ASIA PACIFIC ENERGY RESEARCH CENTRE

ELECTRICITY SECTOR DEREGULATION

IN THE APEC REGION

MARCH 2000

Disclaimer

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FOREWORD

I am pleased to present the final report of the study, Electricity Sector Deregulation in the Asia Pacific Region. After completing the APEC Energy Demand and Supply Outlook in March 1998 and the September 1998 Update to the Outlook, APERC focused on the six research themes designated by the APEC Energy Working Group, including this Electricity Sector Deregulation study.

The objective of the study is to evaluate electricity sector reform processes in APEC member economies, in an effort to provide a useful description and analysis of the growing trend of deregulation and privatisation of electricity supply. Some of the more developed economies, such as Australia, New Zealand and the United States of America are now well on the way towards fully competitive wholesale and retail electricity markets as are one or two emerging economies (such as Chile and Singapore). Some emerging economies, such as Korea and Malaysia, have well advanced plans, and are beginning to implement reform. What is striking is the fact that virtually all APEC member economies have some kind of electricity sector reform in mind, with a view to optimising the economic performance of the sector.

The principal findings of the study are highlighted in the executive summary of this report.

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 of individual member economies.

Finally, I would like to thank all those who have been involved in this major and I believe successful exercise including the staff at the Centre, both professional and administrative, the experts who have helped us through our conferences and workshops, and many others who have provided interesting and useful comments. I hope this report will be useful to a wide audience.

Keiichi Yokobori
President
Asia Pacific Energy Research Centre

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We wish to express our appreciation to the APERC Conference and Workshop participants who met with us and provided invaluable insights into the issues they face in electricity deregulation and to the former researchers Mohammed Noer Hidayat, Dr Jung-Hua Wu and Lilian Fernandez for their support.

We also thank all members of the APEC Energy Working Group (EWG), APEC Expert Group on Energy Data and Analysis (EGEDA), APERC Advisory Board and other government officials for their stimulating comments and assistance with the study. Our thanks go also to the APERC administrative staff for their help in administration and publication of this report.

APERC would particularly like to express thanks to Dr David Cope for the large amount of work he put into writing and editing this draft report, as well as contributing analysis.

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ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
ADB	Asian Development Bank
AEEMTRC	ASEAN-EC Energy Management Training and Research Centre
AFTA	ASEAN Free Trade Agreement
AIT	Asian Institute of Technology
ALFC	Automatic Load-Frequency Control
APEC	Asia-Pacific Economic Co-operation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
AVR	Automatic Voltage Regulator
BAU	Business-as-usual
BOO	Build-Own-Operate
BOT	Build-Operate-Transfer
CBD	Central Business District
CCGT	Combined Cycle Gas Turbine
CDEC	The Economic Dispatch Load Centre (Chile)
CEC	China Electric Council
CH_4	Methane
CLP	China Light and Power Holding
CNE	National Energy Commission of Chile
CNG	Compressed natural gas
CO_2	Carbon dioxide
CPI	Consumer Price Index
DES	Department of Electrical Services (Brunei Darussalam)
DSM	Demand Side Management
EAERF	East Asian Electricity Regulatory Forum
EC	European Community
ECA	Export Credit Agency
ECC	Energy Control Centre
ECNZ	Electricity Corporation of New Zealand
EDMC	Energy Data and Modelling Centre (Japan)
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration (USA)
EMCO	The Electricity Market Company Ltd (Australia)
ENDESA	Empresa Nacional de Electricidad (Chile)
EPDC	Electric Power Development Company (Japan)
ESM	Energy Secretariat of Mexico
ESANZ	Electricity Supply Association of New Zealand
ETF	Electricity Task Force (New Zealand)
ETSA	Electricity Trust of South Australia
EUIC	Electricity Utility Industry Council (Japan)
EVN	Electricity Corporation of Viet Nam
EWG	Energy Working Group (APEC)
FAO	Food and Agriculture Organisation
FCCC	Framework Convention on Climate Change
FEC	Final energy consumption
FERC	Federal Energy Regulatory Commission (USA)
FGD	Flue-gas de-sulphurisation
FNDR	National Fund for Regional Development (Chile)
GDP	Gross domestic product

GHG	Greenhouse gas
GW	Gigawatt (10^9 Watts)
GWh	Gigawatt hour (one million kilowatt hours)
HEC	Hong Kong Electric Company
IBRD	International Bank for Reconstruction and Development
IEA	International Energy Agency
IEEJ	Institute of Energy Economics of Japan
IGSO	Independent Grid System Operator (Malaysia)
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IRP	Integrated Resources Planning
ISO	Independent System Operator
JAPC	Japan Atomic Power Company
kcal	Kilo calories
KEEI	Korea Energy Economics Institute
KEPCO	Korea Electric Power Company
KV	Kilovolt (= 1,000 volts)
kW	Kilowatt (= 1,000 watts)
kWh	Kilowatt hour (= 1,000 watts hour)
ktoe	Kilo tonnes of oil equivalent
LBNL	Lawrence Berkeley National Laboratory
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRMC	Long run marginal cost
MARIA	Metering and Reconciliation Information Agreement
MEA	Ministry of Economic Affairs
MEA	Municipal Electricity Authority
MEGABARE	ABARE's global energy model
MERALCO	Manila Electric Company
MITI	Ministry of International Trade and Industry (Japan)
MOCIE	Ministry of Commerce, Industry and Energy (Korea)
MODB	Ministry of Development, Brunei Darussalam
MoIV	Ministry of Industry of Viet Nam
MtC	Million tonnes of carbon
Mtcoe	Million metric tonnes of standard coal equivalent
Mtoe	Million tonnes of oil equivalent
MW	Megawatts (= 1,000 kilowatts)
MWh	Megawatts hour (= 1,000 kilowatts hours)
NEB	National Electricity Board (Malaysia)
NEC	National Electricity Code (Australia)
NEM	National Electricity Market (Australia)
NEMMCo	National Electricity Market Management Company (Australia)
NEPC	National Energy Policy Council (Thailand)
NEPO	National Energy Policy Office (Thailand)
NGCC	Natural gas combined cycle
NGMC	National Grid Management Council (Australia)
NO_X	Nitrogen oxides
NPC	National Power Company (Philippines)
NRC	Natural Resources Canada
NSW	New South Wales
NZEM	New Zealand Electricity Market
OECF	Overseas Economic Cooperation Fund (Japan)
OECD	Organisation for Economic Cooperation and Development

OLADE	Organizacion Latinoamericana de Energia (Latin America)
OPEC	Organisation of Petroleum Exporting Countries
pa	per annum
PDP	Power Development Program
PEA	Provincial Electricity Authority (Thailand)
PER	Rural Electrification Program (Chile)
Phil/DOE	Department of Energy (Philippines)
PLN	Perusahaan Listrik Negara
PNG	Papua New Guinea
PPA	Power Purchase Agreement
PUB	Public Utilities Board (Singapore)
PURPA	Public Utility Regulatory Policies Act (USA)
PPP	Purchasing Power Parity
PV	Photovoltaic
QTSC	Queensland Transmission and Supply Corporation
RAO	Russian Joint Stock Company
SESB	Sabah Electricity Sdn. Bhd
SESCO	Sarawak Electricity Supply Company
SEP	Singapore Electric Pool
SOE	State-Owned Enterprise
SO_X	Sulphur oxide
SPC	State Planning Commission (China)
SPCC	State Power Corporation of China
SPP	Small Power Producer
SRMC	Short run marginal cost
TEPCO	Tokyo Electric Power Company
TNB	Tenaga Nasional Berhad (Malaysia)
TPEC	Total primary energy consumption (supply)
TWh	Terawatt hour
UES	Unified Energy System of Russia
UN	United Nations
US	United States (of America)
US DOE	United States Department of Energy

PREFACE

RATIONALE FOR THE STUDY

At their meeting in Okinawa in October 1998, Energy Ministers *"stressed the importance of promoting private sector participation in infrastructure development in those areas permitted by their respective legal frameworks, and re-emphasised the need for a predictable, transparent institutional and regulatory framework to enhance the investment climate."*

A study of electricity reform processes in individual APEC economies is also compatible with the 14 non-binding energy principles endorsed by APEC Energy Ministers at their meeting in Sydney in 1996.

> *Article 3: "Pursue open energy markets for achieving rational energy consumption, energy security and environmental objectives, recommending action in the appropriate forum of APEC to remove impediments to the achievement of these ends."*
>
> *Article 4: "Recognise that measures to facilitate the rational consumption of energy might involve a mix of market based and regulatory policies, with the relative components of the mix being a matter for the judgement of individual economies."*

A similar set of principles is contained in the Manual of Best Practice Principles for Independent Power Producers, which cover institutional and regulatory structures, tender/bid processes and evaluation criteria, power purchase agreements and associated tariff situation and financing.

OBJECTIVES OF THE STUDY

The objectives of this study are: to evaluate deregulation and privatisation processes in APEC member economies; examine key economic, social and environmental factors that play important roles in changing the landscape of the electricity sector and provide concrete case studies of electricity sector restructuring in some selected APEC member economies.

This study is relevant to all twenty-one APEC member economies, including new members that joined in 1998 (Peru, the Russian Federation and Viet Nam). The study also examines the effect of the 1997 financial crisis on the process of deregulation and privatisation in some Asian economies.

EXECUTIVE SUMMARY

REVIEW OF THE ELECTRICITY SECTOR

Rapid economic expansion in the Asia Pacific region over recent years has led to a large growth in demand for electricity. In much of the APEC region, demand growth has put a severe strain on the ability of individual economies to expand the electricity infrastructure capacity rapidly enough to meet the surge in demand.

The proportion of the population with access to electricity varies widely throughout the APEC region. The per capita consumption of electricity also varies tremendously. For example, at one end of the spectrum, the US is almost 100 percent electrified and per capita electricity consumption is nearly 14,000 kWh, while Indonesia is only about 55 percent electrified and per capita electricity consumption is under 400 kWh.

Coal is currently, and is likely to remain, the dominant fuel for electricity generation in much of the Asia Pacific region. Natural gas and hydropower will increase in importance, and nuclear energy is being promoted by a number of economies requiring large additions of base-load capacity.

Historically, electricity has been viewed as a national strategic asset best provided by a vertically-integrated monopoly, usually owned and directly controlled by the state. Even in cases where the monopoly provider was private (as in the US from the earliest days of the industry), the state still maintained tight control through heavy-handed regulatory policies and measures.

This approach has now been widely rejected, at least in principle. Over the last two decades, the old idea that electric power generation, transmission and distribution represent a “natural monopoly” best handled centrally, has given way to a general consensus among policy-makers, regulators, industry analysts and economists that the generation and retailing elements of the power supply industry would be more efficiently delivered by firms operating in freely competitive energy markets.

FORCES FOR CHANGE

A number of important factors have contributed to the far-reaching changes in global electricity markets we are now seeing. The history of recent economic reform in general, and of electricity sector reform in particular, can be traced back to the OPEC oil embargo in the mid 1970s. This led to a sharp rise in the price of oil, which had many social and economic ramifications. In the early and mid 1980s, in reaction to high oil prices and fears about economic scarcity, a large effort was made by oil exploration companies worldwide to discover new reserves. For the electricity industry, the importance of this lay not in discoveries of new reserves of oil, but in the discovery of enormous amounts of natural gas. This in turn has led to the development of higher efficiency gas turbines to make use of some of this gas in the generation of power at prices that have allowed gas to compete strongly with other fuels, such as coal.

One of the key ramifications of the oil embargo was the economic impact on economies worldwide. In the early 1980s, even highly developed nations were in economic crisis, leading to a widespread wave of economic reform. States were faced with the realisation that limited state financial resources were insufficient to meet the need for infrastructural and other investment, as well as other demands on the state purse. The New Neo-classical economic theory (Becker and Becker, 1997) emerging in the early 1980s insisted that free and competitive markets were more efficient than government agencies at delivering basic services, and that divestiture of state-owned assets would have flow-on social benefits in terms of improved resource allocation, innovation, and ultimately greater employment opportunities.

In more recent years, the expansion of global competition, the information revolution, and the rising demand by consumers for higher quality and more choice in goods and services, have all reinforced policy initiatives to create more competitive electricity markets.

The pace of electricity reform in Asia has been influenced strongly over the last few years by a general shortage of capital to fund infrastructural growth, and in particular by the 1997 financial crisis. Despite the heavy capital squeeze caused by this crisis, with one outcome being a precipitous decline in infrastructural investment, the overall effect of the crisis has been to promote the process of electricity sector restructuring. The International Monetary Fund and other multi-lateral development banks have applied strong pressure for reform, but many governments now see that economic efficiency in the electricity sector is vital in economies strapped for cash.

OPERATIONAL MODELS

A review of the literature on electricity industry structural reform reveals a number of possible theoretical structural models for the sector. For the purposes of this study, we have adapted four broad models: Vertically-integrated monopoly; Monopsony; Wholesale competition; and Full customer choice.

Historically, the sector was usually structured as a vertically-integrated monopoly, in most cases owned and operated by the state. In this model, there is no competition and no customer choice. In situations where power utilities were privately owned under this model (such as in the US), each utility typically had a monopoly franchise area of distribution, and was heavily price-controlled by the regulators.

If these models are considered as forming a continuum from full monopoly to full competition, then the full customer choice model lies at the other end of this spectrum. This model might be considered as the theoretical ideal, but in this study it has become evident that the ideal model for any one economy depends heavily on individual circumstances. For some, a partial reform model may be the most appropriate (e.g. competition in generation, with perhaps development of a wholesale pool).

For developing economies in the Asia Pacific region, the widespread existence of subsidies to promote either industrial expansion or dissemination of electricity to poorer and/or remote communities, the existence of Power Purchasing Agreements with individual IPPs, severe environmental pressure, and other factors must be very carefully considered when electricity sector reform is being contemplated as there can be substantial ramifications.

ECONOMIC POLICY CONSIDERATIONS

There are a number of economic policy threads to draw together. An immediate question is whether the economic benefits of reform will outweigh the costs, and in particular can transaction costs be lowered in moving from a vertically-integrated monopoly structure to one in which many different firms compete in generation, and the wholesaling and retailing of power.

Historically, it was assumed that a vertically-integrated, state owned monopoly would deliver electricity at least cost, and with the greatest degree of security. Because electricity was considered a strategic asset, and security of supply was important to industrialising nations, this idea made sense. It also made sense to believe that it was much more efficient to have electricity dispatched and delivered by internal commands within one organisation.

This idea is being challenged, and now there is a general consensus among policy-makers, regulators, industry analysts and economists that the generation and retailing elements of the power supply industry would be more efficiently delivered by firms operating in freely competitive energy markets.

Critics of reform raise a number of concerns, key among them being questions about energy security and the maintenance of reliability. There is little concrete information available as yet to determine what the effects of reform will be with respect to these issues, but both theoretical and practical considerations lead one to conclude that the long-term outcomes will be positive rather than negative. If firms are competing to provide higher quality, and more highly differentiated services, then system reliability should improve. Centrally controlled bureaucracies, after all, have few incentives to provide improved goods and services, even if they have historically over-invested in generation and network infrastructure. Reserve generation capacities (either peak load or spinning reserve) could definitely become tighter in deregulated electricity markets, but there is no immediate evidence that this is currently a major problem. One reason is that most developed economies have significant generation over-capacity, and developing economies are still struggling with substantial under-capacity.

The electricity generation fuel mix may change in deregulated energy markets, this is already becoming quite clear. Competition favours the cheapest fuels, or plants with low capital and operating costs. In the Asia Pacific, this is leading to an increase in coal consumption for power generation, and is also leading to a sharp increase in the use of natural gas, even where gas is not the cheapest fuel. Newer technologies and renewables will struggle to compete where they are not cost competitive unless states regulate to encourage greater use of clean fuels or technologies. The potential for power interconnection in Asia will also have major ramifications on the future of the electricity industry in this region.

One major economic issue, currently being grappled with by the US, and likely to be faced by Japan and perhaps to some extent by Korea, is the question of stranded costs. Stranded costs can be defined as costs utilities have incurred historically, but may not be able to recover in the prices they are able to charge as a result of policy changes. This is a real problem in economies where the power industry has historically been largely privately owned and operated, but been heavily regulated. In economies where the state owned and operated the power industry assets, stranded costs do not become a serious policy issue because uncompetitive assets are written off or substantially devalued by the government, and all taxpayers bear the costs.

SOCIAL POLICY OBLIGATIONS

In many economies, especially developing ones, the electricity sector has been used as an instrument of social policy. This has taken various forms, ranging from subsidised tariffs for certain groups of consumers, to state-owned utilities serving as employment providers.

Where the state owned and operated the whole power supply infrastructure, it was relatively easy to use the electricity sector as an instrument of social policy, especially during the phase of rapid industrialisation in the 1950s and 1960s. With an urgent requirement for planning, construction, operation, tariff setting and resource prospecting, it was often considered politically necessary to sacrifice economic efficiency for other policy considerations, such as employment creation, and dissemination of infrastructural services to all citizens. Even relatively poor developing economies maintain electricity tariff subsidies to promote industrial growth or dissemination of electricity to poorer communities.

When economic reform is being contemplated, it is difficult to maintain policies which result in severe market distortions, as these end up defeating the purpose of the reform initiative, and nullify many of the benefits. However, eliminating subsidies, and allowing large numbers of electricity sector workers to be laid off after the introduction of competitive market structures have very real political and social repercussions, so must be carefully considered. Even so, from an economic efficiency perspective, it is generally accepted that the energy sector should not be used as an instrument of social policy.

DEREGULATION AND THE ENVIRONMENT

When APEC member economies undertake to reform their energy sectors, they do so for a number of reasons. Usually, the driving force is economic – the need to increase economic efficiency, the requirement to attract investment to develop infrastructure, a desire to streamline bureaucracy and promote transparency in decision-making. Often the goal of sustainable development is mentioned as a supporting policy goal.

In reality, reformers often have little idea what the environmental impacts of reform will be. The broad assumption is often made, and this is supported by empirical evidence, that improvement in economic efficiency (and attendant wealth creation) will eventually lead to a reduction in negative environmental impacts.

It is too early to judge the long-term environmental impacts of energy sector reform, but examples of both positive and negative short-term impacts can be found. The creation of competitive energy markets brings fuel cost into sharp focus, and this in turn drives investment decisions. If investment decisions are driven to a large degree by fuel prices, then in the absence of environmental intervention to establish a price for carbon and other pollutants, the outcome may be a large expansion in the use of less environmentally friendly fuels such as coal.

In looking at unanticipated environmental impacts, it is clear that environmental policy needs to go hand-in-hand with economic and social policy. More often that not, the agencies responsible for environmental policy, and those responsible for economic policy (including energy policy) and social policy do not work in close collaboration. Consequently, it is possible to find examples where environmental policy goals are being frustrated by the effects of economic reform. If governments wish to have all these goals working in harmony, the lesson from past mistakes is that each stream of policy advice, and their interactions, should be closely thought through prior to reforming decisions being taken.

CASE STUDIES

Eight economies have been chosen as case studies. These have been selected because they represent a good cross-section of the 21 APEC member economies. Some are developed nations with advanced industrial and financial infrastructures, some are emerging economies facing shortages of power supply and an urgent requirement for inward direct investment to fuel economic growth, and some are grappling with significant social, environmental, and economic policy issues, and one or two have relatively unique circumstances.

The economies selected as case studies comprise: Australia; Chile; Japan; the Republic of Korea; Malaysia; New Zealand; the Russian Federation; and the United States of America.

AUSTRALIA

The Australian case is of interest because it is a large continent comprising six states and two mainland territories with either limited or no electricity interconnections between a number of them. Also, Australia is a Commonwealth of states, with the Commonwealth setting broad policy goals and enacting national legislation, and states taking responsibility for regulations and legislation pertinent to their own affairs. The Commonwealth has established the concept of the Australian National Electricity Market (NEM), where market participants buy and sell wholesale electricity, each state is free to implement this concept at their own discretion.

Some states, notably Victoria, New South Wales, and South Australia are relatively well advanced with respect to electricity sector reform. Generation assets have been either privatised or corporatised and the NEM is operational in these states, as well as in the Australian Capital Territory, which is interconnected. Queensland does not enjoy interconnection yet, so cannot participate in the NEM, although some privatisation has occurred. Tasmania (where the state owns and operates all electricity sector assets) may become interconnected in the future if a cable is laid across Bass Strait. It is unlikely that the Northern Territories or Western Australia will become party to the NEM any time soon due to their geographic isolation.

The lessons from the Australian case study are:

With the right regulatory controls and incentives, competitive wholesale and retail electricity markets can be achieved without full scale privatisation – provided state owned companies are set up to operate commercially on a level playing field with private sector firms.

CHILE

Chile's power sector was one of the first in the world to undergo substantial reform. The deregulation process was undertaken in tandem with economy-wide restructuring initiatives. In 1978, the National Energy Commission was created to design a new framework. The industry was unbundled and competition was established in generation. Retail electricity tariffs remained regulated, and are based on the cost structure in the electricity supply chain.

Between 1985 and 1990, most of the system was privatised. However, there is still a high degree of concentration in the power sector, with one holding controlling generation, transmission and distribution.

The lessons from the Chilean case study are:

Economies with small power markets subject to takeover by big trans-national companies after privatisation need to carefully craft power sector regulations and enforcement bodies – both specific to the sector as well as of general application to markets – to effectively limit market power, balancing efficiency, investment attractiveness, and consumer protection.

JAPAN

The Japanese electricity sector is divided into 10 private vertically-integrated utilities, with a limited amount of wheeling of power between them. These utilities provide 90 percent of the electricity demand in Japan, with the rest supplied by auto-producers and IPPs.

Deregulation has only been considered very recently, after recognition that tariffs are high by world standards. The first liberalising step has been an attempt to make it easier for IPPs to enter the market. Another policy initiative being considered is the breaking down of monopoly control over fuel supplies. Almost all fuel for power generation is imported, and individual firms have tight control over the fuel market.

Further liberalisation steps are expected, and these will take place at a steady but slow pace. Because the sector is completely privately-owned, full market liberalisation is expected to lead to a substantial stranded costs problem.

The lessons from the Japanese case study are:

In economies with a large private sector involvement in the electricity supply industry, substantive reform requires a high degree of consultation between government policy-makers and private firms, and faces stiff legal and political hurdles.

An industry structure comprising many vertically-integrated private companies with limited interconnections is difficult to reform, as vertical unbundling (divestiture) across the sector is required, as is the encouragement of horizontal competition.

THE REPUBLIC OF KOREA

The Korean power sector is notable for its very rapid growth over the last two decades. In 1980, total electricity demand was 32.7 TWh, by 1997 it had grown to 200.8 TWh, outstripping growth in GDP. Currently, the sector is owned and operated by the vertically-integrated, state-owned enterprise Korea Power Electricity Corporation (KEPCO).

In 1997, the government created the Committee for Electricity Industry Restructuring to design an electricity industry reform process. A plan has been developed and involves four phases: (1) the creation of generation, transmission and distribution subsidiaries; (2) the introduction of competition in generation; (3) the introduction of wholesale competition; and (4) the emergence of full-fledged competition.

The lessons from the Korean case study are:

A rigorous assessment process has to be put in place before implementing any restructuring plan. In Korea, the more than 6 years of deregulation preparation work has uncovered many important issues, which may have been overlooked and could have incurred unnecessary costs.

In order to maximise the benefits of deregulation, other fuel sectors should be deregulated simultaneously, so that power generators can choose the most economic fuel for power generation, and avoid the risk of stranding their assets at a later date when other fuel sectors do become more competitive due to market opening.

MALAYSIA

Malaysia is currently in the midst of an energy sector reform process. Prior to 1990, the National Electricity Board was government-owned, and supplied 80 percent of the total population of Malaysia. The NEB was corporatised in 1990 (to become Tenaga Nasional Berhad, or TNB), and partially privatised in 1992. The generation sector has been opened to IPPs, but TNB still maintains market dominance, through control of most of the generation capacity, the transmission network, and some distribution.

Electricity demand growth has been rapid over the last decade, and this has assisted growth in inward direct investment by IPPs. Further reform is planned, with the creation of a wholesale market and independent transmission ownership and operation. Despite these plans, Malaysia still wishes to achieve social policy goals by regulating the retail tariff of electricity, in particular maintaining a uniform tariff for all consumers.

The lessons from the Malaysian case study are:

In some developing economies, the potential benefits of opening energy markets to full competition must be balanced against competing political, social and economic policy objectives, such as extension of electricity networks to all communities, and maintenance of tariffs at prices poorer consumers can afford.

NEW ZEALAND

Of all the economies in the APEC region, New Zealand has undertaken the most comprehensive nationwide reform of its electricity supply industry. Beginning in late 1980s, when a government department operated the sector as one vertically-integrated monopoly, there has been a steady stream of reform initiatives. Legislation was introduced in 1986 to allow the corporatisation of functional departments, and to provide a framework to limit monopoly power.

Today, the sector is characterised by open access and full competition in generation, a wholesale trading market, independent ownership and operation of the transmission network, open access to the distribution networks, and full competition in retail. The New Zealand electricity reform process is unique in the Asia Pacific region from two points of view: (1) the introduction of a "light-handed" approach to regulation; and (2) the requirement that ownership of distribution lines be separate from ownership of generation assets or operation of retailing activities.

Although a significant amount of private sector investment has occurred in the sector, generation is still controlled predominantly by state-owned enterprises (SOE), and the transmission network is owned and operated by an SOE.

The lessons from the New Zealand case study are:

> *Light-handed regulation is possible with the right regulatory framework of incentives and controls (such as information disclosure requirements).*
>
> *The wholesale market does not need to be designed or imposed from above; the industry can be free to implement a market structure most suited to the workings of the electricity sector (with safeguards to ensure fair play).*
>
> *Full privatisation of the competitive elements of the sector is not necessary, provided state-owned corporations operate under the same business laws as private firms, and are independent of political influence.*

RUSSIA

Russia has undergone large political and economic changes since the early 1990s, and this has had a major impact on the electricity sector. Because of a number of serious structural problems in the Russian economy, the electricity supply industry is burdened with some serious difficulties, including: a large over-capacity of generation plant; non-payment of electricity bills (almost 77 percent of sales in 1997); serious financial constraints; poor quality infrastructure; flaws in state pricing policies; cross-subsidies; and conflicting policies between federal and regional government bodies.

