in order to help create a stable investment climate. In future, cooperation among member economies will further deepen to promote energy sector investment and enhance the stability of energy supply.

ECONOMIC FACTORS AFFECTING ENERGY INVESTMENT DECISIONS

INTRODUCTION

The financial viability of long-term energy investments largely depends on economic conditions in host economies such as the cost of capital, economic growth rate, exchange rates, and tax regime:

1. The cost of capital or discount rate is particularly important since most energy projects are capital-intensive, with a relatively small portion of their total costs accounted for by fuel and other operating costs.
2. The rate of economic growth is important as well, since it affects the rate of growth in demand for electric power and other types of energy, which in turn affects the pace at which investments are needed and will generate cash flow.
3. Exchange rates between economies can affect the ability of projects to repay loans denominated in different currencies, especially if exchange rates shift a great deal.
4. Tax regimes, including the rate of tax on profits and tax breaks on investment, also clearly have a major impact on expected net returns from energy projects.

This chapter describes the impact that such host economy factors may have on energy projects in APEC economies. There are, of course, many other factors as well, including regulatory requirements, availability of raw materials and infrastructure for delivering them, and fuel and operating costs. Some of these more project-specific factors are considered elsewhere in this report.

COST OF CAPITAL, INVESTMENT LOCATION, AND TECHNOLOGY CHOICE

The weighted cost of capital, or discount rate, is a fundamental factor affecting the value of cash flows that investors can anticipate from energy projects over time. For energy projects with long physical lifetimes and correspondingly lengthy debt maturities, relatively small changes in the weighted cost of capital can have major impacts on technology choice and location. Different economies have different real lending rates, reflecting different political and economic risks, different rates of inflation, and anticipated foreign exchange flows and currency valuations. These different lending rates may make it more desirable to invest in some economies than others. Meanwhile, different types of power plants have different shares of capital in overall cost. Hence, as the real cost of capital rises, it becomes relatively less attractive to build capital-intensive nuclear and renewable power plants and more attractive to build coal-fired or gas-fired power plants. At lower costs of capital, on the other hand, renewable and nuclear options can become more viable.

Table 2 compares central bank discount rates in selected APEC economies. These can be considered benchmark rates for publicly financed energy projects. They can also be key indicators for privately financed energy projects, whose cost of capital is higher because it factors in additional project-specific risks for the private parties. The rates are nominal rather than real, so they are not strictly comparable in any given year across the economies illustrated, which have different rates of anticipated inflation and currency adjustment. However, the rates show a general downward trend across a broad range of economies that should encourage capital-intensive energy investment. Some of the economies, such as Russia and Peru, maintain a high central bank discount rate that reflects a scarcity of domestic capital and need to rely on foreign financial resources; investors demand a high rate of return on capital because of high perceived political and economic risks.

Table 2 Central Bank Lending Rates in APEC Economies, 1992-2001

Economy	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
North America										
Canada	7.36%	4.11%	7.43%	5.79%	3.25%	4.50%	5.25%	5.00%	6.00%	2.50%
USA	3.00%	3.00%	4.75%	5.25%	5.00%	5.00%	4.50%	5.00%	6.00%	1.25%
Latin America										
Chile		7.96%	13.89%	7.96%	11.75%	7.96%	9.12%	7.44%	8.73%	6.50%
Mexico										
Peru	48.50%	28.60%	16.10%	18.40%	18.20%	15.90%	18.70%	17.80%	14.00%	14.00%
Northeast Asia										
Japan	3.25%	1.75%	1.75%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.10%
Hong Kong China	4.00%	4.00%	5.75%	6.25%	6.00%	7.00%	6.25%	7.00%	8.00%	3.25%
Korea	7.00%	5.00%	5.00%	5.00%	5.00%	5.00%	3.00%	3.00%	3.00%	2.50%
Chinese Taipei	5.63%	5.50%	5.50%	5.50%	5.00%	5.25%	4.75%	4.50%	4.63%	2.13%
Southeast Asia										
Brunei										
Indonesia	13.50%	8.82%	14.44%	13.99%	12.80%	20.00%	38.44%	12.51%	14.53%	17.62%
Malaysia	7.10%	5.24%	4.51%	6.47%	7.28%					
Philippines	14.30%	9.40%	9.30%	10.83%	11.70%	14.64%	12.40%	7.89%	13.81%	8.30%
Singapore										
Thailand	11.00%	9.00%	9.50%	10.50%	10.50%	12.50%	12.50%	4.00%	4.00%	3.75%
Viet Nam										
Oceania										
Australia	6.96%	5.83%	5.75%	5.75%						
New Zealand	9.15%	5.70%	9.75%	9.80%	8.80%	9.70%	5.60%	5.00%	6.50%	4.75%
PNG	7.12%	6.30%	6.55%	18.00%	10.30%	10.20%	18.15%	12.80%	4.41%	11.25%
China	7.20%	10.08%	10.08%	10.44%	9.00%	8.55%	4.59%	3.24%	3.24%	3.24%
Russia				160.0%	48.00%	28.00%	60.00%	55.00%	25.00%	25.00%

Source: IMF (2002), "International Financial Statistics"

Figure 9 shows how different assumptions about the weighted cost of capital affect the comparative economics of coal-fired and nuclear power plants, according to an analysis by Dimson.[14] The analysis compares the total cost of electricity, including capital costs, fuel costs, and operation and maintenance costs. At discount rates below 7 percent, the analysis finds that the total cost is higher for coal-fired power than for nuclear power. At discount rates above 9 percent, it finds that the total cost is higher for nuclear power than for coal-fired power. At discount rates between 7 percent and 9 percent, it finds that the total costs of coal-fired and nuclear power are similar.

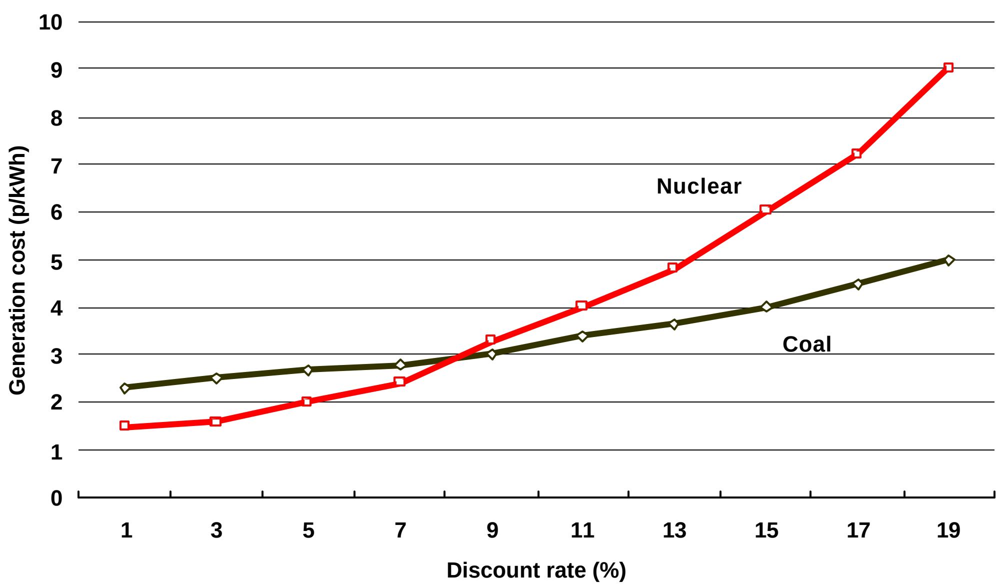
While the particular conclusions of this analysis are based on specific cost assumptions that would not apply to every time and place, the basic point would be valid everywhere. Capital costs represent a higher share of total costs for nuclear power than for coal-fired power. Hence, the higher the weighted cost of capital, the less likely that nuclear power can compete with coal-fired power, and the lower the weighted cost of capital, the more likely it can compete economically.

Similar points can be made in comparing other types of power plants. Gas-fired plants have high fuel costs and low capital costs compared with coal-fired plants, so gas-fired plants will tend to

14 Dimson (1989).

be favoured when the discount rate is high and disfavoured when the discount rate is low. Wind turbines have no fuel costs but substantially higher capital costs per kilowatt-hour generated than do coal-fired power plants, so wind power will tend to be favoured when the discount rate is low and disfavoured when the discount rate is high. Expectations about fuel costs play an important role in investment decisions as well, but discount rates on capital will always be a major influence.

Figure 9 Sensitivity Analysis of Supply Cost with Different Discount Rates



Source: Dimson (1989)

DEMAND GROWTH AND PROJECT MARKETABLITY

A project's viability comes down to its marketability, which ultimately depends on demand for its product over the project cycle. Normally, an evaluation of project marketability is conducted in order to assess whether there will be sufficient demand at a certain price level. For this purpose, investors need to carefully analyse historical trends, key drivers and underlying constraints for the trends. Investors should also assess the factors that might change the future course of energy demand. If investors overestimate future demand growth, they may invest prematurely in projects that will not be needed for a substantial period of time. Projects that are not needed cannot easily generate revenues, and so they may result in huge economic losses for public or private investors.

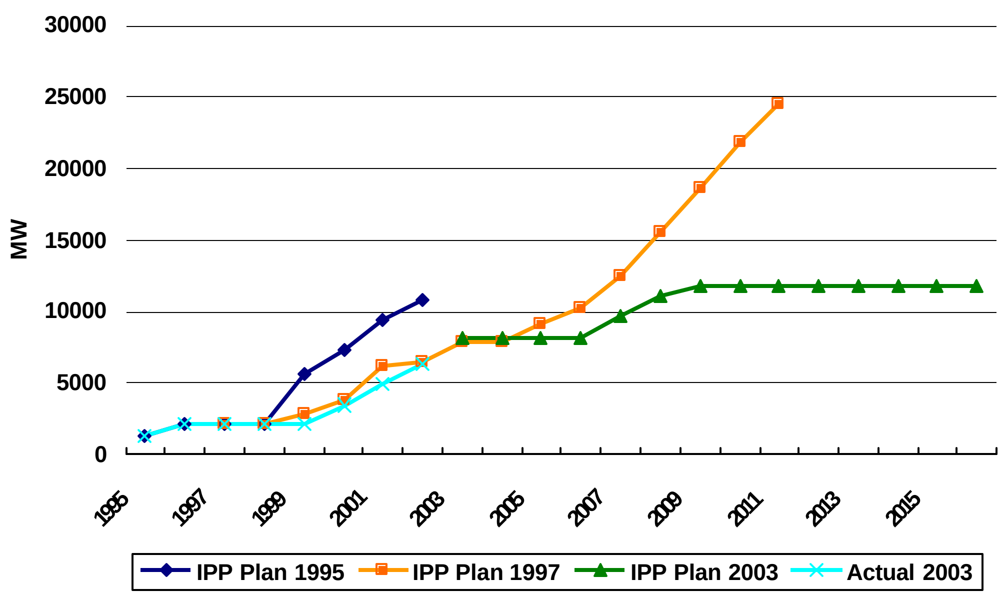
The Asian financial crisis of the late 1990s provides important lessons about how important it is in the energy sector to assess demand prospects in a balanced way. According to Krugman, Asian projects were typically evaluated based not on expected returns, but rather based on returns that might be received under the best of all possible circumstances.[15]

In Thailand, for example, the financial crisis caused electricity demand to decline, creating a situation of oversupply. Pre-crisis plans assumed that the Thai economy would grow 6 to 7 percent per annum (1995-2010), while post-crisis plans assume an annual GDP growth rate of 5.1 percent (2000-2020). Before the financial crisis, the Thai government had ambitious plans to invite IPPs to supplement the generating capacity of state-owned Electricity Generating Authority of Thailand (EGAT) to meet soaring power demand as shown in Figure 10. But with slower growth in GDP and power demand, the government revised its IPP plans substantially downward. For example, the start-up of the second Krabi power plant, with installed capacity of 300 MW, was delayed from 2001

[15] Krugman (1998).

to 2005. Power purchases from the lignite-fired Hongsa project and the Nam Ngum 1 and 2 hydro projects, in the Lao People's Democratic Republic, were delayed to 2004 and 2005 respectively.

Figure 10 Planned IPP Generating Capacity in Thailand in 1995, 1997 and 2003



Source: Electricity Generation Authority of Thailand, EGAT

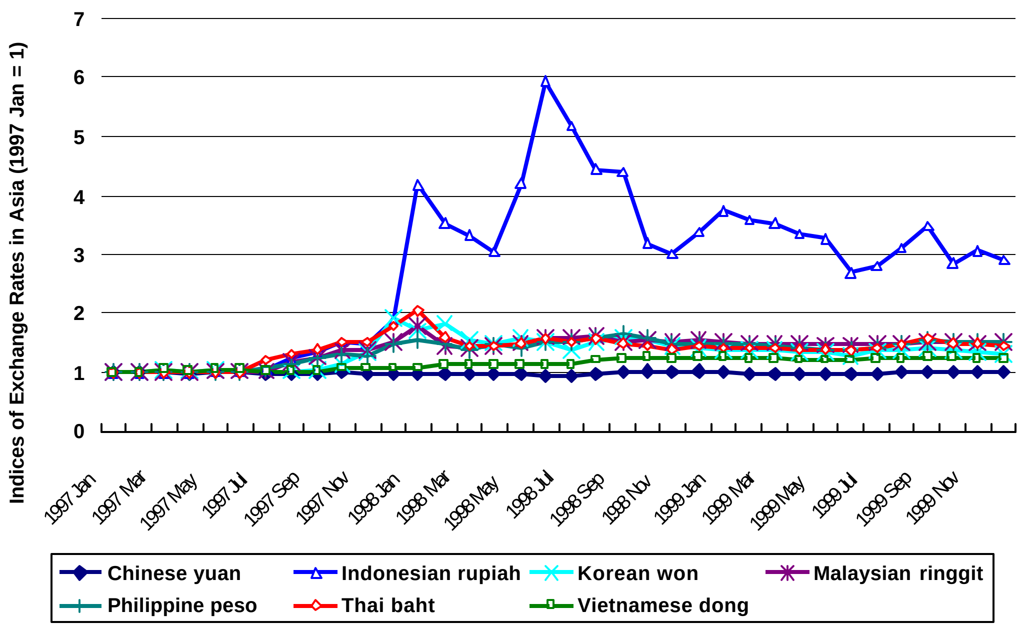
In Thailand, capacity additions made before the financial crisis, combined with the slowdown in electricity demand, have led to generating capacity reserve margins much higher than the power system requires. In 2002, the reserve margin reached 27.5 percent, which is much higher than the 15 percent system reserve requirement specified by government, making customers bear unnecessary costs. IPP investors have suffered as well, since they are obliged bear the costs of delays in plant start-up and delays in power purchases by EGAT. Higher reserve margins have meant delays in power purchases from completed and partially-built plants in which substantial investment has already taken place, on which substantial capital charges must thus already be paid. Thailand thus affords an excellent example of how the failure to accurately assess the prospects for energy demand growth can lead to energy investment beyond what growing demand requires, with both extra costs to energy customers and major adverse impacts on investors' balance sheets.

EXCHANGE RATE STABILITY AND PROJECT CASH FLOW

If a project's revenues or costs are denominated in two or more currencies, changes in exchange rates will affect the project's cash flow. Typically, energy projects built and financed by foreign companies generate their revenue in local currency and service their debt in an internationally traded foreign currency. In such cases, the sudden devaluation of local currency can make it difficult to service the external debt from domestic project revenues. Risks from shifting exchange rates can be hedged though currency forwards or futures or currency swaps. However, such hedging arrangements add to project costs, making investment less attractive.

Most APEC economies do not have exchange rate controls. China, Malaysia and Hong Kong, China are major exceptions. Figure 11 shows indices of monthly exchange rates in selected Asian economies from 1997 through 1999. The Indonesian rupiah shows an especially sharp devaluation and considerable volatility after its economy was severely hit by the Asian financial crisis.

Figure 11 Indices of Monthly Exchange Rates in Asian APEC Economies, 1997-1999



Source: IMF (2002), "International Financial Statistics"

The rupiah's devaluation had strong impacts on the Indonesian economy and energy sector. The 1,230 MW Paiton I independent power production project, the largest coal-fired IPP in Indonesia, offers an interesting illustration. Paiton Energy, the project's operator, reached a power purchase agreement with PLN in 1995 to buy the plant's output at 5.5 US cents per kWh. But the rupiah's devaluation in 1997 made PLN unable to comply with the terms of the PPA. After lengthy negotiations, which finally ended in 2001, Paiton and PLN agreed to a restructured PPA in which the purchased power rate was set at 3.0 cents per kWh. However, as a result of the reduced rate, revenues to Paiton Energy became inadequate to repay the principal borrowed, and it was necessary to restructure Paiton's debt with a longer maturity. The new debt arrangement was announced in March 2003, by the Overseas Private Investment Corporation (OPIC), Japan Bank for International Cooperation, and Nippon Export and Investment Insurance of Japan.

CLEAR AND STABLE TAX REGIME

Designing an effective tax system to collect rents from upstream oil and gas investments is a complicated and difficult process. This is largely because the interests of investors and the needs of host governments frequently diverge. On the one hand, investors would like to expand their return so that they can recover the costs and losses. On the other hand, the state wants to maximise its share of profits since it owns the underground natural resources they are based on.

A stable tax policy is important in order to attract investment in the energy sector. An interesting illustration of how an unstable tax regime may discourage foreign investment is offered by the Sakhalin II project in Russia, described in Box 1. The federal government is supposed to reimburse investors for value added tax but has no funds to do so in its budget. Investors are making up for the lack of VAT reimbursement by withholding royalty payments from the provincial government. The provincial government wants to make up for withheld royalty payments by levying a regional tax on investors, even though the production-sharing agreement exempts investors from taxes other than corporate income tax and royalties. If the PSA is violated in this way, investors will be wary of participating in future energy projects.

Box 1 Sakhalin II Value Added Tax Issue

In late 1999, the Duma or Lower Chamber of the Sakhalin Parliament considered a draft law to levy regional taxes on Sakhalin Energy as operator of the production-sharing agreement (PSA) for the Sakhalin II project. But under the PSA that went into effect on May 1996, Sakhalin Energy had been granted an exemption from any taxes except for the tax on profits and applicable royalty payments for the use of land and other natural resources. According to the Sakhalin Tax Inspector, Sakhalin Energy's exemptions will reach nearly US$1 billion during the period the PSA remains in effect. Since the main purpose of PSAs is to protect investors from changes in laws and regulations, the possibility that a regional government might modify these exemptions is shaking investors' confidence in Russian energy projects.

On the other hand, Sakhalin's regional government is having problems with collecting value added tax (VAT) on projects under PSAs. Under the 1996 PSA Law, PSA contracts provide that the federal government of Russia should reimburse all VAT paid by foreign investors to suppliers and contractors until commercial oil and natural gas production commences. The PSA law and contracts also stipulate that if commercially produced oil or natural gas is exported, the VAT imposed on the exported product should be reimbursed. The burden of VAT reimbursement to the federal government is US$70 million and rising.

The Sakhalin PSA contract stipulates that the VAT debt can be met by investors' withholding royalty payments. Sakhalin Energy, which started commercial production in July 1999, has been withholding royalty payments ever since, with consequent revenue loss to the Sakhalin regional government. In the summer of 1999, the Sakhalin Duma proposed that the federal government reimburse the VAT to the investors. However, the Federal Parliament has failed to include these expenses in the budget.

ENERGY SUBSIDIES AND ENERGY INVESTMENT

Prices for transportation fuels and electricity are often subsidised by governments for social purposes such as making energy affordable to the poor, promoting rural electrification, maintaining international price competitiveness, or protecting energy-intensive industry. But subsidies tend to discourage both domestic and foreign investors because they distort the operations of the market.

A report by the International Energy Agency shows wide disparities in average power price subsidies in APEC economies, measured as a percentage of a reference price without subsidies. The subsidies are found to be roughly 11 percent in China, 28 percent in Indonesia and 33 percent in Russia.[16] In Indonesia, the government has been providing substantial direct subsidies to the state electricity company, PLN. The electricity tariff following the 1997 financial crisis has fallen to around US 3 cents per kWh, which is far below the actual supply cost of US 6 to 7 cent per kWh. Hence, it is impossible for investors in power projects to recover their costs or earn a reasonable rate of return unless investors receive a subsidy similar to that received by electricity customers.

Despite the negative impacts of subsidies on foreign capital investment, subsidy removal is likely to face strong public resistance, making such a policy shift difficult. Especially in developing economies, social policy changes of this nature can lead to social unrest, which then works to undermine economic stability and social cohesion at a broader level. On the other hand, there are well-known ways of achieving social goals that do not depend on price subsidies. These include jobs, educational programmes, and direct welfare payments, among the more obvious alternatives. Indonesia has in fact been able to reduce its energy subsidies considerably despite social pressures.

[16] International Energy Agency (1999).

OVERVIEW OF APEC ENERGY INVESTMENT REQUIREMENTS

INTRODUCTION

The economies of the APEC region are expected to more than double in size between 1999 and 2020, with an average growth rate of 3.5 percent per year in real gross domestic product.[17] Growth of this magnitude will translate into massive increases in demand for energy, including oil for the transportation of people and goods, natural gas and coal for production of electric power, and energy from various non-fossil sources such as nuclear power, hydropower and wind power. To meet growing demand for energy and fuels, major investments will be required for energy production, transportation, distribution and supply facilities throughout the APEC region.

While energy investments accounted for just 1.5 percent of Gross World Product in the early 1990s,[18] the availability of the capital needed for a growing global energy sector cannot be taken for granted. To give a perspective of the magnitude of the required investments in the APEC region, estimates are made here using the macroeconomic data and demand growth projections generated for APERC's *APEC Energy Demand and Supply Outlook 2002*.[19] Estimates of investment requirements presented in that document are updated here with improved methods for estimating certain types of investment needs, the addition of estimated investment requirements for domestic oil and gas pipelines, and the inclusion of newly announced projects.

The infrastructure categories for which investment requirements are estimated include coal production and shipping facilities, oil production and processing, gas production and processing, oil and gas shipping and pipeline infrastructure, and power generation and transmission infrastructure. Due to data limitations on smaller projects, this analysis covers only major facilities in each of the infrastructure categories. Moreover, the analysis does not consider the potential role of renewable technologies outside of the electric power sector or the capital costs of retrofitting older power plants with environmental controls. Hence, the investment needs described tend to understate the total resources that APEC economies will have to allocate to energy production and delivery in the coming two decades. Estimated investment requirements are shown as ranges to account for differences in construction sites, types of installations, and capital and labour costs.

ENERGY DEMAND ASSUMPTIONS

Primary energy demand in APEC is projected to grow at an annual rate of 2.1 percent from 5,969 Mtoe in 1999 to 8,777 Mtoe in 2020. Figure 12 shows the trends by fuel type in the previous 20-year period compared to the projections over the forecast period of APERC's *Energy Demand and Supply Outlook 2002*.

Oil is expected to maintain the highest share in APEC energy demand at around 36 percent over the projection period (1999-2020). Oil demand is projected to grow at an average rate of 2.1 percent per annum from 2,023 Mtoe in 1999 to 3,107 Mtoe in 2020. The transport sector will lead oil demand growth, contributing 72 percent to incremental oil demand growth over the period.

Coal is projected to be the second-largest component of primary energy demand over the projection period, maintaining a 27 percent share with average annual demand growth of 2.1 percent. More than four-fifths of the increase in coal demand (83 percent) will come from power generation. China will become the largest coal consuming economy in the APEC region,

17 APERC (2002a).

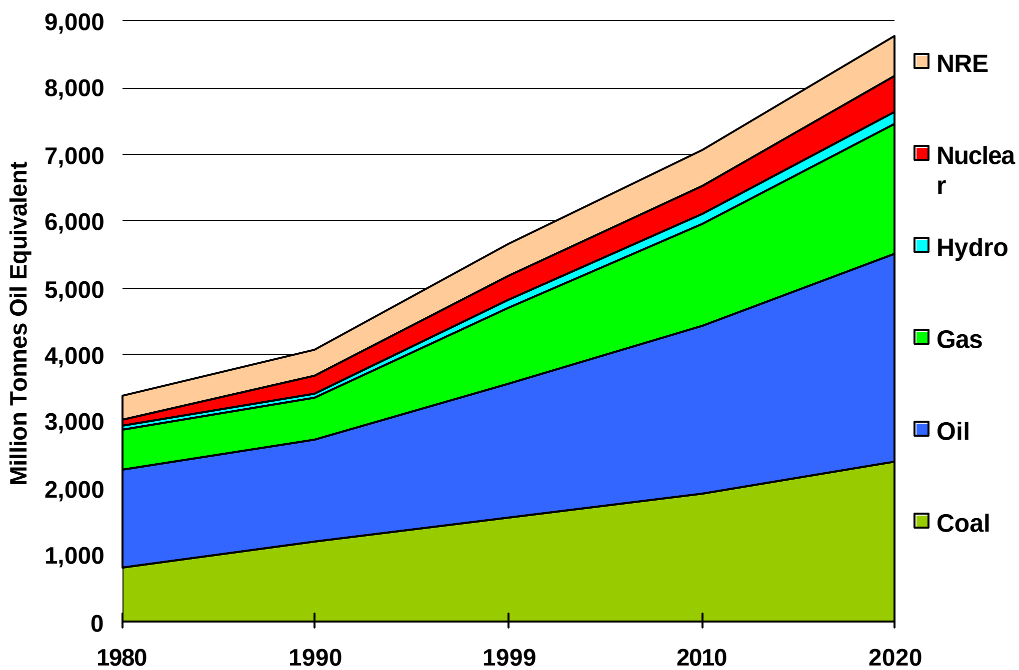
18 IIASA/WEC (1998).

19 APERC (2002a).

accounting for 41 percent of its coal demand by 2020. Projected growth in coal demand is driven by coal's cost competitiveness relative to other fossil fuels, as well as its ready availability within the region.

Coal production is concentrated in the 6 APEC economies with the largest reserves: Russia, USA, China, Australia, Canada and Indonesia. These six economies account for almost 99 percent of APEC's total coal reserves and production. Coal demand has increased substantially in recent years, a rise matched by increased production. But the APEC region is expected to change from being a net coal exporter in 1999 to a marginal net importer of coal by 2020.[20]

Figure 12 Primary Energy Demand by Fuel Type in APEC (Mtoe)



Source: APERC (2002a), based upon data from International Energy Agency. IEA data is available for Viet Nam from 1986 onwards and for Russia from 1992 onwards, hence these are included from 1990 and 1999 onwards, respectively.

Natural gas is projected to constitute the third-largest portion of primary energy demand at around 22 percent over the forecast period. Rising per capita income, ease of use, low environmental emissions and high combustion efficiency have all been factors promoting its use. Gas demand in APEC should grow around 2.8 percent per annum during the first half of the period, slowing somewhat to 2.4 percent yearly in the second half. But in the Asian economies of APEC, gas demand is projected to grow much faster, at an average annual rate of 4.6 percent. In Asia, the current share of natural gas in primary energy demand is low at 8 percent compared with North America (24 percent), Latin America (19 percent) and Oceania (18 percent). To meet growing gas demand, infrastructure development requiring massive investment is crucial. Transport by either pipeline, or as LNG, along with distribution networks for industrial and residential use will need to be constructed at a fast pace.

[20] APERC (2002a).

Table 3 Primary Energy Demand by Fuel (Million Tonnes Oil Equivalent)

		Primary Energy Demand (Mtoe)					Average Annual Growth Rates				
		1980	1990	1999	2010	2020	1980-1990	1990-1999	1999-2010	2010-2020	1999-2020
Coal	Net import	-37	-67	-28	-77	6					
	Production	853	1,253	1,568	1,982	2,396	3.9%	2.5%	2.2%	1.9%	2.0%
	Supply	816	1,186	1,540	1,905	2,402	3.8%	2.9%	2.0%	2.3%	2.1%
Oil	Net import	496	534	726	1,076	1,678	0.7%	3.5%	3.6%	4.5%	4.1%
	Production	948	983	1,297	1,446	1,429	0.4%	3.1%	1.0%	-0.1%	0.5%
	Supply	1,444	1,517	2,023	2,522	3,107	0.5%	3.2%	2.0%	2.1%	2.1%
Natural Gas	Net import	5	-9	-132	-169	-85					
	Production	590	637	1,266	1,705	2,036	0.8%	7.9%	2.7%	1.8%	2.3%
	Supply	595	628	1,135	1,537	1,951	0.5%	6.8%	2.8%	2.4%	2.6%

Source: APERC (2002a).

Nuclear power is projected to represent a stable share of primary energy demand, declining slightly from 6.7 percent in 1999 to 6.1 percent in 2020. Nuclear power generation is projected to expand at an average rate of 1.7 percent per year, or more slowly than overall energy demand growth. Northeast Asia (Japan, Korea and Chinese Taipei) will contribute 70 percent of total incremental growth of nuclear power (1999-2020) to meet rising electricity demand. By contrast, North America will see a decline in nuclear power of 0.3 percent per annum as a result of the retirement of existing reactors.

Hydroelectricity shows the fastest growth in primary energy demand at 2.7 percent per annum (1999-2020), though its share is expected to be low at 2 percent for the entire forecast period. Endowed with the largest potential for hydroelectricity, China will see the fastest annual growth of 6.9 percent, accounting for around 70 percent of the total incremental growth of hydroelectricity in APEC.

New and Renewable Energy (NRE) is assumed in this study to include biomass, solar, wind, tidal and wave energy. In the APEC region, homes in rural areas of less-developed economies rely heavily on biomass for cooking and heating, accounting for almost all the NRE consumed today. As these economies develop, they are likely to shift to commercial fuels for these purposes. Thus, despite a measurable increase in the use of more advanced NRE forms like wind and solar energy, NRE overall is projected to grow an average of just 1.1 percent per annum over the projection period, or at half the pace of primary energy demand, its share falling from 8.4 percent in 1999 to 6.8 percent in 2020.

TOTAL ENERGY INVESTMENT REQUIREMENTS IN APEC

A summary of the total estimated energy investment requirements in the APEC region is shown in Table 4. Some US$3.4 trillion to US$4.4 trillion of energy investment (at 1999 prices) will be required in APEC over the period from 2000 to 2020. Yearly investment needs are conservatively projected to be somewhere between US$149 billion to US$207 billion in 2000, between US$168 billion and US$217 billion by 2010, and US$198 billion to US$252 billion in 2020.

Table 4 Annual and Total Energy Investment Requirements in the APEC Region by Category of Energy Investment, Billion 1999 United States Dollars

Category of Energy Investment	2000	2010	2020	2000 – 2020
Coal production & transportation	$10 – 12 B	$4 – 5 B	$5 – 6 B	$90 – 114 B
Oil & gas production & processing	$52 – 77 B	$35 – 52 B	$34 – 50 B	$668 – 1,008 B
Oil & gas international trade	$23 – 33 B	$15 – 19 B	$9 – 12 B	$294 – 384 B
Oil & gas domestic pipelines	$36 – 51B	$24 – 34 B	$25 – 35 B	$481 – 688 B
Electricity generation & transmission	$28 – 34 B	$91 – 108 B	$125 – 149 B	$1,866 – 2,219 B
Total	**$149 – 207 B**	**$168 – 217 B**	**$198 – 252 B**	**$3,419 – 4,412 B**

Figure 13 shows the shares of investment requirements that are projected to be taken up by each category of energy investment. Electricity generation and transmission are projected to account for nearly half of total investment needs, or 49 percent of the total projected between 2000 and 2020. Oil and gas production and processing are projected to account for nearly a quarter of total investment needs, or 23 percent of the total projected for the period. Domestic oil and gas pipelines represent nearly a sixth of total energy infrastructure investments, or 16 percent of the total. Investments for the international trade of oil and gas, which include the costs of tankers, LNG facilities, and pipelines used for international trade, represent another 9 percent of the total. The coal industry has the smallest share, at only 3 percent of total investment requirements.

Figure 13 Total Investment Requirements by Infrastructure Category, Percent

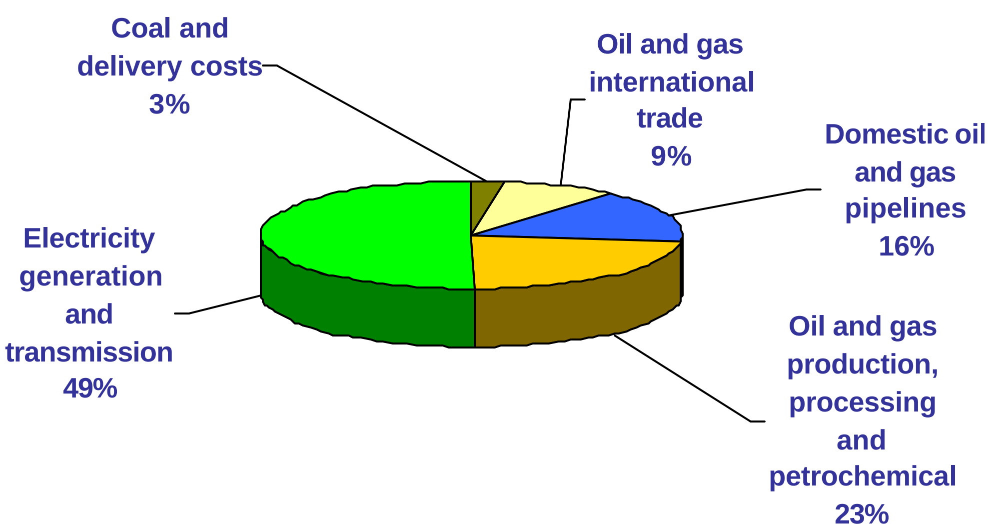
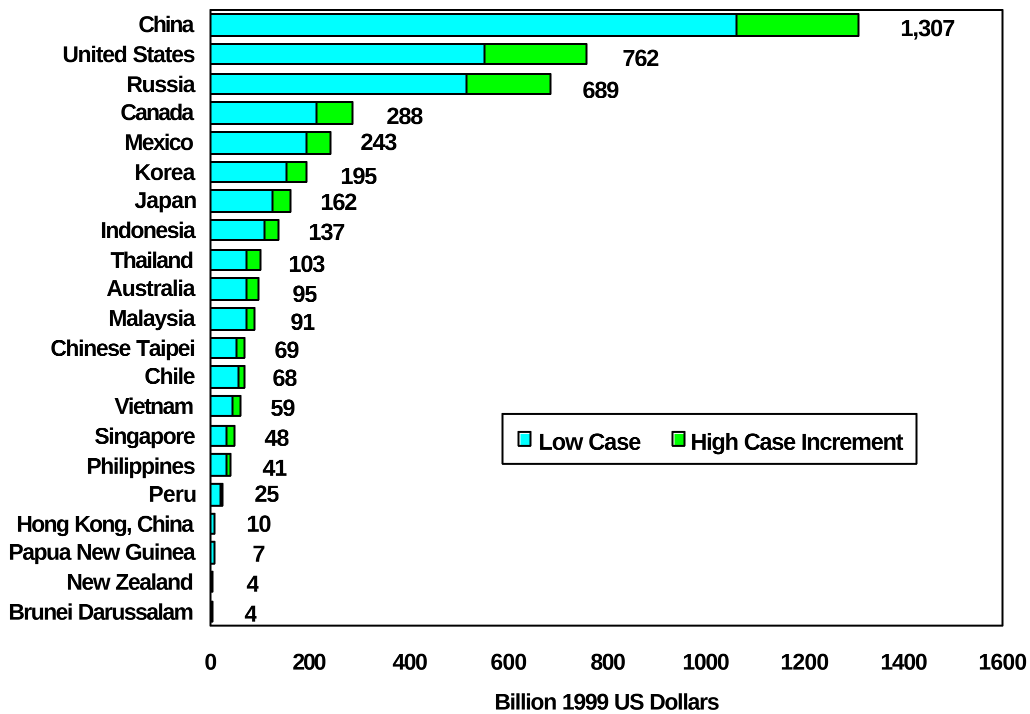


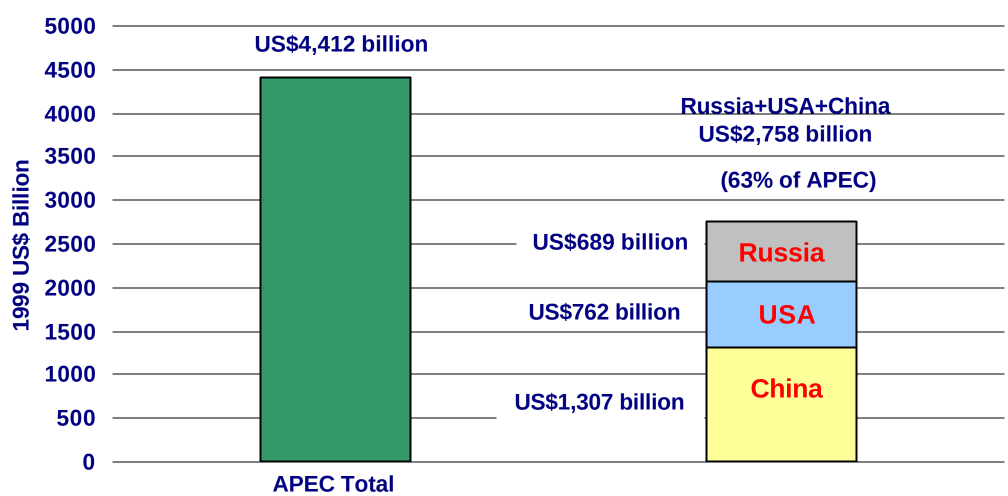
Figure 14 shows total energy investment requirements that are projected for each APEC economy for the two-decade period from 2000 through 2020. The lower estimate of investment needs is indicated by the blue portion of each bar. The higher estimate of investment needs is indicated by the sum of blue and green portions of each bar. The economies are shown in order from greatest to least projected investment requirements over the period.

Figure 14 Total Energy Investment Requirements by Economy 2000 – 2020



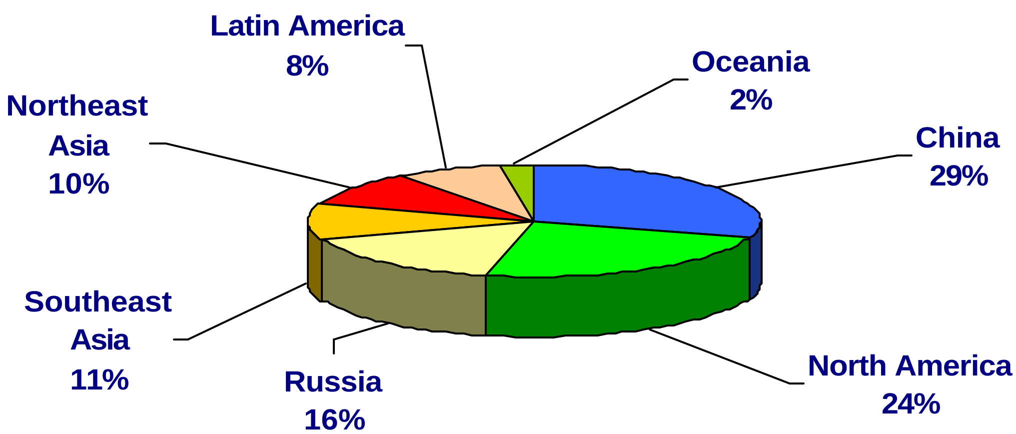
Three economies are likely to account for over three-fifths of the energy infrastructure investment requirements in the APEC region: China, United States and Russia. According to the high-case estimates of energy investment needs, these economies are projected to require as much as US$2,758 billion for energy infrastructure in the period from 2000 through 2020, or 63 percent of the requirements for the region as shown in Figure 15. High-case investment needs are projected at US$1,307 billion for China, US$762 billion for the United States and US$689 billion for Russia.

Figure 15 Total Energy Investment Requirements of China, United States and Russia Compared with Total APEC Requirements: High Case (Billion 1999 US$)



Canada, Mexico, Korea and Japan will together represent about another fifth of the total energy investment requirements from 2000 through 2020. In the high case, Canada is projected to require US$288 billion, Mexico US$243 billion, Korea US$196 billion and Japan US$163 billion. The final fifth of energy investment needs will be divided between the fourteen APEC economies with the smallest needs, ranging from Indonesia with US$138 billion of energy investment requirements to New Zealand and Brunei Darussalam with around $4 billion of requirements each.

Figure 16 Shares of Energy Investment Requirements by APEC Economy Group



THE BURDEN OF ENERGY INVESTMENT REQUIREMENTS BY ECONOMY

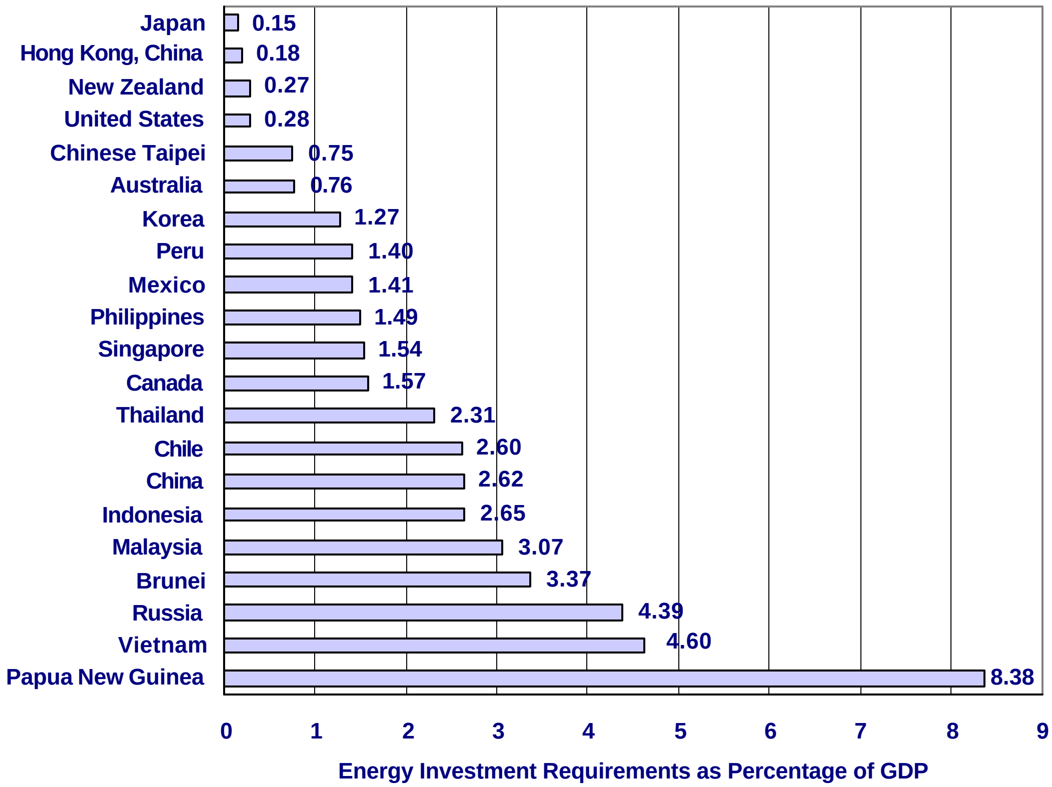
The magnitude of the energy investment requirements over the next two decades has raised concerns over whether sufficient financial resources can be obtained to meet them. Later portions of this report appraise the availability of financial resources for energy sector investment in APEC economies and examine policies and mechanisms to attract the resources required. But to put the issue in perspective, it is important to evaluate the burden of anticipated energy investment needs in relation to overall economic output. For economies where energy investment needs represent a small share of gross domestic product, the burden should be light and easily met. For economies where energy investment needs are a larger share of GDP, they may be more difficult to satisfy.

Figure 17 shows the share of GDP that the projected energy investment requirements will represent in each APEC economy over the period from 2000 through 2020. For the APEC region on average, the energy investment share of GDP is projected to be 0.8 percent. It can be seen in the figure that only six APEC economies fall below this average: Japan, Hong Kong, China, New Zealand, United States, Chinese Taipei and Australia, in ascending order of energy investment burden. All of these economies are highly developed, with high incomes per capita.

According to the World Energy Council and International Institute for Applied Systems Analysis, global capital spending on energy projects amounted to 1.5 percent of Gross World Product in the early 1990s and should not exceed 2 percent of GWP in the future.[21] But nine APEC economies are projected to have energy investment burdens that exceed this 2 percent threshold: Thailand, Chile, China, Indonesia, Malaysia, Brunei Darussalam, Russia, Viet Nam and Papua New Guinea. Several of these economies are major energy producers and exporters, including Indonesia, Malaysia, Brunei Darussalam and Russia. Papua New Guinea, with the largest projected investment burden, plans aggressive investments to develop its natural gas industry.

21 IIASA/WEC (1998).

Figure 17 Energy Investment Requirements as Percentage of GDP, 2000 – 2020



On the face of it, these figures would seem to indicate that at least for two major subsets of APEC economies, the burden of energy investment should be quite sustainable. For highly developed economies, energy investment needs represent a very small share of domestic product and should thus be fairly easy to finance from domestic sources. For many of the economies with the greatest energy investment burdens, there are very substantial energy resources with which energy investments can be financed.

To further assess the sustainability of energy investment burdens in the APEC region, the remainder of this chapter adopts two different approaches. One approach, taken in the following section, is to compare energy investment burdens over time, comparing the burden of investment that is anticipated for the next twenty years with the burden that was actually incurred over the last twenty years. Data preclude this analysis for the energy sector as a whole, but allow it for two major subsectors: oil refining, which is projected to account for 7 percent of energy investment needs through 2020, and electric power (sans transmission), which is projected to account for 33 percent of future investment needs. A second approach is to compare energy investment burdens as a function of income levels and development in different APEC economies. This approach is taken in the final section of this chapter for the electric power sector.

COMPARING THE PAST AND FUTURE BURDEN OF ENERGY INVESTMENT

PAST AND FUTURE BURDEN OF OIL REFINERY INVESTMENT

In 18 APEC economies, taken as a group, additions to oil refinery capacity in the 20-year period from 2001 through 2020 are projected to be just slightly more than half the additions to oil refinery capacity that were actually made over the previous 20 years. (Data for three APEC economies is incomplete or presents mathematical impediments.) APERC's database shows that refinery capacity additions in these 18 economies between 1981 and 2000 totalled 46.9 million barrels per day. By comparison, these economies are projected to require just 24.1 million barrels per day of capacity additions through 2020, or 51 percent as much as in 1981 through 2000. [22]

Box 2 Falling Petroleum Product Demand and Refining Overcapacity in the 1980s

After many years of sustained growth the refining industry experienced a dramatic change at the end of the 1970s. Perceiving the initial downturn as a temporary condition, the industry continued the construction of capacity after demand for refined products peaked in 1978. This additional capacity and a decline in demand that continued for five years led to a substantial level of excess refining capacity. Utilisation rates in the United States, which stood at around 90.9 percent in 1973, reached a low of 65.8 percent in 1982. Refining margins and with them profits, fell sharply and forced a drop of 123 operating plants between 1981 and 1986. These changes forced the refining industry to adjust their projections for long-term demand growth to lower levels. It was until 1984 that low prices for petroleum products helped the demand trends come around, and since then, demand has slowly and gradually risen although not without brief periods of adjustment. In 1997 with the utilisation rate in the United States reaching 95.2 percent refiners finally started to increase capacity. Tendencies similar to these were observed around the world, and as a result the global rate of infrastructure construction has been slow in the past 20 years and investments are only now beginning to show yearly increases.[23]

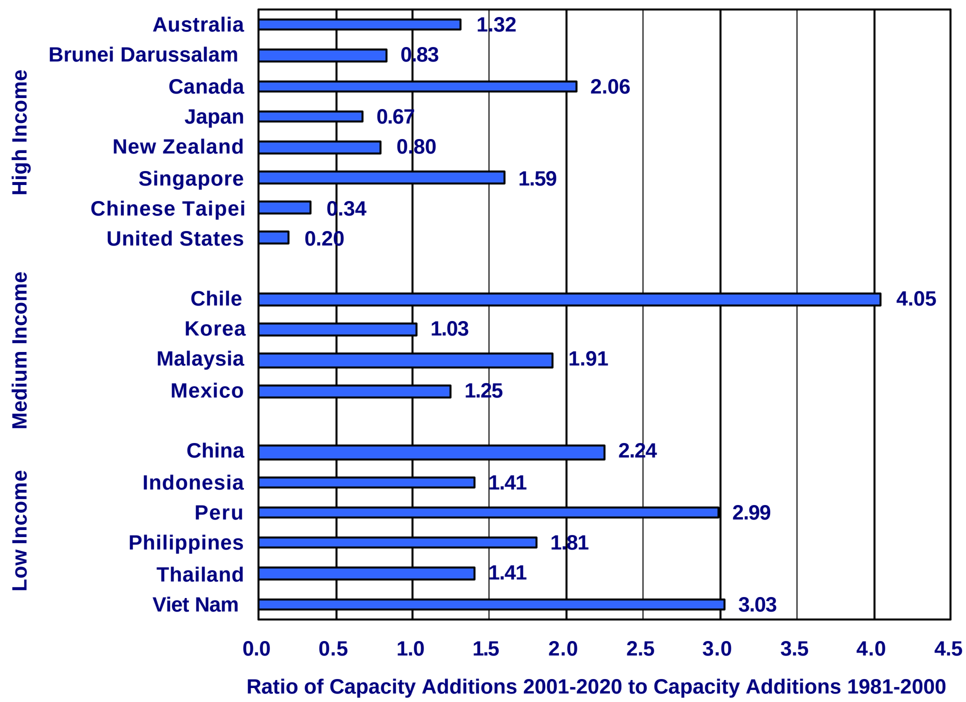
Figure 18 shows the ratio of refinery capacity additions projected from 2001 through 2020 to historical additions from 1981 through 2000 for each of the 18 APEC economies analysed. Among the eight economies with high levels of income per capita, five should have lower refinery investment burdens in the projection period than in the previous twenty years, as shown by a ratio of less than one. These include the United States, Chinese Taipei, Japan, New Zealand and Brunei Darussalam, in ascending order of comparative burden. Just three of the eight high-income economies are projected to have greater refinery investment burdens looking forward than they had historically. These include Australia, Singapore and Canada, again in ascending order of relative burden. In Canada, the burden is expected to be twice as heavy in the future as it was in the past.

In economies with medium and lower-levels of income per capita the picture is reversed, with many more economies likely to experience a relatively heavy burden of oil refinery investment going forward. The future burden is projected to be roughly four times as heavy as the historical burden in Chile, three times as heavy in Viet Nam and Peru, and twice as heavy in China, Malaysia, and the Philippines. Most of these economies have strong projected growth in demand for oil products in their transportation and industrial sectors, according to projections from APERC's *Outlook 2002*. Only in Korea, Mexico, Indonesia and Thailand, within the middle and low-income groups, are future investment needs for oil refinery capacity projected to exceed historical investment needs for oil refinery capacity by less than half.

[22] APERC (2002a).

[23] Beck (2001).

Figure 18 The Burden of Investing in Additions to Petroleum Refinery Capacity: Ratio of Projected Additions in 2001-2020 to Historical Additions in 1981-2000



PAST AND FUTURE BURDEN OF ELECTRIC POWER SECTOR INVESTMENTS

In 15 APEC economies, analysed as a whole, investment requirements for electric generating capacity over the two decades from 2001 through 2020 are projected to be very similar to the actual investments in generating capacity over the preceding two decades. (Data for six APEC economies was too incomplete to analyse). The calculations in this section take into consideration the historical trend of power plant capital costs and make allowances for the expected behaviour of costs in the future. APERC data indicate that investment in electric generating capacity in these 15 economies between 1981 and 2000 totalled US$1,092 billion. By comparison, these economies are projected to require US$1,160 billion of new investment in generating facilities between 2001 and 2020, or just 6 percent more than in the previous 20 years.

Figure 19 shows the ratio of investment in generating capacity projected for the period from 2001 through 2020 to the actual investment in generating capacity between 1981 and 2000 for each of the 15 APEC economies analysed. It is striking that all economies in the high-income group, with mature power systems and relatively slow projected growth in electricity demand, will require less investment in generating capacity in the 2000-2020 period than in the previous twenty years. In New Zealand, United States, Hong Kong, China and Japan, the burden of investment in new electric generating capacity should be less than half as heavy looking forward as it was looking back.

However, for several economies in the medium and lower-income groups investment requirements for electric generating capacity in the future are expected to be much larger than those in the past. In China, Chile and Mexico, the burden of investment in generating capacity is projected to be more than twice as heavy between 2001 and 2020 as it was between 1981 and 2000. In Malaysia, Thailand, Russia and Viet Nam, which are not included in the figure because available data were incomplete, the needs for investment in generating capacity also appear to be much greater in the future than in the past. But in Korea and Indonesia, the burden is projected to be only slightly heavier looking forward than looking back, and in Peru and Papua New Guinea it is projected to be somewhat lighter. In these last two economies, electricity demand growth over the next 20 years will be unusually low as compared to that in other medium and low-income economies, according to APERC's *Outlook 2002.*

Figure 19 Burden of Investment in New Electric Generating Capacity: Ratio of Projected Investment 2000-2020 to Historical Investment 1980-2000

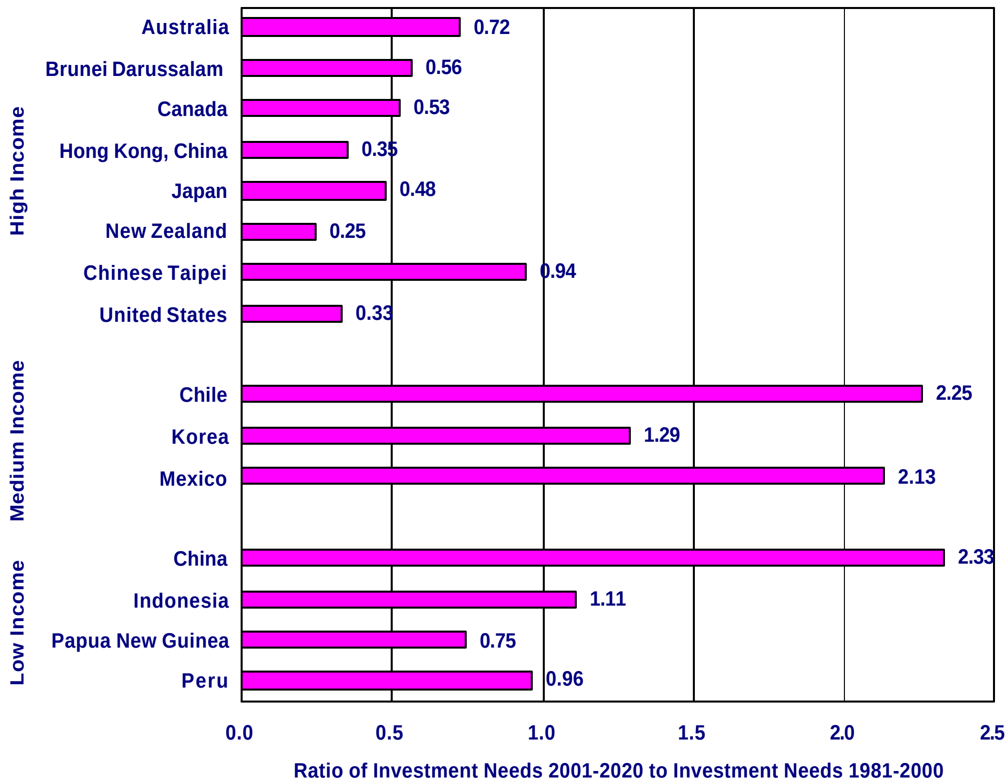


Figure 20 breaks down investment trends in electricity generation by type of power plant. Among fossil-fuelled plants, investment is expected to be strongest in those running on natural gas, with capital expenditures in the period from 2001 to 2020 nearly triple those in 1981 through 2000. Combined cycle gas-fired plants can be built quickly on a variety of scales to suit demand and are substantially cleaner and more efficient than other types of fossil plants currently available.

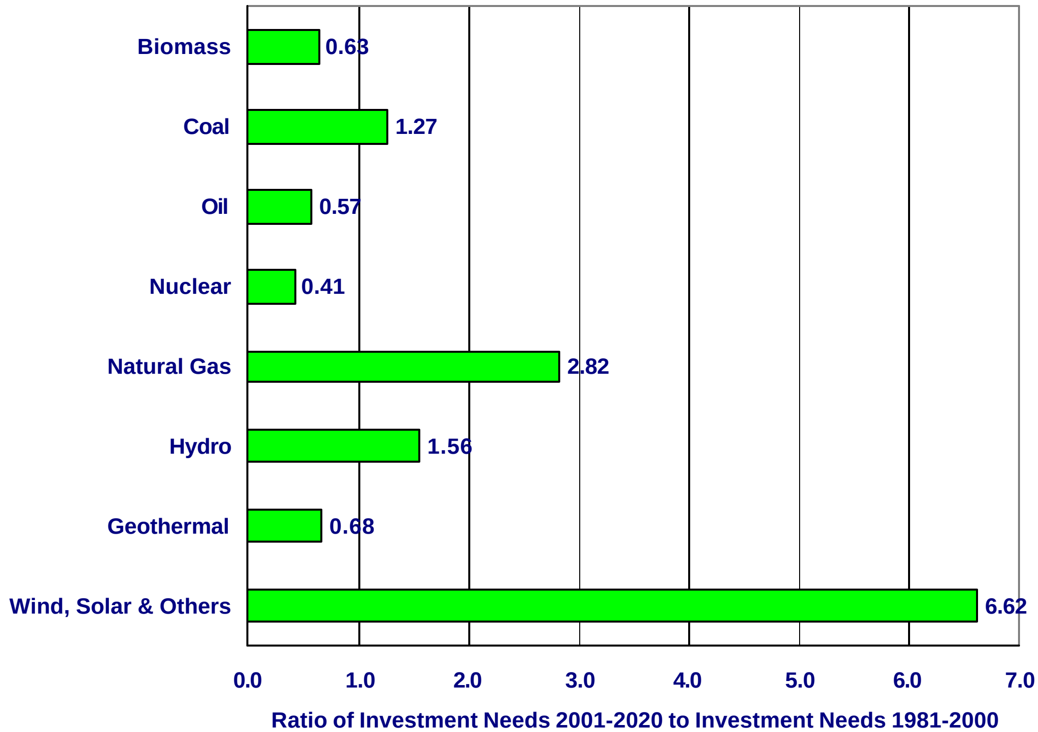
Strong investment is also expected to continue in coal-fired plants, with projected capital expenditure over the next two decades about 27 percent greater than over the prior two decades. While coal-fired power plants have relatively high carbon dioxide emissions, clean coal technology has greatly reduced their atmospheric emissions of conventional pollutants like particulates, sulphur dioxide and nitrogen oxide, and coal remains cheap and abundant. Among the economies in which investments in coal-fired plants should be larger in the future than in the past are China, Chinese Taipei, Indonesia, Korea and Mexico. By contrast, fuel oil plants are falling out of favour, with projected investment over the next 20 years some 43 percent below that over the past 20 years.

For nuclear power plants, investment is projected to be much smaller over the next two decades than it was over the past two decades. Investment in nuclear generating capacity is projected to be about 59 percent lower on average from 2001 through 2020 than it was between 1981 and 2000, even though the APEC region has more aggressive construction plans for nuclear plants than any other region of the world.[24] In part, this might be seen as the ongoing result of public concerns in many economies over nuclear safety issues and power producers' past experience with uncertain nuclear plant construction costs. But it can also be attributed to the fact that the period from 1981 to 1999 saw a very high rate of nuclear power plant construction. Fully two-thirds of the reactors in operation worldwide were completed during that period.[25]

24 IAEA (2003).

25 Ibid.

Figure 20 Investment Trends for Different Types of Electric Generating Plants: Ratio of Projected Investment 2001-2020 to Historical Investment 1981-2000



Among power plants running on renewable resources, projections indicate strong growth for investment in hydropower plants and extremely strong growth for investment in new renewable technologies. Investment in hydropower plants is projected to be about 56 percent greater in 2001 through 2020 than in the previous 20 years as potential resources continue to be developed in economies such as China, Korea, Papua New Guinea, Mexico and Peru. New renewable energies are projected to attract more than six times as much investment in the coming 20 years as in the past 20 years, when the technologies were just being developed and their costs were relatively high.

On the other hand, investment in geothermal and biomass power, which are also renewable, is expected to be relatively weak. Geothermal power, though economically proven, is limited by the availability of resources, with investment projected to be about 32 percent lower in the period from 2001 through 2020 than in the preceding two decades. Unsophisticated biomass plants fuelled by bagasse were common in the past for auto production of power, but such plants are being phased out due to low operating efficiency. Modern biomass power plants using technologies such as combined cycle with integrated gasification are much more expensive, which may explain why investment in biomass plants is projected to be 37 percent less going forward than in the past.

THE BURDEN OF POWER INDUSTRY INVESTMENT AS A FUNCTION OF THE LEVEL OF ECONOMIC DEVELOPMENT

There is an apparent tendency, noted earlier, for the burden of energy investment as a percentage of economic output to be relatively heavy for less developed economies and relatively light for more developed economies. In this section, that pattern is examined in greater detail with respect to investment in the electric power sector. In the power sector, as for energy as a whole, energy investment often represents the greatest share of output for the least developed economies.

Figure 21 shows how the burden of investment in electric generating capacity has varied with income levels historically. The burden of investment as a share of gross domestic product, on the y-axis, is plotted against real gross domestic product per capita, on the x-axis, for ten representative APEC economies. For each economy, the plot shows how the ratio of investment to GDP has varied with GDP per capita over the 20-year period from 1981 through 1999. To smooth out short-term fluctuations in investment, each point is plotted as a five year moving average. So the first point on each line plots the average ratio of investment to GDP against average GDP per capita for the period from 1981 through 1985, and the last point plots the average ratio against average GDP per capita for 1999 through 2003.

For low-income economies, such as China, Indonesia, Peru and Thailand, the burden of power sector investment as a share of GDP has sometimes exceeded 3 percent. For middle-income economies like Mexico and Korea, the burden of power sector investment as a share of GDP has usually been below 2 percent. And in higher-income economies including Australia, Canada, Japan and the United States, the burden of power sector investment as a share of GDP has generally been well below 1 percent. In broad terms then, power sector investment has been less of a burden for more developed economies than for less developed ones.

Figure 21 Historical Burden of Electric Power Sector Investment as a Function of Gross Domestic Product Per Capita in APEC Economies, 1981-1999

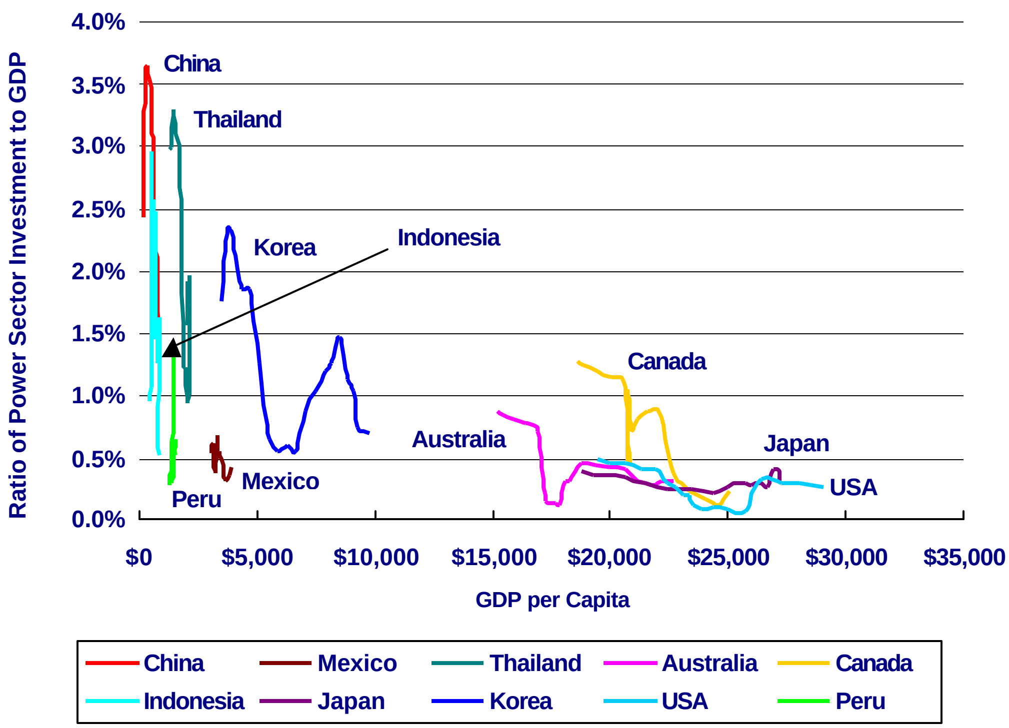
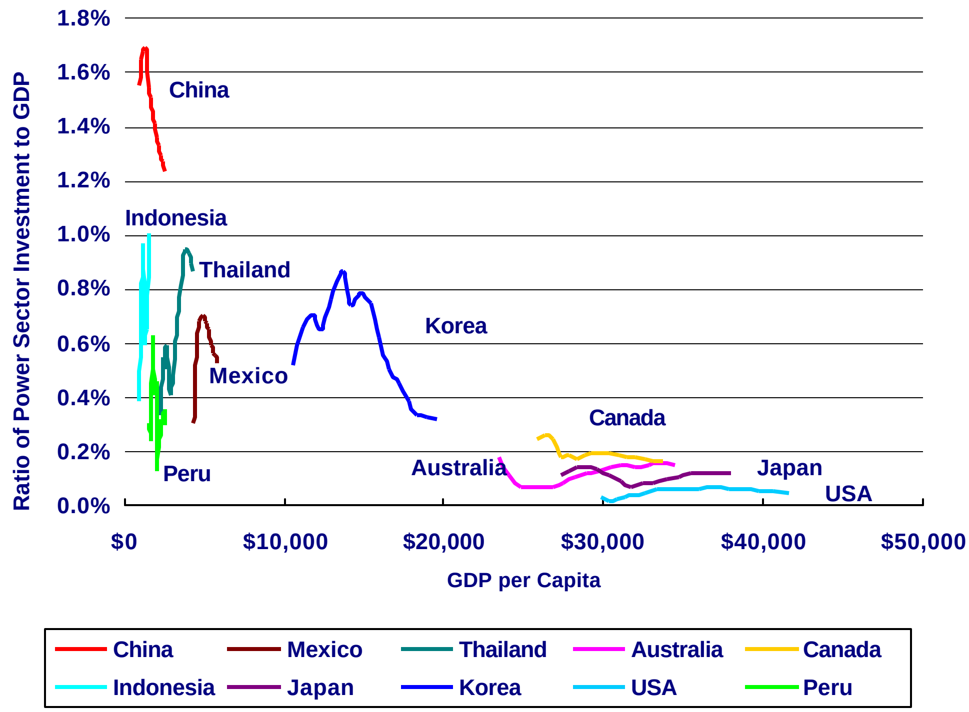


Figure 22 shows that this pattern is expected to persist over the next two decades, albeit with generally lighter burdens of power sector investment in view of the continued development and income growth that is anticipated for APEC economies across the board. For those economies currently at lower income levels, the share of power sector investment in GDP is projected to lie in the range of 0.2 to 0.6 percent for Peru, 0.4 to 1.0 percent for Indonesia and Thailand, and 1.2 to 1.7 percent for China. Among economies currently at middle income levels, the share of power sector investment in GDP is projected to range from 0.3 to 0.9 percent for Korea and from 0.3 to 0.7 percent for Mexico. Thus, the share for these middle-income economies is broadly in line with the share for lower-income economies except for China. On the other hand, the projected burden of power sector investment in GDP is noticeably lower for the higher-income economies of Australia, Canada, Japan and the United States, generally remaining well below 0.2 percent.

Figure 22 Projected Burden of Electric Power Sector Investment as a Function of Gross Domestic Product Per Capita in APEC Economies, 2000-2020



For less-developed APEC economies, the past and projected burden of electric power sector investment as a function of GDP is detailed in Figure 23. In most cases, a rapid burst of power investment can be observed at early stages of development, followed by a long, steady decline. This decline turns into a gradual increase, albeit at lower levels than in the previous 20-year period, in response to renewed demand growth following the economic downturn that many APEC economies experienced in the late 1990s as projected by APERC's *Outlook 2002*.

13. In China, the five-year moving average ratio of power investment to GDP surged from 2.42 percent in 1985 to a peak of 3.65 percent in 1992, as the five-year moving average of GDP per capita rose from $208 to $358. The investment ratio then fell by more than half to 1.52 percent by 2003, as GDP per capita more than doubled to $860. In the future, the ratio of power investment to GDP is projected to rise slightly to 1.67 percent by 2010 and then decline gradually 1.23 percent by 2020, as GDP per capita increases steadily to $1,358 in 2010 and $2,484 in 2020.