The Russian electricity sector is controlled by the Unified Energy System (52.7 percent state-owned), which produces and distributes more than 94 percent of the total electric power supply. The rest is produced by a number of small local companies.

The lessons from the Russian case study are:

> *Russia has taken the initial steps towards the creation of a market structure in the power sector. This includes partial privatisation of a state monopoly, regional restructuring and introduction of a wholesale power market. However the previous state monopoly structure has been replaced by a set of regional monopolies controlled by the RAO-UES, with the state maintaining a golden share, and consequently wholesale competition is not actually occurring.*
>
> *Power sector reforms are being impeded by the ineffective operation of general market institutions in the Russian economy. Therefore the major barriers to electricity industry reform lie outside the sector.*

THE UNITED STATES OF AMERICA

The US power system is characterised by its large size and the predominance historically of private ownership. Each state developed its own electricity supply industry, usually a number of vertically-integrated, privately owned utilities. Today, there are over 3,000 utilities, although the majority do not own and operate generation facilities. Heavy-handed regulation has been another feature of the sector, and this has lead over time to a number of problems that are now emerging as the reform process begins to develop support in individual states.

Abuse of monopoly power has always been an issue in the US, and attempts to limit these in the power industry go back to legislation introduced in 1935. More recently, legislation has been introduced to open access to transmission networks, and to encourage the separation of the monopoly function of transmission from the competitive parts of the business. The rate of reform varies greatly between states, with high tariff states like California relatively well advanced in introducing full-fledged competition, and other states having made no progress at all.

The lessons from the US case study are:

In an economy where the pre-reform electricity sector is comprised of privately owned and operated, vertically-integrated monopolies, the question of stranded costs is likely to arise where electricity supply assets that were developed under the influence of the policies of regulators and governments, may not be commercially viable in a competitive market.

It is possible to undertake reform where existing structures are not overly conducive to change, providing the costs and benefits can be clearly demonstrated in advance to those most likely to be affected by the changes.

CONCLUSIONS AND POLICY IMPLICATIONS

The strong expectation is that power sector reform will yield important short and long-term benefits due to enhanced economic efficiency. In economies that have been liberalised through the introduction of competitive electricity markets, there is emerging evidence that consumers have gained through lower average prices, and the sector's overall cost structure has declined markedly. Other significant gains are expected, notably further efficiency improvements, the encouragement of greater technological innovation, improvements in service quality and variety, and improved investment decisions. Economy-wide benefits from improved electricity industry efficiency will also become increasingly evident, as electricity is an input to almost all goods and services.

For the benefits of competition to be realised relatively quickly, the reform plan must be carefully thought through prior to implementation. Issues such as social and environmental impacts, competition law, stranded costs, and appropriate electricity market structure are all relevant. It has to be accepted that reform can have significant costs. For example, there may be heavy job losses, particularly in the generation sector, and there may be substantial tariff increases for some or all consumers (depending on the level and distribution of any previous subsidies and cross-subsidies).

It must also be acknowledged that the impacts of market liberalisation on long-term generating capacity investment and diversity of fuel inputs to power generators is not yet fully clear, given that energy sector liberalisation has a relatively short history anywhere in the world.

CHAPTER 1

INTRODUCTION

It is widely recognised that electricity underpins economic growth, and hence is vitally important to the development and welfare of nations. Because of its versatility, convenience, and relative ease of transport, it makes possible many of the goods and services that we associate with modern life.

Unsurprisingly, developed nations typically have very high levels of electrification, and over the last hundred years electricity has gradually replaced other forms of energy to operate industrial and commercial processes, as well as becoming increasingly predominant in the household sector. From electric lights, electric motors, and microwave ovens, to television, telephones, and computers, electricity has become a critical input supporting a wide range of consumption, transportation and production activities. Worldwide, the electricity sector now accounts for around US$1 trillion of annual sales revenue, and about US$200 billion in annual investment. (Joskow, 1998)

Over the next twenty years, barring major extended economic dislocations, energy demand worldwide is projected to grow by over 50 percent. The growth will be unevenly distributed however, with only about 25 percent growth in the industrialised world, and about 100 percent growth in the developing world, with Asia accounting for the bulk of the increase. (CSIS, 1999). This trend will be stimulated by the dynamics of current technological development (which includes semiconductors, telecommunications and information technologies).

Going back as far as Thomas Edison, early industry leaders and politicians alike shared the view that electricity could be most efficiently supplied by vertically-integrated monopolies. In the United States, these were largely privately owned and operated, with the government playing a role as regulator. In many other nations around the globe, the state assumed the primary responsibility for the development and operation of the electricity infrastructure. There were a number of historical and practical reasons for this, chief among them being the ability of the state to raise the capital required, and the widespread view that such a strategic asset must be under the control of central government. Economies of scale could be achieved by building larger and larger generation plants, in tandem with transmission and distribution networks that gradually extended to even the most remote consumers. Further economies were achieved through additional vertical integration into the upstream energy resources sector especially oil, coal and gas.

Over the last two decades, the old idea that electric power generation, transmission and distribution represent a “natural monopoly” best handled centrally, has given way to a general consensus among policy-makers, regulators, industry analysts and economists that the generation and retailing elements of the power supply industry would be more efficiently delivered by firms operating in freely competitive energy markets. It is interesting to note that one of the theoretical justifications for the vertical disaggregation of the vertical monopoly structure and creation of wholesale and retail power markets is the current view that this will lower transaction costs in the sector, and lead to increased economic efficiency.

A number of factors have contributed to this change in theoretical stance, and become forces for change. In addition to the current focus on economic efficiency, these forces include a shortage of capital in rapidly industrialising nations, recent technological and information management innovations, emerging global competition, and consumer demand for more sophisticated and diversified products and services.

This report looks at the increasingly widespread trend of electricity sector reform in the Asia Pacific region, focussing on economies that are members of APEC. Some of the more developed economies, such as Australia, New Zealand and the United States of America are now well on the way towards fully competitive wholesale and retail electricity markets. Some emerging economies, such as Chile, Korea, Malaysia, and Singapore are well advanced with respect to either planning or implementing reform. What is striking is the fact that virtually all APEC member economies have some kind of electricity sector reform in mind, with a view to optimising the economic performance of the sector.

The "Asian economic crisis" of recent years has actually acted as a stimulus to this process, partly as a result of intense pressure from the International Monetary Fund and the multi-lateral development banks for developing economies to introduce private capital into their state energy enterprises, but also through the growing realisation that private capital and the optimisation of economic efficiency are indispensable to the ongoing development of much needed energy infrastructure.

As outlined in this report, the 21 APEC member economies have very diverse circumstances, whether they be economic, social or environmental. An ideal "best practice" reform model might comprise full separation of the natural monopoly from the competitive elements of the electricity supply industry, wholesale competition with an independent trading market, independent transmission system operation, and full retail competition. However, the individual economic and social circumstances of each economy, as well as the incumbent industry structure may not allow this "ideal" to be easily realised. Given these circumstances, which may include under-developed capital markets, significant under-capacity in generation facilities and networks, an unsustainable burden of subsidies to consumers, it is clear that electricity reforms must be based on the needs and circumstances of individual economies.

CHAPTER 2

REVIEW OF THE ELECTRICITY SECTOR

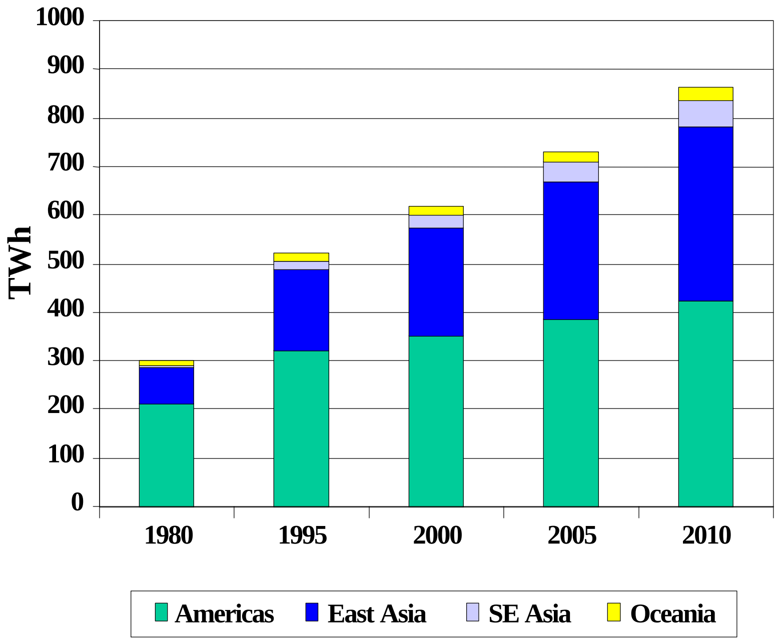
SUPPLY AND DEMAND

Growth in demand for electricity is outstripping demand for other types of energy in the Asia Pacific region, as the region becomes increasingly electrified and per capita consumption rises. This trend is particularly marked in the developing economies. How this rapid growth in electricity demand will be satisfied is possibly one of the most critical issues facing the region over the medium term.

The Asia Pacific Energy Research Centre (APERC) has projected that electricity consumption in Asia Pacific Energy Cooperation (APEC) economies will grow by 65 percent between 1995 and 2010 (an annual growth rate of 3.4 percent) (APERC, 1998). This compares to a 74 percent (3.8 percent annual) increase for the fifteen-year period 1980 – 1995 (Figure 1).

Southeast Asia is expected to have the fastest growth in electricity demand over the forecast period with 7.8 percent per annum, contributing 11 percent of the total APEC increase. East Asia will have the next fastest growth in electricity demand (5.2 percent per annum).

Figure 1 Growth in demand for electricity by region



Notes: Americas – (Canada, USA, Mexico, Chile), East Asia – (Japan, Korea, China, Chinese Taipei), S.E. Asia – (Indonesia, Malaysia, Singapore, Brunei Darussalam, Thailand), Oceania – (Australia, New Zealand, Papua New Guinea)

Source: APERC (1998)

The projected increase for the Americas is 31 percent (1.8 percent per annum), making a contribution to the overall APEC increase of 30 percent. The United States alone will contribute 23 percent to demand growth. In Oceania the expected increase is 63 percent (3.3 percent per annum), contributing 3 percent to the total increase. Demand for electricity is driven mostly by the projected economic expansion in the region. For example, GDP in Southeast Asia is expected to increase by 6.1 percent annually, leading to 7.8 percent growth per annum in electricity demand. As argued by Hansen (1998), industrial production is becoming increasingly reliant on electricity-intensive technologies, so that electricity demand tracks GDP growth more closely.

Coal is likely to remain the dominant fuel for electricity generation, but natural gas and hydropower are projected to increase in importance. The relative share of fuel oil used for power generation is expected to decline. Most of the economies studied are richly endowed with natural energy resources except Japan, South Korea and Chinese Taipei. These all lack significant natural energy resources, apart from hydropower potential. As a result these economies import a high percentage of their fuel requirements for power generation. The lack of natural resources is one of the strong motivating forces behind the push by the respective governments of these three economies to promote nuclear generation.

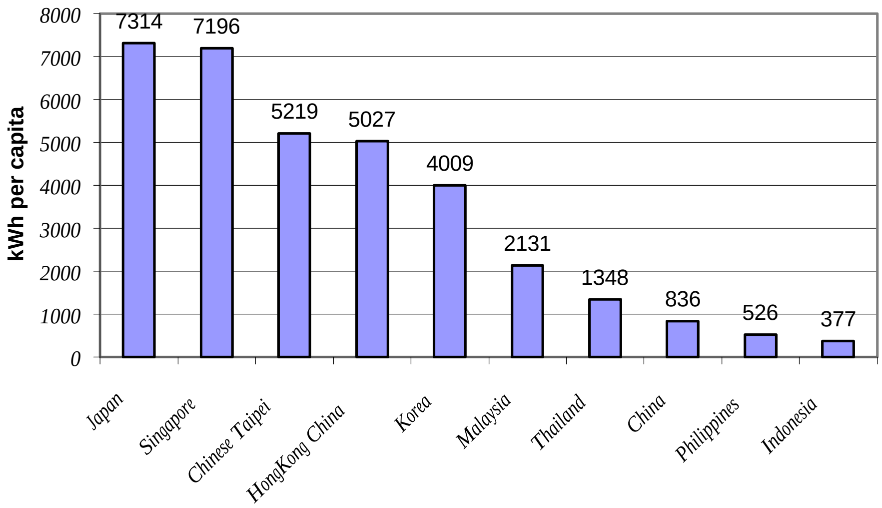
Total installed power generation capacity in the APEC region is forecast to increase by 38 percent between the year 2000 and the year 2010 (Table 1).

Table 1 Total generation capacity in the APEC region (1995 – 2010)

	Generation capacity (GW)			
	1995	2000	2005	2010
Americas	930	1,012	1,097	1,187
East Asia	505	659	846	1,075
S.East Asia	54	81	113	156
Oceania	47	49	56	64
Total	1,536	1,801	2,112	2,482

Source: APERC, (1998).

Figure 2 Per capita electricity consumption for selected Asian economies (1996)



Source: Morgan Stanley Dean Witter Research (1998).

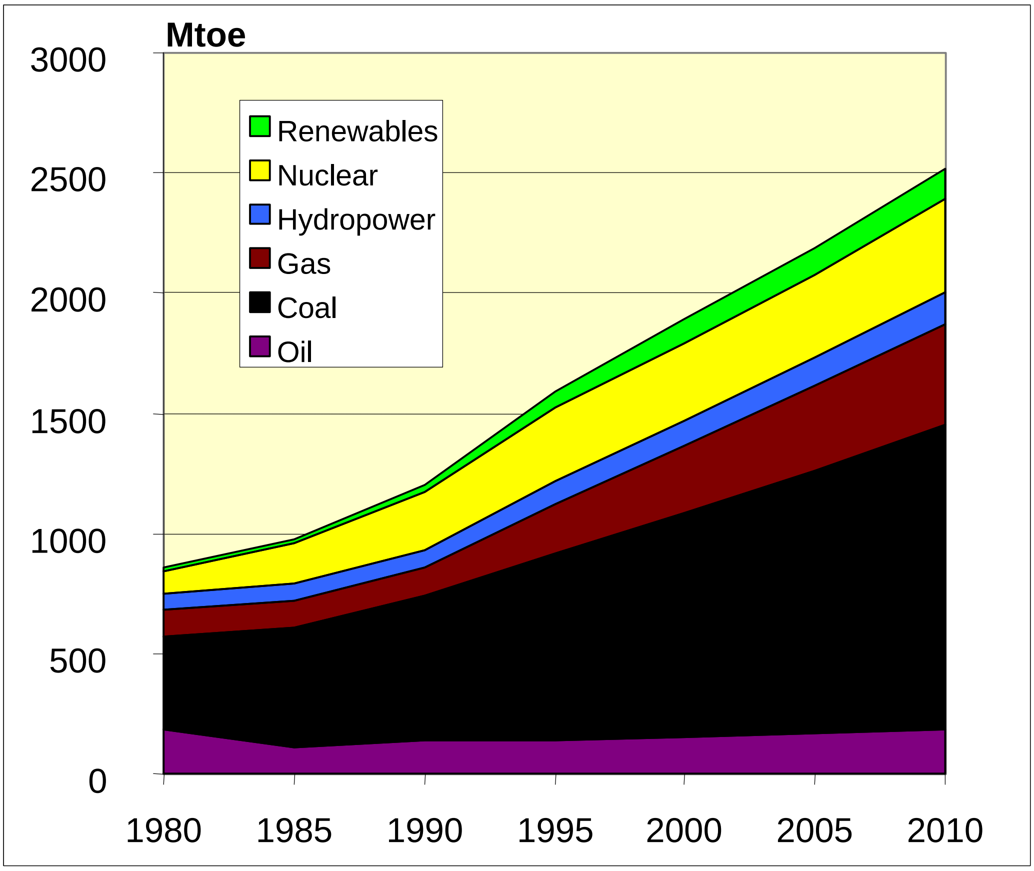
Per capita consumption of electricity in 1996 in selected APEC economies is shown in Figure 2. The distinct patterns of per capita electricity consumption are the result of a number of factors, the most important of which include: the rate at which national production and income grows; the extent to which the marginal propensity to consume electricity falls as income rises; the rate at which traditional and other fuels are replaced by electricity (e.g. for cooking in urban and semi-urban households); and the rate of change of access of (in particular rural) populations to electricity.

GENERATION MIX

The primary energy sources used to generate electricity differ significantly among the various APEC economies, although there are common themes. The current mix of energy sources includes thermal (almost totally fossil fuel powered), nuclear, hydroelectric and geothermal, with wind and solar gaining some ground at the margins.

Total electricity generation fuel requirements by energy source are shown in Figure 3. For APEC an increase of 58 percent (3.1 percent per annum), from 1595 Mtoe in 1995 to 2,514 Mtoe in 2010 is expected (APERC, 1998).

Figure 3 Projected fuel requirements for electricity generation in the Asia Pacific region

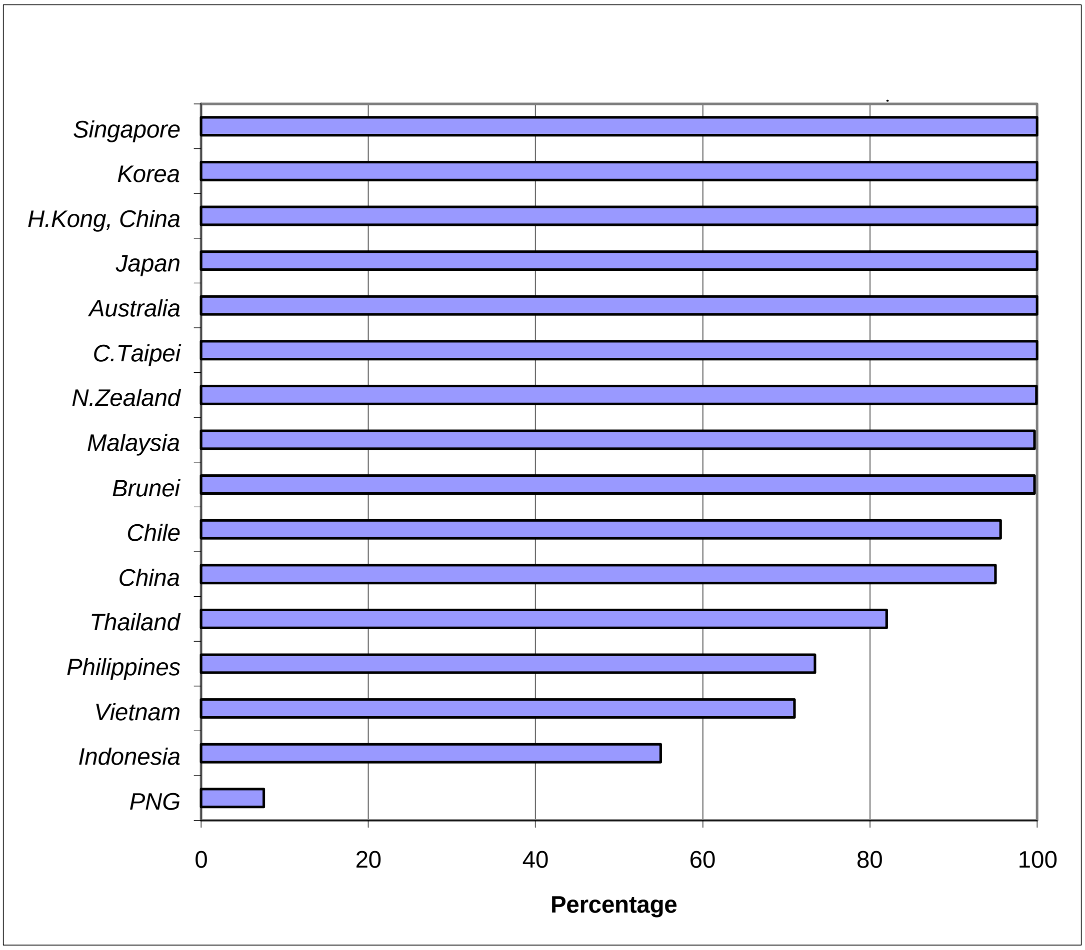


Source: APERC (1998).

ELECTRIFICATION RATE AND LEVEL OF EFFICIENCY

The proportion of the population with access to electricity varies widely throughout the APEC region. In general, there is an income threshold below which access to electricity is low, either because electric tariffs represent too high a percentage of disposable income, or because the overall wealth of the economy is not adequate to provide the service at a price the poorer consumers can afford to pay. In some parts of Southeast Asia, access of rural communities to electrification services is still low, while penetration in urban cities and industrial economics zones is increasing significantly. National transmission and distribution networks may take many more years to reach some rural areas in poorer economies. As shown in Figure 6 beyond a certain threshold of overall relative wealth, the percentage of the population with access to electricity is around 100 percent.

Figure 4 Percentage of population with access to electricity in selected APEC economies

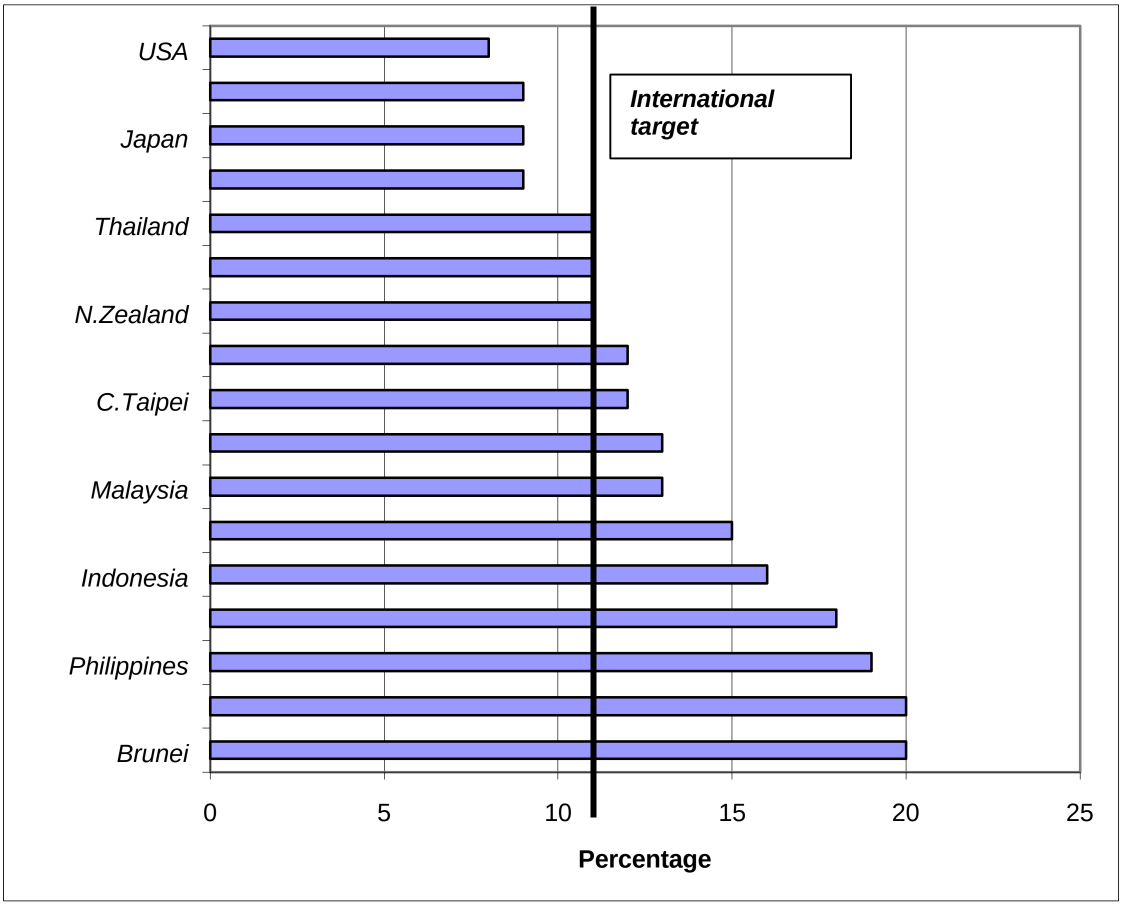


Source: AESIEAP Gold book (1999).

Owing to differences in geography, resource endowment, wage and other cost structures, as well as income distribution within economies (and to other differences), it is difficult to establish a reference threshold income level above which consumers can be expected to have access to electricity.

A shortage of public resources has resulted in limited levels of investment in recent years. Today, a lack of financial resources and investment has resulted in relatively high electrical losses for networks in some economies (Figure 7).

Figure 5 System losses in selected APEC economies



Note: The electricity supply industry on some of APEC member economies still shows high system losses when compared with international target of about 10 - 12 percent (World Bank, 1996)

Source: APERC (1998).

INDUSTRY STRUCTURE

Regulatory reform is usually directed at ensuring that regulations are fully responsive to changes in economic, social and environmental policy positions, as well as reflecting technological advances which change the nature of the way in which sectors operate. In the mid to latter years of the 1900s, electricity was thought of as (1) a national strategic asset, and (2) a natural monopoly industry. It was frequently assumed that maintaining a reliable national energy supply required public ownership and operation. State departments have played a dual role in providing electricity services (often with an obligation to supply), and also acted as policy-advisor and regulator.

This approach has now been widely rejected, at least in principle. Although the strategic importance of energy as a driver of economic vitality and growth is as great as ever, most governments are now coming to accept the view that the provision of energy is a service, and that this may best be delivered by competitive markets. Competition is being introduced into elements of the sector and international investors are being encouraged to enter many liberalised markets to provide much needed capital for infrastructure growth.

Developments in the electricity sector are particularly striking. Traditionally the sector has been shielded from competition in many APEC economies. Utilities were, for the most part, state-owned vertically-integrated monopolies, and consumers have been captive to utilities with individual franchise rights.

Restructuring of the electricity supply industry in the Asia Pacific began in the mid to late 1980s in some economies - for some, even earlier (see Figure 6). Progress differs from economy to economy, but the introduction of competition has provided a strong platform for private investors to participate in power development in the region. Many governments have moved to create an attractive environment to attract private capital to build, own and operate new power plants.

AMERICAS

In the US, private investors own most electricity assets, although these have until recently been heavily regulated. Substantial reform is taking place, at Federal and state levels, with the creation of wholesale power pools, divestment of generation assets, and introduction of competition in generation and retailing. Deregulation is being implemented largely at state level, at different speeds, and with different envisaged end-points. Although designs differ, the overall theme is generally consistent.

In Canada, the most significant event in the industry is the ambitious change underway in the Province of Ontario. This will result in the break up of Ontario Hydro, the introduction of full retail competition by 2000, and the creation of a new regulatory framework overseen by the Ontario Energy Board. Privatisation is not yet on the agenda. Alberta has the greatest private sector involvement of any provincial electricity system and is currently moving to full retail competition, although the vertically-integrated utilities have retained their current structure.

Restructuring and privatisation efforts in Latin America began in Chile with the privatisation of generation, transmission and distribution companies. Full competition was introduced in generation and is possible in retail for large consumers. Peru has followed a similar restructuring route to Chile. Asset sales were undertaken during the period 1993-1996, principally through the sale of majority stock-holdings to large private investors (around 60 percent of stocks), with 10 percent offered to employees and the remaining 30 percent offered to small investors via the local stock market. An important element of the Peruvian privatisation process has been the placing of obligations on incoming investors to build additional capacity. In addition, international tenders for the construction and operation of new transmission lines have been let.

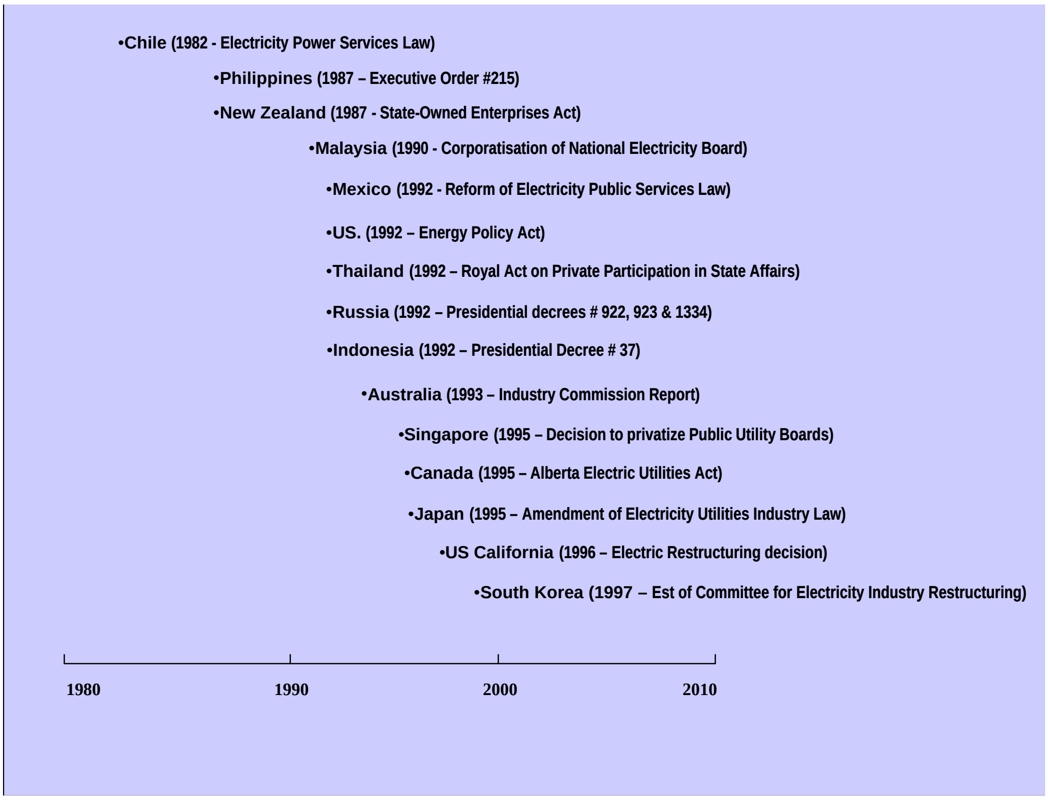
In Mexico, the President has put forward a proposal to Congress for the restructuring of the Mexican electricity system. The proposal will require constitutional reform, as the constitution restricts private involvement in the electricity sector. Reform is expected to lead to vertical unbundling of the functions of utilities, the creation of a competitive electricity market, the introduction of competition in generation and retail, and the award of concessions for services such as transmission and distribution.

OCEANIA

In Australia, the state of Victoria has led the way, with the vertical desegregation of the sector, and creation of competitive generation and distribution companies. A state wholesale market was established, and this has become part of the National Electricity Market (NEM). Privatisation of generation and distribution assets aroused considerable investor interest and generated high proceeds. New South Wales and Queensland have corporatised their competitive assets. South Australia is proceeding with privatisation via long-term leasing arrangements (Pritchard, 1999).

In New Zealand, a radical restructuring of the sector is nearing completion, involving the break-up of the state-owned generation and transmission monopoly into four separate generators - three State-Owned Enterprises (SOEs) and one sold to private investors - and one SOE responsible for transmission and system control. A wholesale market has been created, now owned and operated by the private sector. At the distribution level, the government has required the mandatory separation of the lines businesses from retailers, who may also own generation assets.

Figure 6 Dates of significant restructuring initiatives taken in APEC economies



EAST AND SOUTHEAST ASIA

Private sector initiatives in Asia to date have principally involved Build-Own-Operate (BOO) and Build-Operate-Transfer (BOT) projects. IPPs are now an established feature of the landscape in the Philippines, Malaysia, Indonesia and other economies.

OWNERSHIP

Although electricity sector reform is gaining momentum in the Asia Pacific, emerging frameworks still emphasise public ownership and control in many cases, as well as regulated tariffs and markets. Table 2 shows the key players in the electricity sectors of some selected APEC economies.

Some economies have established joint venture companies (usually with state majority ownership, in collaboration with private investors). Such ventures have a mandate to operate commercially, but under the auspices of government, not necessarily through direct control by investors, shareholders or financial markets.

Table 2 Key electricity sector participants in some selected APEC economies (1999)

Economy	Government or public	Private sector
Australia	All states other than Victoria and South Australia.	Various **(G)**
Brunei Darussalam	Department of Electrical Services **(VIM)**	
China	Provincial power companies **(G&T)**	IPPs (including Beijing Datang, Huaneng Power, and Shandong Huaneng Power)
Indonesia	PLN **(VIM)**, captive generators	IPPs
Japan		Tokyo Electric Power **(VIM)**, Kansai Electric Power **(VIM)**, Hokkaido Electric Power **(VIM)**, Chugoku Electric Power **(VIM)**, Hokuriku Electric Power **(VIM)**, Shikoku Electric Power **(VIM)**, Kyushu Electric Power **(VIM)**, Okinawa Electric Power **(VIM)**, Tohoku Electric Power **(VIM)**, Chubu Electric Power, IPPs
Korea	Korea Electric Power Company **(VIM)**	
Malaysia	Tenaga Nasional Berhad **(G,T,D,R)**, Sabah Electricity Board, Sarawak Electricity Supply Corp and 14 IPPs	IPPs (33% of installed generation capacity).
New Zealand	Meridian Energy Ltd **(G&R)**, Mighty River Ltd (G&R), Genesis Ltd **(G&R)**, Transpower **(T)**	TransAlta (G&R), Edison Mission **(G&R),** Utilicorp (lines), Mco (wholesale pool), over 30 lines companies.
Philippines	National Power Corporation **(G&T)**, Manila Electric Co – MERALCO **(D&R)**	111 private co-operatives **(D)**, 25 private distribution Co.s **(D)**, and IPPs **(G)**
Chinese Taipei	Taipower **(VIM)**	Cogenerators, IPPs
Thailand	Electricity Authority of Thailand – EGAT **(G&T)**	IPPs. EGCO & SPP **(D&R)**, Metropolitan Electricity Authority **(D&R)**, Provincial Electricity Authority **(D&R)**

Key: VIM – Vertically-integrated monopoly
G - Generation
T - Transmission
D - Distribution
R - Retail

A difficult issue facing most economies wishing to introduce competitive energy markets and direct inward investment in the sector is public reaction. Even in developed economies with sophisticated capital markets and widespread private ownership of many goods and services important to the well-being of the nation, the public can respond quite negatively to the prospect of public assets being sold to private investors. One issue is a concern over the loss of strategic public assets, another is the prospect of job losses and potential loss of socially oriented services. Quite another, and difficult problem, is public reaction to the price governments are likely to receive for assets at auction. If the assets are sold cheaply (either because the capital value has long ago been written off, or it is difficult to assess the commercial viability when privatised) the public reaction can be quite negative, especially when the assets are revalued by the new owners, and given much higher valuations. If the assets are sold at too high a price, the new investors may struggle to make reasonable returns, potentially damaging the viability of the newly emerging markets.

ELECTRICITY PRICING

OVERVIEW

As rightly pointed out by Rosenburg (1998), the dynamics of current technological development (which includes semiconductors, telecommunications and information technologies) is likely to greatly extend the present trend of rising electricity consumption well into the future. As electricity gains dominant status in the energy consumption profile, electricity pricing practices will play significant roles in economic development, technology development and energy consumption behaviour.

TRANSFORMATION IN PRICING PRACTICES

Different pricing practices in the electricity sector have been developed in accordance with changing industry structure. While natural monopolies are compatible with a usual cost-of-service pricing practice, deregulated markets require more complex pricing mechanisms. Since the extent to which markets are deregulated and unbundled could be different in each economy, the pricing mechanism may also differ.

It is common practice in deregulated markets to allow generation prices to be set by supply and demand, while governments or regulators control transmission and distribution prices. So price regulation with respect to networks still retains some importance in the presence of fully deregulated markets. As illustrated in Table 4, there are a number of ways to regulate transmission prices, ranging from a traditional ROR-based pricing mechanism to a performance-based Price Cap approach. Every approach has its advantages and pitfalls because it is difficult to strike a balance between equity and efficiency. To illustrate, it is often argued that the Price Cap approach is better than the ROR-based one as the former would offer more incentives for cost reduction. However, the Price Cap approach may easily fail to reflect true costs in prices because of the lack of information available to the regulator. The price cap may well over- or under-shoot with respect to the optimal price level. This will create equity concerns between electricity suppliers and end-users.

State-based monopoly electricity markets, with regulated or mechanistically administered electricity prices, still remain, particularly in developing economies. Price controls are established in Japan, Korea, the Philippines, Russia and Chinese Taipei, although in some cases these are being phased out. Administered prices are prevalent in China, Indonesia and Viet Nam, and are used to assist with wider energy policy objectives (see Table 3).

Transparency is an important issue in pricing practices especially in the case of a natural monopoly. As all costs incurred in the fuel chain from generation to distribution can be passed on to end-use consumers, it is important to maintain transparency in price determination processes to the extent possible. Otherwise consumers have to bear unnecessary costs, even from mistakes in economic decision-making, for example, with respect to investment in assets, their operation and maintenance.

As shown in Table 4, in case of opaque systems, electricity prices could be subsidised to fulfil social policy obligations. Electricity consumers can be either directly or indirectly subsidised by governments. In some cases, these subsidies are offered as preferential fuel prices. The report by the Japanese Overseas Economic Cooperation Fund (OECF, 1995) indicates that electricity prices for certain demand categories are set lower than actual costs as a policy measure. In some extreme cases the rates set for the various customer classes are inversely proportional to actual cost structures. For example, rates may be lowest for residential consumers even though their supply cost is highest.

Table 3 Electricity price regulation in APEC economies

Economy	Price regulation	Competitive Wholesale Market	Comments
Australia	No*	Yes	In Victoria, NSW, ACT, South Australia, and Queensland. Emerging retail competition
Brunei Darussalam	Yes	No	
Canada	Yes	No	
Chile	Yes	Yes	Both regulated and unregulated prices
China	Yes	No	
Chinese Taipei	Yes	No	
Hong Kong, China	Yes	No	
Indonesia	Yes	No	
Japan	Yes	No	
Korea	Yes	No	
Malaysia	Yes	Yes	
Mexico	Yes	No	
New Zealand	No	Yes	Full retail competition
Papua New Guinea	Yes	No	
Peru	Yes	Yes	Both regulated and unregulated prices
Philippines	Yes	Partial	
Russia	Yes	No	
Singapore	Yes	Yes	Emerging retail competition
Thailand	Yes	No	
USA	Yes/No	Yes	Emerging retail competition on state by state basis
Viet Nam	Yes	No	

Notes: Adapted and updated from "The Benefits and Deficiencies of Energy Sector Liberalisation, Current Liberalisation Status", Volume II, 1998, World Energy Council.

* For contestable customers consuming greater than 160MWh per annum.

For example, Manila Electric Company (MERALCO), the largest distributor of electricity in the Philippines maintains a residential rate of 3.12 pesos per kWh, while its unit supply cost is calculated at 3.9 pesos. On the other hand, the rates for commercial and industrial users are set higher than their service costs. This indicates the degree of cross-subsidisation in the provision of electricity in the Philippines.

Table 4 Pricing approaches under different market structures

	Monopolistic		Transition	Competitive	
	Administered Prices	Price Control Regulation	Reregulation Process	Wholesale Competition	Retail Competition
Industry Structure	• Vertical integration of generation, transmission and distribution. • Vertical integration of generation and transmission only.		• Unbundling of generation, transmission and distribution segments of the industry. • Competition in generation.	• Generation, transmission and distribution are unbundled. • Competition in generation; access to transmission network; electricity pool.	• Generation, transmission and distribution are unbundled. • Competition in generation; access to transmission and distribution network; electricity pool.
Utility Ownership	• Public sector ownership is dominant.		• Increase in private sector participation.	• Private sector ownership is dominant.	
Price Regulation Regimes	• Generation and retail prices are determined by the government.	• Generation and retail prices are regulated by the government. • Rate-of-return (ROR) • Price-cap (PC) • Revenue-cap (RC) • Sliding Scale (SS) • Hybrid (H)	• Generation, transmission and retail prices are regulated. • Adoption of a transparent price regulation regime. • In many developing countries undergoing transition or considering transition, price-cap regulation appears to be popular.	• Generation prices are either regulated or not regulated; transmission prices are regulated; retail prices are regulated; based on the existing price regulation regime.	• Generation prices are either regulated or not regulated; transmission prices are regulated; retail prices are not regulated. Regulation is based on the prevailing price regulation scheme.
Pricing Objectives	• Seek to balance the following objectives: economic efficiency, financial viability and social equity.		• In pursuit of economic efficiency and financial viability.	• Economic efficiency and financial viability.	
Price Determination	• Price determination under this regime is either transparent or opaque. • In transparent schemes, they are indexed either on LRMC or average costs and sometimes adjustments are made to accommodate SRMC changes (TOU or TOD). • In opaque systems, prices are sometimes influenced by the social objectives in energy pricing. In this case, prices are subsidised.	• Rate-of-return – electricity price corresponds to the average cost prices plus the permitted rate of return to assets. • Price-cap – costs are based in either average cost or LRMC. Future price is set based on the adjustment factor CPI-X. • Revenue cap – fixed amount of revenue is allowed. • Sliding scale – excessive profit or abnormal loss is shared by regulator and utility. • Hybrid – mix elements of other regimes.	• Electricity prices are unbundled. • Generation, transmission and retail prices are determined according to the type of price regulation adopted by each economy.	• Wholesale prices are market-determined which approaches to SRMC. • Peak-period price adjustment is sometimes done to reflect “reliability adjustment”. • Other components of electric industry are price regulated – according to the type of price regulation adopted by each economy.	• Wholesale and retail prices are market-determined which approaches to SRMC. • Peak-period price adjustment is sometimes done to reflect “reliability adjustment”. • Other components of electric industry are price regulated – according to the type of price regulation adopted by each economy.
	• In developing economies, either prices are administered or regulated, cross subsidies (either among consuming sectors, geographic regions, or between rural and urban consumers) are prevalent. • In several developing economies, a price adjustment mechanism is put in-place to automatically adjust electricity prices due to the fluctuation of input prices.		• In the transition phase, cross-subsidies are normally removed. • TOU or TOD schemes are sometimes introduced.	• Stranded costs recovery are also provided.	

Source: Pacudan (1998)

THE 1997 FINANCIAL CRISIS

From the late 1980s, many APEC economies, in particular the fast developing parts of East and Southeast Asia, experienced a surge of private capital inflow. Japanese, European, and American investors were looking aggressively for lucrative opportunities, and invested heavily. Banks competed aggressively for projects to finance in the region and were offering very attractive rates. Capital markets in the region flourished. As strong economic growth amongst the "Asian Tigers" continued unabated, lenders, sponsors and investors (such as IPPs) became more comfortable with the risks. Asian governments for their part were implementing some of the reforms needed to encourage global investors. Support from Export Credit Agencies (ECA) and multi-laterals became less critical and, where possible, were avoided by developers in view of the length of the approval processes, relative inflexibility and higher combined interest rates and fees.

This process of burgeoning economic growth, and the high investment levels needed to fuel it, suffered a major setback in the last quarter of 1997, when a severe recession hit the region. Currencies linked to the appreciating US dollar aggravated the economic problems and contributed to further destabilization. Some of the other factors that together helped destabilise several Asian economies during the latter half of 1997 included infrastructure inadequacies, and the slow pace of structural reforms.

In the past, rapid growth rates had concealed structural weaknesses, but these came to light with the region's economic slowdown. Several economies had to raise interest rates to high levels during the course of the crisis to stem the outflow of capital and further depreciation of their currencies. Price controls, postponed increases in electricity and gas tariffs, and wage and salary cuts all helped to moderate price increases temporarily. However, governments announced either the postponement or review of large infrastructure projects - in the hope that such actions would improve their fiscal positions and restore investors' confidence. The effects of the financial crisis in some APEC economies are shown in Table 5.

The financial crisis has had a major impact on the electricity sector, particularly in Indonesia, Malaysia, Philippines, Thailand and Korea. For example, private capital flows into the emerging markets in Asia have dropped by one third - to a level of US $200 billion for all sectors in 1997 as a result of the crisis (Cutting et al, 1999). The currency crisis has created a new challenge for electricity infrastructure financing.

Table 5 Economic growth figures for selected Asian economies (1997, 1998 and 1999)

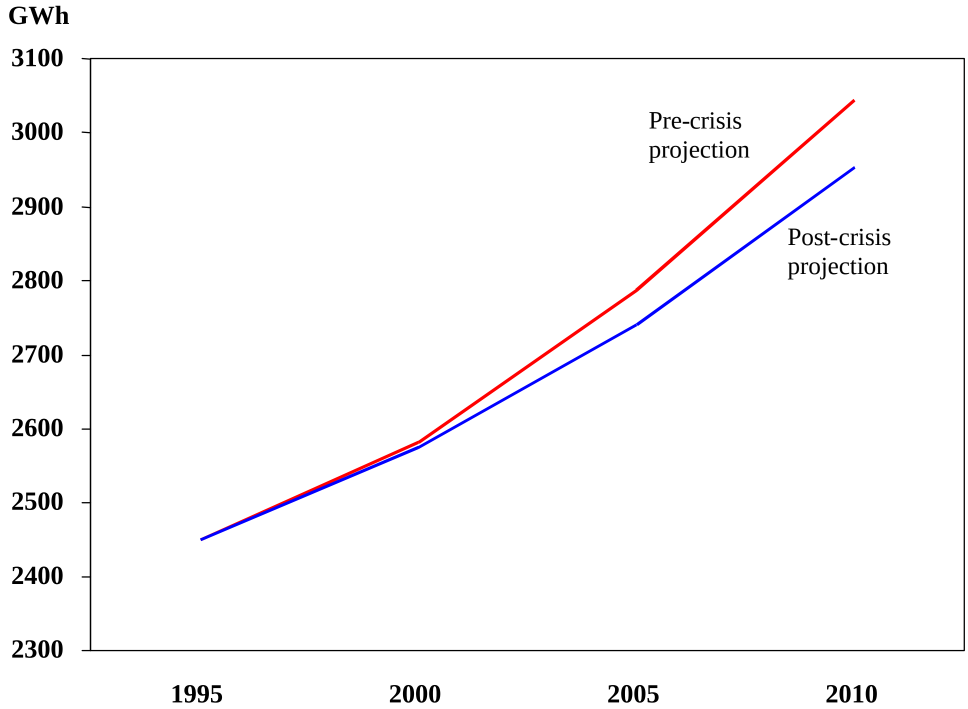
Economy (Source)	1997	1998	1999
Korea (Bank of Korea)	5%	-5.8%	8.8%
China (State Statistical Bureau)	8.8%	7.8%	7.1%
Thailand (Bank of Thailand)	-1.8%	-10%	3-4%*
Malaysia (Statistics Dept.)	7.5%	-7.5%	2.8%
Indonesia (Central Bureau of Statistics)	4.7%	-13.2%	-1.7%*

Note: * Forecast figures are from Far Eastern Economic Review, Oct 7, 1999

The crisis is expected to have a substantial impact on supply and demand over the next decade. The primary impacts have been to temporarily reduce local electricity demand, and cause many power developments and privatisation plans to be delayed or put on hold indefinitely (see Appendix III). The economic slowdown appears to be altering the supply/demand picture to the point where some utilities could begin to see capacity surpluses.

Electricity consumption is now projected to increase 52 percent (2.8 percent per annum) from 1995 to 2010, compared to a pre-crisis estimate of 60 percent (3.2 percent per annum). Figure 7 shows the forecasted effect of the financial crisis on growth in electricity consumption over the next decade. However, Table 5 shows that the recovery has been faster than expected, so the pre- and post-crisis projections may have the same slope in the medium to long term.

Figure 7 Projected growth in electricity demand for the Asia Pacific region



APERC (1998).

CHAPTER 3

FORCES FOR CHANGE

EFFICIENCY

A number of important factors have contributed to the far-reaching changes in global electricity markets. Economic efficiency has been a strong driver. Micro-economic reforms in many developed economies in the early 1980s were driven by severe fiscal crises, in turn brought on by the ramifications of the 1973 OPEC oil embargo and subsequent oil price hikes. States were faced with the realisation that in the face of a need for infrastructural and other investment, limited state financial resources were insufficient to meet this need, as well as the other demands on the state purse. The New Neo-classical economic theory emerging in the early 1980s insisted that free and competitive markets were more efficient than government agencies at delivering basic services, and that divestiture of state-owned assets would have flow-on social benefits in terms of improved resource allocation, innovation, and ultimately greater employment opportunities.

By the middle part of the 20th Century, electricity was viewed as a national strategic asset, in much the same way that coal, and then oil, were viewed. A stable and secure supply of electricity to all consumers was considered an essential ingredient of the national infrastructure by the more developed economies, and a goal to aim for by the developing economies. Obligations to supply were commonplace, along with vertically-integrated and state owned monopolies. Heavy-handed regulation has also been a common feature of the sector.

This view of the electricity sector has undergone significant change. Not only as a result of economic pressure to increase economic efficiency through deregulation and restructuring, but also as a result of a paradigm shift with respect to the delivery of services – brought on by the information revolution and other technological advances. This is most evident in the telecommunications sector, where deregulation has resulted in an explosion in the array of services available, and rapid technological innovation.

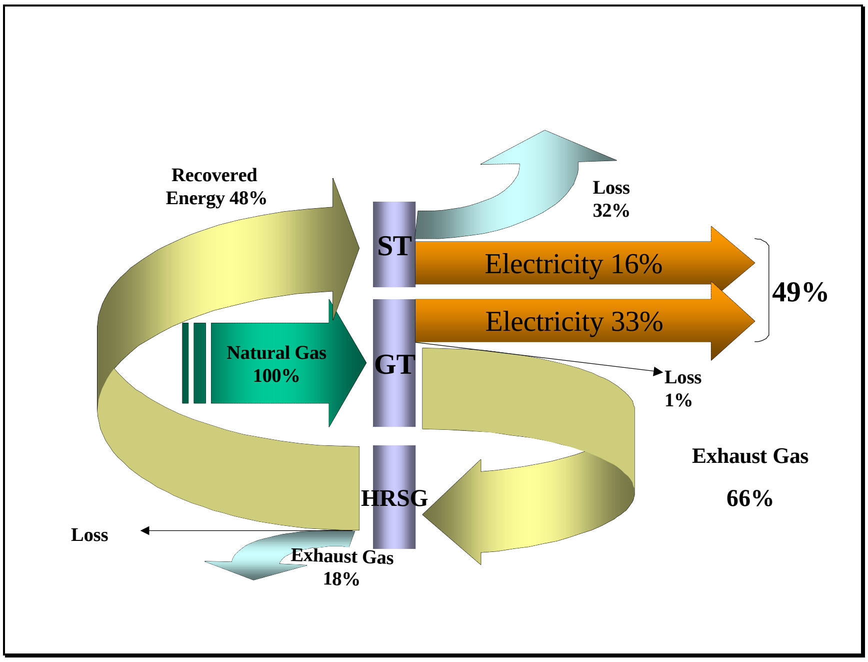
Many leaders in government and industry alike are now recognising that electricity sector deregulation can make it more responsive to changes in business and technology, and more open to the forces of free-market competition.

TECHNOLOGICAL INNOVATION

Next to the drive to achieve greater economic efficiency, the greatest force for change is quite probably the inexorable advance of technological innovation. In the electricity sector, two important areas of innovation are having a major impact on the industry. The first is the development of the natural gas combined cycle turbine (CCGT). In comparison with the 30 – 40 percent efficiencies achieved by the old single cycle turbines installed 20 years ago, today's systems are running at 50 – 60 percent efficiency, and improving with time (Figure 8). High thermal efficiency means low emission levels, and this in turn means that power plants can now be situated closer to centres of demand.