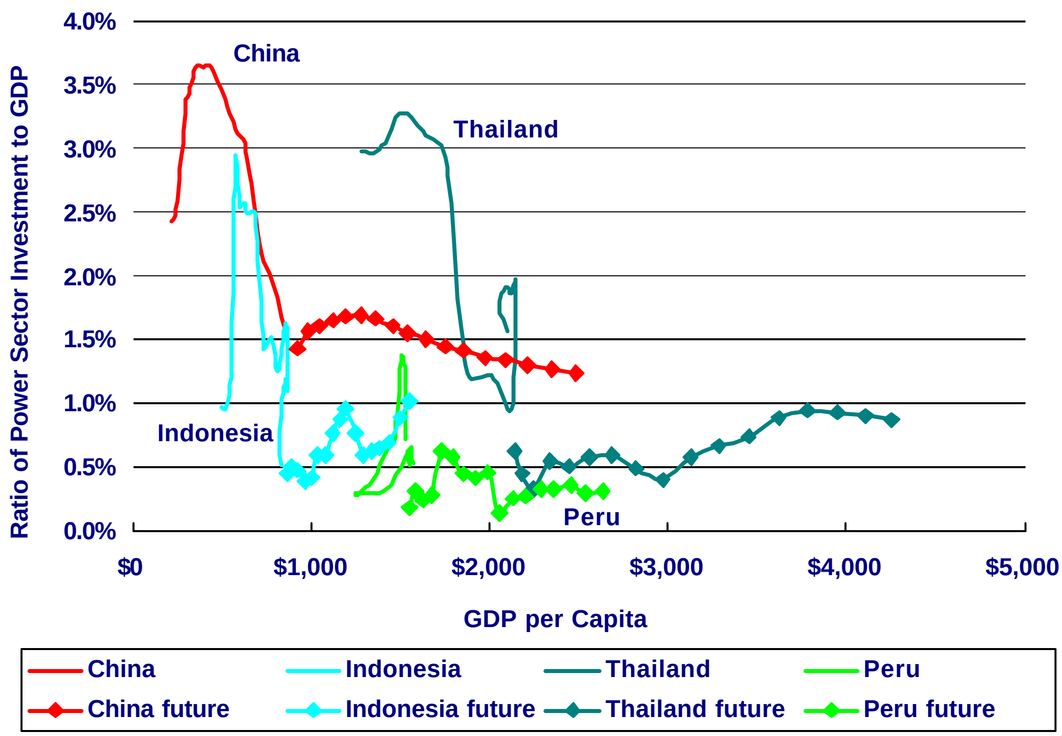
14. In Indonesia, the five-year moving average ratio of power investment to GDP surged from 0.97 percent in 1985 to a peak of 2.90 percent in 1989, as the five-year lagging average of GDP per capita rose from $492 to $566. After a few years of gradual decline, the investment ratio then fell sharply to 1.44 percent in 1994 and 0.52 percent in 2003, as GDP per capita rose to $724 and $836. Looking forward, the ratio of power investment to GDP is projected to subside to 0.39 percent by 2007, before beginning a gradual rise to 0.58 percent in 2010 and 1.01 percent in 2020 as GDP per capita grows to $1,074 in 2010 and $1,550 in 2020.

15. In Thailand, after peaking at 3.13 percent in 1993, when the five-year moving average of GDP per capita was $1,624, the five-year moving average ratio of power investment to GDP fell sharply, bottoming out at 0.93 percent during the financial crisis of 1997. The ratio of power investment to GDP then recovered, standing at 1.56 percent in the five-year period ending 2003, during which GDP per capita stood at $2,092. In coming years, the power investment ratio is likely to

fall sharply before staging a modest recovery. APERC projections indicate a power investment ratio of 0.59 percent for the five years ending in 2010 and 0.87 percent for the five years ending in 2020, with GDP per capita rising to $2,688 and $4,256.

16. In Peru, the ratio of power investment to GDP rose from 0.52 percent in the five years ending in 1985 to 0.65 percent in the five years ending in 1988, fell gradually to 0.27 percent by the five years ending in 1994, rose strongly to 1.37 percent for the five years ending in 1999 and then declined again to 0.72 percent in the five years ending in 2003. Meanwhile, GDP per capita fell from $1,564 in the five years ending 1985 to $1,252 in the five years ending 1994 and recovered to $1,530 in the five years ending 2003. The five-year moving average of power investment to GDP is projected to be 0.44 percent in 2010 and 0.31 percent in 2020, as the moving average of GDP per capita increases to $1,854 in 2010 and $2,632 in 2020.

Figure 23 Historical and Projected Burden of Electric Power Sector Investment as a Function of GDP Per Capita in Lower-Income APEC Economies, 1981-2020

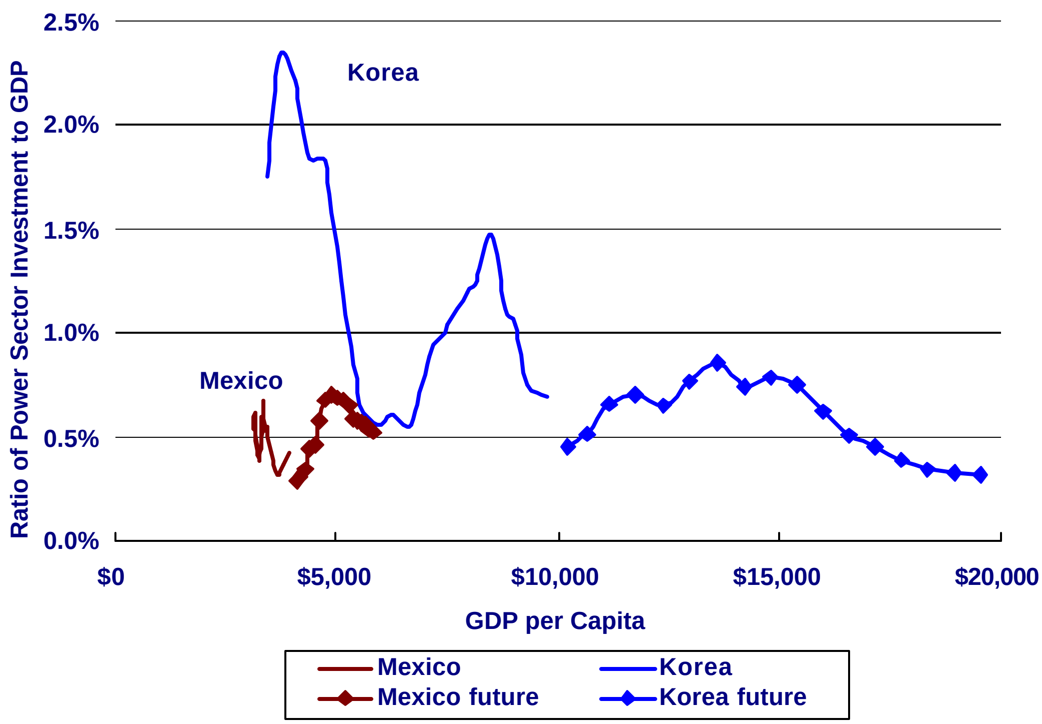


For middle-income APEC economies, the historical and anticipated burden of power sector investment as a function of GDP is detailed in Figure 24.

17. In Korea, the five-year moving average ratio of power investment to GDP rose from 1.75 percent in 1985 to 2.21 percent in 1987, fell sharply to 0.56 percent in 1992, recovered to 1.47 percent by 1999 and fell again to 0.70 percent by 2003. Meanwhile, the five-year moving average of GDP per capita rose steadily from $3,468 in 1985 to $4,040 in 1987, $5,912 in 1992, $8,486 in 1999 and $9,776 in 2003. The power investment ratio seems poised to fall further before recovering to 0.86 percent for the five years ending in 2010 and then declining slowly to 0.32 percent for the five years ending in 2020. GDP per capita should keep growing to around $13,604 for the five years to 2010 and $19,536 for the five years to 2020.

18. In Mexico, the ratio of power sector investment to GDP has been steadier than in most other economies, standing at 0.59 percent for the five years ending in 1985 when GDP per capita averaged $3,314, peaking at 0.68 percent for the five years ending in 1996 when GDP per capita averaged $3,326, and declining to 0.42 percent for the five years ending in 2003, when GDP per capita averaged $3,928. A steady course seems likely to persist, with a five-year moving average of power investment to GDP projected at 0.68 percent in 2010 and 0.53 percent in 2020 as the moving average of GDP per capita grows to $4,756 in 2010 and $5,822 in 2020.

Figure 24 Historical and Projected Burden of Electric Power Sector Investment as a Function of GDP Per Capita in Middle-Income APEC Economies, 1981-2020

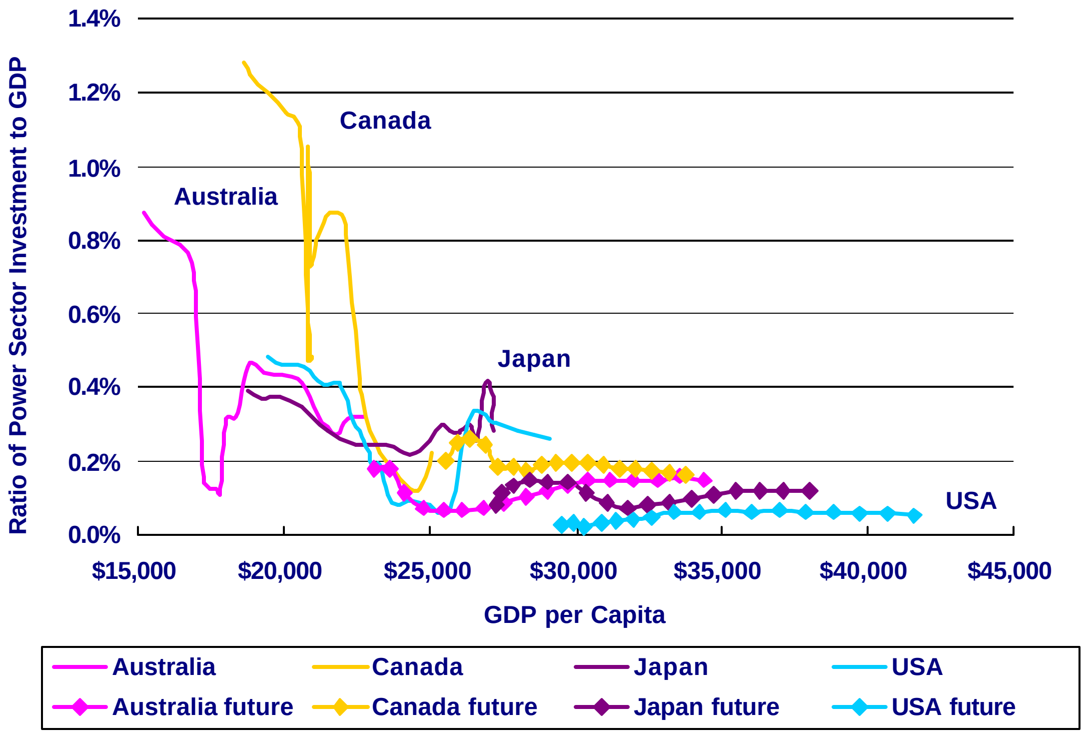


A closer look at past and future burden of power sector investment in higher-income APEC economies is offered in Figure 25. In all of these highly developed economies, the projected share of power sector investment in overall economic output is extremely modest.

19. In Australia, the five-year moving average ratio of power investment to GDP fell from 0.87 percent in 1985 to a low of 0.11 percent in 1993, increased again to 0.47 percent by 1996, and stood at 0.32 percent in 2003. Meanwhile, the five-year moving average of GDP per capita rose from $15,170 in 1985 to $17,800 in 1993 to $18,786 in 1996 to $22,678 in 2003. Looking forward, the power investment ratio is projected to be just 0.07 percent in the five years to 2010, when GDP per capita is projected to grow to roughly $26,834, and just 0.15 percent in the five years to 2020, when GDP per capita is projected to grow to around $34,416.

20. In Canada, the five-year moving average ratio of power investment to GDP fell from 1.28 percent in 1985 to 0.47 percent in 1993, and then moved higher for several years before subsiding to stand at 0.22 percent in 2003, as the five-year moving average of GDP per capita rose from $18,588 to $20,790 to $25,092. Looking ahead, the power investment ratio is projected to be just 0.17 percent in the five years to 2010, with GDP per capita on the order of $28,326, and just 0.16 percent in the five years to 2020, with GDP per capita of approximately $33,782.

Figure 25 Historical and Projected Burden of Electric Power Sector Investment as a Function of GDP Per Capita in Higher-Income APEC Economies, 1981-2020



21. In Japan, the ratio of power investment to GDP fell from 0.39 percent during the five-year period ending in 1985 to a low of 0.21 percent during the five years ending in 1992 and stood at 0.28 percent for the five years ending in 2003. Meanwhile, GDP per capita rose from $18,752 in the five years through 1985 to $24,320 in the five years through 1992 to $27,182 in the five years through 2003. Looking forward, the power investment ratio is projected to be just 0.11 percent over the five years ending in 2010, with GDP per capita of $30,362, and just 0.12 percent over the five years through 2020, with GDP per capita of $37,982.

22. In the United States, the ratio of power investment to GDP fell from 0.48 percent in the five years through 1985 to a low of 0.07 percent in the five years through 1998 before recovering modestly to 0.26 percent in the five years through 2003. Meanwhile, the five-year moving average of GDP per capita rose from $19,455 in 1985 to $25,680 in 1998 and $29,068 in 2003. Looking ahead, the power sector investment ratio is projected to be just 0.05 percent over the five-year period through 2010, with GDP per capita of about $32,608, and still just 0.05 percent over the five-year period through 2020, with GDP per capita of some $41,620.

CONCLUDING OBSERVATIONS

The foregoing analysis indicates that while future energy sector investment requirements for APEC economies will be very large in absolute terms, they should not be large relative to historical energy sector investment requirements or relative to projected economic output. For the APEC region as a whole, energy investment over the next two decades should take up less than one percent of total production. With respect to electric power generation, which accounts for nearly one-third of investment needs, there is a clear trend for the economic burden of investment to decline over time as economies grow, and this trend is projected to continue for most economies in the region. A number of lower-income economies, including Chile, China and Mexico, will need to invest more than twice as much in new electric generating capacity during the first two decades of the century as during the previous two decades, but their economies will grow substantially as well.

Yet the burden of energy sector investment will generally be greater for less developed economies than for more developed ones. Nine APEC economies are projected to have energy investment burdens greater than two percent of gross domestic product. Several of these have substantial undeveloped energy resources that might be of value for financing energy investment. These include Brunei Darussalam, Indonesia, Malaysia, Russia, Papua New Guinea and perhaps Viet Nam. But others, like Chile, China and Thailand, do not have abundant undeveloped energy resources and would generally have to obtain financing without energy as collateral. And for all economies in the region, future energy investment needs remain very large in absolute terms, so governments and energy firms will need to maintain or establish conditions to attract a mix of domestic and foreign investors to provide the necessary investment capital.

ENERGY INVESTMENT REQUIREMENTS BY INFRASTRUCTURE TYPE

INTRODUCTION

This chapter details the investment requirements for different types of energy infrastructure in APEC economies from 2000 through 2020. Types of energy infrastructure discussed include coal production and transportation, oil and gas production and processing, oil and gas transportation, electricity generation and electricity transmission. Major considerations for the estimation of investment requirements are explained in each section. Notes on the methodology used and details of the types of installations considered in the calculations can be found in the Appendix.

INVESTMENTS IN COAL PRODUCTION AND TRANSPORTATION

According to APERC's *Energy Demand and Supply Outlook 2002*, coal is plentiful and cost-competitive, and will continue to fuel a large percentage share in power generation in APEC economies.[26] World coal consumption is projected to grow slowly and account for a shrinking share of primary energy consumption. However, Asia is projected to account for a major share of the total increase in coal use worldwide, with China and India contributing three-quarters of incremental coal demand.[27]

TRENDS AFFECTING INVESTMENT IN THE COAL INDUSTRY

In Australia and the United States, two of the world's largest coal-producing economies, productivity gains in coal mining have been responsible for a major portion of increased production capacity, reducing the need for investment in new mines. This section summarises some key points made in a recent study by the Institute of Energy Economics, Japan (IEEJ), which analysed trends of production, productivity and investment in coal mines in Australia and the United States.[28]

In Australia's state of New South Wales, investment outlays in the coal industry did not seem to correlate with coal prices during the 10-year period from 1989 to 1999. The lack of correlation is especially noticeable between 1992 and 1994, when investment increased sharply as the price of coal was falling. However, the level of investment each year clearly followed net profits of the preceding year; investment decisions are generally made a year in advance on the basis of financial results. Exploration costs, on the other hand, are correlated not with coal prices or profits but with coal output. So as coal demand and production rise, the cost of expanding proven coal reserves increases as well, and investment is discouraged. In Queensland, Australia, though, data show a more conventional pattern in which coal sector investment is promoted when coal prices are high.

In the United States, over the 20 years between 1977 and 1997, real coal prices fell 53 percent, and exploration costs and mine development investments followed suit, declining 71 percent, but coal output increased by 56 percent. These data imply that a significant portion of the increases in output were achieved through gains in productivity. They also imply that investment in facility expansions or in new mines was in part discarded in favour of restarting idled capacity or mines that had been closed when competitiveness was lost due to low coal prices.

In Australia and the United States alike, growing productivity in coal mines should allow the price of coal to decline further. In the United States, for the 20-year period through 2020, EIA and

26 APERC (2002a).
27 EIA (2003c).
28 IEEJ (2002).

projects average annual increases of 2.9 percent for productivity and 0.9 percent for production[29], implying an average yearly decline in total production costs of 1.4 percent. In Australia, IEEJ projects that coal mine productivity will grow an average of 2.3 percent per annum for the 20-year period through 2018, while the International Energy Agency and US Energy Information Administration project that coal production will grow an average of 1.8 percent per annum between 1999 and 2015, again implying a substantial average annual decline in total production costs.[30]

These findings show that coal mine development investment, which is generally linked to coal prices, is also affected by corporate profits. Moreover, cost reductions by way of productivity improvements play an important role in ensuring those profits. Furthermore, the data clearly indicate that coal production rises as the level of investment decreases, indicating that productivity improvements contribute significantly to production capacity growth. This establishes the existence of a direct link between coal mine productivity and investment in coal mine development.

Since productivity improvements at existing coal mines will account for a significant portion of incremental coal output, investment in new coal mining facilities will continue to be limited, allowing investment policy to focus on the most promising projects. Further, if a large share of proposed coal mine projects are developed and come into production, coal price competition is likely to intensify. This could lead to a new cycle of productivity improvement and cost reductions. In any event, it appears that coal industry investment will continue to focus on improvement and expansion of existing facilities, rather than on development of greenfield projects.

Another influential factor is revealed in recent studies suggesting that the amount of new coal-fired generating capacity built in the United States over the next couple of decades will be perhaps double the amount that was estimated just a few years ago. In 2003, the *RDI Outlook for Power Research Service* projected the addition of nearly 22,000 MW of new coal-fired capacity in the United States by 2014. The study cites many factors for this, including the fact that as much as half of US generating capacity additions in 2002 and 2003 consisted of gas combustion turbines. Since gas turbines have relatively high operating costs and are thus intended mainly to serve peak loads, there remains a distinct need for new base-load plants, including coal-fired plants.

This need is likely to be reinforced by the apparent upward trend in North American gas prices over the last few years, which has led to higher expectations for gas prices than before. The study argues that the projected cost of natural gas of around US$4.50 per million Btu between 2009 and 2015 will make coal more competitive. In addition, the study notes plans to replace old base-load plants with coal-fired units in areas with low coal prices. A further short-term factor is a reduction in the cost of new contracts and new turbines due to project contract cancellations. Under such conditions, the study estimates that by 2009, coal-fired generating capacity will make up from 20 to 25 percent of total capacity additions in the United States.[31]

ESTIMATED INVESTMENT REQUIREMENTS IN THE COAL INDUSTRY

Coal infrastructure for the purposes of these calculations includes major mine installations, equipment and transportation facilities in the form of a shipping water dock or a railway shipping port. Other types of transportation infrastructure such as water barges, rail cars or road transport are not considered.

The estimated results show that coal production and transportation infrastructure for the 20-year period from 2000 to 2020 will amount to US$114 billion at 1999 prices. This sum represents a 3 percent share of total energy investment requirements in APEC economies over the period. China leads APEC economies in coal infrastructure requirements for the future, with an estimated requirement of 58 billion US dollars for the 20-year period, or half the APEC total.

A detail of the investment required by economy is shown in Table 5. Figures in the first three columns show annual investments in the years 2000, 2010 and 2020; and those in the last three columns show cumulative results for the periods described.

29 EIA (2001a), EIA (2000).
30 IEEJ (2002), IEA (2000), EIA (2001b).
31 Coal Age (2003).

Table 5 APEC Investment Requirements in Coal Production and Transportation Facilities, High Case (Billion 1999 US Dollars)

Economy	2000	2010	2020	Total 2000 - 2010	Total 2011 - 2020	Total 2000 - 2020
Australia	1.013	0.278	0.355	6.519	3.597	10.116
Brunei Darussalam	-	-	-	-	-	-
Canada	-	-	-	0.610	-	0.610
Chile	-	-	-	-	-	-
China	4.900	2.366	4.000	26.529	31.893	58.422
Hong Kong, China	-	-	-	-	-	-
Indonesia	0.219	0.409	0.544	3.410	4.873	8.282
Japan	0.044	-	-	0.044	-	0.044
Korea	-	-	-	-	-	-
Malaysia	-	-	-	-	-	-
Mexico	-	-	-	-	-	-
New Zealand	-	0.001	0.001	0.016	0.012	0.028
Papua New Guinea	-	-	-	-	-	-
Peru	-	-	-	-	-	-
Philippines	-	-	-	0.372	0.015	0.387
Russia	2.779	0.703	0.830	12.548	8.670	21.218
Singapore	-	-	-	-	-	-
Chinese Taipei	-	-	-	-	-	-
Thailand	0.028	0.054	-	0.302	0.054	0.356
United States	3.225	0.898	0.280	10.796	1.930	12.725
Viet Nam	0.137	0.098	0.089	0.969	0.857	1.826
Total	**12.340**	**4.810**	**6.100**	**62.110**	**51.900**	**114.010**

INVESTMENTS IN OIL AND GAS PRODUCTION AND PROCESSING

TRENDS AFFECTING UPSTREAM INVESTMENT IN THE OIL INDUSTRY

The APEC region includes five of the ten largest oil-producing economies in the world as well as five of the ten largest oil consumers. APEC economies produce 38 percent of the world's oil supply but account for 58 percent of world oil demand. The imbalance results in a present oil import dependency of 36 percent for the APEC region as a whole.

According to APERC's *Outlook 2002*, oil demand in APEC is projected to increase at an annual rate of 2.1 percent, for an overall increase of 54 percent between 1999 and 2020. APEC oil production, on the other hand, will increase by only 10 percent over the period, at an average annual growth rate of 0.5 percent. Hence, net oil import dependency for the APEC economies as a group is projected to rise to 54 percent by 2020. Russia and Canada are projected to increase their production the most, while China and the United States will likely see slight falls in production. In Russia and Canada, growth in demand will absorb most of the increased production. Annual oil demand is projected to reach 293 million tonnes (5.88 million barrels per day) in China and 347 Mt (6.96 mbd) in the United States by 2020. Together, China and the United States account for nearly three-fifths (59 percent) of the total projected rise in APEC oil demand.

Current and projected import/export balances for the APEC economies are shown in Table 7. The table indicates that net imports are projected to increase at an annual rate of 4.1 percent from around 727 million tonnes (14.6 million barrels per day) in 1999 to 1,668 Mt (33.7 mbd) in 2020. The APEC region currently imports around 9.7 mbd and is projected to import around 22.3 mbd in 2020. Six million barrels per day, or 48 percent of the 12.6 mbd total additional import demand, will be needed to meet the increased demand from China, assuming production levels there remain static as projected in the APERC *Outlook 2002*.

Table 6 Oil Production by Economy (Thousand Metric Tonnes)

Economy	1999	2000	2005	2010	2015	2020
Australia	25,093	33,683	28,778	30,313	31,327	32,374
Brunei Darussalam	9,712	9,953	10,790	10,862	11,019	11,204
Canada	123,376	125,283	185,400	206,500	208,800	193,600
Chile	412	392	303	234	181	140
China	159,896	165,656	162,272	157,137	151,958	151,886
Hong Kong, China	0	0	0	0	0	0
Indonesia	70,053	71,068	71,067	75,072	58,556	42,040
Japan	746	746	746	0	0	0
Korea	446	447	446	446	447	446
Malaysia	37,348	38,507	39,986	37,613	35,241	32,874
Mexico	167,250	163,404	174,385	183,646	183,552	181,879
New Zealand	2,279	1,979	1,651	2,159	2,185	1,937
Papua New Guinea	4,335	3,253	1,808	829	302	210
Peru	5,341	4,969	6,340	5,716	6,946	7,818
Philippines	41	47	2,465	1,230	1,125	1,124
Russia	304,921	312,141	328,696	356,038	367,183	377,713
Singapore	0	0	0	0	0	0
Chinese Taipei	44	44	44	44	0	0
Thailand	4,138	4,467	7,462	5,950	4,484	3,560
United States	365,986	366,842	365,348	346,830	353,336	360,343
Viet Nam	15,331	16,516	20,369	25,523	25,524	30,529
Total APEC	**1,296,748**	**1,319,397**	**1,408,356**	**1,446,142**	**1,442,166**	**1,429,677**

Source: APERC (2002a).

Table 7 Net Oil Imports (Exports) in APEC Economies (Thousand Metric Tonnes)

Economy	1999	2000	2005	2010	2015	2020
Australia	11,012	6,477	15,593	18,825	22,983	27,634
Brunei Darussalam	(9,284)	(9,400)	(10,144)	(10,095)	(10,095)	(10,095)
Canada	(33,049)	(34,991)	(90,271)	(101,844)	(95,587)	(72,776)
Chile	10,578	9,875	11,126	15,264	20,340	27,141
China	44,395	43,309	97,984	171,149	251,661	345,363
Hong Kong, China	11,241	12,186	15,249	17,773	20,740	23,876
Indonesia	(23,387)	(19,393)	(11,214)	(4,954)	25,097	57,983
Japan	265,692	264,259	266,186	277,084	284,250	288,359
Korea	99,467	96,950	108,660	128,482	145,396	162,599
Malaysia	(15,117)	(13,285)	(9,240)	(292)	9,314	19,255
Mexico	(74,103)	(64,454)	(74,427)	(77,206)	(78,021)	(77,514)
New Zealand	4,178	4,542	5,435	5,748	6,561	7,749
Papua New Guinea	(3,413)	(2,427)	(985)	50	663	852
Peru	1,063	2,617	1,499	1,690	1,903	2,505
Philippines	17,641	18,252	17,611	23,901	29,218	35,872
Russia	(177,606)	(184,687)	(189,622)	(194,615)	(187,262)	(179,956)
Singapore	21,218	21,560	23,245	25,656	27,213	27,842
Chinese Taipei	38,183	37,261	39,479	45,671	48,335	51,085
Thailand	29,721	29,432	29,853	40,754	55,085	69,557
United States	516,097	536,182	604,186	701,879	784,162	868,517
Viet Nam	(7,799)	(8,812)	(8,845)	(8,690)	(1,845)	1,709
Total APEC	**726,728**	**745,453**	**841,358**	**1,076,230**	**1,360,111**	**1,677,557**
Total APEC (mbd)	**14.6 mbd**	**15.0 mbd**	**16.9 mbd**	**21.6 mbd**	**27.3 mbd**	**33.7 mbd**

Source: APERC (2002a).

Currently, around 70 percent of Asian oil imports are sourced from the Middle East and 60 percent of Middle East exports are destined for Asia. This trade flow is expected to increase, especially as the Middle East's production costs are the lowest in the world and, on a purely economic basis, it is the 'natural' supplier to the Asian region.

TRENDS AFFECTING UPSTREAM INVESTMENT IN THE NATURAL GAS INDUSTRY

According to APERC's *Outlook 2002,* natural gas demand should grow faster than demand for any other type of energy but hydropower over the projection period in the APEC economies. It is forecast to grow at 2.6 percent per annum, from 1,135 Mtoe in 1999 to 1,951 Mtoe in 2020, with its share in total primary energy supply increasing from 20 to 22 percent. But growth in gas demand is expected to vary considerably, outpacing the APEC annual average of 2.6 percent in most of Asia and Latin America while lagging in North America and Russia. Over the period from 1999 through 2020, annual growth in gas demand is projected to average 8.3 percent in China, 6.3 percent in Latin America, 3.9 percent in Southeast Asia, and 3.3 percent in Northeast Asia, but only 2.6 percent in Oceania, 2.0 percent in Russia and 1.8 percent in North America.

Of course, future gas demand in each area depends not only on the projected rate of growth but also on the starting point. Russia, with one of the lowest rates of demand growth, will remain the APEC economy most dependent on natural gas in 2020, even though the gas share in Russia's total primary energy supply will fall to 45 percent in 2020 from 52 percent in 1999. In Oceania with an average rate of demand growth, the share of gas in total primary energy supply is projected to remain stable at around 20 percent. In Latin America, with rapid demand growth, the share of natural gas in total primary energy supply is projected to increase from 19 percent in 1999 to 37 percent in 2020. Yet in China, with the fastest growth in natural gas demand, the share of gas in energy supply will rise from a very modest base to just 7 percent in 2020.

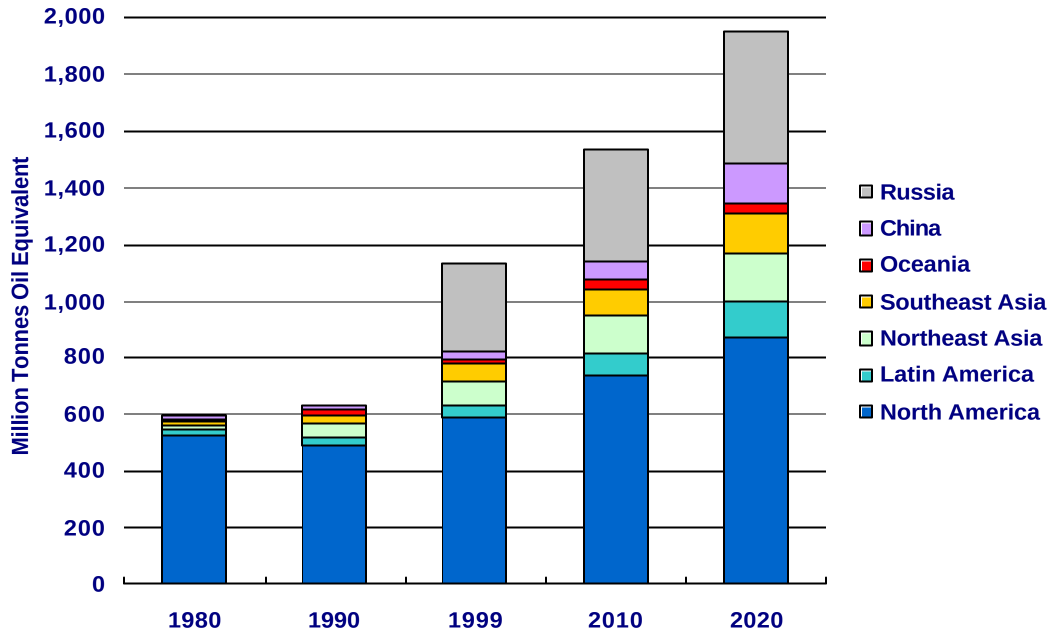
Figure 26 shows how historical and projected demand for natural gas is divided among different geographic regions. With North America's relatively slow growth, the continent's share of total APEC natural gas consumption is projected to fall from 52 percent in 1999 to 44 percent in 2020. Russia's share of APEC's natural gas use is meanwhile projected to fall from 27 percent to 24 percent. Yet despite the fact that Asia's growth in gas demand will be the fastest in APEC, its share of the region's gas use is projected to increase only from 13 percent in 1999 to 16 percent in 2020.

In terms of incremental gas demand in APEC economies through 2020, roughly a third will take place in North America, another third in Asia, and another third everywhere else. Asia's gas demand, while growing rapidly, is starting from a relatively modest base. North America's gas demand, while growing slowly, is starting from a very large base. Russia's gas demand is also growing slowly from a large base and is thus projected to account for about a fifth of incremental gas demand between 1999 and 2020. Hence, Russia combined with either Asia or North America would account for over half of projected growth in gas demand in the APEC region.

It is interesting to note that an overwhelming share of the projected increase in natural gas consumption through 2020 can be attributed to the use of gas to generate electricity. As shown in Figure 27, about 68 percent of the increase in natural gas consumption is projected to occur in the electric power sector. Another 19 percent is projected occur in the industrial sector, thus nearly seven-eighths of all incremental gas demand will be required for production of electricity. The remaining eighth of incremental gas demand is projected to occur in the residential and commercial sectors. Natural gas use for transport is projected to remain rather minimal, contributing a mere 0.6 percent to incremental gas demand, as oil products will continue to be the main fuel in this sector.

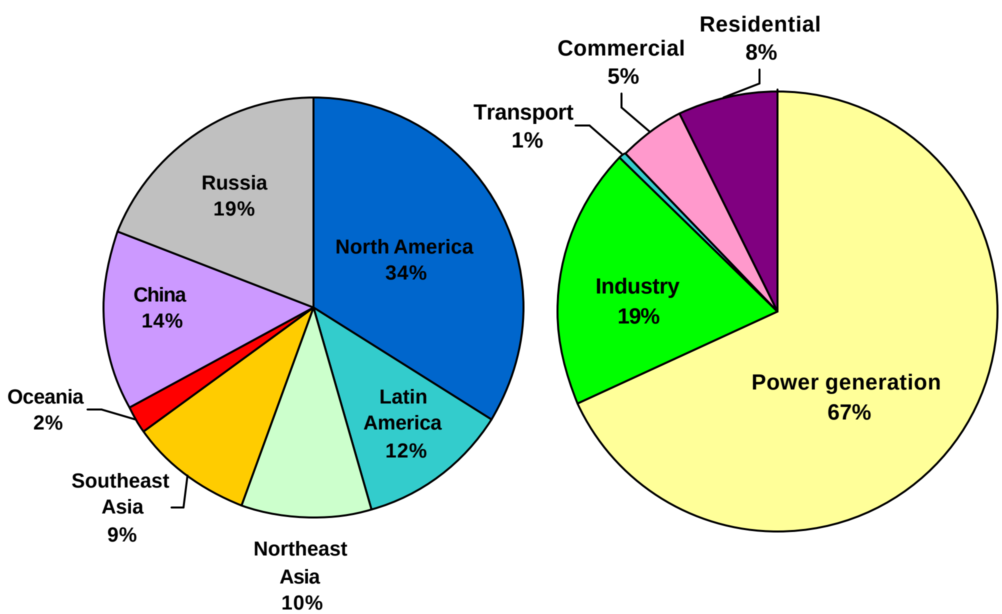
Natural gas consumption in APEC is projected to almost double within the next two decades, and the volume consumed in 2020 is forecast to be more than triple that for 1980. The distribution of natural gas reserves and differing reserve-to-production ratios across regions imply that there should be active international trades of natural gas either through pipelines or in liquefied form.

Figure 26 Natural Gas Demand in APEC (Million Tonnes Oil Equivalent)



Source: APERC (2002a), based upon data from International Energy Agency. IEA data are available for Viet Nam from 1986 onwards and for Russia from 1992 onwards; hence they are shown here from 1990 and 1999 onwards, respectively.

Figure 27 Regional and Sectoral Contributions to Incremental Gas Demand, 1999-2020



Source: APERC (2002a).

TRENDS INFLUENCING UPSTREAM OIL AND GAS INVESTMENT

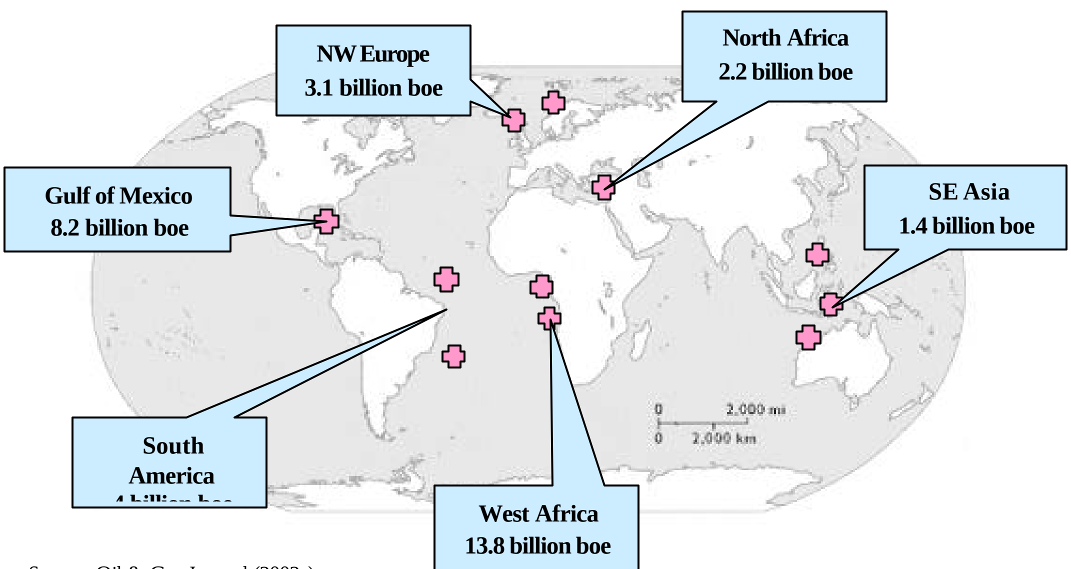
The apparent consensus among experts is that there will be a significant increase in investment in the oil and gas industries at least for the next 5 to 10 years. After worldwide uncertainty and economic difficulties observed especially in the last couple of years, growth has been seen to resume in certain sub-sectors of the energy industry and particularly in the oil and gas sectors.

Oil exploration and production (E&P) investments have been significant and have shown steady growth in recent years. Demand is and will continue to be strong not only in the APEC region but also in the rest of the world according to our own and other forecasts despite recent economic uncertainties. The increase in oil prices and the likelihood of these remaining high will support increased investment in the industry.

Of importance to capital expenditures in oil and gas exploration and production will be the impact from deepwater field developments. Deepwater developments can be expected to comprise a larger share of oil and gas E&P in the near future. Development of fields located at depths in excess of 500 metres are now commercially attractive with the increase in oil prices and the perception of a deteriorating base of existing resources elsewhere. Deepwater production with its higher investment costs could represent 7-9 percent of total global oil and gas production in 2010, after which it is expected to decline. At present, deepwater fields account for only 2 percent of production.[32] However the oil “majors”, which are the companies with the largest participation in deepwater operations, claim that because of these operations finding and development costs in the last decade have been on the rise.[33]

For the period 2003-2007, 148 new deepwater fields are expected to come onstream, more than twice the number during the previous 5 years. Of a total of 32.8 billion boe of deepwater reserves identified for future development, 8.2 billion boe reside in the Gulf of Mexico and 1.4 billion boe are in the Asia-Pacific region (not counting the Americas). Other regions with future deepwater developments include West Africa with 13.8 billion boe, Brazil with 4 billion boe, northwestern Europe with 3.1 billion boe and the Mediterranean with 2.2 billion boe. Capital expenditures forecast for these projects totals 57.9 US billion between 2003 and 2007.[34]

Figure 28 Recently Discovered Worldwide Deepwater Basins



Source: Oil & Gas Journal (2002a).

In 2002, worldwide refining capacity reached its highest level ever, reversing the previous two years’ downward trend. Worldwide capacity as of January 1, 2003 was 81.9 million barrels per calendar day (b/cd) according to the *Oil & Gas Journal*, showing an increase of 712,000 b/cd from the previous year.[35] According to the same survey, the largest increases in refining capacity occurred in North America and the Middle East. Mexico had the biggest increase of the three

32 Sandrea and Al Buraiki (2002).

33 Ibid.

34 Oil & Gas Journal (2003b).

35 Oil & Gas Journal (2003a).

North American economies with PEMEX increasing its capacity to 320,000 b/cd. South America was the third largest growing region while a slight capacity increase was observed in Asia Pacific (not including the Americas).

ESTIMATED INVESTMENT REQUIREMENTS IN UPSTREAM OIL AND GAS SECTORS

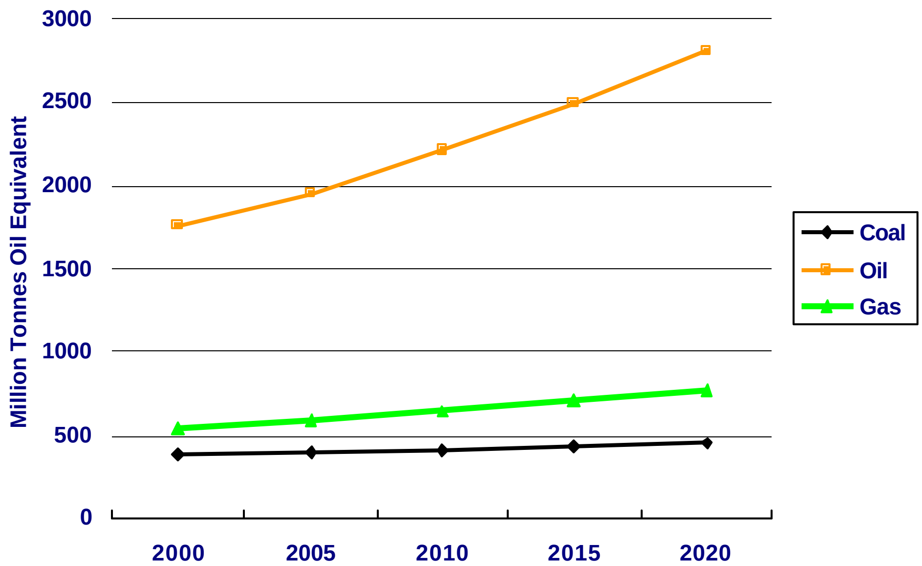
Table 8 shows the investment in energy infrastructure required in APEC economies for oil and gas exploration, production, processing and petrochemical installations. In the 20-year period from 2000 to 2020, US$1,008 billion will be needed in this sector. This sector is the second most important in energy infrastructure accounting for 23 percent of the total energy investments required in APEC. Annual investments in oil and gas upstream activities in APEC are projected to decline by around 36 percent from US$77 billion in the year 2000 to US$50 billion in 2020 despite increases in oil and gas demand in the region.

Table 8 APEC Investment Requirements in Oil and Gas Production, Processing and Petrochemical Installations, High Case (Billion 1999 US Dollars)

Economy	2000	2010	2020	Total 2000 - 2010	Total 2011 - 2020	Total 2000 – 2020
Australia	8.00	1.48	1.33	20.05	12.49	32.54
BD	0.27	0.03	0.04	1.48	0.35	1.82
Canada	14.25	8.57	5.55	87.52	57.75	145.27
Chile	1.03	0.51	0.66	7.72	5.84	13.56
China	9.79	6.10	7.96	58.56	68.51	127.08
Hong Kong, China	-	-	-	-	-	-
Indonesia	2.55	2.41	2.55	24.58	21.74	46.33
Japan	-	0.92	0.62	7.20	6.74	13.94
Korea	1.40	2.92	2.37	24.50	24.53	49.03
Malaysia	2.17	1.26	1.50	14.68	14.25	28.94
Mexico	3.11	2.04	2.38	42.93	21.43	64.36
New Zealand	0.10	0.07	0.08	0.70	0.81	1.51
PNG	0.00	-	-	1.07	0.01	1.08
Peru	0.18	0.31	0.27	3.71	3.83	7.54
Philippines	0.13	0.40	0.56	5.18	4.82	10.00
Russia	11.49	8.83	6.41	84.41	61.47	145.88
Singapore	2.06	0.96	1.15	10.86	11.18	22.03
Chinese Taipei	0.74	0.54	0.51	5.55	5.30	10.85
Thailand	0.76	1.76	2.33	15.19	21.77	36.96
United States	17.82	11.48	12.04	114.74	116.16	230.90
Viet Nam	1.13	1.10	1.23	10.81	7.61	18.42
Total	**76.98**	**51.70**	**49.56**	**541.42**	**466.60**	**1,008.03**

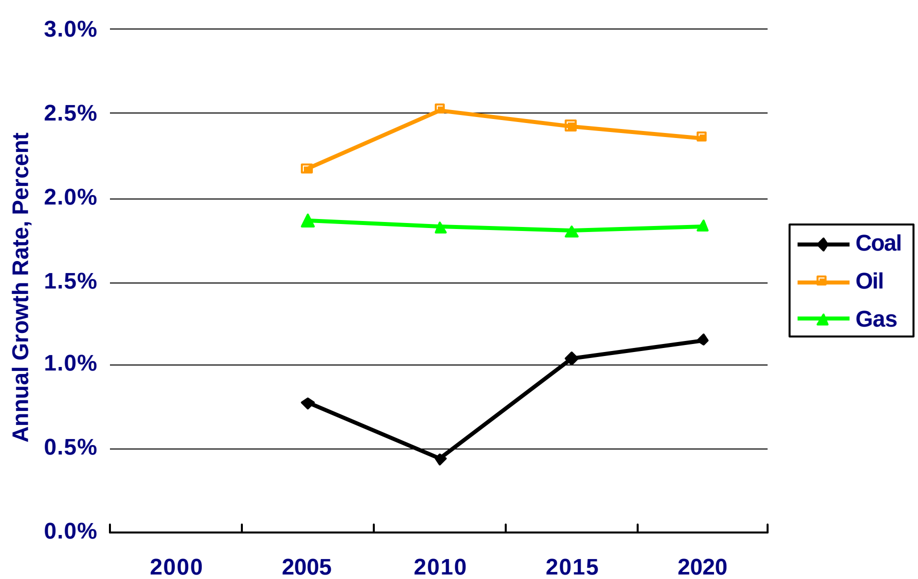
The reasons for this can be seen in Figure 29 and in Figure 30. Figure 29 shows APERC's *Outlook 2002* demand for the three main primary fuels between 2000 and 2020, and Figure 30 shows the demand growth rates for the same fuels. Even though demands are on the increase, they do so at a slower rate in the last half of the 20-year period covered in this analysis. A lower rate of demand growth translates into an annual decrease in the amount of additional infrastructure required and of the investments needed for it. Investments are a direct consequence of energy demand growth rate.

Figure 29 Coal, Oil and Gas Demand in APEC (Million Tonnes Oil Equivalent)



Source: APERC (2002a)

Figure 30 Coal, Oil and Gas Demand Annual Growth Rates in APEC (Percent)



Source: APERC (2002a)

INVESTMENTS IN OIL AND GAS TRANSPORTATIO N

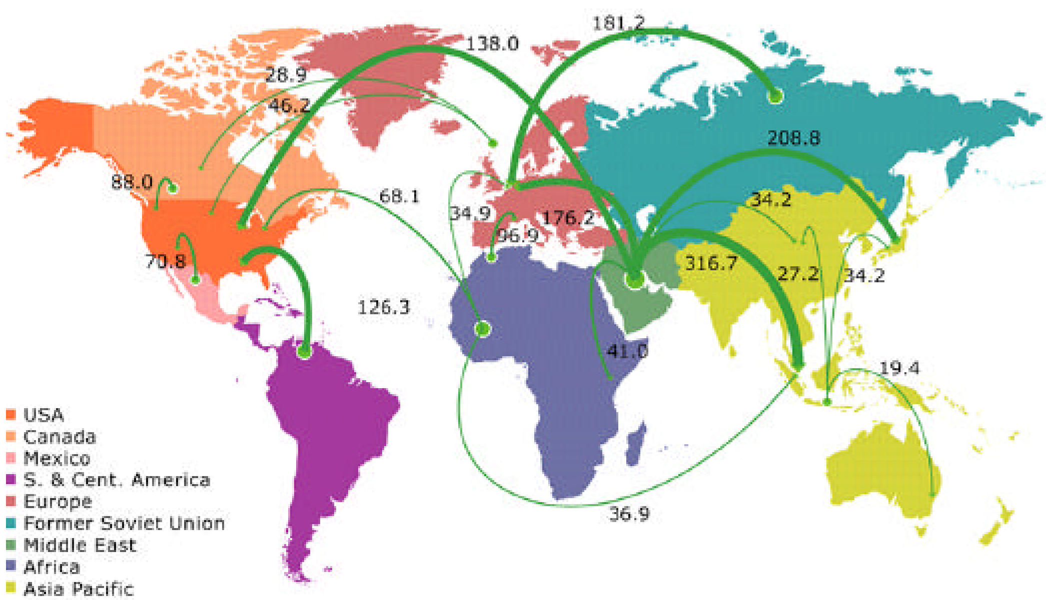
Infrastructure for oil and gas transportation has two major components. One component consists of facilities for international trade; the other includes systems of pipelines for moving oil and gas inside each economy. These two components are dealt with separately below.

INTERNATIONAL OIL AND GAS TRADE

International trade of oil and natural gas was considered to take place in one of two ways: either in tanker ships or through pipelines. Future infrastructure calculations are based on import and export projections in APERC's *Outlook 2002.* [36] In the case of natural gas, the tankers carry LNG, and the cost of associated onshore LNG facilities is included as part of this international trade category. The shares of natural gas traded internationally as pipeline gas and as LNG are assumed to be those published by BP.[37]

Figure 31 shows the major channels of oil trade around the world. In the APEC region, pipeline trade movements take place mainly between United States and Canada and between Russia and Europe through a number of states in the former Soviet Union. This trade is expected to grow with more investments being directed at Russian production and transportation infrastructure. An important volume of oil trade amounting to 400-600 thousand barrels per day is being considered for the near future also between Russia and China through a new 2,400 km pipeline (depending on the chosen route) going from the Siberian oil fields to Northeast China at a cost of US$2.5 billion.

Figure 31 Major Oil Trade Flows in the World (Million Tonnes)



Source: BP (2002).

The fraction of oil trade currently taking place by pipeline for Canada, China, Russia and the United States was determined using BP oil trade figures[38] and the estimated capacities of the existing import/export pipelines connecting these economies. Pipeline share for future trade was calculated based on the plans for future trade as announced by these economies.

36 APERC (2002a).

37 BP (2001).

38 BP (2001).

Most other oil trade was considered to take place by tanker. As shown in Table 9, the tankers available to APEC economies are estimated to have a capacity of 168.5 million deadweight tonnes. This includes tonnage registered under foreign flags, a common procedure among ship owners to facilitate legal and administrative operating procedures. Overall tanker capacity was estimated using UNCTAD's *Review of Maritime Transport 2002*.[39] Combining information on domestic tonnage (in the second column) with information on the fraction of the merchant fleet with foreign flags (in the third column), it is possible to infer the overall tonnage available (in the fourth column).

Table 9 Estimated Oil Tanker Fleets Owned in APEC Economies, Including Ships Registered under Foreign Flags, at the End of 2001

Economy	Domestic Oil Tanker Fleet in Thousand Deadweight Tonnes	Foreign Flag Ships as Fraction of Merchant Fleet	Total Tanker Tonnage in Thousand Deadweight Tonnes
Australia	408	45.24 %	745
Brunei Darussalam	0		-
Canada	550	73.64 %	2,087
Chile	167		167
China	3,815	48.30 %	7,379
Hong Kong, China	2,784	48.91 %	5,449
Indonesia	1,325	26.42 %	1,801
Japan	6,088	86.14 %	43,925
Korea, Republic of	1,588	49.79 %	3,163
Malaysia	1,527	22.83 %	1,979
Mexico	745		745
New Zealand	91		91
Papua New Guinea	3		3
Peru	53		53
Philippines	202	13.63 %	234
Russian Federation	2,062	46.06 %	3,823
Singapore	15,533	34.14 %	23,585
Chinese Taipei	1,480	49.13 %	2,910
Thailand	419		419
United States	16,857	75.81 %	69,686
Viet Nam	257		257
Total			**168,499**

Source: APERC, UNCTAD (2002), CPC (2002).

Figure 32 shows the principal patterns of natural gas trade in the APEC region. Pipeline movements of natural gas in APEC are concentrated in the commerce between Canada, the United States and Mexico in North America; and between Russia, the Former Soviet Union Republics and Europe. LNG trade in APEC takes place between South America and the United States, and between Northeast Asia and its four main sources: Middle East, Malaysia, Indonesia and Australia. Table 10 below shows some of the new expansion projects announced for the APEC region, all of which have been included in the infrastructure investment calculations.

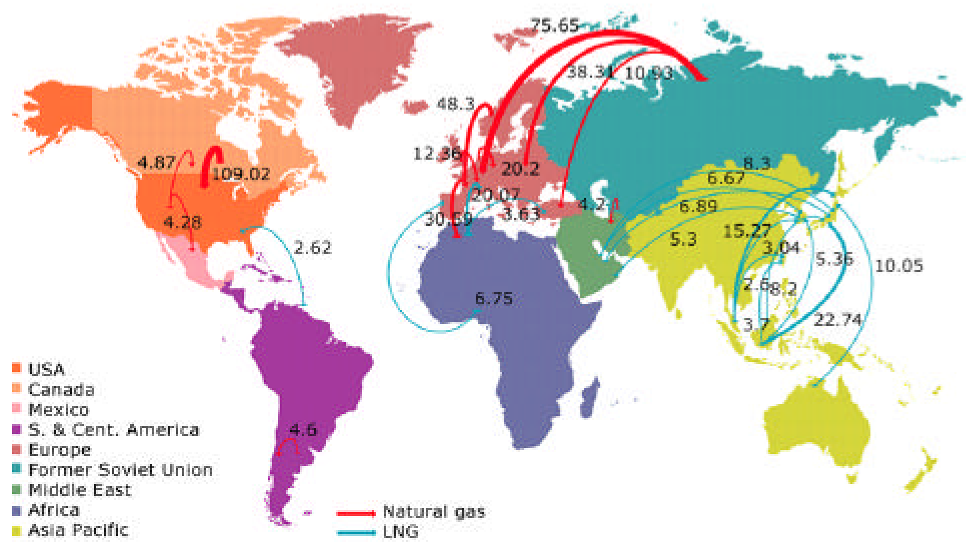
Total exports of natural gas via pipelines in 2000 were estimated at around 390 billion cubic meters, while those as LNG were 137 billion cubic meters.[40] The APEC region includes some of the world's largest natural gas exporters and importers: Russia, Canada, Indonesia and Malaysia are among the largest gas exporters while the United States, Japan and Korea figure among the largest natural gas importers. Total imports into APEC economies amounted to 41 percent of worldwide natural gas trade in 2000 while exports from APEC economies accounted for 60 percent. Liquefied natural gas (LNG) imports in APEC represented 76 percent of the total LNG exported worldwide.

[39] UNCTAD (2002).

[40] CEDIGAZ quoted in BP Statistical Review of World Energy 2001, p. 28.

LNG is a relatively young and expanding form of business and together with deepwater oil field development, they are the fastest growing energy sub-sectors today. LNG growth is being pushed by an average increase of around 2.8 percent per annum in worldwide demand for natural gas between 2001 and 2025 as projected by the US Energy Information Administration.[41] Many new economies are joining the ranks of participants every year. Close to 20 new projects have been proposed and expansions have been announced at almost every major LNG existing installation. In Asia, however, although there will be growth, it will be slower than in the past for the traditional Asian markets Japan, Korea and Chinese Taipei. According to the *Oil & Gas Journal*, exports of LNG have grown 6.4 percent per year since the mid-1980s, compared to a 1.6 percent increase in marketed world gas production and a 3.3 percent rise in pipeline trade.[42]

Figure 32 Major Gas Trade Flows in the World (Billion cubic metres)



Source: BP (2002).

Table 10 Proposed LNG Expansions in the Asia Pacific Region (New Projects)

Economy	Annual Capacity
Indonesia	
Bontang Train 1	3.0 Mt
Tangguh	7.0 Mt
Donggi	7.0 Mt
Australia	
Northwest Shelf 4	4.2 Mt
Northwest Shelf 5	4.2 Mt
Gorgon	5.0 Mt
Bayu-Undan	3.5 Mt
Sunrise	5.3 Mt
Malaysia	
LNG Tiga	6.8 Mt
Russia	
Sakhalin 2	9.6 Mt
Total	**55.6 Mt**

Source: Oil & Gas Journal (2003c)

41 EIA (2003c).

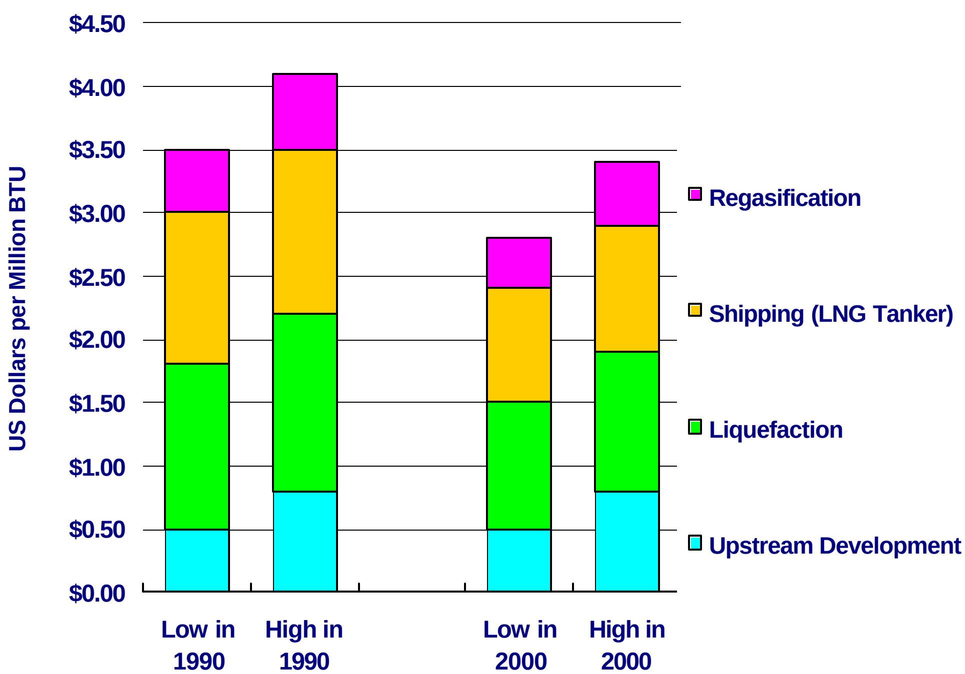
42 Sen (2002).

TRENDS INFLUENCING INVESTMENT IN NATURAL GAS TRADE

Natural gas in the Asia-Pacific region is facing increased competition and therefore needs to seek for new markets. Growing reserves in economies such as Australia, Indonesia, Malaysia and Russia force the search for new long-term export markets. However, the APEC region faces even greater competition from the Middle East, specifically Qatar and Iran. Middle East projects dwarf projects currently being proposed in Asia.

For Asian producers to secure markets in the region, LNG will have to ensure low cost production. Trends in the cost of LNG facilities have shown important decreases in the last 30 years. In the past decade LNG production and transportation costs have declined by 35 to 50 percent. The most important reasons for this are economies of scale, as the average train size has grown from 1 million tonnes per year (tpy) in the 1960s to 3 million tpy in 2000, to between 4.0 million and 4.8 million tpy in 2003. All the while, the number of trains per project has declined.[43] Competition for construction contracts is another factor that has reduced plant costs and is likely to influence unit costs in the near future. Technical factors that are contributing to cost reductions are: enhanced engineering execution techniques, use of more efficient gas turbines instead of steam turbines, use of more efficient axial compressors, improved equipment configurations, larger and fewer storage tanks, and in some cases, integration of LNG terminals with power plants.

Figure 33 Cost Reductions in LNG Infrastructure (US Dollars per Million Btu)



Source: Valais, Chabrelie and Lefeuvre (2001).

Transportation infrastructure is also experiencing a downward trend in costs mainly caused by increased competition among existing and new shipyards and increased construction. LNG tankers, once mostly owned by gas sellers, are nowadays being ordered by importers in order to have more control and flexibility over operations, maximising their regasification plants' capacities, and allowing cargo swaps and placement of cargoes in the highest value markets. The average cost of an LNG tanker in 1990 was 260 million US dollars and is now around 170 million. Again, economies of scale are in play as can be seen by average ship capacity growing from 125,000 cubic metres in 1990 to 138,000 cubic metres in 2001. Even larger ships are under consideration today.[44]

43 Sen (2003).

44 Khawam (2002).

A new trend in LNG production that will also influence the costs of production and transportation in the future are floating LNG facilities. This type of facility has been in use since the 1970s for offshore oil production, and a number of companies are looking into the possibility of adapting the technology to incorporate LNG liquefaction. Gas floating production, storage and off-take (GFPSO) vessels would be barges moored in the vicinity of a gas field incorporating facilities for gas processing, liquefaction and storage. Direct off-loading onto LNG tankers would then be possible for transport to market, eliminating the need for port facilities or the construction of pipelines to shore.

The concept will allow savings in project costs as infrastructure is minimised to essentials. High construction costs in harsh production areas can be avoided as the units can be constructed in a shipyard and towed to the location. A floating LNG unit can be used during the life of a field for 20 years or so and then be transferred to a new site without the need for the construction of a new facility. Shell is planning to construct the world's first floating facility. Shell claims using the technology in the Timor Sea will reduce costs by 40 percent compared to an onshore project, the savings coming mostly from the elimination of the pipelines to shore.[45]

ESTIMATED INVESTMENT REQUIREMENTS IN INTERNATIONAL OIL AND GAS TRADE

Table 11 displays the investment needs for oil and gas trade in APEC, which total 384 billion US dollars for the 20-year period. Economies with large trade volumes are the United States that will require investments in the order of 68.6 billion, Canada with 55.8 billion, Russia with 53.2 billion, Mexico with 44.6 billion and China requiring investments of 38.6 billion US dollars.

Table 11 APEC Investment Requirements in Oil and Gas International Trade, High Case (Billion 1999 US Dollars)

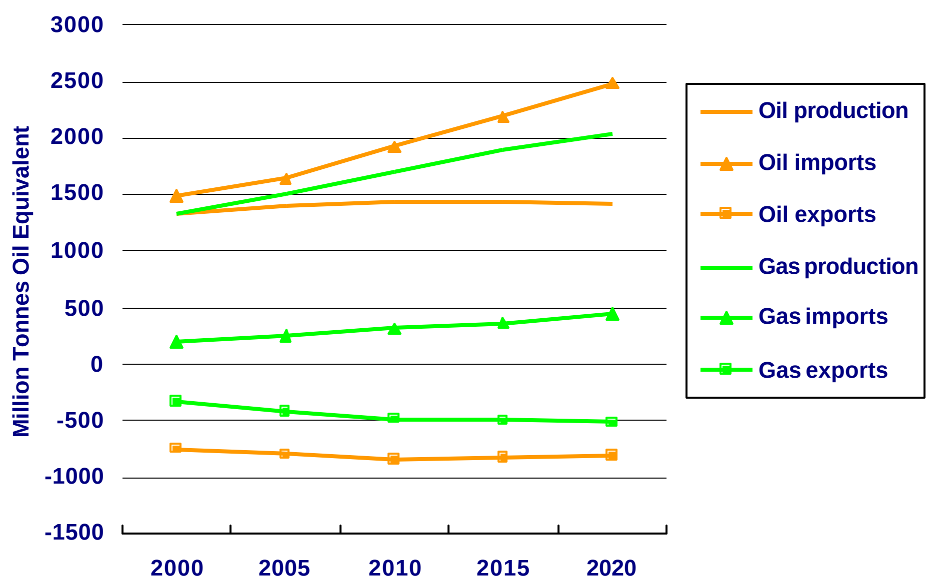
Economy	2000	2010	2020	Total 2000 – 2010	Total 2011 – 2020	Total 2000 - 2020
Australia	0.16	0.73	0.35	3.92	2.97	6.89
Brunei Darussalam	-	-	-	1.58	-	1.58
Canada	3.99	1.99	-	46.90	8.90	55.80
Chile	0.82	0.43	0.84	9.26	6.76	16.02
China	0.08	1.97	2.96	15.10	23.54	38.63
Hong Kong, China	0.14	0.07	0.08	0.86	0.79	1.65
Indonesia	0.26	0.35	0.56	8.69	4.17	12.86
Japan	0.14	0.76	0.18	7.02	2.33	9.35
Korea	0.49	2.24	0.28	12.59	4.22	16.82
Malaysia	0.58	0.23	0.23	13.06	2.33	15.39
Mexico	1.82	3.26	1.91	25.53	19.05	44.58
New Zealand	0.00	-	-	0.01	0.01	0.02
Papua New Guinea	0.60	-	-	5.10	-	5.10
Peru	0.01	-	0.40	2.92	3.20	6.12
Philippines	0.00	0.01	0.16	0.08	2.53	2.61
Russia	12.83	1.85	0.31	50.13	3.10	53.23
Singapore	1.09	0.83	0.57	10.06	4.56	14.62
Chinese Taipei	0.10	0.17	-	2.53	1.25	3.78
Thailand	1.74	0.02	0.24	6.89	1.77	8.66
United States	7.67	3.72	3.24	37.51	31.06	68.57
Viet Nam	0.44	-	0.02	1.34	0.11	1.45
Total	**32.95**	**18.63**	**12.33**	**261.11**	**122.65**	**383.75**

Similar to the case of oil and gas production and processing, oil and gas international trade annual investments experience a downturn between 2000 and 2020, even though trade volumes increase during the period. In the case of international trade investments, the decrease amounts to

45 Poten & Partners (2002).

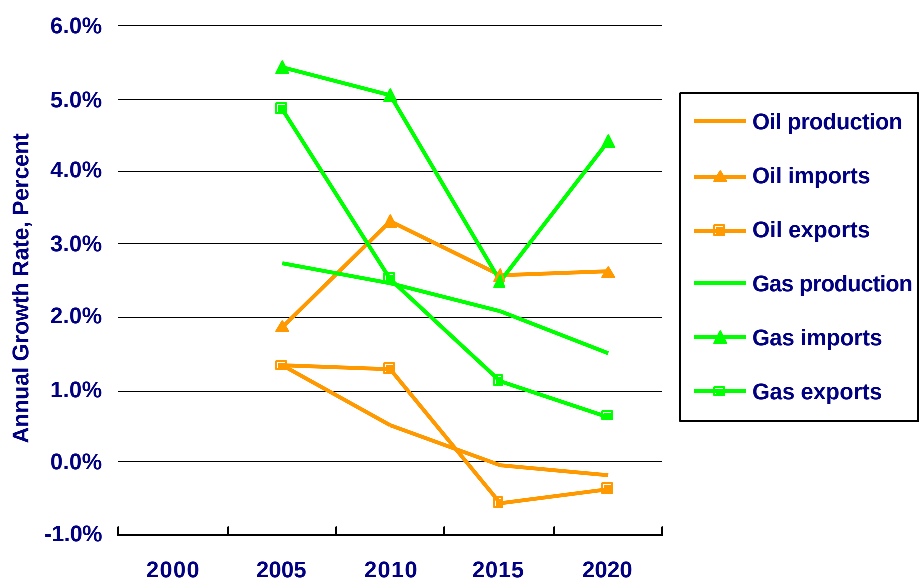
62.6 percent. The explanation again can be found by analysing the projected trade volumes and trade volume growth rates in APEC economies. Figure 34 and Figure 35 show that even though trade volumes increase in the period, import and export growth rates are expected to decrease in the APEC region in the next 20 years.

Figure 34 Oil and Gas Production and Trade in APEC (Million Tonnes Oil Equivalent)



Source: APERC (2002a).

Figure 35 Oil and Gas Production and Trade Annual Growth Rates in APEC (Percent)



Source: APERC (2002a).

ESTIMATED INVESTMENT REQUIREMENTS FOR DOMESTIC OIL AND GAS PIPELINES

Total projected investment requirements for domestic oil and gas transportation pipelines in APEC economies are shown in Table 12. The United States and Russia stand out in this category with projected needs of US$282 billion and US$199 billion respectively.

Table 12 APEC Investment Requirements in Oil and Gas Domestic Pipelines, High Case (Billion 1999 US Dollars)

Economy	2000	2010	2020	Total 2000 - 2010	Total 2011 – 2020	Total 2000 - 2020
Australia	1.05	0.90	1.04	9.62	9.82	19.44
Brunei Darussalam	0.02	0.02	0.04	0.21	0.32	0.53
Canada	2.77	1.27	1.37	14.52	13.07	27.59
Chile	0.06	0.77	0.46	5.99	5.17	11.16
China	2.67	3.43	5.65	29.96	46.19	76.15
Hong Kong, China	0.05	0.09	0.13	0.63	1.13	1.76
Indonesia	0.14	0.14	0.20	1.27	1.73	3.01
Japan	0.09	0.09	0.07	0.78	0.67	1.45
Korea	0.33	0.39	0.35	3.98	3.43	7.41
Malaysia	0.10	0.19	0.26	1.44	2.35	3.80
Mexico	2.59	1.56	1.88	19.27	16.76	36.03
New Zealand	0.02	0.01	0.01	0.09	0.06	0.15
Papua New Guinea	-	-	-	-	-	-
Peru	0.08	0.30	0.08	2.65	2.24	4.89
Philippines	0.01	0.06	0.09	0.34	0.79	1.13
Russia	13.50	9.26	9.63	99.71	99.57	199.28
Singapore	-	-	-	1.59	-	1.59
Chinese Taipei	0.04	0.05	0.07	0.42	0.60	1.02
Thailand	0.21	0.36	0.54	3.02	4.62	7.64
United States	27.29	14.61	13.49	152.59	129.49	282.08
Viet Nam	-	0.06	0.05	0.85	0.63	1.48
Total	**51.02**	**33.57**	**35.42**	**348.93**	**338.64**	**687.58**

Transportation pipelines represent an important part of capital requirements, and therefore a major component to be included in this investment outlook, even with the difficulties present in attempting an assessment of existing infrastructure and future plans for expansion. Domestic transportation for these computations consisted only of pipeline infrastructure for oil, oil products and natural gas; other forms of fuel transportation such as railroad and road tanker trucks were not considered due to the non-availability of detailed information.