Power generation plants using these turbines (CCGT) also have low capital costs and rapid construction times when compared with other options. Fuel costs may in many places still be higher, but the low capital costs and rapid installation offset this disadvantage, especially for peaking plants that may run at low capacity factors. However, because modern CCGT plants run at high levels of reliability, they are increasingly being used for base load, and because they come in small sizes, adding extra capacity matches increments in demand more closely than was possible in the past when additional capacity was likely to cause considerable "lumpiness" in the match between supply and demand.

Figure 8 Energy and heat flows in a typical modern combined cycle gas turbine



Source: TEPCO (Chiba thermal power plant).

The second innovation likely to have a major impact on the electricity sector is the electronic information revolution. Markets, such as wholesale power pools can now be operated largely through electronic means such as the Internet, with buying and selling designed to match demand on a five minute basis throughout the day and night. With the ability of market players to have access to real time information on all aspects of their operations, and on constantly changing market prices for electricity, it is now feasible to operate a disaggregated industry structure with high levels of economic efficiency. This has been an underpinning argument supporting the view now widely held (Spicer et al, 1991) that competitive markets lower transaction costs over the old vertically-integrated bureaucracies of the past.

CONSUMER CHOICE

If one looks at recent reforms in the telecommunications industry, one prominent feature has been an explosion in technological innovation, and in the bewildering choice of goods and services consumers can now enjoy. Many energy industry experts are now becoming increasingly convinced that change on a similar scale could occur in the energy sector once the effects of deregulatory reform become widespread.

In fact, substantial changes that will bring a wide array of new goods and services to electricity consumers are already emerging in economies that have fully deregulated their electricity markets. Already, the market power of large industrial electricity consumers is having a significant impact on the behaviour of electricity industry participants. As the power to choose between suppliers reaches down to smaller businesses and residential consumers, this will act as a further spur to the development of even more goods and services tailored to meet individual needs. Although there are barriers to switching suppliers, there is evidence to suggest that new metering technology and a better understanding of the market by small consumers will in time lead to true retail competition, and then to further stimulation of electricity markets as retailers compete to provide a more diverse and higher quality range of goods and services (Bradford, 1999).

GLOBAL COMPETITION

Energy intensive commodities tend to be traded globally, and hence the cost structure of competing firms is vitally important to their international competitiveness. For industries where energy costs form a significant part of the total cost structure, the price of electricity is important enough for firms to be important stakeholders in the debate over electricity sector reform. Because large industries have considerable market power, they stand to benefit from reforms that may allow them to negotiate favourable tariffs with competing electricity suppliers. For these reasons, global trade in energy-intensive products and services is an important force for change.

INTERCONNECTION

Interconnection can drive reform by opening up opportunities for wholesale power competition. For interconnection to work effectively, some kind of wholesale pool or market is desirable, although not necessary. The benefit of the development of a wholesale market is the facilitation of power transfers to meet demand on an efficient real-time basis.

Ample opportunities exist for regional trade in electricity. In the APEC region, Canada, the United States and Mexico have for many years engaged in cross-border trading in electricity (as well as gas). This trade is likely to increase in the future as US and Canadian electricity markets in particular become more competitive. For example, Ontario Hydro has created a new unit Ontario Hydro Interconnected Markets, Inc. with the goal of expanding export opportunities in the United States, where its rates are more competitive, in order to enhance its value on the open market.

And the government in Quebec is considering a legislative proposal that would open up Hydro Quebec's transmission grid to electricity trade from other provincial utilities and from independent power producers. Such a move would give access to electricity markets in the United States, in New York, Vermont, New Hampshire, and Maine. Hydro Quebec has established a US subsidiary, Hydro Quebec Energy Services, which is seeking application to sell electricity in the United States. In order to obtain approval from the Federal Energy Regulatory Commission, Hydro Quebec has also proposed to allow wholesale electricity transactions in Quebec by US providers (LCG Consulting, 1997).

Within economies, the practice of wheeling (the transmission of power across common power lines from one independent entity to another) is on the rise. In Southeast Asia, one benefit of cross-border electricity interconnection will be closer political as well as economic cooperation. The introduction of micro-economic reform, including restructuring of the electricity sector will serve as a key facilitator of cross-border electricity interconnection. As the region embraces the rules and challenges of the ASEAN Free Trade Agreement (AFTA) era, this could underpin a new regime of economic integration, based on free market competition and trade liberalisation policy (AEEMTRC, 1998).

FINANCIAL CONSTRAINTS

The demand for additional generation capacity, as well as the need to upgrade existing distribution and transmission networks, is placing a large financial and organisational burden on the rapidly industrialising economies in the Asia Pacific region. New power plants for example, the most expensive assets in the electricity chain, can require US$1 million or more in capital investment per MW of electricity. With demand for electricity over the next decade measured in the tens of thousands of megawatts, governments have found it impossible to finance additional capacity themselves at the rate of investment needed.

Self-financing in the energy sector is low in most developing APEC economies. In combination with severe budget constraints in the public sector, an option is to allow a substantial degree of private participation in the power supply system, and this is happening. On average, in 1990-2020, electricity suppliers will spend US$143 billion per year, of which external financing will have to supply US$48 billion per year (Hyman, Fenner, & Smith, 1994). Of course, the opportunities for financing through private channels depend on the financial viability of the proposed projects, which is closely linked to electricity prices.

Some APEC economies, particularly in East and Southeast Asia, are now attempting to attract private capital into the electric power sector by privatising government-owned assets, or encouraging IPPs to invest under attractive conditions. In some cases, this results in Power Purchase Agreements (PPAs) very favourable to the investor. An increasing reliance on foreign capital for infrastructure development is a two-edged sword. On the one hand, the capital is needed to support infrastructure development. On the other, significant problems can arise when global capital is attracted into markets which are immature or in which substantial subsidisation and cross-subsidisation exist. For example, where financial institutions and laws are immature, there are questions concerning the rule of law, and other questions arise (such as the ability to repatriate earnings), then private investors will demand substantial premiums in order to invest.

Meanwhile economies under International Monetary Fund (IMF) supervision have to abide by its prescriptions in order to meet requirements for financial assistance and restore the industry to a level where it can attract private funds. IMF conditions are explained in the box below:

International Monetary Fund Lending Policy – Energy Sector

The requirements are:

- Corporate restructuring and privatisation of utilities;
- Financial restructuring of utilities and tariff reform;
- Establishment of independent regulator;
- Establishment of competitive power market;
- Integration of transmission grids and sub regional power trade.*

Case study

In Indonesia, the government is reviewing and accelerating the privatisation of the state owned enterprise, Perusahaan Listrik Negara (PLN), to meet the above requirements. At this juncture, the company's corporate and financial structure will be restructured. To achieve this, a new electricity law, a new independent regulatory agency and a new tariff structure that is commercially viable will be established. Current power purchase contracts will be renegotiated in an effort to lower the massive financial burden imposed by current power purchase obligations. It is envisaged that after the full process of restructuring, the commercial viability of the industry will be restored, its efficiency will be improved and most importantly the industry should be able to attract private investment into the sector.**

Source: * Sumi (1999) ** IMF (2000).

Recently, there has been a decline in interest by investors to build IPP plants because of the inadequacy of institutional structures to support them, disagreements about who should take responsibility for the various risks inherent in them and because of the difficulties experienced by both government officials and private sector proponents with IPP negotiating processes which are both random and complex (Pritchard, 1999). However, a more serious concern is that the introduction of IPPs could operate as a major impediment to the future scope of action of governments pursuing wider industry reforms.

CHAPTER 4

OPERATIONAL MODELS

For the purposes of this study, four models have been constructed to describe the prevailing range of situations in the APEC region. The models have been largely adapted from the excellent study on competition and choice in electricity markets undertaken by Sally Hunt and Graham Shuttleworth (Hunt & Shuttleworth, 1996). Although these models can be viewed as sequential, with the full competition model representing the end-point of full competition with the least regulatory distortion, other models may be more suited to the conditions existing in some economies. The models are described in terms of their major characteristics:

- Vertically-integrated monopoly
- Monopsony
- Wholesale competition
- Full customer choice

Understanding the generic functions of the electricity sector allows us to see the value added by each function and to construct a framework for evaluating different theoretical models of the industry. Governments contemplating changes in their national monopoly electricity sectors have a broad range of issues to consider. These include changes in management and ownership, and changes in structure, introducing competition and choice. The introduction of fully competitive energy markets through desegregation and privatisation could be considered an end-point of reform changes, especially if the intent is to maximise economic efficiency and private capital availability.

The box below describes in broad terms some of the processes associated with reform of the electricity supply industry.

Restructuring *is the process of changing the structure of the electric power industry from one of guaranteed monopoly over service territories, to one where the competitive elements of the sector are exposed to open competition, preferably across the whole economy.*

Deregulation *is the process of relaxing previous tight regulatory control over either state or private monopolies, and opting for more light-handed, performance oriented regulations to control both natural monopoly and competitive elements of the sector.*

Commercialisation *is the process of attempting to introduce commercial incentives into a state department. This is often a precursor to selling a potentially commercial activity.*

Corporatisation *is the process of turning a state trading department into a State-Owned Enterprise forced to operate under normal business laws and compete on a level playing field with private firms. This may or may not lead to privatisation.*

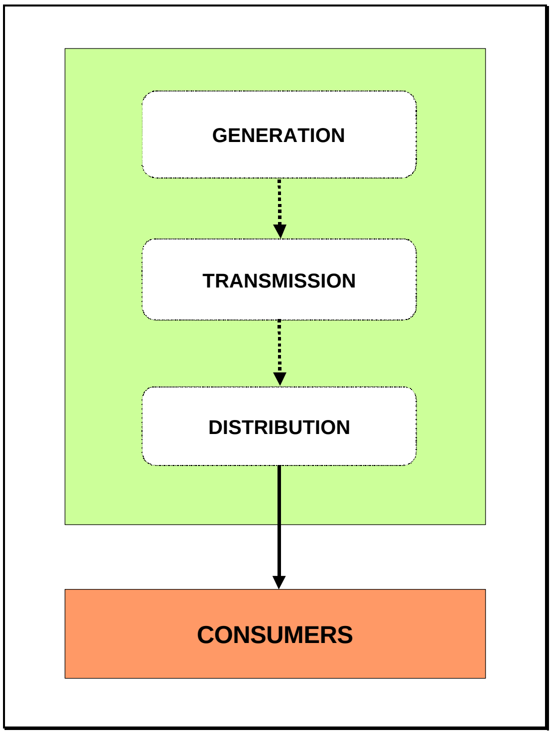
Privatisation *is the selling of government state-owned assets and transfer of ownership.*

VERTICAL INTEGRATION MONOPOLY MODEL (VIM)

CHARACTERISTICS

In this model, there is no competition and no consumer choice. Typically this model is characterised by the existence of one vertically and horizontally integrated system (Figure 9). In some cases, a number of vertically-integrated monopolies may exist, but each has their own separate franchise area of operation – usually mandated in law.

Figure 9 Vertical integration monopoly model



The monopoly utility owns and operates all generation plants, and transmission and distribution networks. It may be under an obligation to supply consumers, but consumers for their part are captive and have no choice of supplier. The service area may be national in coverage. The utility is usually also tightly regulated – usually through price control.

ADVANTAGES

Historically, this model developed as a logical way of dealing efficiently with a number of the rather unique characteristics of the electricity supply industry at a time when rapid industrialisation required rapid growth in supporting infrastructure.

Electricity is physically more complicated to deliver to final consumers than most other goods. Transmission requires split-second control to coordinate supply and demand at any moment. In the early days of development of an electricity infrastructure, it was easy to imagine, and argue, that generation, transmission and distribution were intimately inter-related, were natural monopoly components of the overall supply system, and best handled by a single monopoly structure. This approach also allowed for the construction of large-scale generation plants and transmission systems at a time when economies of scale were important in the industry.

This model allows subsidies and cross-subsidies - as there is no competitive market - as well as investment in public goods such as rural electrification and distribution of power to poor communities.

DISADVANTAGES

The shortfalls of a vertically-integrated monopoly structure have really only become evident in recent years, and in economies with relatively large and mature electricity supply industries. With technological advances allowing for the construction and siting of smaller-scale generation plants closer to demand centres, advances in information technology, the deregulation and development of competition in other infrastructural industries, and the realisation that the sale of the product (electrons) can be separated from the means of transport, it has become increasingly difficult to sustain the argument that a vertically-integrated monopoly structure is the only way of structuring the electricity sector.

The major deficiencies of the vertical monopoly structure that have been identified include: a lack of incentives to improve services and lower costs; a lack of transparency; poor investment decision-making; "gold-plating" of infrastructural components; and political interference.

TRANSITIONAL ISSUES

Dismantling the above monopoly structure normally will involve separating out the potentially competitive generation, wholesaling and retailing elements from the natural monopoly elements of transmission and distribution. The difficulties in achieving this depends on who owns the assets to begin with, what regulatory regime will be instituted to deal with abuses of market power, and what subsidies and cross-subsidies exist.

In the US and Canada, where utilities are largely privately owned and operated, substantial hurdles have existed to electricity industry reform. Because private capital was involved in the creation of the system, and this capital was heavily influenced by decisions made by regulators, there are many political, financial and legal thorns involved in unbundling the system. Where the electricity supply industry was owned and operated by governments on behalf of all taxpayers, the issues are easier to deal with. Provided the separation process is achieved prior to any privatisation, it is a relatively straight-forward matter to disaggregate the system and put in place the regulatory requirements under which the competitive markets and natural monopoly elements will operate.

MONOPSONY MODEL (MM)

CHARACTERISTICS

This model may be considered as a first step towards deregulation, and is actually quite common in the Asia Pacific region. One or several vertically-integrated monopolies still control the sector, but some private investment is made possible by licensing Independent Power Producers (IPPs) to build generation capacity. These may be created from existing utilities by divestiture, or they may be new producers who enter the market when new plant is needed.

With this model, it is possible to have competition in generation, with a single buyer purchasing the wholesale electricity. In reality, this may not happen, instead each IPP might negotiate a separate long-term Power Purchasing Agreement (PPA) with the respective government, often on terms quite favourable to the IPP. Another possible problem with PPAs is that they are often structured so that the energy payment is designed to match, as accurately as possible, the marginal cost of running the plant. Setting energy payments to actual costs incurred gives the generators poor incentives to reduce these costs (Hunt & Shuttleworth, 1996).

The vertically-integrated utility may encourage competition at the generation level, but still has control over transmission and distribution. Retail consumers are still captive.

ADVANTAGES

The major advantage of this model is that it allows for direct inward investment by private investors, and allows investment risks to be shared. This can be particularly desirable where emerging economies are struggling to meet all social priorities out of the public purse.

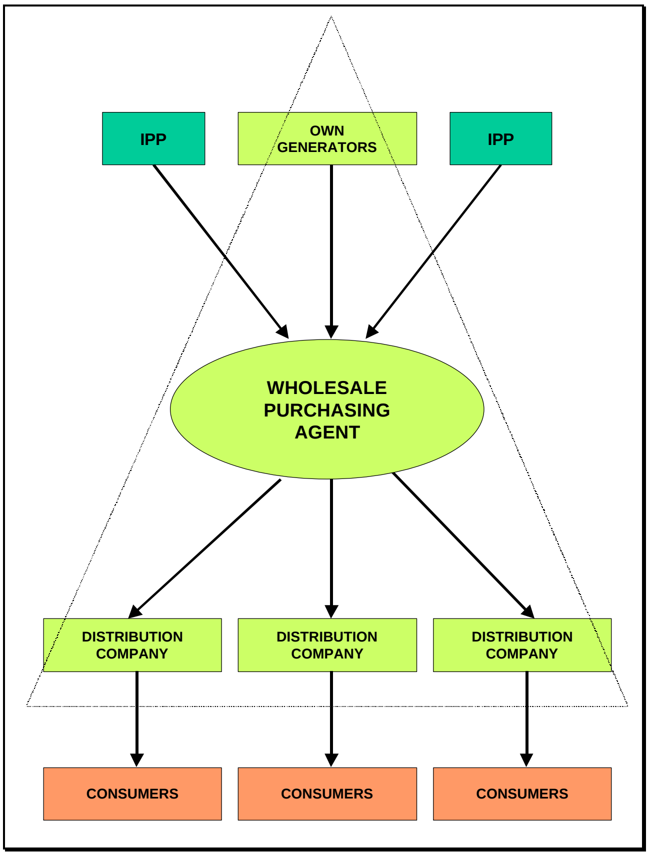
This model still allows governments to use the electricity industry to meet social policy obligations and create public goods, as there is still no competitive market at the electricity retailing level. An important social policy objective common for both this and the previous model, is an “obligation to supply”. Although consumers cannot choose their supplier, or generate their power usually under these models, it is common for the utility to be obligated to supply all consumers, even those in remote areas. It is also possible to maintain uniform tariff pricing to all consumers, regardless of their remoteness from major centres of supply or the transmission grid.

DISADVANTAGES

This model (as shown below in Figure 10) suffers the same problems as the previous model, there is no competitive market, so it is difficult to maintain economic efficiency.

Another potential problem can arise if the single buyer discriminates unfairly between generators.

Figure 10 Monopsony model



TRANSITIONAL ISSUES

The purchasing agent should ideally be independent of the owners of generation, but this is not usually the case when an economy moves from the VIM model to this one. The problem arises where the purchasing agent is accused of discriminating in favour of its own generation facilities. Against this is the fact that the purchasing agency is taking the market risk in this model (as sole buyer, usually under long-term contracts), allowing IPPs to be financed with high proportions of debt. This can allow IPPs to keep their overall cost structures down, and hence be more competitive than the incumbent utility.

If the utility is also the system operator, and is responsible for the dispatch of contracts, there is considerable potential for conflict if the utility uses its position to discriminate against other generators. This is the reason there has been strong support in the US for the formation of Independent System Operators (ISOs). An ISO can manage the dispatching function, or have overall responsibility of the management of the whole transmission system. This would be a further step towards sector reform, and would be more adequately accommodated under the Wholesale competition model (see below).

Despite the potential problems, the Monopsony model can represent a good transitional structure, where the sophisticated arrangements needed for a more complete market structure are not in place and would be hard to establish. For example, an economy where there are as yet no reasonable accounting systems in the industry, proposing a more complicated model may not make sense.

WHOLESALE COMPETITION MODEL (WCM)

CHARACTERISTICS

This model allows a distribution company that retails electricity to consumers to choose their supplier. This brings competition into generation and wholesale supply. In this model, separate distribution companies purchase electricity from any competing IPP generator. The distribution companies maintain a monopoly over energy sales to the final customers (usually within franchise areas).

As there is no longer a single buyer, the market and technology risks are pushed back onto generators, who in return have open access to the transmission network. In this model, an existing generation company has to compete against new entrants. The ability of governments to direct the choice of new generation technology is, by and large, no longer desirable or necessary.

As there can now be a power pool or wholesale power market, it is possible to have a relatively competitive wholesale trading market, where the cost structure of generators is determined by the electricity wholesale price. It is still possible with this model, to have relatively few traders, and have “wheeling” contracts where distribution customers and generators make bilateral contracts to move power from one utilities’ transmission system through that of its competitors. Without very heavy regulation, this form of operation is difficult because of the intrinsic conflicts of interest in a transmission owner opening his network to his competition to steal his customers. (Hunt & Shuttleworth, 1996).

There is still monopoly market power in the sector, as final consumers still have no choice of supplier. This allows for the delivery of certain public goods at the retail level, and some subsidies can be maintained, although it limits the form in which they can be imposed.

ADVANTAGES

As the choice of generation assets (in terms of capacity additions and fuel type) is left to the market, economic efficiency can be improved, and risks transferred from government to private investors. Although investors may seek a long-term contract before building generation capacity, the existence of a wholesale electricity market (which normally includes a spot market) means that such contracts are not essential.

The importance of this model lies in the fact that a decision to introduce wholesale electricity competition indicates that policy-makers have taken the important philosophical step of rejecting heavy handed regulation as an adequate tool to manage the sector, and have instead taken the leap of faith that competition can be introduced into the electricity supply industry, and that social and economic benefits will flow from this decision.

DISADVANTAGES

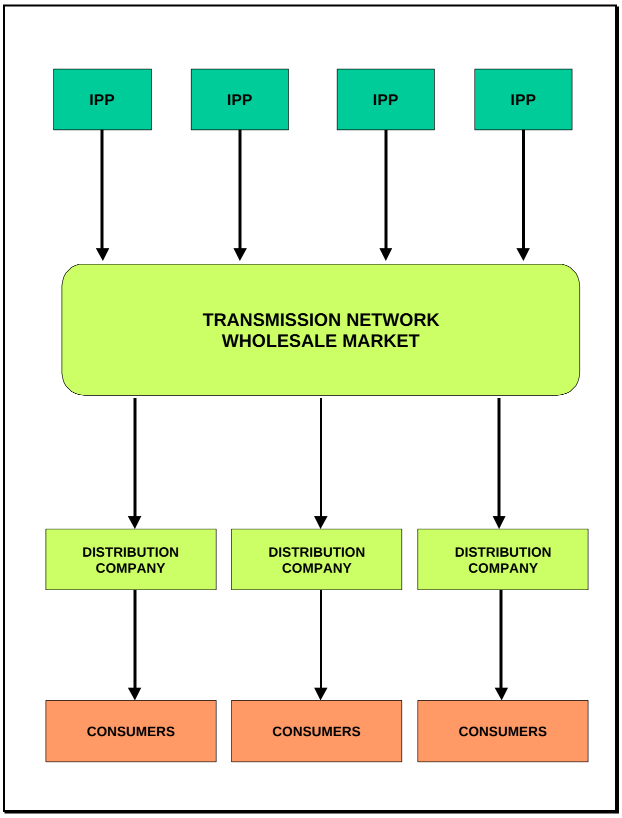
The ability of generators to accommodate social policy obligations connected with generation virtually disappears under this model.

TRANSITIONAL ISSUES

Because generation assets are being valued by the wholesale market (in terms of their comparative competitiveness), the issue of stranded costs begins to arise. This is discussed more fully in Chapter 5.

This model represents only a partial step towards the introduction of competition in the electricity supply industry. Consumers are still captive, and so the full economic benefits of a fully deregulated market are not achieved. However, once the introduction of competition at the wholesale level has been achieved it becomes easier to devise the means to introduce competition at the retail level, and this step usually follows soon after the introduction of a wholesale market.

Figure 11 Wholesale competition model



FULL CUSTOMER CHOICE MODEL (FCC)

CHARACTERISTICS

In this model, competition has been introduced into all levels of the industry, ideally from wholesaling down to individual domestic consumers (Figure 12). A key component of this model is direct (or third party) access to transmission and distribution networks. With the right regulatory structure in place, any electricity consumer should theoretically be able to purchase from any retail supplier, who in turn is purchasing electricity from a competitive wholesale market.

Ideally, the network functions of transmission and distribution (natural monopolies) are completely separated from the functions of generation and retailing. Dispatch can be handled by the transmission network owner, but where more than one transmission network exists, this is best handled by an ISO.

With this structure, there should be free entry by firms into the competitive functions of generation and retailing. For example, in New Zealand the only impediments to investors building generation capacity are environmental requirements under the Resource Management Act. There are no permitting or licensing requirements. This allows anyone, including householders, to build their own generation plants.

The wholesale market operates as an auction, buyers and sellers meet and exchange goods (electrons) on the basis of longer term (hedged) contracts and spot contracts. There is no single buyer. The operators of the market never own the power and never assume the market risk, they merely act as auctioneers, making their income from the transactions.

ADVANTAGES

The advantage of this model is that it optimises economic efficiency, at least once the regulatory regime has been optimised to minimise any market imperfections and control abuses of market power.

The experiences of economies where this model has been introduced suggest that a number of benefits become obvious. Firstly, costs in the generation sector are driven down substantially, and this usually is expressed in lower retail tariffs. At the retail level, competition is beginning to become evident, with the range of goods and services being offered by electricity retailers increasing in both quantity and quality.

Because of the competition in the generation sector, the utilisation factors of individual plants are driven up as non-competitive plant is decommissioned or revamped, and planning is better optimised to match incremental increases in demand. Driving this has been advances in technology, in particular the CCGT.

DISADVANTAGES

As with the previous model the ability to use the electricity sector as a tool to deliver social policy obligations disappears under this model. If there is a need to provide power to poor and/or isolated communities, or to promote a certain sector of the economy (such as industry), this has to be handled using other, market oriented, social policy tools.

It can be argued that the transaction costs involved with managing the contracting aspects of this model are not negligible. The response to this is that advances in material and information technologies reduce such costs sufficiently to ensure that the overall benefits of full electricity market competition outweigh the disadvantages of increased transaction costs. With this model, firms in the industry are free to engage in joint venturing, acquisitions and other market activities. If the initial market conditions are sub-optimal after reform, significant firm-driven industry restructuring can be expected, including vertical and/or horizontal re-integration. The job of the regulators is to ensure that individual firms do not acquire excessive market power, or engage in anti-competitive behaviour.

TRANSITIONAL ISSUES

In the US, there has been some concern expressed that Demand Side Management and other energy efficiency policies and measures are negatively impacted by the introduction of competition. There are also concerns about long-term R&D and environmental impacts. These can be considered transitional issues, as reforms will require policy-makers to devise new ways of dealing with some of these issues, and allow the market to deal with others.

A substantial issue still under development is that of metering. With the possible introduction of sophisticated meters in individual households in the near future, the demand side management, and customer choice issues could be dealt with by technology. Consumers may be able to optimise their end-use to take advantage of lower tariffs in certain periods, and be better placed to shop between retailers.

The stranded costs problem, if it exists, becomes much more acute under this model (Hunt & Shuttleworth, 1996)

Figure 12 Full customer choice model

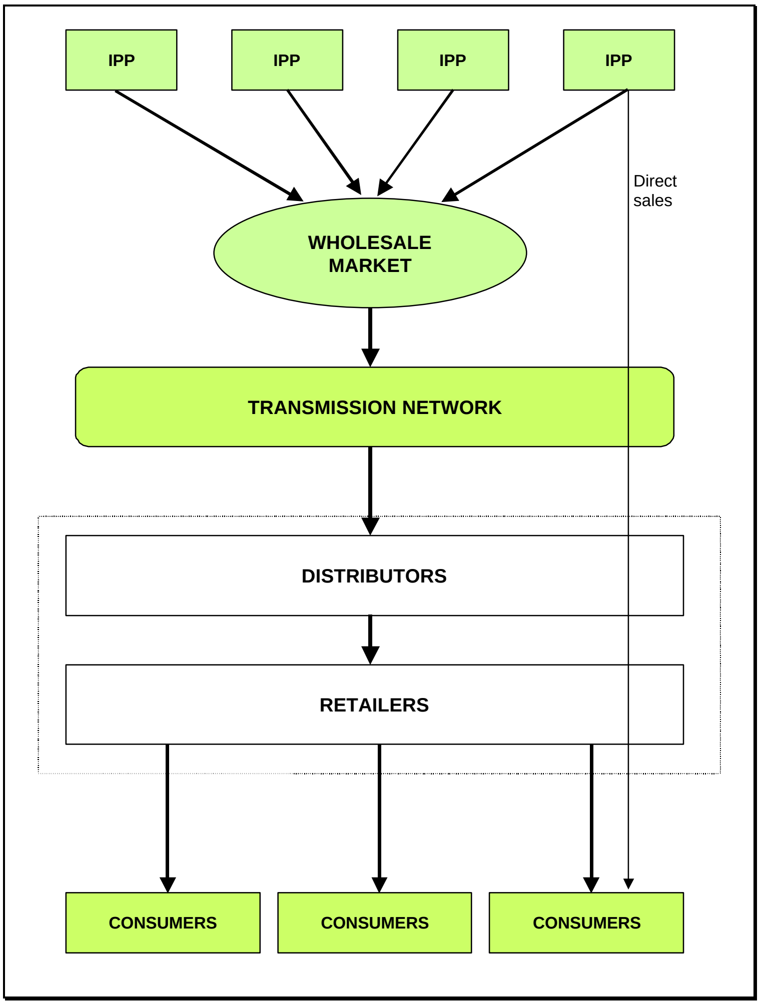


Table 6 below describes the four structural models in terms of their characteristics, from the most regulated (VIM model) to the least (FCC model).

Table 6 Characteristics of theoretical power sector models

Model of Power Sector Structure	VIM Model	M Model	WC Model	FCC Model
Definition	Monopoly	Monopoly	Competition among power generators	Competition among power generators
	At every level	With single buyer	Plus choice for distributors	Plus choice for consumers
Competition in Generation?	No	Yes	Yes	Yes
Retailer choice?	No	No	Yes	Yes
Customer choice?	No	No	No	Yes

Source: Adapted from Hunt and Shuttelworth (1996).

MODEL STRUCTURE AND OWNERSHIP

Based on the above theoretical models, the status of each APEC economy can be expressed, as set out below.

Figure 13 The degree of electricity sector competition in the APEC region

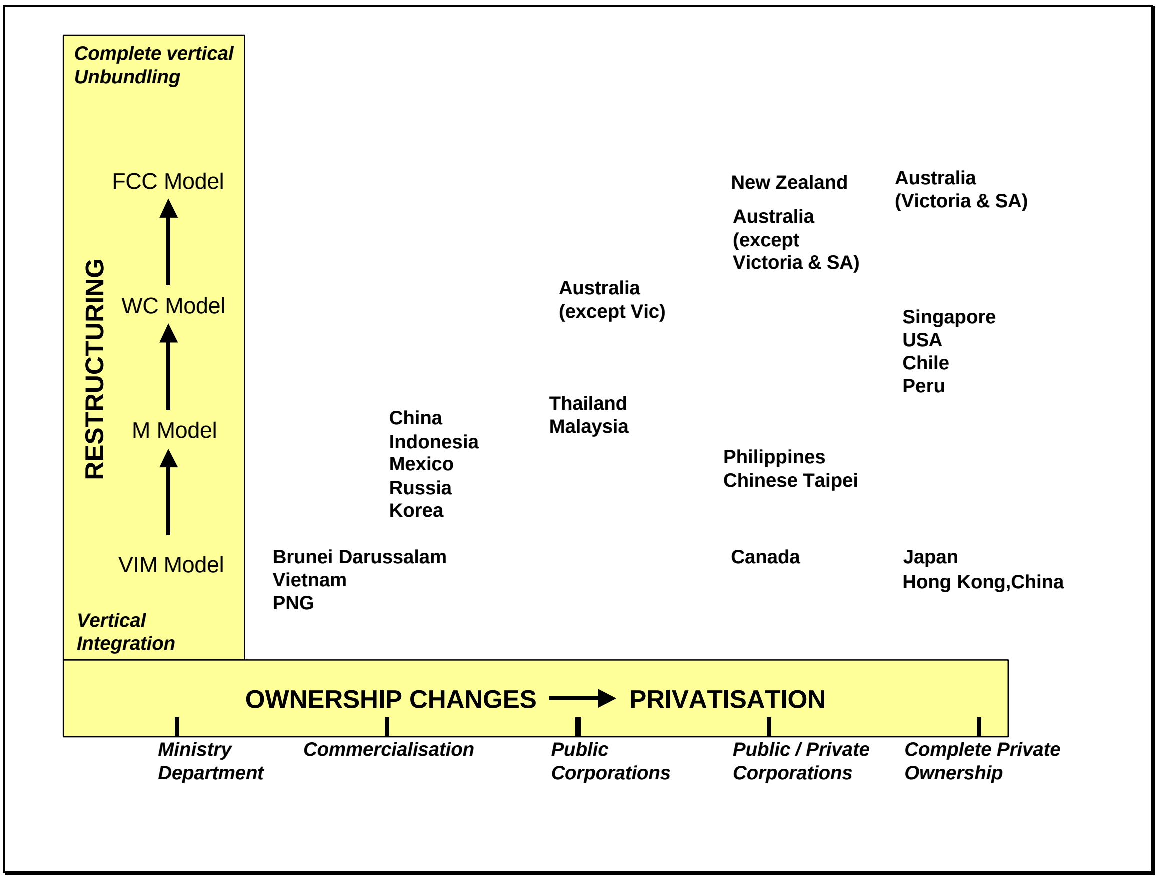


Figure 13 and Table 7 show in broad outline how the theoretical models apply to each economy in the APEC region. The vertical axis shows a gradation from vertically-integrated monopoly, to full competition. The horizontal axis shows the degree of government control. The trend in time is a shift from the bottom left of the diagram to the top right side of the diagram.

Table 7 Theoretical models of electricity sector operation in the Asia Pacific region

Economy	Reform Model	Degree of unbundling
Australia	Wholesale competition/National Electricity Market (pool)	Separated transmission and unbundling of distribution
USA (California)	Wholesale competition Pool	Unbundling transmission and bundled with supply
Chile	Cooperative generation pools with retail wheeling	Unbundling of distribution
Peru	Wholesale competition/Pool	Unbundling of distribution
New Zealand	Full competition	Full unbundling with incomplete privatisation
Malaysia	Monopsony/competitive bidding in generation	Unbundling of generation and transmission under consideration
Thailand	Monopsony/competitive bidding in generation	Unbundling of distribution and generation in progress
China	Monopsony/competitive bidding in generation	Partial unbundling of generation and transmission
Japan	Monopsony/competitive bidding in generation	Bundled transmission and distribution
Singapore	Wholesale Competition/Pool	Unbundling of generation and supply
Viet Nam	Monopsony/competitive bidding in generation	Generation & transmission to be run as profit centres
Indonesia	Monopsony/competitive bidding in generation	Unbundling generation
Russia	Monopsony/competitive bidding in generation	Vertically integrated/partial unbundling in generation
Brunei Darussalam	Monopoly	Vertically integrated
Chinese Taipei	Monopsony/competitive bidding in generation	Vertically integrated/partial unbundling in generation
Hong Kong (China)	Monopoly	Vertically integrated
Papua New Guinea	Monopoly	Vertically integrated
Mexico	Monopsony/competitive bidding in generation	Vertically integrated/Unbundling generation in progress
Philippines	Monopsony	Vertically integrated/Unbundling generation and supply
Korea	Monopoly	Vertically integrated/Unbundling generation
Canada	Monopoly	Vertically integrated

CONCLUSIONS

Although theoretically, there may be one ultimate reform model that all economies should aim for, the world is more complex than this. In the Asia Pacific, economies vary regionally from the wealthiest globally to some of the poorest. They also vary greatly in size. For example, a full competition model might not make a lot of sense in an economy like Papua New Guinea with a total installed capacity of around 262 MW.

Economic and social policy objectives also vary widely. It is perhaps more sensible to acknowledge the diversity of economic and social policy goals, and to acknowledge that, at this point in history at least, a number of useful models can be constructed, and any one of these might be the most appropriate to suit the individual needs of a particular economy.

CHAPTER 5

ECONOMIC POLICY CONSIDERATIONS

INTRODUCTION

The regional trend of electricity sector reform is being driven largely by the perceived benefits in terms of improved economic efficiency, lower electricity prices, and access to much needed capital to fund infrastructural growth. Apart from a few cases, reform is replacing vertically-integrated structures with ones in which there are vertically and horizontally disaggregated competitive elements.

While the maximisation of economic efficiency is a primary goal, security of supply is another interacting consideration of some importance. In developed economies with established energy infrastructures, demand growth tends to be relatively low, and in many instances significant generation over-capacity has existed over the last few years. With market liberalisation, this reserve capacity has tended to diminish substantially, leading to public concern about supply security, especially with respect to potential disruptions (which can result from abnormal weather patterns, natural hazards, or a mechanical failure of some kind in the supply system). In developing economies, security of supply is also a major issue, but for a different reason. In many cases, capacity growth can't keep up with the potential demand, and an urgent requirement exists to draw more capital into the sector to improve the adequacy of the electricity supply system, and hence supply security. Market liberalisation in this situation, may be seen as a means of increasing investment in the sector, and hence bolstering security.

CONVENTIONAL ELECTRICITY SECTOR STRUCTURE

Historically, it has been assumed that a vertically-integrated, state-owned monopoly would deliver electricity at least cost, and with the greatest degree of security. Because electricity was considered a strategic asset, and security of supply was vital during the industrialising process, there was some merit in this idea. It also made sense to believe that it was much more efficient to have electricity dispatched and delivered by internal commands within one organisation. This idea was rooted in the fact that electricity is no ordinary product – the electrons cannot be stored in large quantities, and supply must match the load from instant to instant to maintain the voltage and frequency within acceptable limits.

In a vertically-integrated business, costs are internalised. Vertical desegregation raises the issue of the transaction costs imposed by the need for upstream to downstream products and services to be negotiated through contracts (Williamson, 1977). For a discussion of the "transaction cost" framework developed by Williamson, please refer to Appendix IV.

EFFICIENCY GAINS IN COMPETITIVE ELECTRICITY MARKETS

Although vertically-integrated, bureaucratic structures can be efficient at undertaking certain functions, significant inefficiencies can creep in over time due to the lack of competitive pressure and efficiency benchmarks, and a lack of transparency. Because of the nature of the electricity industry, requiring a high degree of contingency capability, the generation capacity of state operated systems in many economies were typically "gold plated" (IEA, 1999c). Many instances can be found where generation facilities existed solely for contingency purposes, and to manage infrequent peak demand situations. In New Zealand, for example, an economy heavily dependent on hydro capacity (67 percent of total installed capacity), and hence subject to very infrequent "dry year" shortages of capacity, the Marsden B power station was built solely for just such a contingency. It was designed to run on fuel oil, and during its entire lifetime, was never called.

State-owned sectors are also often over-staffed by the standards of most competitive industries. This results in substantial labour shedding when reform is instituted. For example, in England and Wales, Australia, Chile and New Zealand, there were a significant number of layoffs post-reform, largely in the generation sector, but also in management and maintenance of networks.

Another source of cost reduction relates to fuel choice, and more specifically to attempts to maintain security of supply by favouring one particular fuel through subsidisation. When a cheaper fuel becomes available, regulations designed to protect certain fuels become an obstacle to overall cost reduction. Coal has usually been protected through subsidies on price, or through regulations preventing alternatives. In the UK prior to deregulation, the relatively expensive domestic coal was subsidized, and gas was barred from use in generation. After deregulation, the "dash for gas" brought about not only a large shift from coal-fired generation to gas combined cycle generation, but substantial savings in fuel costs.

There are also considerable cost savings possible from improvements of performance in the existing generation, transmission and distribution system. In the past, little incentive existed to replace old, inefficient plant, as costs were not overly transparent. Generation plants have traditionally been kept in operation well past their commercial lifetime, which can be long anyway, so a lot of old infrastructure exists in the sector.

Of great significance today in the sector are the efficiencies now available through recent technological advances. Combined cycle gas turbines are available "off-the shelf" at much lower capital cost per MW than most other forms of plant. These allow small-scale units to be quickly installed, and providing the gas is available, allow for flexibility in siting. CCGT plants are leading the trend towards more distributed forms of power, a trend that may gather significant momentum in the decades ahead, with consequences for the established network infrastructure.

Technology has also had a very large impact on the processes of dispatching and wholesale pooling. Wholesale markets can now be set up easily and cheaply, and can be operated at a distance using the Internet and other electronic means of communication. As long as the market participants agree to the rules, it can operate with high efficiency. Dispatching can be handled just as easily and efficiency, regardless of firm ownership.

POWER SUPPLY INDUSTRY COST STRUCTURE

The power generation sector has the largest share in terms of total electricity supply cost, and so is likely to be the major source of cost reduction. As seen in the table below, in case of the UK, the generation sector shared about 65% of the total supply cost of electricity.

Table 8 Structure of the power sector supply chain in the UK

Function	Fraction of Total Cost
1. Generation	65%
2. Transmission	10%
3. Distribution	20%
4. Supply	5%

Source: IEA (1999).

VERTICAL DESEGREGATION AND TRANSACTIONS COSTS

Historically, vertical integration was considered the optimal way to minimize transaction costs associated with asset-specificity, frequency of transaction, uncertainty and complexity. Therefore, it is sensible to assume that post-reform unbundling will increase transaction costs, and reduce the overall economic efficiency gain. In practice, the hidden costs associated with vertically-integrated bureaucracies may have been sufficiently high to greatly outweigh any minor increase in the cost of transactions between independent firms operating in a competitive market environment. Technological development is also helping to reduce the transaction costs associated with the workings of wholesale electricity markets, and will have a profound effect on retail markets.

TECHNOLOGY – A SOLUTION FOR IDIOSYNCRASY

Technological development has also made power supply assets less idiosyncratic. For instance, CCGT power plants are now designed in standardised modules, are largely constructed off-site (with automated production, off the shelf computerized control systems, and are easily transportable to any place in the world. With "virtual reality" 3D computer simulations, design changes can be easily accommodated, and many of the costs established before commitments are made by purchasers. With the introduction of market liberalization, where market risks may be higher, investors can more easily enter the market with standardized generating facilities, reducing the transactions costs.

Table 9 shows the progress made between 1990 and 1995 based upon Siemens power plant data. Although this result is not comprehensive enough to be generalized, it shows that there are significant cost reductions in plant cost ($/kW), and generation costs (US cents/kWh). Also, it should be noted that efficiency is improving in each power generation system. Delivery times have been cut sharply from 36 months to 24 months with respect to CC power, and 60 months to 30 months for coal steam power.

Table 9 Cost analysis for combined cycle and coal steam power plants in the US

	1990		1995	
	CC	Steam	CC	Steam
Parameters for life cycle cost analysis				
Plant costs ($/kW)	500.0	815.0	345.0	440.0
Efficiency (%)	52.2	40.4	57.2	42.0
Fuel costs ($/m BTU)	3.3	2.0	3.3	2.0
Delivery time (months)	36	60	24	30
Electricity generation costs (US cents/kWh)				
Fuel	3.5	3.1	3.3	2.9
Operating	0.7	1.7	0.5	0.8
Capital	0.8	1.4	0.5	0.7
Total	5.0	6.2	4.3	4.4

Notes: Parameters for life-cycle cost analysis and electricity generating costs of combined cycle and coal steam power (2x660MW Units).

Source: Hansen, (1998).

THE INTERNET – DEALING WITH FREQUENCY

As is the case for other commodities, the Internet is beginning to play an important role in billing, retail marketing and wholesale marketing in the USA, and this will result in transactions cost minimization. The Internet has also become a key tool for wholesale power markets.

- Customer Billing

  It is now possible for customers to pay their bills over the Internet. In May and July 1999, Consolidated Edison of New York Inc. and PECO Energy announced respectively that as many as 5 million customers may register to receive an electronic bill, or "e-bill", over the Internet through TransPoint, a joint venture of Microsoft and First Data Corp, instead of receiving their utility bills through the mail.

- Retail Marketing

  Power suppliers are using the Internet to market their electricity to utility customers where customer choice laws have been enacted. For instance, the ConEdison subsidiary ConEdison Solutions, offers prospective business and residential customers a chance to choose it as energy supplier through its website. By simply going to the sign-up section, large/small commercial and residential customers can fill in the form to be supplied. Power marketers[1] are also beginning to use the Internet to capture customers. For instance, Utility.com, an entirely web based company, launched its business in March 1999. They sell electricity to residential and business consumers via the Internet at low prices, since they can reduce operating costs, compared to incumbent utilities.

- Wholesale Marketing

  Several websites have been created for wholesale energy trading in the USA. Their advantage lies in the relatively low cost of the Internet compared to costly dedicated lines that support electronic trading platforms, such as the Bloomberg Power Match. However, there are concerns about security and privacy issues, site reliability and the lack of a paper trail to record trading terms.

The Website can be a powerful tool for customers to shop around for cheaper electricity. Also, it may become a powerful tool for suppliers and marketers to capture customers, without spending amounts on advertising. The advantage for customers is the ease of accessing information and the simple format for filling in an application.

Some marketers even plan to use the Internet to establish an Online Power Supermarket, with a database providing customers with analysis of all power and utility costs, along with a complete list of providers in certain service areas.

CALIFORNIA RETAIL SALES CASE

In California, competition in retail electricity sales began in April 1998. Since then, consumers in California have been able to choose between: (1) a Utility Distribution Company (UDC) or (2) an Energy Service Provider (ESP). The UDC is the incumbent distribution company, while an ESP is a new electricity supplier that offers a range of energy services.

After March 1998, only 123,148 customers out of a total of 10,000,000 (or 1.3 percent) had changed their supplier to an ESP. However, for large industrial customers, 20.3% had undertaken a contract with an ESP. This shift is attributable to price competition. On the other hand, only 1.0% of total residential customers have changed supplier from a UDC to an ESP.

For residential customers, a tariff reduction before liberalization is thought to have lowered the incentive to change supplier. The transaction costs involved in searching, coordinating and negotiating with a new ESP would also be a factor. ESPs also have little incentive to chase the custom of householders because of the relatively small margins involved.

1 "Marketer" is any entity that buys electric energy, transmission, and other services from traditional utilities and other suppliers, and then resells those services at wholesale or to an end-use customer (http://www.cpuc.ca.gov/electric_restructuring/esp_registration/glossary.htm)

STRANDED COSTS

WHAT ARE STRANDED COSTS?

Stranded costs can be defined as costs utilities have incurred historically, but may not be able to recover in the prices they are able to charge as a result of policy changes. In order to meet national and public service obligations, many utilities, both public and private, have made substantial investments - including the construction of nuclear power plants. A significant percentage of this investment may not be recoverable in a competitive environment. The term, 'strandable' may be more suitable than 'stranded' as some part of past investments may be recovered over time.

Historically, in all states in the US (and even today in many states), the level of utility profit was tied to the level of capital investment made by the utility. As profit would increase with amount of invested capital, utilities had an incentive to maximise their capital investment, so long as they could show that it was "prudent" and providing benefits to consumers (Fisher et al, 1997). Given this regulatory framework, not all US utility expenditures have been wise investments.

A recent Moody's report (Moodys Investors Service, 1999) estimated that US investor-owned utilities had potential stranded costs of around US$10 billion, a much smaller figure than previous estimates made by Moodys in 1995 of US$130 billion. Previous estimates by others (Fox-Penner, 1988)[2] ran as high as US$200 billion, a figure that would exceed the total value of the equity in the US electricity sector (Hirst and Baxter, 1995).

Stranded costs represent a significant policy problem, especially where attempts have been made to recover these costs over the short-term by allowing retail electricity prices to rise significantly above marginal costs. The difference between the current low marginal cost of electricity generation and existing tariff rates set to cover the past investment has been a major driving force for the introduction of competition. As the difference becomes greater and more apparent, consumers are likely to leave incumbent electric power suppliers in an attempt to lower their electricity bills. In this case, the investment cost may not be recovered by those utilities that made large capital investment in generation and networks under a past regulatory regime.

Stranded costs are of great importance to economies in transition to competition because the financial burden can be very large, no matter who bears it. If government is held responsible for the debt such as in the 'regulatory compact' argument, it would be redistributed as a tax on all citizens. If electricity consumers are forced to pay the debt (through higher tariffs), this creates an un-level playing field with respect to new entrants not burdened by these costs. The utilities straddled with this burden under free market conditions will likely suffer serious financial losses, possibly leading to bankruptcy.

Classic examples are nuclear power plants in the United States. Early retirement of most nuclear plants to date has uncovered a number of factors that deserve attention. One problem is the inability to collect funds for the decommissioning of plants that have been (or will be) retired early, preventing the accumulation of sufficient funds to manage the decommissioning process. This problem exists largely because of a gross underestimation of decommissioning costs. For example, interim waste storage costs have not been adequately reflected in decommissioning trust funds in the United States, and nuclear decommissioning liabilities in general were not financially covered. As seen in the case of the decommissioning of Yankee Rowe in Massachusetts, which was retired early, the cost over-run in decommissioning created serious financial problems for utilities as well as regulators.

Some APEC economies may face the stranded costs problem with respect to nuclear plants sooner or later. In particular, Japan and Korea depend heavily on nuclear power generation, and may find it difficult to avoid this issue in the future if these plants prove to be uneconomic in a

2 See for details Table 16-1 in Fox-Penner (1998).

competitive environment. The problem could be heightened if nuclear power plants must be shut down earlier than originally planned, for reasons other than economic ones.

TYPES OF STRANDED COSTS

There are four main types of stranded costs (Fox-Penner, 1998). The first results from a combination of increased competition and technology development, which brings in new competitors with cheaper electricity production capacities than existing plants. These new competitors could put old plants out of business by charging customers less for the electricity generated.

The second type originates from long-term fuel or power purchasing contracts with governments to which regulated utilities are committed to ensure security of electricity supply. As competition could provide lower cost alternatives, those utilities tied to uneconomic obligations would inevitably be faced with higher input costs, resulting in loss of earnings. Eventually this will make cost recovery difficult.

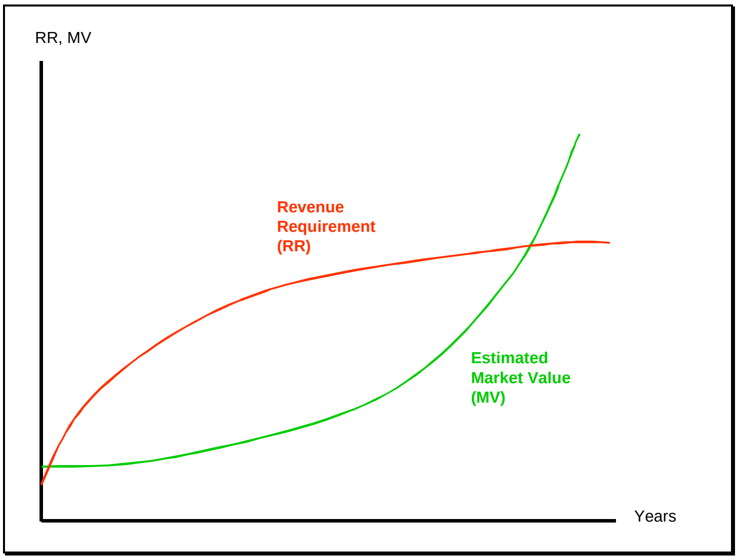
The third type is associated with "regulatory assets." Regulatory assets are an assortment of regulator-approved 'extended payment plans' for certain kinds of large expenditure incurred by regulated utilities. Easing utilities' financial obligations from such expenditure, regulators allow them to amortise costs over an extended period of time. However if the regulatory regime changes during the middle of the amortisation period, utilities may not be able to complete the amortisation due to deregulation-induced low prices.

The fourth type of stranded costs are miscellaneous public-policy programs ranging from Demand Side Management (DSM) programs paid for by all customers, and support for energy research and development. Investment in all these policy programs would be stranded as their cost recovery becomes impossible after deregulation.

STRANDED COSTS ESTIMATION

Stranded costs are differences between the projected and realized net values of an investment, taking into account revenues and expenditures, which come into being where retail electricity prices are above marginal costs. When utilities cannot produce electricity at prices equal to marginal costs, customers are likely to leave them for other utilities, putting investment at risk of being stranded.

Figure 14 Diagram showing calculation of stranded costs



Estimation of stranded cost seems simple, but is complicated in practice due to a number of factors. Among them are the projected market prices of electricity, operating and maintenance costs including fuel prices, interest rates, technology development, and government regulations, to list a few. For example, rising fuel prices for inefficient facilities[3] would shift the RR curve in Figure 14 upward, which will lead to higher stranded costs. The same is true of rising interest rates. Thus projections of stranded costs for a single economy could vary widely with assumptions about these variables.

Stranded cost could be calculated with the following formula:

Stranded Cost (SC) = Required Revenue (RR) – Market Value (MV) - where:

RR = g{Load Factor (-), Fuel Cost (+), Interest Rates (+), Deferred Cost (+), etc}, and

MV= f{Avoided cost (+), Costs for new entrants (+), etc}

WHO SHOULD BEAR THE COSTS?