INVESTMENTS IN THE ELECTRIC POWER SECTOR

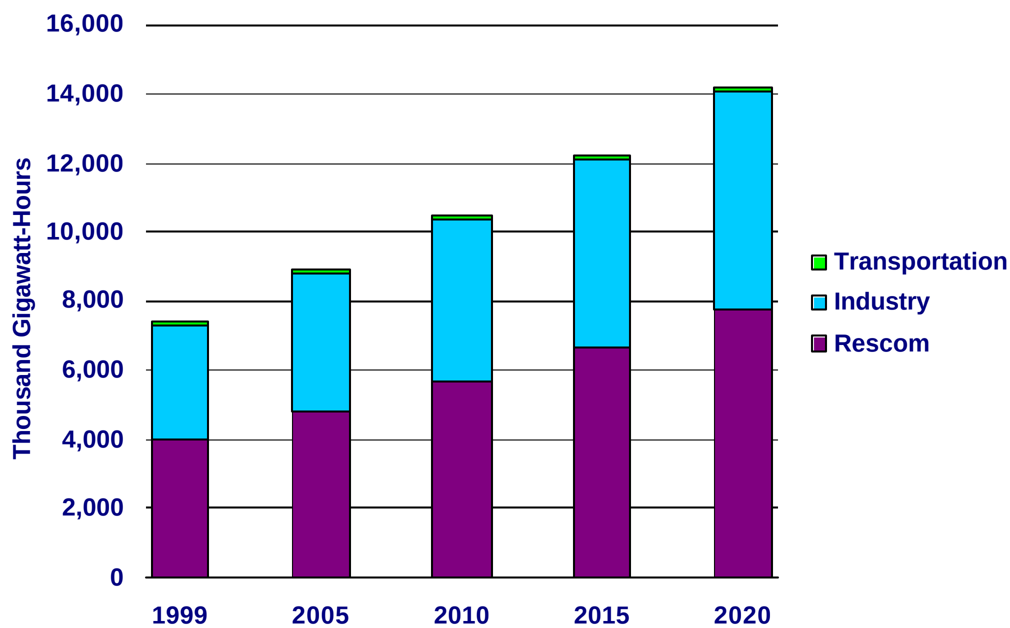
Final demand for electricity will continue growing faster than demand for any other form of energy in the APEC region for the next 20 years, according to APERC's *Outlook 2002*. Electricity demand will grow at an average annual rate of 3.2 percent while total final energy consumption will grow 2.2 percent annually. The share of electricity demand in final energy demand will increase from 17 percent in 1999 to 21 percent in 2020 in the APEC economies.[46]

Figure 36 shows how projected electricity demand is divided between the residential and commercial sectors, industry and transportation. With improvements in lifestyle and prosperity in the APEC region as a whole, the residential and commercial sectors will consume more than half of all electricity generated. Their combined demand is projected to grow at an average rate of 3.2 percent per annum, from 3.982 million GWh in 1999 to 7.741 million GWh by 2020. Residential/commercial's share of total electricity demand will be 55 percent in 2020 compared to

46 APERC (2002a).

44 percent for industry. The industrial sector will grow at a slightly slower rate of 3.1 percent annually while the transport sector will grow at a rate of only 2.1 percent, maintaining a marginal share of just 1 percent in the demand for electricity in the APEC region.

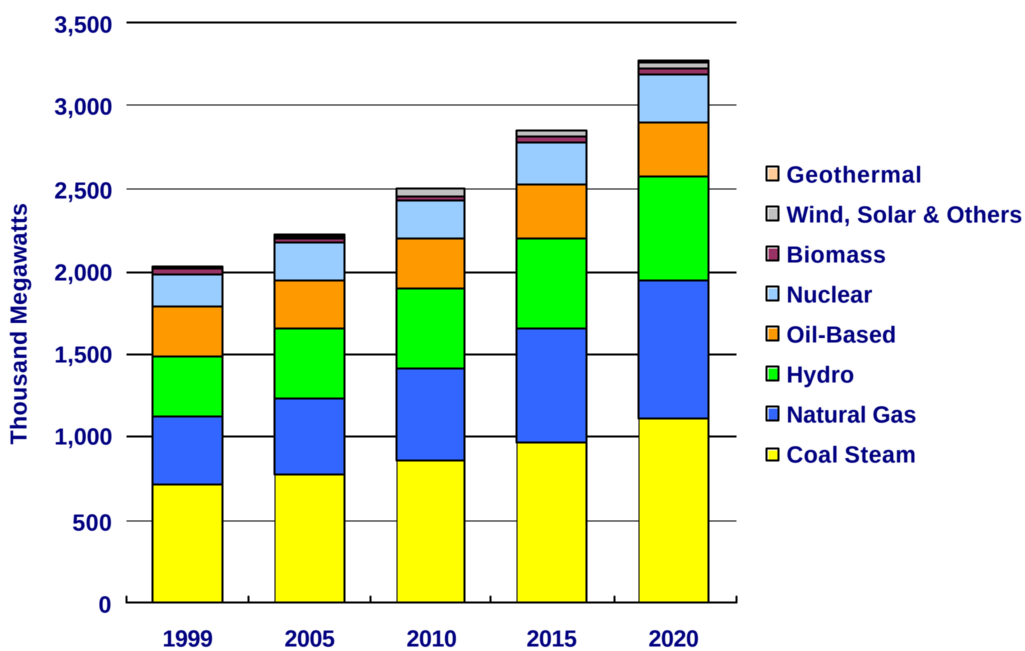
Figure 36 APEC Sectoral Electricity Demand (Thousand Gigawatt-Hours)



Source: APERC (2002a).

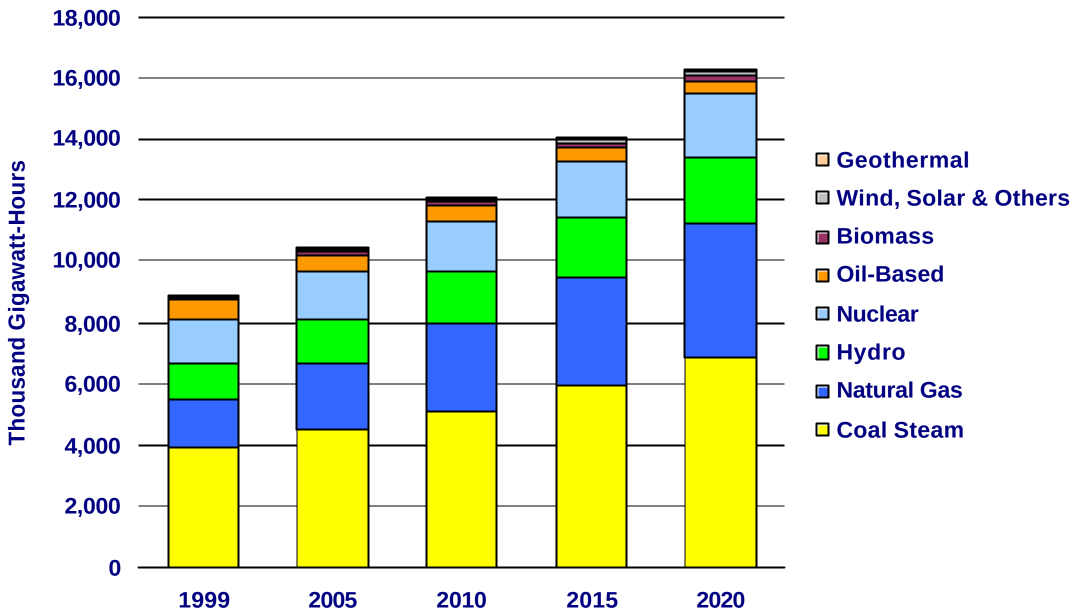
According to APERC's *Outlook 2002*, total installed electricity generating capacity will increase by 1,250 GW between 2000 and 2020. The evolving shares of different fuels in electric generating capacity and electricity generated are shown in Figure 37 and Figure 38 respectively.

Figure 37 APEC Installed Generating Capacity, 1999-2020 (Thousand Megawatts)



Source: APERC (2002a).

Figure 38 APEC Electricity Generation, 1999-2020 (Thousand Gigawatt-Hours)



Source: APERC *Outlook 2002* (APERC 2002a).

The most popular type of plant for power generation in the APEC region is and will continue to be coal-fired. Coal plant capacity will increase from 713 GW in 1999 to 1,114 GW in 2020, its share remaining almost constant: 35 percent in 1999 compared to 34 percent in 2020.

Natural gas plants will grow faster than any other type of plant at 3.6 percent annually, more than doubling their capacity from 403 GW in 1999 to 839 GW in 2020. Their share of total generating capacity should grow from 20 percent in 1999 to 26 percent in 2020.

Gas-fired capacity will grow at the expense of oil-fired and nuclear capacity, the shares of which are projected to decrease by 2020 to 10 and 9 percent respectively. Hydro, biomass and geothermal generating capacity are projected to grow modestly. Solar and wind generating technologies are likely to grow very fast from a small base, but their combined contribution to generating capacity in the baseline projections considered here would rise to 1.2 percent in 2020.

TRENDS IN ELECTRICITY TRANSMISSION INVESTMENTS

Investment in electricity transmission depends on each economy's level of infrastructure development and specific requirements. Whereas in developing economies the priority in transmission investments can be placed on the construction of new infrastructure to provide electricity to unserved segments of the population, in developed economies the priority can be in the replacement of aging equipment. Thus making an accurate estimation of the investments needed for transmission infrastructure in the 21 APEC economies without detailed knowledge of their specific needs in the next 20 year period can be a complex task.

To come up with a valid criterion for the estimation of future transmission investments in the APEC region, an analysis was made of current and planned investment practices on this field in selected member economies. The selection includes economies with large and small, and with differing degrees of electricity transmission infrastructure development. Included are:

- Industrialised economies such as Japan and the United States.
- Developing economies with high electrification rates such as Malaysia with a rate of 94 percent and Mexico with 95 percent.

- Developing economies with large unelectrified areas, such as Papua New Guinea with a low electrification rate of 8 percent[47], and China with an electrification rate of 98 percent, but with 24 million people without the benefit of electricity service.[48]

CHINA

The power industry in China is still centralised but plans are underway for structural reform and the introduction of market-based competition. The operation of power plants and generation grids will be unbundled, and competitive bidding for generation by independent power producers will become a possibility in the near future.

According to information from the government of China, investment in that economy in 2002 on transmission and distribution systems was 68 percent of the total electricity infrastructure expenditures.[49] As well, the amount invested in transmission and distribution was 2.6 times that allocated to generation capacity, as can be calculated from Table 13.

Table 13 Electricity Sector Investments in China, 2002

Type of Investment	Amount	Share
Infrastructure		
Installed capacity	48 billion RMB	26.1 %
Transmission line	39 billion RMB	21.2 %
Other	5 billion RMB	2.7 %
Distribution network		
Distribution network for urban area	13 billion RMB	7.0 %
Distribution network for rural areas	73 billion RMB	39.7 %
Generation upgrades		
Large-scale units replacing smaller units	6 billion RMB	3.2 %
Total	**184 billion RMB**	**100.0 %**

Source: DRCCU (2001).

JAPAN

TEPCO is one of 10 electric utilities operating in Japan. It is the economy's largest power company with 27,020,000 customers, an installed generating capacity of 60,375 megawatts and sales of 275.5 billion kWh that represent 33.4 percent of Japan's total sales.

Table 14 Electricity Sector Investments by TEPCO, 1980-2002 (100 Million Yen)

Investment Type	1980	1985	1990	1995	2000	2001	2002*
Power							
Hydro	513	181	402	745	426	396	400
Thermal	388	1,717	813	1,237	1,481	2,429	1,464
Nuclear	2,845	2,321	1,591	1,239	-	-	199
Subtotal	3,747	4,220	2,807	3,222	1,907	2,826	2,063
Distribution							
Transmission	3,113	1,415	2,906	2,667	878	606	665
Transformation	1,169	410	1,513	1,177	664	266	181
Distribution	755	1,014	2,015	1,835	1,266	1,093	1,109
Other	46	13	14	13	9	2	31
Total	**8,833**	**7,074**	**9,257**	**8,916**	**4,726**	**4,795**	**4,049**
Distribution / Total	**57%**	**40%**	**70%**	**64%**	**59%**	**41%**	**48%**

Source: TEPCO (2003). Note: * Planned.

[47] APERC (2001b).

[48] CERS (2002).

[49] DRCCU (2002).

TEPCO's investments in transmission, transformation and distribution from 1980 to 2001 averaged 58 percent of the total investments in electricity capacity additions. Further, investments in transmission, transformation and distribution are, in average, 1.5 times larger than those for generation capacity in the same period.[50]

Table 15 Electricity Sector Investments for Capacity Expansion by the Ten Major Electric Power Companies in Japan, 2001 (100 Million Yen)

Investment Type	2001
Power	
Hydro	774
Thermal	4,818
Nuclear	2,330
Subtotal	7,923
T&D	
Transmission	2,375
Transformation	961
Distribution	2,230
Other	458
Total	**13,950**
Distribution / Total	**40%**

Source: TEPCO (2003).

During 2001, Japan's 10 electric power companies' investment in transmission, transformation and distribution represented 40 percent of the total investment required for power infrastructure expansions. Also for the 10 Japanese power companies, investment in transmission, transformation and distribution in the same year was 0.7 times that for generation plants.[51]

MALAYSIA

The electricity industry in Malaysia is partly privatised. Tenaga Nasional Berhad (TNB), the national electric utility company, serves the peninsular and east regions. Sabah Electricity Sendirian Berhad (SESB) serves the State of Sabah with major funding in the form of grants and soft loans from the central government. The Sarawak Electricity Supply Corporation (SESCO), a statutory body controlled by the State of Sarawak, provides service to that State. Additionally, there are twelve IPP plants currently in operation, five of them in the peninsular region, five in the State of Sabah and two in the State of Sarawak. Malaysia has an electrification rate of 94 percent.

According to the *Eighth Malaysia Plan*[52], investment in the electricity industry between 1995 and 2000 was dominated by IPPs, resulting in a reduction in capital requirements by the utilities. The breakdown of the investments is shown in Table 16. Investment in rural electrification in Malaysia, which during the period amounted to RM 463.6 Million, is funded using different mechanisms and therefore is not included in this table.

Table 16 Electricity Sector Investments in Malaysia, 1995-2000 (Million Ringgit)

Investment Type	TNB	SESB	SESCO	IPPs	Total	Share
Generation	5,489.3	331.6	116.5	17,576.2	23,513.6	57.2%
Transmission	7,600.0	648.6	22.2	-	8,270.8	20.1%
Distribution	8,566.0	241.7	517.5	-	9,325.2	22.7%
Total	21,655.3	1,221.9	656.2	17,576.2	41,109.6	100.0%
Share of Total	52.7 %	2.9 %	1.6 %	42.8%	100 %	

Source: Malaysia (2001).

50 TEPCO (2003).

51 Ibid.

52 Government of Malaysia (2001).

Figure 39 Map of Malaysia

Source: US DOE.

Between 1995 and 2000, a total of RM 17.6 Billion was spent on the upgrade and construction of transmission and distribution networks, or 43 percent of the total investments in infrastructure. Expenditures on transmission and distribution (T&D) represented 0.7 times those for generation.

MEXICO

In Mexico, the State's two utility companies are the sole providers of public electricity services. Comisión Federal de Electricidad (CFE) is the major electric power provider covering most of the territory and serving 19 million people. Luz y Fuerza del Centro (LFC) covers Mexico City and the central industrial area and has 5 million customers. A reform in the legal framework introduced in 1992 allowed for the participation of private investors mainly in the form of independent power producers. Mexico has an electrification rate of 95 percent, which is higher than that of most other developing economies in APEC.

The Mexican government's estimation of the investments required in the power sector in the period from 2001 to 2010 [53] is shown in Table 17. Transmission and distribution costs combined represent 1.1 times the cost of generation investment, or 53 percent of the total funds programmed for infrastructure additions.

Table 17 Projected Electricity Sector Investments in Mexico, 2001-2010

Investment Type	Amount	Share
Generation	242 billion pesos	46.5 %
Transmission	152 billion pesos	29.2 %
Distribution	126 billion pesos	24.2 %
Total infrastructure	**520 billion pesos**	**100.0 %**
Major maintenance	80 billion pesos	
Engineering and other investment	15 billion pesos	
Capital payments on previous years' projects	61 billion pesos	
Grand total	**676 billion pesos**	

Source: SENER (2002).

[53] SENER (2002).

PAPUA NEW GUINEA

PNG Power Ltd. is the nationwide electric utility in Papua New Guinea in charge of planning and development of the electricity infrastructure. Although the Government at the moment is discussing future privatisation of this company, it still is completely owned by the State. Papua New Guinea has an electrification rate of 8 percent, meaning that 92 percent of the population, an estimated 4.3 million people, do not have access to the electricity grid.[54] PNG Power Ltd. provides service at present mostly to urban areas, with a large portion of the rural population still remaining to be electrified. There are currently three main transmission and distribution systems in operation: the Port Moresby system, serving the economy's capital city; the Ramu system, financed by ADB and intended to become a major electricity network hub; and the Gazelle Peninsula system.

The expected investments in generation capacity and transmission and distribution infrastructure for the period 2003-2011 are listed in PNG Power Ltd.'s 10-year expansion plan.[55] These are shown in Table 18.

Table 18 Projected Electricity Sector Investments in Papua New Guinea, 2003-2011

Infrastructure Type	Amount	Share
Generation plant additions	382 million kina	33.3 %
Transmission additions	378 million kina	33.0 %
Distribution additions	384 million kina	33.6 %
Total	**1144 million kina**	**100.0 %**

Source: PNG Power Ltd. (2002).

The cost of additional transmission and distribution infrastructure capacity for the period 2003-2011 in Papua New Guinea represents 67 percent of the total investments in electricity generation infrastructure. Resources needed for the development of distribution infrastructure are twice those needed for generation plants.

UNITED STATES

The *Annual Energy Outlook* published by the US Energy Information Administration[56] estimates that over the period from 2000 through 2009, as much as 210 thousand megawatts of additional installed capacity will be required in the United States. A study by the Edison Electric Institute[57] estimates that such generating capacity will cost US$105 billion, while investment in new transmission for the same period will amount to around US$56 billion, or about half as much again. For this infrastructure-mature economy, transmission investments represent only 35 percent of total planned investments in the power sector according to these numbers.

OTHER STUDIES OF TRANSMISSION INVESTMENT TRENDS

A report by the Institution of Electrical Engineers (IEE) estimates that capital investments needed worldwide in the power industry for the period 1995-2010 are of around US$2,500 billion (in 1996 US dollars).[58] Of the total capital investments, generation projects account for 63 percent, transmission 9 percent and distribution 21 percent. The remaining 7 percent is to be used for general expenditures related to control, telecommunications and similar activities. Table 19 shows the results by type of economy.

54 APERC (2001a).

55 PNG Power Ltd. (2002).

56 EIA (2003a).

57 EEI (2001).

58 IEE (1997).

Table 19 Comparative Investments in Generation, Transmission and Distribution Infrastructure Worldwide, 1995-2010

Type of Economy	Generation Investment Billion 1996 US$	T&D + General Investment Billion 1996 US$	Total Investment Billion 1996 US$	T&D Share of Total Investment	Ratio of T&D to Generation Investment
Developed	520	280	800	35%	0.54
Developing	890	570	1,460	39%	0.64
Transitional	160	80	240	33%	0.50
Total	**1,570**	**930**	**2,500**	**37%**	**0.59**

Source: IEE (1997).

According to these estimations, developed economies will need to assign 35 percent of electricity sector investment funds to transmission and distribution. For developing economies that figure is 39 percent. This is a higher share than for developed economies, although not much higher as would be expected given the typical deficiencies and needs of their evolving electricity network systems. In many developing economies, the allocation of low percentages of funds to transmission and distribution can be a reflection of a lack of financial resources. This partly contributes to the fact that transitional economies (in eastern Europe and the Former Soviet Union) will allocate the smallest percentage of investment to T&D: 33 percent. The world average share of investment assigned to T&D is listed as 37 percent, and the proportion of T&D investment to generation investment lies between 0.5 and 0.7 in all cases.

ANALYSIS OF TRANSMISSION INVESTMENT TRENDS

Table 20 summarises the allocation of investment funds to transmission and distribution infrastructure in the selected APEC economies described above.

Table 20 Transmission and Distribution Allocations in Selected APEC Economies

Economy	T&D Share of Total Electricity Investment	Ratio of T&D to Generation Investment	Electrification Rate
TEPCO (1980-2002)	58.1 %	1.50	--
Japan (2001)	39.9 %	0.70	100 %
US (2000-2009)	34.7 %	0.50	100 %
Malaysia (1995-2000)	42.8 %	0.75	94 %
Mexico (2001-2010)	53.4 %	1.20	95 %
China (2002)	67.9 %	2.60	98 %
PNG (2003-2011)	66.6 %	2.00	8 %

The shares of investment assigned to T&D in Japan and the United States are the lowest of the cases analysed at 40 and 35 percent respectively. Also the ratios of T&D to generation investment in these two economies are lowest at 0.7 and 0.5 in the same order. For Malaysia and Mexico, two developing economies with high electrification rates, T&D shares of the total electricity sector investments are 43 and 53 percent respectively. T&D investments in these two economies will be between 0.7 and 1.2 times those of generation capacity investments.

China and Papua New Guinea, two economies with large segments of their populations still with no access to electricity service, show the highest shares of investment apportioned to T&D: 68 and 67 percent respectively. Their proportions of T&D to generation investment are also the highest: China spent 2.6 times more on T&D than on generation capacity while Papua New Guinea plans to invest twice as much. Only the case of TEPCO falls outside of these trends, with a T&D share and a T&D to generation ratio more in line with those of Malaysia and Mexico at 58 percent and 1.5 times respectively.

Compared to the numbers of this sampling of APEC economies, the worldwide estimates by IEE in Table 19 show lower percentages allocated to T&D. Also, while for four out of the seven

APEC economies analysed T&D budgets are larger than generation budgets, for the IEE's three groups of economies T&D investments are smaller as indicated by T&D to generation ratios of less than one.

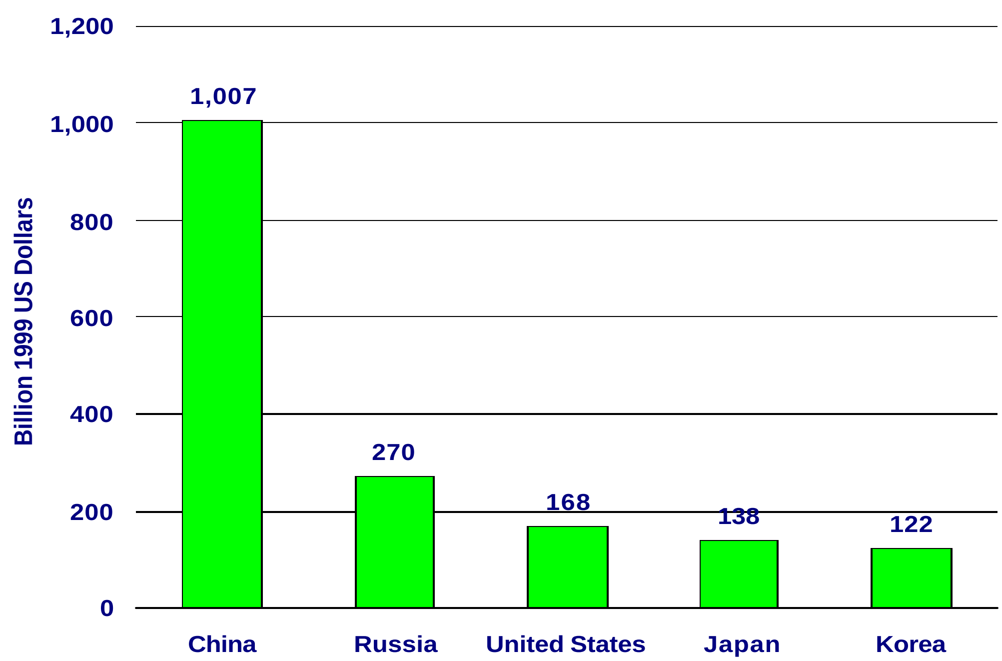
Notwithstanding the findings in the selected APEC economies, by the information available it cannot be inferred that a similar high proportion of T&D to generation investment would exist in all APEC economies. Making such an assumption to estimate T&D investment requirements in the 2000-2020 period could lead to an overly inflated result. Therefore the electricity infrastructure calculations were made choosing a factor for T&D investments more in line with the IEE data, given that the study by this Institution includes a larger sample of economies, and also in the interest of having a more conservative estimation of transmission and distribution investment requirements. Hence for this outlook transmission and distribution requirements were computed as an additional 50 percent of the amounts required for generation infrastructure in the upper limit calculations, and as an additional 35 percent in the lower limit.

ESTIMATED INVESTMENT REQUIREMENTS IN THE ELECTRIC POWER SECTOR

Power sector investment is by far the most important category in terms of the total energy investment requirements. In the APEC region, power industry capital investments represent 49 percent of the total energy capital requirements for the period 2000-2020.

As shown in Figure 40, China accounts for the largest requirement for power infrastructure, US$1,007 billion, or 45 percent of the APEC total. For reference, this sum is larger than the combined total energy capital requirements of 15 APEC economies including Japan. Other economies with large power capital needs are Russia with 270 billion, the United States with 168, Japan with 138 and Korea with 122 billion US dollars. The vast investment requirements of China correspond to its very high projected average growth rate in electricity consumption for the 20-year period of 5.6 percent, with a resulting requirement for 500 GW of additional installed generating capacity and associated transmission and distribution system infrastructure.

Figure 40 Comparative Power Sector Infrastructure Requirements in Five APEC Economies from 2000 through 2020 (Billion 1999 US Dollars)



Large projects are already taking shape in China, such as the Three Gorges Dam hydro project. Construction of the US$22 billion mega-project began in 1993 and should be completed by 2009. Three Gorges will have a total of 26 generators, the first four of which were due to go online around the end of 2003. When complete, the project will have 20,900 MW of capacity, more than the total installed capacity in Thailand in 1999. The dam itself will stand 185 meters and will span 2,039 meters across the Yangtze River. This project by itself will represent one sixteenth of China's total power capacity and will avoid the burning of 50 million tonnes of coal each year.

Figure 41 Three Gorges Dam Project in China

Source: University of Washington. http://faculty.washington.edu

The Three Gorges project was intensely debated before it was started due to the possibility of it harbouring industrial waste that could later cause ecological damage, and the need to relocate 1.13 million people at a cost of 10 billion US dollars, an indirect cost not computed into the present report's infrastructure estimations. On the other hand, according to government officials, the construction of the dam will benefit 10 million people who live along the Yangtze and whom will not have to suffer again from the fatal consequences of seasonal flooding.[59]

China has plans to build four more hydro plants with a combined installed capacity of 38,500 MW in the Jinsha River on the upper reaches of the Yangtze. The strong focus on hydroelectricity by China is part of a policy to find alternative generating sources to coal. This particular project is intended to transmit electricity from the resource-rich and underdeveloped west to the more developed, energy demanding eastern areas. Construction of two giant dams is expected to begin before 2005 and will involve the resettlement of fewer people than the Three Gorges project.[60]

Figure 42 shows projected investments in electric generating capacity by economy. The costs of investment in transmission and distribution facilities are not included here.

[59] Reuters (2003a).

[60] Reuters (2003b).

Figure 42 Investments in Power Generation, 2000-2020 (Billion 1999 US Dollars)

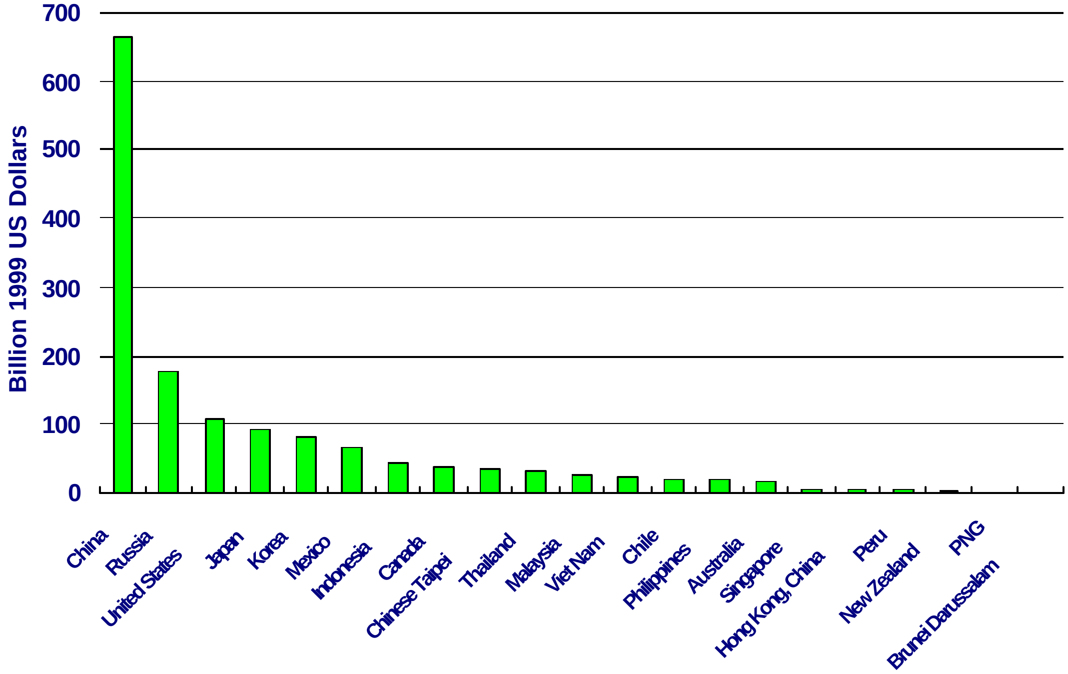


Figure 43 shows the breakdown by technology. In terms of type of plant, in APEC the largest portion of the investment in generation capacity will go to coal steam plants, which will account for US$475 billion over the 20-year period, or 32 percent of the total. Hydropower plants will require US395 billion of investment, gas-fired plants US$274 billion, and nuclear plants $163 billion.

Figure 43 Total Expenditures in APEC for Power Capacity Additions, 2000-2020 (1999 US Dollars)

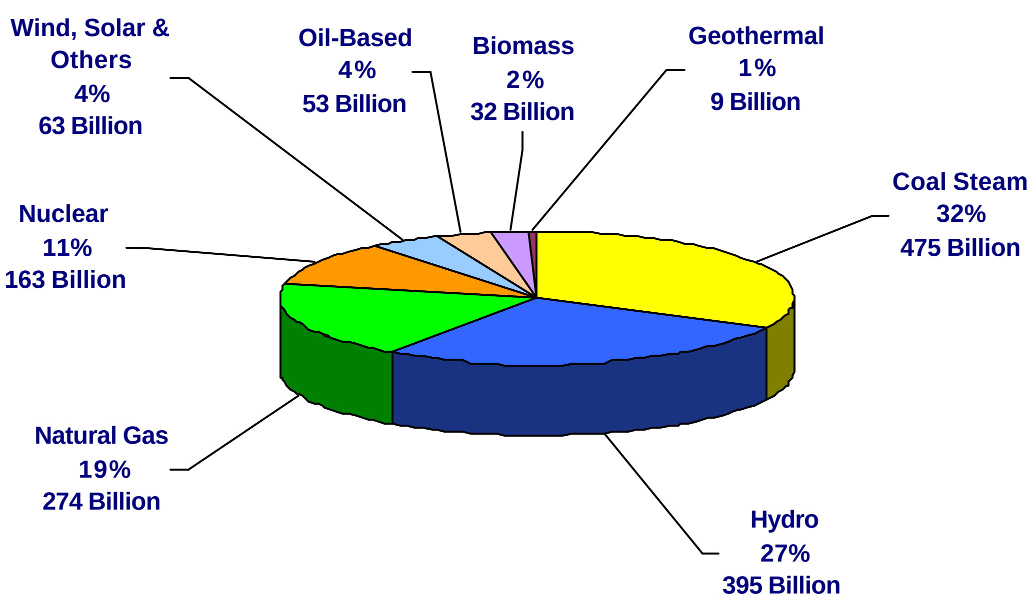


Table 21 shows the detailed economy-by-economy results of total investments required in APEC for power sector infrastructure in the 20-year period, including capacity additions for generation, transmission and distribution. As usual, the first three columns show the annual investment requirements for the years 2000, 2010 and 2020; and the last three columns indicate cumulative totals for the periods described.

Table 21 APEC Investment Requirements in Electricity Generation and Transmission Infrastructure, High Case (Billion 1999 US Dollars)

Economy	2000	2010	2020	Total 2000 – 2010	Total 2011 - 2020	Total 2000 – 2020
Australia	0.21	0.63	1.57	9.59	16.83	26.42
Brunei Darussalam	-	-	-	0.20	0.11	0.31
Canada	-	3.11	3.37	27.90	31.11	59.01
Chile	-	1.67	2.43	6.75	20.61	27.36
China	12.42	47.50	70.31	393.69	613.20	1,006.89
Hong Kong, China	0.28	0.38	0.43	2.81	4.01	6.82
Indonesia	3.70	5.39	7.09	22.16	45.07	67.23
Japan	2.79	3.87	7.90	65.06	73.02	138.08
Korea	-	10.51	4.98	64.69	57.70	122.39
Malaysia	-	1.82	2.54	19.76	23.18	42.94
Mexico	1.32	7.46	5.97	39.07	59.35	98.42
New Zealand	0.77	0.21	0.51	1.71	0.95	2.66
Papua New Guinea	0.27	0.12	0.12	0.62	0.46	1.08
Peru	0.18	0.17	0.55	2.99	3.57	6.57
Philippines	0.54	0.65	2.88	4.29	22.80	27.08
Russia	1.79	10.17	17.28	99.02	170.52	269.54
Singapore	0.48	0.48	0.44	4.28	5.67	9.96
Chinese Taipei	3.74	2.40	5.14	24.73	28.18	52.91
Thailand	2.68	1.78	4.14	15.53	34.31	49.84
United States	0.03	8.11	9.48	55.66	112.10	167.75
Viet Nam	2.58	1.69	1.38	16.67	19.12	35.79
Total	**33.79**	**108.12**	**148.53**	**877.19**	**1,341.87**	**2,219.06**

ENERGY INVESTMENT FOR ENVIRONMENTAL PROTECTION

INTRODUCTION

A major portion future energy sector investment will likely be devoted to environmental protection. To better understand the magnitude of investment required to limit the impact of energy operations on the environment, this chapter calculates the costs of adopting a selection of environmental control measures in the petroleum industry and the electric power industry. These costs are calculated for all the APEC economies over the two decades from 2000 through 2020.

Many environmental control costs involve retrofitting refining and generating capacity that already exists. For the purpose of estimating such costs, existing capacity is assumed to be as described in APERC's *Energy Demand and Supply Outlook 2002* [61]. In the petroleum industry, the analysis considers the costs of installing equipment in refineries to produce diesel fuel with less sulphur, as well as pipeline and storage systems to transport such fuel. In the power sector, the analysis considers the costs of three distinct environmental strategies: installation of post-combustion emission control equipment, fuel switching, and demand-side management.

ENVIRONMENTAL PROTECTION IN THE OIL SECTOR

Many APEC economies have established regulations for reducing contaminants in gasoline and diesel fuel, and many are considering more stringent regulations toward this end. Production of cleaner burning fuels will require sizeable investments for additional control equipment. This section focuses on the costs of supplying ultra-low-sulphur diesel fuel (ULSD) for highway transportation since clean diesel fuel requirements are likely to be adopted by many economies in the near future and would significantly affect the investment of oil refineries and pipelines.

The use of ULSD is meant to reduce the emissions of nitrogen oxides (NOx) and particulate matter (PM) from heavy-duty highway engines and vehicles that use diesel fuel. ULSD allows the use of better performing catalytic converters on diesel engines that reduce NOx emissions to the levels required by newer, stricter standards. Sulphur content in conventional road diesel fuels being used at present varies from economy to economy depending on local requirements. Table 22 shows that average sulphur content values can vary from 5000 parts per million (ppm) to 300 ppm.

Table 22 Sulphur Content and Cetane Number in Selected Diesel Fuels

Regulatory Regime	Sulphur Content by Weight	Cetane Number
PEMEX Diesel pre-1992	0.5 percent	-
PEMEX Diesel	0.03 percent	55.0
US Environmental Protection Agency	0.03 percent	44.0
California Air Resources Board (CARB)	0.03 percent	48.6
Europe average	0.09 percent	50.5
Japan	0.13 percent	53.2

Sources: PEMEX and Paramins.

[61] APERC (2002a).

New regulations are expected to reduce the sulphur content of diesel to 10 ppm in Germany, 15 ppm in United States, and 50 ppm in Australia and the European Union. Using tax incentives, Germany began an early introduction program for the marketing of 10 ppm sulphur content diesel in January 2003. The European Union mandated a reduction to 50 ppm in diesel that will take effect in 2005, although early marketing of fuel of this quality has already been commenced by a number of refiners in the Continent motivated also through tax incentives.[62] In the United States highway diesel will be required to have a maximum sulphur content of 15 ppm by mid-2006.

Refineries can somewhat reduce the sulphur content of diesel fuel by switching to a crude oil feedstock with less sulphur. But for levels as low as those required by ULSD, refineries will require substantial additional equipment. Current technologies can be modified to produce diesel with less than 10 ppm sulphur. The upgrades required at a given refinery depend on individual circumstances, including the plant's configuration and its crude inputs. Some refineries with limited access to capital might just decide not to produce diesel fuel any longer. However, experience in the United States and Europe has shown that ultra-low sulphur diesel fuel can be produced through conventional hydrotreating, a commercially-proven process that many refineries already use.

For the calculations in this section, it is assumed that all refineries in the APEC region will have to reduce the sulphur content of diesel fuel to 10 ppm. This assumption is based on the ULSD rule adopted by the United States Environmental Protection Agency in February 2001, for full implementation by mid-2006, which would require refiners and importers to reduce the sulphur content of highway diesel to 15 ppm.[63] But pipeline operators are expected to require refiners to provide fuel with even lower sulphur content of approximately 10 ppm in order to compensate for possible contamination from higher- sulphur products in the system and to provide a tolerance for testing.

INVESTMENTS IN OIL REFINERIES

To achieve a diesel product with less than 10 ppm sulphur two stages of desulphurisation will likely be required in most refineries. A first stage would reduce the sulphur content to around 250 ppm or lower and a second stage would complete the reduction to less than 10 ppm. The first stage can be achieved using conventional design hydrotreaters, but the second stage requires that hydrotreating equipment be heavily modified to accommodate higher operating pressures, higher hydrogen purity and rates, a reduced space velocity and different catalysts. It is possible, according to equipment manufacturers, to also retrofit existing hydrotreaters with more vessels, a new reactor, a hydrogen compressor, a recycle scrubber, an interstage stripper and other associated process hardware. Hydrogen consumption and needed investment in hydrogen producing equipment are also an important part of the costs of retrofitting or expanding refineries for ULSD production.[64]

To meet the ULSD Rule in the United States, various studies analysing the cost of ULSD production[65] estimated that 40 percent of diesel-producing refinery capacity would require the installation of a new hydrotreater while the remaining 60 percent would need to revamp their existing units. This is the assumption made for this exercise. As for the weight percent yields of ULSD produced by a distillate hydrotreater, these can vary considerably depending on the type of crude used and on the particular operating conditions of the refinery, therefore an estimate was made for this study based on the average gasoil yields of different crudes.

On-site capital costs for a new hydrotreater in these calculations consist of three parts: a two-reactor system with interstage H_2S stripping, hydrogen makeup compressors, and remaining inside battery limit equipment (ISBL). The capital cost for a revamped unit includes only an additional reactor, heater and separator, and assumes that the existing inside battery limit equipment will remain unchanged. The cost of a revamped unit is estimated to be 50 percent that of a new unit.

62 Oil & Gas Journal (2003b).

63 EPA (2000). *Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*. The rule was signed by President Clinton in December 2000 and approved by the Bush Administration in February 2001.

64 EIA (2001a).

65 EIA (2001a).

Off-site capital cost for a new plant is assumed to be 45 percent of the on-site cost, and the off-site capital cost for a revamped unit is assumed to be 30 percent of the on-site capital cost.

Table 23 shows existing and projected crude oil refinery capacity in APEC economies, in barrels per day. Table 24 shows various estimates of the capital cost of new hydrotreater equipment, expressed in dollars per barrel per day of diesel produced. To obtain an estimate of capital costs for new hydrotreater equipment, selected values from Table 24 were averaged to come up with an assumed estimated cost of US$2,074 per barrel per day. Thus, it is possible to estimate the cost of retrofitting refinery capacity with hydrotreater equipment by applying these factors to the yield of diesel deduced from Table 23, and making considerations for the fraction of refineries to have new or revamped units and adding off-site costs.

Table 23 Crude Oil Refinery Capacity Existing in 1999 and Projected to 2020 for APEC Economies (Thousands of Barrels per Day)

Economy	1999	2010	2020
Australia	812.4	1,021.7	1,251.5
Brunei Darussalam	8.6	12.6	18.6
Canada	1,911.7	2,266.1	2,640.4
Chile	204.6	310.0	544.2
China	4,346.8	7,469.1	11,512.4
Hong Kong, China		-	-
Indonesia	992.7	1,506.7	2,213.7
Japan	4,997.7	5,310.6	5,636.3
Korea	2,540.1	3,574.8	4,610.8
Malaysia	524.4	916.9	1,338.3
Mexico	1,525.0	1,978.7	2,359.3
New Zealand	98.0	123.0	151.2
Papua New Guinea		-	-
Peru	182.3	230.2	308.8
Philippines	401.0	610.6	940.9
Russia	6,673.0	9,084.9	11,940.3
Singapore	1,255.0	1,859.1	2,318.7
Chinese Taipei	770.0	994.1	1,210.8
Thailand	712.8	1,052.3	1,716.2
United States	16,541.0	20,308.9	23,991.2
Viet Nam	130.0	312.2	593.8
APEC Total	**44,626.9**	**58,942.3**	**75,297.4**

Source: APERC with data from Oil and Gas Journal Surveys.

Table 24 Capital Cost of New Hydrotreaters (In side Battery Limit Equipment) According to Recent Studies (1999 US Dollars per Barrel per Day)

Model	Capital Cost
Charles River Associates/Baker and O'Brien	$1,622
Environmental Protection Agency (EPA)	$1,240 - 1,680
EIA Refinery-by-Refinery Analysis	$1,043 - 1,807
EnSys Energy and Systems, Inc.	$2,350 - 3,296
EIA National Energy Modeling System Base Case	$1,331 - 1,849
EIA National Energy Modeling System High Case	$1,655 - 2,493

Source: EIA (2001a).

Notes: For EPA, low end of range is for straight-run distillate, high end for light cycle oil. For EIA refinery-by-refinery analysis, the range depends on unit size and feedstock. For other EIA cases and Ensys case, the low end of the range is for low-sulphur feeds, the high end for high-sulphur feeds with greater aromatics improvement.

The total estimated cost of retrofitting hydrotreater units in APEC refinery capacity is shown in Table 25. The column titled 1999 represents the cost of retrofitting all the existing diesel-producing refinery capacity. The columns for 2010 and 2020 represent the annual investments required to fit additional refinery capacity. Between 1999 and 2020, a total of US$38 billion would be required to outfit all existing refinery capacity in 2020 with the hydrotreating equipment necessary to produce USLD with United States specifications in APEC. This amount represents 12.4 percent of the total investment in new refinery capacity projected in the 21 APEC economies between 2000 and 2020.

Table 25 Capital Costs of Hydrotreater Equipment for Producing Ultra-Low Sulphur Diesel Fuel in Refineries in APEC Economies (Billion 1999 US Dollars)

Economy	Existing 1999	Yearly 2010	Yearly 2020	Cumulative 1999 - 2009	Cumulative 2010 - 2020	Cumulative 1999 - 2020
Australia	408.6	10.6	12.3	503.3	126.2	629.4
Brunei Darussalam	4.3	0.2	0.3	6.1	3.2	9.3
Canada	961.5	18.7	18.8	1,121.7	207.0	1,328.7
Chile	102.9	8.6	15.2	147.3	126.4	273.7
China	2,186.2	181.4	238.6	3,575.1	2,215.0	5,790.1
Hong Kong, China	-	-	-	-	-	-
Indonesia	499.3	27.8	42.8	730.0	383.4	1,113.4
Japan	2,513.5	22.4	15.1	2,665.1	186.2	2,851.3
Korea	1,277.5	62.0	50.4	1,736.0	583.0	2,319.0
Malaysia	263.7	19.8	21.9	441.4	231.7	673.1
Mexico	767.0	20.6	20.3	974.6	212.0	1,186.6
New Zealand	49.3	1.4	1.6	60.5	15.6	76.1
Papua New Guinea	-	-	-	-	-	-
Peru	91.7	2.5	4.5	113.2	42.1	155.3
Philippines	201.7	14.0	18.8	293.1	180.2	473.2
Russia	3,356.1	120.8	145.5	4,448.3	1,557.0	6,005.3
Singapore	631.2	25.3	14.5	915.1	256.5	1,171.6
Chinese Taipei	387.3	11.2	10.5	488.8	120.2	609.0
Thailand	358.5	27.3	34.5	501.9	361.2	863.2
United States	8,319.2	202.0	193.3	10,012.2	2,054.0	12,066.2
Viet Nam	65.4	10.6	17.0	146.5	152.2	298.6
APEC Total	**22,444.9**	**787.3**	**875.6**	**28,880.1**	**9,013.0**	**37,893.1**

INVESTMENTS IN TRANSPORTATION AND DISTRIBUTION SYSTEMS

Handling petroleum products with low sulphur content specifications will impose new logistical challenges to pipeline operators and will require new investments in the form of additional storage or pipeline infrastructure. In normal oil-product pipeline operations, materials of different characteristics are generally transported in sequence, one after another, creating a downgraded mix of "interface material" between batches. This downgraded material is usually blended into a fuel with lower-quality specifications. To minimise production of such material, pipeline operators attempt to ship materials of similar characteristics together. Hence, large storage tanks are required to hold petroleum products of specific grades, both at points of entry into the pipeline system and at points of destination. Downgraded interface material is also created in piping systems within terminals and storage facilities as products are transferred between storage tanks. It is even created inside the tanks themselves. Because station piping layouts can be very complex, especially in large terminals with many tanks, more interface material can be generated in terminals than in pipelines.

The US Environmental Protection Agency (EPA) estimates that interface material generated as a result of the ULSD Rule will be equal to 4.4 percent of the highway diesel volume transported.[66]

66 EIA (2001a).

In the United States, current 500 ppm sulphur content diesel, usually prepared with a 300 ppm content for piping purposes, can be wrapped between batches of jet fuel with 2,000 ppm of sulphur and non-road distillate fuel (heating oil) with 3,000 ppm with little possibility that contamination will bring the product out of specification. But ULSD, with its very low sulphur content of 15 ppm, would easily be brought out of specification by a very small contamination from jet fuel, with 133 times the sulphur concentration, or from heating oil, with 300 times the sulphur concentration.

Thus, pipeline operators will avoid transporting ULSD next to jet fuel or heating oil where possible and instead transport ULSD next to other fuels with relatively compatible compositions. Storage of ULSD will also have to be more carefully separated from storage of other fuels. All of this will require enhanced inventory management procedures, as well as costly additional storage capacity at pipeline terminals, bulk product distribution plants and local truck stops. The EPA has estimated that for handling ULSD in the United States, new tanks and related hardware will be required at 40 percent of the existing 853 terminals, at 40 percent of the 9,200 existing bulk plants and at 50 percent of the 4,800 truck stops that handle petroleum products in the economy. Many of the additional facilities will be needed only for the phase-in period when ULSD has to be handled alongside regular diesel fuel, but they will still represent real costs. For the US diesel distribution capacity in place, the EPA estimated resulting additional costs of $1.05 billion at year 2000 price levels.

Table 26 Capital Costs of Additional Storage Capacity for Handling and Distributing Ultra-Low-Sulphur Diesel in APEC Economies (Million 1999 US Dollars)

Economy	Existing 1999	Yearly 2010	Yearly 2020	Cumulative 1999-2009	Cumulative 2010-2020	Cumulative 1999-2020
Australia	60.8	2.9	3.3	85.8	34.1	120.0
Brunei Darussalam	0.7	0.1	0.1	1.3	1.0	2.3
Canada	88.0	3.4	3.7	126.5	39.5	166.0
Chile	23.5	2.5	4.6	41.0	38.5	79.6
China	104.7	9.1	15.0	184.3	131.6	315.9
Hong Kong, China	44.8	1.9	2.2	75.7	23.0	98.6
Indonesia	81.5	7.2	12.2	146.1	104.7	250.8
Japan	291.1	7.5	7.1	352.2	79.3	431.5
Korea	98.3	0.3	11.4	176.8	119.9	296.8
Malaysia	31.4	2.1	2.1	53.6	24.2	77.8
Mexico	88.6	4.9	3.7	127.9	41.4	169.3
New Zealand	13.6	0.5	0.5	19.1	5.6	24.7
Papua New Guinea	1.2	0.0	0.0	1.2	0.2	1.4
Peru	17.7	0.6	0.8	22.8	7.5	30.3
Philippines	3.5	0.2	0.3	4.6	2.4	7.0
Russia	92.8	2.6	2.2	121.8	24.3	146.1
Singapore	12.3	0.2	0.2	14.8	2.3	17.1
Chinese Taipei	30.7	0.9	0.8	39.6	9.8	49.4
Thailand	100.3	9.6	9.5	155.7	119.3	275.0
United States	1,041.2	52.4	57.2	1,419.7	609.8	2,029.6
Viet Nam	27.0	5.4	8.4	65.0	75.4	140.5
Total	**2,253.6**	**124.2**	**145.3**	**3,235.7**	**1,493.8**	**4,729.5**

Table 26 estimates the storage costs resulting from implementing ultra-low-sulphur diesel standards in other APEC economies along the lines of those in the United States. It assumes that storage costs of commercialising ULSD are proportional to final demand for diesel fuel in road transport. It further assumes that the bulk of these costs would be accounted for by the additional investment required for storage capacity in terminals, bulk plants and truck stations for ULSD handling and distribution. Thus, taking the EPA estimate for the United States as a benchmark, it calculates the costs of commercialising ULSD for each APEC economy as the EPA benchmark times the ratio of road transport diesel demand in that economy to road transport diesel demand in the United States.

The cost of retrofitting existing storage facilities to implement a ULSD standard throughout the APEC region, shown in the column for the 1999 base year, would be roughly US$2.3 billion. Annual costs of constructing the additional storage equipment at new installations would amount to about $124 million by 2010 and $145 million by 2020, as shown in the next two columns. Total investment requirements for implementing a ULSD standard APEC-wide, including the costs of retrofitting existing installations and appropriately equipping new installations, would cumulate to some US$4.7 billion through 2020, as seen in the final column. This would add 1.6 percent to the US$300.2 billion of investment in oil and oil product pipeline infrastructure that is projected in the APEC economies through 2020 without such a standard. The amount shown is overstated in the sense that any given economy or economies in APEC might opt not to implement standards of this kind.

ENVIRONMENTAL PROTECTION IN THE ELECTRIC POWER SECTOR

Environmental emissions in the electric power sector can be reduced in at least three ways: by the installation of post-combustion control equipment, by switching to less polluting fuels, and by limiting growth in consumer demand for electricity through demand-side management programmes. Among the atmospheric pollutants that result from combustion of fossil fuels, the ones most targeted for reduction in power generation are sulphur dioxide (SO_2), nitrogen oxides (NOx) and carbon dioxide (CO_2). Whereas SO_2 and NOx emissions can be effectively reduced by the installation of post-combustion controls at coal-fired power plants, the simplest way to limit CO_2 emissions from electricity generation is to switch from coal to less carbon-intensive fuels such as natural gas, or from fossil-fuelled power to nuclear power or renewable power forms. Insofar as demand growth can be limited, emissions of all three of these pollutants will be limited as well.

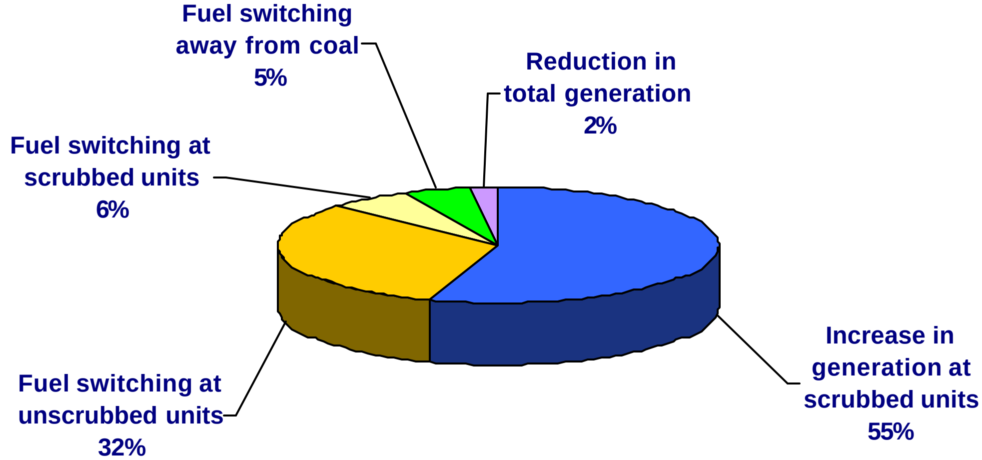
INVESTMENT IN POST-COMBUSTION CONTROL EQUIPMENT

Technologies for post-combustion control of sulphur dioxide and nitrogen oxide emissions have been available for many years, and their costs are well understood. Flue gas desulphurisation or FGD units, often referred to as scrubbers, have been used to suppress SO_2 and particulate emissions for about the last three decades, and emissions reductions are in the order of 95 percent. NOx emissions are usually reduced by adding combustion controls to boilers, by using selective catalytic reduction (SCR) equipment, or by using selective non-catalytic reduction (SNCR) equipment, with emissions reductions typically on the order of 90 percent.

To estimate the cost of limiting power plant SO_2 and NOx emissions throughout the APEC region, all economies were assumed to impose stringent limits on such emissions similar to those set forth in legislation introduced to the United States Congress in 2003 and analysed by the Energy Information Administration.[67] The scenario assumes that NOx emissions have to be reduced by 75 percent below 1997 levels and SO_2 emissions have to be reduced by 75 percent below levels required by full implementation of Title IV of the Clean Air Act Amendments of 1990. As effective emissions controls are required in more and more APEC economies, including those at lower levels of income per capita, this exercise should broadly reflect likely costs in the APEC region. In any event, effective emissions controls along these lines are assumed to be included in the baseline estimates of capital costs for the electric power sector analysed elsewhere in this report. The estimates here show what portion of those costs might be attributable to environmental protection.

[67] EIA (2001b). PUF (2002).

Figure 44 Strategies Used for the Reduction of SO_2 Emissions



Source: Public Utilities Fortnightly.

A study by EIA suggests that the dominant compliance option for reducing SO_2 and NOx emissions is installation of FGD and SCR emission control equipment in coal-fired power plants.[68] Table 27 shows EIA's estimate of how much coal-fired capacity would be fitted with emission control equipment in the United States between 1999 and 2020 to meet the 75 percent emissions reductions case, including those plants existing in 1999 that required retrofitting. The percentages in the table reflect what fraction such plants represent in terms of the total coal-fired installed capacity between 2000 and 2020 projected by APERC's *Outlook 2002*[69]. APERC's *Outlook 2002* estimates the total United States coal-fired generation installed capacity to be 361.5 GW in 2020.

Table 27 Projected Additions of Emissions Control Equipment to Coal-Fired Power Plants in the United States, 1999-2020

Type of Emissions Control Equipment	Gigawatts of Coal Capacity to be Fitted	Share of Total Coal Capacity
SO_2 Scrubber	241.5	66.8 percent
Selective Catalytic Reduction (SCR)	218.1	60.3 percent
Selective Noncatalytic Reduction (SNCR)	43.8	12.1 percent
Hg Fabric Filter	66.9	18.5 percent
Hg Spray Cooler	29.3	8.1 percent

Sources: APERC, US Energy Information Administration.

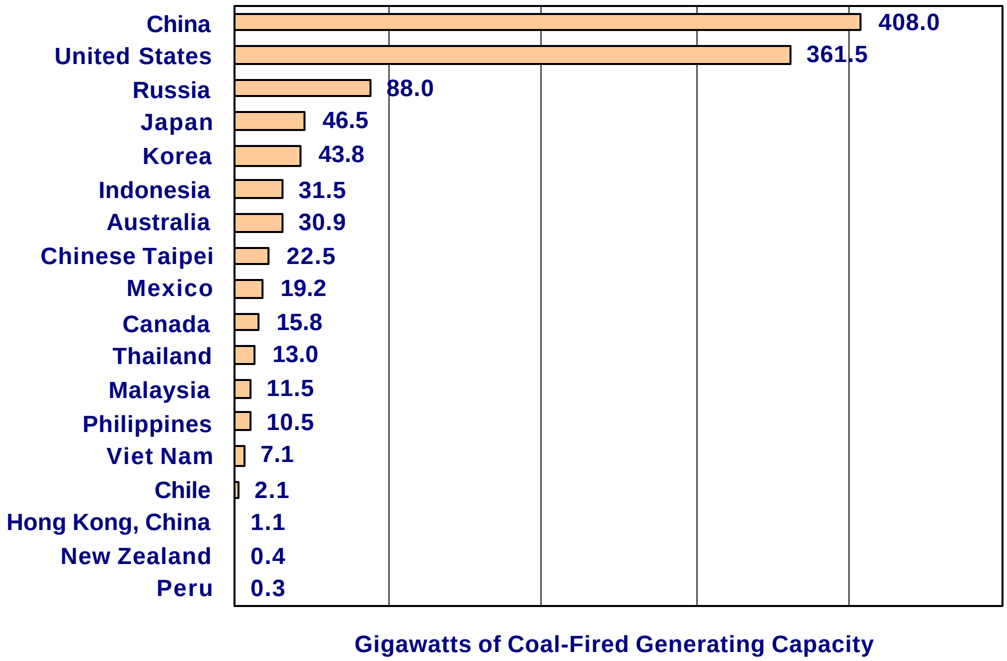
These assumptions form the basis for the estimation of emissions control equipment requirements in coal plants in APEC economies. Based on the data in Table 27, the analysis here assumes that 65 percent of coal-fired capacity in each APEC economy might need to be equipped with SO_2 scrubbers, while 60 percent of coal-fired capacity in each APEC economy might need to be equipped with selective catalytic reduction equipment. Figure 45 shows the total estimated amounts of coal-fired generating capacity in APEC in the year 2020 as projected in APERC's *Outlook 2002*[70]. These amounts were multiplied by 65 percent to estimate the amounts of capacity requiring scrubbers and by 60 percent to estimate the amounts of capacity requiring SCR.

68 EIA (2001b).

69 APERC (2002a).

70 APERC 2002a.

Figure 45 Total Coal Fired Power Plant Installed Capacity by 2020, APEC (GW)



Unit capital costs for flue gas desulphurisation and selective catalytic reduction equipment were obtained from EIA's *Assumptions to the Annual Energy Outlook 2003* [71] and are shown in Table 28. Since coal-fired power plants in the APEC region are built in a wide range of sizes and the costs of FGD and SCR equipment do not seem to vary much with size, a simplifying assumption was made that control equipment costs would be everywhere approximately equal to those estimated by EIA for 500 MW plants, namely $204 per kW for FGD equipment and $82 per kW for SCR equipment. These figures were multiplied by estimated amounts of coal-fired capacity requiring the installation of such equipment to calculate investment requirements for emissions reductions.

Table 28 Emission Control Equipment Capital Costs (1999 US Dollars per Kilowatt)

Coal plant size	FGD Capital Costs	SCR Capital Costs
300 MW	$267 /kW	$93 /kW
500 MW	$204 /kW	$82 /kW
700 MW	$168 /kW	$74 /kW

Source: Energy Information Administration.

Table 29 shows the calculated investment requirements for installing SO_2 and NOx emission control equipment on coal fired generating capacity in APEC economies. Amounts are shown for both capacity existing now and capacity to be built over the 20-year projection period. For coal plants existing in the baseline year of 1999, US$94.5 billion could be needed for retrofits with FGD equipment to control SO_2, while US$35.1 billion could be needed for retrofits with SCR equipment to control NOx. When new coal-fired capacity is considered in addition to existing capacity, investments required for emissions controls could amount to US$149.3 billion for FGD equipment and US$55.4 for SCR equipment. The total costs of providing coal plants with emissions controls, including both new and existing plants, could thus be US$204.7 billion.

The estimated investment requirements for emissions reductions in the APEC region may be overstated insofar as some economies decide not to implement such emissions reductions. On the

71 EIA (2003b).

other hand, the estimates are conservative in that they do not consider the costs of precipitators for particulate control or activated carbon injection equipment for quelling mercury emissions.

The annual average value in Table 29 represents the total amount of investments required divided by the 22-year period from 1999 to 2020. This annual average value is significant because of its possible implications for electricity prices. Of the estimated investment of US$1,464 billion required for additional electricity generating capacity in APEC economies from 2000 through 2020, the estimated investment for emission controls would represent a 14 percent share.

Table 29 Capital Costs of FGD and SCR Emission Control Equipment for Coal Plants in APEC Economies between 1999 and 2020 (Million US Dollars)

	Flue Gas Desulphurisation (FGD)			Selective Catalytic Reduction (SCR)		
Economy	**1999 Retrofit**	**Total cost**	**Annual average**	**1999 Retrofit**	**Total cost**	**Annual average**
Australia	3,388.6	4,094.8	186.1	1,257.3	1,519.3	69.1
Brunei Darussalam	-	-	-	-	-	-
Canada	2,411.6	2,578.4	117.2	894.8	956.7	43.5
Chile	274.9	274.9	12.5	102.0	102.0	4.6
China	26,734.3	54,237.3	2,465.3	9,919.5	20,124.2	914.7
Hong Kong, China	876.2	876.2	39.8	325.1	325.1	14.8
Indonesia	641.1	4,204.3	191.1	237.9	1,560.0	70.9
Japan	4,806.0	6,166.9	280.3	1,783.2	2,288.2	104.0
Korea	1,860.5	5,826.4	264.8	690.3	2,161.8	98.3
Malaysia	212.2	1,524.9	69.3	78.7	565.8	25.7
Mexico	358.3	2,539.6	115.4	132.9	942.3	42.8
New Zealand	53.0	53.0	2.4	19.7	19.7	0.9
PNG	-	-	-	-	-	-
Peru	-	34.5	1.6	-	12.8	0.6
Philippines	464.1	1,404.9	63.9	172.2	521.3	23.7
Russia	4,375.8	11,668.8	530.4	1,623.6	4,329.6	196.8
Singapore	-	-	-	-	-	-
Chinese Taipei	1,392.3	3,082.6	140.1	516.6	1,143.8	52.0
Thailand	348.1	1,720.0	78.2	129.2	638.2	29.0
United States	46,151.8	48,087.3	2,185.8	17,124.2	17,842.3	811.0
Viet Nam	161.5	943.8	42.9	59.9	350.2	15.9
Total	**94,510.2**	**149,318.6**	**6,787.2**	**35,067.1**	**55,403.3**	**2,518.3**

Figure 46 shows the share of estimated investment in electricity generating capacity that is represented by estimated emissions control costs for every APEC economy with planned or existing coal-fired capacity. Remarkably, the estimated share is as high as 60 percent in the United States, 32 percent in Australia and 27 percent in Hong Kong, China. The share is high in the United States due to a large base of existing coal-fired plants that need retrofitting and a moderate pace of new power plant construction relative to other APEC economies. In reality however, the share for the United States includes the cost of emissions retrofits to the 90 GW of existing installed capacity that is already fitted with SO_2 scrubbers due to emission reduction standards previously in place, so this part of the investment has already been made and is not required in the future.[72]

[72] EIA (2001).

Figure 46 Investment in Emission Control Equipment as a Share of Investment in Electric Generating Capacity in APEC Economies, 1999-2020

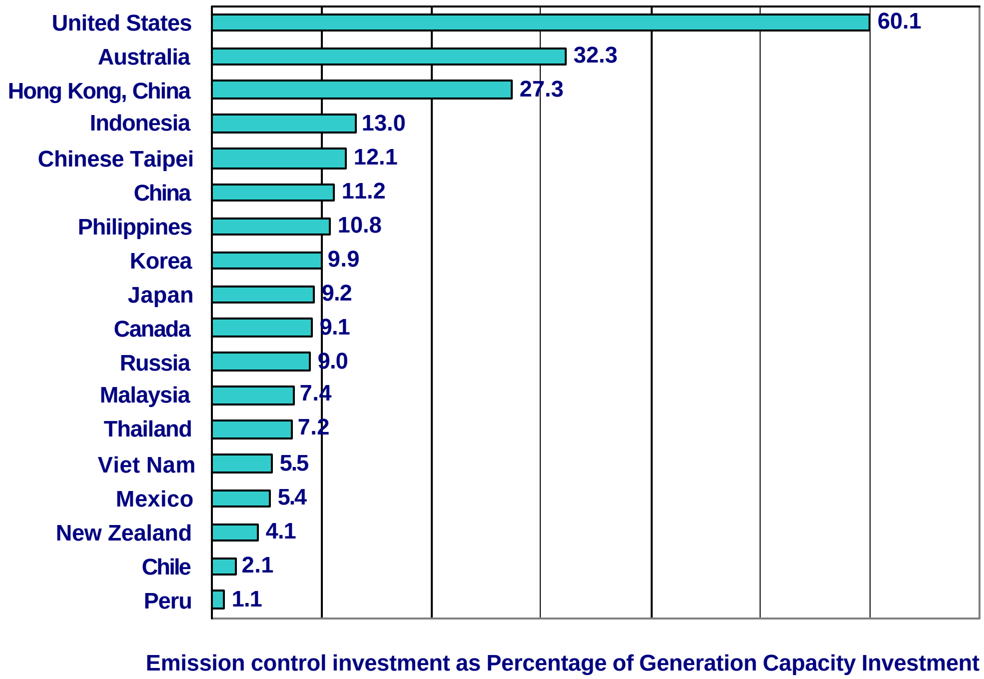
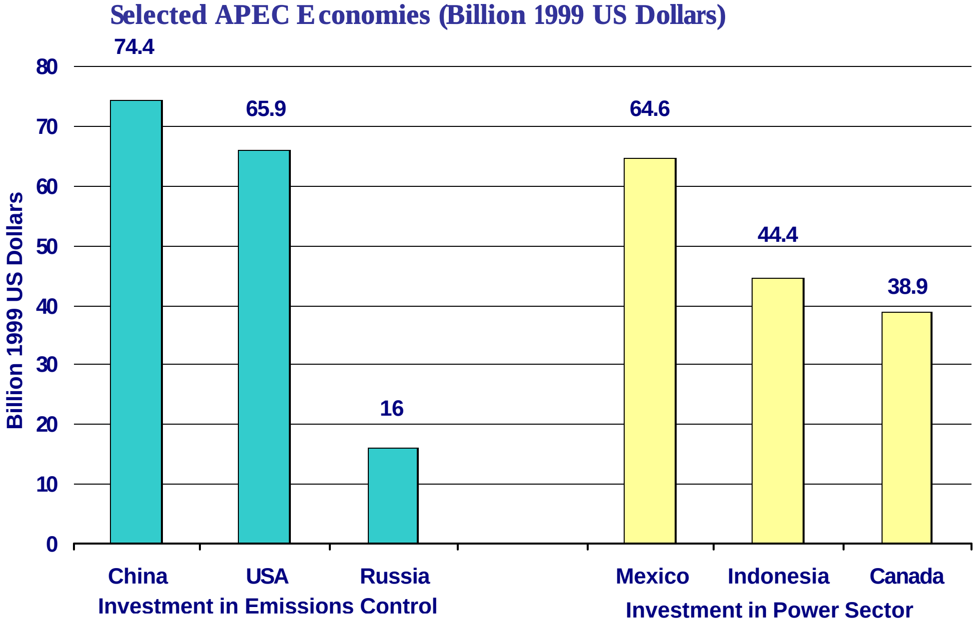


Figure 47 shows that the estimated emission control investments for the power sector in the three largest APEC economies would be similar in magnitude to the total estimated investment required for electric generating capacity in economies like Mexico, Indonesia and Canada.

Figure 47 Comparison of Emission Control and Power Infrastructure Investment in Selected APEC Economies (Billion 1999 US Dollars)



INVESTMENT IN FUEL SWITCHING AND DEMAND MANAGEMENT

An important means of limiting growth in carbon dioxide emissions from electricity production can be switching the fuels used in the generating mix. Significant reductions in CO_2 emissions can be achieved by switching from coal to natural gas, or from fossil fuels to nuclear or renewable energy. Fuel switching can be achieved by modifying existing power plants to use a different fuel, by replacing old power plants with ones that use different fuels, or by changing the intensity with which different types of available power plants are used to generate electricity. For example, oil-fired plants may be modified to use natural gas, coal-fired plants may be replaced by gas-fired plants, new gas-fired plants may make it possible to use existing coal-fired plants less often, and nuclear plants, hydropower or wind turbines may reduce the share of generation by fossil fuels.

Carbon dioxide emissions can also be reduced by limiting growth in electricity demand. Demand-side management policies can restrain consumption by promoting the use of technologies to use energy more efficiently in the residential, commercial and industrial sectors. Cogeneration of heat and power by industrial firms and in district heating systems can also limit net power demand.

Energy prices can play an important role in fuel switching and demand limitation measures alike. For example, if natural gas becomes more expensive or is projected to do so relative to other fuels, it will be more economically attractive to shift to coal-fired, nuclear or renewable generation, and it will also be more economically attractive to limit demand since the price of electricity will go up. If a market value were placed on carbon emissions, the impact on the cost of coal-fired power would be about twice the impact on the cost of gas-fired power, and there would be little or no impact on the cost of nuclear or renewable power, so shifts from coal to gas and from fossil fuels to carbon-free power sources would be promoted, and price increases would again curb demand.

APERC developed an alternative scenario to the base case of the *Outlook 2002* electricity demand projections with the purpose of analysing the impact that the application of fuel switching, demand side management and other energy efficiency measures could have on the future demand and supply of power in the APEC region.[73] This section assesses the impact that alternative scenario assumptions might have on power sector generating capacity investment requirements.

The APERC Alternative Supply and Demand Case for the power sector considers a more aggressive use of policies, measures and technologies to accelerate gains in energy efficiency and environmental protection. Gains are observed primarily through significant reductions in fuel use, reduced infrastructure needs and lower carbon emissions. It incorporates the following elements:

23. Greater share of less carbon intensive fuels in power generation, including natural gas and nuclear at the expense of coal and oil.
24. Greater share of new and renewable energy including biomass, small hydropower, wind, and solar.
25. More efficient centralised electricity generation technologies, including greater rates of refurbishment and retirement of older generating plants.
26. Retrofit and increased penetration of cogeneration through distributed generation for new industrial and commercial facilities.
27. Retrofit and increased penetration of more efficient demand-side technologies in the residential, commercial, and industrial sectors.

The results for the Alternative Supply and Demand Case are obtained with the LEAP model using the fundamental assumptions of APERC's *Outlook 2002* Reference Case and creating a new scenario with the new supply efficiency and fuel choice assumptions. The Reference Case, used as a basis for the estimations of investment requirements on all previous sections of this Chapter, already includes significant technological and energy efficiency improvements. The assumptions for the Alternative Supply and Demand Case are above this reference level. The Alternative Supply and Demand Case assumes that policy changes would be implemented during a policy period beginning in 2004 and continuing through 2020.

The Alternative Supply and Demand Case combines two distinct scenarios, modelled separately, which may be termed the Alternative Supply Case and the Alternative Demand Case.

[73] APERC (2002b).

The Alternative Supply Case includes increased use of low-carbon fuels, a greater share of renewable energy in power production, and improved average generating efficiency. The Alternative Demand Case includes traditional demand-side reductions and cogeneration savings.

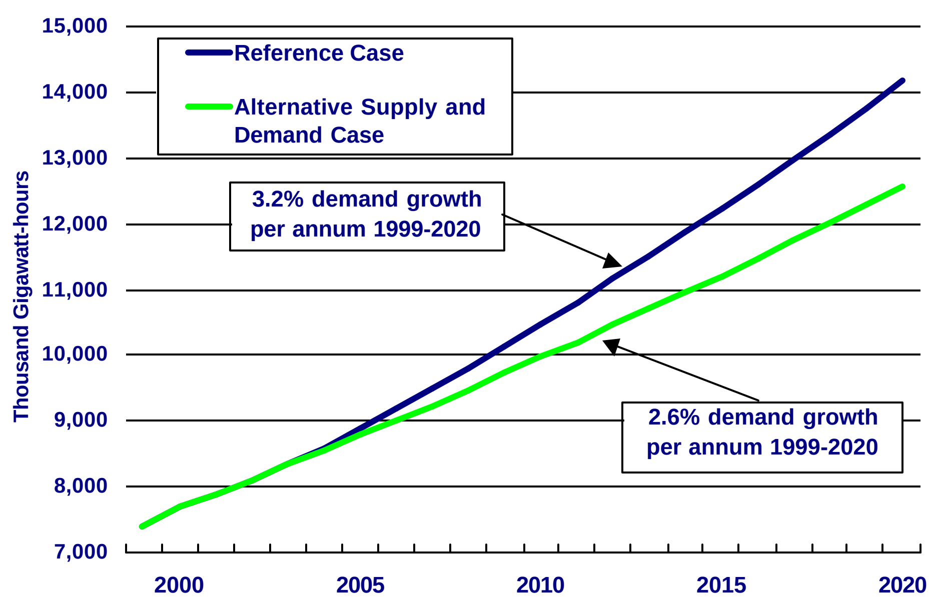
To estimate fuel savings and carbon dioxide emissions reductions from use of cogeneration, a conservative analytical method was employed. Cogeneration by customers will decrease fuel consumption on the interconnected grid but increase fuel consumption on site. The Alternative Demand Case calculates the net impacts of cogeneration, subtracting increases in fuel use and emissions on site from reductions in fuel use and emissions on the interconnected grid.

When supply and demand measures are combined, they may overlap to a significant degree. For example, if there are reductions in demand, then the addition of more environmentally friendly and efficient supply may not be needed. Conversely, if there is very efficient central generation supply, then a cogeneration policy programme might prove an unnecessary expense. As a result, the combined Alternative Supply and Demand Case may double count benefits to some extent.

The LEAP model does not duplicate savings by simply combining the two sides of the equation, but rather gives an average result. It is up to each economy to choose the combination of measures or policies that would produce gains in efficiency that the model estimates. The final savings in each economy would depend on its circumstances and how appropriate its policy mix is.

Figure 48 shows that demand growth over the policy period would average 2.6 percent per annum in the Alternative Supply and Demand Scenario, compared with 3.2 percent in the Reference Case.

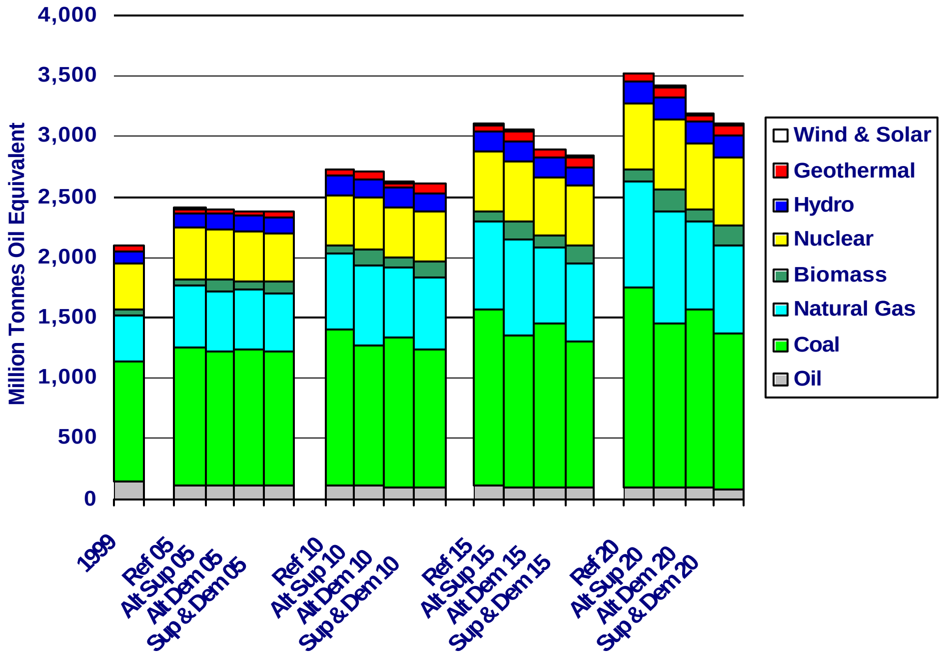
Figure 48 Outlook for Electricity Demand in APEC (1999-2020)



Source: APERC (2002b).

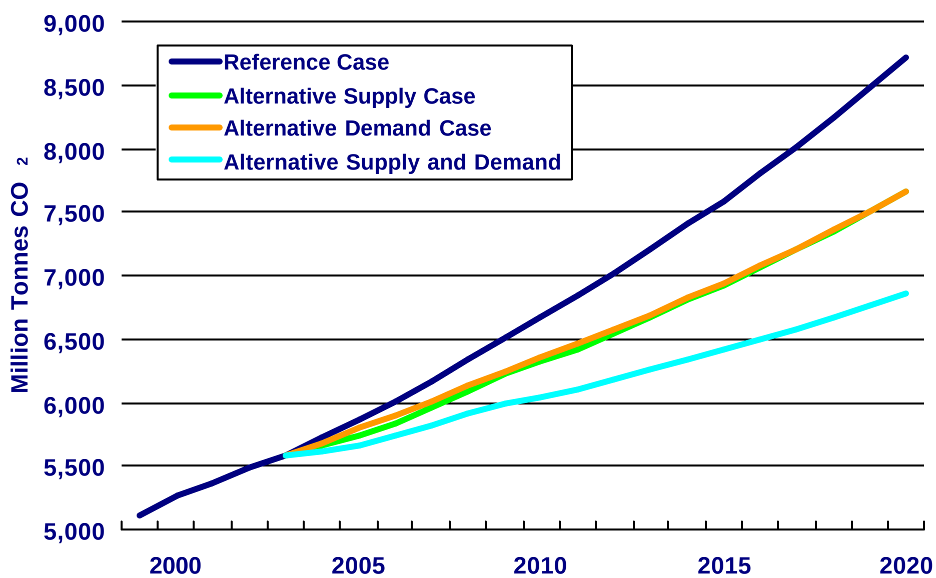
Figure 49 indicates how the Alternative Supply and Demand Case would affect energy inputs to electricity generation. Energy inputs to generation could be reduced by 425 Mtoe, which is roughly equivalent to half the energy inputs of the United States or double those of Japan in 1999. Energy inputs to generation would also be reduced by 12.1 percent compared with the Reference Case. Coal consumption would decline by 371 Mtoe, natural gas consumption by 147 Mtoe and oil consumption by 17 Mtoe. Biomass consumption would grow by 65 Mtoe, nuclear and geothermal energy by 19 Mtoe, wind and solar energy by 4 Mtoe, and hydroelectricity by 1 Mtoe.

Figure 49 Scenario Comparison on Inputs for Power Generation in APEC



Source: APERC (2002b). Notes: **Ref** – Reference Case. **Alt Sup** – Alternative Supply Case. **Alt Dem** – Alternative Demand Case. **Sup & Dem** – Alternative Supply and Demand Case.

Figure 50 Scenario Comparison of Carbon Dioxide Emissions in APEC Economies



Source: APERC (2002b).

As shown in Figure 50, alternative scenarios would reduce growth in carbon dioxide emissions substantially. In the Reference Case, power sector CO_2 emissions are projected to grow an average of 2.6 percent per annum through 2020. In the Alternative Supply Case, with improved energy conversion efficiency and greater utilisation of lower-carbon energy sources, growth in power sector CO_2 emissions could be reduced to 1.9 percent per annum. In the Alternative Demand Case, with end-use efficiency improvements and greater use of cogeneration, growth in power sector CO_2 emissions could also be reduced to 1.9 percent per annum. In both the Alternative Supply Case and the Alternative Demand Case, power sector CO_2 emissions in 2020 would be 12.1 percent below those in the Reference Case. In the combined Alternative Supply and Demand Case, growth in power sector CO_2 emissions could be further be reduced to 1.4 percent per annum, so that power sector CO_2 emissions in 2020 would be 21.3 percent below those in the Reference Case.

The supply-side and demand-side investments that would needed to obtain such reductions in CO_2 emissions growth are shown in Figure 51. Perhaps surprisingly, investment requirements in the Alternative Supply Case are similar to those of the Reference Case. As seen in Table 30, investment requirements in the two scenarios differ by only 3 percent over the period from 2000 through 2020. In the Alternative Supply Case, the model chooses additional nuclear and renewable capacity, which has relatively high capital costs and tends to raise investment needs, but it also chooses additional gas-fired capacity, which has relatively low capital costs and tends to reduce investment needs.

Figure 51 Scenario Comparison of Annual Investment Requirements in APEC Economies

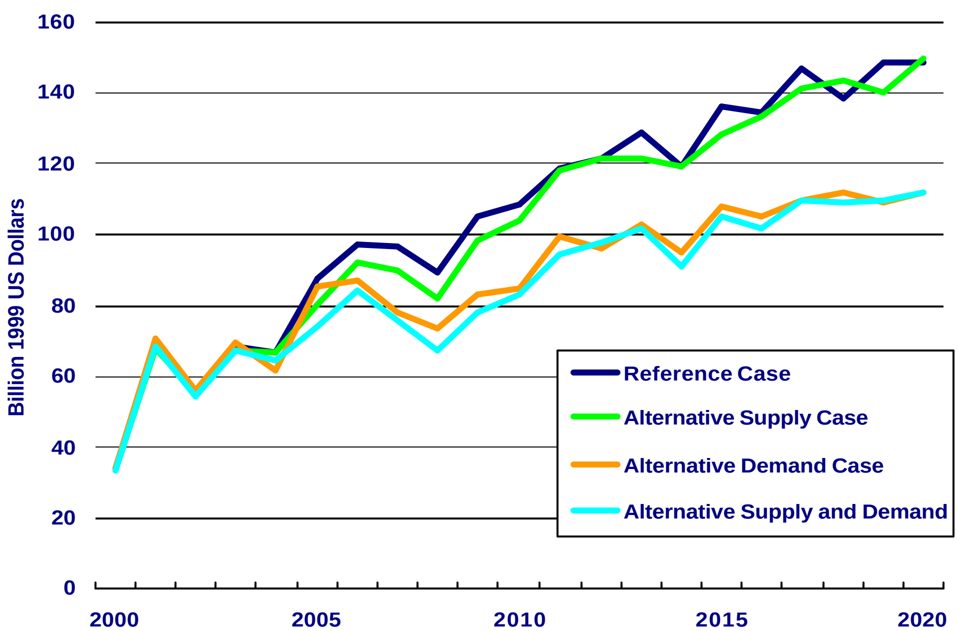
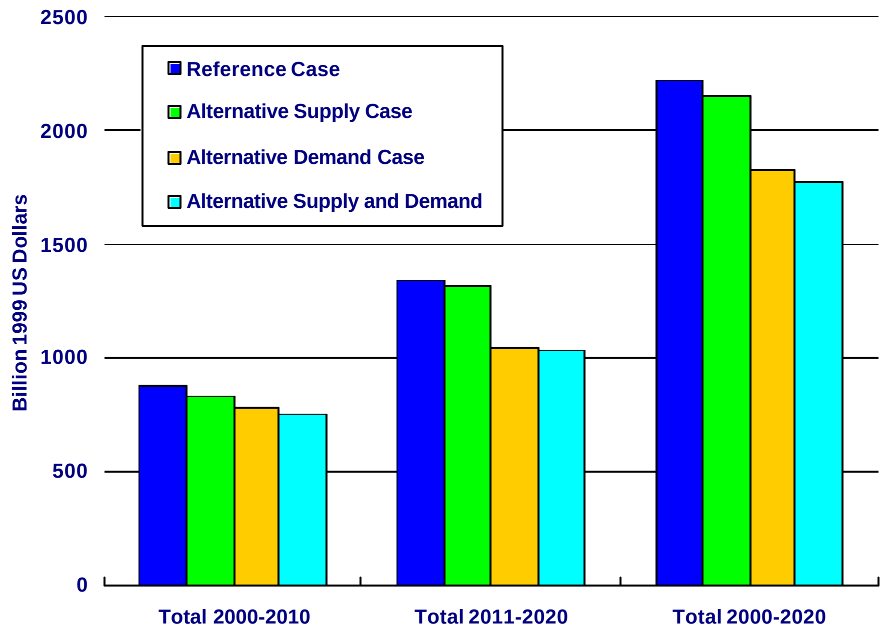


Table 30 Electricity Generation and Transmission Investment in APEC Economies, Reference Case and Alternative Scenarios (Billion 1999 US Dollars)

Analytic Case	2000	2010	2020	2000-2010	2011-2020	2000-2020
Reference Case	33.8	108.1	148.5	877.2	1,341.9	2,219.1
Alternative Supply Case	33.3	103.8	149.5	836.8	1,316.8	2,153.6
Alternative Demand Case	33.8	84.6	112.2	782.8	1,049.7	1,832.5
Alternative Supply and Demand	33.2	83.2	111.6	749.6	1,031.2	1,780.8

Since the Alternative Supply Case has about the same projected power sector investment costs as the Reference Case, the major investment cost savings in the combined Alternative Supply and Demand Case are due almost totally to the Alternative Demand Case incorporating demand side management and cogeneration measures. As seen in both Table 30 and Figure 52, the Alternative Supply and Demand Case reduces total power sector investment needs from 2000 through 2020 by 20 percent compared with the Reference Case. Yet the Alternative Demand Case, even without supply measures, achieves the bulk of these investment cost reductions, alone reducing power sector investment needs over the two-decade projection period by 17 percent.

Figure 52 Scenario Comparisons of Total Investments in Electricity Generation and Transmission in the APEC Region (Billion 1999 US Dollars)



While the Alternative Supply and Demand case would have a much greater impact on carbon dioxide emissions than the Alternative Supply Case or the Alternative Demand Case by itself, as seen earlier, the greater cost savings in the demand-side case would seem to suggest that demand-side measures be given a preference if both demand- and supply-side measures cannot be undertaken simultaneously. The Alternative Demand Case would have about the same impact on carbon dioxide as the Alternative Supply Case, but it would entail 15 percent lower power sector investment requirements over the period from 2000 through 2020, as well as much lower fuel costs. Caution must be used in interpreting these results, however, since the costs and effectiveness of demand-side management policies will naturally differ widely from economy to economy.

An important factor affecting the projections of investment requirements is that the Reference Case shows a large percentage of coal and oil-fired generation capacity in the APEC region. Of total installed generating capacity in 2020, some 1,114 GW or 34 percent is projected to be coal fired, while 338 GW or 10.3 percent is projected to be oil-fired.[74] As explained above, since the cost of new coal- and oil-fired power plant technology in the Reference Case already includes certain efficiency and environmental protection improvements, the Reference Case already carries a higher environmental protection price tag than might otherwise be the case. The reference *Outlook 2002* power industry projections were developed on the basis that newly installed plants would be of the newer, cleaner designs available now and likely to dominate in the future, in part because of the policies in place in most APEC economies expressing a preference to follow that direction.

[74] APERC (2002a).

Several conclusions can be drawn from these results. The first is that there are economic incentives in pursuing an Alternative Supply Case that includes nuclear and renewable power technologies, as these capital intensive technologies will tend to be balanced out by less expensive gas-fired power plants. On the other hand, comparable CO_2 emissions reductions could be obtained with demand side management and cogeneration policies that at the same time allow for relatively greater savings in infrastructure capacity and in fuel consumption.

The savings on investment costs in the Alternative Demand Case provide a metric against which the costs of demand side policies can be measured. The projected reductions in investment needs are US$387 billion over the period from 2000 through 2020, or 17.4 percent relative to the Reference Scenario. The large potential savings on generation and transmission investment would seem to indicate a high potential rate of return on demand side management programmes.

Moreover, estimates could be made of the impact that assumptions of the Alternative Supply and Demand Scenario would have on the rest of the energy industry. A different fuel mix in power generation could have major effects on the energy balances of some APEC economies, changing the pattern of imports, exports, fuel processing and fuel transportation. If the resulting impacts on investment needs were analysed together with the costs of efficiency measures and the savings on power sector investment shown above, an overall estimate could be obtained of the net benefits of Alternative Supply and Demand Case policies. This could be a promising area for further research.

FINANCING ENERGY PROJECTS IN DEVELOPING AND TRANSITIONAL ECONOMIES

INTRODUCTION

As explained earlier in this report, APERC estimates that energy investments in the APEC region will amount to between US$3.4 trillion and US$4.4 trillion over the first two decades of the century. Power sector investments will take up the largest share, followed closely by those in oil and gas resources development, coal resources development and their transportation. Financing investments of such magnitude will pose challenges to energy industries throughout the region. However, the challenges are arguably greatest for developing and transitional economies, not only because their energy investment burdens are often greater as a share of economic output, but also because their capital markets are less well developed and offer fewer options for obtaining funds.

In developing and transitional APEC economies, governments are less and less willing to finance energy projects from public budgets. Budgets are tight, and if energy projects can be financed from private sources, public moneys are better spent on social programmes for which private financing cannot be obtained. Yet capital markets in these economies are at an early stage of development, so private financing may be costly or unavailable. Opaque laws, inconsistent regulations, political risks and new firms without a proven track record can all raise the cost of financing to unsustainable levels.[75] This chapter examines capital markets and project financing in developing economies with a view toward strategies that can help bridge the gap between the interests of lenders and the needs of investors.

DEVELOPMENT OF DOMESTIC CAPITAL MARKETS

Many developing APEC economies have high savings rates, representing 20 to 30 percent of GDP. However, their domestic capital markets are generally under-developed so that the necessary financial resources for energy sector investment may not be readily available from internal sources. Their equity markets have not been very liquid, and their bond markets usually lack the stabilizing presence of large institutional investors such as pension funds and insurance companies.

Table 31 summarises the status of stock and bond markets in the Group C APEC economies of China, Indonesia, Papua New Guinea, Philippines, Thailand, Russia and Viet Nam (Peru is left out). Most of these lower-income developing economies rely on bank lending for well over half of all project financing. This is mainly because their bond and equity markets are at an early stage of development. While stock market capitalisation amounts to more than three-fifths of GDP in the Philippines and nearly half of GDP in Indonesia, it is much smaller in the other economies listed. Bond financing represents about a fifth of overall funding for investment projects in Papua New Guinea and Thailand and Viet Nam but much less in the other economies shown.

In light of the way that most developing economies have industrialised and built up their energy sectors, their heavy reliance on bank lending is not surprising. Historically, the state has often intervened in financing long-term investments, so a combination of self-financing and lending through state-owned banks and development banks has played a major role in financing long-term investments.[76] Later, as state intervention in the financial system was scaled back, commercial bank lending and self-financing have become the major financial sources for energy companies. In the transitional economies of China and Russia, state banks are still a major source of financing.

---

75 Petroleum Economist (2003).

76 Sharma (2000).

Generally speaking, commercial bank loans have short maturities that are not appropriate for long-term energy projects. The reason that a large number of energy projects have been financed through bank lending is borrowers' typical expectation that loans of short maturities will be periodically renewed (rolled over) by banks over an extended portion of each project's life.

Table 31 Role of Different Financing Options in Group C APEC Economies

Economy	Bank Lending	Bond Market	Stock Market
China	Represented 80% of total funding in 2000.	Small market. Inter-bank trade on an over-the-counter basis.	Two markets, in Shanghai and Shenzhen, dominated by state-owned enterprises (SOEs).
Indonesia	Dominant source of funding.	Small market at a nascent stage of development.	Number of listed companies grew from 125 in 1990 to 290 in 2000. Stock market capitalization is equivalent to 45% of GDP.
Papua New Guinea	Major funding source.	Represents about 20% of total financing sources. Only a few customers actively participate.	Market introduced in 2002.
Philippines	Represented 58% of total funding in 2000.	Corporate bond market is almost entirely absent due to a volatile macroeconomic environment.	Number of listed companies grew from 153 in 1990 to 230 in 2000.
Thailand	Represented 61% of total funding in 2002.	Represented 22% of funding in 2002. Needs stronger regulatory framework, secondary market liquidity and investor base.	Represented 17% of total funding in 2002.
Russia	Dominant source of funding.	Government bond: US$7 billion (2000). Corporate bond market is small and under-developed.	Gradually developing since 1994. Total capitalization around 10% of GDP in 2000. Liquidity is low.
Viet Nam	Represented more than 70.3% of total funding in 2001.	Under-developed. Commercial banks plan to issue bonds worth USD 520 million in 2003-2004.	One stock market in Ho Chi Minh City with 17 listed stocks in 2000 valued at less than 0.2% of GDP. Hanoi stock exchange is to open around the end of 2003.

Source: APERC Database (2003).

Bond financing is often preferable for large-scale investments for two reasons. Firstly, bonds provide long-term capital for investment in energy projects at lower interest rates than commercial loans. Secondly, bonds issued in domestic capital markets can replace some portion of borrowings denominated in foreign currency. This reduces the currency mismatch between domestic currency assets and foreign currency liabilities, which is a source vulnerability in many financial systems.

BOND MARKETS IN ASIAN ECONOMIES

During the Asian financial crisis of 1997, some economies learned the painful lesson that over-reliance on short-term borrowing to fund long-term projects can lead to a financial disaster because of mismatches in loan maturity.[77] Excessive short-term borrowing was not intended by most Asian economies, rather, it was inadvertently imposed by the scarcity of long-term capital.[78]

Table 32 compares bond markets across selected economies in order to better understand them. The relative size of the bond market in each economy is calculated as the dollar amount of bond issuance divided by gross domestic product. Total, public and corporate bond markets before the Asian financial crisis, in 1996, are compared with bond markets afterwards, in 2000. Reliance on

[77] Lee (2000).

[78] APERC (2001).

bond markets has increased sharply in all Asian economies but still differs widely among them. Korea and Malaysia have far more developed bond markets than China, Indonesia and Thailand, where the public bond market is substantial but the corporate bond market remains in its infancy.

Table 32 Size of Bond Markets Relative to GDP in Selected APEC Economies

Economy	Domestic Bond Market as Share of GDP		Public Bond Market as Share of GDP		Corporate Bond Market as Share of GDP	
	1996	2000	1996	2000	1996	2000
China	14.6%	30.1%	10.3%	21.0%	0.5%	0.8%
Indonesia	0.15%	0.01%	0.13%	0.01%	0.02%	0.00%
Korea	45.9%	58.4%	8.4%	15.9%	17.4%	20.3%
Thailand	10.4%	25.5%	6.4%	21.2%	2.5%	4.0%
Malaysia	72.5%	85.3%	29.9%	31.6%	23.3%	47.2%
USA	110.2%	147.8%	91.5%	81.7%	58.3%	24.2%

Source: APERC Database (2003).

The reason for limited issuance of corporate bonds in China, Indonesia and Thailand relates to institutional settings of these economies. In Indonesia and Thailand, for example, there persist inter-locking relationships between banks and companies. As Beckman points out, since nearly all the private banks in Indonesia are owned by conglomerates, companies choose to rely on relatively easily available bank loans instead of going through lengthy approval process for issuing bonds.[79] The inter-locking relationship between banks and companies are strong in Thailand as well.

China's limited issuance of corporate bond is partly due to the inter-locking relationship between banks and State Owned Enterprises (SOEs). Historically, the big banks have served as conduits through which the government can allocate financial resources to state owned enterprises (SOEs) so that SOEs can meet priorities specified in the Five Year Development Plan. In other words, necessary funds are mostly made available through bank loans.

In order to efficiently channel the private financial sources to energy projects, economies at the early stage of development need to undertake domestic capital market development, especially bond market for corporate sector. But experience in developed economies suggests that development of domestic capital markets would take time and requires institutional changes. Meanwhile, companies in developing economies can finance energy projects by issuing equities in international stock exchanges, by issuing bonds in international markets, and by borrowing from multilateral institutions and regional development banks.

Box 3 Plans to Create an Asian Bond Market

Seven finance ministers from the economies of ASEAN + 3 (China, Japan and Korea) met in August 2003 to discuss regional integration of economic and financial activities. They agreed to cooperate in creating a common bond market in Asia. Most central bank reserves in these economies are invested outside of Asia, so that savings in Asian economies are financing investment and spending elsewhere. The Asian Bond Market is designed to allow long-term investment in the ASEAN + 3 region to be financed through the issuance of bonds denominated in local currencies, thereby reducing the region's dependence on US and European debt markets. To create such a market, governments need to consider how best to coordinate legal and institutional settings in order to create an environment that is conducive to active participation by both issuers and investors.

Sources: The Japan Times (2003), Xinhua News Agency (2003), Channel New Asia (2003).

[79] Beckman (1999).

INITIAL PUBLIC OFFERINGS ON INTERNATIONAL STOCK EXCHANGES

Listing on international stock exchanges, such as Hong Kong and New York, gives companies the opportunity to efficiently channel private financial resources. Increasingly more firms in developing Asian economies are using this type of financing mechanism. As Table 33 illustrates, oil companies of selected economies in Asia have either listed their shares in international stock markets or planned to get listed. In China, for example, Sinopec, the China National Petroleum Corporation (CNPC) and the China National Offshore Oil Corporation (CNOOC) successfully conducted initial public offerings (IPOs) in which private investors were offered a minority holding between 10 percent and 27.5 percent of the shares in each firm, with Chinese government retaining the majority of shares.

Minority listing on international stock markets is an attractive option for developing economies as it makes firms globally competitive while governments can still retain control over their operations. A successful equity offering requires the companies to improve their operational efficiency to a level that can meet international standards. Yet, by maintaining the majority shares in each firm, the government can continue to control its operation as before.

Table 33 Some Recent Capital Raising Measures in APEC Economies

Economy	Company	Date	Status of Privatisation
China	CNOOC	February 2001	CNOOC listed 27.5% of its shares on New York and Hong Kong stock exchanges, raising US$1.3 billion.
China	PetroChina	October 2000	PetroChina, a subsidiary of China National Petroleum Corporation (CNPC), offered 10% of its shares on New York and Hong Kong stock exchanges, raising US$2.9 billion.
China	Sinopec	April 2000	Sinopec listed 20% of its shares on various stock exchanges and raised about $3.5 billion.
Viet Nam	PetroVietnam		Government allows domestic firms to issue bonds to the public. PetroVietnam is considered as one of the first to raise capital through public offerings.

Source: APERC (2003).

ISSUANCE OF BONDS IN INTERNATIONAL MARKETS

Issuance of bonds in developed economies has been an effective means for financing energy projects in developing economies. Before determining the types of bond, an issuer must consider such factors as regulatory requirements, financial costs, issuance costs, and debt maturities.

Eurobonds provide an important instrument for bond issuance by developing economies. Eurobond offers are underwritten by an international syndicate of banks and security firms who agree to buy a certain amount of securities on a given date and a given price, assuring the issuer the full proceeds of the financing. Since no regulatory authority that oversees the bond issuance, there is no need for issuers to satisfy the lengthy regulatory requirements that apply to public offerings. Eurobonds have higher issuance costs but lower financial costs than other options.

Issuing bonds in the US 144A market (which can be used for equity offerings as well) is also an attractive option for financing energy projects in developing economies. The US 144A market was established in 1990 by the US Securities and Exchange Commission (SEC) to allow foreign companies access to the US capital market. Under 144A, bonds are issued to a limited number of investors in a private placement, rather than in a public offering. Thus, the lengthy approval process and detailed financial disclosure requirements of public offerings are avoided. Maturities are generally longer in the US 144A market than in the Eurobond market, but they can vary depending on the particular guarantees provided by state governments or lending organisations.

MULTILATERAL DEVELOPMENT INSTITUTIONS

Multilateral institutions are playing a catalytic role in making private financial resources available to developing economies. Apart from making loans, such institutions make resources available by providing partial guarantees on bond issuance. According Razavi (1996), lending from multilateral institutions such as IMF and World Bank does not exceed $10 billion per annum while overall annual world investment requirement for energy sector is more than $150 billion.

Even though multilateral financial institutions directly provide only a small portion of the total financing required in the energy sector, their participation is quite important to developing economies for several reasons. First, it improves the creditworthiness of projects in the eyes of private financiers and investors. Second, it provides some assurance of transparent legal, administrative and regulatory procedures. Third, it is often accompanied by partial bond guarantees to share project risks with bond issuers.

A case of the Philippines' National Power Corporation (NPC) offers an interesting illustration on how successfully the World Bank involvement helped NPC to issue bonds. NPC bonds tapped the Eurobond and US 144A markets in 1995 with the World Bank providing partial credit guarantee. With the support by the Bank's guarantee programme, NPC obtained a 15-year maturity, longer than the longest maturity previously attained by Philippine sovereign entity (10 years).[80]

BILATERAL FINANCING AGENCIES

Export-import banks of industrialised economies are the main agencies for bilateral financing of energy projects. Assistance from such banks is closely tied to the interests of the governments by which they are funded. In general, loans offered by export-import banks have longer maturities than commercial bank loans, a major advantage for energy projects since they have long lifetimes. However, such loans often have conditions attached to them related to the strategic interests of the lending economy, such as the purchase of specific products or services from that economy.

Table 34 shows the ten largest mandated arrangers for financing energy project in Group C APEC economies. Mandated arrangers are banks with primary responsibility for loan syndication. Japan Bank for International Cooperation (JBIC), an export-import bank of Japan, is ranked as the top mandated arranger for energy projects in Group C economies. JBIC is involved with projects such as Sakhalin II LNG terminal construction in Russia and restructuring of Paiton power plants in Indonesia. In each case, Japanese companies are involved as a project sponsor or as an "EPC contractor" providing engineering, procurement and construction services.

Table 34 Ten Largest Mandated Arrangers for Energy Project Financing in APEC Group C Economies, 1994-2002

Rank	Mandated Arranger Name	Location	Amount (Million US$)	Number of Projects
1	Japan Bank for International Cooperation (JBIC)	Japan	$2,865.04	14
2	Bank of Taiwan	Chinese Taipei	$2,255.50	2
3	Mitsubishi Tokyo Financial Group Inc	Japan	$1,113.52	11
4	Mizuho Holdings Inc	Japan	$1,027.30	13
5	Sumitomo Mitsui Banking Corp	Japan	$872.66	13
6	UFJ Holdings Inc	Japan	$790.68	12
7	Bangkok Bank pcl	Thailand	$394.13	6
8	China Construction Bank	China	$391.50	3
9	Krung Thai Bank plc	Thailand	$334.16	4
10	Siam Commercial Bank pcl, Bank of Ayudhya pcl	Thailand	$326.29	4

Source: Dealogic Database (2003). Mandated arranger is the institution(s) responsible for putting together the financing.

80 World Bank (1995).

DEVELOPING FINANCING PACKAGES

Sponsors of energy projects, whether they are governments or private firms, need to assess the entire menu of financing options to choose a mix that balances the merits and demerits of each:

28. **Commercial bank loans** are more readily available than bond or equity financing. Bank loans have shorter maturities than bonds, averaging five or six years. Interest rates on bank loans are generally higher than those that must be paid on bonds.
29. **Loans from multilateral institutions** or **bilateral agencies** have longer maturities than commercial bank loans, averaging around ten years, but are not readily available. Loans from bilateral agencies are confined to projects that meet the goals of investing economies, and they may carry restrictive purchase provisions.
30. **Bond financing** is well suited to energy projects since bonds have relatively long maturities, typically ranging from five to ten years (sometimes longer depending on guarantees provided) and carry lower interest rates than commercial bank loans. But bond financing usually requires a lengthy approval process, and legal and administrative expense of issuing bonds can be 3 percent of the amount issued.
31. **Equity financing** is costlier than bond financing since stockholders have a greater risk than bondholders of being unable to recover their capital if projects should fail. However, the issuance of stock also reduces the risk to bondholders, helping to limit the cost of debt financing. Equity financing may also spur companies to improve their operations in order to attract and retain the interest of investors.

In developing a financing package, sponsors of an energy project need to balance their key objectives against the advantages and disadvantages of various financing options. Generally, the equity portion provides between 20 and 40 percent of the total financial requirements, while the debt portion provides between 60 and 80 percent. A higher equity share represents a higher commitment by project sponsors, which makes the project less risky to lenders.

In terms of the term structure of each financing option, project sponsors have several goals:

32. Maximize debt maturity;
33. Minimize cost of debt;
34. Minimize covenant restrictions;
35. Maximize flexibility of terms on post-closing; and
36. Minimise time to achieve closing.

RISK HEDGING ARRANGEMENTS

Capital may not be readily available to energy projects because a host of risks can endanger steady cash flow to service debt and to earn adequate return on equity. Those risks are broadly classified as project-specific risks or host economy risks. Examples of project specific risks include cost overrun incurred from delay in construction, market risks such as sudden decline in demand, lack of raw material supply, and lack of infrastructure needed to operate project. Risks in relation to host economy conditions include currency inconvertibility, regulatory changes, losses from expropriation, nationalisation and confiscation. These risks were detailed earlier in this study.

In order to reduce project risks, a number of agreements are made between sponsors and concerned parties including buyers and EPC contractors. Those agreements can increase sponsors' creditworthiness to service debt, thereby reassuring financiers. For example, LNG projects have high capital investment requirements, partly because gas has a very high volume per unit of energy content and partly because LNG involves a complex series of processes including liquefaction, shipping and regasification. With financing costs so high, financing had not been readily available for LNG projects unless there was a documented customer base to generate sufficient cash flow. To increase the creditworthiness of sponsors, take or pay contracts have been the norm for LNG projects, since such contracts ensure the long-term purchase of a fixed amount of commodity.

Host governments, multilateral institutions and export credit agencies play important roles in mitigating host economy risks. They can issue guarantees to ensure that loans and equity investments will be repaid in case contingencies make project sponsors unable to service their debt.

EXAMPLES OF FINANCING ENERGY PROJECTS

To better understand the role of different players in financing energy projects in developing and transitional economies, this section examines three recent examples of financing energy project. The Sakhlin II project in Russia is described to examine the financial role of export credit agencies. The Laibin B Power project in China is described to consider the financial role of governments. Build-operate-transfer projects in the Philippines illustrate the financial role of private corporations.

EXPORT CREDIT AGENCIES AND SAKHALIN II PROJECT FINANCING IN RUSSIA

The Sakhalin II project involves investment of US$10 billion to develop oil and gas fields in the Okhotsk Sea near Sakhalin Island of Russia's western coast. The project is divided into two phases. The first phase is to produce up to 90,000 barrels of oil a day from the Piltun-Astokhskoye field. The second phase involves the development of the Piltun-Astokhoskoy oil field and the Lunskoye gas field. When the second phase is completed, there will be three offshore platforms, 800 km of oil and gas pipeline from the south of Sakhalin to the port of Prigorodnoye, and natural gas liquefaction plants with a total production capacity of some 9.6 million tonnes per annum.

In the Soviet era, Sakhalin Island was a heavily subsidised periphery that Russian central government has a strong incentive to reverse the economic decline with the advent of economic reform. Currently the majority of the Sakhalin population has relatively low income. According to the Sakhalin Regional Administration for Labour, the average monthly income in 1999 was US$55, while one out of three Sakhalin inhabitants was living on less than that amount.[81] Increased production and exports of crude oil and gas is likely to bring economic and social benefits to Sakhalin Island. Also, the successful implementation of the project under a production sharing agreement will pave the way for foreign investment in other oil and gas projects in Russia.

The first phase of the Sakhalin project, diagrammed in Figure 53, was the largest green-field Russian oil and gas project based on non-recourse finance.[82] The Sakhalin Energy Investment Company, the operator of the Sakhalin II project, is owned by Shell (62.5 percent), Mitsui (25 percent) and Mitsubishi (12.5 percent). Three banks provide loans for the project: the European Bank for Reconstruction and Development (EBRD), Citibank with the guarantee of the United States Overseas Private Investment Corporation (OPIC) and the Japan Bank for International Cooperation (JBIC), with each lending amounts $116 million. Involvements of three export credit agencies in the Sakhalin II project are based on different rationales:

37. EBRD's mission is to further economic development in the former Soviet bloc. By contributing to financing for Sakhalin II projects, the EBRD promotes economic development of Sakhalin Island and boosts the flow of foreign capital to the Russian Federation.

38. OPIC's mission is to mobilise and facilitate the participation of US private capital in projects that facilitate the economic development of less developed economies or economies in transition.[83] For Sakhalin II project, OPIC provides guarantee to

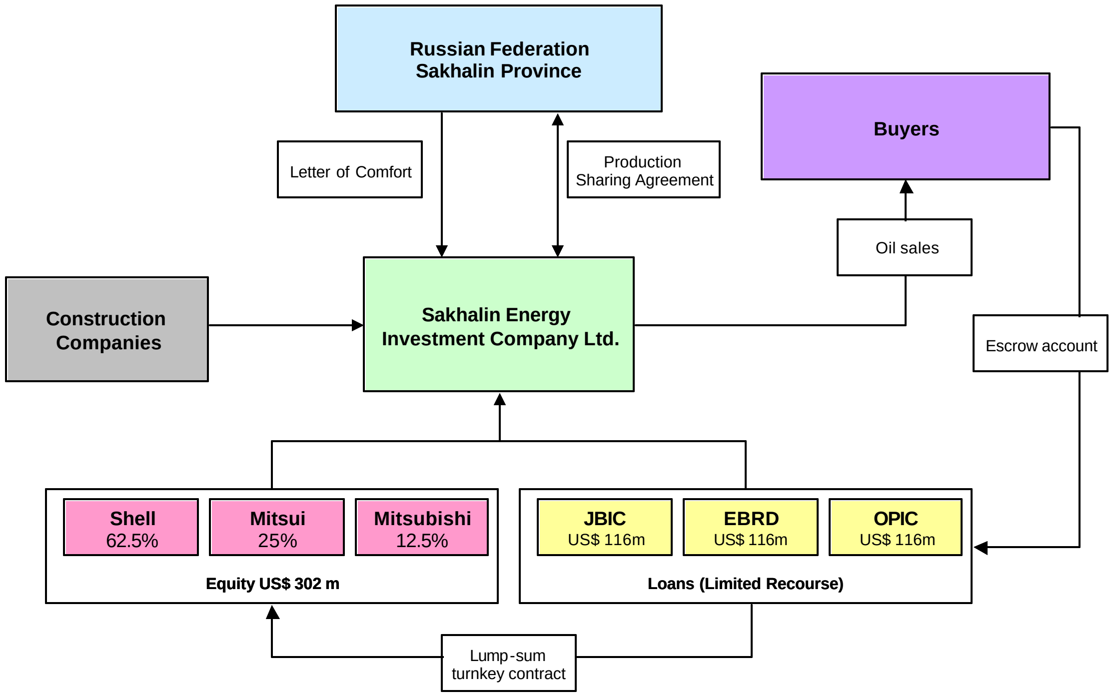
[81] Sakhalin Regional Update (1999). By comparison, average subsistence income in Russia in 1999 was estimated at US$34.

[82] Sakhalin Energy (2003).

[83] Connelly (2002).

the loans from Citibank in order to insure such risks as currency convertibility and deterioration of investors' ability to service its debt. At the time of financial closer in December 1998, OPIC's participation was closely linked with their intention to offer financial support to the two shareholders from US, Texas-based Marathon Oil Company and Luisiana-based MacDermott International Incorporated, both of which transferred their stakes to Shell in December 2000.[84]

Figure 53 Financing Structure of Sakhalin II Project – First Phase



Source: Sekiyu Kaihatsu Jiho (2000) and APERC (2003).

39. Involvement of JEXIM is closely connected with the fulfilment of national objectives for Japan rather than the simple attainment of commercial gains. In other words, oil and gas imports from the Sakhalin II project is meant to contribute to the enhancement of energy source diversification of Japan, which relies about 80 percent of oil and gas imports on the Middle East.

A number of agreements are made in order to minimise project risks. One is the lump-sum turnkey contract, which ensures the project sponsors that the project will be completed on time, within budget and according to appropriate standards. Escrow account is the agreement between the buyers and lenders so that the part of the revenue is channelled to service the debt.

Implementation of a production sharing agreement (PSA) holds the key to the success of Sakhalin II project. The main purpose of a PSA is to protect investors in an environment where laws are vague and taxation is highly complex. Without a production sharing agreement, a conventional natural mineral resource project in Russia would be subject to various taxes, royalties and surcharges that are subject to frequent revision and potentially total more than 100 percent of revenues. These include royalties of 6 percent to 16 percent, geology fund payments of 10 percent, value-added tax of 20 percent, excise tax on production or sales (14 percent), profit tax (38 percent), pension fund payments (28 percent), state employment fund contributions (2 percent), social insurance (5.4 percent), medical insurance (3.6 percent), education fund (1 percent), militia fund (2 percent), and transport fund (1 percent), excess wage tax (38 percent), property tax (2 percent), and land-use payments, as well as customs duty, excise tax and value-added tax on imports.

[84] Overseas Private Investment Corporation (2003).

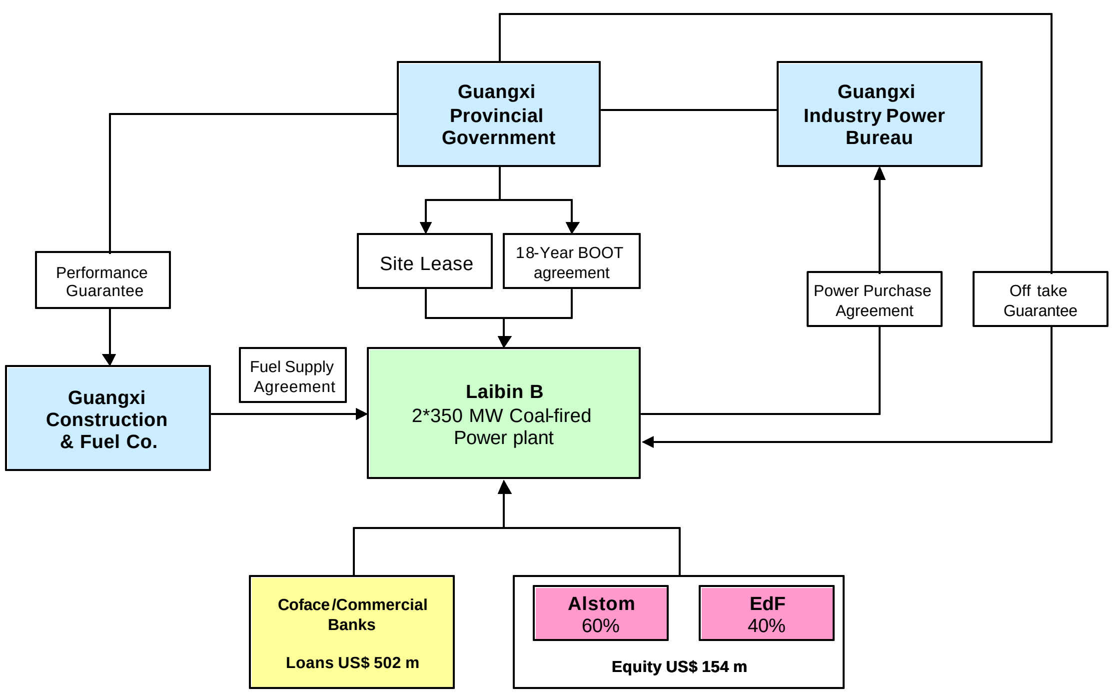
For the Sakhalin II project, information on how profits are split between investors and the government is not available due to confidentiality clauses in the associated contracts. But the available information from Sakhalin IV shows how the profit split in Russian PSAs can change based upon a project's internal rate of return (IRR).[85] At an IRR of less than 22 percent, the split from the hydrocarbon profit is 70 percent to the company and 30 percent to the Russian Federation. For an IRR of 22 percent to 26 percent, the split is 60 percent to the company and 40 percent to the Russian Federation. At an IRR above 26 percent, the profit split changes by 10 percent for every 2 percent of increased IRR. In other words, the Russian government intends to encourage foreign participation by guaranteeing higher returns at the time of project off-take and allowing companies time for build up until the project becomes commercially operational.

Financing for the second phase of Sakhalin II project is being negotiated. Securing customer base on long-term supply contract would enhance the prospect of Sakhalin II. EBRD and JBIC have expressed their intentions to participate in the financing. Other export credit agencies and commercial banks have been approached. In 2003, the companies like Tokyo Electric Power Company, Tokyo Gas and Kyushu Electric Power Company made Heads of Agreements (HOE) with the Sakhalin Investment Energy Company on the long-term purchase of LNG, with each contract amounts representing, 1.2 million ton, 1.1 million ton and 0.5 million ton.

GOVERNMENT ROLE IN THE LAIBIN B BUILD-OPERATE-TRANSFER PROJECT IN CHINA

The Laibin B power project, involving construction of two 350 MW coal-fired powerplants in China's Guangxi province, is considered a model build-operate-transfer power project for several reasons. It is the first BOT project to be carried out in China without a government sovereign guarantee. It is the first BOT project on which foreign developers were invited to bid; previous joint ventures had been set up through negotiations between the government and private firms. It is the first project in China that is entirely owned by a foreign consortium. Electricity de France and GEC Alsthon were awarded an 18-year BOT concession out of 31 bidders. Their respective controlling shares are 40 percent and 60 percent against the total equity amount of US$154 million.

Figure 54 Laibin B – A Model Build-Operate-Transfer Power Project in China



Source: Nevitt and Fabozzi (2000).

85 Holton (1995).

Guangxi is a relatively poor province, with a per capita income in 2002 of 5,168 yuan as compared with 8,225 yuan for China on average. To reduce risk to lenders, the provincial government issued a letter to guarantee the power purchase agreement between Laibin B and the Guangxi power bureau, which provided that the bureau would buy 63 percent of the plant's output. With the purchase guaranteed, cash flow to service the plant's debt was assured. The central government, through the Ministry of Power Industry, helped the provincial government prepare the project feasibility study, reviewed letters of intent from potential foreign investors, and communicated with the State Development and Planning Commission to help move along several different approval processes.[86]

The efforts by central and provincial governments clearly helped to make the project more creditworthy. This resulted in approval of loans totalling US$502 million from the French export credit agency, COFACE, and a syndicate of commercial banks. The loans have relatively long maturities of 15 years for those from COFACE and 10 years for those from the commercial banks.

BUILD-OPERATE -TRANSFER PROJECT FINANCING IN THE PHILIPPINES

The power crisis that gripped the Philippines in the early 1990s had brought the economy practically to a halt with brownouts or power outages lasting 12 to 18 hours daily. Experts surmised that the economic opportunities lost reached US$123 million to US$206 million per day. With limited public funds allotted for energy, the new government of President Corazon Aquino resolved to mobilise private sector investment to bring the power crisis to an end.

In 1987, Executive Order 215 allowed private firms to generate power, breaking the monopoly of the state-owned National Power Corporation (NPC). The Philippine Congress enacted a Build-Operate-Transfer Law soon thereafter (through Republic Act 6957 and later Republic Act 7718). The BOT law allowed the private sector to finance, construct, maintain and operate public infrastructure projects. This helped the government to minimise the burden of infrastructure projects on its budget, reduce external borrowing, and take advantage of private sector efficiencies.

Under BOT contracts, private firms agree to finance, construct, operate and maintain an infrastructure project for a specified period of time. The firms can charge rents, user fees and tariffs to recover their investment and generate a reasonable rate of return. Typically, the firms bring not only financing for the projects but also technology transfer and cost efficiencies in power plant construction, operation and maintenance.

A host of incentives were offered to independent power producers (IPPs), including income tax holidays, repatriation of profits, and tax and duty exemptions for contractors. The electricity generated by IPPs was sold to NPC, which acted as a central purchasing agent or single buyer, through a power purchase agreement (PPA) or energy conversion agreement (ECA).

Through BOT contracts, the government bridged the gap between power developers and the project financiers by taking on the risks that the power sector was unwilling to accept. State-owned NPC assumed market, foreign exchange and fuel risks. The government itself issued a letter of comfort (or performance undertaking) assuring that NPC would comply with its commitments.

The first successful BOT power project was the 210 MW Hopewell Navotas 1 plant in 1991. This was followed by more fast track power projects until 1994, when the power crisis ended. Since 1990, NPC has commissioned or committed to 9,085 MW of IPP generating capacity, and by 2000 nearly half of the total economy's energy sales come from IPPs. The World Bank, one of the creditors, noted in a study that IPPs in the Philippines provided 4,023 MW of new capacity between 1991 and 1999, with investments reaching nearly US$4.5 million. Out of 42 contracts signed by NPC, 13 were BOT contracts providing for 4,346 MW of capacity, while 29 were other types of contracts providing 4,739MW.[87] Almost half of the projects completed during the power crisis between 1991 and 1994 were fast track BOT projects using bunker or diesel fuels.

86 Xu (2002).

87 Roxas (2001).

But while IPPs clearly helped mobilise private investment to solve the power crisis, they were not without drawbacks. For one thing, in signing power purchase agreements (PPAs), the government incurred long-term liabilities to satisfy NPC's short-term contracts to its distributors; after the crisis was over, the terms of the PPAs seemed to some too generous to the IPPs. Second, because of the power crisis and political instability, a large economy risk premium was built into project returns. Third, since IPP projects were needed fast, some were contracted through negotiations rather than competitive bidding. These and other factors made Philippine IPPs costly. While the average electricity tariff for eight APEC Asian economies other than Japan was 6.92 US cents per kWh in 2002, the average tariff in the Philippines was 8.84 cents per kWh.

One of the most controversial aspects of Philippine IPP contracts is their structure.[88] NPC is obligated to pay IPPs on a take-or-pay basis, and NPC's payments are largely denominated in dollars, requiring the government to assume significant currency risk. Generally, payments in IPP contracts have both a capacity component and an operations and maintenance component. The O&M payments can increase up to 20 percent of IPP monthly revenue. But in some geothermal contracts, fees were bundled into a single energy charge that can escalate as much as 75 percent. Some contracts also allow fees to rise along with personnel salaries and the consumer price index. Such contract provisions, potentially quite costly to consumers, are under government review.

CONCLUDING OBSERVATIONS

Strengthening capital markets, especially corporate bond markets, can expand opportunities for companies in developing economies to finance energy projects. Bonds can provide long-term capital for investment in energy projects at lower interest rates than bank loans. Bonds can also limit the amount of energy investment financed by foreign borrowing, reducing the mismatch between domestic currency assets and foreign currency liabilities that contributes to project risk.

While the desire to conserve public funds for public purposes has meant a diminishing government role in the direct financing of energy projects, governments still have important roles to play in promoting the availability of investment capital from the private sector. For example, government loan guarantees can reassure investors of borrowers' creditworthiness, making bank loans easier to obtain and bonds easier to issue for key energy projects. Governments' roles in promoting energy sector investment are explored in greater depth in the chapter that follows.

88 Roxas (2001).

THE ROLE OF GOVERNMENTS IN ENERGY INVESTMENT

THE CHALLENGE OF ATTRACTING INVESTMENT TO ENERGY PROJECTS

Governments have traditionally been involved in the energy sector for a variety of reasons. Perhaps most importantly, they have wished to ensure that energy facilities are built where and when they are needed to support economic growth. They have also wished to ensure that energy production and use are consistent with environmental protection goals. And they have wanted to ensure that the supply of energy is secure, so that economies are not vulnerable to supply cutoffs or disruptions. For all of these reasons, all APEC governments have played an active role in ensuring that energy investments keep pace with energy needs.

Also, regardless of whether the focus is economic growth, environmental protection, or energy security, governments in virtually all APEC economies have recognised that there are clear advantages to promoting private investment in general and foreign investment in particular. Private capital flows to energy projects can reduce pressure on government budgets which may be better devoted to social purposes such as health and education. Private and foreign capital flows can also speed the transfer of technologies to produce energy more cheaply, cleanly and reliably.

But capital flows to where it earns the highest returns. Absent conditions which allow for investments in projects to earn a market-based rate of return, capital will flow elsewhere. It is therefore imperative for governments that wish to secure the benefits of private energy sector investment to make the conditions for such investment attractive. Key conditions for attracting investment include a transparent and predictable framework of laws and regulations, sound macroeconomic management, unrestricted private ownership of energy sector assets, market-based pricing, and fair competition. In applying these conditions to the energy sector, however, governments face particular challenges.

One key challenge for governments is how to balance the need to attract investment with the need to provide energy services at a reasonable cost. If sufficient incentives are provided, in terms of royalties on oil and gas production, high rates of return on gas pipelines and electric transmission and distribution lines, or tax breaks for the installation of energy-efficient equipment, investment in these facilities will be forthcoming. But unless the returns allowed to investors are based in some way on competition among energy providers in the marketplace, with projects built by those that can provide energy most cheaply, the government risks paying more than necessary.

For example, in economies with oil or gas reserves that can be exploited at low cost, governments can provide generous incentives for energy sector investment in production sharing contracts while still earning a profit on the energy produced when it is sold on world markets. But unless there is a competitive bidding process for the production sharing contracts, or a competitive market for upstream investment, governments may wind up paying more than they have to on such contracts. Without a measure of competition, in fact, there is no market process in place to inform governments about "how much is enough" to attract the energy investments they desire.

A second key challenge for governments is how to balance the need for a stable and predictable regulatory regime with the need to modify the regulatory regime over time. If the regulatory conditions that apply to energy facilities are not clearly specified, and if there is no reasonable understanding that these conditions will apply for all or most of the economic lifetime of the facilities, investment in the facilities may be perceived as too risky and may not be forthcoming. But governments may need to alter the regulatory regime to introduce competition, enhance reliability or impose more stringent environmental standards. The challenge is to do so in a manner that will not deter subsequent investment in energy facilities that are needed for the future.

For example, in economies where a major share of electricity is generated from coal, it has been necessary to introduce stricter controls on sulphur dioxide and nitrogen oxide emissions from coal-fired power plants, entailing retrofit costs that were not anticipated when the plants were first built. But some older plants were excluded from these stricter controls, presumably because they were deemed to have too short a remaining lifetime to recover the additional costs. By limiting the new emissions controls to power plants that would clearly be able to amortise the costs of such controls over their remaining operating lifetime, it was possible to ease the fears of subsequent investors that the returns on new facilities might be jeopardised by a further tightening of controls in the future.

The challenge of reconciling the needs for regulatory stability and change has also been evident in efforts to enhance competition in the electric power sector. Many economies have exposed electric utility monopolies to competition from independent power producers. But often the competition applies, at least at first, only to the wholesale market for new power plants and not to existing power plants or to the retail market for final customers. Thus, while returns on new plants are not guaranteed and depend on market conditions, previously existing power plants continue to earn regulated rates of return that were first applied during the monopoly regime. This should reassure investors in transmission and distribution facilities, which usually remain regulated as natural monopolies even under market reforms, that regulated returns on such facilities are reliable.

APEC NON-BINDING INVESTMENT PRINCIPLES

A good point of departure for discussing the role of governments in fostering energy investment is the set of non-binding investment principles (NBIP) that were endorsed by APEC leaders at their meeting in Jakarta in November 1994 for member economies to aspire to:

5. ***Transparency:*** Member economies will make all laws, regulations, administrative guidelines and policies pertaining to investment in their economies publicly available in a prompt, transparent and readily accessible manner.
6. ***Non-discrimination between Source Economies:*** Member economies will extend to investors from any economy treatment in relation to the establishment, expansion and operation of their investments that is no less favourable than that accorded to investors from any other economy in like situations, without prejudice to relevant international obligations and principles.
7. ***National Treatment:*** With exceptions as provided for in domestic laws, regulations and policies, member economies will accord to foreign investors in relation to the establishment, expansion, operation and protection of their investments, treatment no less favourable than that accorded in like situations to domestic investors.
8. ***Investment Incentives:*** Member economies will not relax health, safety, and environmental regulations as an incentive to encourage foreign investment.
9. ***Performance Requirements:*** Member economies will minimise the use of performance requirements that distort or limit expansion of trade and investment.
10. ***Expropriation and Compensation:*** Member economies will not expropriate foreign investments or take measures that have a similar effect, except for a public purpose and on a non-discriminatory basis, in accordance with the laws of each economy and principles of international law and against the prompt payment of adequate and effective compensation.
11. ***Repatriation and Convertibility:*** Member economies will further liberalise towards the goal of the free and prompt transfer of funds related to foreign investment, such as profits, dividends, royalties, loan payments and liquidations, in freely convertible currency.
12.

13. ***Settlement of Disputes:*** Member economies accept that disputes arising in connection with a foreign investment will be settled promptly through consultations and negotiations between the parties to the dispute or, failing this, through procedures for arbitration in accordance with members' international commitments or through other arbitration procedures acceptable to both parties.

14. ***Entry and Sojourn of Personnel:*** Member economies will permit the temporary entry and sojourn of key foreign technical and managerial personnel for the purpose of engaging in activities connected with foreign investment, subject to relevant laws and regulations.

15. ***Avoidance of Double Taxation:*** Member economies will endeavour to avoid double taxation related to foreign investment.

16. ***Investor Behaviour:*** Acceptance of foreign investment is facilitated when foreign investors abide by the host economy's laws, regulations, administrative guidelines and policies, just as domestic investors should.

17. ***Removal of Barriers to Capital Exports:*** Member economies accept that regulatory and institutional barriers to the outflow of investment will be minimised.

A transparent legal and regulatory framework, embodied in the first principle, is essential for attracting investment capital to the energy sector. Absent such a framework, investors have no way of knowing what actions are permitted in pursuit of profit, no real understanding of what revenues can be expected from energy projects, and no assurance that the returns they earn on energy projects can be retained. Many energy markets involve a mix between competitive elements, such as coal, oil or gas production and electricity generation, and regulated natural monopoly elements, such as gas pipeline networks and power transmission grids. As a result of this mix, energy markets are often more complex than other markets, and may well involve greater risk related to changes in laws and regulatory procedures. It is therefore especially important, in the energy sector, to ensure that legal and regulatory provisions are set forth clearly and consistently applied.

As noted above, governments may face tensions between the need to provide a predictable legal and regulatory framework and the need to alter that framework from time to time to make the marketplace more competitive, make service more reliable, or make the environment cleaner. With respect to investment, the key to resolving these tensions probably lies in ensuring that changes in laws and regulations are made in such a way that returns on investment are left largely intact. For example, transitional provisions may allow power plants to continue earning a regulated rate of return for a number of years after competition is introduced among electricity generators, or until a certain amount of the capital invested in the plants has been amortised. If environmental regulations require that existing power plants be retrofitted with scrubbers to reduce sulphur dioxide emissions, there may be provisions to ensure that the additional costs are recovered. With respect to investment, the main purpose of such concessions is not to compensate past investors for the current regulatory changes (although that may well be a political attraction) but rather to reassure future investors that they will be made whole for any subsequent regulatory changes.

Also worth emphasising, with respect to energy-sector investment, are the principles related to expropriation, repatriation, and capital exports. All of these principles have to do with the ability of investors to retain the returns they have earned on investments and to reinvest them wherever it may be most productive. Paradoxically, by providing assurances to investors that they can retain their earnings and repatriate earnings whenever they please, governments can remove a major impetus for removal of investment capital from their economies: the fear of expropriation or restrictions on repatriation. Perhaps more importantly, the same sorts of assurances can help to attract the vast amounts of new capital that are needed to undertake energy projects in the future.

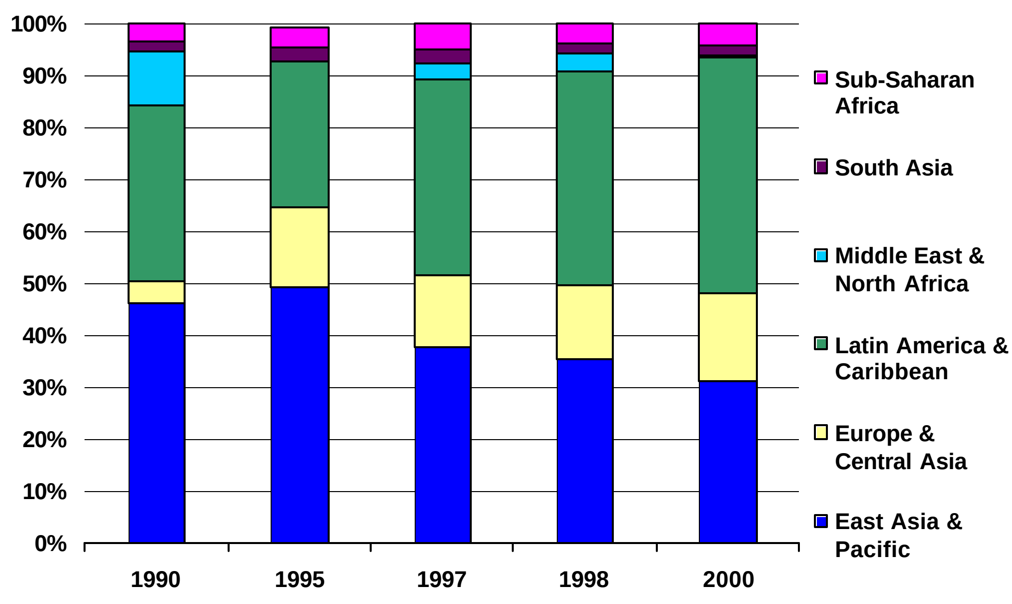
SOUND MACROECONOMIC MANAGEMENT

One key condition for the financing of energy projects in any APEC economy is the soundness of its fiscal and monetary policies. Rates of economic growth, inflation, and domestic savings, as well as the balance of payments in trade, foreign exchange rate stability and a suitable discount rate, are all used extensively by credit rating agencies in assessing the creditworthiness of different economies and the firms that operate within them. Excessive and persistent deficits in government budgets, in particular, have frequently been cited by credit agencies as reasons for downgrading the sovereign credit ratings of various economies. Credit ratings, in turn, affect the extent to which and cost at which governments and firms in any given economy can obtain funds for energy projects. Significant changes in macroeconomic policy are carefully examined by rating agencies, and are a key point of reference as well for private investors involved in energy project financing.

APEC's share of foreign direct investment around the world declined during the 1990s. FDI in East Asia and the Pacific declined from 47 percent of the world total in 1990 to 31 percent in 2000. This contrasted sharply with Europe and Central Asia, whose share of world FDI increased from 4 percent to 17 percent over the decade, and with Latin America and the Caribbean, whose share meanwhile grew from 34 percent to 45 percent. The declining share of East Asia and the Pacific in the world FDI pie was probably due in large part to the Asian financial crisis of 1997-1998, which in turn may have been precipitated by flawed macroeconomic policies.

Perhaps the most important indicator of macroeconomic performance, with respect to energy investment, is the real cost of capital. Most energy projects are capital-intensive, with a large share of production costs related to initial capital investment. In the power sector, hydro, wind and nuclear power plants, as well as transmission and distribution grids, have greater capital costs than fuel or operating costs. Even coal-fired and gas-fired power plants have substantial capital investment, although the fuel share of overall costs is greater. Production and transportation of oil, gas, coal and other fuels entail substantial capital costs as well.

Figure 55 Regional Shares of Foreign Direct Investment



Source: World Bank (2002), World Development Indicators.

It follows that overall investment requirements will be lower, and the ability to attract sufficient investment capital will be greater, if the real cost of capital can be kept at reasonable levels. This may involve a range of fiscal and monetary policies aimed at increasing overall rates of savings, which will increase funds available for investment and lower the cost of capital resulting from the interaction of supply and demand in capital markets. Such policies may include greater reliance on consumption taxes (to discourage current consumption in favour of saving for future needs), fiscal restraint in times of economic expansion (to avoid structural government deficits that constitute dissavings and reduce capital available for business), and fiscal stimulus in times of economic slowdown (to allow resumed or accelerated growth that boosts industry profits, which are savings).

PRIVATISATION AND REDUCED RESTRICTIONS ON PRIVATE OWNERSHIP

It may seem obvious, but privatisation of energy sector assets has been a key means by which APEC governments have expanded access to private capital. At least since 1990, there has been a trend toward private participation in the construction, operation and ownership of energy facilities. The specific legal and contractual arrangements have varied considerably, including divestitures, management contracts (with or without investment commitments), build-operate-own (BOO) contracts, and build-operate-transfer (BOT) contracts. BOT arrangements are especially favoured by governments since facilities are paid for with private funds while ownership of the facilities is eventually transferred to the public.

In Thailand, privatisation efforts in the energy sector were largely motivated by the need to attract new investment capital in the wake of the Asian financial crisis of 1997. The State Enterprise Reforms aimed to increase private sector participation in the economy by building more competitive manufacturing and services sectors. As a result, more than US$6 billion in capital resources flowed to the economy during 1997.

In the Philippines, where electricity generation had been monopolised by the state-owned National Power Corporation, the government began to open up the power market to private sector participation in 1986. The economy faced frequent power outages, as well as fiscal austerity which limited the public funds available for power plant construction to relieve the outages. The government therefore turned to the private sector to build and operate the new electric generating capacity that was needed. Through the Build-Operate-Transfer Law of 1986, over 48 independent power producer (IPP) contracts for some 5,000 MW of capacity were signed and fast tracked, sharply reducing the incidence of major power outages by 1991. Under the law, companies that build and operate new plants can retain all profits from the plants for 20 years, after which ownership of the plants is transferred to the public.

Beyond simply privatising a portion of state energy assets, governments may attract capital investment by reducing or eliminating restrictions on private and foreign ownership of energy assets. The United Nations Conference on Trade and Development noted in its 1996 study of *Incentives and Foreign Direct Investment* that these barriers are of three basic types:

18. ***Restrictions on Entry and Establishment*** including bans on foreign investment in certain sectors, screening and approval processes, restrictions on the legal form of the business entity, minimum capital requirements, conditions on subsequent investment, admission taxes, and prohibition of mergers and acquisitions;
19. ***Restrictions on Ownership*** such as limits on foreign investment in certain sectors, compulsory joint ventures, mandatory transfer of ownership, restriction of ownership to certain nationalities, and restrictions on ownership of land and intellectual property;
20. ***Restrictions on Management and Operations*** such as performance requirements, local content requirements, operational permits or licences, ceilings on royalty payments, restrictions on repatriation of capital and profits, and restrictions on importation of labour, capital and raw materials.[89]

An analysis by Australia's Industry Commission attempted to quantify the extent to which various economies restrict ownership in a 1997 study on Services Trade and Foreign Direct

[89] UNCTAD (1996) as cited in APEC Energy Working Group and ABARE (2000).

Investment. The study assigned heavy numerical weights to restrictions on ownership and much lighter weights to investment screening and approval processes and restrictions on management and operations. It found that among the APEC economies, the greatest restrictions were placed on foreign investment in China, Indonesia, Korea, the Philippines and Thailand, while the fewest restrictions were place on foreign investment in Hong Kong and the United States.[90]

In several economies, however, restrictions on private and foreign investment in the energy sector have since been eased in significant ways. In China, this can be seen from changes in the comprehensive list of types of energy investment that are encouraged, restricted and prohibited. The manufacture of hydropower generating facilities with a capacity of 150 megawatts or greater, which was restricted in 1997, has been encouraged since 2002. The manufacture of advanced fossil-fuelled power plants with a capacity of 100 megawatts or more, including combined cycle gas turbines (CCGT), integrated gasification combined cycle (IGCC) units and pressurised fluidised bed combustion (PFBC) units, as well as desulphurisation equipment, is also encouraged rather than restricted. On the other hand, construction and management of conventional coal-fired power plants smaller than 300 megawatts in size remains restricted, so further progress is possible.

Russia's privatisation programme set the limits on the participation of foreign firms in the privatisation of enterprises in Russia. Permits for foreign participation were issued by either the Russian government or sub-national governments, on a case-by-case basis. Production sharing arrangements (PSA) started in 1995. However, no production sharing agreements were signed until 1999, after new amendments to the law were passed. In Russia as elsewhere, government can play a positive role in attracting investment by reducing restrictions on foreign and private participation.

MARKET-BASED PRICING

Market-based pricing is an important ingredient of a successful policy mix for promoting energy investment. In a properly operating market, prices signal the balance between supply and demand at any given time and place. Where supply is curtailed or demand grows, prices will rise and investments will become more profitable, helping to ensure that new energy investments are made where they are of greatest value. Insofar as market-based price signals are muted or absent, the timing and location of investments in energy facilities will be sub-optimal. Moreover, as noted above, if financial inducements are provided for energy investments but no framework is provided to promote competition among firms so that investments are made at minimum cost, economies risk paying too much for the investments they require. Hence, government has an important role to play in seeing that prices are market-determined, reducing or eliminating energy subsidies, and taking steps to ensure that market prices reflect the environmental costs of energy production.

Even in the major segments of energy markets that are regulated as natural monopolies, such as gas pipeline networks and electric power transmission and distribution grids, market-based pricing has an important role to play. If investments in these market segments are to have a reasonable prospect of being profitable, they must be able to earn a return in excess of the weighted market cost of capital. Thus, in setting transmission and distribution rates, energy regulators should allow a regulated rate of return that at least equals the weighted cost of debt and equity in the marketplace.

In segments of energy markets where competition is already flourishing in many economies and could potentially be introduced in others, such as oil and gas production and electricity generation, it should be understood that market-based prices are determined not by production costs alone, but by the interplay of supply and demand. In theory, as demand grows and existing supply facilities are retired over time, energy will become scarcer and market prices will become higher, creating an increasing profit incentive for the construction of new supply facilities where they are needed. If demand stagnates, on the other hand, market prices should remain low, so there will be no market incentive for building new facilities and economies will avoid building facilities they do not need.