Presuming that stranded costs are incurred as a result of regulatory changes, the question of who should bear them becomes a key policy question (Boyd, 1996). The utilities who made investments under pressure from regulatory agencies - over and above what would be prudent in a free market - and who are looking to recover these costs to the greatest extent possible, argue that they must be fully compensated, because the investment decision was forced on them at the request of governments.[4] At the time of the investment, an 'implicit social contract', was made to ensure full recovery of investment costs. Contracts, however detailed, cannot cover all contingencies, mandating cost recovery in the event of a regulatory regime change. Further it has been argued (Sidak & Spulber, 1996) that deregulatory actions constitute the government's taking of private property, which was prohibited under the United States Constitution's Fifth Amendment.[5] This is known as a "taking" argument in favour of full recovery of stranded costs.

Regulators have argued that the chance of non-recovery of costs was just as implicit in the contract because contracts (in this case, franchise agreements) do not explicitly specify liability for stranded costs. Further they claim there is evidence in the contracts made under regulation that regulators never prevented utilities from recovering costs, but on the contrary encouraged this. The existence of contracts that specified a minimum term for customers to stay with a particular utility or face cancellation charges for service termination has strengthened their argument.

There is no easy solution to this issue as every contract was made under different circumstances, and interpretations even with respect to a particular contract could differ quite substantially. Both legal and economic reasoning could help address this problem. Brennan and Boyd (1997) provide a good exposition of the pros and cons regarding the compensation issues of stranded costs. On a spectrum between no compensation and full compensation, most experts take the middle ground, suggesting that there is an implicit deal (Fox-Penner, 1998)[6] in the contract, but it does not necessarily imply a guarantee of full recovery for the investment made under regulation.

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3 An example would be an old, inefficient oil-fired power plant faced with rising oil price.

4 Regulators here mean public bodies, which regulate and influence investment decisions of utilities.

5 The United States Constitution's Fifth Amendment states "No person shall be held to answer for a capital, or otherwise infamous crime, unless on a presentment or indictment of a Grand Jury, except in cases arising in the land or naval forces, or in the Militia, when in actual service in time of War or public danger; nor shall any person be subject for the same offence to be twice put in jeopardy of life or limb; nor shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty, or property, without due process of law; **nor shall private property be taken for public use, without just compensation.**"

6 Peter Fox-Penner has described it as " utilities are granted exclusive franchises in exchange for an obligation to render adequate service at reasonable prices to all within the franchise."

In a nutshell, a general view is that the size of recoverable costs should be determined on a case-by-case basis, depending on the specific attributes, and without discouraging cost saving efforts by those who want compensation. If a fixed rule for cost recovery is applied, utilities may simply shift costs into the account of stranded costs.

HOW TO PAY FOR STRANDED COSTS?

There have been a number of studies on the ways to recover stranded costs. In the APEC region most of them were conducted in the United States. The most important factors for consideration include the economic consequences, both in the short and long run. Given the economic situation there are a number of ways that have been implemented or suggested. In the US FERC Order 888 allows public utilities and transmission companies to fully recover stranded costs from those customers wishing to leave their current supply arrangement.

There are other methods of collecting stranded costs. It is possible to view these strategies from the perspective of whether they are transaction or non-transaction related. The classification adopted in the NRRI study (NRRI, 1994) is as follows:

Transaction-Related Recovery Devices

- Access charge tied directly to continued transmission or distribution service
- Exit fees charged to departing customers but unrelated to costs incurred on behalf of those customers
- Exit fees charged to departing customers and calculated to recover costs incurred on behalf of those customers
- A share of net generation savings realized by departing customers over time

Non-Transaction-Related Recovery Devices

- Shifting costs to captive customers
- Charging ratepayers above-cost prices where market exceeds cost
- Accelerated and decelerated depreciation
- Price cap on performance-based rates

Broader Bases

- Entrance fees charged to new generation
- All sellers pay a per-kWh tax on generation
- Taxes to include credits for financial write-downs or trust funds to subsidize buyout of contracts from non-utility generators

There is no best way for all cases. Each of the above 11 strategies (US DOE, 1999) has to be evaluated to determine its applicability in comparison with other strategies considering differences in economies or regions. The criteria must include consideration of static and dynamic efficiency, consistency with evolution to a competitive market, consistency with regulatory quid pro quo, and difficulties in implementation.

SECURITY OF SUPPLY

The question of supply security has been much debated within economies undertaking electricity sector reform. Two issues are important, the securing of long-term supplies of generation fuels at affordable prices, and the reliability of the electricity system. The maintenance of adequate generation reserve capacity is a component of the system reliability concern.

The introduction of competition into electricity generation results in strong pressure to reduce investment and operating costs. The incentives to void over-building and over-designing power plants, and to reduce operation and maintenance costs, raises the possibility that reserve capacities could drop to levels well below what is prudent to manage contingency situations. In the US, the concern over this issue has brought about suggestions that an explicit market may need to be created for capacity, and policy tools implemented to achieve this, including capacity payments (IEA, 1999c).

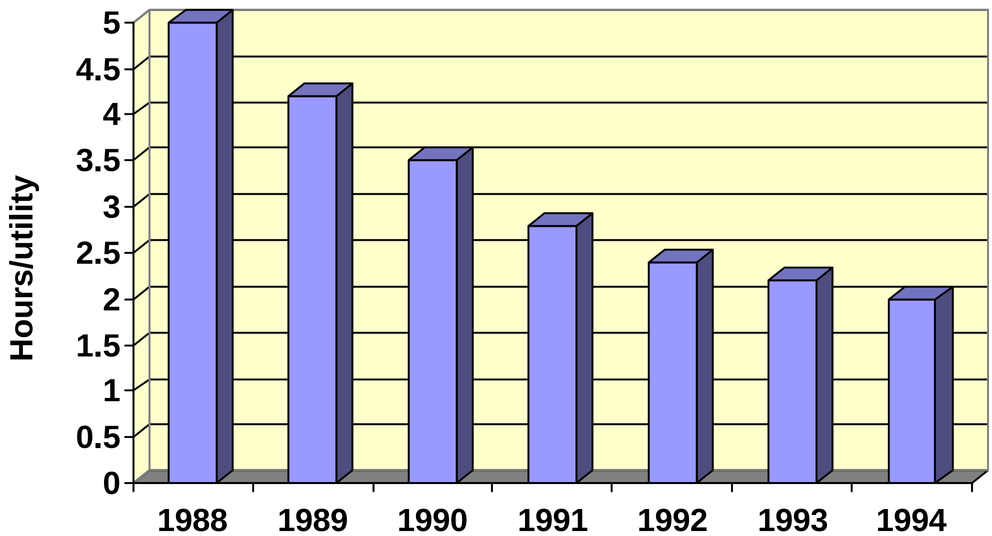
Arguments about reserve capacity can be considered a component of long-term reliability, which requires the planning and the construction of enough aggregate capacity (generating and network) to balance total demand and supply at prevailing prices at all times. Short-term reliability requires adequate reaction to load fluctuations over time scales ranging from microseconds to months.

RELIABILITY IN DEREGULATED POWER MARKETS

Electricity sector reform has had a short history worldwide. Although some economies undertook partial reform measures during the 1970s and 1980s, most substantial reform has occurred in the 1990s. This leaves a very short timeframe over which to try and assess whether the impacts with respect to the overall reliability of the system will be positive or negative. This question will also obviously be affected by policy decisions made in the near term to address real or perceived problems in this area.

From a theoretical perspective, appropriate market signals with respect to the need for additional generation capacity or network upgrading, along with market incentives to maintain the provision of high quality services, should ensure sustainable and efficient allocation of capital. If true competition develops through the supply chain, suppliers will compete to provide a range of products and services, including the level security of supply demanded by customers.

Figure 15 Chile: Dynamics of emergency attention



Notes: Average annual time in hours

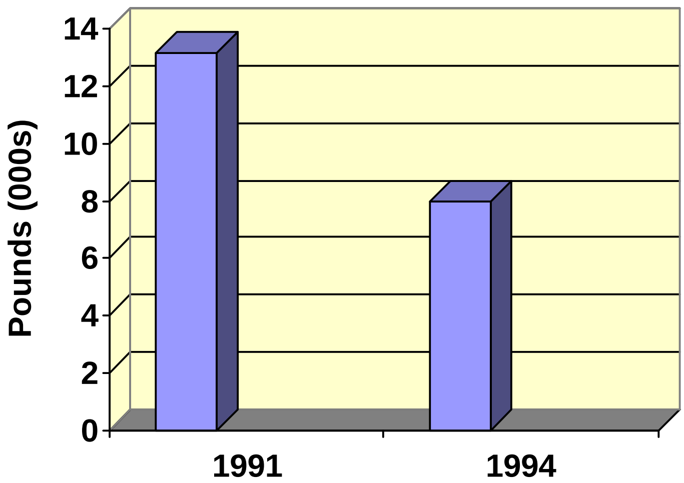
Source: Klenner (1999)

Although time trend data is scarce, some information for Chile and UK does exist as shown below, and tends to reinforce the view that reform should ensure that high levels of reliability are maintained, or may actually improve post deregulation.

During the process of deregulation the quality of service experienced by electric customers depends on the extent of cooperation between regulated and liberalised stages. In deregulated electricity markets reliability becomes an economic marketable good. It should get a special position in electricity bills. For customers it is possible to make tradeoffs between price and quality, and the marketplace provides a variety of qualities and prices from which to choose.

The key change in the deregulation process is from reliability defined by service obligation in the vertical integrated scheme to reliability defined by contractual scheme involving generators, distributors and customers in liberalised markets. The emphasis on technical system reliability is shifting towards economical system reliability. The structure of contractual relations among the parties in liberalised markets should be designed with the appropriate level of reliability.

Figure 16 England/Wales: Payments for failure by supplier under guaranteed standards



Note: Annual average per 10,000 services in thousand pounds sterling.
Source: Klenner (1999)

THE INDUSTRIAL SECTOR AND THE IMPACT OF REFORM

Over the course of the present century, electricity has become a preferred form of energy in the industrialised world. The industrial sector is a large consumer of electricity sold by utilities, and in addition, undertakes a substantial amount of self-generation, usually in combined heat and power facilities. The Manufacturing Energy Consumption Survey 1994 (DOE/EIA, 1997) showed that most of the electricity used in the industrial sector in the United States (80 percent) is used for the purpose of manufacturing. Of all of the electricity used, the greatest portion (54 percent) was used to drive electric motors.

The paper and chemical industries are the largest electricity users in the manufacturing sector. The third largest user of electricity, the primary metal industries, also used electricity mainly for processing, but only a small share is used to drive motors. In 1994, the manufacturing industries in the United States bought 788 billion kWh of electricity. The annual electricity expenditure in the industrial sector for electric motor-driven system was over US$33 billion.

Historically, in many economies, the electricity tariff for industrial customers was lower than for other customer classes, due to subsidisation by governments to encourage industrialisation.

However, in some situations such as in certain states in the United States, cost accounting methods show that industrial customers pay more than their share of the common capital cost of generation and distribution, and residential customers pay less, due to perception of fairness.

In a fully competitive market situation, subsidies are usually eliminated because they seriously distort the effective operation of the market. Large industrial consumers have market power however, and will benefit from an ability to negotiate favourable tariff rates in a competitive market. Electricity suppliers will be willing to charge lower tariffs to customers who represent economies of scale from a supply perspective, and can guarantee load levels over long time frames. For these reasons, and because reform will lower the overall cost of electricity supply, industrial firms have supported calls for electricity sector deregulation. Lower electricity bills for large manufacturing industries have important consequences for profitability and international competitiveness.

ELECTRICITY PRICES FOR INDUSTRIAL CUSTOMERS

Deregulation in the electricity industry is considered to have brought efficiency improvements in industrial sectors as well as in related sectors. Evidence suggests electricity price reductions have occurred in the industrial sector in some economies. In the United Kingdom, industrial tariffs are currently the fifth cheapest in the European Union, less expensive than in Germany, Spain, Italy and France. At present there are 55,000 contestable customers in the above 100-kW market. This contestability was extended to all customers in 1998.

US electricity prices to industrial consumers, in contrast to those in Europe, remained essentially flat between 1984 and 1995, although overall electricity prices have fallen every year since 1982 (Oldak, 1998)

With regard to the availability and reliability of electricity sold by utilities, large industrial companies may prefer to build their own electricity generation on-site. This is often the case for the pulp and paper and chemical industries. In 1994, 90 percent of the self-generation in manufacturing industries in the United States involved cogeneration. Some economies also set their regulations to provide incentives for industries to develop self-generation.

In Chinese Taipei and Singapore, a number of industrial companies that have on-site cogeneration plants have excess capacity, and are able to sell their surplus electricity to the national grid. The impact of restructuring on the future of cogeneration systems will be influenced by the wholesale price of electricity. A lower market price may discourage manufacturers to build generation capacity, while higher price may increase incentives for cogeneration, especially for small industries with small electricity loads.

TRANSPARENCY

In a fully competitive market, all electricity consumers should be able to choose their retail supplier, based on price and/or quality of services provided. In such a situation, consumers need good price and service information, in order to make informed purchase choices. In the past, electricity bills were normally comprised of a tariff and delivery charge, and this is still a widespread practice. In California, electricity bills (as shown in Figure 17) now reflect a high degree of transparency in the delivery of services, and as shown below, the bill is fully itemized, with 7 different components making up the total charge of US$29.73. With this degree of transparency, it is possible for the consumer to see what each component costs to deliver, and makes it more difficult for firms to pass on hidden costs.[7]

[7] Appendix VII shows typical electricity bills for a number of other selected economies.

Figure 17 Typical electric power bill for a consumer in California

PG & E Pacific Gas and Electric Company Energy Statement

EPRI

JANE SAMPLE
KJQ 99 99999-9

ELECTRIC ACCOUNT DETAIL

Rate Schedule: E1 TB Bundled Services
Service: From 05/12/98 To 06/10/98 Billing Days: 29 Electric Meter #: J99999

	Prior Meter Read	Current MeterRead	Difference	Constant	Usage
ELECTRIC	86467	86744	277	1	277Kwh

Total Electric Charges	$33.03
Legislated 10% Reduction	3.30 -
Net Chares	$29.73

The net charges shown above include the following components. Please see definitions on Page 2 of the bill.

1	Electric Energy Charge	$0.02400*	$6.65	
2	Transmission		1.08	
3	Distribution		9.60	
4	Public Purpose Programs		1.14	
5	Nuclear Decommissioning		0.15	
6	Competition Transition Charge (CTC)		6.64	
7	Trust Transfer Amount (TTA)			$4.47

The sum of these = the net charges

* This rate is based on the weighted average costs for purchases through the Power Exchange. This service is subject to competition. You may purchase electricity from another supplier. (Call 1-800-743-0040 for a supplier list.)

ELECTRIC	Kwh		Price
Baseline Quantities	223.3		
Baseline Usagee	223.3	@	$0.11589
Over Baseline Usage	53.7	@	0.13321

Usage Comparison	Days	Kwh Billed	Kwh per Day
This Year	29	277	9.6
Last Year	29	280	9.7

Electricity Energy Charge: the average cost of buying electricity from the power Exchange for billing period
Transmission: the towers and high-voltage lines that transmit energy from power plants to the distribution system
Distribution: the lower-voltage system of power lines, poles, etc directly connected to homes and businesses
Public Purpose Programs: Efforts to benefit society, such as low-income ratepayer assistance and energy efficiency
Nuclear Decommissioning: A fee to restore plant sites to as near original condition as possible once shut down.
Competition Transition Charge (CTC): Cost recovery for a portion of investments in power plants and power contracts, previously included in rates and authorized by the California Public Utilities Commission.
Trust Transfer Amount (TTA): The cost of repaying state authorized bonds used to refinance-at better terms-a portion of past investments previously included in rates and authorized by the California Public Utilities Commission

Source: Adapa (1999).

POWER GENERATION FUEL MIX TRENDS

Once markets are deregulated, competition in the power sector puts strong pressure on generators to lower overall costs, including those associated with fuel inputs. Although the choice of input fuel for existing facilities may be constrained, there still exists inter-fuel substitution potential. For example a conversion from fuel oil to natural gas is possible through the replacement of burner tips without a substantial amount of investment. Another possibility for lowering costs and increasing competitiveness is to increase the capacity factor (utilization rate) of a particular plant or plants, usually those that are already cost effective in a deregulated market.

Deregulated electricity markets, with the emphasis on cost structures, will tend to encourage investment in power generation plants that are least cost over the capital depreciation period. In most cases this will favour the lowest cost fuels, usually coal, but also hydro where this is readily available, and gas because new CCGT plants have relatively low capital costs, even if operating costs are somewhat higher. Private investors in fully competitive markets would be unlikely to invest in nuclear, because of the very high capital cost, and requirement for relatively large plant size. With respect to both hydro and gas plants, the future will likely see a large increase in smaller sized plants placed much closer to demand centres (encouraging the trend towards more highly distributed generation).

Below are some graphs showing generation fuel mix trends over a twenty (plus) year period for a number of selected APEC economies. In almost all cases, these trends precede significant reform in each of the economies chosen, but some observations about the likely effect of reform can be made. For example Figure 18 shows that in the United States coal has shown steady and relatively strong growth with respect to all other fuels. Nuclear has grown over this time period, but one would expect this trend to reverse over the next twenty-year period (see EIA, 1999). Little new investment has occurred in nuclear since the early 1980s, and as old plants reach retirement, the share of nuclear generation will decline. Although gas generation shows only modest growth, this fuel should become increasingly important over the next twenty years as gas market deregulation and growing investment in CCGT plants takes effect.

Canada has undergone very little reform, and has abundant supplies of hydro, so investment in this form of generation may continue into the foreseeable future, with gas and coal generation possibly becoming more important once some reform measures begin to take effect. Another economy with abundant hydro capacity, but with a long history of electricity sector reform, is Chile. Hydro has shown very strong growth, as has coal generation. With the construction of links to Argentinean gas in 1997 and 1999, gas generation capacity has grown substantially, and should continue to do so. In New Zealand, abundant hydro capacity has ensured strong investment over the last twenty years. What is important however, is that the investment since the early 1980s has switched from large-scale hydro to small scale plants closer to demand centres. Very recently, gas generation has undergone dramatic growth, and this trend could continue into the near future (while gas supplies last).

In Australia, coal is the cheapest fuel, and growth in coal consumption for power generation has undergone strong growth. Although no new capacity has been added so far post-reform, brown coal plants in Victoria have been operating at higher capacity factors, displacing some more expensive fuels, such as gas.

It has been argued that, faced with the uncertainties created by deregulation - such as loss of protected service areas and/or long-term contracts - electricity generation investment is likely to face higher financing costs (Hansen 1998). Such an effect would discourage investment in power plants with high capital costs and long-term payback periods. This is probably a correct analysis, at least in the early post-reform stage, but the development of lower cost CCGT plants, and the recent world-wide expansion in gas supply, has tended to mitigate this effect.

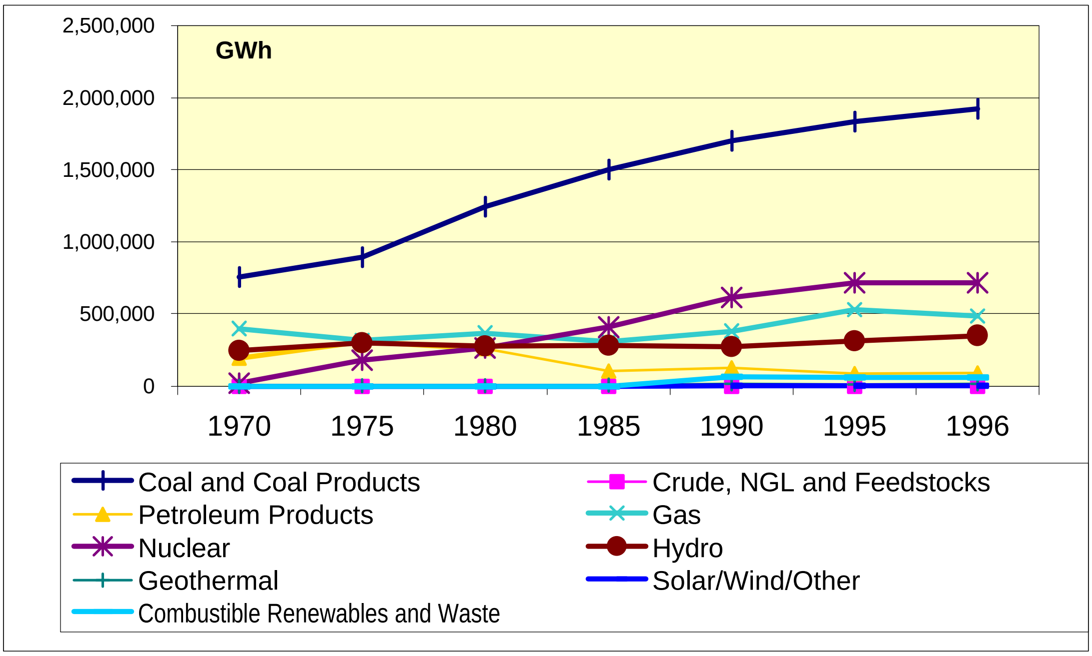
Table 10 Past and projected power plant sales (GW per annum)

Power Plant Technology	1987-1996	1997-2006
Gas Turbine	5.3	5.7
Gas Combined Cycle	14.7	24.6
Coal Steam Power	27.5	39.4
Total	47.5	69.7

Source: Hansen (1998), reproduced from Riedle and Taud, (1997)

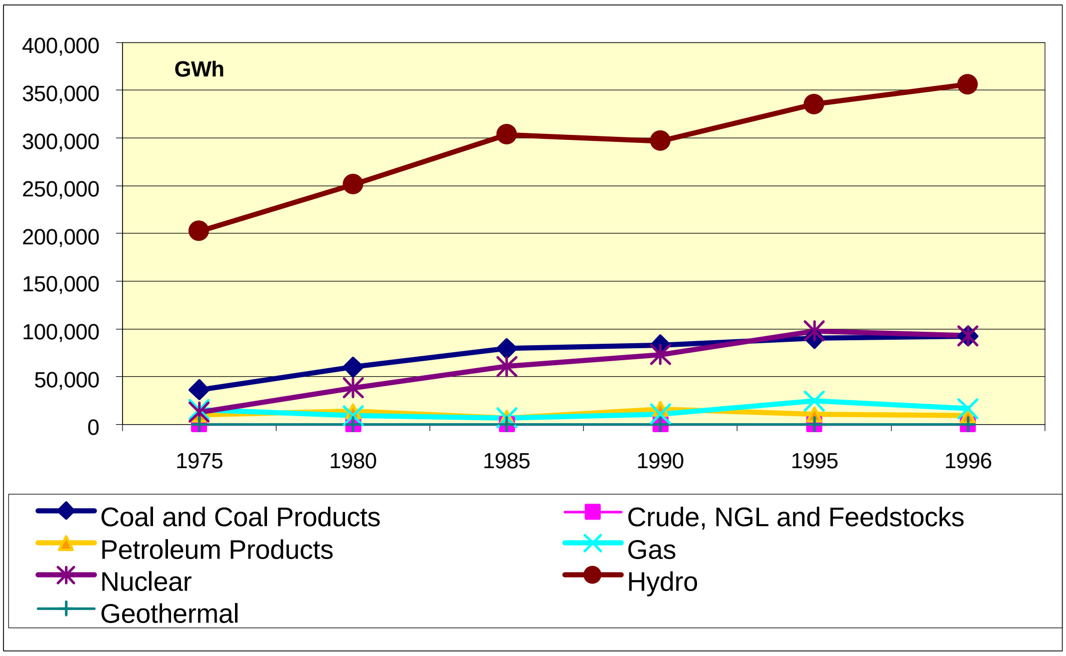
According to Hansen (1998), fossil fuel based power plants in the US constituted 70% of all awarded contracts between 1987 and 1996. As shown in Table 10, from 1997 to 2006, the bulk of new electricity will be supplied by coal-based steam turbines, but with an increasing share of gas combined cycle plants. This is a clear indication that technology development in gas turbines, along with market deregulation, will increase the share of fossil fuel based power generation. Thus there will be more intense competition in the power generation industry for cheaper fossil fuel resources.