[90] Industry Commission (1997) as cited in APEC Energy Working Group and ABARE (2000).

In addition, since any technically qualified firm is allowed to build and operate a new oil or gas well or power plant, competition among firms should ensure that needed facilities are built at least cost.

Some major APEC gas producers, including Brunei Darussalam, Indonesia and Malaysia, have policies of providing gas to power producers at a price which apparently covers production costs but is well below the price at which gas can be exported. Such policies limit incentives for private investment in pipeline projects to bring gas to domestic markets, so that capital for such projects may have to be provided by the state. If oil and gas companies are required to reserve part of their output for domestic markets at subsidised prices, as has been the case in Indonesia, this may reduce the incentives for them to invest in upstream production projects as well.

Formal energy price subsidies, with prices held below costs, appear to be fairly rare in the APEC region and are becoming rarer over time. Indonesia, for example, has subsidised the price of electricity so that lower income groups can better afford it. The budgetary cost of maintaining the subsidy grew from 1.98 trillion rupiah in 1999 to 4.62 trillion rupiah in 2001. In part to deal with budgetary pressures, the size of the subsidy was reduced for non-household customers in 2001, and the fuel price was allowed to fluctuate based on costs within a certain range in 2002. Moreover, the subsidy has been more closely targeted at low-income consumers by limiting it to a maximum consumption of 30 kWh per month and certain consumer groups. In 2004, the subsidy is to be removed entirely and replaced by targeted compensation programmes for poor households.

In the Philippines, the Downstream Oil Industry Deregulation Law of 1998 introduced market pricing of oil products to replace government price controls. The Energy Regulatory Board (ERB) maintained authority to limit prices on petroleum products sold to consumers. But the law reversed a 25-year policy of setting prices for petroleum products through an Oil Price Stabilization Fund that had absorbed fluctuations in product prices while providing refiners adequate returns. Domestic prices are now adjusted automatically based on Singapore Import Parity, an average of costs at Singapore refineries, and in line with international crude prices. In the five years following the law's passage, some 181 new firms entered the business of marketing, storing, reprocessing or bunkering petroleum fuels, bringing in more than P14 billion of investment.

A limitation of market-based pricing is that it does not automatically account for costs imposed by the negative environmental externalities of many energy investments. Among others, such externalities include atmospheric emissions of particulates, sulphur dioxide, nitrogen dioxide and carbon dioxide. Governments can ensure that the value of such externalities is reflected in market prices through regulations that set limits on emissions, through taxation of emissions, or through incentives for production of energy from non-emitting energy sources. Several governments in the APEC region have in fact set plant-level limits or overall limits on emissions of particulates, sulphur dioxide and nitrogen oxide, placed a tax on carbon dioxide emissions, or provided tax incentives for production of energy from substantially emission-free energy sources like wind and solar power.

ENSURING FAIR COMPETITION AND LIFTING BARRIERS TO MARKET ENTRY

To earn a market-based return on their investments in competitive energy industries, investors must be able to sell their products (coal, oil, gas, electricity) freely to customers. And before committing their scarce capital to energy projects, investors will need an assurance that they can sell their products on the same terms as competing energy producers. There are many steps that governments can take to promote fair competition:

21. ***Transparency*** in the formulation, promulgation, and implementation of rules, regulations, and technical standards, as well as their consistent application;
22. ***Competitive bidding procedures*** for participation in production sharing contracts, public sale of shares in energy facilities, and selection of independent power producers or strategic partners;
23. ***Independent regulatory authorities*** with no financial interest in any supplier of energy services and no accountability to any such supplier;

24. ***Non-discriminatory energy transportation,*** including third party access to and interconnection with energy transmission and distribution grids on similar terms for similarly situated parties;

25. ***Prohibition of anticompetitive practices*** such as cross-subsidization of competitive energy businesses (like electric power generation or oil or gas production) by monopoly businesses (like gas and electric transmission and distribution).[91]

In several developed economies that began opening up their energy markets to competition in the mid-1980s, such steps are in fact the norm. For example:

40. Independent regulatory authorities include the Australian Competition and Consumer Commission, Canada's National Energy Board (NEB), the United States Federal Energy Regulatory Commission (FERC), and numerous state, provincial and territorial regulators in Australia, Canada and the United States.

41. Non-discriminatory transportation of gas is provided by the National Third Party Access Code to Natural Gas Pipeline Systems in Australia, by the National Energy Board Act and the Agreement on Natural Gas Prices and Markets in Canada, and by FERC Orders 436 and 636 in the United States.

42. Non-discriminatory transportation of electricity is provided by the National Electricity Market and cooperating states and territories in Australia, by the provincial regulatory authorities of Alberta, British Columbia, Manitoba, Ontario and Quebec in Canada, and by FERC Orders 888 and 889 in the United States.

43. Anti-competitive practices are prohibited by the Australian Competition and Consumer Commission, Canada's Competition Bureau, the Federal Trade Commission in the United States, and the anti-trust laws that empower these regulatory authorities.[92]

China, upon its accession to the World Trade Organisation, is actively revising laws, statutes and regulations to build an environment for fair market competition. Actions to date include:

26. Prohibition of arbitrary charges, examinations, or punishment of foreign enterprises;

27. Breaking down of local protections and industrial monopolies;

28. Reinforced laws on protection of intellectual property;

29. Improved complaint mechanisms and protections for foreign enterprises.

Indonesia's "New Reformation Policy" gives regional governors and the Minister of Investment, who is also Chairman of the Investment Coordinating Board (BKMP), authority to issue foreign investment approvals. The BKMP will use the 'Negative List' for technical guidance. But within BKMP, regulatory streamlining has reduced the time required for obtaining foreign investment approvals from 42 working days to 10. These changes will ensure that investors need not spend much time getting necessary permits.

In the Philippines, the Electric Power Industry Reform Act of 2000 (EPIRA) created a Power Sector Assets and Liabilities Management Corporation (PSALM) to spin off transmission assets of the National Power Corporation (NPC) to the National Transmission Company (TransCo). This will help ensure that the transmission of electricity over high-voltage power lines is completely separate from electricity generation, so that no generator will have an unfair advantage over any other. It is also intended that NPC's generating assets be split among several new companies to provide further assurance against market dominance. The bidding processes for both generating and transmission assets are expected to be fair and transparent.

---

91 United States Department of Energy, Office of Policy and International Affairs (2002).

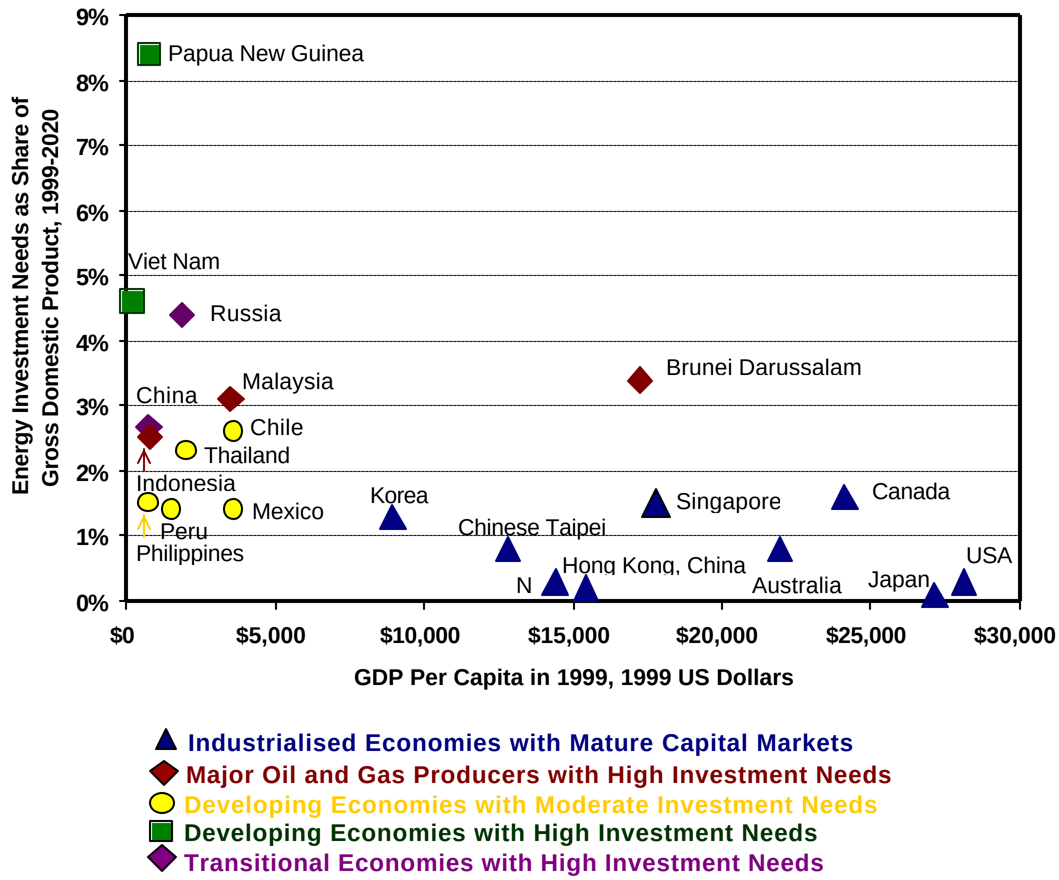
92 APERC (2000a), APERC (2003), and APEC Energy Working Group (2002a).

A key lever for governments to boost market competition can be the regulation of mergers and acquisitions. Corporate mergers and acquisitions can be an important means of bringing needed capital to the energy sector, since they allow stronger firms with greater assets and financial wherewithal to acquire weaker firms with fewer assets and less ability to issue new debt or equity. But mergers and acquisitions can also weaken competition by reducing the number of players in the market. Governments can counterbalance the effects on competition by conditioning mergers and acquisitions on competitive concessions such as unbundling of transmission assets (gas pipelines or electric transmission lines) from production assets (gas wells or electric power plants). In the United States, for example, all mergers and acquisitions must be approved by the Federal Energy Regulatory Commission, which has frequently conditioned them on substantial asset unbundling. This tends to boost the number of producers competing over open-access transmission networks.

RECOMMENDATIONS FOR ENSURING ADEQUATE INVESTMENT

The investment requirements and challenges faced by APEC economies are by no means identical. Consequently, different economies might wish to take different sorts of steps to ensure that their energy investment needs are met and their energy supplies remain secure. This section attempts to group APEC economies according to the investment environments they face and then to offer some suggestions on steps they might consider to meet their investment needs. In part, the grouping is based on investment requirements as a share of GDP as shown in Figure 56.

Figure 56 Energy Investment Burdens and Development in APEC Economies



INDUSTRIALISED ECONOMIES WITH MATURE CAPITAL MARKETS

Most industrialised economies in the APEC region have relatively modest requirements for capital investment in their energy sectors relative to the size of their domestic product. Six of them have energy investment requirements of less than one percent of GDP, including Japan (0.1 percent), Hong Kong, China (0.2 percent), New Zealand (0.3 percent), United States (0.3 percent), Chinese Taipei (0.8 percent) and Australia (0.8 percent). Three have energy investment needs of one to two percent of GDP, including Korea (1.3 percent), Singapore (1.5 percent) and Canada (1.6 percent).

In addition, these industrialised economies have relatively mature capital markets and regulatory regimes. Most of their energy companies are rated by international bond rating agencies, so the risks and rewards of investing in the bonds of each company are generally well known. There are clear and predictable rules for investment, including enforcement of contracts and settlement of disputes by impartial courts or arbiters. There are few limits on investment flows in and out of projects, so profits can be repatriated by investors from other economies. In regulated markets such as gas and electric transmission lines, there are clear regulations specifying the returns on projects. In competitive markets such as oil and gas production and electricity generation, there are usually regulations are in place to ensure or encourage non-discriminatory treatment of all competitors.

Despite these advantages, industrialised economies still face a number of challenges in securing the energy investment they need. One key challenge is presented by regulatory barriers to construction of energy facilities. The "not in my backyard" or "NIMBY" syndrome is often very strong in those economies. Hence, it is frequently difficult and costly to build needed energy facilities even where capital can in principle be obtained for their construction.

Another key challenge is the need to maintain regulatory oversight of possible conflicts of interest at bond rating agencies and market gaming by energy firms. If the same agency provides investment banking services for some of the companies it is rating, regulators must see that firewalls are in place to ensure that the desire of the banking arm for business does not affect the judgment of the rating arm. Otherwise, ratings for various energy firms will be lower or higher than justified by their true financial condition, and their cost of issuing debt will be correspondingly higher or lower, distorting investment decisions about where capital can be placed most productively. And if markets are not properly designed, particularly in fast-moving fields like gas and electricity trading that often operate in "real time," regulators may find it difficult to prevent some competitors from "gaming" the rules in ways that raise prices unduly.

While industrialised economies with mature capital markets should in principle have little difficulty in financing needed energy investments, there are several steps they might usefully take to ensure that regulation is predictable, markets are transparent, and competition is fair:

44. Regulatory processes can be streamlined to reduce unnecessary duplication and delay, which may extend the construction time required for capital-intensive energy projects and thereby significantly increase the costs of energy to consumers.

45. Regulators should be scrupulous in ensuring that there are information firewalls between the bond rating and investment banking divisions of financial firms and in meting out appropriate punishment to individuals who breach these firewalls.

46. Regulators can take measures to ensure that competing energy firms have fair access to oil and gas pipelines, LNG terminals and electric transmission lines so that investment in energy projects can be rewarded with market returns.

MAJOR OIL AND GAS PRODUCERS WITH HIGH INVESTMENT REQUIREMENTS

Some of the APEC region's most important oil and gas exporters, not surprisingly, have very high energy investment burdens relative to the size of their economies. Indonesia is projected to require 2.6 percent of its GDP for energy investments between 2000 and 2020, Malaysia 3.1 percent, and Brunei Darussalam 3.4 percent. But each of these economies has major state financial interests in its largest energy firms, and these energy firms have sufficient revenues from their energy production to finance their investment requirements internally.

While such economies may have little difficulty meeting their energy investment needs, the dominant state role in their energy industries may still present significant disadvantages. If public funds are used to finance energy investments that might be financed by private capital, less public funding may be available for social purposes like health, education and retirement pensions. Lack of competition in energy industries may slow improvements in productive efficiency so that costs are higher then necessary, again limiting the funds that are potentially available for public purposes.

Despite their fortunate situation, major oil and gas producing economies may wish to consider measures to attract private investment and free up public funds for other uses, insofar as such measures have not already been implemented:

47. Private firms can be allowed to bid competitively on production sharing contracts and other energy projects sponsored by state-owned oil and gas firms.

48. Assets of state-owned energy firms could be partially divested by selling shares of the firms or specific energy facilities to private investors.

49. Private firms could be allowed to produce energy in competition with state firms.

DEVELOPING ECONOMIES WITH MODERATE INVESTMENT REQUIREMENTS

Several APEC economies have energy investment requirements that are fairly substantial relative to their economic output but are not far out of line with historical trends. Energy investment between 2000 and 2002 is projected to take up about 1.4 percent of GDP for Peru and Mexico, 1.5 percent of GDP for the Philippines, 2.3 percent of GDP for Thailand, and 2.6 percent of GDP for Chile. Within this group, Peru and Philippines have the lowest incomes per capita but also relatively modest investment burdens. Chile has a relatively heavy investment burden but one of the higher per capita incomes. Thailand has a relatively heavy investment burden but only a modest level of income per capita.

For the most part, economies in this group have strong energy and capital markets. As in the industrialised economies, there are generally clear rules for investment including enforceable contracts, and there are few limits on repatriation of capital. However, regulatory institutions are generally less well developed, so that returns on capital in regulated energy industries may not always be predictable and provisions for non-discriminatory treatment of competing energy firms may sometimes be weak.

Developing economies with moderate energy investment requirements can take several steps to strengthen the environment in which they obtain capital to finance energy projects:

50. Elaborate or reinforce measures to ensure that competing energy firms have fair access to pipelines, LNG facilities and electric transmission lines through which they their investments can earn returns.
51. Streamline and clarify regulatory rules so that returns on regulated energy projects are high enough and predictable enough to attract investment.

DEVELOPING ECONOMIES WITH HIGH INVESTMENT NEEDS

Two APEC economies stand out as having particularly high energy requirements relative to their output. Viet Nam is projected to require 4.6 percent of its GDP through 2002 for energy investment, while Papua New Guinea is projected to require 8.4 percent. Both economies are fairly small and undeveloped, with relatively weak capital markets and regulatory institutions. Thus, it may be difficult for energy companies in these economies to obtain needed investment unless there are special provisions to secure collateral or the investment is financed by international firms.

Probably, developing economies with high investment requirements should consider the same sorts of measures as those with moderate investment requirements. As just mentioned, these relate to fair access to energy transportation networks by competing energy producers, as well as to adequate and predictable returns on investments in regulated segments of the energy industry. But for countries with higher investment requirements, the need to take such steps is more urgent.

TRANSITIONAL ECONOMIES WITH HIGH INVESTMENT NEEDS

APEC's two formerly non-market economies, China and Russia, face a special set of challenges in meeting their energy investment needs. Both have investment needs which are substantial in both relative and absolute terms. Russia will need to use 4.4 percent of GDP through 2020 to finance energy investments, while China will need 2.6 percent. China's investment requirements, as explained above, amount to nearly half of the total investment requirements in the APEC region.

And both economies have had numerous difficulties in securing capital owing to the unpredictable nature of their regulations and the inconsistent enforcement of their contracts, as well as the fact that new or newly privatised firms lack a track record on which their long-term performance may be judged. All of these factors tend to lower the debt rating by international rating agencies and make it difficult to issue debt at a reasonable cost. On numerous occasions, investment consortia have found that the terms of their contracts and the taxation regime to which they are subject have changed considerably between the time the contract is signed and the time that production begins. This has lowered bond ratings and discouraged subsequent investors.

The key challenges for transitional economies with high investment needs relate to their financial and regulatory institutions. In particular, they may wish to consider the following steps:

52. Strengthen legal enforcement of contract provisions by courts and civil authorities.
53. Follow the rule of law in awarding and monitoring contracts for energy facilities.
54. Avoid restrictions on foreign investment and repatriation of investment returns.
55. Allow end-use prices for energy to fully reflect the costs of investment in energy production, transmission and distribution, including a fair return on investment.
56. Allow new energy projects to compete on fair terms with established projects.
57. Provide government guarantees on a portion of the debt issued by newly established domestic firms to limit the risk premiums that rating agencies assess.
58. Promote joint ventures with foreign partners to obtain their capital and expertise.

CROSS-BORDER PROJECTS AND INTERNATIONAL COOPERATION

Many energy investments in the APEC region span two or more economies, each of which has different laws and regulations affecting the placement of energy facilities, the returns that can be earned on those facilities, and the terms of cross-border trade between those facilities. Insofar as the laws and regulations are inconsistent or in conflict, complex contractual provisions may be required before the financing for new energy projects can be obtained, and the more likely it is that disputes may arise after projects are built. Both more complex contracts and aversion to the risk of disputes may raise the cost of financing projects and make the financing more difficult to obtain.

While an extensive analysis of cross-border trade issues is not the subject of the present study, it is worth pointing out here a few ways in which APEC governments might cooperate to facilitate investment in cross-border projects. Potential areas for cooperation in this regard might include:

59. Reciprocal recognition of licences granted by one economy in another economy;
60. Free flow of funds and repatriation of capital among participating economies;
61. Elimination of duties and import and export restrictions on energy trade;
62. Agreements to avoid double taxation of cross-border energy projects;
63. Sharing of information on energy markets to better guide investment decisions;
64. Harmonisation of consumer protection and safety standards, employment laws, project zoning regulations, and environmental regulations across economies.

CASE STUDIES

CHINA

INTRODUCTION

Having embarked upon an "open door" economic policy in 1978, China achieved robust GDP growth averaging 9.4 percent per annum through the year 2000. Over the coming two decades, the momentum of economic growth is expected to be maintained, with annual growth averaging 7.6 percent from 2000 through 2010 and 6.7 percent from 2010 through 2020. The growth will be driven partly by increased domestic demand and partly by expanded trade stemming from China's membership in the World Trade Organisation (WTO). Growth is projected to slow slightly in the second half of the forecast period as China continues to industrialise and becomes somewhat less attractive as a low-wage target for foreign investment.

Rapid growth in China's economy will mean substantial growth in China's energy sector. China's energy demand is projected to expand at an average annual rate of 2.8 percent from 1999 through 2020. Over that period, China should account for about one-seventh (14 percent) of overall energy demand growth in APEC, but more than a quarter (27 percent) of the growth in APEC oil demand and over two-fifths (42 percent) of the growth in APEC's coal demand. To cope with rising energy demand, China will need very substantial new investment in energy infrastructure. This will include upstream investment in coal, oil, gas, hydroelectric and nuclear power production, midstream investment in oil and gas pipelines and electric transmission lines, and downstream investment in petrol stations, gas and electric distribution lines.

China has abundant energy resources. It is the largest producer of coal and the seventh largest producer of oil in the world. However, its energy resources are very unevenly distributed. The eastern coastal area is experiencing rapid economic growth but is poorly endowed with natural resources. By contrast, the ten western provinces are underdeveloped but rich in energy sources such as coal, oil, hydro and gas; they hold 80 percent of China's hydroelectric potential and 40 percent of its proven coal reserves. As the Tenth Five Year Plan suggests, the mitigation of income disparities between these regions is a top policy priority. Energy projects such as the West-East gas pipeline and West-East electricity transmission line could play catalytic roles in this regard.

ENERGY SECTOR INVESTMENT REQUIREMENTS

China's investment in fixed energy assets totalled US$32.2 billion in 2001, including US$1.4 billion in the coal industry, US$6.9 billion in the oil and gas industries, and US$23.9 billion in the electric power industry. APERC estimates that to meet rising energy needs, China will require additional investment of more than US$1.3 trillion through 2020. About $1 trillion will be required just for new electricity generation and transmission facilities.

ELECTRICITY

Demand for electricity is expected to grow at an annual rate of 5.6 percent, roughly doubling between 1999 and 2020. China will account from some 15 percent of all additions to electric generating capacity in APEC over the period, with its share of the APEC total exceeded only by that of the United States. The State Power Corporation (SPC), which owns half of China's electric generating capacity, has placed priority on development of coal-fired, hydroelectric and natural gas-fuelled capacity, which are expected to account for 42 percent, 34 percent, and 16 percent of capacity additions respectively. The large capacity additions along with transmission facilities translate into an estimated investment requirement of US$1,007 billion.

Table 35 Energy Investment Requirements in China: High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & trans portation	4.90	2.06	2.37	3.06	4.00	26.53	31.89	58.42
Oil & gas production, processing, petrochemical	9.79	4.66	6.10	6.82	7.96	58.56	68.51	127.08
Oil & gas international trade	0.08	1.84	1.97	1.98	2.96	15.10	23.54	38.63
Oil & gas domestic pipelines	2.67	2.65	3.43	4.46	5.65	29.96	46.19	76.15
Electricity generation & transmission	12.42	34.32	47.50	59.62	70.31	393.69	613.20	1,006.89
Total	**29.86**	**45.52**	**61.36**	**75.94**	**90.88**	**523.84**	**783.33**	**1,307.16**

The under-developed transmission network has been a bottleneck in securing a stable electricity supply in China. SPC's capital expenditure on transmission has been far below international standards. In 1990s, for example, SPC allocated 15 percent of total capital expenditure on transmission, while international standards call for an allocation of 50 percent. In order to alleviate the network shortage, the Tenth Five-Year Plan (2001-2005) aims to develop an inter-provincial transmission network supplying power from resource-rich western provinces to the booming but resource-limited eastern coastal area. Three routes are being planned:

65. North: from Inner Mongolia, Shaanzi and Shanxi to Beijing, Tianjin and Tangshan.
66. Centre: from Sichuan province to middle and eastern China.
67. South: from Yunnan, Guizhou and Guangxi to south China, mainly Guangdong.

The State Electricity Regulatory Commission (SERC) plans to allocate 30 percent of the end-use price of electricity to investment in the transmission and distribution grids. Anticipated asset sales by SPC should also provide capital for such investment, while creation of grid companies could attract further capital for network development.

OIL

Investment requirements for oil – from upstream to downstream -- are estimated to take the large portion of total cumulative energy sector investment requirements in China through 2020, amounting to some US$160 billion. China's oil demand is expected to increase at an annual rate of 4.3 percent, with the share supplied by imports rising to 66 percent from 22 percent today. Making security of energy supply a key policy goal in the Tenth Five Year Plan, the Chinese government is encouraging exploration and development of oil and gas fields both at home and abroad.

China is trying to maintain domestic oil production at current levels offshore of the eastern coast while intensifying development of new fields in the Tarim Basin and elsewhere in the west. In addition, China is building infrastructure that can transport oil and gas from western provinces to eastern consumption centres. As shown in the table below, responsibilities for implementing these major projects are shared by three vertically-integrated oil firms:

(1) China National Petroleum Corporation (CNPC) in the north and west,

(2) China Petrochemical Corporation (Sinopec) in the south and east and

(3) China National Offshore Oil Corporation (CNOOC) in offshore.

Table 36 Key Features of Oil Firms in China

	CNPC	Sinopec	CNOOC
Proven Oil Reserves	11 billion barrels	3.22 billion barrels	1.3 billion barrels
Proven Gas Reserves	36 trillion cubic feet	3.49 trillion cubic feet	3.2 trillion cubic feet
Business Area	North and West China	South and East China	Offshore China
Principal Oil Field	Daqin oil field		Bohai Bay
Overseas Oil Projects	Concessions: Kazakhstan, Venezuela, Sudan, Iraq, Iran, Peru, Azerubaijan	Concession: Iran	Stakes: Indonesia
Overseas Gas Projects	Feasibility study: Russia (Angarsk-Daqin pipeline)		Stakes: Indonesia (Tangguh gas field)
Gas Projects in China	West-East pipeline		Guangdong LNG, Fujian LNG, offshore development
Refinery Strategy		Upgrade to handle heavier, more sour Middle East crudes	
Downstream (Retail)	Joint ventures with oil majors	Joint ventures with oil majors	
Stock IPOs	PetroChina listed on Hong Kong and New York exchanges in April 2000, raising US$3 billion	Sinopec Corporation listed on Hong Kong and New York exchanges in October 2000, raising US$3.7 billion	CNOOC Ltd raised US $1.3 billion on Hong Kong and New York stock exchanges February 2001.
Oil Major Participation	BP: US$620 million (21%)	BP: US$400 million (10%) ExxonMobil: US$1billion (26%) Shell: US$430 million (12%)	BP: US$200 million (15%) Shell: US$300 million (24%)

Each oil firm has a distinct strategy towards overseas oil operations. CNPC considers oil a strategic asset and is actively engaged in a variety of oil and gas field projects in Sudan, Azerbaijian, Myanmar, Peru, Venezuela, Kazakustan, Iraq, Thailand, Canada and Turkmenistan. Sinopec, the largest importer of crude oil in China, treats oil as a commodity, placing equal importance on both oil trading and taking stakes in overseas projects. For CNOOC, oil is perceived as a financial asset; its recent acquisition of Indonesian oil fields can be considered an example of asset management[93].

NATURAL GAS

China's gas market, in contrast to its oil market, remains at an early stage of development. Natural gas is still considered an expensive premium fuel, and it accounts for only 2 percent of TPES. However, the Chinese government has set a target to raise the share of natural gas in TPES to about 10 percent by 2020. While this is less than half the share of gas in the United States or Europe, there are some impediments to achieving such a target. Three major projects are being undertaken for the target to be met: the West-East pipeline and the Guangdong and Fujian LNG terminals.

[93] China OGP, April 2002

The West-East pipeline is designed to meet a major goal of the Tenth Five Year Plan – to alleviate the income disparities between west and east. The pipeline will bring natural ga s from the Tarim Basin in the west to rapidly growing markets in the east. Together with associated upstream development, the pipeline should boost the lagging economy in the west. The project is to start delivering gas in 2004 with the annual volume of supply projected to grow from 2.8 billion cubic metres (Bcm) initially to 8.0 Bcm in 2005, 10.0 Bcm in 2006 and 12.0 Bcm in 2007.

A production sharing contract (PSC) will be used in the upstream exploration and development while a joint venture will be responsible for construction and operation of the pipeline. In both the upstream PSC and pipeline joint venture, PetroChina will take a leading share of 50 percent, an international consortium led by Shell will take 45 percent and Sinopec will take 5 percent.[94] The total project cost is estimated at US$8.5 billion, of which the cost of upstream development is estimated at US$3.3 billion. Project participants are responsible for funding of the upstream development in a manner proportional to their interests. Construction of pipeline will cost US$5.2 billion, or which 35 percent will be financed by equity from Petro-China, the Shell-led international consortium and Sinopec and the remaining 65 percent will be financed through debt.

Table 37 Summary of China's West-East Pipeline Project

Length	4,200 km from Lunnan to Shanghai
Capacity	12 billion cubic metres per annum
Participants	PetroChina (50%); Sinopec (5%); International Consortium of Shell, Gazprom and ExxonMobil (45%)
Estimated Cost	Upstream development: US$3.3 billion. Pipeline construction: US$5.2 billion
Financial Structure	65 percent debt, 35 percent equity

Guangdong LNG is a pilot LNG project in China. The first phase of the project will include construction of an LNG receiving terminal, natural gas pipeline and two new gas-fired power plants. It will also involve conversion of three existing oil-fired power plants to burn ga s and construction of a town gas distribution network. The second phase of the project includes extension of the gas pipeline and supply of town gas to other cities in the Pearl River Delta. BP has been selected to build the LNG import terminal.

Table 38 A Summary of LNG Projects in China

Project	**Guangdong LNG**	**Fujian LNG**
Participants	CNOOC (33%), Guangdong Province (31%), BP (30%), Hong Kong Gas Corporation (3%)	Joint Venture: Fujian Investment & Development Company, CNOOC
Volume	First stage: 3 Mt per year Second stage: 5 Mt per year	First stage: 2.6 Mt per year (2007) Second stage: 2.4 Mt per year (2011)
Supplier	ALNG from Northwest Shelf of Australia	Tangguh, Indonesia (with a 50% interest to be held by BP)
Cost	US$6 billion.	First stage: US$5.1 billion. Second stage: N.A.

94 Members in the international consortium include the following companies: Shell and Hong Kong China Gas (15 percent), Gazprom and Stroytransgaz (15 percent) and Exxon Mobil, Hong Kong China Light and Power (15 percent).

ASSESSING SOURCES OF FINANCING

ADEQUACY OF SAVINGS

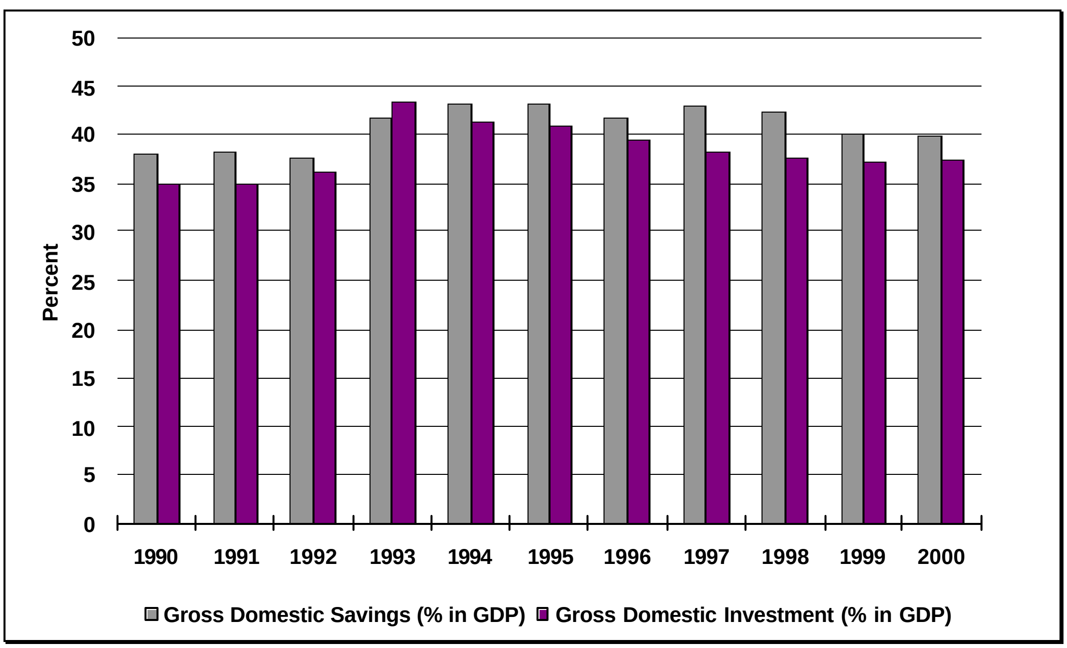
China has high level of domestic savings. Its ratio of savings to GDP has recently ranged from 35 to 43 percent, which is one of the highest in the world. As Figure 57 shows, domestic savings have historically been slightly higher than domestic investment. This implies that China has sufficient enough domestic funding sources to undertake needed investment. However it remains questionable whether China can mobilize available financial resources in an efficient fashion.

BANK LOANS

China's capital market is relatively under-developed, and bank loans are the dominant source of funding for Chinese companies, accounting for four-fifths of all their funding in 2001. Four large state-owned banks represent about two-thirds of the domestic banking system. They are joined by one private bank, several nation-wide commercial banks, and a number of urban and rural cooperative banks.[95] The four state-owned banks include the Industrial and Commercial Bank of China, the Bank of China, China Construction Bank, and the Agricultural Bank of China. These banks are the main vehicles to channel financial sources for the industry and infrastructure projects.

Historically, the four big banks have served as conduits through which the government can allocate financial resources to state owned enterprises (SOEs) so that SOEs can meet priorities specified in the Five Year Development Plan. Such so-called "policy lending" has helped China to achieve its economic targets and will continue to be undertaken in the future. However, the four banks are expected to be given greater autonomy in deciding on individual loan applications.

Figure 57 China's Domestic Savings and Investment as Percentage of GDP



Source: World Bank (2002), World Development Indicators.

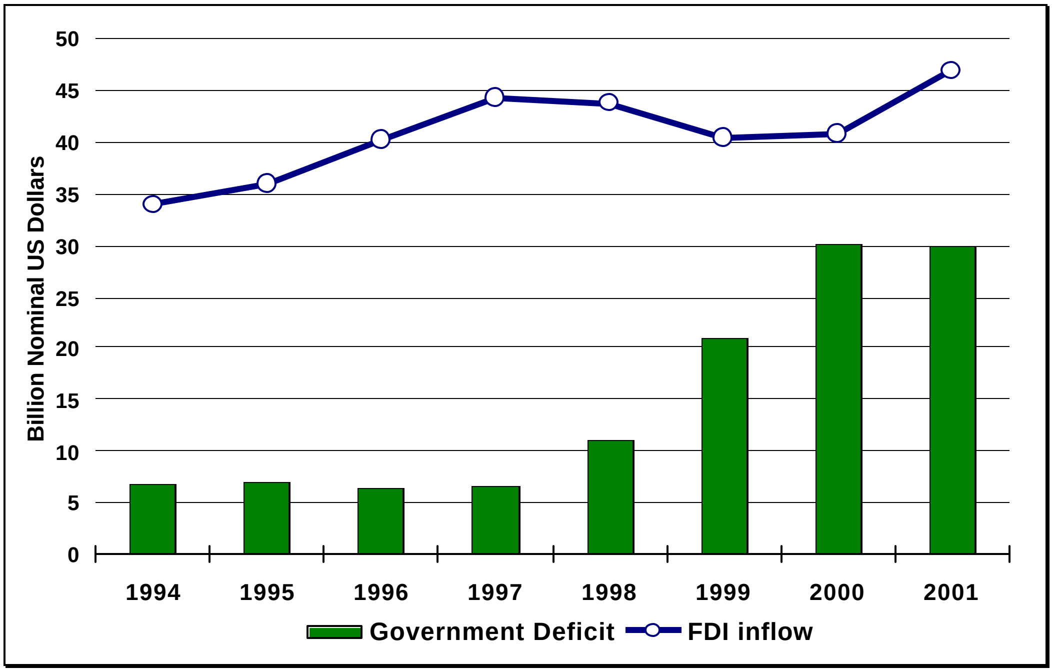
The profitability of the four state banks is weak. Their non-performing loans are estimated to account for about a quarter of their total loan value. Yet Chinese banks' classification of non-performing loans covers only the portion of a loan that is overdue, not the entire loan[96]. If

95 Economist Intelligence Unit Risk Wire (2003).
96 John L. Walker (2000).

international standards are applied, non-performing loans are estimated to exceed 50 percent of the total. About two thirds of the non-performing loans are from industrial or infrastructure loans[97].

Banking sector reform is an imminent task for China since the WTO accession makes the competition with foreign counterparts plausible. However, China's banking sector is taking a gradual approach to reform for fear that a drastic approach might cause political upheaval. The four state banks are gradually shifting away from their traditional lending pattern, which was focused on SOEs, toward a lending pattern based on commercial criteria.

Figure 58 China's Foreign Direct Investment and Government Deficit



Source: World Bank (2002), World Development Indicators.

Energy projects, especially power projects, have relatively easy access to bank loans since bankers expect that rapid growth in energy and electricity demand will provide stable long-term profits to energy producers in general and electricity generators in particular. The nominal interest rate on power sector loans is typically 5 to 6 percent, while the rate of return on power sector projects is generally much higher; the return on Guangdong projects, for example, is estimated to be around 15 percent. However, the question remains whether China's power sector will continue to provide attractive returns in the future. Power tariffs have been on a downward trend, as have rates of return. This means that power generators will probably have to provide stronger commitments, in the form of equity, to obtain loans.

CAPITAL MARKET

The role of capital markets in financing energy projects in China is relatively small. During the 1990s, the share of equity and corporate debt accounted for about 0.7 percent of total financial intermediation. The Shanghai and Shenzhen stock markets are dominated by state-owned enterprises, which are usually listed more for political reasons than economic reasons.

97 During the 90s, about 80 percent of all bank loans was directed for the state owned enterprises.

INTERNATIONAL FINANCING: INITIAL PUBLIC OFFERINGS

Listing on international stock exchanges, such as Hong Kong and New York, gives companies the opportunity to efficiently channel private financial resources. Recently, China's energy companies, in particular oil companies, have successfully listed their shares in international stock markets. Sinopec, CNPC and CNOOC conducted initial public offerings (IPOs) in which private investors were offered a minority holding between 10 percent and 27.5 percent of the company, with Chinese government retaining the majority of shares in each firm.

Minority listing on international stock markets is considered to meet China's strategy towards its three state oil firms[98]. China has sought a means to make these firms globally competitive while retaining control over their operations. Offering a minority of shares in each firm to the public serves the purpose well. A successful equity offering requires the companies to improve their operational efficiency to a level that can meet the international standards. Yet, by maintaining the majority shares in each firm, the government can continue to control its operation as before.

PetroChina, a subsidiary company of CNPC, offered 10 percent of its shares in an IPO on the Hong Kong Stock Exchange and New York Stock Exchange in April 2000. The resulting capitalization amounted to US$3 billion, of which BP took 20 percent. Sinopec offered 20 percent of its shares in an IPO on the same exchanges in October 2000, successfully raising US$3.5 billion. ExxonMobil, Shell and BP together purchased about 50 percent of the stakes being offered. CNOOC listed 27.5 percent of its shares on the two exchanges in February 2001, collecting about US$1.3 billion. BP and Shell together purchased about 48 percent of the stakes that were offered.

Table 39 A Summary of IPOs by China's Oil Companies

Issuer	Exchange	Date	Note
CNOOC	NYSE	February 2001	Raised US$1.3 billion
Sinopec	NYSE	October 2000	Raised US$3.5 billion.
PetroChina	NYSE	April 2000	Raised US$2.9 billion.

FOREIGN DIRECT INVESTMENT

Foreign investment has been essential to China's economic growth. From 1993 through 2001, China was the world's second-largest recipient of foreign direct investment (FDI) after the United States. In 2002, China surpassed the US with FDI of US$50 billion. Accession to the WTO in 2002 and subsequent revision of concerned laws and regulations on FDI, most of which had become effective in 2002, eased the entry of foreign parties. Yet FDI's contribution to the energy sector remains marginal. In 2001, FDI accounted for just 10 percent of investment in the coal, oil and gas industries and 9 percent of investment in the power sector.[99]

In large part, the limited role of FDI to date may be attributed to a complex and lengthy approval process for foreign investments, together with restrictions on foreign investment in many types of energy projects. Foreign investment in the energy sector, which generally takes the form of a joint venture, is governed by the following rules and regulations:[100]

68. China-Foreign Joint Venture Law;
69. The Regulations for the Implementation of the Law of the People's Republic of China on Chinese-Foreign Equity Joint Ventures;
70. The Detailed Rules for the Implementation of the Law of the People's Republic of China on Wholly Foreign-owned Enterprises in China.

[98] Unlike the case of oil firms, Chinese government carries out so called "debt-to equity swap" to unprofitable state owned firms.

[99] China Statistical Yearbook (2002)

[100] As the Detailed Rules for the Implementation of the Law of the People's Republic of China stipulate, wholly foreign-owned enterprises are not allowed in China.

The approval process for foreign investment in Chinese energy projects has four steps:

1) Submission of a project proposal for establishment of the enterprise, to be approved by planning departments or managing departments concerned with technological reform;

2) Submission of a research report on project feasibility;

3) Submission of contracts and regulations of the enterprises, for approval by concerned departments in the Ministry of Foreign Trade and Economic Cooperation (MOFTEC) and subsequent issuance of an approval certificate by MOFTEC;

4) Registration with administrative institutions of industry and commerce.

Generally, foreign investments larger than US$30 million require approval by the central government. For energy and raw material industrial project, central government approval is also needed when total project investment exceeds US$50 million. For projects with foreign investment of less than US$30 million, approval is needed from the following authorities.

71. Project with between US$10 million and US$30 million of foreign investment: Approval from a provincial economic and trade commission;

72. Project with between US$5 million and US$10 million of foreign investment: Approval from a provincial bureau;

73. Project with less than US$5 million of foreign investment: Approval from local economic and trade commission.

The framework of Chinese government towards FDI is determined in the Regulations on Guiding the Direction of Foreign Investment (Guideline). This Guideline, in turn, includes two catalogues: the Catalogue for Guiding Foreign Investment Industries and the Catalogue of Priority Industries for Foreign Investment in the Central and Western Regions.

The Catalogue divides foreign-invested projects into four categories: encouraged, permitted, restricted and prohibited. Projects not listed as encouraged, restricted or prohibited are permitted. The categories for different types of projects are revised from time to time. The Catalogue was first issued in 1995 and then revised in 1997 and 2002 in accordance with China's socio-economic development. China places great emphasis on the "encouraged" industries. For instance, the regulations concerning "encouraged area" are designed in order for FDI to benefit China by providing capital along with the advanced technology and business know-how. Hence they provide for preferential treatment such as lower income tax rate of 15 percent instead of the usual 33 percent. By contrast, the regulations regarding "restricted and prohibited areas" are provided in order to protect domestic industries for political, economic or security reasons.

GOVERNMENT STRATEGIES FOR ATTRACTING INVESTMENT

The Chinese government has used a number of strategies to attract investment in energy infrastructure. In the electric power sector, it has embarked upon regulatory reform designed to create competition among different electricity generators, as well as tariff revisions to make investments in regulated portions of the industry more attractive. In the oil sector, the government has relied upon joint ventures with foreign firms to attract capital. In the gas sector, a supply-push strategy has been pursued. For energy investments in general, rules on foreign direct investment are being eased so that fewer types of investments are prohibited and more are encouraged.

ELECTRIC POWER SECTOR REFORM

Given the sheer size of investment requirements and the limited scope to allocate public funds due to budgetary constraints, the government is planning to implement electricity sector reforms in order to mobilize private and external financial sources. The restructuring will take place as part of the Plan for the Reform of the Electric Power System which the State Council approved in April 2002 and released in March 2003. The restructuring framework has four basic components:

(1) privatization of SPC's generation assets into the five national generation companies,

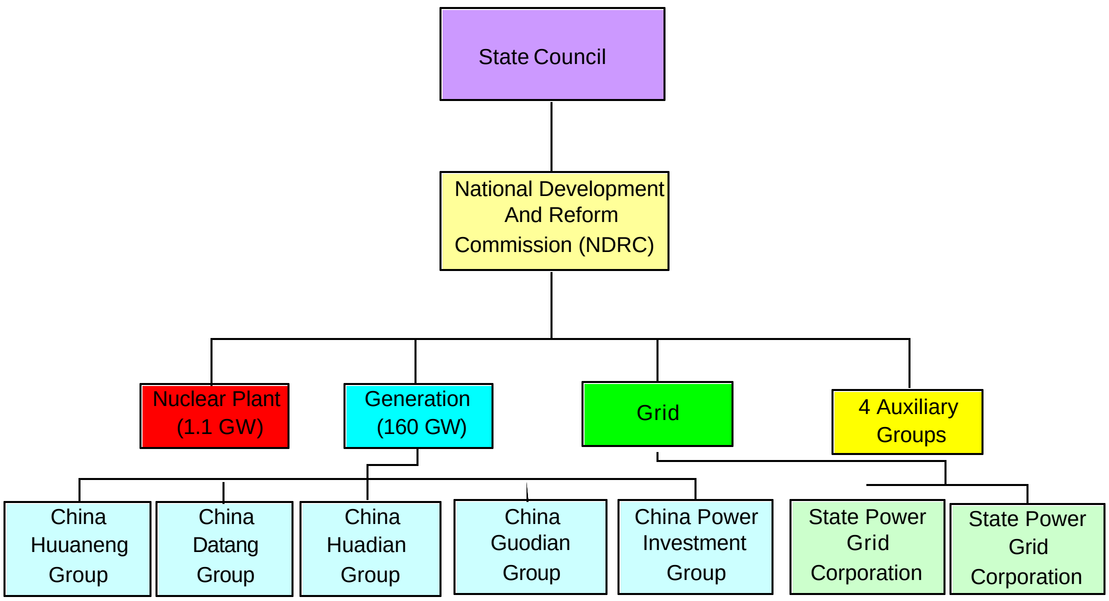
(2) formation of two grid corporations,

(3) establishment of four auxiliary groups for construction, maintenance and design, and

(4) creation of a power pool to promote competition.

The five national generation companies include China Huaneng Group, China Datang Group, China Huadian Group, China Guodian Group and China Power Investment Group. Each company will be of similar scale, initially retaining about a fifth of non-nuclear generating assets. Their assets will be gradually sold to independent power producers (IPPs). Nuclear generating assets are to be separately held by the State Council.

Figure 59 China's State Power Corporation Restructuring Plan



Source: APERC

The two grid corporations will own and operate the power grid in different geographic areas. The State Power Grid Corporation of China, a division of the SPC, will control power networks in the north, northeast, northwest, east and central regions. South China Power Grid Corporation will control power networks in Guangdong, Guangxi, Guizhou, Hainan and Yunnan provinces.

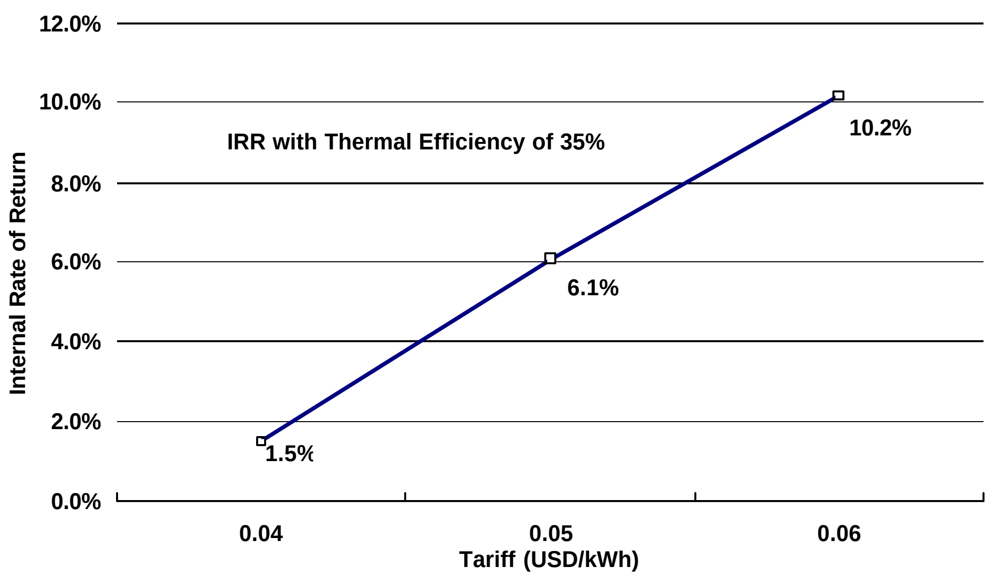
The basic framework for tariff-setting in China's electric power industry has two components: the "on-grid" tariff paid to generators and the end-use tariff paid by consumers. The on-grid tariff is determined on a cost-plus basis that covers the costs of power generation, debt service, taxes and a reasonable return on capital. Thus, it varies significantly with differences in equipment and construction costs, as well as the extent to which debt has been depreciated over time. The on-grid tariff will be lower for older, more fully depreciated plants than for plants that have been built more recently. This means that newer, more efficient plants will receive higher "on-grid" payments than older, less efficient plants. However, the details of tariff-setting are opaque, with tariffs determined through negotiations between grid operator and government.

The end-use tariff in principle includes both the costs of generation, reflected in the on-grid tariff, and the costs of transportation (transmission and distribution), which are internal to the grid company. At times, however, the end-use tariff may be lowered for political reasons. For example, the tariff was lowered in Guangdong province when it faced a power shortage in May 2001[101].

[101] South China's Guangdong Province has regulated major energy consumers on its power grid since 1 April, 2001, with electricity prices raised at peak period and lowered during off-peak hours to cope with power shortages.

The National Development and Reform Commission (NDRC) is formulating China's first national tariff guidelines. The NDRC's general policy is to lower tariffs by implementing cost reductions in transmission and distribution and eliminating guaranteed rates of return on investment in generating assets. Power sector investors will thus be exposed to increased risks. An example is provided by the Power Purchase Agreements (PPAs) for the Zhonghua Power Project, China's largest BOT power project with a total installed capacity of 30,000 MW.[102] In 1998, the PPA for the project's Shiheng plant was made at 0.41 yuan/kWh (US$0.05/kWh). But PPAs for other plants in the project, for which tariff negotiations began in 2003, will have tariffs set around 0.33 yuan/kWh (US$0.04/kWh), reflecting the government policy to lower overall tariff levels.

Figure 60 A Sensitivity Analysis of Tariffs and Returns on Coal-Fired Power in China



Source: APERC Analysis.

Lower tariffs clearly affect the rate of return (IRR) on power projects as shown in the figure above. For example, the tariff of 0.33 yuan/kWh (US$0.04/kWh) would yield an IRR as low as 1.5 percent, while the tariff of 0.41 yuan/kWh (US$0.05/kWh) could provide a 6.1 percent IRR. Additional factors such as debt service payment and depreciation period would change the IRR. However the general trend of lowering tariffs may limit the scope for attracting foreign investment to China, as the IRR available to investors in other economies has often been around 10 percent.

OIL INDUSTRY JOINT VENTURES

Oil majors are actively entering into China's energy markets with the expectation of future demand growth and widening business opportunities through China's accession to the WTO. As Table 40 shows, three oil majors - BP, ExxonMobil and Shell – are extending their presence in the Chinese energy market by forming joint ventures (JVs) with China's three oil firms.[103]

For example, Shell's largest joint venture project in China will invest US$4.2 billion to build a new petrochemicals plant in Juizhou, Guangdong Province with CNOOC. Shell Nanhai BV and

[102] Zhonghua Power Project is a joint venture of Shangdong Power Company (36.69 percent), Shangdong International Investment Company (14.49 percent), Hong Kong Zhonghua Power Company (29.49 percent) and EDF (19.69 percent). The project's total investment cost is estimated at US$16.8 billion. The project is comprised of plants at Shiheng (4 x 300 MW), Heze (2 x 300 MW) and Liaocheng (2 x 600 MW).

[103] The Detailed Rules for the Implementation of the Law of the People's Republic of China on Wholly Foreign-Owned Enterprises in China prohibit or restrict the establishment of wholly foreign-owned enterprises in the energy sector. The Catalogue for the Guidance of Foreign Investment Industries provides that the State assets shall take the holding or leading position in the enterprises.

CNOOC Petrochemical Investment Limited (CPIL)[104] each hold a 50 percent share of the project. This equal partnership was realised from the expectations of both sides. CNOOC considers the joint venture a starting point for downstream business that can be integrated with its upstream activities through the utilisation of advanced technology and international management. Shell expects the joint venture to strengthen its performance by improving its knowledge of the Chinese business environment.[105]

Table 40 Investment in China by Major Oil Companies

ExxonMobil	Shell	BP
Fujian refinery and petrochemical complex An agreement was made to establish a JV with Sauji Aramco, Sinopec and Fujian provincial government to expand refining capacity and construct ethylene plant with $3 billion	**E&D of gas field, Changbei, in Ordos Basin** Joint development with CNPC	**Three upstream assets: South China Sea and Bohai Bay** BP has a 34.3 interest in the Yacheng 13-1 gas field, a 24.5 percent interest in Liuhua 11-1 oil field in the South China Sea and a 24.5 percent interest in the CNOOC operated Quin Huang Da oil field in Bohai bay.
Guangdong refinery and petrochemical complex	**E&D of oil fields, offshore Xijiang**	**LNG terminal in Guangdong and associated pipeline**
An agreement was made to evaluate a JV to invest with Saudi Aramco on the expansion of refinery and petrochemical facilities of Sinopec.	Shell has a 39 percent share of oil production from two fields. These fields are jointly operated by CNOOC and Phillips.	JV with CNOOC to develop LNG terminal and associated pipeline.
Service stations in Fujian	**Petrochemical project in Huizhouo, Guangdong**	**Petrochemicals in Gaojin, near Shanghai**
An agreement was made to establish JV with Saudi Aramco, Sinopec and Fujian provincial government to build and operate 600 service stations in Fujian.	JV with CNOOC to construct a $4.2 billion petrochemical complex in Guizhou, Guangdong.	BP to form a SECCO Petrochemical Company with Sinopec and Shanghai Petrochemical to invest $2.7 billion on ethylene cracker complex.
Service stations in Guangdong An agreement was made to develop 500 service stations by JV with Sinopec.	**Service stations in Jiangsu Province** JV with Sinopec to acquire more than 500 services stations.	**Downstream business** Retail business with PetroChina in Guangdong/LPG import and sales/JV to supply aviation fuel at Shnzen airport.
West-East Project	**West-East Project**	
Share participation along with Shell and Gazprom	Share participation along with ExxonMobil and Gazprom	

Source: APERC, www.bp.com, www.exxonmobil.com and www.shell.com

In summary, the strategy for domestic oil market development in China is characterized by efforts to integrate the upstream and downstream segments of the market. This strategy is carried out by forming joint ventures with oil majors. It is hoped that such joint ventures can make Chinese oil firms more efficient and profitable by imparting to them the oil majors' advanced technology and business know-how.

SUPPLY PUSH STRATEGY FOR NATURAL GAS

China's natural gas development policy is characterized by a "supply push" strategy that appears to be driven more by political considerations than by market fundamentals. For example, the Guangdong and Fujian LNG projects are planning to develop extensive distribution networks at an estimated cost of US$7 billion to US$8 billion, and some gas turbines are already being ordered. However, not all the 45 letters of intent for the gas purchase has been transformed into firm sales commitment, mainly because there is no clear guideline for downstream natural gas pricing. Similarly, construction of the West-East Pipeline appears likely to proceed even though the anticipated costs may be far in excess of what gas users can realistically be charged.

104 CPIL is owned by CNOOC (90%), and the Guangdong Investment & Development Company (10%).

105 Speech by Evert Henkes, Chief Executive Officer of Shell Chemicals.

Assuming that power generation will utilize natural gas for peak shaving[106], APERC has calculated the break-even price that natural gas would have to beat in the power sector in order for gas-fired power plants to compete with coal-fired power plants, as a function of the market price of coal. In the analysis, a coal-fired plant is assumed to cost US$740 per kilowatt while a combined cycle gas turbine is assumed to cost US$450 per kilowatt. Assuming a 12 percent internal rate of return (IRR) on investment, the breakeven price of natural gas is found to range roughly from US$4 to US$5 per MBtu if the coal price ranges between US$1 and US$2 per MBtu. If the costs of gas delivery exceed these levels, as appears quite likely, then the economic prospects of gas for power production in China may be questionable.

For several reasons, it makes sense to develop prospective markets for gas, insofar as possible, before investments are made in projects to serve those markets, rather than after such investments are made:

74. Downstream development of natural gas markets requires greater capital expenditure than upstream development. In the West-East pipeline project, for example, while upstream production is estimated to require US$3.3 of investment, midstream transmission pipelines are estimated to require US$5.2 billion and downstream distribution networks are estimated to require US$15 billion.

75. Natural gas development has historically been a market-led activity. Experience has shown that unless a firm commitment is in place, the gas stays under developed in the reservoir.[107]

76. Transmission and distribution pipelines for gas transportation in the domestic market are geographically inflexible; they cannot be moved once put in place.

EASING RULES ON FOREIGN DIRECT INVESTMENT

The Chinese energy sector will inevitably expand its reliance on foreign investment in the future given the sheer size of its investment requirements and the budgetary constraints on allocation of public resources to the energy sector. Recognizing the importance of foreign direct investment, China has been making efforts to improve its investment climate. These include harmonization of provisions in the Chinese Foreign Investment Laws with other economic and commercial laws.[108] More broadly, the catalogue that specifies which types of direct foreign investment are permitted has been revised in recent years so that fewer types of energy sector investments are prohibited and more are encouraged, as shown in Table 41.

In the power sector, for example, investment in natural gas-fired power plants is now explicitly encouraged. The manufacture of power generation units larger than 100 megawatts and large-scale transformers rated at 200 kilovolts or more is no longer restricted. Whereas the manufacture of hydropower generating equipment of more than a minimal scale had previously been restricted, the manufacture of run-of-river and pumped storage hydro units of 150 megawatt capacity or greater is now encouraged. On the other hand, construction and management of small coal-fired power plants of less than 300 megawatts in capacity remains restricted as before. Construction and operation of thermal power units larger than 300 megawatts, as well as hydropower and nuclear plants and plants using renewable energy, were already encouraged in 1997 and remained so in 2002.

[106] Even though there is no firm commitment, there are plans of natural gas fired project that generate electricity for peak shaving. For example Beijing No.3 Thermal Power Plant is planning to install two 300MW gas fuelled turbines (Beijing). Nanjing Thermal Power Plant, located in the capital city of Jiangsu province is planning to invest 2.6 bn yuan to install two 300MW gas fuelled turbines.

[107] Williams (2003).

[108] Zeng (1998).

Table 41 Changes in China's Catalogue of Foreign Direct Investment

Catalogue in 1997	Catalogue in 2002
ENCOURAGED	**ENCOURAGED**
Oil & Gas	**Oil & Gas**
Construction and management of oil and gas pipelines, oil and gas storage facilities and dedicated oil docks	Oil, natural gas exploration and development Low pervasion oil gas field development
Development and utilization of tertiary oil recovery technology	New technology development & application for enhancing crude oil recovery
Power	**Power**
Construction and management of thermal power stations with a single unit installed capacity of 300MW or over	Construction and operation of thermal power stations with a single unit installed capacity of 300MW or over
Construction and management of hydropower stations with the main purpose of generating power	Construction and operation of hydroelectric plants
Construction and management of nuclear power stations	Construction and operation of nuclear power stations
Construction and management of power stations using clean-coal technology	Construction and operation of power stations using clean-coal technology
Construction and management of power stations with sources including solar, wind, magnetic, geothermal, tidal and biomass energy	Construction and operation of renewable power plants (including solar, wind, geothermal, tidal and biomass) Construction and operation of natural gas power plants
Coal	**Coal**
Design and manufacture of coal mining, transportation and selection equipment	Coal and associated resource exploration and development
Coal washing and dressing	Coal layer gas exploration and development
Coal-water production and coal liquefaction	**Machinery**
Comprehensive development and utilization of coal. Pipeline transportation of coal Exploration and development of coal-bed methane	Manufacture of thermal power equipment: super critical units and large gas turbines of 600 MW or more; CCGT, IGCC, PEBC of 100 MW or more; and large-scale air cooled units of 600 MW or more.
New and Emerging Industries	Manufacture of power plant desulphurisation equipment
Marine energy development technology Development of energy-saving technology Technology for recycling and comprehensive resource use	Manufacture of hydropower generating equipment: large scale pumped storage units over 150 MW and large scale run-of-river turbines over 150MW
	Manufacture of nuclear power units 600MW or larger
	Manufacture of super high voltage DC power transmission and transforming equipment over 500kV
RESTRICTED	**RESTRICTED**
List A	Construction and management of oil refineries
Oil refineries with output capacity of less than 5 million tonnes per year	Construction and management of the urban networks for gas, heat, water supply and discharge
Gasoline stations Manufacture of diesel generators	Construction and management of conventional coal-fired plants with single unit capacity of less than 300MW
List B	
Construction and management of conventional coal-fired plants with single unit capacity of less than 300MW	Wholesaling of oil products and construction and management of petrol stations
Manufacture of power generation units larger than 100 MW each, including CCGT, CFBC, IGCC, PFBC, de-sulphurisation equipment and de-nitrification equipment	
Manufacture of hydroelectric generating units with a wheel diameter over 5 metres, large-scale pumped storage units over 50MW, large-scale run-of-river turbines over 10 MW	
Manufacture of large-scale transformers of 200kV or over, high-voltage switches, mutual inductors and cable equipment	
PROHIBITED	**PROHIBITED**
Construction and management of power grids.	Construction and management of power grids.
Construction and management of the urban networks for gas, heat, water supply and discharge	

Source: The Catalogue of Industries for Guiding Overseas Investment (2002)., IEA (2002).

FINDINGS AND IMPLICATIONS

Because its energy investment requirements are enormous, China must inevitably rely in large part on private and international capital flows to finance them. Success in mobilizing needed investment funds will depend upon the pace and scope of energy sector reforms, in particular the privatization of state-owned enterprises and the establishment of a more transparent regulatory framework. But privatization and regulatory reform efforts are likely to proceed only gradually.

For example, China has sought to transform its three state oil firms into globally competitive enterprises. Its strategy for doing so has been to list the firms on international stock markets with only minority shares of private ownership. In this way, Chinese oil firms can mobilize private financial sources while the government retains direct control over the companies' operations.

It appears that efforts are needed to create a regulatory framework that is attractive for investors. In the power market, investors might face risks arising from a changing tariff-setting mechanism that no longer provides a guaranteed rate of return. In order to better attract foreign investment, as well as to help meet energy security and environmental goals, the tariff setting mechanism could usefully benchmark plant costs to plant efficiency. That is because most projects financed through foreign investment utilize advanced technologies with higher efficiency and lower fuel consumption per unit of power produced.

In the natural gas market, while production facilities transportation and distribution networks are being built under a "supply push" policy, there is still no regulatory framework for setting downstream tariffs. Accordingly, no firm commitment for the purchase of natural gas has been made by customers downstream. In general, incentives for investment in natural gas projects could be enhanced by putting in place a more transparent regulatory framework, reforming electricity tariffs to better reflect costs, and enforcing environmental regulations in a more consistent fashion. Current plans call for the role of natural gas in power generation to be mainly focused on peak shaving, so that the volume of natural gas utilization will be limited and the cost per unit of volume delivered will be relatively high. In this context, where purely economic considerations might not favour gas over coal, environmental regulations are likely to be a critical factor in determining the extent to which coal-fired generation is in fact displaced by gas-fired generation in coming years.

To form a coherent energy regulatory framework in China, various policy goals must be realigned. This will be a difficult process due to the distinct features of China's energy sector, notably including major disparities of income and energy resources between west and east. The energy sector, in turn, will be largely shaped by external factors including China's economic reform efforts, relationships between central, provincial and local governments, and the gradual integration of China into the global economy as a result of its accession to the World Trade Organisation.

INDONESIA

INTRODUCTION

Indonesia is a net energy exporter of coal, gas and oil. In 2001, 36.3 percent of national revenue came from oil and gas production. In the next 20 years however, Indonesia will face challenges to maintain its capacity as energy exporter as well as to fulfil domestic energy demand. The predicted decline of oil reserves and the increase of domestic demand will result in Indonesia becoming a net energy importer by 2010, if no additional reserves are found.[109] Gas reserves at current production levels are predicted to last until 2019.

Figure 61 Map of Indonesia

Source: EIA (2003).

Energy consumption per capita in Indonesia is 0.7 toe and the electrification rate is 58 percent, indicating that much of the population still lacks access to commercial energy. Among the factors that contribute to this situation are dispersal of the population over thousands of islands; a mismatch between the location of energy resources and energy demand centres, limited electric generation capacity, and insufficient infrastructure for gas and power transportation.

Thus, Indonesia's main energy challenges are finding more oil, gas and coal reserves, exploiting them for domestic and export markets, and providing transportation infrastructure to improve the population's access to energy. Also, to preserve its position as a leading LNG exporter in the face of competition from other exporters, Indonesia needs to make its gas industry more efficient.

The investment needed to meet these challenges is substantial, requiring that the economy expand access to capital both domestic and foreign. There are several hurdles to be surmounted in obtaining the needed energy investment, including a pricing regime which has held domestic energy prices substantially below export prices. This pricing system has limited the incentives for investment in domestic energy production facilities and transportation infrastructure.

109 Center for Energy Study University of Indonesia (2002).

ENERGY SECTOR INVESTMENT REQUIREMENTS

Indonesia's final energy demand is projected to reach 186 Mtoe in 2020, rising 74 percent from 107 Mtoe in 1999.[110] The residential and commercial sectors will together account for 46 percent of demand in 2020, transport for 30 percent and industry for 23 percent. Primary energy supply is projected to reach 246 Mtoe by 2020, with oil accounting for 100.0 Mtoe, new and renewable energy for 54.7 Mtoe, coal for 50.7 Mtoe, natural gas for 39.4 Mtoe, and hydropower for 1.6 Mtoe.

APERC estimates that to meet its rising energy needs, Indonesia will require additional investment of some US$138 billion through 2020. Nearly half of the investment, US$62 billion, will be required for production, processing, transport and trade of oil and gas. Most of the other half, US$67 billion, will be required for new electricity generation and transmission facilities. Overall energy investment requirements will be equivalent to 2.7 percent of the economy's GDP over the period.

Table 42 Energy Investment Requirements in Indonesia: High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.22	0.28	0.41	0.47	0.54	3.41	4.87	8.28
Oil & gas production, processing, petrochemical	2.55	2.26	2.41	2.13	2.55	24.58	21.74	46.33
Oil & gas international trade	0.26	1.08	0.35	0.39	0.56	8.69	4.17	12.86
Oil & gas domestic pipelines	0.14	0.11	0.14	0.17	0.20	1.27	1.73	3.01
Electricity generation & transmission	3.70	4.92	5.39	2.16	7.09	22.16	45.07	67.23
Total	**6.88**	**8.64**	**8.70**	**5.31**	**10.94**	**60.12**	**77.58**	**137.71**

ELECTRICITY

The dispersal of Indonesia's 207 million people over 14,000 islands creates a special challenge for energy supply. Since the population and economic activity are concentrated in Java and Bali, these are the islands where most investment in the power sector has historically focused. As shown in Table 43, of 23,426 MW of installed generating capacity, nearly three quarters is located in Java. Only 58 percent of the population has access to electric power supply, and electricity consumption per capita is only 405 kWh,[111] among the lowest for economies in the APEC region.

A critical issue that Indonesia faces in the electricity sector is the deterioration of supply in the outer islands. The power systems on these islands are mostly isolated and have a small capacity and low efficiency. Power shortages are now being experienced in 28 areas. There is no flow of electricity from areas with supply surplus to those with deficit due to the lack of transmission lines. The geographical conditions of some of the outer islands make the construction cost of new transmission lines prohibitive for the Indonesian government.

110 APERC (2002).

111 Directorate General Electricity and Energy Utilization (2002).

Table 43 Electricity Supply on Indonesia's Main Islands

Main Islands	Population	Area (square kilometres)	Generating Capacity (megawatts)	Transmission Lines (kilometres)		Distribution Lines (kilometres)	
				500 kilovolt	20-150 kilovolt	Low voltage	Medium voltage
Java -Madura	121,293,000	132,000	17,102	2,849	14,948	170,520	104,482
Sumatra	43,269,000	476,000	3,289	0	5,583	66,973	61,296
Sulawesi	14,881,000	189,000	923	0	1,189	21,100	21,865
Kalimantan	11,307,000	539,000	695	0	800	20,877	19,003
W. Papua	2,214,000	422,000	117	0	0	2,657	1,504
Others	13,366,000	164,570	1,290	0	620	14,707	14,205
Total	206,300,000	1,922,570	23,426	2,849	23,140	296,834	222,355

Source: Directorate General Electricity and Energy Utilisation (2002)

The Java-Bali region has experienced rapid demand growth, so its reserve margin is deteriorating. A bottleneck exists between the western and eastern parts of the transmission grid, which limits the dispatch of power to meet loads. The government's 10-year power development plan (2000-2010) aims to overcome these critical issues with the addition of 25,435 MW of generation capacity. Of this amount, nearly 12,000 MW are required for the Java-Bali areas.

Table 44 Ongoing Electricity Projects in Indonesia

Project	Project Value (US Dollars)	Source of Funding	Status
E-1: Hydro Generation Peusangan 1 & 2	$131.7 million	ADB	Completion 2006
E-2: Hydro Generation Renun	$ 65.9 million	OECF	Completion 2005
E-3: Hydro Generation Musi	$120.0 million	ADB	Completion 2005
E-4: Steam Fired Generation Tarahan	$297.74 million	JBIC/OECF	Completion 2005
E-5: Hydro Generation Bili Bili	$ 15.1 million	JBIC/OECF	Completion 2003
E-6: 500 kV Java-Bali Transmission System	$ 69.79 million	World Bank	Proposed
E-7: 150 kV Java-Bali Transmission System	$ 90.39 million	World Bank	Proposed
E-8: 1,300 MW Tanjung Jati A	$1.6 billion	National Power Plc Tomen Power	Renegotiating for continuation after postponement due to financial crisis
E-9: Repowering Muara Tawar	$ 248 million	PLN Japan Loan	Expected to be completed in 2004
E-10: 2,700 MW Muara Karang Gas Generation	$ 465 million	PLN Japan Loan	Renegotiated contract signed
E-11: Cilacap 600 MW Steam Generation	$ 677 million	PT Citra Kartika Daya	Renegotiated contract signed
E-12: 10 Hydro Projects in Eastern Indonesia	$114.29 million	ADB	Operation 2005-7

Sources: Ministry of Energy and Mineral Resources, The Jakarta Post and Asean Centre for Energy

Investments needed to improve electricity infrastructure, of which some are listed in Table 44, will be considerable over the next 20 years. The nearly US$67 billion which are estimated to be needed to finance electricity generation and transmission projects through 2020 include projects to overcome the Java-Bali power shortages (US$9.5 billion) and the installation of diesel power generation units in isolated areas of the islands of Sumatra, Sulawesi, Nusa Tenggara Barat and

Timur, Maluku and Irian Jaya. The latter considers 462 MW of low capacity (1.0-2.5 MW each) diesel power generation units, planned to be completed by 2005 at a cost of over US$68 million. Only 91 MW of planned capacity additions are being financed by Belgium (US$9.67 million), KFW of Germany (US$13.2 million), JBIC of Japan (US$14.89 million) and IDB (US$9.67 million). Funding for the remaining 371.5 MW of planned capacity is still not available.

The main challenges that Indonesia faces in funding the investment required for its electric power sector are low profitability of the business, an uncertain legal system, and inadequate domestic funding sources. The lack of profitability is caused by the low electricity price, which sometimes does not even cover the production cost. The uncertainty in the legal system is due to the past treatment of IPP contracts and the current deregulation process, which does not provide enough signals as to how the industry will be regulated. Inadequate domestic funding has made Indonesia heavily dependent on foreign investment, which makes it susceptible to currency exchange risks. On the other hand, the absence of adequate incentives has resulted in the failure to attract investors. In fact, since 1997 no investment has been made in the electricity sector by private investors.

OIL AND GAS

The oil and gas sectors are expected to require the second-highest investment after the power sector. There are 60 oil basins currently known in Indonesia, of which 38 have been explored. There are 9.6 billion barrels (Bbl) of oil reserves, of which 5.1 Bbl (53 percent) are proven. There are 171 trillion standard cubic feet (Tscf) of gas reserves, of which 94.7 Tscf (55 percent) are proven.

Indonesia produced 1.4 million barrels of oil per day (Mbd) or 2 percent of world production in 2000, declining slightly to around 1.3 Mbd in 2001 and 2002 and 1.1 Mbd in 2003. Of this amount, 0.75 Mbd are processed in domestic refineries and 0.50 Mbd are exported. Domestic refining capacity is 1.055 Mbd so Indonesia also refines around 0.30 Mbd of imported oil, mostly from Kuwait and Saudi Arabia. Further, Indonesia imports about 0.20 Mbd of petroleum products.

Indonesia's oil production is in a downward trend. In 1983, its share of OPEC production was around 10 percent, while in 2002 it dropped to 5 percent, or 2 percent of the exported crude. On the other hand, domestic oil demand is increasing steadily at a rate of 3.7 percent per annum. Therefore, finding new additional reserves is necessary in order to sustain production; otherwise, Indonesia will soon become a net importer of oil, which may bring serious economic consequences. The possibility of finding additional resources is encouraging, considering that only 38 out of 60 basins have been explored. Currently available technology seems promising for exploring these basins thoroughly and intensively. The main issue thus is how best to boost investment.

In 2002, Indonesia produced 3,102 Bcf of natural gas, 2.09 Mt of LPG and 26.18 Mt of LNG. Roughly 42 percent of Indonesian gas was marketed as LNG or LPG for export, 3 percent exported through pipelines, 8 percent for electricity, 7 percent for fertiliser and 2 percent for city gas, while less than 6 percent was flared.

In the gas sector, Indonesia faces challenges in maintaining gas reserves, marketing and encouraging domestic gas use. Additional reserves must be found in order to maintain production. The marketing environment has changed as Indonesian LNG faces more competing LNG development around the world today than in any time in the past. In addition, a gas and power markets in many economies are opened up to competition, fewer utilities hold monopoly positions in their market areas, so many are no longer in a position to make the sort of long-term purchase commitments that assured the development of the LNG plants in operation today. Competition is intense to secure commitments from buyers in a position to contract for LNG supplies, putting increased pressure on projects to make offers that meet the needs of potential buyers while also making it more difficult to finance projects. Expansion of domestic gas use is hindered by the fact that major gas reserves – in Arun, Papua, Donggi and East Kalimantan – are distant from potential consumers in Java. It follows that substantial new infrastructure such as pipelines or LNG receiving terminals will need to be built in order to facilitate domestic gas utilisation.

To maintain reserves and production for oil and gas, while encouraging their use domestically, Indonesia will require some US$49 billion of investment capital through 2020, of which roughly US$3 billion will be needed for development of domestic oil and gas pipelines and more than US$46 billion will be needed for oil and gas exploration, processing and petrochemical installations. To maintain export volumes of oil and gas a further US$13 billion will be needed. Part of the investment will go to currently planned projects such as:

77. exploration of oil basins in the eastern part of Indonesia;
78. an integrated gas network that will link Sumatra, Java and Kalimantan via 3,588 km of gas pipeline with capacity to carry 2.2 Bcfd, to be completed by 2010 with the help of funding from the World Bank, ADB and other financial institutions; and
79. LNG projects including the Tangguh, Train I Bontang and Donggi LNG production plants and the Muara Tawar LNG receiving facility.

Currently planned oil and gas infrastructure projects are shown in the tables below. Table 45 lists downstream oil and gas projects, while Table 46 enumerates gas pipeline projects and Table 47 catalogues upstream infrastructure projects for development of oil and gas fields.

Table 45 Planned Downstream Oil and Gas Projects in Indonesia

Project	Capacity	Investor	Investment	Status
D-1: Sumbawa and Sabang refinery	Process Iran Light Crude to Produce LPG, naphtha, gasoline and kerosene for export	PT Mayhill International Trading & Services (MITS) Ltd (UK), Gehad Dairwan (United Arab Emirates)	US$2.8 billion	Approved
D-2: Tuban refinery	Process 150,000 to 200,000 b/d of which 50,000 b/d Aramco light crude to make gasoline, kerosene, diesel oil	HiTech International Group of Saudi Arabia	US$2 billion	Approved
D-3: Pare-Pare South Sulawesi refinery	Process 300,000 b/d of crude oil to produce LPG, petrochemicals, naphtha, gasoline, jet fuel, kerosene, asphalt, diesel fuel, sulphur	US and Saudi Arabian investors	US$3 billion	Approved
D-4: Rempang Island, Riau refinery	Process 300,000 b/d of crude oil to produce LPG, petrochemicals, naphtha, gasoline, jet fuel, kerosene, asphalt, diesel fuel, sulphur	US and Saudi Arabian investors	US$3 billion	Approved
D-5: Badak Train I	LNG plant to produce 3 million tones per year			FEED contract awarded
D-6: Tangguh	2-train LNG plant to produce 7 million tonnes per year	BP-led consortium	US$2 billion	EPC contract opened. Production start 2007
D-7: Donggi	LNG plant to produce 3 million tonnes per year from 12 tcf gas reserves	Pertamina	Pertamina	Under study

Source: Directorate General Oil and Gas and Pertamina

Table 46 Planned Gas Pipeline Projects in Indonesia

Project	Size (inches)	Length (km)	Flow (Mscfd)	Funding Source	Investment (US Dollars)	Schedule and Status
P-1: E. Kalimantan – Java	32 inch	1100km	700 Mscfd	Loan, PGN	$1,100 million	2002-2005
P-2: Samarinda – Balikpapan	4-6 inch	100 km	50 Mscfd	Loan, PGN	$35 million	2002-2005
P-3: Gresik -Semarang	28 inch	390 km	360 Mscfd	Loan, PGN	$210 million	2004-2007
P-4: Sengkang – Ujung Pandang	16 inch	200 km	65 Mscfd	Loan, PGN	$80 million	Study 2004-2007
P-5: East & Central Java distribution	4-16 inch	300 km	700 Mscfd	Loan, PGN	$105 million	2004-2007
P-6: Kondur – Minas	28 inch	80 km	200 Mscfd	Loan, PGN	$80 million	MOU signed

Source: Directorate General Oil and Gas and Energy Information Center

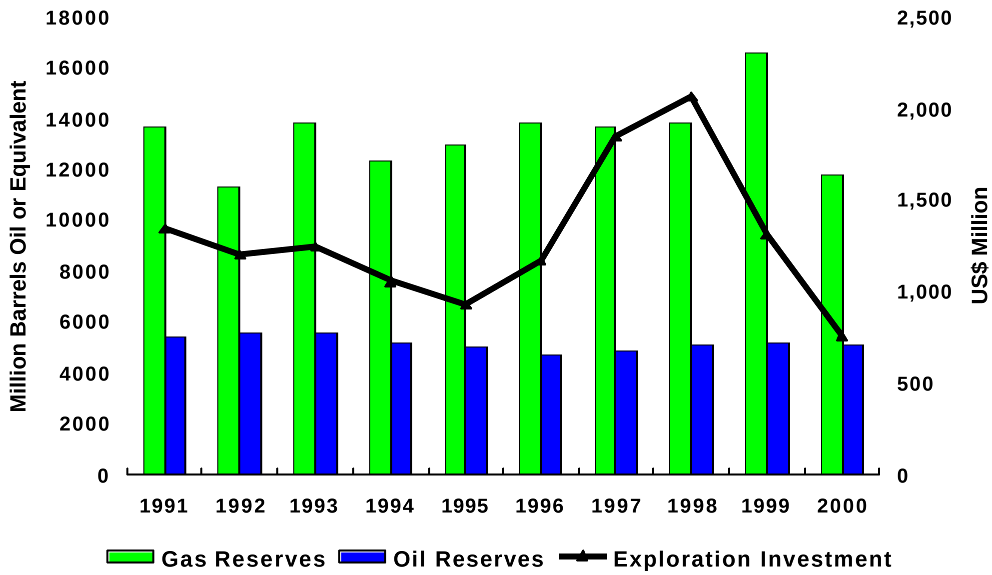
Table 47 Upstream Oil and Gas Infrastructure Projects in Indonesia

Project	Description	Investor	Investment	Status
X-1: Belanak Natuna	FPSO unit, two wellhead platforms, LPG floating storage offloading, gas export pipeline, oil offloading bay, intrafield pipelines, 38 development wells: 550 Bcf gas and 100 Mbpd oil	Conoco	US$1.6 billion	2004
X-2: Cepu-Central Java	Oil and condensate field with capacity to produce 100 Mbpd	Exxon-Mobil	US$18 million	Delayed due to blow out
X-3: West Seno, East Kalimantan	First Indonesian deepwater oil project (3,000 ft depth) to produce 60,000 bpd	Unocal 350 million, OPIC 300 million	US$700 million	Production Start 2003-4
X-4: Merah Besar	Development of deepwater gas project	Unocal		POD approved
X-5: Matra-S. Sumatra				
X-6: Jabung-South Sumatra Gas Sales to Singapore	Pertamina 20-year contract to supply gas to Gas Supply Pte Ltd via 500 km pipeline, ramping from 150 Mscfd in 2003 to 350 Mscfd in 2009. Supply of LPG and associated condensate.	Devon Energy, Gulf Resources and Talisman		
X-7: Blok B West Natuna	1.5 tcf gas field development to be exported to Malaysia	Conoco 40%, Inpex 35%, Texaco 25%	US$2.5 billion	250 Mscfd production by 2007
X-8: Banggai Gas Development	4 tcf gas for sale as LNG to US market starting in 2005-2006	Expan, El Paso, Shell		Signed MOU
X-9: Ketapang Field	Potential recoverable 680 MBO and 0.5 tcf of gas			
X-10: Ujung Pangkah	Will supply East-Java and Java-Bali Combined Cycled Power plants	Amerada Hess		
X-11: Terang and Sirasun	Development of 1 tcf gas field with Sub-sea well, floating production unit	BP		Need contract extension
X-12: open acreage concession	Onshore at Merangin; Offshore at Rembang, Bulu, South Madura, NE Madura, North Bali, Tarakan	Santos, SK Corp, Medco, PT Selayar, PT Petroland, PetroVietnam, Exindo Petroleum, Provident Indonesia Energy	US$170 million	8 out of 36 bidders were awarded development contracts in August 2003.

Source: Directorate General Oil and Gas and The Jakarta Post

In attracting investment for oil and gas projects, Indonesia faces two important challenges: ensuring the physical security of projects and providing an adequate return on them. At times, political factors have placed the security of Indonesian oil and gas operations in jeopardy. Oil companies have faced both political demonstrations and theft. Meanwhile, fiscal constraints have sharply limited the returns on oil and gas investments. Consequently, investment in exploration has dropped sharply from US$2 billion in 1998 to US$0.7 billion in 2000, reducing the rate at which new oil and gas reserves are found, and oil and gas reserves have stagnated as shown in Figure 62. Although investment increased slightly to US$1.1 billion in 2001, Indonesia was able to attract just a single investor for 14 prospective acreages opened for bidders. Nonetheless, a survey conduced by PricewaterhouseCooper in 2002 indicated that most oil companies operates in Indonesia feel that the potential for additional oil and gas exploration and production opportunities in Indonesia remains still encouraging.[112]

Figure 62 Oil and Gas Reserves versus Exploration Investment in Indonesia



Source: Directorate General Oil and Gas

LNG Tangguh: Does Political Stability Matter?

The decision of China's Guangdong Province selecting Australia North West to supply 3 million metric tonnes of LNG per year for 25 years, despite the lower price offered by Indonesia, could be an indication that political stability is important in long-term energy contracts. Indonesia offered US$2.4 per MBtu, a lower price than Australia which offered US$3.1 per Mbtu[113]. However, later Indonesia made the winning bid to supply Fujian with 2.6 million metric tonnes per year for 25 years. In the latter case economic factors could be the prime consideration in China's decision, as well as a probable change in the risk perception regarding Indonesia. It is difficult to make a balance between the risk concerning the political condition of an economy and the economics of a certain project, especially in the oil and gas business. Experience shows that even countries with high political instability such as Myanmar or Angola, receive foreign investment in their oil industries.

112 PricewaterhouseCooper (2002).

113 Media Indonesia 30 October 2002

COAL

The share of coal in Indonesia's energy consumption rose from 8 percent in 1990 to 17 percent in 2001, due to the development of large coal-fired power plants with an installed capacity of 5,931 MW. Besides being consumed domestically, coal is also exported. In 2001 Indonesia exported 75 percent of coal production, earning more than US$1.3 billion. Coal exports are expected to reach 79.7 Mt in 2003. Indonesia is endowed with ample coal resources, enough to fulfil both export and domestic demand. Currently there are 5,362 Mt of mineable coal reserves in Indonesia, with 11.5 billion tonnes of measured resources and 27.3 billion tonnes of reserves. In addition to those coal resources, Indonesia has 336 Tcf of coal bed methane (CBM).

For the period from 2000 through 2020, it is estimated that some US$8 billion will be needed to finance the exploration and exploitation of coal reserves to maintain export capacity and satisfy domestic demand. Given the abundance of coal resources and coal bed methane, they will likely be used increasingly as fuels for electricity generation. In 2000, coal accounted for 46 percent of total electricity production, with a consumption of 13 Mt. This figure is projected to increase to about 27.8 Mt in 2005 and 56 Mt by 2010. The additional demand will come from PLN, IPP projects, and some planned mine-mouth power plants in Sumatra and Kalimantan. In addition, Indonesia has signed an MOU with Malaysia to develop a 1,200-MW power station at Cerenti Riau to supply the Sumatran and Malaysian markets. This plant will form part of the ASEAN power grid.

There are at least five disincentives that could discourage investment in the coal sector, namely the removal of tax incentives, security concerns, provincial regulation, the absence of more appropriate mining laws, and the fact that some prospected coal areas have been declared forest conservation areas. Furthermore, more stringent environmental regulations may inhibit the growth of coal utilisation and exports. But new financing mechanisms such as the Clean Development Mechanism (CDM) may help to finance coal projects that meet environmental standards.

ASSESSING SOURCES OF FINANCING

PAST EXPERIENCE

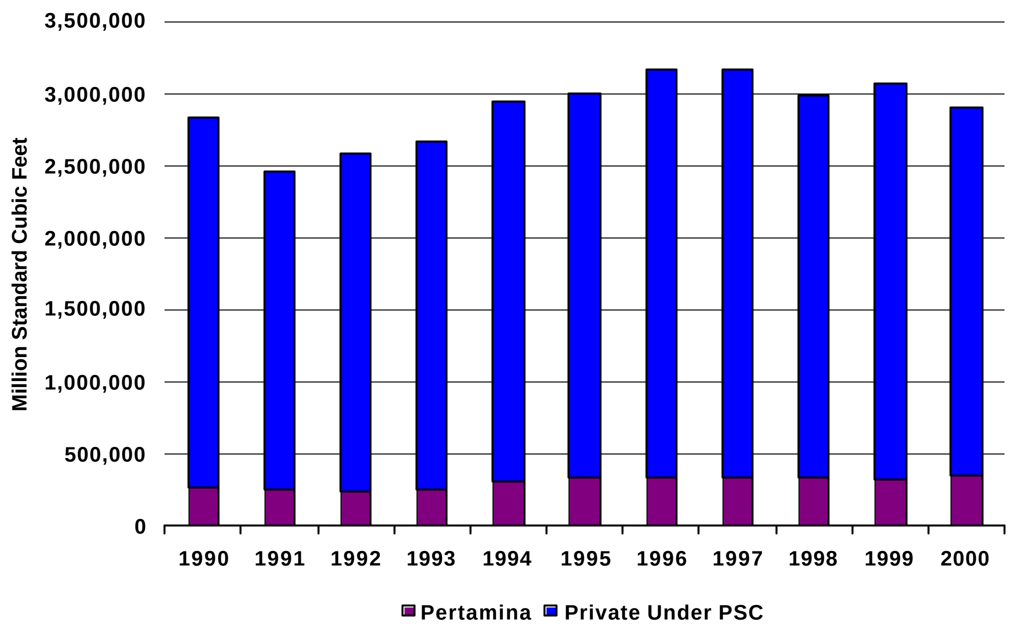
Historically, substantial financing for development of the Indonesian energy sector has come from government, export credit agencies (ECA), multilateral lending agencies and the private sector (mostly foreign). Between 1994 and 1999, export credit agencies led by the Japan Export Import Bank, KFW Germany, US Export-Import Bank (Eximbank) and the Canada Export Development Corporation, provided Indonesia with almost US$13 billion for energy sector development.

Among the projects supported by these agencies are LNG Bontang (US$1,880 million), Pertamina debottlenecking (US$633 million), Sengkang Gas (US$179 million), and Pertamina Refinery Balikpapan (US$152 million). OPIC recently financed the Unocal Co Ltd deep-water oil development in West Seno field, amounting to US$400 million. In total, ECA channelled US$4.87 billion to finance power projects and US$4.13 billion for oil and gas projects from 1994 to 2002, with most of the funds in the oil and gas sector going to downstream activities.

Since as early as 1967, however, the private sector has been the main investor in the exploration and production of oil and gas resources. As a result, almost 90 percent of oil and gas production comes from privately-owned international companies, as shown in Figure 63 and Figure 64. Other upstream investments have come from state-owned Pertamina and private domestic oil companies.

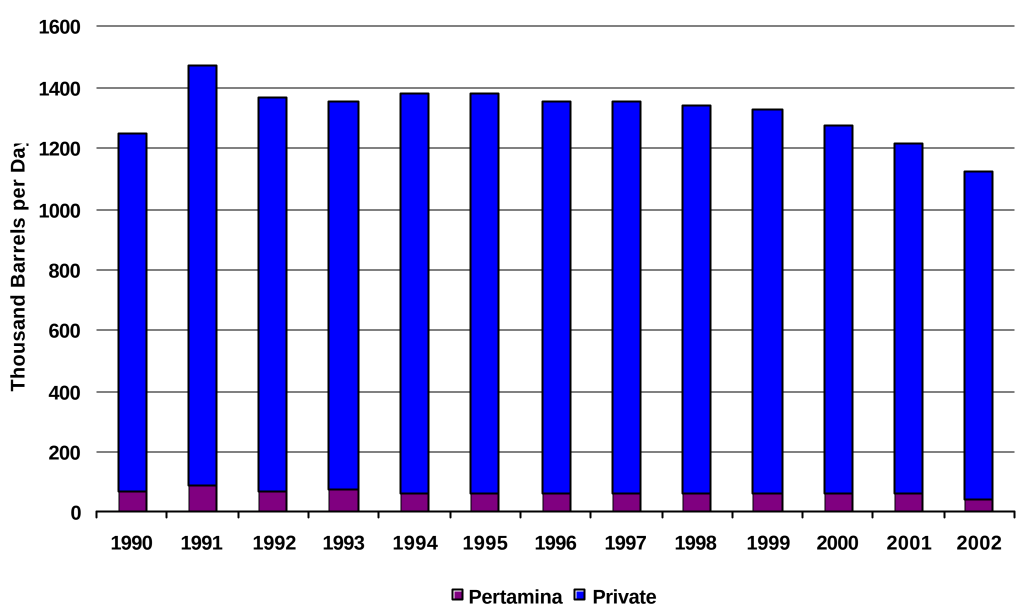
The Indonesian coal industry started in the 1980s. Development of coal resources is conducted by the state-owned company PT Tambang Batubara Bukit Asam (PT BA) and by private companies under coal contracts of work (CCOW). Coal production increased from 10.8 million tonnes in 1990 to 77.1 million tonnes in 2000. Fifteen private contractors account for the majority of production, as shown in Figure 65.

Figure 63 Public and Private Gas Production Shares in Indonesia



Source: Directorate General Oil and Gas and US Embassy Jakarta

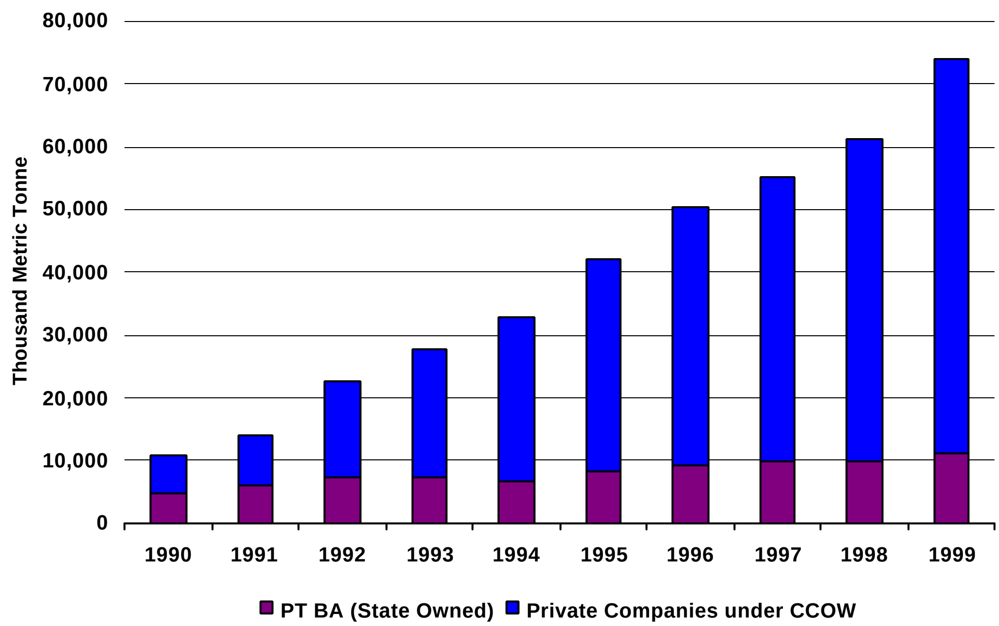
Figure 64 Public and Private Oil Production Shares in Indonesia



Source: OPEC

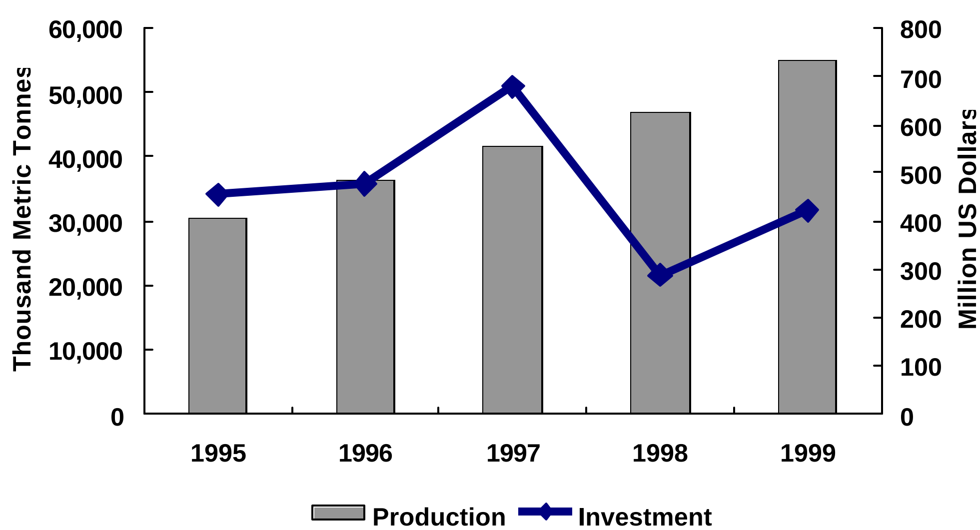
During the period from 1984 through 1994, total investment by coal contractors reached only US$ 1,555 million. But investment then grew dramatically to US$455 million in 1995 and peaked at US$679 million 1997 before slowing to US$ 288 million in 1998 due to an anticipated slowdown in domestic coal demand in the wake of the financial crisis of 1997, as shown in Figure 66. Total coal-related investment during the period 1995-1999 amounted to some US$2,915 million.

Figure 65 Public and Private Coal Production Shares in Indonesia



Source: PT Batubara Bukit Asam , US Embassy Jakarta, Energy Information Centre

Figure 66 Relationship of Coal Production to Investment In Indonesia



Source: US Embassy Jakarta, Energy Information Centre

The issuance of bonds seems to be a good option for Indonesian private oil companies. PT Medco Energy raised US$100 million by issuing a five-year note in March 2002. The note was issued with a spread of roughly 600 basis points over the 5-year US treasury notes.

Not all energy projects in the past have been attractive for investment. Although in 2000 the Investment Coordinating Board approved foreign investment to build five refineries located in Aceh, East Java, Riau and South Sulawesi, with a total investment of US$10 billion, no refineries have been built yet. As a consequence, Indonesia has had to import 91 million bbl of petroleum products in 2000, which will likely increase in coming years.

Indonesia faces difficulty to find funds even for the upgrade of a refinery to phase out leaded gasoline. After being delayed for about 2 years, Indonesia found the sponsor to finance the construction of a catalytic reformer unit (CRU) that costs US$225.2 million. Pertamina signed a project-financing scheme with Mitsui Co in April 2003, in which JBIC will lend US$120 million, while UFJ Bank, the Bank of Tokyo-Mitsubishi, France's Credit Lyonnais and ING of the Netherlands will provide US$20 million each to finance the project. Mitsui is to receive 20,000 to 31,000 barrels of low-sulphur fuel oil on a daily basis for just over three years for sale to thermal power plants in Japan, South Korea and elsewhere.

The rapid growth of Indonesia's electricity demand in the 1990s, combined with a lack of sufficient government funds to build additional generation capacity, stimulated Indonesia to open the electricity business to domestic or foreign private sectors. As a result, 27 IPP contracts to build approximately 6,000 MW of generating capacity were successfully signed. Foreign investment in these projects reached US$ 6.9 billion. However, the 1997 financial crisis hit the economy, followed by decreasing electricity demand. This situation led Indonesia into lengthy negotiations to reschedule the projects, as there was no immediate demand for their output. The crisis resulted in a temporary slowdown of demand, which resumed steady growth in the years that followed.

Electricity development projects still face difficulties in raising funds. Investors are probably taking a 'wait and see' attitude, to see how Indonesia will resolve the 27 IPP projects which are under intense negotiation. There is some funding available from the Asian Development Bank. However, ADB loans have been very limited, amounting to US$500,000 and executed in 2002, directed to regional power transmission and competitive market development.

To prevent blackouts in Java-Bali, PLN extended the Muara Tawar Power Plant by building six power units with a generating capacity of 100-150 MW. To finance the project PLN would issue bonds worth Rp. 900 million and use its own funds and a domestic loan.[114]

FUTURE SOURCES OF FINANCING

Figure 67 shows that the financial crisis that hit Indonesia in 1997 eroded the investment climate, as indicated by a negative inflow of FDI. Economic activity has not fully recovered yet, as shown by the gap between savings and investment (Figure 68). This suggests that there is domestic capital to finance a certain level of potential investment in the short term. However, considering the amount needed for energy investment in the next 20 years, domestic capital seems insufficient. In addition, domestic capital markets are not well developed yet.

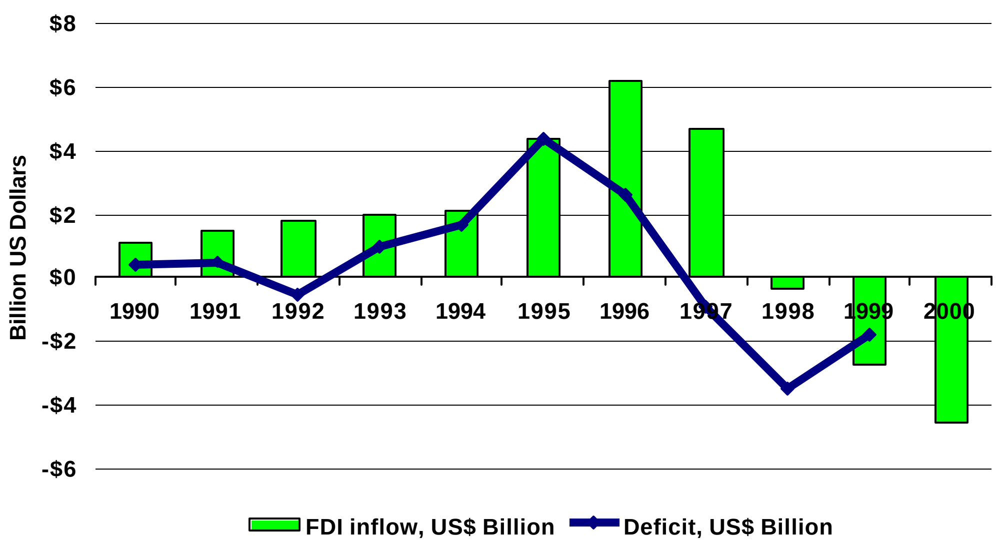
There are three main domestic financial sources in Indonesia: bank lending, the bond market and the stock exchange. Domestic banks have limited experience in financing energy projects. In 1990's PLN issued 2 trillion rupiah bond to finance electricity projects. Currently, PLN and PGN are considering bond issues to finance gas transmission lines and electricity generation; PGN plans to issue US$500 million in Eurobonds and PLN US$900 million. While transactions on the stock exchange reached a volume of US$26,834 million or 45 percent of GDP in 2000, no energy projects have yet been financed through the stock market. Thus, new energy projects in Indonesia will likely be financed mainly through private companies' equity, bond and foreign direct investment.

In sum, Indonesia offers interesting investment opportunities in its energy sector, especially in oil and gas. However, the materialisation of these opportunities will result from a balance where

[114] The Jakarta Post, 15 April 2003, Siemens Wins Muara Tawar Power Project.

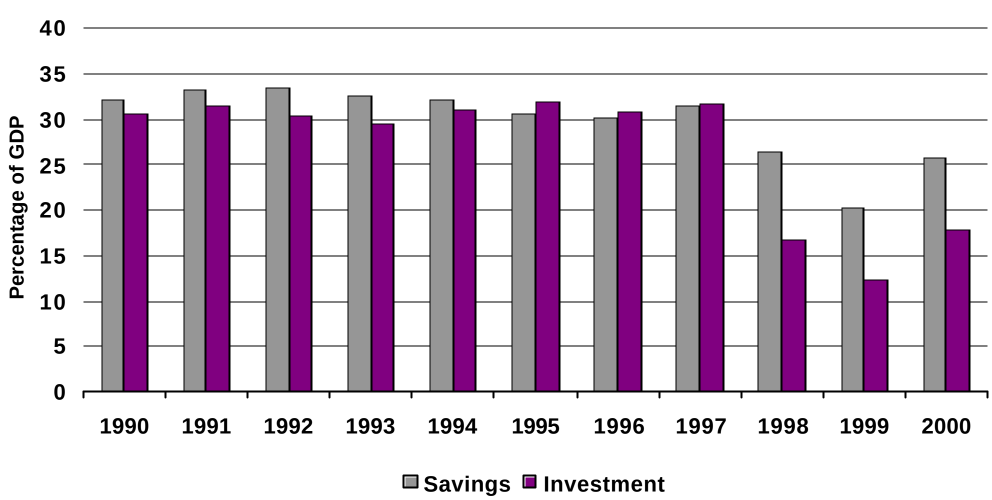
investors consider the profitability of the project as well other factors such as security, government involvement and guarantee. These issues will be discussed in the following sections.

Figure 67 Foreign Direct Investment and Current Account Deficit in Indonesia



Source: World Development Indicator (2002)

Figure 68 Investment and Savings as Percentage of GDP in Indonesia



Source: World Development Indicator (2002)

GOVERNMENT STRATEGIES FOR ATTRACTING INVESTMENT

The enactment of a foreign direct investment law in 1967, when other oil-endowed economies still had their doors closed, has been an important factor in inviting foreign investment to the oil sector. The openness of the economy, together with good geological prospectivity (indicated by a success ratio of drilling exploration between 46 and 56 percent, which is much better than that in the US where the success ratio is around 26 percent) have led Indonesia to become a major oil exporter and the largest world's largest LNG exporter. During the 1990s, private investment kept flowing into the power sector, despite heavily subsidised electricity prices, thanks to stable political and macroeconomic conditions, good security and a potential market.

Profitability of projects is one of the most important considerations for investors. For example, transmission of gas to Singapore will give an internal rate of return (IRR) of 21.3 percent at US$15 per barrel of oil and 69.1 percent at US$30 per barrel of oil. Thanks to good geological prospectivity, investors are still conducting exploration work in Indonesia. However, they have expressed concerns about the security of operations and ambiguities the regulatory reform process.

Oil refineries in Indonesia have been open to private investment and foreign direct investment since 1997, but no such investment has been forthcoming. Profit margins for refineries have fallen globally, and policies that cap domestic oil prices limit what can be earned on refined oil products. In the power sector, investors are waiting to see how Indonesia will resolve the IPP contract disputes before committing funds to future projects for electricity generation.

Over the last twenty years, conditions in the energy business have changed a great deal, and economies have become increasingly active in competing with each other to attract investment. Thus, besides developing a domestic capital market, the government would be well-advised to take measures to improve the climate for foreign investment in the Indonesian energy sector. Several studies have assessed the current investment climate in Indonesia and elsewhere, such as Johnston (1994), Machmud (2000), World Bank (2000, 2003) and PricewaterhouseCooper (2002). Indonesia could draw guidelines from these studies in order to develop investment-enhancing strategies such as greater transparency in the legal and fiscal systems, appropriate energy pricing, competitive restructuring of energy business, and maintaining security and political stability.

PROMOTING CERTAINTY IN THE LEGAL SYSTEM

The government enacted the Foreign Direct Investment Law in 1967 to provide a legal foundation for foreign investment in Indonesia. However, for a long time only the upstream oil business was open to foreign and private investment. Distribution of oil products was limited to state-owned Pertamina. Generation, transmission and distribution of electricity was reserved for the state firm PLN. Gas transmission and distribution were monopolised by the state firm PGN.

To increase efficiency and cope with the lack of domestic financing capability, regulations have been issued to allow private participation in financing of power projects by independent power producers (IPPs). Furthermore, Indonesia enacted a new oil and gas law in 2001 and a new electricity law in 2002, in order to qualify for financial aid from the IMF and the World Bank. Both laws provide basic assurances for private and foreign participation, promoting comparable treatment of private and state-owned companies. An independent regulatory body has been set up to supervise the oil and electricity markets, with legal provisions to ensure that the body is generally free from political interference.

This is also the case of the efforts done to resolve the disputes with IPPs. The postponement of 27 IPP projects due to the 1997 financial crisis eroded the investment climate. Although the decision to postpone the projects came as a result of the financial crisis –where a reduction in demand made the power to be produced from IPPs unnecessary– and of strong domestic pressure to break the contracts which were regarded as unfair, the government sought the most legally acceptable solution for the case. Honouring the spirit of the contracts, the government renegotiated the continuation of the IPPs. Recently all IPP disputes except Karaha Bodas have been settled. Of the 26 successfully renegotiated projects, 14 will be continued, 7 agreed to be terminated and 5 will be acquired by PLN and Pertamina. This successful renegotiation sends a positive signal that Indonesia respects and wants to maintain an adequate legal system, by honouring every contract and considering the benefit of each party.

FISCAL SYSTEM

The fiscal contract regime system is the most crucial factor affecting investment in the oil, gas and coal business in Indonesia. It determines how much investors will receive for production resulting from their investment. It is a tool for government to modify the profit split in order to attract investment, especially as exploration moves to more difficult or remote areas.

Table 48 Development of Oil and Gas Production Sharing Contracts in Indonesia

Contract Regime	Cost Recovery	Profit Split with Private Investors	Domestic Market Obligation DMO	Income Tax and Investment Credits
1966 First Generation PSC	40% cost recovery limit	**Oil:** 65% to government (67.5% above 75000 bpd) 35% to contractor (32.5% above 75000 bpd) inclusive of taxes	25% of production to domestic market, at full price for first 5 years of production, 20 cents per barrel thereafter	Paid by Pertamina
1976 Second Generation PSC	100% cost recovery; 10-year amortization of non capital costs, 14 year depreciation of capital costs	**Oil:** 85% to government, 15% to contractor inclusive of taxes	25% of production to domestic market, at full price for first 5 years of production, 20 cents per barrel thereafter	Paid by Pertamina; 20% investment credit
1978 Changes		**Oil:** 85% to government, 15% to contractor on an after-tax basis. **Gas:** 70% to contractor, 30% to government on an after-tax basis		Effective tax rate 56%, 45% tax on net income, 20% withholding tax
1984 Third Generation PSC	Depreciation: Oil 7 year DDB, Gas 14 year DDB	**Oil:** 85% to government, 15% to contractor on an after-tax basis **Gas:** 65-70% to contractor, 30-35% to government on an after-tax basis		Effective tax rate 48%, 35% tax on net income, 20% withholding tax, 17% investment credit
1988-89 Fourth Generation PSC	First tranche Petroleum 20% Depreciation: Oil 5 year DB, Gas 8 Year DB	**Oil:** 80% to government, 20% to contractor for production of up to 50,000 bpd and production from marginal fields yielding less than 10,000 bpd	DMO price set at 10% of export price after first 5 years of production	17% investment credit. Deepwater investment uplift 110% of oil and 55% for gas
1992 Incentive	Depreciation of capital goods is established at half of the life of the project	**Oil:** 20% to contractor in frontier areas, 25% in deep sea areas. **Gas:** 35% to contractor in conventional areas, 40% in frontier areas	DMO price set at 15% of export price after first 5 years of production	Investment credit 110% for pre-tertiary reserves and water depths of 200-1500 metres, 125% for depths greater than 1500 metres
1994 Eastern Frontier	First tranche petroleum 15%	**Oil:** 35% to contractor. **Gas:** 40% to contractor.	DMO price set at 25% of export price after first 5 years	
2003		**Oil:** contractor share in conventional fields raised from 15% to 20% or 25% **Gas:** contractor share in conventional fields raised from 30% to 35% or 40%		

Source: DGOG (2002), The Jakarta Post (2003)

There have been four generations of Production Sharing Contracts (PSC), as shown in Table 48. The provisions of the contracts have been quite different for oil and gas production. In the first generation PSC, which prevailed for the decade starting in 1966, investors were allowed to recover 40 percent of oil project costs from profits after the start of production, after which the government retained 65 percent of the profits and investors were allowed to keep 35 percent. In the second generation PSC, which ran from 1976 through 1984, initial cost recovery provisions were improved while subsequent production-sharing was made less generous. Investors were allowed to recover 100 percent of oil project costs from profits after the start of production, with the government keeping 85 percent of the subsequent profits and investors allowed 15 percent. Modifications to the fiscal regime in 1978 made profit sharing more generous by allowing investors to keep 15 percent of profits on an after-tax basis instead of a pre-tax basis.

The 85/15 split in profits was retained in the third generation PSC and has remained in place for conventional oil projects for the last two decades. However, more generous profit sharing has been allowed for upstream projects in non-conventional oil fields. The fourth generation PSC allowed investors to keep 20 percent of profits for the first 50,000 barrels per day of production and for all production from marginal fields yielding less than 10,000 barrels per day. Additional incentive provisions enacted in 1992 allowed investors to take 20 percent of profits from oil projects in frontier areas and 25 percent of profits from oil projects producing from the deep sea.

In the case of natural gas, by contrast, the sharing of profits with investors has become less generous over time. Initially, when gas was first seriously considered by the fiscal regime in 1978, most gas production was associated with oil production. The government wanted to discourage the flaring of associated gas by offering a 70 percent share of profits to investors for providing gas to the marketplace. In many cases, the investor share of profits from gas projects was reduced slightly to 65 percent by the third generation PSC that was implemented in 1984. But 1992 modifications to the fourth generation PSC reduced the investor share of profits in gas projects more dramatically. By this time, many projects were designed primarily to produce gas, rather than just to market associated gas. Thus, the government decided to reduce the investor share of profits in gas projects to 35 percent in conventional areas and 40 percent in frontier areas.

A significant drag on potential profits to investors results from socially-imposed domestic market obligations for oil and gas production. Under the first generation PSC, 25 percent of production had to be reserved for the market, which receive a full market price during the first five years of production but received only a nominal payment of 20 cents per barrel thereafter, which was far below production costs. These terms were retained in the second and third generation PSC. The fourth generation PSC provided that the 25 percent domestic market obligation be sold at 10 percent of the prevailing export price after the first five years of production. The price allowed for the required sales rose to 15 percent of the export price in 1992 and further, in the case of production from the eastern frontier region, to 25 percent of the export price in 1994. Still, the earnings from domestic oil and sales remained far below foregone earnings on oil and gas exports.

Table 49 Comparison between Two Types of Coal Contracts in Indonesia

No	Coal Cooperation Contract (CCC)	Coal Contract of Work (CCOW)
1.	Principal: PT BA (state coal company)	Government (Ministry of Energy and Mineral Resources)
2	Production share: 13,5% (fixed and in kind calculated at sales point)	Levies and royalties: 13.5% (negotiable for special case and in cash (FOB))
3	Need mining authorization for every stage of activities	One package
4	All exploration activities should be completed before contractor commences production activities	Contractor may proceed with exploitation during the exploration period
5	Initial cost	None
6	Advance payment	None
7	Lump sum payment for regional tax	None
8	Taxation regime: according to prevailing tax	Taxation regime: nailed down
9	Every coal export needs approval from PT BA	Only long term export agreements of more than 3 years need written approval from government
10	Strict divestment program	Less strict divestment, follows government Regulation No. 20 of 1994

Source: US Embassy Jakarta (2000).

In a recent comparison of profit sharing between government and investors in oil projects in different petroleum-producing countries, the Indonesian fiscal system was found to allow a lower share of profits to investors than any other country but Venezuela.[115] The tough Indonesian fiscal system has resulted in a slow-down in investment. For 14 prospective oil and gas production areas offered in 2002, only one investor expressed interest in bidding. For 11 blocks offered in 2003, no investor indicated willingness to invest until the near closing date of the bidding process.[116]

In the coal sector, Indonesia used Coal Cooperation Contracts (CCC) to permit private participation and FDI. The state-owned coal company PT Tambang Batubara Bukit Asam (PT BA) administered these contracts. In 1996, the government changed the contract arrangement from CCC to Coal Contract of Work (CCOW) and transferred the administration responsibility from PT BA to government (Ministry of Energy and Mineral Resources). The change from CCC to CCOW resulted in improvement of fiscal terms as well as procedures as shown in Table 49.

Contractors wishing to participate in coal mining must submit an application to the Ministry of Energy and Mineral Resources with a topographic map scale 1:250,000 and a brief description of the area being applied for, work plan and budgeting program. The contractor is obligated not to mine other minerals, is fully responsible for all risks of all activities, must complete a general survey and to relinquish 25 percent of the initial contract area within the first year of the general survey, 50 percent within 3 years and 75-80 percent of the contract area on or before the end of the exploration period. In addition, the contractor should spend US$2.50/ha on the coal-field by the end of the general survey period, to commence exploration upon completion of the general survey and spend at least US$15.00/ha on exploration.

Following the enactment of an autonomy law, a new CCOW is being drafted to empower regional governments and introduce a new royalty scheme. CCOW terms require that domestic entities must eventually have majority ownership of mining projects. During the first 10 years of production, foreign shareholders must transfer shares according to a fixed timetable so that Indonesian companies eventually hold 51 percent of the mining project. However, it is sometimes difficult to comply with such divestment obligation, as the local company may consider the sales offer not commercially attractive.

IMF[117] suggests that it would be best to fully centralise oil revenues in order to simplify procedures and their administration. It suggests as well that this should be accompanied by an appropriate distribution of revenue.

RESTRUCTURING THE ENERGY SECTOR

Indonesia is currently restructuring its energy sector, especially in oil, gas and electricity. The process aims to provide more access for private entities, promote a more transparent and competitive market that could promote efficiency. The reform was initiated with the enactment of the Oil and Gas Law in 2001 and the Electricity Law in 2002. By giving competing firms greater access to energy markets, the government hopes to attract more capital to the energy sector.

Under the new Oil and Gas Law, Pertamina, the state petroleum company, becomes a limited liability company in 2003, while its role of supervising production sharing contracts will be exercised by BP Migas. In the downstream sector, Pertamina's monopoly on refining, transportation and distribution was ended, granting access to private and public entities to conduct business in the downstream sector.

In gas distribution, the government will create a multi-seller multi-buyer market, abolishing the monopoly of the state-owned company PT PGN. Open access to distribution and transmission networks is mandatory. The new agency, called Regulating Body, will supervise the downstream business and transportation through pipelines. As a first step in the reform of the transportation

115 Johnston (2002).

116 Kompas 6 June 2003.

117 IMF (2002).

business, PGN has created three strategic business units for gas distribution and established Transco, a transmission subsidiary for the Grissik-Duri Pipeline in Sumatra. The latter has also been privatised but PGN maintains 60 percent of its equity. Furthermore, PGN will fully unbundle its transmission and distribution function, and plans to invite private investors through an IPO.[118]

Under the new Electricity Law, the state-owned PLN Electricity Company will be unbundled to separate companies in Java-Bali, Batam and the rest of Indonesia. Java-Bali, which represents 50 percent of PLN sales and Batam, will become the focus of the reform. A multi-seller and multi-buyer scheme will be introduced in Java-Bali and Batam. For the remaining regions, the government will establish a social electricity fund.

APPROPRIATE PRICING

Energy in Indonesia has been subsidised for a long time. The domestic price of five major products that account for most of domestic consumption was roughly 43 percent of the international price in December 1999. This required a government subsidy of some US$4.9 billion or 5 percent of GDP. The World Bank estimated that the economic loss due to fuel subsidies amounted to US$780 million in 1999. It also estimated that if subsidies were not removed, they would cost the government US$24 billion between 2000 and 2005.

In 2001, the government took the decision to reduce the subsidy to non-households, following the requirements of international financial institutions, considering the subsidy's budgetary burden, and taking note that the subsidy promoted fuel smuggling while failing to improve social equity. In 2002, the government allowed fuel prices to follow a border price movement within a certain range. In 2004, it is expected that all remaining fuel subsidies will be abolished. By removing subsidies and letting the electricity price reflect the economic cost of providing the service, Indonesia expects that the electricity sector will become more attractive for investors.

Although the government of Indonesia provided a lifeline subsidy for electricity prices, prior to the 1997 financial crisis the tariff was close to 7 US cents per kWh, which provided sufficient operating income to provide the state-owned electricity company (PLN) with a financial rate of return of almost 7 percent.[119] The collapse of the Indonesian currency reduced the tariff level to about 2.6 US cents per kWh, because the electricity bill was paid in local currency. On the other hand the operation cost rose significantly, which led to insolvency of the electricity company. To prevent electricity shortages, the government provides a subsidy amounting to 4.62 trillion rupiah in 2001 to maintain PLN's cash flow.

To enable PLN to pass on to consumers the increase in fuel prices, the power purchases and debt service, the government increased the tariff starting in 2001 with the objective of reaching an equivalent to 7 US cents per kWh, the tariff considered as economic by 2005. When this level is achieved, an automatic tariff adjustment mechanism will be installed to accommodate the fluctuation of operating variable costs such as fuel and spare parts. The government also changed the lifeline subsidy to a targeted subsidy. The new subsidy scheme covers only a maximum of 30 kWh per month of electricity consumption for specific customer groups: households with voltage classification of 450 KVA, social institutions and small businesses. As mandated by the Electricity Law of 2002, the development of electricity supply facilities in order to help underprivileged groups, the development of electricity supply facilities in underdeveloped or remote areas, and the development of electricity in rural areas will be funded by the central or regional governments.

MAINTAINING SECURITY

Some current security issues could adversely affect the Indonesian energy sector. In Aceh, the separatist movement threatens the stability of LNG operations. ExxonMobil suspended natural gas production from March to July 2001, from its onshore Arun, South Lhoksukon and North Pase

[118] The Indonesian Petroleum Association has expressed some concerns about the lack of clarity in the oil and gas law regarding the role of government with respect to the regulatory body. See Indonesian Petroleum Association (2002).

[119] World Bank (2003)

fields in North Aceh since the company facilities and personnel increasingly became a target of the Separatist Free Aceh Movement. BP operations in offshore North West Java and Caltex operations in Riau experienced concurrent disturbance from thefts that stole a power line, wellhead Christmas Tree, valves and other operation materials. Although in terms of the amount of money the loss of these materials is small, the impact to the operation could be significant because a stop of operations could lead to significant production losses.

Communities in West Papua, Kalimantan and Riau province demanded more profits from natural resources produced in their regions and proposed additional taxes on the companies that extract them. Even the low level of insurgency in West Papua was considered as a significant factor in the China's decision not to select LNG Tangguh to supply Guangdong, despite the more economically favourable offer. The power sector seems to face a lower-level security problem. A few disturbances have been reported, usually in opposition to the level of payment for land taken for the location of power plants or high voltage transmission lines.

The government has taken various measures to address these security issues. To prevent recurrent theft to local municipalities, energy projects will promote community development and participation. The LNG Tangguh project has encouraged such a programme since the beginning of the project. The government has also taken serious measures to face rebel insurgency. Lately Indonesia applied martial law to the Aceh Province and deployed 40,000 troops there to suppress the Aceh Separatist Movement.

FINDINGS AND IMPLICATIONS

The steady growth of energy demand as well as the need to continue exporting oil, gas and coal to earn foreign currency, will require significant investment, which APERC estimates will amount to some US$138 billion through 2020. The government's budget and domestic savings will not be sufficient to fund the investment required. Therefore, considerable foreign investment will be indispensable for the development of energy infrastructure.

Geological prospective in Indonesia's oil and gas fields is high. The current success ratio in exploration drilling is 46 percent to 56 percent, much better than in the Gulf of Mexico (where it is only around 20 percent) or the North Sea. This has made Indonesian oil fields an attractive place for private domestic or multinational oil companies to explore for oil and gas. However, the government should consider providing a fiscal system that offers a more attractive share to companies, with a higher security level for their operations. In addition, the government should provide certainty that reform in the oil, gas, mining and electricity sectors will improve performance, promoting a healthier cash flow to attract investment. Further, the government should provide favourable security conditions for doing business within the framework of the law.

Considering critiques made in relation to foreign direct investment, the government could take certain measures to balance domestic political issues with the need of inviting foreign capital. The following measures could be considered as neutral policies:

1. Improve the transparency of tendering and approval processes in every project that involves the private sector, be it domestic or foreign.
2. Encourage competition by opening the market for both domestic and international players in order to seek the most efficient performance.
3. Streamline bureaucratic processes for approval of energy projects.

PHILIPPINES

BACKGROUND

The Philippines has significant and varied energy resources, but they provide for slightly less than half of the economy's total energy requirements. Indigenous resources include some 37 million to 45 million cubic metres (Mcm) of crude oil, 82 billion to 107 billion cubic metres (Bcm) of natural gas, 399 million tonnes (Mt) of coal (mostly lignite), and significant untapped reserves of geothermal energy. But even with aggressive energy resource development, the economy is expected to remain a net energy importer for the foreseeable future. In addition, despite a current excess of generating capacity for electric power production, continued electricity demand growth and power plant retirements are expected to lead to major new investment requirements in the power sector before 2010.

The Philippines has had considerable success in developing indigenous energy resources through a Build-Operate-Transfer (BOT) approach to mobilising foreign and domestic financing. Ongoing reforms to encourage greater competition in the gas and power sectors may also help to mobilise needed capital investment. However, multilateral financial institutions have cited a number of problems, which may make it more difficult to attract investment. These include limited capacity of government agencies to absorb assistance, lack of institutional capacity by local governments to undertake development projects, project delays, and incidents of corruption.[120] In addition, social and political considerations may make it difficult for the government to refrain from intervening in energy markets when scarcity or demand pressures cause prices to rise significantly. If prices were reduced from market levels, the incentives for investment to restore the supply-demand balance would be reduced as well.

ENERGY SECTOR INVESTMENT REQUIREMENTS

The Philippines consumed 23.3 Mtoe of energy in 1999, amounting to 0.6 toe per capita or 736 toe per million 1990 US$ of GDP. APERC projects that with stable macroeconomic performance and productivity-enhancing measures, the economy's GDP could grow 4.9 percent per annum through 2020, so that its final energy consumption grows 2.2 percent annually, more than doubling to 51.2 Mtoe. Resulting cumulative investment requirements for new energy infrastructure in the Philippines would then add up to more than US$41 billion through 2020, including some US$27 billion in the electric power sector and US$14 billion in the oil and gas sectors.

Table 50 Economic and Energy Indicators for the Philippines

				Annual Average Growth Rates	
	1980	1999	2020	1980-1999	1999-2020
GDP (Billion 1990 US$)	37.5	56.5	153.0	2.2	4.9
Population (Millions)	48.3	74.3	105.3	2.3	1.7
GDP per capita	775.9	760.4	1,452.4	-0.1	3.1
Energy Intensity (toe/million 1990 US$)	565.8	736.4	586.2	1.4	-1.1
Energy per capita (toe/person)	0.4	0.6	0.9	1.3	2.0
Final Energy Consumption (Mtoe)	15.9	23.3	51.2	2.0	3.8

120 Asian Development Bank (2003)

Sources: DRI-WEFA (2001) for data on GDP and population. IEA (2001) for historical data on energy. APERC (2002) for energy projections.

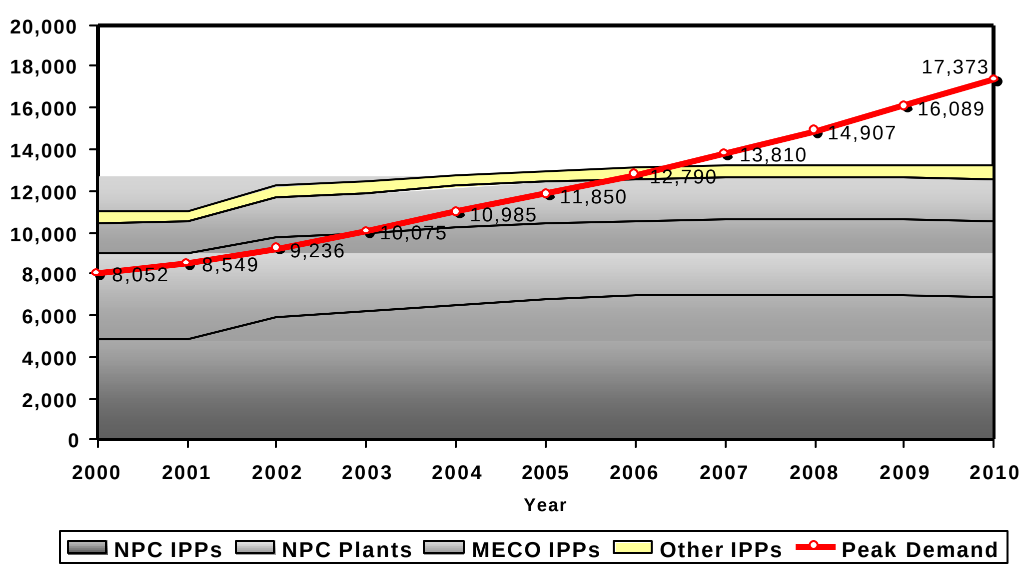
Table 51 Energy Investment Requirements in the Philippines: High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.03	-	-	-	0.37	0.02	0.39
Oil & gas production, processing, petrochemical	0.13	0.09	0.40	0.47	0.56	5.18	4.82	10.00
Oil & gas international trade	0.00	0.01	0.01	0.39	0.16	0.08	2.53	2.61
Oil & gas domestic pipelines	0.01	0.00	0.06	0.08	0.09	0.34	0.79	1.13
Electricity generation & transmission	0.54	0.15	0.65	3.70	2.88	4.29	22.80	27.08
Total	**0.69**	**0.29**	**1.11**	**4.64**	**3.69**	**10.26**	**30.95**	**41.21**

ELECTRICITY

In 2000, the Philippine economy had 11,209 megawatts (MW) of dependable electric generating capacity and a reserve margin of 1,253 MW in its power system. But moderate demand growth combined with the retirement of ageing coal- and oil-fired plants will likely lead to a need for new electric generating capacity by 2008 on the Luzon grid and by 2005 on the Visayas and Mindanao grids. Figure 69 details the needed capacity additions beyond that of NPC plants and the IPPs can supply as early as 2006. APERC estimates that some 14,512 MW will be added to the system from 2000 to 2020. Resulting cumulative investment requirements in the electricity sector are projected to exceed US$27 billion through 2020.

Figure 69 Power System Supply-Demand Profile of the Philippines (Megawatts)



Source: Philippine Power Development Plan, NPC (2001).

To accommodate additions to generating capacity and relieve congestion on the transmission grid, the economy's transmission system must also be improved. Currently, the national transmission system has a substation capacity of 22,617 megavolt-amperes (MVA). Its transmission lines of varying voltages extend for 20,087 circuit-kilometres. For the island of Luzon alone, it is estimated that about 840 circuit-kilometres of line and installation of 1,350 MVA in substation capacity is set to be installed from 2003 to 2012.[121] To fuel new and existing gas fired power plants, enhancements are also required to infrastructure for the transportation of natural gas.

NATURAL GAS

The Philippine Department of Energy has embarked on an aggressive programme to establish an integrated physical infrastructure network for natural gas from 2003 to 2020. Gas infrastructure projects are envisioned for the island of Luzon where gas demand is projected to be concentrated. As shown in Figure 70, planned infrastructure includes:

80. A high-pressure gas transmission pipeline from Tabangao, Batangas to Metro Manila (BatMan 1), of 80 to 100 kilometres in length, that will serve the converted Sucat thermal plant and co-generation needs of industrial zones along its route;
81. A high-pressure gas transmission pipeline from the Bataan peninsula to Metro Manila (BatMan 2), of 130 to 150 kilometres in length, that will supply gas to the Limay plant and possibly the Sucat plant; or alternatively, a 40 km undersea high pressure gas transmission pipeline from the Bataan peninsula to Metro Manila or Cavite province (BatCave) to serve the Sucat plant and the cogeneration needs of industrial zones in Cavite province;
82. A 35 km high-pressure gas transmission pipeline from Sucat to Pililia, Rizal province, to fuel the 650 MW Malaya thermal power plant that currently runs on bunker fuel;
83. A 40 km city gas pipeline network along Metro Manila's main artery (EDSA) to serve large commercial users;
84. LNG receiving terminals in the Bataan peninsula or Batangas province; and
85. A network of refueling stations for natural gas vehicles in Batangas and Metro Manila.

An LNG receiving facility is also envisaged in Bataan which will be anchored on the conversion of Limay oil thermal plant to natural gas. The plan is to build a 40 km undersea high-pressure gas transmission pipeline that will traverse Manila Bay which will transport LNG from the Bataan peninsula to Metro Manila or Cavite province. Alternatively, the Batangas LNG facility could service the needs of the Sucat or Malaya power plants. These plants could fill the need for additional gas-fired generation capacity in 2008.

Significant use of gas is envisaged not only by electricity generators, but also by industry, commercial enterprises, and public transport. Industries clustered along the proposed pipeline routes are expected to tap gas from the network to provide process heat and conditioning requirements. Firms in some 20 industrial parks and economic zones can harness gas for their various needs. The government is studying the use of natural gas for lighting and air conditioning large commercial establishments such as shopping malls, airports and hospitals. The government has also budgeted for the operation of 100 public transport buses running on natural gas by 2003.

APERC estimates that additional infrastructures such as these, together with other related facilities necessary to transport natural gas, gas fired power plants, CNG-refilling network, bunkering, storage and marketing would require a total investment of US$ 3.8 billion by 2020.

[121] Philippine Department of Energy (2002).

Figure 70 Proposed Natural Gas Distribution Infrastructure in the Philippines

Source: Philippine Department of Energy (2003).

ASSESSING SOURCES OF FINANCING

PROJECT FINANCING

The Philippines has had a successful record of project financing, especially in the power sector. This can be attributed to a sound policy and legal framework for contract enforcement, investor confidence and capital flows, and potential institutional investor resources. It is also relatively easy to acquire information necessary to set up a project for financing in the Philippines.

The Build Operate Transfer (BOT) Law of 1990 (Republic Act 6957, amended to RA 7718 in 1994) allows private firms to finance, build, maintain and operate public infrastructure projects over a specified period of time under contract with the government. The contractor was allowed to collect rent, user charges, and toll fees to recover its investment outlay plus a reasonable rate of return. The government was able to reduce the budgetary and debt burden of infrastructure projects while bringing private sector cost efficiencies and technological advances to these projects.

The first successful project was the 210 MW Hopewell Navotas 1 power plant in 1991. This was followed by more fast-track power projects until 1994, bringing an end to the power shortage that had prevailed. Recent large BOT projects were signed with Mirant Asia Pacific, with the Sual plant to provide 1,000 MW of capacity for the 25-year period from 1999 through 2024 and the

Pagbilao project to provide 735 MW of capacity for the 25-year period from 2000 through 2020. At the end of the contract term in each case, ownership of the plant will be transferred to NPC. Mirant also has a 20 percent interest in Ilijan, a 1,251 MW gas fired combined cycle power plant that will operate under a 20-year energy conversion agreement for 1,200 MW capacity with NPC.

Under the BOT arrangements at Sual and Pagbilao, NPC acts as both fuel supplier and energy off-taker, buying all the fuel needed by the plants at no cost to Mirant and accepting all fuel-related risks and obligations. Mirant, on the other hand, is responsible for management, operation and maintenance of the plants and receives compensation for these services through fixed capacity fees, variable energy fees and incidental fees. More than 90 percent of the revenues should come from fixed capacity charges, which are paid without regard to dispatch level of the plant. The plants' net available capacity is sold to NPC and large industrial and commercial users at contracted prices.

Quezon Power, a partnership consisting of InterGen, Ogden Energy Group, Global Power Investments, and PMR Limited, was financed by some US$809 million in debt and equity with political risk guarantees of US$405 million from the US Export-Import Bank (Eximbank). The project issued US$215 million of bonds registered with the Philippine Securities and Exchange Commission (SEC). Quezon Power is the first build-own-operate (BOO) power project in the Philippines and the first power project to be financed without government or sovereign guarantee. The project commissioned a 470 MW coal fired power plant in Mauban, Quezon.

Project financing was also used for the Camago-Malampaya Deep Water Gas to Power Project, the single largest energy investment in Philippine history. While funding requirements for the project amount to some US$4.5 billion, it is expected to reduce the economy's oil bill by US$250 million to US$600 million per annum. The project involves supply of Camago-Malampaya natural gas by Shell Philippines Exploration and partners to 3,000 MW of combined cycle power plants, built half by the government through National Power Corporation and half by Meralco, a private distribution utility. Meralco assigned its share of the capacity to First Gas Holdings Corporation (FGHC), a consortium held 51 percent by First Philippine Holdings Corporation (FPHC), 40 percent by BG Asia Pacific, and 9 percent by Meralco Pension Fund. FGHC has built the 1,000 MW Santa Rita plant and the 500 MW San Lorenzo plant, both in Santa Rita in Batangas province.

The total cost of the Sta. Rita Combined Cycle Gas Turbine project is estimated at US$890 million, inclusive of capital costs, working capital requirements, related transmission upgrades and financing, insurance and development costs. The financing is based on a structure of 75 percent debt and 25 percent equity structure. Given the optimal risk allocation achieved in the course of developing the project, FGPC secured US$680 million worth of limited recourse project financing on September 3, 1997 with favourable terms, notwithstanding the onslaught of the regional financial crisis. The US$680 million debt financing is broken down as follows:

86. US$190 million KFW-Hermes guaranteed loan facility;
87. US$160 million U.S. private placement;
88. US$110 million Philippines FCDU syndication;
89. US$78 million EIB loan facility;
90. US$66 million MEXIM-Mecib guaranteed loan facility;
91. US$26 million MEXIM loan facility; and
92. US$50 million revolving credit/working capital facility.

The second project, San Lorenzo Combined Cycle Gas Turbine Power, required approximately US$450 million. The lead sponsors for the San Lorenzo Project are First Gas Holdings Corporation (FGHC), BG plc and Lopez Inc. FGHC owns 42 percent of FGP Corp. BG plc, which owns 23 percent of FGP Corp., is a publicly listed UK Company with extensive experience in the industry. Lopez Inc., owns 35 percent of FGP Corp. In 1999, FGP Corp. entered into an agreement with Siemens, a leading power plant contractor in the world, for the Engineering, Procurement and Construction (EPC) of the San Lorenzo Project. The operation and maintenance of the San Lorenzo Plant was also awarded to Siemens Power Operations, Inc. (SPO), a 100 percent-owned subsidiary of Siemens incorporated in the Philippines. SPO, among other activities, will manage, operate, maintain the plant and perform the services and obligations specified in the O&M Agreement. SPO is also the operator of the adjacent Sta. Rita project. The EPC Contract is a fixed-price turnkey, date certain basis with guarantees for completion and performance (heat rate & output) of the power plant. The construction period is guaranteed at 23 months or 27 months depending on whether the four-month early start option is exercised by FGP Corp.

BOND MARKET [122]

The Philippines debt market is divided into public and private sector debt issues. The main investors in this market are banks, insurance companies and sometimes corporate and institutional investors who have funds available for placement in longer-dated issues. Public debt securities are issued by the national government, central bank and other government agencies. Commercial banks and corporations, on the other hand, mainly issue private debt securities.

The Philippine Department of Finance (DOF) reported that in 2000, most external borrowings were from bond offerings. Gross external borrowings totalled P120.3 billion, of which bonds accounted for P99.9 billion or 83 percent, project loans for 13 percent, and program loans 4 percent. Bond issues included Global Bonds (P65.7 billion), Samurai Bonds (P14.3 billion), and RP Bonds (P20.0 billion), although most of the project loans were taken from multilateral institutions.

A total of US$1.6 billion was issued in 2000. US$800 million of this issue represented new money for the National Government, US$500 million for the National Power Corporation's (NPC) funding requirements and another US$300 million in new bonds in exchange for about US$340 million in outstanding NPC bonds. As of 2000, NPC still needed to raise at least US$1.2 billion to cover for maturing debts and other financing obligations.

An innovative approach to fundraising was the government's Progress Bonds. The offering allows the bondholder an option to exchange the bonds for shares of government corporations during privatisation or cash out in a trade sale. Investors are also entitled to an automatic 5 percent bonus applicable at the time of the exercise of the exchange option. Another approach is the 25-year fixed rate treasury bond (FXTB). According to the DOF this bond issue is considered having the longest maturity in the domestic capital market in Asia, except Japan. Before this issue, the longest fixed rate of the economy was for a 20-year bond issued in 1997.

DOMESTIC FINANCING

Gross domestic borrowings by the economy posted a 2.7 percent increase to P164.9 billion in 2000 from P160.5 billion in 1999. Gross flotation of Treasury Bills reached P509.3 billion, but higher redemption of maturing T-bills resulted in a negative net borrowing of P8.4 billion. Longer-term securities (i.e. Treasury Bonds) however netted P140.4 billion. It was in 2000 that a 25-year Treasury Note was issued that lengthened the maturity profile of government's domestic debt.

ROLE OF BILATERAL AND MULTILATERAL FINANCIAL INSTITUTIONS

The Asian Development Bank, World Bank, US Trade and Development Agency (TDA), Overseas Private Investment Corporation (OPIC) and the Japan Bank for International Cooperation (JBIC), as well as the US Agency for International Development (USAID) and the US Eximbank are active in the Philippines and provide funding for a wide range of projects.[123]

122 Philippine Department of Finance Annual Report (2000). Peso figures are retained for accuracy.

123 JBIC in 2003 has provided a special yen (ODA) loan equivalent to Y5,857.00 million to the Northern Luzon Wind Power Project. The project capitalises on NRE development to reduce the country's dependence on imported energy. Another Y2,034 million has been earmarked for the Sustainable Environmental Management Project in Northern Palawan that will provide the infrastructure development works for the prevention of erosion, research and ecotourism activities. Of the 31 loan commitments of JBIC in Southeast Asia in 2001, the Philippines gathered the biggest share of 48.5% or an equivalent of Y169,060.00 million. (JBIC 2003).