Figure 18 Power generation fuel mix trends in the US



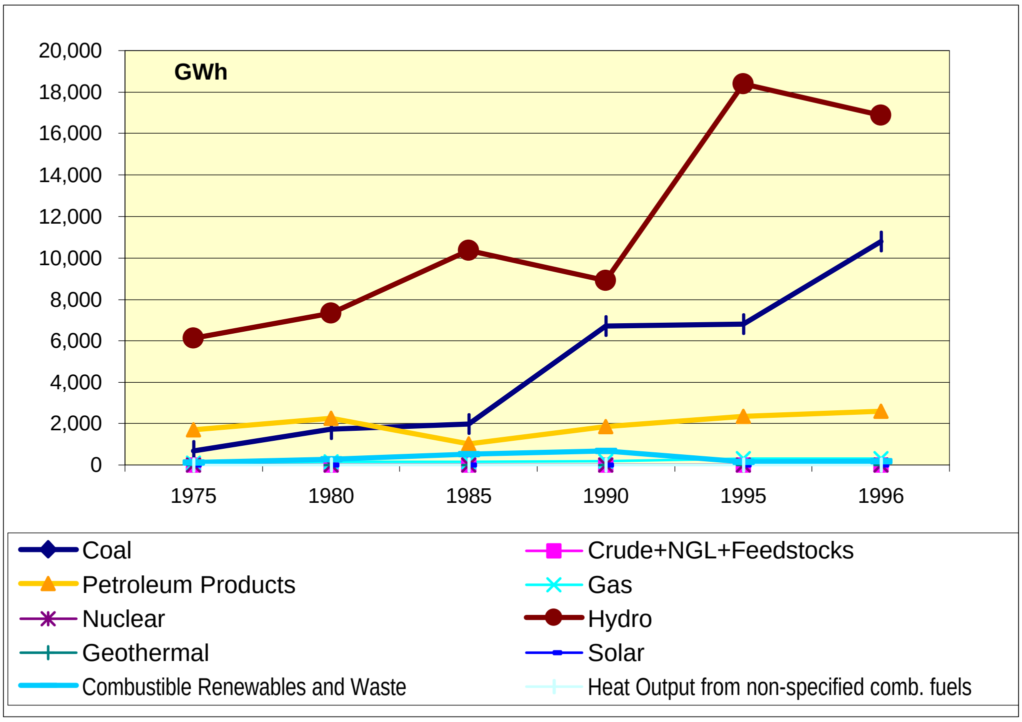
Source: IEA (1998b)

Figure 19 Power generation fuel mix trends in Canada



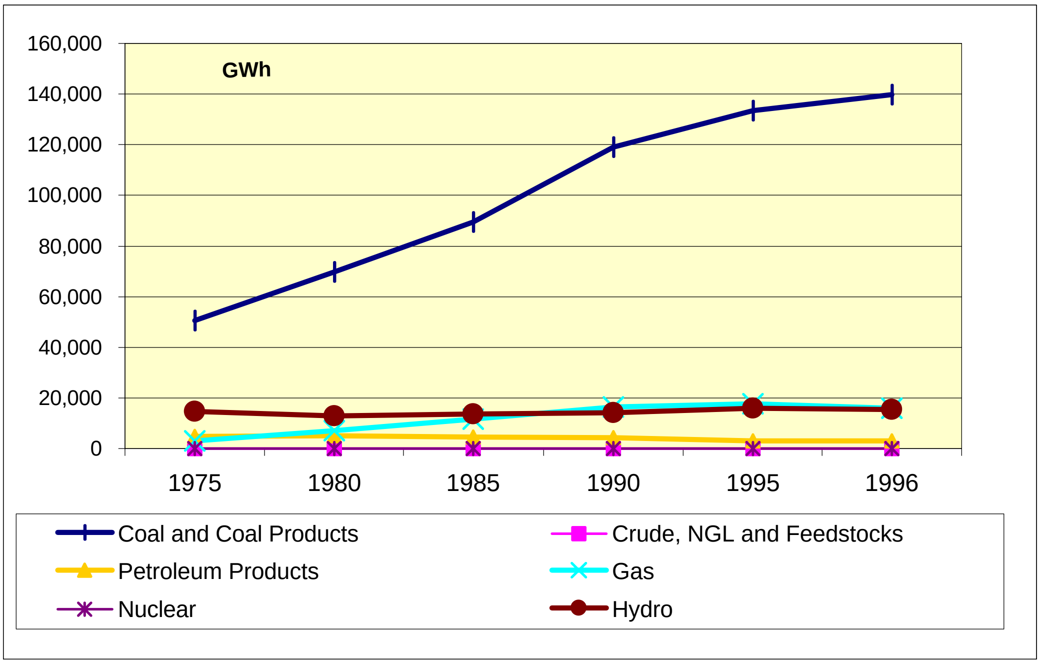
Source: IEA (1998b)

Figure 20 Power generation fuel mix trends in Chile



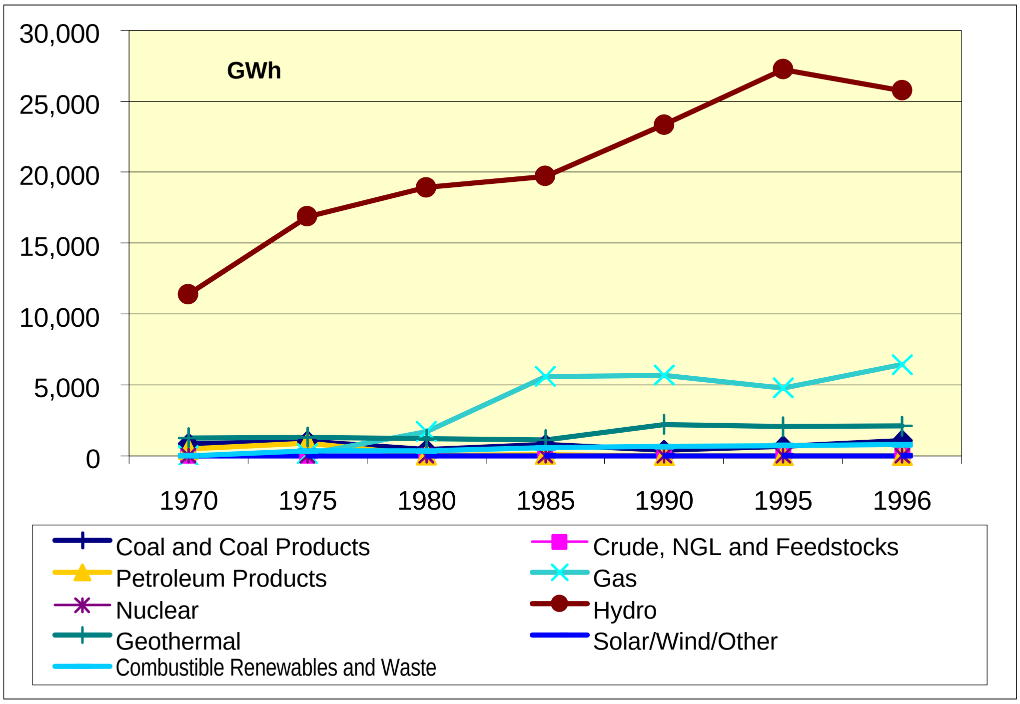
Source: Source: IEA (1998c)

Figure 21 Power generation fuel mix trends in Australia



Source: IEA (1998b)

Figure 22 Power generation fuel mix trends in New Zealand



Source: IEA (1998b)

The incentive among electricity generators to find more economic fuels can result in undesirable consequences such as environmental degradation. This is discussed in more detail in Chapter 7. However the course of deregulation impact can be altered by way of government policies and supporting enabling legislation. In the United States, for example, the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 helped increase natural gas consumption in the electricity sector.

To facilitate effective competition amongst fuels, natural gas markets should be deregulated in parallel with power markets. One way to facilitate competition in natural gas markets is to guarantee open access to gas networks, in order to discourage monopolistic practices by pipeline owners. In addition where electricity competes with other types of fuel for a given market, such as household heating, the justification for deregulation in these fuel industries is greatly enhanced. Should natural gas compete against electricity, natural gas transportation costs become an increasingly important factor as their share in terms of total supply cost is large and electricity transmission costs are anticipated to fall steadily with technology development (Ellig & Kalt, 1996).

An interesting question is what effect electricity sector deregulation will have on commitment by investors to long-term gas contracts. This is most significant with respect to bringing new (particularly offshore) gas fields to production.[8] With fragmentation of ownership in the power sector, many players may have to be brought to the table to ensure sufficient markets exist for investment in new gas supplies. From the financer's point of view, this may increase the rate of interest required on loans.

8 For example, the take-or-pay is still a “must” in Liquified Natural Gas (LNG) contracts.

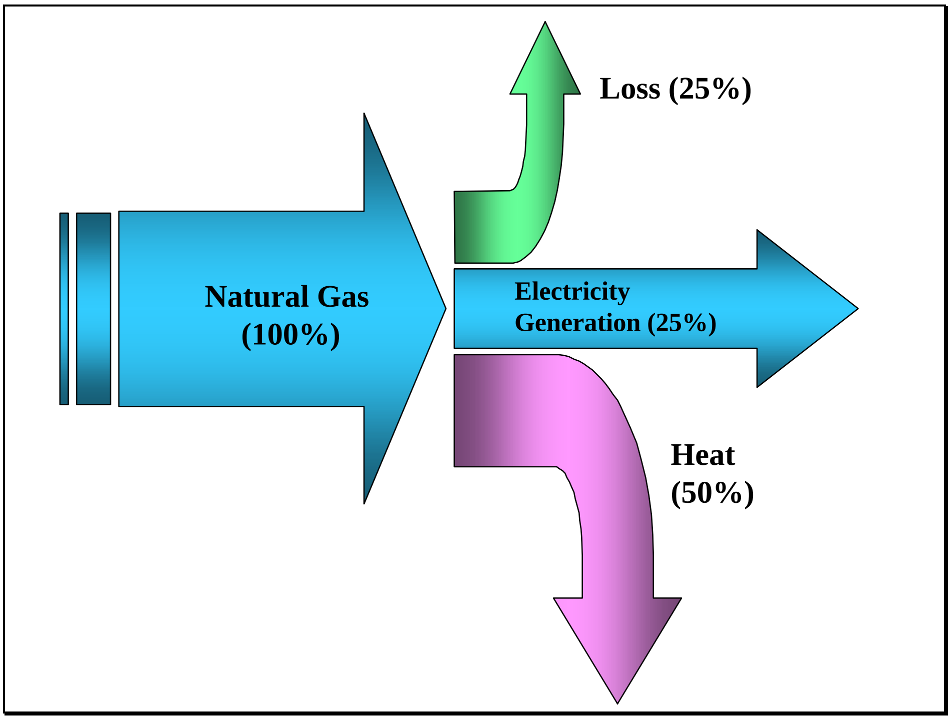
THE DISTRIBUTED GENERATION TREND

As observed elsewhere in this report, electricity sector reform has happened in parallel with some important technological developments. The emergence of the CCGT has been discussed, and the way in which this development has dramatically altered economies of scale in power generation. Other developments that will reinforce a trend towards smaller scale, distributed power systems are advances in fuel cell technology, wind turbines, and other smaller scale, clean power sources.

Another influence on the possible location of future power supplies is the lowering of power transmission losses with technology development. In this case, gas network vs electricity network competition may be intensified. Recent deregulation in natural gas markets in the United States, which helped remove all price controls on the wellhead sales[9] of natural gas as of January 1 1993, set the stage for competition among alternative substitutes.

The emergence of new technologies such as the micro gas turbine and fuel cell, could be an important factor in changing the future configuration of the electricity sector. Micro gas turbines exist in the range 28 kW-70 kW, sufficient to power approximately 10-30 households[10]. The energy balance (input and output) for a micro gas turbine (Figure 23), results in 25 percent of the total natural gas input being available for electricity generation, while 50 percent is transformed into heat. When the heat is used for hot water supply, the overall thermal efficiency is 60 – 75 percent.

Figure 23 Energy balance for a micro gas turbine



Source: Takuma Corporation brochure, 1999.

9 The Natural Gas Wellhead Decontrol Act of 1989 revoked the Supreme Court Phillips Decision in 1954, which imposed wellhead price control on the interstate sales of natural gas.

10 This is the approximate number calculated by taking the average scale used in Japanese residential sector.

CHAPTER 6

SOCIAL POLICY OBLIGATIONS

INTRODUCTION

Governments must respond to numerous obligations. In many economies, especially developing ones, the electricity sector has been used as an instrument of social policy. This has taken various forms, ranging from subsidised tariffs for certain groups of consumers, to state-owned utilities serving as employment providers. This section analyses the changes that the restructuring process will likely bring about in this area.

GOVERNMENT AND THE PRIVATE SECTOR SOCIAL POLICY ROLES

As discussed in Chapter 4, the traditional model of the state-owned vertically-integrated and monopolistic utility has been widely adopted in the past among APEC economies[11]. Its functions were various, including planning, construction, operation, tariff setting and resource prospecting. However, in many economies it was also asked to undertake functions that did not pertain to the sector. These diverse functions responded to equally diverse objectives, namely economic, financial, political and social.

Given this situation, it flowed naturally for governments to incorporate social policy both into energy policy and the operation of the utilities. Economic efficiency could be sacrificed in certain areas, deficits being covered by the national budget.

However, the restructuring of the power sector calls for a redefinition of the role of the government and of the actors that participate in it. As seen in previous chapters, there is no single model that responds to the requirements of all APEC member economies. Nevertheless, as a general trend, there has been a clear separation of the development-operation activities from policy ones. Private and state-owned companies participating in the former activities have to increasingly comply with market rules and are judged according to their performance. The state has to design an appropriate regulatory framework, while regulatory bodies have to enforce the compliance of all the actors with this framework.

Given the distinct objectives and liabilities of the state and of the companies in this new setting, social policy remains as a responsibility and burden of the state. However, as it will be discussed in this section, new instruments must be designed and put into practice to channel it.

In this context, regulation plays a crucial role, providing the framework and necessary incentives for all involved actors in order to harmonise private and public objectives, both at a national and local level. Thus, an effective regulation does not replace governments; rather it provides the setting for it to pursue its policies.

[11] The most notable exception has been the United States, where private ownership of utilities has been the norm.

SOCIAL OBLIGATIONS IN A RESTRUCTURED ENVIRONMENT

EQUITY

Historically, utilities that were granted a monopoly over distribution were subject to a "social contract", where in compensation for protection from competition, they had an obligation to provide universal service. Underlying the concept of universal service the fact that electricity has been considered a national strategic asset and not just another tradable commodity, and also a social obligation, namely equity. In this context, equity refers to giving equal opportunities to all members of a society.

Universal service normally comprises three parts:

- Electricity provision to anyone who requests it;
- Tariffs should be affordable; and
- Electricity should be supplied on a non-discriminatory terms.

There are different electricity sector frameworks, pricing systems and subsidies[12] being applied throughout the APEC region to address the objective of universal service. Many economies, even after restructuring, have maintained or plan to maintain the obligation to supply[13] (for example, Malaysia). This may entail the financing of the investment through taxes, through a reimbursable payment by the soliciting customer (as in Chile), and other methods. Some economies (such as Japan) are planning to establish a provider of last resort. On the other hand, New Zealand – which has full retail competition – has eliminated the obligation to supply beyond the year 2013.

Subsidies usually have been aimed at rural dwellers and low-income groups[14], which normally constitute the least attractive customers strictly from a commercial point of view[15]. Some economies, such as Thailand (EGAT, 1999), have the same nationwide tariff for all residential consumers, in spite of presumably different supply costs. In other cases, the tariff to rural dwellers is higher than for urban consumers, but nevertheless lower than that which reflects the full cost of service. In the US many restructuring frameworks consider a System Benefits Charge[16]. In other economies, notably Russia, non-payments of bills have constituted a form of subsidy. Table 11 shows this situation among selected APEC economies.

In both cases – investment and tariffs– subsidies are being applied, since they respond to social objectives. As the table shows, the financing of these subsidies has come from other customers through cross-subsidies, but also from government funds, electricity company funds, or a combination of them.

However, under a restructured electricity sector –especially one with full retail competition (see Chapter 4)– this may no longer be feasible, at least not in the same way as before. As discussed earlier, the traditional vertically-integrated, state-owned monopoly company, where possibly deficits were absorbed by the national budget, is replaced by a new structure, where market rules play a bigger role. Pricing mechanisms may change, charging each customer the real cost of service. Thus,

12 For a discussion of the pricing systems and subsidies in APEC member economies, see APERC (2000).

13 The obligation to supply includes new and existing customers.

14 Cross-subsidies between industrial, commercial and residential consumers have also been applied, but this responds more to economic than social policies.

15 Rural electrification differs from urban due to several factors, including a lower density, lower demand and – especially in developing economies– a lower payment capacity. Therefore, investment and cost of service are usually higher in rural than in urban areas.

16 The funds from this charge will be directed to various programs, including tariff subsidies and energy efficiency programs for low-income customers.

although wholesale electricity prices may fall, as a result of efficiency improvements, retail prices after the restructuring may likely go up for previously subsidised customers.

Nevertheless, this doesn't mean that Governments have to abandon the pursuit of social policy objectives, rather, that they must find new instruments and clearly delimit the role and responsibility of the State and of the private sector.

The experience of some Latin American economies that have undergone restructuring processes can provide some insight regarding the possible alternatives to address the main issues of rural electrification, that is, costly infrastructure and higher tariffs.

Table 11 Electricity sector subsidies in selected APEC economies

Economy	Subsidies
Thailand	The Government allows two deviations from the general principle of pricing at cost to take account of equity, and social and developmental considerations: 1) MEA consumers pay tariffs that exceed the cost of service and as a group subsidise PEA consumers, thus, residential customers in Bangkok and in provincial areas have the same tariff rates; and 2) the residential category is subsidised by other consumer groups, with a life-line tariff in effect for customers with consumption of less than 150 kWh/month.
Viet Nam	Rural households have a lower wholesale tariff than urban (400 dong/kWh versus 470-490). Also, the rate per kWh/month increases as consumption increases (up to 100 kWh, from 101-150, 151-250, 251-350, more than 350 kWh). There appears to be a cross-subsidy from commercial and low voltage rural customers to other retail customers, such as urban residents.
Philippines	The cross-subsidies present are: Between Meralco customers: from commercial and industrial to residential and street lights; Between NPC customers in the Luzon grid: from Meralco to small utilities, non-utilities and other utilities; Between grids: from Luzon to Visayas, Mindanao and Small Island MERALCO subsidises residential and general service (RGS) customers consuming no more than 300 kWh per month by charging the first 50 kWh of their monthly consumption 50% of purchased power cost.
China	According to an IEA study, 38.2% of the reference price corresponds to subsidy. Subsidies were focused mainly on capital expenditures in generating capacity, through reduced capital costs via the Power Generation Infrastructure Fund, which is financed through a small levy on the price of electricity. This has lead to overcapacity in some regions.

Source: APERC (1999) and IEA (1999).

In the majority of these economies, legislation assigns rural electrification as a responsibility of the state. Its role is to "promote, subsidise, finance, grant concessions for, regulate and/or plan, by means of entities and funds especially set up, projects aimed at providing electricity to rural areas, whether they are far or not from national power grids" (Ayala, 1999). Cooperatives and municipal entities are being used to promote projects. For dispersed and remote settlements that are far away from power grids, renewable energy options, such as solar, have been implemented (Ibid).

The financing of funds for investment has come from the state budget, sales of assets and from fines to utilities that fail to comply with regulations. However, from a long-term perspective, only the first of these options seems more appropriate to plan and carry out a sustained rural electrification program.

In some cases, these funds have also been used to subsidise electricity rates to focalised marginal sectors.

The Chilean experience shows how sustained efforts have been implemented in a restructured and private power sector. Several components have intervened in the process: (1) a rural electrification program (PER), designed by the National Energy Commission in order to accelerate the electrification rate in rural areas; (2) earmarked investment funds which are financed by the national budget (first the National Fund for Regional Development, FNDR, and later a complement to further enhance the process, the FNDR-ER, where ER stands for rural electrification); and (3) a social assessment methodology which ranks the projects –including renewables– which compete for the funds, and where only those projects with a positive social net present value and negative private net present value are eligible. Projects are co-funded by: (a) the consumers who will receive the service; (b) the company or organisation that will provide the service; and (c) the state through the two funds mentioned above, where the subsidy – focused exclusively to the investment and not the consumption– has as a limit the private net present value of the project, which must be lower than the total investment. This subsidy permits the service company to have a rent equal to that of the rest of its distribution areas. The results of the program have been an increase of the rural electrification rate from 57 percent in 1994, to 72 percent in 1998, with a desired goal of 100 percent of the electrifiable households by the year 2005 (Chilean National Energy Commission, 1999)

CONSUMER PROTECTION

Monopolistic practices and service quality are two areas that can affect consumers – either positively or negatively – after a restructuring process. In this section the negative effects will be discussed.

After a restructuring and privatisation process, new actors will enter the electricity sector. In order to develop in competitive environments, these actors may adopt different strategies, including increasing market share in one or more elements of the value chain, product or service differentiation, and others.

This can lead, in the first case, to the acquisition of significant market power by relatively few companies. Generators, which control transmission and/or distribution lines, may engage in practices, which seriously affect the efficiency of the sector. These monopolistic practices can translate into conditions that negatively affect consumers.

In the second case, the drive to reduce costs may affect service quality to customers (for example, power outages due to lack of proper maintenance and significant voltage variations).

In the US, considerable debate has accompanied restructuring plans. In terms of consumer protection, the potential for "redlining" has been frequently mentioned, especially for hard-to-serve or payment-troubled residential customers. Redlining may include: refusal to serve, territorial pricing, lack of infrastructure development, lack of facility development and a reduced service (Colton, 1997)

In all these cases the State has the responsibility of protecting consumers, especially residential ones, from undue practices. This calls for the need of appropriate regulation, both of general application to ensure competitive markets, and specific to the electricity sector. For the first issue, and specifically addressing transmission, regulation has taken various forms, ranging from keeping it under State control, to limiting the percentage that private companies can have in its ownership, imposing open access and clear pricing mechanisms. As for the second issue, regulation must clearly state the quality standards that the companies must comply with. Crucial issues are the enforcement capacity and the clear determination of liabilities.

ENVIRONMENTAL PROTECTION / LONG-TERM SUPPLY SECURITY

Both environmental protection and long-term supply security are dealt with elsewhere in this study. However, from a social obligation point of view, the approach to be taken is similar to the consumer protection issue, that is, an appropriate regulatory framework and bodies is crucial.

TRANSITIONAL ISSUES

PRICE INCREASES

As inferred in Chapter 3, one of the drivers of restructuring processes has been the expectation of lower electricity prices. However, this has not always been the case, especially when subsidies to certain customer classes have been removed or reduced, or when final customers have had to pay for the transitional costs of restructuring, namely stranded costs. This can cause social unrest, especially in low-income households.

A similar conflict may arise from the enforcement of bill payment and the elimination of illegal connections to distribution grids (the so-called "non-technical losses").

Different approaches can be applied to address these issues, including: gradual increase in price levels; maintain focused subsidies, but financed by the state; pricing systems that incorporate efficiency gains that will translate into price reductions over time; enhancement of competition where applicable; information campaigns, etc.

REDUCTION IN EMPLOYMENT LEVELS

A common concern among members of companies that will be restructured or privatised – mostly state employees – is the probable reduction in employment levels. This concern has proved real in many restructuring processes, the intensity of which largely depends on the previous conditions. Utilities that were used by governments as employment providers without consideration of real in-company necessities, and/or those with low productivity, may have to cope with significant layoffs. Many functions that were previously performed inside the company may disappear outright – such as the design of long-term national energy plans – or may be externalised. New functions or departments may be created which will demand new skills, not present in the old structure.

Employment levels can also be affected outside of the electricity sector, if uncompetitive fuels for power generation were previously favoured and/or subsidised, as has been the case of coal in some economies. In the cases where these industries are located in remote areas and support a significant portion of the local labour force, their elimination may pose a serious social and political problem.

These changes may bring about considerable opposition to the restructuring process and social unrest if not properly managed. The strategies that governments will use to face these issues will depend on their particular circumstances.

CONCLUSIONS

Governments should avoid the temptation of addressing social policy through energy policy, imposing an undue burden to companies, which have to respond to different objectives.

The experience of economies that have already restructured their power sectors shows that the process can be accompanied with potentially significant social issues. In order to minimise them, a clear delimitation of the roles and responsibilities of the Government and of the private sector has to be made, together with an appropriate regulatory framework and the redesign of adequate instruments to pursue social objectives.

CHAPTER 7

DEREGULATION AND THE ENVIRONMENT

INTRODUCTION

Fossil fuels supply around 85 percent of the world's commercial primary energy needs. Natural gas provides about 25 percent of this, and its share is growing. Power plants represent by far the largest group of coal end users, consuming 60 percent of the total world coal production to produce heat and generate electricity. Electric power sector emissions of carbon dioxide are almost 10 percent of the world total. Total world demand for coal has continued to grow steadily, with coal currently providing fuel for 37 percent of the world's electricity generation.

THE IMPACT OF REFORM ON THE ENVIRONMENT

Bernow et al (1998) argue that, "while there are potential environmental benefits from restructuring, the environmental threats appear larger". On the one hand, the future looks relatively bright if gas combined cycle plants replace coal-fired generation, leading to lower CO_2 emissions. On the other, it is argued that capital-intensive renewables and end-use efficiency (which tends to have a long pay-back period), will suffer due to the higher cost of capital, reflecting greater levels of perceived risk in the marketplace. It is also argued that the demise of Demand Side Management (DSM) and Integrated Resource Planning (IRP) activities, nuclear retirements, different market structures with deviations from optimal dispatch, sales promotion and shifting load profiles, and cost cutting at power plants, would tend to increase emissions.

In the US, it has been argued (Dooley, 1998) that once utilities find themselves in a highly competitive market, many of the public benefit activities carried out while they where regulated (such as weatherisation programs for low-income individuals and utility-sponsored demand side management programs) will be de-emphasised or eliminated.

Another issue is that coal plants in some economies (especially pre-reform) suffer significant under-utilisation, relative to their full availability. With relatively low coal prices, these plants have a significant competitive advantage in a wholesale electricity market. Increasing utilisation of such plants would lead to significant increases in carbon emissions. This has turned out to be the case in Victoria, Australia, where increased use of power stations burning brown coal has led to increases in CO_2 emissions (see case study below).

Embedded technologies have an advantage over new and emerging ones - the physical stock and expertise are well entrenched, and investment risks are lower. This situation favours fossil fuels, especially in a situation where markets have systematically failed to account fully for the social and environmental costs.

A wholesale electricity market is driven by costs of production, and is a market where the lowest cost generators - regardless of fuel type - will invariably be called first. If the lowest cost plants happen to run on the least environmentally friendly fuels, then in the absence of any mechanisms to limit emissions, overall emissions of environmentally harmful substances are bound to increase.

EMERGING TECHNOLOGIES

From a purely technical perspective, commercially available technologies exist to mitigate almost entirely the adverse impacts of all the pollutants that result from the combustion of carbon intensive fossil fuels to generate electricity. The most carbon intensive fuel is coal, and in many cases the addition of these technologies can be achieved without making coal uncompetitive with alternatives, such as natural gas or renewables.

At least this is true for technologies that mitigate pollutants other than CO_2. This is the one pollutant that cannot easily be dealt with in the smokestack, and with technology that would still allow coal to compete with other fuels. If one compares the trajectories of energy-related CO_2 emissions (under a business as usual scenario) with those required to meet Kyoto commitments, it is obvious that a large gap exists, and without substantial mitigation, this gap will grow increasingly large with time.

So it can be seen that the importance of new and emerging technologies lie in the role of innovation as a means of increasing both economic and technical efficiency, and the growing requirement for cost-effective solutions to the greenhouse gas problem. This is where energy sector reform should have a very significant role to play. If, as expected, reform acts as a spur for technological innovation, we should see over the next few years significant advances with respect to improved goods and services, and in dealing with environmental impacts.