JBIC issued a limited-recourse loan to KEPCO Ilijan Corporation (KEILCO), a company incorporated in the Philippines in 1997, together with Korea Electric Power Corporation (KEPCO), Mitsubishi Corporation, Southern Energy, and Kyushu Electric Power Company to finance the 1,200 MW combined-cycle power plant in Ilijan, Batangas City. The loan was co-financed by the Bank of Tokyo-Mitsubishi, BNP Paribas, Citibank, and Sumitomo Bank, with JBIC assuming US$153.1 million or 60 percent of the total amount. The loan will purchase goods and services from Japan for the natural gas combined-cycle plant developed by KEILCO.[124]

The ADB, headquartered in Manila, lent a record of US$42.5 billion in 2001 to 8 APEC economies.[125] Interestingly, the largest share of sectoral lending went to the social infrastructure sector, which includes water, sanitation, urban development, education and health projects. The other large sectors of lending were agriculture and natural resources, transport and communications, and energy. Both the ADB and the IFC also made financing available directly to private enterprises without government guarantee.

GOVERNMENT STRATEGIES FOR ATTRACTING INVESTMENT

The Philippine government has utilised a number of different strategies in recent years to attract private investment to the energy sector. Some are general strategies that apply throughout the economy, such as macroeconomic policies to boost savings and investment and corporate investment tax incentives. Others are sector specific, notably including reforms to increase competition in the natural gas and electric power sectors. The various strategies that have been used to attract energy investment are briefly reviewed below.

MACROECONOMIC REFORMS TO BOOST SAVINGS

To boost economic growth throughout the Philippine economy, the government has embarked on macroeconomic policies designed to boost savings and investment. These involve fiscal measures to increase government revenues and streamline government expenditures. By reducing its budget deficit, the government hopes to free additional funds to finance private investments, and therefore strengthen the economy's prospect of maintaining a sustainable growth (BSP 2002).

On the expenditure side, the government has taken steps to improve project implementation and raise investment productivity by setting up the Presidential Committee on Flagship Programs and Projects, and the Investment Priorities Plan (IPP). On the revenue side, the government has upgraded the Bureau of Internal Revenue (BIR) and Bureau of Customs (BOC) and had considered extensive tax collection campaigns on large delinquent taxpayers to improve revenue collections.

INCENTIVES FOR PRIVATE INVESTMENT

The Philippine economy has been opened up to greater foreign investment by allowing up to 100 percent foreign ownership of enterprises that produce goods for exports and 40 percent foreign ownership of enterprises involved in the exploration and development of natural resources. The banking sector, through which debt financing for energy projects, like other investments, is obtained, has been deregulated. Attractive investment incentive packages have been offered to qualified enterprises in the economy's numerous Special Economic Zones and Industrial Estates. Corporate income taxes were reduced from 34 percent to 32 percent in 1998, and companies located in special economic zones or export zones are subject only to a 5 percent overall tax rate.[126]

ELECTRIC POWER SECTOR REFORM

The Electric Power Industry Reform Act of 2001 (Republic Act 9136) helped to set the stage for meeting the economy's very substantial electric power investment needs by providing for fair access to electric transmission facilities by all competing electric power generators. Under the

124 International Finance Operations, JBIC (2000).
125 Asian Development Bank Annual Report (2001).
126 IPP (2002). BSP (2002).

Reform Act, transmission assets are to be completely unbundled from generation and distribution assets, so that the entire transmission grid is run by an independent National Transmission Corporation or Transco. All transmission assets are to be privatised through bids for a 25-year concession, renewable for another 25 years. The winning bidder will be awarded a franchise to maintain and operate the transmission grid throughout the economy. Because the Transco will have no generating assets, it will have no incentive to discriminate in favour of any generator. It follows that the least-cost generators should be able to access the grid to serve their customers.

To help ensure that there are a number of competing generators, the Reform Act provides that the generating assets of the National Power Corporation will be divided into several independent generating companies or Gencos and sold to investors. Investors will be allowed to build or buy as many power plants as they wish, subject to limits on overall generating market share.

GAS MARKET REFORM

The Philippine gas industry is at a very early stage of development. The Camago-Malampaya Deep Water Gas to Power Project is the largest private investment project in Philippine history. A single consortium produces and transmits gas from the Malampaya field to large gas-fired electric power plants which contracted for the gas before the production facilities and pipelines were built. Under the 20-year Gas Sales and Purchase Agreement (GSPA), gas is to be provided from the field to fuel 2,700 MW of generating capacity, which is only slightly short of the capacity of 3,000 MW or 400 million standard cubic feet of gas per day declared in the Joint Declaration of Commerciality in 1998. But substantial expansion of gas use is planned as more gas-fired power plants are built and gas is introduced to industry, commerce and transportation.

To help attract investment to the growing gas industry, the Philippine Department of Energy issued Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas in 2002. These Gas Rules were designed to maximize the economic efficiency of the industry while it is in its development stage while ensuring efficient use of natural gas resources at the lowest possible production costs. Key elements of the Gas Rule include entry conditions, pricing, promotion of competition, institutional arrangements and review. Natural gas prices are to be regulated by the independent Energy Regulatory Commission (ERC). The DOE, meanwhile, will be responsible for the issuance of permits for construction of pipelines and related facilities.

OIL AND GAS DEVELOPMENT REGIME

The Philippines adopted a petroleum development regime based on production sharing concessions with the passage of the Petroleum Act of 1949 (Republic Act 387), while a Service Contract (SC) System and specific statutes guided other upstream energy activities. The Oil Exploration and Development Act of 1972 gave directions for oil and gas exploration, providing the petroleum industry with more attractive contractual terms and a liberalized fiscal regime that favoured offshore exploration. By 1987, the government had adopted a Build-Operate-Transfer (BOT) scheme to obtain industry financing for petroleum projects.

Once commercial production begins, the contractor receives a service fee of 40 percent of net proceeds and the government received the remaining 60 percent as royalty payments. The contractor also received reimbursement of up to 70 percent of gross production costs with a carry-forward of unrecovered costs for the first five years of production. The Filipino Participation Incentive Allowance (FPIA) reimburses up to 7.5 percent of gross proceeds for service contracts awarded to ventures with a minimum Filipino company participation of 15 percent. A further incentive for investment in the industry is provided by exemption from all taxes and duties for the importation of materials and equipment for petroleum operations.

The contractor is exempt from all taxes and duties except income tax. Capital items for exploration and development are depreciated over ten years, while no deductions are allowed for interest paid to finance operations. In the case of the Camago-Malampaya field development, government will pay all income taxes from the project out of its share of the net proceeds. This means that the contractor will effectively be operating on a tax-free basis. According to the DOE, in the case of other natural gas infrastructure projects included in the Philippine Investment Priorities Plan, investors will receive an income tax holiday of up to six years.[127]

To further encourage investment in the oil subsector, the government has undertaken a Philippine Petroleum Resource Assessment (PhilPRA) and a Philippine Petroleum Exploration Investment Promotion (PhilPRO) project to publicise PhilPRA's results through international road shows. The Department of Energy (DOE) is studying the possibility of using a "bidding round system" to award exploration contracts to the applicant with the best work program proposal including its technical and financial capability.[128] It also plans to review its current service contract system to draw more exploration investors.

The Downstream Oil Industry Deregulation Act of 1998 (Republic Act 8479) called for the market pricing of oil products to replace the system of price controls that had been administered by the Energy Regulatory Board (ERB), which nonetheless maintained authority to limit price increases to consumers. The law reversed a 25-year policy of setting prices for petroleum products through an Oil Price Stabilization Fund (OPSF) that absorbed fluctuations in product prices while providing oil refiners adequate profit margins. Domestic oil prices have since been adjusted automatically based on Singapore Import Parity, an average of costs at Singapore refineries, and in line with international crude prices. Petron, a state owned company, was privatised, with the government retaining 40 percent of its equity shares. Another 40 percent was sold to Saudi Aramco, a strategic partner. The remaining 20 percent was sold through an initial public offering (IPO), bringing in about 49,000 new Filipino stockholders in the company.[129]

Since 1997 and until December 2001, the market share of the new petroleum players has increased from 3 percent in 1997 to 11.4 percent in 2001. They have brought in a cumulative investment of around Php 15.1 billion or US$621 million (1990 forex).

ANALYSIS AND FINDINGS

During the Asian financial crisis, private financing for all but a few select projects in the Philippines required government guarantees or multilateral support. Credit was extremely stiff and bankers were reluctant to get involved in any project financing. International financial institutions, insurance funds, and investor funds were also apprehensive of participating in most new projects. Most financial institutions have taken a wait and see attitude toward financing new energy projects.

Over the years, the Philippine government has subsequently improved its fiscal and monetary policies and promoted reforms in its energy sector. However, ADB cannot simply ignore the economy's poor development project performance over the last twenty years, and has blamed it on the limited capacity of government agencies to absorb financial assistance as well as the growing corruption, which caused the poor implementation of some projects. The lack of institutional and financial capacity, especially of local government units to undertake development projects, also added to the problem. Although it can be argued that the loans included non-energy projects, the issues raised were sector neutral.

There is also a need to balance the needs of investors against that of the consumers' desires for lower electricity tariffs. But the government's decision to reduce NPC tariffs magnified its liquidity problems, which later increased its external financing requirements.

Restoration of investor confidence will be a continuing challenge for the Philippines. To succeed, it requires a strong government commitment to reform, social accord for policies and programmes, better fiscal management, better project implementation to improve the productivity

127 Provided that it is a new project and caters to shipping vessels and land transport or a combination of both, and includes proof of application with the concerned regulatory agency, PEP 2003-2012

128 The First Philippine Public Contracting Round (PCR-1) will be opened in 2003 where forty six (46) contract areas will be offered to cover shallow to ultra deep water areas close to oil discoveries and producing fields in Northwest, Southwest and Eastern Palawan, Sulu Sea and Reed Bank.. http://www.doe.gov.ph (2003)

129 Austria (2001).

of investments, and a strengthened domestic capital market. But the government remains hopeful that the flow of private investments will continue to grow over the next ten or twenty years.

VIET NAM

BACKGROUND

Owing to social and economic reforms, Viet Nam's economy has grown at an unprecedented rate of 10 per cent per annum over the last decade. But the economy remains one of the poorest in the APEC region, and in the world, with an annual per capita income of just US$420 (at 1995 prices) and energy consumption of 0.5 tonnes oil equivalent (toe) per person in 2000.[130] Energy remains a key component of the economy, supporting industrialisation and contributing to export earnings.

Viet Nam is endowed with significant reserves of fossil fuels such as oil, gas and coal, as well as substantial hydro resources. Indigenous resources are estimated to include some 420 million cubic metres (Mcm) of crude oil, 617 billion cubic metres (Bcm) of natural gas, and 17,000 megawatts of economically developable hydropower capacity. However, only 40 percent of the total primary energy supply (TPES) comes from these resources, while the bulk is supplied by non-commercial biomass energy such as wood, charcoal and rice husks. As of 2003, most, or 80 percent of Viet Nam's population still live in rural communities and mountainous areas and only about 75 percent of the entire economy has access to the national electricity grid.[131]

To be able to develop its commercial energy resources and expand its power grid, Viet Nam will require substantial new investments in the energy sector and some regulatory and institutional arrangements that are favourable to attracting such investments.

ENERGY SECTOR INVESTMENT REQUIREMENTS

APERC estimates that from 2000 to 2020, Viet Nam's total primary energy supply will grow at an average annual rate of 4.3 percent, while its commercial energy supply (excluding renewables) will grow nearly twice as fast, at an average of 7.6 percent per annum. This projected growth in supply will translate into cumulative investment requirements of some US$59 billion through 2020, amounting to 4.6 percent of projected GDP. Three-fifths of this investment, some US$36 billion, will be needed for electricity generation and transmission, in order to meet projected average growth of 8.2 percent per annum in electricity demand. Production, processing and transport of oil and gas will account for most of the rest, roughly US$21 billion.

ELECTRICITY

More than three-fifths of Viet Nam's electricity in 2003 was generated from hydropower. Among other major power sources, coal contributed 15 percent of electricity generated, while gas and diesel fuel contributed 13 percent and 11 percent respectively.[132] Two major 500 kilovolt transmission lines link the North and South as well as the Central province of Pleiku with Ho Chi Minh City. These transmission links help make the power supply more reliable and reduce the overall needs for generating capacity, by making it possible to move power between areas when one area is experiencing its peak demand hours while the other has surplus generating plant. In 2003, Electricity of Viet Nam (EVN), a state owned company, began the construction of a third 500 kV transmission line to connect the three southern provinces of Phu My, Nha Be and Phu Lam. The Japan Bank for International Co-operation (JBIC) is financing most of the project cots, estimated at US$ 100 million.

130 APERC (2002).

131 Ministry of Industry of Viet Nam

132 Data provided by Electricity of Viet Nam (EVN).

Table 52 Energy Investment Requirements in Viet Nam: High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.14	0.09	0.10	0.09	0.09	0.97	0.86	1.83
Oil & gas production, processing, petrochemical	1.13	0.88	1.10	0.37	1.23	10.81	7.61	18.42
Oil & gas international trade	0.44	-	-	0.01	0.02	1.34	0.11	1.45
Oil & gas domestic pipelines	-	0.11	0.06	0.08	0.05	0.85	0.63	1.48
Electricity generation & transmission	2.58	1.23	1.69	2.06	1.38	16.67	19.12	35.79
Total	**4.30**	**2.31**	**2.95**	**2.60**	**2.77**	**30.64**	**28.32**	**58.96**

Viet Nam's electricity transmission and distribution systems need to be rehabilitated. The poor quality of existing equipment (especially transformers), together with a lack of modern dispatching facilities, has resulted in unduly high transmission and distribution losses. At the same time, EVN still has to construct new transmission lines to supply electricity to the entire economy. The Master Plan for Power Development specifies that coal-fired and gas-fired power generation are to play larger roles in power supply in the medium term, while hydropower is to play the largest role in the long term.

But hydropower is vulnerable to weather conditions, and transmission lines for bringing in alternative power sources, when rainfall is low, are costly. In this regard, Viet Nam's government is encouraging the development of coal-fired power generation in the North and gas-fired and diesel-fired power generation in the South so that growth in energy demand in these areas could be adequately covered without overly investing in transmission lines. For example, the state-owned coal producer, Vinacoal, will begin supplying power to the North in 2003. Vinacoal is expected to own 8 percent of the economy's total electric generation capacity by 2010, amounting to nearly 12,000 MW at that time. EVN, Tokyo Electric Power (TEPCO), Sumitomo and Electricité de France (EdF) are building a 720 MW gas-fired power plant for Phu My in the Mekong Delta in the South.

OIL AND GAS

Of the US$21 billion in total investment requirements that APERC estimates for Viet Nam's oil and gas sector through 2020, US$18 billion will be needed for production, processing and petrochemicals, US$1.5 billion for international trade, and US$1.5 billion for pipelines. Much of the investment needed will be driven by the growing demand for natural gas. Gas use in urban households is projected to increase to 0.2 Bcm in 2005 and 0.4 Bcm in 2010. Likewise, gas use in industrial zones in Hanoi and Ho Chi Minh City will increase to 1.4 Bcm in 2005 and 2.5 Bcm in 2010. The capacity of natural gas-fired power plants is also set to grow dramatically. For example, the capacity of natural gas fired power plants in the Cuu Long Delta is projected to increase from 1,200 in 2003 to 1,300 MW in 2005, and 3,000 - 3,500 MW by 2010.

As of 2003, Vietnam Oil and Gas Corporation (PetroVietnam), a state owned oil and gas corporation, is the only firm authorized to conduct upstream, midstream and downstream petroleum operations in Viet Nam.

To meet growing gas demand, two major pipeline systems have been undertaken pursuant to the Gas Master Plan. The first system, with 390 km of pipeline, was completed in 2002 at a cost of US$565 million by a consortium of PetroVietnam (52%), BP (32.6%) and Conoco (16.33%). The pipeline transports natural gas from Block 06-1 of Lan Tay and Lan Do gas reserves in Nam Con Son Gas basin, which can supply 3.0 Bcm annually to the Phu My gas-power-fertilizer complex.

Investment in that complex, which includes a 720 MW power plant and an 800,000 tonne nitrogenous fertilizer plant, is estimated to total some US$6 billion. The second system, with 330 km of pipeline, should be finished in 2005 at a cost of US$300 million. It will transport 2 Bcm of gas annually from the PM3 Block offshore in the Southwest Sea to the gas-power-fertilizer complex in Ca Mau province. Both of these pipelines could be important components of an eventual Trans-ASEAN gas pipeline system.

COAL

Viet Nam's demand for coal and coal products is projected to grow at an average rate of 8.2 per cent annually over the period from 1999 through 2020.[133] The Viet Nam Coal Corporation (Vinacoal) aims to develop and exploit 23 million to 24 million tonnes of coal annually from 2000 to 2010, and increasing to 30 million tonnes annually by 2020. Many state-owned co-operatives will become parent subsidiary enterprises to help ensure that these growth targets are met.

APERC estimates that some US$1.8 billion of investment will be needed to meet Viet Nam's growing coal demand through 2020. Most of this investment will be needed to ensure mine safety, provide effective management, and the use of cutting-edge technology. Screening lines and processing methods will be modernised, and the distribution network will be restructured to reduce environmental pollution. Mining equipment will be upgraded or replaced to minimise losses and increase production capacity. Labour conditions will be improved to reduce the risk of accidents.

The government has allowed Vinacoal to fund the construction of coal-fired power plants using its low quality coal as fuel. In 2002, to promote coal production, Vinacoal has initiated a contract system of production expenses, production selling, and profit for coal subsidiary companies. It is hoped that this system will restore dynamism to coal production and development.

ASSESSING SOURCES OF FINANCING

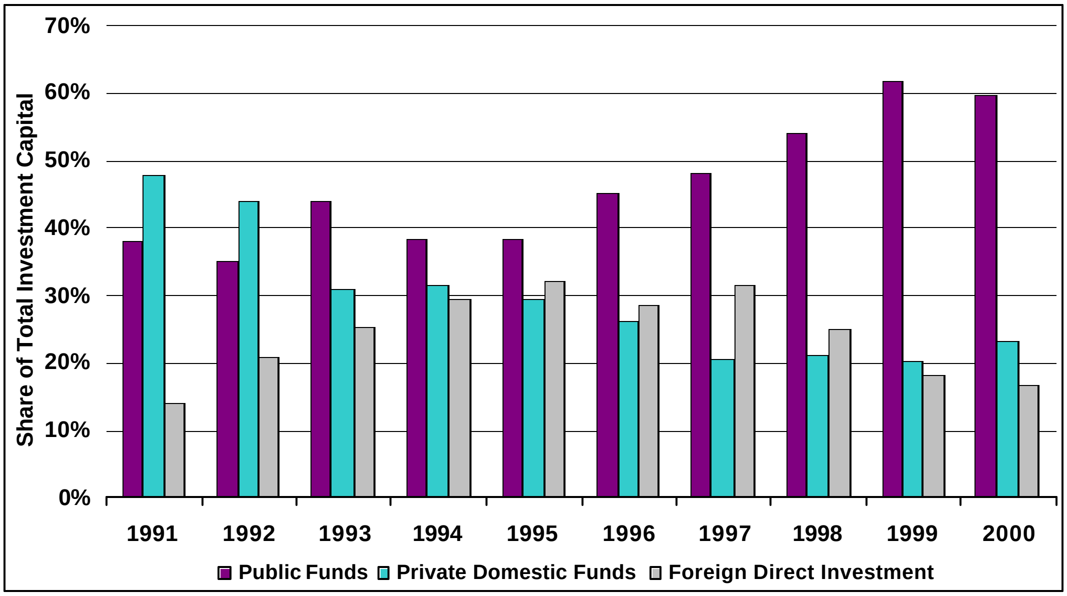
Historically, investment capital in Viet Nam has been mobilised from three sources: public state funds, private domestic capital, and foreign direct investment (FDI). As shown in Figure 71, investment capital from public state funds have increased roughly from two-fifths to three-fifths in the late 1990s, while the shares of domestic and foreign private capital declined.

Likewise during the 1990s on average, foreign direct investment represented 25 percent of gross capital formation in Viet Nam, as compared with just 10 percent in Southeast Asia as a whole. FDI inflow peaked between 1994 and 1997 when it averaged roughly 30 percent of gross capital formation, or more than US$2 billion per year, as shown in Figure 72. FDI fell after the Asian financial crisis of 1997. Due in part to high levels of taxation and cumbersome regulatory procedures, FDI inflow has not yet returned to the peak value reached in 1996. Since domestic savings in Viet Nam have consistently fallen far short of investment requirements, as shown in Figure 73, and since this savings shortfall is expected to persist, attracting FDI is essential. To boost the role of foreign private capital in the energy sector, the government has established a list of power, coal, oil and gas projects in which foreign investment is invited through 2010.

Based on World Bank figures, self-financing represents a relatively minor share of total financing for energy projects. One figure suggests that the power sector in Southeast Asia as a whole has a self-financing ratio well above 40 percent, while self-financing in Viet Nam's power sector is below 25 percent. Moreover, Viet Nam's domestic capital market, which could be used to attract domestic funds to energy projects other than those provided directly by the project owners, is still under early stage of development. Nearly all transactions on the domestic capital market come from share trading; bond trading accounts for only 6.4 percent of the total.[134]

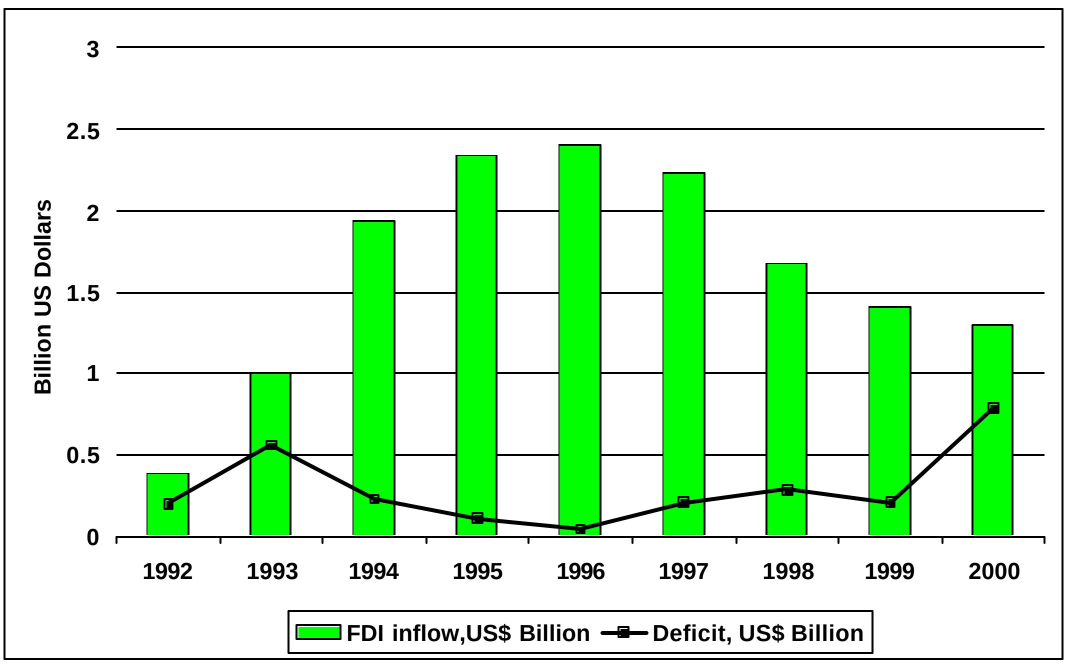
133 APERC (2002).
134 ADB (2002).

Figure 71 Public, Private and Foreign Capital Sources in Viet Nam



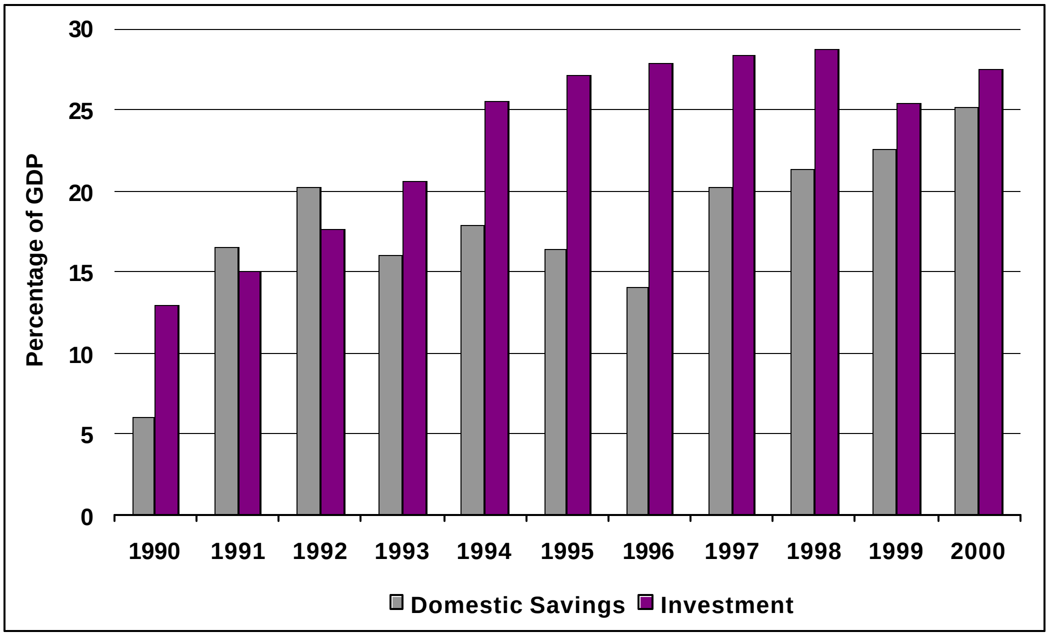
Source: Viet Nam General Statistics Department

Figure 72 Foreign Direct Investment and Current Account Deficit in Viet Nam



Source: IMF (2002).

Figure 73 Investment and Savings as Percentage of GDP in Viet Nam



Source: World Bank (2002).

GOVERNMENT STRATEGIES FOR ATTRACTING INVESTMENT

Viet Nam's government has relied on several different strategies to attract more private investment to the energy sector. Several new laws have provided a more transparent legal framework for private investment in general and foreign direct investment in particular. Financial incentives have been offered for certain investment in the oil and gas sector. The electric power sector has been opened up to greater competition. Efforts have also been made to reform energy pricing to provide for more appropriate market signals. Finally, steps have been taken to develop domestic capital markets in order to more effectively tap the growing pool of savings within Viet Nam.

A MORE TRANSPARENT LEGAL FRAMEWORK FOR PRIVATE INVESTMENT

To attract foreign investors to Viet Nam and its energy sector, the government has established several new laws to improve the transparency and consistency of its legal system:

1) Law on Foreign Investment in Vietnam;
2) Petroleum Law;
3) Law on Corporate Income Tax
4) Law on Value Added Tax
5) Law on Import and Export Tax;
6) Law on Environmental Protection;
7) Customs Formalities for Import and Export Commodities;
8) Regulations on Foreign Exchange Management;
9) Law on Insurance;
10) Law on Labour;
11) Other Laws and Regulations relating to Inter-Government Agreements on Tax

The foreign direct investment (FDI) activities in Viet Nam are directed by the Law on Foreign Investment in Viet Nam that was adopted in 1987 and amended in 1990, 1992, 1996, and 2000. The Law on Foreign Investment in Vietnam allows four basic forms of foreign investment: joint ventures (JVs); 100 percent foreign-owned enterprises; Business Cooperation Contracts (BCCs), and Build- Operation-Transfer (BOT) projects. BOT projects may be joint ventures or 100 percent foreign-owned enterprises that are transferred to the state without compensation at the end of the project life. BOT projects can take advantage of a number of incentives, such as exemption from or reduction of certain taxes, and a guarantee from the government on foreign exchange.

To make Viet Nam and its energy sector more attractive to foreign investors, the government issued the following set of measures on 28 August 2002[135].

30. Further improvement of the legal system with respect to foreign investment, making it more attractive, open, transparent and stable, with subsequent establishment of a common legal basis for both foreign and domestic investors.
31. Development of policies to make the business environment more competitive, including reduced fees and charges for services; improved land, foreign exchange and tax regulations to facilitate implementation of licensed projects; and better incentives for businesses that produce for export or manufacture spare parts or components.
32. Diversification to allow deployment of more investment options, with experimental equitisation of selected foreign enterprises and gradual opening of the real-estate market, services and commercial sectors to be in line with world economic integration.
33. Improvement of government management capability at all levels from the central to local provinces, expanding the authorities and responsibilities of local authorities in order to resolve problems of investors in a timely manner.
34. Simplification of administrative procedures to save time and costs for businesses, reviewing and eliminating unnecessary regulations and licences and expanding the list of projects that are required only to register for investment licences.
35. Further improvement of and investment in infrastructure such as supply of electricity, and water, as well as improving the quality of banking, financial and technological services to make them more favourable for business activities.
36. Improving the supply of information on the investment environment and policies, and strengthening investment promotion activities.

More transparent laws aim to attract investment not only from foreign sources, but from domestic sources as well. It was observed that since the Law on Enterprise was issued on January 2000 the private sector has flourished. The number of private small and medium enterprises (SME) grew from around 10,000 in 2000 to more than 35,000 in 2003. To ensure equal investment opportunity for state and private enterprises, the government has implemented several reforms in taxation, land use rights, and registration procedures. Privatisation is advancing rapidly, with 1,110 SMEs divested, of which 965 have sold equity shares while 145 had their ownerships diversified. The private sectors and households have contributed VND174 billion to the output value, accounting for about two fifths of GDP in 2001[136].

135 Ministry of Planning and Investment of Viet Nam (2002).

136 Le thi Bang Tam (2003).

FINANCIAL INCENTIVES FOR PRIVATE INVESTMENT

The Petroleum Law was issued in 1993 and amended by The National Assembly of Viet Nam in 2000 to effectively conserve, exploit and utilize petroleum resources for the development of the national economy and the promotion of cooperation with foreign economies. Different forms of petroleum contracts are applied in Viet Nam, such as: Production Sharing Contract (PSC); Business Co-operation Contract (BCC); Joint Operating Contracts (JOC); Contract for Non Exclusive Seismic Data Services; Joint Study Contract. To attract foreign investors in oil and gas sector, several taxes and investment incentives have also been issued, as summarised in Table 53:

Table 53 Regular and Incentive Royalties on Oil and Gas in Viet Nam

Rate of Oil or Gas Production	Incentive Royalty Rate	Regular Royalty Rate
Oil: Up to 20,000 barrels per day	4	6
Oil: Over 20,000 to 50,000 barrels per day	6	8
Oil: Over 50,000 to 75,000 barrels per day	8	10
Oil: Over 75,000 to 100,000 barrels per day	10	15
Oil: Over 150,000 barrels per day	20	25
Gas: Up to 5 million cubic metres per day	0	0
Gas: Over 5 to 10 million cubic metres/day	3	5
Gas: Over 10 million cubic metres per day	6	10

Source: The Law on Foreign Direct Investment.

ELECTRIC POWER SECTOR REFORM

Before 2000, EVN was a state monopoly providing electricity to the economy. In 2003, many of the state owned enterprises were converted to parent-subsidiary enterprises. The government has allowed Vinacoal to build coal-fired power plants in the north and Petrovietnam to build gas-fired power plants in the south. These quasi-independent power producers (IPPs) are allowed to generate electricity and sell directly to customers at prices negotiated between IPPs and customers via the national grid with the same fee that is applied to EVN affiliates. The private share of total power generation remained a modest 7 percent in 2003 but is expected to reach 20 percent by 2020.

The Electricity Law, after long and arduous discussions, involving 18 drafts, expects to be finally promulgated in 2003. The Law aims to strengthen the regulatory framework for the power sector which will create a transparent legal environment for commercial activity in the sector. It should decentralise the power sector and help ensure that power companies can finance the construction of facilities that are needed to provide safe, reliable power supply at reasonable costs. It is also expected to reduce power plant accidents and improve operating efficiency through better management of distribution grids at times of peak demand, reducing system losses to 0.8 percent and limiting electricity reserved for own-use-consumption to 2.5 percent by 2005.

At present, the government is restructuring the power sector, unbundling generation from transmission and distribution to strengthen its competitiveness and effectiveness. As a result, EVN had encouraged the private sector and foreign investors to participate in the construction of power generating units with a capacity of less than 100 kW, as well as the construction of a low-voltage distribution network system in the form of IPP, BOT, BT, joint venture and joint-stock company. However, EVN still remains as the majority shareholder in the power plant projects and in the high-voltage national electricity grids.

APPROPRIATE PRICING

Domestic prices of electricity and coal in Viet Nam are relatively lower than its production costs. Electricity prices averaged VND840 (US$0.0549) per kWh in 2003, about 13 percent higher than the year before but still well below the estimated long-run marginal production cost of US$0.07 per kWh. However, the government has decided to adjust the electricity price annually so that it matches the long-run marginal production cost by 2005. Coal, meanwhile, is to be sold at market prices by 2006.

There are still separate electricity tariffs for foreign and domestic users. Electricity tariffs for foreign users are 5.73 percent higher than those paid by domestic users. To address this disparity, the government is considering a uniform electricity tariff across the country by the end 2003.

In 2003, the electricity-ceiling tariff in rural areas increased to VND700 per kWh from the level of VND 670 per kWh that was set in 1997. This happened because the government allows some degree of flexibility for local authorities, which are selling power to users, to recover its distribution costs. In 2003, the power companies of EVN sold electricity to local distributors at a government approved wholesale price of VND 360 (US$0.026) per kWh, less than the generation cost. This implies that there is a cross subsidy to consumers in rural areas from consumers in other areas.

BANKING REFORMS TO MOBILISE DOMESTIC CAPITAL

Domestic banks are currently being reformed to reduce the substantial amount of non-performing loans. Investments in energy require long-term maturities due to their long project lifetimes. However, the domestic banking sector has limited ability to provide long-term loans.

Viet Nam's government is strengthening the national banking system to make it more transparent and accountable and to improve financial intermediation. Reforms should make banking services more widely available, make the banking system more stable, promote better mobilization of domestic financial resources, and improve allocation of those resources to commercially viable activities. As of 2003, there were four main banking reform programmes:

1) improved legal, regulatory and supervisory framework to level the playing field for all banks;
2) restructuring Joint Stock Banks (JSBs),
3) Restructuring State Owned Commercial Banks (SOCBs), which has allowed the auditing of such banks according to international accounting standards;[137] and
4) building capacity and developing human resources in banking.

The management of financial policy has gradually shifted from direct instruments to indirect ones. Currency exchange rates are basically set by market forces, as are interest rates for borrowing in domestic and foreign currencies. The banking sector has attracted considerable capital resources through the use of flexible interest rate mechanisms. Regulation of lending practices aims to ensure non-discriminatory treatment of all state and private enterprises with respect to the size, length and interest rate of loans, as well as measures for loan security.[138]

A new regulation by the Ministry of Finance should allow energy companies to offer bonds to the public in order to finance large energy projects starting in 2003. Accordingly, Petrovietnam was to issue its first five-year domestic bonds of VND300 billion for domestic investments by the end of 2003. These bonds are expected to meet Petrovietnam's needs for its current investment projects. Like Petrovietnam, EVN has allowed selling domestic bonds in Vietnamese currency.

137 World Bank in Viet Nam (2002a) and (2002b).
138 State Bank of Viet Nam (2003).

ANALYSIS AND FINDINGS

In the next ten or twenty years, Viet Nam will be faced with a formidable task of financing its energy infrastructure project worth between 3.6 to 4.6 percent of its GDP to meet its increasing electricity demand. The lack of EVN's ability to build new and additional plants (at least 63 more) can be considered an opportunity for domestic private and foreign investors to join-in in the form of IIP, BOT, BT, joint venture and or as a joint-stock company.

Viet Nam's economy will undergo immense changes by late this decade as a result of the demand for the economy's aggressive economic development and commitments signed with the Viet Nam-US BTA, the Asian Free Trade Area (AFTA), and the requirement to join the World Trade Organization (WTO) in 2006. These milestones will not only allow Viet Nam to boost its transformation into a manufacturing-based export-oriented economy but also to attract foreign investors to Viet Nam in general and in the energy sector in particular from the whole world.

Growth in the energy sector is expected to reach 4.3 per cent per year (that is 7.6 percent without biomass) during 1999-2020. It is higher than most ASEAN countries like Indonesia-2.9 per cent, Thailand-4.0 per cent and the Philippines-3.7 per cent[139]. To reach this target, the energy sector of Viet Nam needs a huge investment capital of about US$ 59 billion to diversify all energy resources, while domestic saving is not large enough. Therefore foreign investment is necessary to the energy sector in the next two decades.

Although Viet Nam has exhibited great improvements on investment environment, banking system reform, privatisation of SOEs, amendments to simplify documentation, shorten appraisal time and decentralization, there are still many obstacles such as weak infrastructure, high input expenses, slow reform progress; legal and policy system that need further improvement with more openness, transparency and predictability; use of investment resources should be closely examined more effectively in order to attract foreign investors.

139 APERC (2002a).

REFERENCES

GENERAL REFERENCES

Asian Development Bank (2002). *Asian Development Outlook 2002.* Website: www.adb.org

Asian Development Bank (2003). *Asian Development Outlook 2003.* Website: www.adb.org

APEC Energy Working Group (2002a). *APEC Energy Overview 2002*. Singapore.

APEC Energy Working Group (2002b). *APEC Energy Statistics 2000*. Singapore.

APERC (2000a). *Electricity Sector Deregulation in the APEC Region.* Tokyo.

APERC (2000b). *Natural Gas Infrastructure Development in Northeast Asia*. Tokyo.

APERC (2000c). *Natural Gas Infrastructure Development in Southeast Asia*. Tokyo.

APERC (2001a). *Energy Supply Infrastructure Development in the APEC Region.* Tokyo.

APERC (2001b). *Making the Clean Development Mechanism Work.* Tokyo.

APERC (2001c). *Sustainable Electricity Supply Options for the APEC Region.* Tokyo.

APERC (2002a). *APEC Energy Demand and Supply Outlook 2002.* Tokyo.

APERC (2003). *Natural Gas Market Reform in the APEC Region.* Tokyo.

World Bank (2002). *World Development Indicators.*

INTRODUCTION

Dunkerley, Joy (1995). "Financing the Energy Sector in Developing Countries. Context and Overview." *Energy Policy*, November 1995.

Petroleum Economist (2003). "Asia: Opening the Way for Gas", June 2003.

Pollio, Gerald (1999). *International Project Analysis and Financing*. The University of Michigan Press.

Weare, Christopher (2003). *The California Electricity Crisis: Causes and Policy Options*. Public Policy Institute of California.

Xu, Yi-Chong (2002). *Powering China.* Dartmouth Publishing Company.

RISKS AND RESTURNS AS DRIVERS OF ENERGY INVESTMENT

Adelman, M (2002). "World Oil Production & Prices 1947 – 2000." *The Quarterly Review of Economics and Finance* 42, January 2002.

Cunanan, T (2002). *The Philippine National Oil Company (PNOC) on Regional Energy Cooperation and Joint Investment Opportunities*. OSEA 2002, the 14th International Oil and Gas Technology Exhibition and Conference, Singapore, October 2002.

Edison Electric Institute (2001). *Construction Survey*.

EIA – Energy Information Administration (1998). *Performance Profiles of Major Energy Producers 1996.*

EIA – Energy Information Administration (1999). *Performance Profiles of Major Energy Producers 1997.*

EIA – Energy Information Administration (2001a). *Performance Profiles of Major Energy Producers 2001*.

Hirst, Eric (2000). *Expanding U.S. Transmission Capacity*. Edison Electric Institute, August 2000.

Gujarati, D (1999). *Essentials of Econometrics*. Irwing MacGraw-Hill.

Hyman, L. (1999). "Transmission, Congestion, Pricing, and Incentives." *IEEE Power Engineering Review,* August 1999.

Johnson, D. (2002). *Petroleum Tax Design.* Workshop on Petroleum Revenue Management, Washington DC, October 23-24, 2002.

Joskow and Tirole (2002). *Transmission Investment: Alternative Institutional Framework*.

METI – Ministry of Economy, Trade and Industry (1999). *An Analysis of Companies in the World.*

NERC – North American Electric Reliability Council (2003). *Transmission Loading Relief Procedure Logs.*

Razavi, H. (1996). *Financing Energy Projects in Emerging Economies*. Penwell Books.

Sandrea, R. (2003). "Upstream Opportunity Index Assesses E&P Investments." *Oil and Gas Journal*, May 2003.

Shams, M. (1989). "The Impact of Oil Revenues on the OPEC Economy." *Energy Economics*, October 1989.

Tucker, R. (2003). *Facilitating Infrastructure Development: A Critical Role for Electric Restructuring.* National Energy Modelling System/Annual Energy Outlook Conference, March 2003.

ECONOMIC FACTORS AFFECTING ENERGY INVESTMENT DECISIONS

APERC (2000b). *Natural Gas Infrastructure Development in Northeast Asia*. Tokyo.

APERC (2001b). *Making the Clean Development Mechanism Work.* Tokyo.

Dimson, Elory (1989). "The Discount Rate for a Power Station." *Energy Economics*, July 1989.

IEA – International Energy Agency (1999). *World Energy Outlook 1999 Insights.* IEA/OECD.

IEE – The Institution of Electrical Engineers (1997). *Financial and Economic Evaluation of Projects in the Electricity Supply Industry*. IEE Power Series 23, A.T. Johns and D.F. Warne, editors. London

IMF – International Monetary Fund (2002). *International Financial Statistics.*

Krugman, Paul (1998). "What Happened in Asia?" *the Economist*, January 10, 1998

Lan, Yisheng (1997). *Foreign Direct Investment and Economic Development in Guangdong: Problems and Prospects.* Working Paper of the University of Adelaide, School of Economics.

Tietenberg, Tom (2000). *Environmental and Natural Resource Economics.* Addison Wesley Longman.

OVERVIEW OF APEC ENERGY INVESTMENT REQUIREMENTS

Beck, Robert J. (2001). *Worldwide Petroleum Industry Outlook Eighteenth Edition*. PennWell.

IAEA – International Atomic Energy Agency (2003). *Power Reactor Information System*. Vienna.

IIASA/WEC (1998) *Global Energy Perspectives*. International Institute for Applied Systems Analysis (IIASA), World Energy Council (WEC). Cambridge University Press.

ENERGY INVESTMENT REQUIREMENTS BY INFRASTRUCTURE TYPE

BP (2001). *Statistical Review of World Energy 2001.* London.

BP (2003). *Statistical Review of World Energy 2003*. London.

CERS – China Energy Research Society (2002). *Energy Policy Research 2002.1.*

DRCCU (2002). *Power Production Investment Newsletter.* China Resources, Conservation and Environmental Protection Network (www.drccu.gov.cn).

EIA – Energy Information Administration (2000). *Annual Energy Outlook 2000*. Washington, DC.

EIA – Energy Information Administration (2001a). *Annual Energy Outlook 2001.* Washington, DC.

EIA – Energy Information Administration (2001b). *International Energy Outlook 2001.* Washington, DC.

EIA – Energy Information Administration (2003a). *Annual Energy Outlook 2003.* Washington, DC.

EIA – Energy Information Administration (2003b). *Assumptions to the Annual Energy Outlook 2003.* Washington, DC.

EIA – Energy Information Administration (2003c). *International Energy Outlook 2003.* Washington, DC.

EEI – Edison Electric Institute (2001). *Transmission Planning for a Restructuring US Electricity Industry*. By Eric Hirst and Blendan Kirby. Washington, DC.

Government of Malaysia, Prime Minister's Department, Economic Planning Unit (2001). *Eighth Malaysia Plan 2001-2005*. Putrajaya.

IAEA – International Atomic Energy Agency (1984). *Expansion Planning for Electrical Generating Systems.* IAEA Technical Report Series No. 241. Vienna.

IEA – International Energy Agency (2000). *Coal Information 2000*. IEA/OECD.

IEE – The Institution of Electrical Engineers (1997). *Financial and Economic Evaluation of Projects in the Electricity Supply Industry*. IEE Power Series 23, A.T. Johns and D.F. Warne, editors. London

IEEJ – Institute of Energy Economics, Japan (2002). *Impact of Coal Price on Mine Development Investment*. By Yoshimitsu Mirumoto. Tokyo.

Khawam, Francois (2002). *LNG – The Way Forward.* Fourth Annual Ship Finance Forum, Norway, 30 May 2002.

Oil & Gas Journal (2003a). "2002 Worldwide Refining Survey." January 1, 2003.

Oil & Gas Journal (2003b). "Growth in Deepwater Sector Expected to Double within 5 years." January 13, 2003.

Poten & Partners (2002). "Floating LNG gaining ground as companies pursue technology options." *LNG in World Markets,* February 25, 2002.

PNG Power Ltd. (2002). *10 Year Expansion Plan 2002-2011.*

Reuters (2003a). "Interview – China Three Gorges Dam Plans IPO by Year-End." February 2003.

Reuters (2003b). "China to Build More Yangtze Power Plants." February 2003.

Sandrea, Ivan and Al Buraiki, Osama (2002). "Future of Deepwater, Middle East Hydrocarbon Supplies." *Oil & Gas Journal,* June 17, 2002.

Sen, Colleen Taylor (2002). "Global LNG Industry Expanding to Meet Heightened Gas-Demand Projections." *Oil & Gas Journal,* August 12, 2002.

Sen, Colleen Taylor (2003). "LNG Poised to Consolidate its Place in Global Gas Trade." *Oil & Gas Journal,* June 23, 2003.

SENER – Secretaría de Energía (2002). *Prospectiva del Sector Eléctrico 2001 – 2010*. Mexico City.

SETC – State Economy and Trade Commission (2001). *Power Industry Tenth Five-Year Plan 2001-2005*. Beijing.

TEPCO – Tokyo Electric Power Company (2003). *TEPCO Illustrated FY 2002*. Tokyo.

True, Warren (2001). "Pipeline Economics." *Oil & Gas Journal*, September 3, 2001.

UNCTAD – United Nations Conference on Trade and Development (2002). *Review of Maritime Transport 2002*.

Valais, Michel (Total/Final/Elf), Chabrelie, Marie-Francoise (Cedigaz) and Lefeuvre, Thierry (Gaz de France) (2001). *World LNG Prospects: Favorable Parameters for a New Growth Era*. World Energy Conference, France, 2001.

Vaninetti, Betsy S. (2003). "Brighter Outlook for Coal Generation." *Coal Age*, March 1, 2003.

Vautrain, John (2003). "Asia-Pacific Gas Faces More Competition, Seeks New Markets." *Oil & Gas Journal*, March 10, 2003.

ENERGY INVESTMENT FOR ENVIRONMENTAL PROTECTION

APERC (2002b). *Alternative Development Scenarios for Electricity and Transport to 2020 for the APEC Region*. Tokyo.

EIA – Energy Information Administration (2001b). *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*. Washington, DC.

EIA – Energy Information Administration (2001c). *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*. Washington, DC.

IIASA – International Institute for Applied Systems Analysis and WEC – World Energy Council (1998). *Global Energy Perspectives*. Cambridge University Press.

Lee, C. K.; Rost, Klaus-Dieter; Herold, Rupert; and Chou, Tai-Sheng (2003). "German Refiner Produces Ultralow Sulfur Diesel." *Oil & Gas Journal*, June 2, 2003.

Palmer, Karen; Banzhaf, Spencer; and Burtraw, Dallas (2002). "Capping Emissions: How Low?" *Public Utilities Fortnightly*, December 2002.

FINANCING ENERGY PROJECTS IN DEVELOPING AND TRANSITIONAL ECONOMIES

APERC (2001b). *Making the Clean Development Mechanism Work*. Tokyo.

Bechman, Michael (1999). *Asian Eclipse: Exposing the Dark Side of Business in Asia*. Singapore: Johon Wiley and Sons Pte. Ltd.

Connelly, Ross J. (2002). "OPIC Support for U.S. Investors in Russia." A Paper Presented at the US Russian Commercial Energy Summit, 1 October, 2002

Dealogic Database (2003). *ProjectWare*. London.

Department of Energy (2003). *Yearbook 2003*. Manila.

EIA – Energy Information Administration (2003). *Financial Reporting System*.

Fabella, Raul and Madhur, Srinivasa (2003). *Bond Market Development in East Asia: Issues and Challenges*. ERD Working Paper No. 35

Holton, Jack (1995). "Sakhalin – giant reserves and hungry markets." *Gas in the Former Soviet Union, Petroleum Economist*

Lee, Hsien Long (2000). "Drawing and Implementing the Lessons of the Asian Crisis." *International Herald Tribune*. September 22, 2000

Nevitt, Peter and Fabozzi, Frank (2000). *Project Financing*. Euromoney Books.

OPIC homepage at http://www.opic.gov

Pollio, Gerald (1996). *International Project Analysis and Financing*. The University of Michigan Press

Razavi, Hssein (1996). *Financing Energy Projects in Emerging Economies*. Penwell Books.

Peter Rigby (2002). "What Happened to the Energy in Energy Merchant Companies?" *Standard & Poor's Project & Infrastructure Finance*.

Roxas, Fernando (1999). *BOT in the Philippines*. Second Workshop on Economic Cooperation in Central Asia: Challenges and Opportunities in Energy.

Sakhalin Energy homepage at http://www.sakhalinenergy.com

Sharma, Krishnan (2000). "The Underlying Constraints on Corporate Bond Market Development in Southeast Asia." *DESA Discussion Paper No. 14*. United Nations

Standard & Poor's (2002), *Project & Infrastructure Finance*.

World Bank (1995). "World Bank Guarantees Broaden Capital Market Access", Project Finance and Guarantees, September 1995

Yoshitomi, Masaru and ADB Staff (2003). *Post-Crisis Development Paradigms in Asia*. Asian Development Bank Institute

THE ROLE OF GOVERNMENTS IN ENERGY INVESTMENT

ABAC – APEC Business Advisory Council (2002). *Report to APEC Leaders: Sharing Development to Reinforce Global Security*.

APEC Energy Working Group and ABARE (2000). *Trade and Investment Liberalisation in APEC: Economic and Energy Sector Impacts* (by Karen Schneider, Brett Graham, Charles, Millsteed, Matthew Saunders, and Roger Stuart). Canberra.

APEC Secretariat (2003). *Guide to the Investment Regimes of the APEC Member Economies (5th Edition)*. Singapore. Website: www.apecsec.org.sg

Austria, M. (2002). *Investment Liberalization and Facilitation in the Asia Pacific: Can APEC Make a Difference?*

Industry Commission (1997). *Services Trade and Foreign Direct Investment*. Canberra.

UNCTAD – United Nations Conference on Trade and Development (1996). *Incentives and Foreign Direct Investment*. Geneva.

United States Department of Energy, Office of Policy and International Affairs (2002). *Governance and Finance for Sustainable Energy and Water Resource Management*. Washington, DC.

World Bank Group (2003). *Energy and Mining Sector Board Discussion Paper No. 6: What International Investors Look for When Investing in Developing Countries?* (by Lamech and Saeed).

World Bank Group (2002). *A Review of Projects with Private Participation, 1990-2001*.

World Bank Group (1998). *The Impact of IPPs in Developing Countries: Out of the Crisis and into the Future*.

CHINA

BP (2003). "Business Overview." Website: www.bp.com

The Catalogue of Industries for Guiding Overseas Investment (2002).

Economist Intelligence Unit (2003). "China risk: Financial risk.", *The Economist Intelligence Unit*

ExxonMobil (2003). "News Releases." Website: www.exxonmobilchemical.com

IBRD – International Bank for Reconstruction and Development (2002). *World Development Indicators*.

IEA – International Energy Agency (2002). *Developing China's Natural Gas Market*. IEA/OECD.

Kwan, Gordon (2002). "China's Giant Oil Trio." HSBC.

Lardy, Nicholas. R. (1998). *China's Unfinished Economic Revolution.* Brookings Institution Press.

Lee, Ivan (2003). "China Power Sector." HSBC.

Shell (2003). "Shell in China." Website: www.shell.com

Walker, John (2000). "Financial Reform in China." *ChinaOnline*

Williams, Michael (2003). "From Theory to Practice: Implementing Gas Projects in Greater China." *A Paper Presented at the APERC's Annual Conference, February, 2003*

Zeng, Huaqun (1999). *Chinese Foreign Investment Laws.* Singapore University Press.

INDONESIA

ADB – Asian Development Bank (2002). Loan No. 1357-INO, *Gas Transmission and Distribution Project.*

Center for Energy Study University of Indonesia (2002). *Indonesia Energy Outlook and Statistics.*

Directorate General Electricity and Energy Utilisation (2002), *Statistics of Electricity and Energy 2001.*

IBRD – International Bank for Reconstruction and Development (2002). *World Development Indicators.*

Indonesian Petroleum Association (2002). *Annual Report.*

IMF – International Monetary Fund (2002). *Oil Revenue Assignment: Country Experience and Issues.*

The Jakarta Post (2003). "Siemens Wins Muara Tawar Power Project." 15 April 2003.

Johnston, Daniel (2002). *Petroleum Tax Design.* Workshop on Petroleum Revenue Management, Washington DC, October 23-24, 2002.

Johnston, Daniel (1994). *International Petroleum Fiscal Systems and Production Sharing Contracts.*

Kompas (2003). 6 June 2003.

Machmud, T. N. (2001). *The Indonesian Production Sharing Contract: An Investor Perspective.*

Media Indonesia (2002). *Menelisik Benefit LNG Tangguh (In Search of LNG Tangguh Benefit).* 30 October 2002.

PricewaterhouseCooper (2002). *CEO Survey - Upstream Oil and Gas.*

US Embassy Jakarta (2000). *Coal Sector Report.*

World Bank (2003). *Indonesia: Selected Fiscal Issues in a New Era.* Washington, DC

World Bank (2000). *Indonesia Oil and Gas Sector Study.* Washington, DC.

PHILIPPINES

APEC Energy Regulators Forum (1999). *Summary Submission on Gas Regulatory Arrangements, Philippines.*

ASEAN Centre for Energy (200x). *Philippine Primary Energy Exports and Imports.* Website: www.aseanenergy.org/publications_statistics/energy_profile/philippines.

Austria, Benjamin (1999). *Development of the Energy Industry in the Philippines.* Second Workshop on Economic Cooperation in Central Asia:: Challenges and Opportunities in Energy.

Bangko Sentral ng Pilipinas (2001). *Financial Statistics.* Manila.

Bangko Sentral ng Pilipinas (2002). *Financial Statistics.* Manila

BKR Lew & Barr Ltd (2001). *Asia Pacific Tax Facts: Philippines.* Website: www.bkrlewbarr.com

Board of Investments (2003). *Cost of Getting Started.* Website: www.boi.gov.ph

Department of Energy (2003). *Fueling the Future: The Philippine Natural Gas Industry.* Manila.

Department of Energy (2003). *Philippine Energy Plan 2003-2012.* Manila.

Department of Finance (2000). *Annual Report 2000.* Manila.

Department of Finance (2003). *Statistics.* Website: www.dof.gov.ph

EMEAP – Executives' Meeting of East Asia-Pacific Central Banks, Working Group on Payment and Settlement Systems (2002). *Payment Systems in EMEAP Economies.* Website: www.emeap.org

First Gas Holdings Corporation (2003). *Developing a Combined Cycle Gas Turbine Power Station.* Website: www.firstgas.com.ph

International Monetary Fund – IMF (1999). *Philippine Supplementary Memorandum on Economic and Financial Policies.* Website: www.imf.org/external

Llanto, Gilberto M. and Soriano, Maria Cecilia G. (1997). *Government Guarantees in Infrastructure Projects: A Second, Third Look at the Policy.* Philippine Institute for Development Studies, Manila.

Mirant Corporation (2003). *Annual Report 2003.*

National Power Corporation (2003). *NPC - MRC at a Glance.* Website: www.mozcom.com

Philippine Business (2003). *Guide to Doing Business: Philippines.* Website: philippinebusiness.com.ph

Roxas, Fernando (1999). *BOT in the Philippines.* Second Workshop on Economic Cooperation in Central Asia: Challenges and Opportunities in Energy.

US Department of Commerce (2001). *Trade and Project Financing: Types of Projects Receiving Financing Support.* Website: www.strategis.gc.ca

VIET NAM

Government of Viet Nam (1999). *The Law on Foreign Direct Investment.* Hanoi.

Government of Viet Nam (2002). *High and Sustainable Development to Reduce Poverty.* Hanoi.

Ministry of Science and Technology (2000). *Viet Nam Energy Strategy Development in 2010 and Projections to 2020.* Hanoi.

Ministry of Planning and Investment (2002). *Viet Nam: A Destination for Foreign Investment.* Hanoi.

Ke, Phung Khac, Deputy Governor of the State Bank of Vietnam (2003). *The Banking Industry in the Process of Developing the Private Sector.* Conference on Market Opening and Continuing Growth: Viet Nam and the Asian Economy, Hanoi, 5-7 March 2003.

Tam, Le Thi Bang, Vice Minister of Finance (2003). *Financial Policies to Support the Development of Vietnam's Private Sector.* Conference on Market Opening and Continuing Growth: Viet Nam and the Asian Economy, Hanoi, 5-7 March 2003.

Viet Nam Economic News. Various issues.

World Bank (1998). *Fuelling Viet Nam's Development – New Challenges for the Energy Sector.*

World Bank in Vietnam (2002a). *Vietnam Development Report 2002.*

World Bank in Vietnam (2002b). *Viet Nam's Pillars of Development.*

APPENDIX I

NOTES ON THE METHODOLOGY

OVERALL CONSIDERATIONS

The investment outlook is based on the assumptions, data and results of APERC's *APEC Energy Demand and Supply Outlook 2002*.[140] For the same reason, baseline data for the calculations is the year 1999. The projections for energy infrastructure and its related investment requirements are calculated over the 21-year period spanning the years 2000 to 2020 and use APERC's *Outlook 2002* fuel by fuel projections for production, imports, exports, and internal demand. All money figures are in 1999 US dollars, except where otherwise noted.

Calculations are made on an economy-by-economy basis and on a yearly basis. In every infrastructure category results are shown as a range. High Case and Low Case cost factors are defined in every category to account for such things as differences in construction sites, in installation type or complexity, and in differences in regional costs.

Not considered in the infrastructure categories are renewable technologies other than those used in power generation, as would be the case of renewable sources used for cooking or the production of heat. Note that renewable energies used for electricity generation are included in the power infrastructure section.

Also not considered are capital requirements for retrofitting older installations with new energy efficiency or environmental control systems, but energy efficient designs and environmental control equipment are considered as part of the design of new installations and this is accounted for in the determination of their unit cost factors. The consideration is made that all new plants to be installed are of a modern, efficient and environmental design.

INVESTMENTS IN THE COAL SECTOR

Coal infrastructure for the purposes of the calculations in this investment outlook consists of the installations required for mining and for the preparation of the product to a condition suitable for delivery to the consumer entities. This includes the mine, coal crushing plant, dense medium coal washery, overland conveyor, coal and diesel-fired small generating plant for own-use, workshop, warehouse and offices. Construction time for a set of facilities such as this is estimated to be of around 3 to 8 years.

To account for transportation facilities, the unit cost factor for coal infrastructure used in the estimations also includes the expenses needed to construct a shipping water port or a railway shipping facility. Other types of transportation infrastructure such as water barges, rail cars or road transport are not considered. Neither is road nor railway construction, given the difficulty in estimating an average transportation distance for coal in different economies.

Most of the world's coal is consumed close to where it is mined to avoid high transportation costs that would make using coal uneconomical. Therefore, not including road or railway infrastructure should not impact the results in a perceptible way in the majority of APEC economies, with the noted exceptions of geographically large economies such as United States or China, where coal movements over long distances are common and can be as large as 2,000 km.

140 APERC (2002a).

INVESTMENTS IN OIL AND GAS PRODUCTION AND PROCESSING ACTIVITIES

This infrastructure category includes exploration and production activities as well as processing operations for both the oil and gas industries. These are the operations defined as "upstream activities" in the present report.

The cost factors developed for the extraction of oil and natural gas include all the investment costs necessary to increase the production capacity by 1,000 barrels per day in the case of oil, and by one billion cubic feet per day in the case of gas. The determination of the cost factors was made in such a way as to also include the approximate average cost involved in the exploration activities required to find the resources for such an increase in production capacity.

The future infrastructure capacity and cost projections for upstream activities are based on the oil and natural gas production capacities estimated for each economy by APERC's *Outlook 2002*.

Processing in the oil industry refers to refinery installations and petrochemical facilities. For natural gas, it stands for gas-processing plants. Petrochemical installations are included as they are deemed to be a consequence of an economy's activities in oil and gas production and processing, even though they are not necessarily investments that have to be made to obtain additional energy product. Two common kinds of installations are included: ethylene and sulphur production plants.

INVESTMENTS IN OIL AND GAS TRANSPORTATION

Oil and gas transportation infrastructure is divided into two parts: one to include the infrastructure required for international trade, and another to estimate the pipeline systems for oil and natural gas transportation inside each economy.

INTERNATIONAL TRADE

International trade of oil and natural gas is considered to take place in one of two ways: by ship tankers or by pipeline. Infrastructure for sea trade includes the ship tanker tonnage. In the case of natural gas, it also includes liquefied natural gas (LNG) processing, liquefaction and regasification facilities. Pipeline trade infrastructure includes the pipeline and compressor station materials, labour, miscellaneous expenses and right of way. Future infrastructure calculations are based on APERC's *Outlook 2002* imports and exports projections.

A record of major transportation infrastructure projects announced for the APEC region was made based on published data and on information obtained by APERC from each economy. This data was later included in the international trade calculations.

The proportion of pipeline and tanker trade flows for each economy is determined using data published by BP in its *Statistical Review of World Energy 2001*.[141]

DOMESTIC PIPELINES

Domestic transportation in this outlook consists of pipeline infrastructure for oil, oil products and natural gas used for transportation within each economy. Included are pipelines, compression stations and related infrastructure for what is known as "transmission". Not considered are "distribution" pipelines and infrastructure, the financing of which follow a different business model than that of larger scale transmission equipment. Other forms of fuel transportation such as

141 BP (2001).

railroads, road tanker trucks or barges are also not considered due to the inexistence of detailed information.

Costs include the four major components of pipeline construction: material, labour, miscellaneous expenses and right of way. Materials include: line pipe, pipe coating and cathodic protection. Miscellaneous accounts for surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AFUDC), administration and overheads, and regulatory filing fees. Right of way (ROW) includes obtaining right of way and allowing for damages.

Safety margin factors were included to account for cost overruns in this category as well as in every other infrastructure category in this outlook. A study by the *Oil and Gas Journal*[142] estimates that the typical pipeline project underestimates its costs by 24.25 percent. It shows that the actual costs of materials are on average 2.6 percent lower than originally estimated, but labour costs are 19.64 percent higher. The costs of the "miscellaneous" category is 41.19 percent higher and the costs for right of way are typically 67.72 percent over budget.

To determine the existing pipeline infrastructure in APEC and the plans for future expansion, a survey was conducted among its member economies. Table 54 shows the "transmission" pipeline lengths existent in the APEC economies. Distribution infrastructure is not included.

Table 54 Existing transmission pipeline infrastructure capacity in APEC economies

Economy	Domestic oil & products transmission pipelines km	Domestic natural gas transmission pipelines Km
Australia	3,676.00	19,393.00
Brunei Darussalam	350.00	333.00
Canada	18,000.00	30,000.00
Chile	2,388.00	3,017.00
China	13,272.00	14,283.00
Hong Kong, China	-	904.00
Indonesia	1,071.00	1,194.00
Japan	406.00	2,000.00
Korea	1,634.00	2,435.00
Malaysia	136.00	2,000.00
Mexico	17,426.00	10,359.00
New Zealand	170.00	308.00
Papua New Guinea	-	-
Peru	1,216.00	280.00
Philippines	210.00	526.00
Russia	46,700.00	150,000.00
Singapore	-	1,180.00
Chinese Taipei	-	536.00
Thailand	255.00	2,337.00
United States	321,800.00	448,911.00
Viet Nam	-	500.00
Total	**428,710.00**	**690,292.00**

142 O&GJ (2001). "Pipeline Economics". Oil and Gas Journal. September 3, 2001.

INVESTMENTS IN THE POWER SECTOR

Power sector costs are calculated for both installed generation capacity and transmission grid system infrastructure. Calculations were made for every economy and for each individual power generation technology based on the detailed projections of APERC's *Outlook 2002*. As well, calculations were made on a yearly basis, as is done for every other infrastructure category in this outlook. Renewable energies used for electricity generation are included based on each economy's expansion plans for the future.

The cost factors for existing and new technologies for power generation were determined based on the U.S. Department of Energy/Energy Information Administration's *Assumptions to the Annual Energy Outlook 2003*.[143] These cost factors represent existing and new technologies and include the price premiums to account for improved efficiency and environmental control systems, or as in the case of nuclear power plants, advanced designs.

TRANSMISSION ASSUMPTIONS

Transmission costs calculations were made in two parts: local transmission or substation, and transmission grid infrastructure.

Local transmission is a substation adjacent to a power plant that is used to raise plant output to transmission voltage and connect the plant to a switchyard on the transmission system. This equipment is considered part of the generating plant and its cost is included in the power station plant cost. The cost is based on the considerations found in the IAEA's technical report on power system expansion planning.[144] This cost value is applied only to "Electricity Generation Capacity" and "CHP Generation", as "Autoproducer Capacity" generally does not require connecting to the grid.

Transmission grid cost estimations are based on an analysis of transmission infrastructure investments in a selection of APEC economies as described in the "Investments in the Power Sector" section of the investment outlook chapter.

143 EIA (2003b). "Assumptions to the Annual Energy Outlook 2003", Energy Information Administration, USDOE. Washington, 2003.

144 IAEA (1984). Expansion Planning for Electrical Generating Systems, IAEA Technical Report Series No. 241, IAEA, 1984.

APPENDIX II

ENERGY INVESTMENT OUTLOOK TABLES

ENERGY INVESTMENT OUTLOOK BY INFRASTRUCTURE

Table A: 1 Total Energy Infrastructure Investments, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**29.86**	**45.52**	**61.36**	**75.94**	**90.88**	**523.84**	**783.33**	**1,307.16**
Latin America	**11.21**	**17.45**	**18.50**	**16.14**	**17.84**	**168.80**	**167.83**	**336.62**
Chile	1.91	2.70	3.39	3.32	4.40	29.72	38.38	68.10
Mexico	8.84	13.21	14.32	11.37	12.14	126.80	116.59	243.40
Peru	0.45	1.54	0.79	1.46	1.31	12.27	12.85	25.12
North America	**77.05**	**47.07**	**53.77**	**54.54**	**48.82**	**548.75**	**501.57**	**1,050.32**
Canada	21.01	18.01	14.95	12.95	10.29	177.46	110.83	288.29
United States	56.04	29.06	38.82	41.59	38.53	371.29	390.74	762.03
Northeast Asia	**10.37**	**28.38**	**25.39**	**23.41**	**23.13**	**223.39**	**213.92**	**437.31**
Hong Kong, China	0.47	0.21	0.53	0.72	0.64	4.30	5.94	10.23
Japan	3.06	14.10	5.64	9.00	8.78	80.10	82.77	162.87
Korea	2.22	6.76	16.06	7.94	7.99	105.77	89.89	195.65
Chinese Taipei	4.62	7.30	3.17	5.75	5.73	33.22	35.34	68.56
Southeast Asia	**24.03**	**22.50**	**22.55**	**26.04**	**31.43**	**221.17**	**263.67**	**484.84**
Brunei Darussalam	0.28	0.03	0.05	0.07	0.08	3.47	0.77	4.24
Indonesia	6.88	8.64	8.70	5.31	10.94	60.12	77.58	137.71
Malaysia	2.85	4.67	3.51	4.48	4.54	48.95	42.11	91.06
Philippines	0.69	0.29	1.11	4.64	3.69	10.26	30.95	41.21
Singapore	3.62	2.81	2.27	2.22	2.16	26.79	21.41	48.20
Thailand	5.42	3.75	3.97	6.72	7.25	40.93	62.52	103.46
Viet Nam	4.30	2.31	2.95	2.60	2.77	30.64	28.32	58.96
Oceania	**12.18**	**5.38**	**4.43**	**5.14**	**5.37**	**59.01**	**48.02**	**107.03**
Australia	10.42	3.49	4.02	4.49	4.65	49.70	45.71	95.41
New Zealand	0.89	0.80	0.29	0.53	0.60	2.52	1.85	4.37
Papua New Guinea	0.87	1.10	0.12	0.12	0.12	6.79	0.47	7.26
Russia	**42.39**	**32.94**	**30.81**	**34.93**	**34.46**	**345.82**	**343.33**	**689.15**
Total	**207.09**	**199.25**	**216.81**	**236.15**	**251.94**	**2,090.77**	**2,321.67**	**4,412.44**

Table A: 2 Total Energy Infrastructure Investments, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**22.36**	**36.76**	**49.87**	**61.98**	**74.12**	**422.90**	**639.26**	**1,062.16**
Latin America	**8.59**	**13.80**	**15.08**	**13.12**	**14.56**	**132.36**	**136.40**	**268.76**
Chile	1.50	2.28	2.74	2.74	3.64	24.30	31.62	55.92
Mexico	6.75	10.17	11.78	9.21	9.79	98.27	94.42	192.69
Peru	0.34	1.36	0.57	1.18	1.12	9.79	10.35	20.14
North America	**53.75**	**34.11**	**39.34**	**40.75**	**35.96**	**396.13**	**372.41**	**768.55**
Canada	15.16	13.48	11.20	10.01	7.86	130.76	85.09	215.85
United States	38.60	20.63	28.14	30.75	28.10	265.37	287.33	552.70
Northeast Asia	**8.09**	**22.18**	**20.20**	**18.27**	**18.47**	**176.50**	**168.93**	**345.43**
Hong Kong, China	0.33	0.15	0.41	0.56	0.48	3.19	4.47	7.66
Japan	2.37	11.03	4.36	7.01	7.23	62.66	65.03	127.69
Korea	1.59	5.28	12.84	6.31	6.37	84.65	71.07	155.72
Chinese Taipei	3.80	5.72	2.59	4.40	4.40	26.00	28.36	54.36
Southeast Asia	**16.94**	**17.25**	**17.47**	**20.66**	**24.85**	**165.27**	**208.49**	**373.75**
Brunei Darussalam	0.18	0.02	0.03	0.04	0.05	2.70	0.53	3.23
Indonesia	5.38	7.07	6.97	4.15	8.90	47.14	62.42	109.56
Malaysia	2.04	3.84	2.76	3.56	3.59	40.27	33.39	73.66
Philippines	0.54	0.21	0.87	3.91	3.06	7.54	25.73	33.27
Singapore	2.38	1.96	1.54	1.69	1.63	17.89	16.30	34.19
Thailand	2.96	2.39	3.03	5.17	5.53	25.94	47.70	73.64
Viet Nam	3.46	1.76	2.26	2.13	2.09	23.79	22.41	46.20
Oceania	**8.48**	**4.44**	**3.38**	**4.01**	**4.19**	**45.12**	**37.20**	**82.32**
Australia	6.91	2.69	3.04	3.47	3.58	36.79	35.35	72.15
New Zealand	0.74	0.67	0.24	0.44	0.50	2.03	1.44	3.46
Papua New Guinea	0.84	1.08	0.10	0.10	0.11	6.30	0.40	6.71
Russia	**31.03**	**25.28**	**22.92**	**25.98**	**25.67**	**261.37**	**256.29**	**517.66**
Total	**149.26**	**153.81**	**168.26**	**184.78**	**197.81**	**1,599.65**	**1,818.98**	**3,418.62**

Table A: 3 Coal Production & Transportation Facilities, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**4.900**	**2.059**	**2.366**	**3.055**	**4.000**	**26.529**	**31.893**	**58.422**
Latin America	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Chile	-	-	-	-	-	-	-	-
Mexico	-	-	-	-	-	-	-	-
Peru	-	-	-	-	-	-	-	-
North America	**3.23**	**1.18**	**0.90**	**0.15**	**0.28**	**11.41**	**1.93**	**13.34**
Canada	-	0.446	-	-	-	0.610	-	0.610
United States	3.225	0.731	0.898	0.155	0.280	10.796	1.930	12.725
Northeast Asia	**0.04**	**-**	**-**	**-**	**-**	**0.04**	**-**	**0.04**
Hong Kong, China	-	-	-	-	-	-	-	-
Japan	0.044	-	-	-	-	0.044	-	0.044
Korea	-	-	-	-	-	-	-	-
Chinese Taipei	-	-	-	-	-	-	-	-
Southeast Asia	**0.38**	**0.41**	**0.56**	**0.55**	**0.63**	**5.05**	**5.80**	**10.85**
Brunei Darussalam	-	-	-	-	-	-	-	-
Indonesia	0.219	0.275	0.409	0.469	0.544	3.410	4.873	8.282
Malaysia	-	-	-	-	-	-	-	-
Philippines	-	0.032	-	-	-	0.372	0.015	0.387
Singapore	-	-	-	-	-	-	-	-
Thailand	0.028	0.006	0.054	-	-	0.302	0.054	0.356
Viet Nam	0.137	0.095	0.098	0.085	0.089	0.969	0.857	1.826
Oceania	**1.01**	**0.49**	**0.28**	**0.34**	**0.36**	**6.53**	**3.61**	**10.14**
Australia	1.013	0.491	0.278	0.340	0.355	6.519	3.597	10.116
New Zealand	-	0.002	0.001	0.001	0.001	0.016	0.012	0.028
Papua New Guinea	-	-	-	-	-	-	-	-
Russia	**2.78**	**0.94**	**0.70**	**0.86**	**0.83**	**12.55**	**8.67**	**21.22**
Total	**12.34**	**5.08**	**4.81**	**4.96**	**6.10**	**62.11**	**51.90**	**114.01**

Table A: 4 Coal Production & Transportation Facilities, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**3.850**	**1.617**	**1.859**	**2.400**	**3.143**	**20.845**	**25.059**	**45.903**
Latin America	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Chile	-	-	-	-	-	-	-	-
Mexico	-	-	-	-	-	-	-	-
Peru	-	-	-	-	-	-	-	-
North America	**2.53**	**0.92**	**0.71**	**0.12**	**0.22**	**8.96**	**1.52**	**10.48**
Canada	-	0.350	-	-	-	0.479	-	0.479
United States	2.534	0.574	0.706	0.122	0.220	8.482	1.516	9.998
Northeast Asia	**0.03**	**-**	**-**	**-**	**-**	**0.03**	**-**	**0.03**
Hong Kong, China	-	-	-	-	-	-	-	-
Japan	0.034	-	-	-	-	0.034	-	0.034
Korea	-	-	-	-	-	-	-	-
Chinese Taipei	-	-	-	-	-	-	-	-
Southeast Asia	**0.30**	**0.32**	**0.44**	**0.44**	**0.50**	**3.97**	**4.56**	**8.53**
Brunei Darussalam	-	-	-	-	-	-	-	-
Indonesia	0.172	0.216	0.321	0.369	0.427	2.679	3.828	6.507
Malaysia	-	-	-	-	-	-	-	-
Philippines	-	0.025	-	-	-	0.292	0.012	0.304
Singapore	-	-	-	-	-	-	-	-
Thailand	0.022	0.005	0.043	-	-	0.237	0.043	0.280
Viet Nam	0.107	0.075	0.077	0.067	0.070	0.761	0.673	1.435
Oceania	**0.80**	**0.39**	**0.22**	**0.27**	**0.28**	**5.13**	**2.84**	**7.97**
Australia	0.796	0.386	0.218	0.267	0.279	5.122	2.826	7.948
New Zealand	-	0.002	0.001	0.001	0.001	0.012	0.009	0.022
Papua New Guinea	-	-	-	-	-	-	-	-
Russia	**2.18**	**0.74**	**0.55**	**0.67**	**0.65**	**9.86**	**6.81**	**16.67**
Total	**9.70**	**3.99**	**3.78**	**3.90**	**4.79**	**48.80**	**40.78**	**89.58**

Table A: 5 Oil & Gas Production, Processing & Petrochemical Infrastructure, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**9.79**	**4.66**	**6.10**	**6.82**	**7.96**	**58.56**	**68.51**	**127.08**
Latin America	**4.31**	**5.76**	**2.87**	**3.05**	**3.32**	**54.35**	**31.11**	**85.46**
Chile	1.03	0.67	0.51	0.57	0.66	7.72	5.84	13.56
Mexico	3.11	4.93	2.04	2.10	2.38	42.93	21.43	64.36
Peru	0.18	0.15	0.31	0.38	0.27	3.71	3.83	7.54
North America	**32.07**	**16.00**	**20.05**	**18.20**	**17.59**	**202.26**	**173.92**	**376.17**
Canada	14.25	6.21	8.57	6.43	5.55	87.52	57.75	145.27
United States	17.82	9.79	11.48	11.77	12.04	114.74	116.16	230.90
Northeast Asia	**2.14**	**3.98**	**4.38**	**3.64**	**3.50**	**37.25**	**36.58**	**73.83**
Hong Kong, China	-	-	-	-	-	-	-	-
Japan	-	1.05	0.92	0.65	0.62	7.20	6.74	13.94
Korea	1.40	2.46	2.92	2.45	2.37	24.50	24.53	49.03
Chinese Taipei	0.74	0.47	0.54	0.53	0.51	5.55	5.30	10.85
Southeast Asia	**9.07**	**7.22**	**7.91**	**7.80**	**9.36**	**82.78**	**81.72**	**164.50**
Brunei Darussalam	0.27	0.02	0.03	0.03	0.04	1.48	0.35	1.82
Indonesia	2.55	2.26	2.41	2.13	2.55	24.58	21.74	46.33
Malaysia	2.17	1.09	1.26	1.45	1.50	14.68	14.25	28.94
Philippines	0.13	0.09	0.40	0.47	0.56	5.18	4.82	10.00
Singapore	2.06	0.83	0.96	1.16	1.15	10.86	11.18	22.03
Thailand	0.76	2.06	1.76	2.20	2.33	15.19	21.77	36.96
Viet Nam	1.13	0.88	1.10	0.37	1.23	10.81	7.61	18.42
Oceania	**8.10**	**1.07**	**1.55**	**1.33**	**1.42**	**21.81**	**13.31**	**35.12**
Australia	8.00	1.01	1.48	1.25	1.33	20.05	12.49	32.54
New Zealand	0.10	0.06	0.07	0.08	0.08	0.70	0.81	1.51
Papua New Guinea	-	-	-	-	-	1.07	0.01	1.08
Russia	**11.49**	**7.76**	**8.83**	**6.89**	**6.41**	**84.41**	**61.47**	**145.88**
Total	**76.98**	**46.44**	**51.70**	**47.73**	**49.56**	**541.42**	**466.60**	**1,008.03**

Table A: 6 Oil & Gas Production, Processing & Petrochemical Infrastructure, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**6.38**	**3.15**	**4.12**	**4.61**	**5.38**	**39.32**	**46.32**	**85.64**
Latin America	**3.04**	**3.91**	**2.00**	**2.12**	**2.33**	**36.73**	**21.66**	**58.39**
Chile	0.73	0.47	0.36	0.39	0.46	5.45	4.03	9.48
Mexico	2.19	3.33	1.43	1.48	1.68	28.81	15.11	43.92
Peru	0.12	0.11	0.21	0.25	0.19	2.47	2.52	4.99
North America	**22.56**	**11.22**	**13.92**	**12.72**	**12.37**	**141.10**	**121.88**	**262.98**
Canada	10.06	4.37	5.89	4.58	4.03	60.77	41.51	102.27
United States	12.51	6.85	8.03	8.15	8.34	80.33	80.37	160.70
Northeast Asia	**1.49**	**2.76**	**3.04**	**2.52**	**2.43**	**25.84**	**25.38**	**51.22**
Hong Kong, China	-	-	-	-	-	-	-	-
Japan	-	0.73	0.64	0.45	0.43	5.01	4.69	9.70
Korea	0.97	1.70	2.02	1.69	1.64	16.94	16.97	33.91
Chinese Taipei	0.52	0.33	0.38	0.38	0.36	3.89	3.72	7.61
Southeast Asia	**6.03**	**4.84**	**5.37**	**5.39**	**6.42**	**55.38**	**56.15**	**111.53**
Brunei Darussalam	0.17	0.01	0.02	0.02	0.03	0.94	0.22	1.16
Indonesia	1.71	1.51	1.63	1.48	1.76	16.47	15.05	31.52
Malaysia	1.43	0.76	0.87	1.00	1.04	9.96	9.86	19.82
Philippines	0.09	0.06	0.27	0.32	0.38	3.36	3.24	6.60
Singapore	1.40	0.58	0.66	0.80	0.81	7.43	7.74	15.18
Thailand	0.52	1.36	1.22	1.53	1.62	10.35	15.15	25.50
Viet Nam	0.71	0.56	0.70	0.24	0.78	6.87	4.88	11.75
Oceania	**5.15**	**0.74**	**1.05**	**0.91**	**0.98**	**14.46**	**9.16**	**23.61**
Australia	5.08	0.70	1.00	0.86	0.92	13.31	8.59	21.90
New Zealand	0.07	0.04	0.05	0.05	0.06	0.48	0.56	1.04
Papua New Guinea	-	-	-	-	-	0.67	0.01	0.67
Russia	**7.43**	**5.01**	**5.68**	**4.51**	**4.20**	**54.56**	**40.34**	**94.90**
Total	**52.08**	**31.63**	**35.18**	**32.79**	**34.10**	**367.38**	**320.88**	**688.26**

Table A: 7 Oil & Gas International Trade, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**0.08**	**1.84**	**1.97**	**1.98**	**2.96**	**15.10**	**23.54**	**38.63**
Latin America	**2.65**	**5.67**	**3.69**	**2.94**	**3.15**	**37.72**	**29.01**	**66.72**
Chile	0.82	1.37	0.43	0.63	0.84	9.26	6.76	16.02
Mexico	1.82	3.66	3.26	1.91	1.91	25.53	19.05	44.58
Peru	0.01	0.65	0.00	0.40	0.40	2.92	3.20	6.12
North America	**11.66**	**9.40**	**5.71**	**4.99**	**3.24**	**84.42**	**39.96**	**124.37**
Canada	3.99	6.59	1.99	1.78	0.00	46.90	8.90	55.80
United States	7.67	2.81	3.72	3.21	3.24	37.51	31.06	68.57
Northeast Asia	**0.87**	**1.77**	**3.25**	**0.61**	**0.54**	**23.00**	**8.60**	**31.60**
Hong Kong, China	0.14	0.06	0.07	0.08	0.08	0.86	0.79	1.65
Japan	0.14	1.20	0.76	0.16	0.18	7.02	2.33	9.35
Korea	0.49	0.42	2.24	0.37	0.28	12.59	4.22	16.82
Chinese Taipei	0.10	0.09	0.17	-	-	2.53	1.25	3.78
Southeast Asia	**4.11**	**3.81**	**1.43**	**1.60**	**1.78**	**41.71**	**15.46**	**57.18**
Brunei Darussalam	-	-	-	-	-	1.58	-	1.58
Indonesia	0.26	1.08	0.35	0.39	0.56	8.69	4.17	12.86
Malaysia	0.58	0.99	0.23	0.23	0.23	13.06	2.33	15.39
Philippines	0.00	0.01	0.01	0.39	0.16	0.08	2.53	2.61
Singapore	1.09	1.28	0.83	0.40	0.57	10.06	4.56	14.62
Thailand	1.74	0.44	0.02	0.18	0.24	6.89	1.77	8.66
Viet Nam	0.44	-	-	0.01	0.02	1.34	0.11	1.45
Oceania	**0.76**	**1.72**	**0.73**	**0.29**	**0.35**	**9.03**	**2.98**	**12.02**
Australia	0.16	0.74	0.73	0.29	0.35	3.92	2.97	6.89
New Zealand	0.00	0.00	-	0.00	0.00	0.01	0.01	0.02
Papua New Guinea	0.60	0.98	-	-	-	5.10	-	5.10
Russia	**12.83**	**5.62**	**1.85**	**0.31**	**0.31**	**50.13**	**3.10**	**53.23**
Total	**32.95**	**29.82**	**18.63**	**12.73**	**12.33**	**261.11**	**122.65**	**383.75**

Table A: 8 Oil & Gas International Trade, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**0.04**	**1.12**	**1.13**	**1.10**	**1.82**	**8.51**	**14.00**	**22.50**
Latin America	**2.35**	**5.25**	**3.29**	**2.66**	**2.85**	**34.49**	**26.19**	**60.69**
Chile	0.73	1.34	0.38	0.56	0.75	8.82	5.99	14.81
Mexico	1.61	3.26	2.91	1.71	1.70	22.76	17.00	39.76
Peru	0.00	0.65	0.00	0.40	0.40	2.91	3.20	6.12
North America	**7.58**	**6.69**	**4.06**	**3.61**	**2.03**	**59.88**	**27.54**	**87.42**
Canada	3.16	4.87	1.76	1.59	0.00	36.43	7.94	44.37
United States	4.42	1.82	2.30	2.02	2.03	23.46	19.59	43.05
Northeast Asia	**0.56**	**1.49**	**2.85**	**0.41**	**0.36**	**19.45**	**6.44**	**25.89**
Hong Kong, China	0.06	0.03	0.03	0.03	0.03	0.36	0.33	0.69
Japan	0.07	1.11	0.53	0.09	0.12	5.64	1.47	7.11
Korea	0.39	0.32	2.17	0.28	0.21	11.96	3.64	15.60
Chinese Taipei	0.04	0.04	0.12	-	-	1.49	1.00	2.50
Southeast Asia	**1.76**	**2.77**	**1.00**	**1.24**	**1.30**	**29.04**	**11.87**	**40.91**
Brunei Darussalam	-	-	-	-	-	1.44	-	1.44
Indonesia	0.22	1.05	0.31	0.35	0.50	8.17	3.73	11.89
Malaysia	0.54	0.90	0.20	0.21	0.21	12.41	2.06	14.47
Philippines	0.00	0.01	0.00	0.37	0.14	0.03	2.32	2.35
Singapore	0.56	0.82	0.47	0.31	0.44	5.65	3.66	9.31
Thailand	0.00	0.00	0.01	0.01	0.01	0.02	0.06	0.09
Viet Nam	0.44	-	-	0.00	0.01	1.32	0.04	1.36
Oceania	**0.73**	**1.65**	**0.66**	**0.26**	**0.31**	**8.57**	**2.65**	**11.23**
Australia	0.13	0.67	0.66	0.26	0.31	3.47	2.65	6.12
New Zealand	0.00	0.00	-	0.00	0.00	0.00	0.00	0.01
Papua New Guinea	0.60	0.98	-	-	-	5.10	-	5.10
Russia	**10.47**	**4.89**	**1.53**	**0.28**	**0.28**	**42.53**	**2.77**	**45.30**
Total	**36.46**	**41.71**	**26.37**	**17.73**	**15.80**	**202.47**	**91.47**	**293.94**

Table A: 9 Oil & Gas Domestic Pipelines, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**2.67**	**2.65**	**3.43**	**4.46**	**5.65**	**29.96**	**46.19**	**76.15**
Latin America	**2.74**	**3.14**	**2.64**	**2.33**	**2.41**	**27.91**	**24.18**	**52.09**
Chile	0.06	0.66	0.77	0.34	0.46	5.99	5.17	11.16
Mexico	2.59	2.33	1.56	1.66	1.88	19.27	16.76	36.03
Peru	0.08	0.15	0.30	0.33	0.08	2.65	2.24	4.89
North America	**30.06**	**13.79**	**15.88**	**14.54**	**14.87**	**167.11**	**142.56**	**309.67**
Canada	2.77	1.18	1.27	1.34	1.37	14.52	13.07	27.59
United States	27.29	12.61	14.61	13.20	13.49	152.59	129.49	282.08
Northeast Asia	**0.51**	**0.57**	**0.60**	**0.58**	**0.63**	**5.80**	**5.83**	**11.63**
Hong Kong, China	0.05	0.05	0.09	0.11	0.13	0.63	1.13	1.76
Japan	0.09	0.07	0.09	0.07	0.07	0.78	0.67	1.45
Korea	0.33	0.41	0.39	0.34	0.35	3.98	3.43	7.41
Chinese Taipei	0.04	0.03	0.05	0.06	0.07	0.42	0.60	1.02
Southeast Asia	**0.48**	**0.90**	**0.85**	**1.04**	**1.18**	**8.73**	**10.44**	**19.16**
Brunei Darussalam	0.02	0.02	0.02	0.03	0.04	0.21	0.32	0.53
Indonesia	0.14	0.11	0.14	0.17	0.20	1.27	1.73	3.01
Malaysia	0.10	0.14	0.19	0.23	0.26	1.44	2.35	3.80
Philippines	0.01	0.00	0.06	0.08	0.09	0.34	0.79	1.13
Singapore	-	0.26	-	-	-	1.59	-	1.59
Thailand	0.21	0.26	0.36	0.45	0.54	3.02	4.62	7.64
Viet Nam	-	0.11	0.06	0.08	0.05	0.85	0.63	1.48
Oceania	**1.06**	**0.83**	**0.91**	**0.98**	**1.05**	**9.71**	**9.88**	**19.60**
Australia	1.05	0.82	0.90	0.98	1.04	9.62	9.82	19.44
New Zealand	0.02	0.01	0.01	0.01	0.01	0.09	0.06	0.15
Papua New Guinea	-	-	-	-	-	-	-	-
Russia	**13.50**	**8.49**	**9.26**	**10.34**	**9.63**	**99.71**	**99.57**	**199.28**
Total	**51.02**	**30.37**	**33.57**	**34.28**	**35.42**	**348.93**	**338.64**	**687.58**

Table A: 10 Oil & Gas Domestic Pipelines, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**1.87**	**1.85**	**2.40**	**3.12**	**3.96**	**20.97**	**32.33**	**53.30**
Latin America	**1.92**	**2.20**	**1.85**	**1.63**	**1.69**	**19.54**	**16.92**	**36.46**
Chile	0.04	0.46	0.54	0.24	0.32	4.19	3.62	7.81
Mexico	1.81	1.63	1.10	1.16	1.32	13.49	11.73	25.22
Peru	0.06	0.11	0.21	0.23	0.05	1.86	1.57	3.43
North America	**21.04**	**9.66**	**11.12**	**10.18**	**10.41**	**116.98**	**99.79**	**216.77**
Canada	1.94	0.83	0.89	0.94	0.96	10.17	9.15	19.32
United States	19.10	8.83	10.23	9.24	9.45	106.81	90.64	197.46
Northeast Asia	**0.36**	**0.40**	**0.42**	**0.40**	**0.44**	**4.06**	**4.08**	**8.14**
Hong Kong, China	0.03	0.04	0.06	0.08	0.09	0.44	0.79	1.23
Japan	0.06	0.05	0.06	0.05	0.05	0.54	0.47	1.01
Korea	0.23	0.29	0.27	0.24	0.25	2.79	2.40	5.19
Chinese Taipei	0.03	0.02	0.03	0.04	0.05	0.29	0.42	0.71
Southeast Asia	**0.34**	**0.63**	**0.59**	**0.73**	**0.82**	**6.11**	**7.31**	**13.41**
Brunei Darussalam	0.01	0.01	0.02	0.02	0.03	0.15	0.22	0.37
Indonesia	0.10	0.08	0.10	0.12	0.14	0.89	1.21	2.10
Malaysia	0.07	0.10	0.13	0.16	0.18	1.01	1.65	2.66
Philippines	0.01	0.00	0.04	0.05	0.07	0.24	0.55	0.79
Singapore	-	0.18	-	-	-	1.11	-	1.11
Thailand	0.15	0.19	0.26	0.32	0.38	2.11	3.23	5.35
Viet Nam	-	0.07	0.05	0.05	0.03	0.60	0.44	1.04
Oceania	**0.74**	**0.58**	**0.63**	**0.69**	**0.74**	**6.80**	**6.92**	**13.72**
Australia	0.73	0.57	0.63	0.68	0.73	6.73	6.87	13.61
New Zealand	0.01	0.01	0.00	0.00	0.00	0.06	0.04	0.11
Papua New Guinea	-	-	-	-	-	-	-	-
Russia	**9.45**	**5.94**	**6.48**	**7.24**	**6.74**	**69.80**	**69.70**	**139.49**
Total	**35.71**	**21.26**	**23.50**	**24.00**	**24.79**	**244.25**	**237.05**	**481.30**

Table A: 11 Electricity Generation & Transmission, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**12.42**	**34.32**	**47.50**	**59.62**	**70.31**	**393.69**	**613.20**	**1,006.89**
Latin America	**1.51**	**2.88**	**9.30**	**7.83**	**8.96**	**48.81**	**83.53**	**132.34**
Chile	-	-	1.67	1.78	2.43	6.75	20.61	27.36
Mexico	1.32	2.29	7.46	5.70	5.97	39.07	59.35	98.42
Peru	0.18	0.59	0.17	0.35	0.55	2.99	3.57	6.57
North America	**0.03**	**6.70**	**11.23**	**16.65**	**12.84**	**83.56**	**143.21**	**226.77**
Canada	-	3.58	3.11	3.40	3.37	27.90	31.11	59.01
United States	0.03	3.12	8.11	13.25	9.48	55.66	112.10	167.75
Northeast Asia	**6.81**	**22.05**	**17.16**	**18.59**	**18.46**	**157.29**	**162.92**	**320.21**
Hong Kong, China	0.28	0.10	0.38	0.53	0.43	2.81	4.01	6.82
Japan	2.79	11.78	3.87	8.13	7.90	65.06	73.02	138.08
Korea	-	3.47	10.51	4.78	4.98	64.69	57.70	122.39
Chinese Taipei	3.74	6.71	2.40	5.15	5.14	24.73	28.18	52.91
Southeast Asia	**9.98**	**10.17**	**11.81**	**15.04**	**18.47**	**82.90**	**150.26**	**233.15**
Brunei Darussalam	-	-	-	-	-	0.20	0.11	0.31
Indonesia	3.70	4.92	5.39	2.16	7.09	22.16	45.07	67.23
Malaysia	-	2.45	1.82	2.57	2.54	19.76	23.18	42.94
Philippines	0.54	0.15	0.65	3.70	2.88	4.29	22.80	27.08
Singapore	0.48	0.44	0.48	0.67	0.44	4.28	5.67	9.96
Thailand	2.68	0.98	1.78	3.88	4.14	15.53	34.31	49.84
Viet Nam	2.58	1.23	1.69	2.06	1.38	16.67	19.12	35.79
Oceania	**1.25**	**1.28**	**0.96**	**2.20**	**2.20**	**11.92**	**18.24**	**30.16**
Australia	0.21	0.43	0.63	1.63	1.57	9.59	16.83	26.42
New Zealand	0.77	0.73	0.21	0.45	0.51	1.71	0.95	2.66
Papua New Guinea	0.27	0.12	0.12	0.12	0.12	0.62	0.46	1.08
Russia	**1.79**	**10.14**	**10.17**	**16.53**	**17.28**	**99.02**	**170.52**	**269.54**
Total	**33.79**	**87.54**	**108.12**	**136.45**	**148.53**	**877.19**	**1,341.87**	**2,219.06**

Table A: 12 Electricity Generation & Transmission, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**10.22**	**29.02**	**40.36**	**50.75**	**59.82**	**333.26**	**521.56**	**854.82**
Latin America	**1.29**	**2.45**	**7.95**	**6.71**	**7.69**	**41.60**	**71.62**	**113.22**
Chile	-	-	1.46	1.55	2.12	5.84	17.99	23.82
Mexico	1.13	1.94	6.34	4.86	5.09	33.21	50.57	83.78
Peru	0.16	0.50	0.15	0.30	0.47	2.55	3.06	5.61
North America	**0.03**	**5.62**	**9.53**	**14.12**	**10.93**	**69.21**	**121.69**	**190.90**
Canada	-	3.06	2.66	2.90	2.86	22.92	26.49	49.41
United States	0.03	2.56	6.87	11.22	8.07	46.29	95.21	141.49
Northeast Asia	**5.66**	**17.52**	**13.89**	**14.94**	**15.24**	**127.11**	**133.04**	**260.14**
Hong Kong, China	0.24	0.08	0.32	0.45	0.35	2.40	3.35	5.74
Japan	2.21	9.14	3.13	6.42	6.63	51.43	58.41	109.84
Korea	-	2.97	8.38	4.09	4.27	52.96	48.07	101.02
Chinese Taipei	3.21	5.33	2.06	3.98	3.99	20.33	23.22	43.54
Southeast Asia	**8.51**	**8.69**	**10.07**	**12.87**	**15.81**	**70.77**	**128.60**	**199.38**
Brunei Darussalam	-	-	-	-	-	0.17	0.09	0.27
Indonesia	3.18	4.21	4.61	1.84	6.08	18.93	38.60	57.54
Malaysia	-	2.09	1.55	2.19	2.16	16.89	19.82	36.70
Philippines	0.45	0.12	0.55	3.17	2.47	3.62	19.61	23.22
Singapore	0.41	0.38	0.41	0.58	0.38	3.70	4.90	8.60
Thailand	2.28	0.84	1.51	3.32	3.53	13.21	29.21	42.43
Viet Nam	2.20	1.05	1.44	1.76	1.19	14.25	16.37	30.62
Oceania	**1.06**	**1.09**	**0.82**	**1.88**	**1.88**	**10.16**	**15.63**	**25.79**
Australia	0.17	0.36	0.54	1.39	1.34	8.16	14.41	22.57
New Zealand	0.66	0.62	0.18	0.39	0.43	1.46	0.82	2.28
Papua New Guinea	0.23	0.10	0.10	0.10	0.11	0.54	0.40	0.93
Russia	**1.50**	**8.69**	**8.68**	**13.27**	**13.80**	**84.62**	**136.66**	**221.29**
Total	**28.28**	**73.07**	**91.29**	**114.53**	**125.18**	**736.73**	**1,128.80**	**1,865.53**

ENERGY INVESTMENT OUTLOOK BY ECONOMY

Table B: 1 Australia, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	1.01	0.49	0.28	0.34	0.36	6.52	3.60	10.12
Oil & gas production, processing, petrochemical	8.00	1.01	1.48	1.25	1.33	20.05	12.49	32.54
Oil & gas international trade	0.16	0.74	0.73	0.29	0.35	3.92	2.97	6.89
Oil & gas domestic pipelines	1.05	0.82	0.90	0.98	1.04	9.62	9.82	19.44
Electricity generation & transmission	0.21	0.43	0.63	1.63	1.57	9.59	16.83	26.42
Total	**10.42**	**3.49**	**4.02**	**4.49**	**4.65**	**49.70**	**45.71**	**95.41**

Table B: 2 Australia, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.80	0.39	0.22	0.27	0.28	5.12	2.83	7.95
Oil & gas production, processing, petrochemical	5.08	0.70	1.00	0.86	0.92	13.31	8.59	21.90
Oil & gas international trade	0.13	0.67	0.66	0.26	0.31	3.47	2.65	6.12
Oil & gas domestic pipelines	0.73	0.57	0.63	0.68	0.73	6.73	6.87	13.61
Electricity generation & transmission	0.17	0.36	0.54	1.39	1.34	8.16	14.41	22.57
Total	**6.91**	**2.69**	**3.04**	**3.47**	**3.58**	**36.79**	**35.35**	**72.15**

Table B: 3 Brunei Darussalam, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.27	0.02	0.03	0.03	0.04	1.48	0.35	1.82
Oil & gas international trade	-	-	-	-	-	1.58	-	1.58
Oil & gas domestic pipelines	0.02	0.02	0.02	0.03	0.04	0.21	0.32	0.53
Electricity generation & transmission	-	-	-	-	-	0.20	0.11	0.31
Total	**0.28**	**0.03**	**0.05**	**0.07**	**0.08**	**3.47**	**0.77**	**4.24**

Table B: 4 Brunei Darussalam, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.17	0.01	0.02	0.02	0.03	0.94	0.22	1.16
Oil & gas international trade	-	-	-	-	-	1.44	-	1.44
Oil & gas domestic pipelines	0.01	0.01	0.02	0.02	0.03	0.15	0.22	0.37
Electricity generation & transmission	-	-	-	-	-	0.17	0.09	0.27
Total	**0.18**	**0.02**	**0.03**	**0.04**	**0.05**	**2.70**	**0.53**	**3.23**

Table B: 5 Canada, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.45	-	-	-	0.61	-	0.61
Oil & gas production, processing, petrochemical	14.25	6.21	8.57	6.43	5.55	87.52	57.75	145.27
Oil & gas international trade	3.99	6.59	1.99	1.78	0.00	46.90	8.90	55.80
Oil & gas domestic pipelines	2.77	1.18	1.27	1.34	1.37	14.52	13.07	27.59
Electricity generation & transmission	-	3.58	3.11	3.40	3.37	27.90	31.11	59.01
Total	**21.01**	**18.01**	**14.95**	**12.95**	**10.29**	**177.46**	**110.83**	**288.29**

Table B: 6 Canada, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.35	-	-	-	0.48	-	0.48
Oil & gas production, processing, petrochemical	10.06	4.37	5.89	4.58	4.03	60.77	41.51	102.27
Oil & gas international trade	3.16	4.87	1.76	1.59	0.00	36.43	7.94	44.37
Oil & gas domestic pipelines	1.94	0.83	0.89	0.94	0.96	10.17	9.15	19.32
Electricity generation & transmission	-	3.06	2.66	2.90	2.86	22.92	26.49	49.41
Total	**15.16**	**13.48**	**11.20**	**10.01**	**7.86**	**130.76**	**85.09**	**215.85**

Table B: 7 Chile, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	1.03	0.67	0.51	0.57	0.66	7.72	5.84	13.56
Oil & gas international trade	0.82	1.37	0.43	0.63	0.84	9.26	6.76	16.02
Oil & gas domestic pipelines	0.06	0.66	0.77	0.34	0.46	5.99	5.17	11.16
Electricity generation & transmission	-	-	1.67	1.78	2.43	6.75	20.61	27.36
Total	**1.91**	**2.70**	**3.39**	**3.32**	**4.40**	**29.72**	**38.38**	**68.10**

Table B: 8 Chile, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.73	0.47	0.36	0.39	0.46	5.45	4.03	9.48
Oil & gas international trade	0.73	1.34	0.38	0.56	0.75	8.82	5.99	14.81
Oil & gas domestic pipelines	0.04	0.46	0.54	0.24	0.32	4.19	3.62	7.81
Electricity generation & transmission	-	-	1.46	1.55	2.12	5.84	17.99	23.82
Total	**1.50**	**2.28**	**2.74**	**2.74**	**3.64**	**24.30**	**31.62**	**55.92**

Table B: 9 China, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	4.90	2.06	2.37	3.06	4.00	26.53	31.89	58.42
Oil & gas production, processing, petrochemical	9.79	4.66	6.10	6.82	7.96	58.56	68.51	127.08
Oil & gas international trade	0.08	1.84	1.97	1.98	2.96	15.10	23.54	38.63
Oil & gas domestic pipelines	2.67	2.65	3.43	4.46	5.65	29.96	46.19	76.15
Electricity generation & transmission	12.42	34.32	47.50	59.62	70.31	393.69	613.20	1,006.89
Total	**29.86**	**45.52**	**61.36**	**75.94**	**90.88**	**523.84**	**783.33**	**1,307.16**

Table B: 10 China, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	3.85	1.62	1.86	2.40	3.14	20.84	25.06	45.90
Oil & gas production, processing, petrochemical	6.38	3.15	4.12	4.61	5.38	39.32	46.32	85.64
Oil & gas international trade	0.04	1.12	1.13	1.10	1.82	8.51	14.00	22.50
Oil & gas domestic pipelines	1.87	1.85	2.40	3.12	3.96	20.97	32.33	53.30
Electricity generation & transmission	10.22	29.02	40.36	50.75	59.82	333.26	521.56	854.82
Total	**22.36**	**36.76**	**49.87**	**61.98**	**74.12**	**422.90**	**639.26**	**1,062.16**

Table B: 11 Hong Kong, China, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	-	-	-	-	-	-	-	-
Oil & gas international trade	0.14	0.06	0.07	0.08	0.08	0.86	0.79	1.65
Oil & gas domestic pipelines	0.05	0.05	0.09	0.11	0.13	0.63	1.13	1.76
Electricity generation & transmission	0.28	0.10	0.38	0.53	0.43	2.81	4.01	6.82
Total	**0.47**	**0.21**	**0.53**	**0.72**	**0.64**	**4.30**	**5.94**	**10.23**

Table B: 12 Hong Kong, China, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	-	-	-	-	-	-	-	-
Oil & gas international trade	0.06	0.03	0.03	0.03	0.03	0.36	0.33	0.69
Oil & gas domestic pipelines	0.03	0.04	0.06	0.08	0.09	0.44	0.79	1.23
Electricity generation & transmission	0.24	0.08	0.32	0.45	0.35	2.40	3.35	5.74
Total	**0.33**	**0.15**	**0.41**	**0.56**	**0.48**	**3.19**	**4.47**	**7.66**

Table B: 13 Indonesia, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.22	0.28	0.41	0.47	0.54	3.41	4.87	8.28
Oil & gas production, processing, petrochemical	2.55	2.26	2.41	2.13	2.55	24.58	21.74	46.33
Oil & gas international trade	0.26	1.08	0.35	0.39	0.56	8.69	4.17	12.86
Oil & gas domestic pipelines	0.14	0.11	0.14	0.17	0.20	1.27	1.73	3.01
Electricity generation & transmission	3.70	4.92	5.39	2.16	7.09	22.16	45.07	67.23
Total	**6.88**	**8.64**	**8.70**	**5.31**	**10.94**	**60.12**	**77.58**	**137.71**

Table B: 14 Indonesia, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.17	0.22	0.32	0.37	0.43	2.68	3.83	6.51
Oil & gas production, processing, petrochemical	1.71	1.51	1.63	1.48	1.76	16.47	15.05	31.52
Oil & gas international trade	0.22	1.05	0.31	0.35	0.50	8.17	3.73	11.89
Oil & gas domestic pipelines	0.10	0.08	0.10	0.12	0.14	0.89	1.21	2.10
Electricity generation & transmission	3.18	4.21	4.61	1.84	6.08	18.93	38.60	57.54
Total	**5.38**	**7.07**	**6.97**	**4.15**	**8.90**	**47.14**	**62.42**	**109.56**

Table B:15 Japan, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.04	-	-	-	-	0.04	-	0.04
Oil & gas production, processing, petrochemical	-	1.05	0.92	0.65	0.62	7.20	6.74	13.94
Oil & gas international trade	0.14	1.20	0.76	0.16	0.18	7.02	2.33	9.35
Oil & gas domestic pipelines	0.09	0.07	0.09	0.07	0.07	0.78	0.67	1.45
Electricity generation & transmission	2.79	11.78	3.87	8.13	7.90	65.06	73.02	138.08
Total	**3.06**	**14.10**	**5.64**	**9.00**	**8.78**	**80.10**	**82.77**	**162.87**

Table B: 16 Japan, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.03	-	-	-	-	0.03	-	0.03
Oil & gas production, processing, petrochemical	-	0.73	0.64	0.45	0.43	5.01	4.69	9.70
Oil & gas international trade	0.07	1.11	0.53	0.09	0.12	5.64	1.47	7.11
Oil & gas domestic pipelines	0.06	0.05	0.06	0.05	0.05	0.54	0.47	1.01
Electricity generation & transmission	2.21	9.14	3.13	6.42	6.63	51.43	58.41	109.84
Total	**2.37**	**11.03**	**4.36**	**7.01**	**7.23**	**62.66**	**65.03**	**127.69**

Table B: 17 Korea, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	1.40	2.46	2.92	2.45	2.37	24.50	24.53	49.03
Oil & gas international trade	0.49	0.42	2.24	0.37	0.28	12.59	4.22	16.82
Oil & gas domestic pipelines	0.33	0.41	0.39	0.34	0.35	3.98	3.43	7.41
Electricity generation & transmission	-	3.47	10.51	4.78	4.98	64.69	57.70	122.39
Total	**2.22**	**6.76**	**16.06**	**7.94**	**7.99**	**105.77**	**89.89**	**195.65**

Table B: 18 Korea, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.97	1.70	2.02	1.69	1.64	16.94	16.97	33.91
Oil & gas international trade	0.39	0.32	2.17	0.28	0.21	11.96	3.64	15.60
Oil & gas domestic pipelines	0.23	0.29	0.27	0.24	0.25	2.79	2.40	5.19
Electricity generation & transmission	-	2.97	8.38	4.09	4.27	52.96	48.07	101.02
Total	**1.59**	**5.28**	**12.84**	**6.31**	**6.37**	**84.65**	**71.07**	**155.72**

Table B: 19 Malaysia, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	2.17	1.09	1.26	1.45	1.50	14.68	14.25	28.94
Oil & gas international trade	0.58	0.99	0.23	0.23	0.23	13.06	2.33	15.39
Oil & gas domestic pipelines	0.10	0.14	0.19	0.23	0.26	1.44	2.35	3.80
Electricity generation & transmission	-	2.45	1.82	2.57	2.54	19.76	23.18	42.94
Total	**2.85**	**4.67**	**3.51**	**4.48**	**4.54**	**48.95**	**42.11**	**91.06**

Table B: 20 Malaysia, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	1.43	0.76	0.87	1.00	1.04	9.96	9.86	19.82
Oil & gas international trade	0.54	0.90	0.20	0.21	0.21	12.41	2.06	14.47
Oil & gas domestic pipelines	0.07	0.10	0.13	0.16	0.18	1.01	1.65	2.66
Electricity generation & transmission	-	2.09	1.55	2.19	2.16	16.89	19.82	36.70
Total	**2.04**	**3.84**	**2.76**	**3.56**	**3.59**	**40.27**	**33.39**	**73.66**

Table B: 21 Mexico, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	3.11	4.93	2.04	2.10	2.38	42.93	21.43	64.36
Oil & gas international trade	1.82	3.66	3.26	1.91	1.91	25.53	19.05	44.58
Oil & gas domestic pipelines	2.59	2.33	1.56	1.66	1.88	19.27	16.76	36.03
Electricity generation & transmission	1.32	2.29	7.46	5.70	5.97	39.07	59.35	98.42
Total	**8.84**	**13.21**	**14.32**	**11.37**	**12.14**	**126.80**	**116.59**	**243.40**

Table B: 22 Mexico, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	2.19	3.33	1.43	1.48	1.68	28.81	15.11	43.92
Oil & gas international trade	1.61	3.26	2.91	1.71	1.70	22.76	17.00	39.76
Oil & gas domestic pipelines	1.81	1.63	1.10	1.16	1.32	13.49	11.73	25.22
Electricity generation & transmission	1.13	1.94	6.34	4.86	5.09	33.21	50.57	83.78
Total	**6.75**	**10.17**	**11.78**	**9.21**	**9.79**	**98.27**	**94.42**	**192.69**

Table B: 23 New Zealand, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.00	0.00	0.00	0.00	0.02	0.01	0.03
Oil & gas production, processing, petrochemical	0.10	0.06	0.07	0.08	0.08	0.70	0.81	1.51
Oil & gas international trade	0.00	0.00	-	0.00	0.00	0.01	0.01	0.02
Oil & gas domestic pipelines	0.02	0.01	0.01	0.01	0.01	0.09	0.06	0.15
Electricity generation & transmission	0.77	0.73	0.21	0.45	0.51	1.71	0.95	2.66
Total	**0.89**	**0.80**	**0.29**	**0.53**	**0.60**	**2.52**	**1.85**	**4.37**

Table B: 24 New Zealand, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.00	0.00	0.00	0.00	0.01	0.01	0.02
Oil & gas production, processing, petrochemical	0.07	0.04	0.05	0.05	0.06	0.48	0.56	1.04
Oil & gas international trade	0.00	0.00	-	0.00	0.00	0.00	0.00	0.01
Oil & gas domestic pipelines	0.01	0.01	0.00	0.00	0.00	0.06	0.04	0.11
Electricity generation & transmission	0.66	0.62	0.18	0.39	0.43	1.46	0.82	2.28
Total	**0.74**	**0.67**	**0.24**	**0.44**	**0.50**	**2.03**	**1.44**	**3.46**

Table B: 25 Papua New Guinea, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.00	-	-	-	-	1.07	0.01	1.08
Oil & gas international trade	0.60	0.98	-	-	-	5.10	-	5.10
Oil & gas domestic pipelines	-	-	-	-	-	-	-	-
Electricity generation & transmission	0.27	0.12	0.12	0.12	0.12	0.62	0.46	1.08
Total	**0.87**	**1.10**	**0.12**	**0.12**	**0.12**	**6.79**	**0.47**	**7.26**

Table B: 26 Papua New Guinea, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.00	-	-	-	-	0.67	0.01	0.67
Oil & gas international trade	0.60	0.98	-	-	-	5.10	-	5.10
Oil & gas domestic pipelines	-	-	-	-	-	-	-	-
Electricity generation & transmission	0.23	0.10	0.10	0.10	0.11	0.54	0.40	0.93
Total	**0.84**	**1.08**	**0.10**	**0.10**	**0.11**	**6.30**	**0.40**	**6.71**

Table B: 27 Peru, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.18	0.15	0.31	0.38	0.27	3.71	3.83	7.54
Oil & gas international trade	0.01	0.65	0.00	0.40	0.40	2.92	3.20	6.12
Oil & gas domestic pipelines	0.08	0.15	0.30	0.33	0.08	2.65	2.24	4.89
Electricity generation & transmission	0.18	0.59	0.17	0.35	0.55	2.99	3.57	6.57
Total	**0.45**	**1.54**	**0.79**	**1.46**	**1.31**	**12.27**	**12.85**	**25.12**

Table B: 28 Peru, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.12	0.11	0.21	0.25	0.19	2.47	2.52	4.99
Oil & gas international trade	0.00	0.65	0.00	0.40	0.40	2.91	3.20	6.12
Oil & gas domestic pipelines	0.06	0.11	0.21	0.23	0.05	1.86	1.57	3.43
Electricity generation & transmission	0.16	0.50	0.15	0.30	0.47	2.55	3.06	5.61
Total	**0.34**	**1.36**	**0.57**	**1.18**	**1.12**	**9.79**	**10.35**	**20.14**

Table B: 29 Philippines, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.03	-	-	-	0.37	0.02	0.39
Oil & gas production, processing, petrochemical	0.13	0.09	0.40	0.47	0.56	5.18	4.82	10.00
Oil & gas international trade	0.00	0.01	0.01	0.39	0.16	0.08	2.53	2.61
Oil & gas domestic pipelines	0.01	0.00	0.06	0.08	0.09	0.34	0.79	1.13
Electricity generation & transmission	0.54	0.15	0.65	3.70	2.88	4.29	22.80	27.08
Total	**0.69**	**0.29**	**1.11**	**4.64**	**3.69**	**10.26**	**30.95**	**41.21**

Table B: 30 Philippines, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	0.03	-	-	-	0.29	0.01	0.30
Oil & gas production, processing, petrochemical	0.09	0.06	0.27	0.32	0.38	3.36	3.24	6.60
Oil & gas international trade	0.00	0.01	0.00	0.37	0.14	0.03	2.32	2.35
Oil & gas domestic pipelines	0.01	0.00	0.04	0.05	0.07	0.24	0.55	0.79
Electricity generation & transmission	0.45	0.12	0.55	3.17	2.47	3.62	19.61	23.22
Total	**0.54**	**0.21**	**0.87**	**3.91**	**3.06**	**7.54**	**25.73**	**33.27**

Table B: 31 Russia, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	2.78	0.94	0.70	0.86	0.83	12.55	8.67	21.22
Oil & gas production, processing, petrochemical	11.49	7.76	8.83	6.89	6.41	84.41	61.47	145.88
Oil & gas international trade	12.83	5.62	1.85	0.31	0.31	50.13	3.10	53.23
Oil & gas domestic pipelines	13.50	8.49	9.26	10.34	9.63	99.71	99.57	199.28
Electricity generation & transmission	1.79	10.14	10.17	16.53	17.28	99.02	170.52	269.54
Total	**42.39**	**32.94**	**30.81**	**34.93**	**34.46**	**345.82**	**343.33**	**689.15**

Table B: 32 Russia, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	2.18	0.74	0.55	0.67	0.65	9.86	6.81	16.67
Oil & gas production, processing, petrochemical	7.43	5.01	5.68	4.51	4.20	54.56	40.34	94.90
Oil & gas international trade	10.47	4.89	1.53	0.28	0.28	42.53	2.77	45.30
Oil & gas domestic pipelines	9.45	5.94	6.48	7.24	6.74	69.80	69.70	139.49
Electricity generation & transmission	1.50	8.69	8.68	13.27	13.80	84.62	136.66	221.29
Total	**31.03**	**25.28**	**22.92**	**25.98**	**25.67**	**261.37**	**256.29**	**517.66**

Table B: 33 Singapore, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	2.06	0.83	0.96	1.16	1.15	10.86	11.18	22.03
Oil & gas international trade	1.09	1.28	0.83	0.40	0.57	10.06	4.56	14.62
Oil & gas domestic pipelines	-	0.26	-	-	-	1.59	-	1.59
Electricity generation & transmission	0.48	0.44	0.48	0.67	0.44	4.28	5.67	9.96
Total	**3.62**	**2.81**	**2.27**	**2.22**	**2.16**	**26.79**	**21.41**	**48.20**

Table B: 34 Singapore, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	1.40	0.58	0.66	0.80	0.81	7.43	7.74	15.18
Oil & gas international trade	0.56	0.82	0.47	0.31	0.44	5.65	3.66	9.31
Oil & gas domestic pipelines	-	0.18	-	-	-	1.11	-	1.11
Electricity generation & transmission	0.41	0.38	0.41	0.58	0.38	3.70	4.90	8.60
Total	**2.38**	**1.96**	**1.54**	**1.69**	**1.63**	**17.89**	**16.30**	**34.19**

Table B: 35 Chinese Taipei, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.74	0.47	0.54	0.53	0.51	5.55	5.30	10.85
Oil & gas international trade	0.10	0.09	0.17	-	-	2.53	1.25	3.78
Oil & gas domestic pipelines	0.04	0.03	0.05	0.06	0.07	0.42	0.60	1.02
Electricity generation & transmission	3.74	6.71	2.40	5.15	5.14	24.73	28.18	52.91
Total	**4.62**	**7.30**	**3.17**	**5.75**	**5.73**	**33.22**	**35.34**	**68.56**

Table B: 36 Chinese Taipei, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	-	-	-	-	-	-	-	-
Oil & gas production, processing, petrochemical	0.52	0.33	0.38	0.38	0.36	3.89	3.72	7.61
Oil & gas international trade	0.04	0.04	0.12	-	-	1.49	1.00	2.50
Oil & gas domestic pipelines	0.03	0.02	0.03	0.04	0.05	0.29	0.42	0.71
Electricity generation & transmission	3.21	5.33	2.06	3.98	3.99	20.33	23.22	43.54
Total	**3.80**	**5.72**	**2.59**	**4.40**	**4.40**	**26.00**	**28.36**	**54.36**

Table B: 37 Thailand, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.03	0.01	0.05	-	-	0.30	0.05	0.36
Oil & gas production, processing, petrochemical	0.76	2.06	1.76	2.20	2.33	15.19	21.77	36.96
Oil & gas international trade	1.74	0.44	0.02	0.18	0.24	6.89	1.77	8.66
Oil & gas domestic pipelines	0.21	0.26	0.36	0.45	0.54	3.02	4.62	7.64
Electricity generation & transmission	2.68	0.98	1.78	3.88	4.14	15.53	34.31	49.84
Total	**5.42**	**3.75**	**3.97**	**6.72**	**7.25**	**40.93**	**62.52**	**103.46**

Table B: 38 Thailand, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.02	0.00	0.04	-	-	0.24	0.04	0.28
Oil & gas production, processing, petrochemical	0.52	1.36	1.22	1.53	1.62	10.35	15.15	25.50
Oil & gas international trade	0.00	0.00	0.01	0.01	0.01	0.02	0.06	0.09
Oil & gas domestic pipelines	0.15	0.19	0.26	0.32	0.38	2.11	3.23	5.35
Electricity generation & transmission	2.28	0.84	1.51	3.32	3.53	13.21	29.21	42.43
Total	**2.96**	**2.39**	**3.03**	**5.17**	**5.53**	**25.94**	**47.70**	**73.64**

Table B: 39 United States, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	3.23	0.73	0.90	0.15	0.28	10.80	1.93	12.73
Oil & gas production, processing, petrochemical	17.82	9.79	11.48	11.77	12.04	114.74	116.16	230.90
Oil & gas international trade	7.67	2.81	3.72	3.21	3.24	37.51	31.06	68.57
Oil & gas domestic pipelines	27.29	12.61	14.61	13.20	13.49	152.59	129.49	282.08
Electricity generation & transmission	0.03	3.12	8.11	13.25	9.48	55.66	112.10	167.75
Total	**56.04**	**29.06**	**38.82**	**41.59**	**38.53**	**371.29**	**390.74**	**762.03**

Table B: 40 United States, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	2.53	0.57	0.71	0.12	0.22	8.48	1.52	10.00
Oil & gas production, processing, petrochemical	12.51	6.85	8.03	8.15	8.34	80.33	80.37	160.70
Oil & gas international trade	4.42	1.82	2.30	2.02	2.03	23.46	19.59	43.05
Oil & gas domestic pipelines	19.10	8.83	10.23	9.24	9.45	106.81	90.64	197.46
Electricity generation & transmission	0.03	2.56	6.87	11.22	8.07	46.29	95.21	141.49
Total	**38.60**	**20.63**	**28.14**	**30.75**	**28.10**	**265.37**	**287.33**	**552.70**

Table B: 41 Viet Nam, High Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.14	0.09	0.10	0.09	0.09	0.97	0.86	1.83
Oil & gas production, processing, petrochemical	1.13	0.88	1.10	0.37	1.23	10.81	7.61	18.42
Oil & gas international trade	0.44	-	-	0.01	0.02	1.34	0.11	1.45
Oil & gas domestic pipelines	-	0.11	0.06	0.08	0.05	0.85	0.63	1.48
Electricity generation & transmission	2.58	1.23	1.69	2.06	1.38	16.67	19.12	35.79
Total	**4.30**	**2.31**	**2.95**	**2.60**	**2.77**	**30.64**	**28.32**	**58.96**

Table B: 42 Viet Nam, Low Case (Billion 1999 US$)

Sectors	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
Coal production & transportation	0.11	0.07	0.08	0.07	0.07	0.76	0.67	1.43
Oil & gas production, processing, petrochemical	0.71	0.56	0.70	0.24	0.78	6.87	4.88	11.75
Oil & gas international trade	0.44	-	-	0.00	0.01	1.32	0.04	1.36
Oil & gas domestic pipelines	-	0.07	0.05	0.05	0.03	0.60	0.44	1.04
Electricity generation & transmission	2.20	1.05	1.44	1.76	1.19	14.25	16.37	30.62
Total	**3.46**	**1.76**	**2.26**	**2.13**	**2.09**	**23.79**	**22.41**	**46.20**

ENERGY INVESTMENT OUTLOOK ALTERNATIVE SCENARIOS

Table C: 1 Alternative Supply Case: Electricity Generation & Transmission, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**12.42**	**28.82**	**44.73**	**54.12**	**69.61**	**373.01**	**585.16**	**958.17**
Latin America	**1.51**	**2.90**	**9.45**	**8.43**	**9.57**	**49.01**	**86.77**	**135.78**
Chile	0.00	0.00	1.69	1.96	2.76	6.82	21.84	28.66
Mexico	1.33	2.31	7.59	6.12	6.39	39.20	61.41	100.61
Peru	0.18	0.59	0.17	0.35	0.43	2.99	3.52	6.51
North America	**0.03**	**6.80**	**9.11**	**14.75**	**12.71**	**76.82**	**132.77**	**209.59**
Canada	0.00	3.68	3.17	3.47	4.37	28.46	34.66	63.12
United States	0.03	3.12	5.94	11.27	8.34	48.36	98.11	146.47
Northeast Asia	**6.81**	**22.13**	**17.32**	**21.96**	**21.15**	**156.14**	**193.83**	**349.97**
Hong Kong, China	0.28	0.16	0.45	0.75	0.86	3.42	6.83	10.26
Japan	2.79	11.78	3.87	7.83	7.55	65.06	80.36	145.42
Korea	0.00	3.47	11.88	8.58	7.73	64.01	79.81	143.82
Chinese Taipei	3.74	6.72	1.13	4.80	5.01	23.65	26.82	50.47
Southeast Asia	**9.59**	**10.38**	**11.99**	**10.62**	**17.99**	**84.13**	**136.53**	**220.66**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.12	0.21	0.16	0.37
Indonesia	3.30	4.82	5.36	0.00	5.91	22.26	37.70	59.95
Malaysia	0.00	2.45	2.41	1.95	2.78	18.21	19.79	38.00
Philippines	0.54	0.31	0.34	3.28	3.10	5.25	22.37	27.63
Singapore	0.48	0.45	0.48	0.68	0.45	4.35	5.74	10.09
Thailand	2.68	0.98	2.09	2.48	3.50	17.14	31.01	48.14
Viet Nam	2.58	1.37	1.30	2.22	2.13	16.72	19.76	36.47
Oceania	**1.12**	**1.14**	**1.31**	**1.81**	**2.32**	**11.20**	**14.07**	**25.27**
Australia	0.00	0.29	0.95	1.20	1.23	8.57	11.70	20.27
New Zealand	0.77	0.73	0.24	0.49	0.96	1.86	1.77	3.63
Papua New Guinea	0.35	0.12	0.12	0.12	0.12	0.77	0.60	1.37
Russia	**1.79**	**8.07**	**9.85**	**16.62**	**16.20**	**86.48**	**167.64**	**254.13**
Total	**33.28**	**80.24**	**103.77**	**128.30**	**149.55**	**836.80**	**1316.77**	**2153.57**

Table C: 2 Alternative Supply Case: Electricity Generation & Transmission, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total	Total	Total

						2000-2010	2011-2020	2000-2020
China	**10.02**	**23.82**	**37.18**	**45.03**	**57.28**	**309.02**	**483.36**	**792.39**
Latin America	**1.27**	**2.41**	**7.91**	**7.07**	**8.04**	**40.93**	**72.75**	**113.67**
Chile	0.00	0.00	1.45	1.67	2.35	5.78	18.61	24.39
Mexico	1.11	1.92	6.32	5.10	5.33	32.65	51.19	83.83
Peru	0.15	0.49	0.14	0.29	0.36	2.50	2.95	5.45
North America	**0.03**	**5.64**	**7.67**	**12.43**	**10.63**	**62.97**	**111.99**	**174.95**
Canada	0.00	3.09	2.63	2.89	3.55	22.85	28.70	51.56
United States	0.03	2.56	5.04	9.54	7.08	40.11	83.28	123.40
Northeast Asia	**5.55**	**17.25**	**13.57**	**16.84**	**16.75**	**123.48**	**152.55**	**276.03**
Hong Kong, China	0.23	0.14	0.38	0.63	0.71	2.90	5.73	8.62
Japan	2.16	8.96	3.07	5.96	6.14	50.42	62.64	113.06
Korea	0.00	2.91	9.19	6.65	6.11	51.16	62.24	113.39
Chinese Taipei	3.16	5.23	0.94	3.60	3.79	19.01	21.94	40.95
Southeast Asia	**8.01**	**8.69**	**10.00**	**8.86**	**15.01**	**70.32**	**114.18**	**184.50**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.10	0.17	0.14	0.31
Indonesia	2.77	4.04	4.49	0.00	4.96	18.64	31.63	50.27
Malaysia	0.00	2.05	2.00	1.63	2.29	15.23	16.52	31.75
Philippines	0.44	0.25	0.28	2.75	2.57	4.35	18.81	23.16
Singapore	0.41	0.38	0.41	0.58	0.38	3.68	4.85	8.53
Thailand	2.23	0.82	1.73	2.04	2.91	14.24	25.65	39.89
Viet Nam	2.16	1.15	1.09	1.86	1.79	14.01	16.58	30.60
Oceania	**0.94**	**0.95**	**1.09**	**1.52**	**1.95**	**9.31**	**11.75**	**21.06**
Australia	0.00	0.23	0.79	1.01	1.03	7.11	9.77	16.88
New Zealand	0.64	0.61	0.20	0.41	0.81	1.56	1.47	3.03
Papua New Guinea	0.30	0.10	0.10	0.10	0.10	0.65	0.50	1.15
Russia	**1.47**	**6.75**	**8.24**	**13.06**	**12.56**	**72.13**	**131.10**	**203.23**
Total	**27.30**	**65.51**	**85.66**	**104.81**	**122.22**	**688.16**	**1077.67**	**1765.83**

Table C: 3Alternative Demand Case: Electricity Generation & Transmission, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**12.42**	**33.96**	**41.68**	**53.66**	**61.14**	**365.76**	**539.62**	**905.38**
Latin America	**1.51**	**2.88**	**7.72**	**6.61**	**7.88**	**43.29**	**71.27**	**114.56**
Chile	0.00	0.00	0.96	1.70	2.43	5.33	18.24	23.57
Mexico	1.32	2.29	6.58	4.83	5.10	34.97	50.26	85.23
Peru	0.18	0.59	0.17	0.08	0.35	2.99	2.77	5.76
North America	**0.03**	**6.70**	**1.88**	**6.66**	**2.94**	**45.05**	**46.77**	**91.82**
Canada	0.00	3.58	1.87	2.25	2.31	24.75	22.12	46.87
United States	0.03	3.12	0.00	4.40	0.63	20.30	24.65	44.95
Northeast Asia	**6.81**	**21.96**	**12.83**	**15.13**	**10.44**	**148.04**	**118.07**	**266.11**
Hong Kong, China	0.28	0.00	0.38	0.55	0.49	2.16	3.53	5.69
Japan	2.79	11.78	3.87	6.33	2.51	65.06	50.20	115.26
Korea	0.00	3.47	8.35	3.66	3.38	58.26	42.67	100.93
Chinese Taipei	3.74	6.71	0.24	4.60	4.06	22.56	21.68	44.24
Southeast Asia	**9.98**	**10.21**	**10.45**	**10.98**	**14.89**	**78.88**	**124.38**	**203.25**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.20
Indonesia	3.70	4.92	5.39	0.00	5.54	22.16	35.18	57.35
Malaysia	0.00	2.45	1.82	1.64	1.93	18.83	19.48	38.31
Philippines	0.54	0.15	0.03	3.49	2.26	3.67	19.33	22.99
Singapore	0.48	0.48	0.48	0.76	0.44	3.81	4.72	8.53
Thailand	2.68	0.98	1.78	3.41	3.93	14.85	28.60	43.45
Viet Nam	2.58	1.23	0.95	1.69	0.80	15.35	17.06	32.42
Oceania	**1.25**	**1.28**	**0.96**	**1.12**	**1.92**	**11.86**	**8.74**	**20.61**
Australia	0.21	0.43	0.63	0.55	1.29	9.59	7.49	17.08
New Zealand	0.77	0.73	0.21	0.45	0.51	1.71	0.95	2.66
Papua New Guinea	0.27	0.12	0.12	0.12	0.12	0.57	0.30	0.87
Russia	**1.79**	**8.35**	**9.12**	**13.81**	**12.96**	**89.93**	**140.82**	**230.75**
Total	**33.79**	**85.33**	**84.63**	**107.96**	**112.17**	**782.81**	**1049.67**	**1832.48**

Table C: 4 Alternative Demand Case: Electricity Generation & Transmission, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**10.02**	**28.15**	**34.63**	**44.69**	**50.89**	**303.01**	**448.98**	**752.00**
Latin America	**1.27**	**2.40**	**6.45**	**5.55**	**6.63**	**36.12**	**59.88**	**96.00**
Chile	0.00	0.00	0.82	1.45	2.08	4.51	15.60	20.10
Mexico	1.11	1.91	5.49	4.03	4.26	29.11	41.96	71.08
Peru	0.15	0.49	0.14	0.07	0.29	2.50	2.32	4.82
North America	**0.03**	**5.56**	**1.55**	**5.62**	**2.51**	**36.19**	**39.73**	**75.91**
Canada	0.00	3.00	1.55	1.87	1.92	19.80	18.34	38.14
United States	0.03	2.56	0.00	3.75	0.60	16.39	21.38	37.77
Northeast Asia	**5.55**	**17.10**	**9.98**	**11.75**	**8.19**	**116.84**	**92.72**	**209.57**
Hong Kong, China	0.23	0.00	0.32	0.45	0.39	1.81	2.86	4.67
Japan	2.16	8.96	3.07	4.78	1.96	50.42	38.08	88.50
Korea	0.00	2.91	6.40	3.08	2.84	46.51	34.48	80.99
Chinese Taipei	3.15	5.22	0.20	3.44	3.00	18.11	17.30	35.41
Southeast Asia	**8.35**	**8.55**	**8.74**	**9.21**	**12.48**	**66.00**	**104.30**	**170.30**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.17
Indonesia	3.11	4.13	4.52	0.00	4.65	18.56	29.53	48.10
Malaysia	0.00	2.05	1.52	1.37	1.60	15.78	16.32	32.10
Philippines	0.44	0.11	0.02	2.93	1.90	3.02	16.29	19.32
Singapore	0.40	0.40	0.40	0.64	0.37	3.22	4.00	7.22
Thailand	2.23	0.82	1.48	2.86	3.27	12.38	23.83	36.21
Viet Nam	2.16	1.03	0.80	1.42	0.68	12.87	14.33	27.19
Oceania	**1.04**	**1.07**	**0.81**	**0.94**	**1.61**	**9.91**	**7.33**	**17.25**
Australia	0.17	0.35	0.52	0.46	1.08	8.00	6.28	14.28
New Zealand	0.64	0.61	0.18	0.38	0.43	1.44	0.80	2.24
Papua New Guinea	0.23	0.10	0.10	0.10	0.10	0.48	0.25	0.73
Russia	**1.47**	**7.03**	**7.67**	**10.75**	**9.92**	**75.71**	**109.23**	**184.93**
Total	**27.73**	**69.86**	**69.83**	**88.51**	**92.24**	**643.79**	**862.17**	**1505.95**

Table C: 5 Combined Supply-Demand Case: Electricity Generation & Transmission, High Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**12.42**	**24.26**	**39.81**	**49.20**	**59.41**	**344.95**	**516.77**	**861.71**
Latin America	**1.51**	**2.90**	**7.59**	**8.17**	**6.92**	**44.57**	**72.52**	**117.08**
Chile	0.00	0.00	0.98	1.96	2.05	5.40	19.08	24.48
Mexico	1.33	2.31	6.43	6.12	4.51	36.17	50.58	86.76
Peru	0.18	0.59	0.17	0.08	0.36	2.99	2.85	5.85
North America	**0.03**	**6.80**	**2.12**	**6.89**	**3.01**	**46.65**	**48.42**	**95.07**
Canada	0.00	3.68	2.11	2.71	2.38	26.35	24.91	51.26
United States	0.03	3.12	0.00	4.19	0.63	20.30	23.51	43.81
Northeast Asia	**6.81**	**21.97**	**12.89**	**16.53**	**12.11**	**148.35**	**133.10**	**281.44**
Hong Kong, China	0.28	0.00	0.38	0.55	0.58	2.16	3.53	5.69
Japan	2.79	11.78	3.87	7.83	3.46	65.06	64.49	129.55
Korea	0.00	3.47	8.36	3.88	3.90	58.31	43.71	102.02
Chinese Taipei	3.74	6.72	0.29	4.27	4.17	22.81	21.37	44.18
Southeast Asia	**9.59**	**10.41**	**12.20**	**9.07**	**14.84**	**82.01**	**116.64**	**198.65**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.02	0.21	0.06	0.26
Indonesia	3.30	4.82	5.36	0.00	4.70	22.26	29.30	51.56
Malaysia	0.00	2.45	2.09	1.64	2.46	19.10	20.01	39.11
Philippines	0.54	0.31	0.34	3.50	2.54	5.25	18.61	23.87
Singapore	0.48	0.48	0.48	0.48	0.45	3.87	4.79	8.66
Thailand	2.68	0.98	2.09	1.23	3.29	15.40	26.69	42.10
Viet Nam	2.58	1.37	1.83	2.22	1.39	15.92	17.17	33.10
Oceania	**1.04**	**1.14**	**0.96**	**1.46**	**1.90**	**10.65**	**7.75**	**18.40**
Australia	0.00	0.29	0.60	0.85	0.81	8.22	5.68	13.90
New Zealand	0.77	0.73	0.24	0.49	0.96	1.86	1.77	3.63
Papua New Guinea	0.27	0.12	0.12	0.12	0.12	0.57	0.30	0.87
Russia	**1.79**	**6.57**	**7.60**	**13.43**	**13.38**	**72.43**	**136.05**	**208.48**
Total	**33.20**	**74.06**	**83.17**	**104.75**	**111.58**	**749.60**	**1031.24**	**1780.84**

Table C: 6 Combined Supply-Demand Case: Electricity Generation & Transmission, Low Case (Billion 1999 US$)

Region/Economy	2000	2005	2010	2015	2020	Total 2000-2010	Total 2011-2020	Total 2000-2020
China	**10.02**	**19.98**	**33.04**	**40.89**	**48.69**	**285.40**	**425.82**	**711.22**
Latin America	**1.27**	**2.41**	**6.34**	**6.84**	**5.80**	**37.17**	**60.72**	**97.89**
Chile	0.00	0.00	0.84	1.67	1.74	4.56	16.24	20.80
Mexico	1.11	1.92	5.36	5.10	3.75	30.11	42.09	72.20
Peru	0.15	0.49	0.14	0.07	0.31	2.50	2.39	4.89
North America	**0.03**	**5.64**	**1.75**	**5.80**	**2.54**	**37.46**	**40.87**	**78.33**
Canada	0.00	3.09	1.74	2.24	1.96	21.07	20.55	41.62
United States	0.03	2.56	0.00	3.56	0.58	16.39	20.32	36.71
Northeast Asia	**5.55**	**17.11**	**10.03**	**12.82**	**9.52**	**117.09**	**104.38**	**221.47**
Hong Kong, China	0.23	0.00	0.32	0.45	0.46	1.81	2.89	4.69
Japan	2.16	8.96	3.07	5.96	2.71	50.42	49.32	99.74
Korea	0.00	2.91	6.41	3.25	3.26	46.56	35.17	81.73
Chinese Taipei	3.16	5.23	0.24	3.16	3.09	18.31	17.01	35.32
Southeast Asia	**8.01**	**8.72**	**10.18**	**7.56**	**12.37**	**68.56**	**97.47**	**166.04**
Brunei Darussalam	0.00	0.00	0.00	0.00	0.01	0.17	0.04	0.22
Indonesia	2.77	4.04	4.49	0.00	3.94	18.64	24.58	43.22
Malaysia	0.00	2.05	1.73	1.37	2.03	15.99	16.75	32.74
Philippines	0.44	0.25	0.28	2.93	2.10	4.35	15.64	19.99
Singapore	0.41	0.41	0.41	0.41	0.38	3.27	4.05	7.32
Thailand	2.23	0.82	1.73	0.98	2.73	12.78	22.00	34.79
Viet Nam	2.16	1.15	1.54	1.86	1.18	13.35	14.41	27.77
Oceania	**0.87**	**0.95**	**0.80**	**1.22**	**1.59**	**8.85**	**6.44**	**15.29**
Australia	0.00	0.23	0.49	0.71	0.68	6.81	4.71	11.53
New Zealand	0.64	0.61	0.20	0.41	0.81	1.56	1.47	3.03
Papua New Guinea	0.23	0.10	0.10	0.10	0.10	0.48	0.25	0.73
Russia	**1.47**	**5.49**	**6.34**	**10.38**	**10.20**	**60.31**	**104.55**	**164.86**
Total	**27.23**	**60.31**	**68.47**	**85.51**	**90.71**	**614.85**	**840.26**	**1455.11**