The counter argument to this is that a reformed energy sector could represent a significant barrier to the adoption of certain new technologies, because of entrenched mind-sets, the cost of risk capital, and the costs inherent in bringing new technologies on-stream. If newly emerging energy sector firms are driven by short-term thinking, and the requirement for a short-term return on assets, it is argued this could lead to a reduction in the commitment to long-term planning and investment.

On the other hand, firms thrive on innovation, especially if incentives exist to encourage the penetration of new technologies into the marketplace. Incentives can include customer preferences, such as a demand for new/better goods and services, or a willingness to pay extra for added value (e.g. "green electricity"), or incentives created by governments through market-based policies and measures. On the energy scene, a significant number of environmentally responsive innovations are reaching the marketplace, or are on the horizon. Examples include: large-scale wind turbines, community energy systems, natural gas-fired or coal-fired combined cycle turbines, and fuel cells for transportation applications and for distributed power generation.

The IEA, in a recent study on the role of technology on reducing energy-related greenhouse gas emissions (IEA, 1998), has suggested four ways to accelerate the availability of advanced technologies:

- Technical information dissemination to facilitate the functioning of the market.
- Demonstration or pilot projects for technologies with proven commercial potential.
- Focused R&D on remaining technical hurdles.
- Support for efforts to fundamentally change "hearts and minds".

ENERGY R&D

There is evidence to support the view that energy sector reform has resulted in a significant decline in strategic (longer-term) energy research. Energy R&D data for the period from the mid 1980s to the present, definitely show a marked decline in public sector financing of energy R&D.(Dooley, 1998). Over the period 1985-1995, the major R&D performing nations reduced their expenditure substantially, except for Japan and Switzerland. In the US the decline was modest (-9 percent), but in some cases the decline has been dramatic. Examples include the United Kingdom (-88 percent), Germany (-74 percent), and Italy (-75 percent) (Dooley, 1998).

From an environmental perspective, this trend may not be as bad as it at first appears. For one thing, many of the cutbacks have occurred in the area of nuclear power research. Coal energy R&D has been cut back also. This may be of concern, as there is a growing reliance on coal in the Asia Pacific region, and further research focused on clean coal technologies and mitigation of impacts would be beneficial.

Of greatest concern are cutbacks in long-term research on renewables. Compounding this trend, many government energy R&D programs have shifted in focus from long-term to short-term research. This would imply that very little long-term research is now being undertaken. Once again, this trend may not be as disastrous as it appears. Most of the technologies that will underpin the next generation of energy power sources already exist commercially, or are close to commercialisation. Private firms tend to focus on short-term research, as it is hard to justify "blue-skies" research to pragmatic board members and shareholders. From the perspective of the consumer, this is not necessarily a bad thing. Much of this research has benefits in terms of more efficient, better, or new services. Efficiency improvements deliver monetary as well as environmental benefits.

In deregulated markets, companies are emerging able to deliver any combination of natural gas, electricity, water, sewerage, and telecommunications services to their customers. Electric retailers are also on the verge of being able to offer technologies that will automatically optimise electricity usage for individual householders. In many respects, it is too early to tell if energy sector reform will have a lasting and negative impact on the long-term research needed to bring in a new generation of energy technologies. The late 70s and early 80s were a time when people envisaged the rapid demise of fossil fuels, accompanied by large sustained price rises. A large amount of research and development was carried out at that time in anticipation of this event.

Eventually, a "carbon-constrained" world will lead to a drastic reduction in the economic importance of fossil fuels. Nuclear energy may also have a troubled, and ultimately doubtful, future. Either way, there is little doubt that sustainable energy technologies will be required, and relatively soon. If deregulated markets do not produce them, governments will once again be forced to invest in the long-term research needed to allow this to happen.

SUBSIDIES

The use of subsidies to implement social policy is addressed elsewhere in this report. The issue is, however, relevant to the question of environmental impacts in situations where the existence of fuel subsidies (often on fossil fuels) acts as a barrier to the introduction of cleaner technologies or cleaner fuels.

Energy subsidies have a long history, in both developing and developed economies. In a recent paper, the authors (World Bank, 1997) estimate that in 1985 total fossil fuel subsidies worldwide were US$330 billion. In 1990-92 total fossil fuel subsidies were estimated to be around US$247-257 billion (about $15 billion of this in OECD countries).

Energy is subsidised in many ways, both directly and indirectly. More explicit forms include direct grants and tax breaks to producers and distributors, and price controls. Economies with extensive energy resources often impose export restrictions, and this has the effect of keeping domestic prices artificially low. Compounding the problem of identifying subsidy levels is the fact that state-owned or state-managed companies are often heavily involved in the energy sector.

Whatever form energy subsidies take, they result in prices that fail to reflect the true economic costs of supply. Low consumer prices and high producer prices result in excessive production and operation of high-cost uneconomic, and uncompetitive units. The overall effect is to place a burden on the economy, to bring about a loss of efficiency. Energy subsidies, especially those on fossil fuels, also tend to be damaging to the environment.

In the Asia Pacific region, the major issue from an environmental perspective is the existence of subsidies on the prices of oil, petroleum products and coal. Many developing economies have large coal sectors, and in some cases - for example China - coal is both abundant and relatively cheap to mine. The World Bank (Pagiola et al, 1999) estimated that China had coal subsidies in the order of US$9.1 billion in 1990-91, but declining to around US$3.0 billion by 1995-96. These figures are disputed however, it being argued that in reality the costs of production are low and coal prices actually closely reflect the true costs of production (Wang, 1999).

Of more significance than the price of coal in China perhaps, is the regulated price of natural gas. For many decades, natural gas has been virtually ignored as a fuel in China, largely being considered as a by-product of oil production. The price has been historically controlled at low levels to ensure that fertiliser manufacturers could make a profit, and that farmers could afford the fertiliser, vital for crop production. As a consequence of this policy, gas currently constitutes a mere 2 percent of fuel consumed in China (Williams, 1999).

Largely as a result of coal burning, Chinese urban dwellers now breathe some of the world's most polluted air, and China's decision-makers are now beginning to realise that natural gas could form part of the solution to this problem. Because gas producer prices are low, investors will not under current conditions consider making the huge investments needed to pipe the gas to potential markets. Even more daunting, is the fact that markets for the gas do not yet exist. Most householders burn coal for heating and cooking, and fuel switching on a massive scale would need to occur to allow large-scale gas infrastructure development to occur.

POLICY OPTIONS

COMMAND AND CONTROL

Command and control systems are defined by sets of compulsory rules defining requirements on the level of emissions, on the characteristics of the final goods or services produced, and/or on the technical processes of production. Such systems are completed with a monitoring (control) component.

The problem with the use of this kind of instrument is that unintended - and often negative - outcomes occur. These include failure to secure cost effective solutions, or inhibition of technological progress.

Because regulators are faced with obtaining and processing large amounts of information, they tend to develop uniform sets of rules, producing inequalities in marginal abatement costs for different emitters (static inefficiency). Also, the mere existence of a fixed limit or requirement provokes dynamic inefficiency, since polluters are not encouraged to look for a continuous reduction in emissions. This hampers technological developments (Villot, 1996).

However, command and control instruments have been traditionally popular because they set clearly defined limits, are usually administratively simple to implement (if not necessarily easy to manage), and fit with the traditional "big government" culture.

FORCED RETIREMENT OF PLANT

The forced retirement of old, inefficient plant is a command and control approach to environmental policy which has some associated costs, and should not be necessary in a free and competitive energy market. However, in some areas, such as in Victoria in Australia and the Mid-West US, old coal fired plants exist which can still bid competitively into the wholesale electricity market because capital costs are largely written off and coal prices are low. Because such plants can have very long life spans, they can keep operating well past their commercial "lifetime".

TAXES AND FEES

There are energy taxes or fees on sulphur and nitrogen emissions in various countries around the world (IEA, 1999). Policy makers worldwide have discussed the concept of a tax levied on the carbon content of fuels for some years as a way of curbing the ever-increasing CO_2 emissions arising from the combustion of fossil fuels. Many economies already have transport fuel taxes, and in some cases these are substantial. Such taxes tend to be larger in wealthy countries, and tend to take advantage of the low elasticity of demand for transport fuels to raise funds for road maintenance or for general government expenditure. Because transport fuel taxes are not specifically targeted at reducing demand for fossil fuels, or promoting alternative fuels, they tend not to be effective as a carbon tax instrument.

A carbon tax has been introduced in Denmark, Sweden, Norway, Finland and Netherlands. No economies in the Asia Pacific region have yet taken this step.

The New Zealand government seriously considered introducing a carbon tax in the mid 90s, but backed away from this option after lobbying by industry and careful consideration by policy advisors, and opted instead to promote an international emissions trading regime through the UNFCCC process.

A number of arguments exist against the unilateral imposition of a carbon tax. A carbon tax relies on responses to price changes (as induced by the tax), to meet quantitative emissions targets. Depending on actual responses resulting from price elasticities of demand, the actual achievement of the target can vary significantly. This can lead to unequal impacts on the economy, and the possibility of the tax not achieving its goals (i.e. as could happen in the transport sector). Also, for the tax to be effective on an international scale, a "level playing field" internationally is required. The unilateral imposition of such a tax leaves open the possibility of what is termed "carbon leakage", or in other words, the export of carbon intensive industries to countries with less strict environmental standards.

When due consideration is given to these issues, a tradable emissions permit scheme for controlling/limiting emissions is more appealing. A permit scheme sets quantitative emission limits, ("permits to emit"), allowing the overall system to find the appropriate permit price.

EMISSIONS TRADING

The allure of an emissions trading regime to control environmental pollutants is the argument that it is "least cost". A cap and trade system sets absolute limits for emission levels across a whole sector (or for a particular pollutant), but is achieved through a market-based trading mechanism, so it promotes innovation and flexibility in achieving the pre-ordained outcome.

An emissions trading scheme establishes a market price, and hence an opportunity cost, for emissions because of the scarcity of a commodity. In this case the quantity of the available "permits" is less than is necessary to accommodate business-as-usual emissions.

Assuming well-informed decision makers, either a carbon tax or permit trading scheme will elicit activities that cost up to, but do not exceed, the cost of the carbon charge or the market value for the permits. In this sense, the least cost path is self-selecting.

Through making such choices, individuals and firms also reveal, in aggregate, information to others about the costs and opportunities for reducing emissions. Ensuring that each unit of greenhouse gas emission bears the price for emitting, or faces the opportunity cost of forgoing abatement, leads to a dynamic effect over time. Individuals and firms have the flexibility to decide when to reduce emissions, given information about current and future prices and can seek out and apply their own innovative responses.

The cost or price for each unit of emissions ensures that there is an ongoing incentive to seek out cost-effective emission reduction opportunities. Over time the dynamic effects are likely to lead to the reallocation of resources and capital toward lower emission forms of activity in the economy (NZ Ministry for the Environment, 1998).

Reinforcing the view that emissions trading should prove to be the lowest cost option for mitigating CO_2 emissions, is the successful experience of the SO_2 trading scheme in the US. The US abatement scheme was introduced under the provisions of the Acid Rain Program, authorised by the 1990 Clean Air Act Amendments. The Acid Rain Program annually allocates a declining number of permits to each utility, so that emissions are driven from 18.9 million tonnes in 1980 (the base year) to 8.9 million tonnes in 2000.

What has been notable about the US experience is that the price of permits to emit SO_2 and the volume of permits traded has been significantly less than anticipated (Conrad & Kohn, 1996). The reasons for this are many, but key among them has been the proliferation of new allowances (the rules allowed utilities to create excess, new allowances for emissions already reduced when the scheme was established), and because of stringent air quality standards in some areas and irreversible investments in abatement equipment that reduced the demand for allowances by high cost abaters.

The low price of permits and the low volume of trades has convinced policy makers in the US that the application of a market based approach to pollution control does work, and is a significantly lower cost solution than traditional command and control measures.

COMPLEMENTARY MEASURES

The market-based tax and trading schemes described above would have a significant impact on CO_2 emissions, but many policy-makers believe these will need to be supplemented with a variety of complementary policies and measures. It is argued that complementary measures address market imperfections, encourage change in people's tastes and preferences, and address distributional and equity issues.

Specific energy sector measures include: provision of information; minimum energy performance standards (for electrical equipment and household appliances); energy efficiency requirements for buildings; promotion of energy audits and energy retrofit; energy efficiency labelling; measures focused on the transport sector; and support for new and emerging technologies (including showcasing, and various other commercialisation support schemes).

ENERGY EFFICIENCY

One of the more effective ways to control the environmental impacts of energy utilisation is to institute policies that encourage energy efficiency. Obviously, such policies will be particularly effective in economies that are energy intensive and/or have significant energy efficiency potential, but another important consideration is the extent to which significant energy market reform has already taken place. Experience has taught policy experts that open, competitive markets are more efficient than other alternatives, such as heavily regulated markets, or command and control structures. However, one advantage an economy may have in the pre-reform stage is the ability to easily legislate and heavily regulate for specific desired outcomes.

For example, China changed history by managing to decouple energy intensity from GDP at an early stage of industrialisation.[17] This is a stage historically where the two functions would normally have been closely linked, and rising rapidly. China's actual primary energy consumption in 1995 was 1250 million metric tonnes of standard coal equivalent[18]. It has been estimated (Sinton et al,

[17] China achieved this at quite an early stage in its process of industrialisation. It must also be acknowledged that today's more developed economies also managed to decouple energy intensity growth from economic growth, although at a later stage in development.

[18] Chinese energy figures are typically presented in coal equivalent. One metric tonne of standard coal equivalent equals 29.31 GJ, 7.00 million kcal, and 5.147 barrels of oil equivalent.

1998) that if this same amount of output had been produced at the intensity prevailing in 1977, 2,740 Mtoe would have used.

There are some significant features of this energy efficiency drive. Firstly, the structures and mechanisms were mostly created in the 1980s under a command and control system. Secondly, they are not particularly appropriate to the reformed economic environment now existing in China.

Although the Chinese energy efficiency drive brought dramatic results, this economy began from a position of gross wastage of energy. In its early existence the People's Republic of China borrowed heavily from the Soviet model, with a strong emphasis on energy-intensive heavy industries, and little concern for the costs of production. By the 1970s, China (along with the Soviet Union) had production sectors that were among the most technically and economically inefficient in the world.

A vigorous efficiency drive brought about a dramatic decline in energy intensity from the late 1970s, even greater than that achieved in the USA and in other OECD nations. According to Sinton and Levine, by far the biggest contributing factor has been economic intensity change within industrial sub sectors. Structural change in the economy has accounted for very little of the large decline in energy intensity.

The policies and structures used to achieve this focused on non-market mechanisms such as regulations directly governing energy use, mainly through quotas and standards. State-sponsored efficiency investment projects targeted the industrial sector, and included cogeneration, recovery and use of waste heat and gas, retrofits for small and inefficient power and fertiliser plants, and improvements to steel manufacturing technologies.

The energy quota management system, which is still largely in place, governs that quantity of energy supplied to enterprises and the energy intensity of specific manufacturing processes, and provides for reporting, monitoring and performance evaluation. The problem with non-market interventions is that they are of questionable value in an open, competitive market environment. In fact, such an approach can be counter-productive, leading to market distortions that add costs, instead of removing them.

Markets respond most effectively to financial incentives. Policy measures using financial incentives can include: allowing enterprises to use pre-tax income to pay off loans for energy efficient equipment; the reduction or waiving of taxes on sales of products which promote energy conservation or environmental impact; reducing or waiving import duties on such equipment; and promoting innovation by individuals and firms through the use of various incentive schemes.

IMPACTS – SOME INDIVIDUAL CASES

VICTORIA – AUSTRALIA

As with other economies undertaking micro-economic reforms in the early to mid 1980s, Australian policy-makers were concerned about poor economic performance, high foreign debt levels, a lack of efficiency in government run operations, and an emerging consensus that free and competitive markets could deliver better outcomes.

Despite the fact that Australia is highly dependent on coal for power generation, and that a significant amount of it is low-grade brown coal (mostly in the state of Victoria), environmental considerations were not, in 1990, one of the foremost policy considerations.[19] Of most concern was the desire to increase the efficiency of the sector through vertical separation of generation and retail from the natural monopoly elements of transmission and distribution, corporatisation of

19 The brown coal burned in Victoria contains relatively low sulphur levels, and until recently, greenhouse gas emissions have not been a major concern.

former government utilities, the introduction of competition, and enhancement and extension of the network.

The National Electricity Market (NEM) has been successful in driving down generation costs, as reflected in the trend in wholesale electricity prices (Tucker, 1999). Such a system favours the most efficient operators, and this case has favoured thermal plant in Victoria burning low-grade brown coal. The coal is close to the surface and relatively cheap to mine, generating stations are mostly mine mouth so transportation costs are low, and are also reasonably close to major centres of demand.

Although policy-makers expect the reforms to open up opportunities for new technology, such as combined cycle gas, wind and solar, this has not been the outcome in the short-term. One factor working against new technologies at this stage is an over-capacity of generation capability. Post-reform, no new plants have been commissioned, load switching has occurred to favour the plants able to bid into the NEM at the lowest prices.

Co-incidentally with these developments, Australia has committed to preventing its greenhouse gas emissions from growing by more than 8 percent above 1990 emission levels by the first UNFCCC commitment period of 2008-2012. For an economy, dependant as Australia is on fossil fuels, this will be a demanding target. This challenge has been acknowledged, and in 1998 the Federal Government released a "National Greenhouse Response Strategy", which included a raft of policies and measures aimed at achieving this goal. A component of this strategy is the Renewable Energy Commercialisation Program, which will include a five year A$58 million competitive grants scheme to promote a number of showcase technologies. Time will tell if this, and the other components of the strategy are sufficient to promote fuel switching on the scale required.

THE UNITED STATES

The current moves to reform electricity supply markets in the US will have significant impacts on markets for electricity generation fuels, and hence on the environment. The situation in the US is complicated somewhat by the existence of a relatively large amount of nuclear capacity (13 percent of current generating capacity and about 19 percent of total electricity generation), (EIA, 1998a) some of which is uneconomical in a deregulated wholesale power market.

Currently, the US coal and electricity industries are closely linked. Coal accounts for more than 56 percent of utility power generation, and more than 87 percent of domestic coal consumption is used to generate electricity (EIA, 1998a). The trend in generation investment, however, favours gas combined cycle plants. Although gas accounts for only around 9 percent of electric utility generation currently, the EIA estimates this share will increase dramatically as natural-gas-fired turbines and combined cycle plants garner most of the market for new generation capacity. According to EIA projections, this could lead to a doubling of installed gas fired capacity over the next 15 years.

Because electricity generation from renewable sources (other than hydropower) generally is more expensive in the US than power from conventional sources, these fuels may play a reduced role in fully competitive generation markets unless state and/or federal policy-makers intervene.

As a consequence of the fairly complex nature of the US electricity industry, fuel markets, and state and federal policy interactions, it is difficult to determine what the environmental outcomes of electricity sector reform will be. A decline in nuclear generation as uneconomic plants are retired and decommissioned will please some environmentalists, and the general public – who have expressed concerns about the potential environmental and health impacts of a serious release of radioactivity. A reduction in nuclear fuel use will lead to increased use of fossil fuels, but this will probably be mostly gas, not coal. The coal industry however, with a dominant share of the power generation market, and an ability to compete strongly on price with other fuels, will probably remain a major player in the power sector into the foreseeable future.

Over the last decade, there has been a downward trend in fuel costs. The coal industry has managed to remain competitive by increasing productivity, negotiating lower transportation rates, and staying abreast of changing market conditions (in marked contrast to the situation in the UK discussed below). Average prices for natural gas to utilities have also generally trended downwards. These facts will ensure that these fuels will remain important to the power generation sector.

UNITED KINGDOM

From the 1950s to the 1980s, the UK was frequently labelled the "dirty man" of Europe. In the 1950s coal burning in open fireplaces was a major environmental hazard, and led to a ban on this activity. In the 1970s and 1980s acid rain and later, global climate change came into focus. The main offenders contributing to the acid rain problem were coal-fired power stations. The electricity supply industry at that time accounted for 70 percent of British emissions of SO_X (Eikland, 1998).

When Mrs Thatcher first launched her plan to privatise the electricity sector in 1987, environmental issues were largely ignored. At a later stage, environmental policy processes became more visible, but mostly because of a co-incidental parallel trend of increasing environmental awareness.

Also co-incidentally, in 1988 the EC completed negotiations to put in place the Large Combustion Plant Directive. Compliance would require retrofitting of flue-gas de-sulphurisation equipment (FGD) at coal fired power stations. It soon became apparent that this directive could be met at far lower cost if combined cycle gas turbine (CCGT) plants were used to replace coal-fired stations. The privatised generation companies National Power and Powergen, preparing for a competitive market where compliance costs could not automatically be passed on to consumers, cancelled plans for expanding their newly acquired coal-fired plants. Existing coal plants did require FGD equipment after ratification of the directive, but the final programme was half that initially envisaged.

At around this time, investors had concluded that the existing nuclear plants were not a good investment, partly because of future decommissioning liabilities and the waste disposal problem. As a result, the nuclear plants remained under government control.

Overall, the short-term environmental consequences of the UK energy sector reforms have turned out to be very positive, with the massive closure of uncompetitive coal-fired power stations and the "dash for gas" in electricity generation. It can be argued that the liberalised UK electricity market was not only compatible with, but also a driving force for improved environmental performance.

However, it must be stated that this outcome came about largely as a result of a significant number of co-incidental developments and circumstances. With the ready availability of large quantities of North Sea gas at competitive prices, the existence of a gas infrastructure, and the un-competitiveness of coal in a liberalised market, it was only a matter of time before change in the fuel mix occurred. In this case, the rate of change was greatly accelerated by environmental policy pressures, commercial realities and public opinion.

NEW ZEALAND

The short-term environmental impacts of reform in New Zealand have been somewhat less clear-cut than in the UK or Australia, but close examination would suggest that the impacts are decidedly positive. The longer-term impacts are also likely to be positive. In fact, the potential exists for New Zealand, over time, to become a world leader in terms of installed wind capacity as a percentage of the total load. Although the reforms have promoted a significant increase in investment in fossil fuel fired generation, the new plants are CCGT units, and have led to the decommissioning and sidelining of older, higher cost, single cycle fossil fuel powered plants.

Post reform, two wind farms have been commissioned. The first was a 3.5 MW plant at Hau Nui in the Wairarapa, and the second a 35 MW plant near Palmerston North. A second phase of the Palmerston North facility was initially planned, but the current generation over-capacity and a change of ownership resulted in these plans being put on hold temporarily (Trustpower has announced an intention to complete the full project as soon as possible). The striking feature about this wind farm is an average wind speed of over 10 m/sec and a load factor, which exceeds 50 percent (very high by international standards).

The percentage of renewables as a percentage of total capacity is high in New Zealand, with hydro accounting for 66.7 percent of total capacity (March year 1999) and geothermal 6.5 percent. New geothermal stations have been commissioned post-reform, but significant new (especially large scale) hydro increases are unlikely. From an environmental perspective, a moratorium on large-scale hydro construction may be considered desirable. There has been substantial public resistance to at least two large-scale hydro schemes (Manapouri and Clyde), and there is now a strong feeling that enough wild waterways and lakes have been significantly impacted by power schemes.

REGULATORY OPTIONS (MARKET BASED INCENTIVES VS COERCIVE REGULATION)

In a deregulated energy market, and in the absence of strong and sustained policy initiatives, the falling costs of coal and oil will impede the diffusion of efficient and renewable technologies (Bernow & Duckworth, 1998). As energy prices tend not to include the large social and environmental costs of energy production and use, fossil fuels continue to enjoy an economic advantage in the marketplace. This effect is reinforced by the existence of direct and indirect subsidies.

This invites the question of whether government intervention is desired to either balance the situation (provide a "level playing field" for all fuel types), or tilt the odds in favour of more highly desired fuels or technologies. In such a discussion, it is important to bear in mind that many environmentally friendly technologies are already competitive at market prices (or very nearly so). Such technologies may not be purchased, however, owing to a variety of market and institutional barriers (as discussed elsewhere).

With this situation pertaining, substantial reductions in energy use and environmental impacts could be realised with technologies that are currently commercially available, if the appropriate policies and measures were in place to overcome the barriers (Bernow & Duckworth, 1998).

Policy makers in many economies, especially developed economies that have undergone significant economic reform recently, are reluctant to consider direct intervention in the market, in order to promote one technology over another. There are very good historical, as well as theoretical, reasons for this. For example, attempts were made in the 1980s, in response to the OPEC oil price shocks, to promote a diverse range of energy technologies and fuels to reduce reliance on oil supplies from OPEC countries. Large sums of money were spent on alternative fuel research, and alternative technologies. Governmental energy research budgets during this era were at an all-time high.

No doubt, the fact that many new and emerging technologies are now commercially viable can be traced back to the huge research effort of the 1980s. However, policy-makers are also well aware that much investment never produced tangible benefits, as oil prices declined substantially in the late 1980s, and stayed low ever since. In fact, the large expenditures of that decade have left some economies with significant debts.

However, the fact that governments and their advisors have made bad business investments in the past, and are now more enlightened, in that they now understand the importance of free and competitive markets, should not be a reason for not acting at all. The term "deregulation" is a misnomer. Few energy markets are actually "deregulated", in the sense that they now operate in a completely unfettered fashion. Reform has resulted in significant deregulation it is true, but in reality, new ones have replaced old regulations. The new regulations tend to be more performance oriented, and more "light-handed", but still control to some extent the workings of the market. For example, natural monopolies tend to be closely controlled, and are usually required to engage in information disclosure to ensure fair play. Regulatory agencies also have powers to prevent anti-competitive behaviour, and to prevent mergers and acquisitions, which lead to excessive market power.

This is a relatively enlightened approach to regulation, and one, which could flow over into the area of environmental policy. If certain technologies are harmful to the environment, then controlling those technologies or encouraging less harmful ones are legitimate concerns for governments. The “first best” option is to achieve these through market mechanisms - such as financial incentives, cap and trading schemes, and tax instruments.

What is clear from the experiences of reforming economies is that if energy reforms are enacted without thought being given to desirable environmental outcomes, detrimental outcomes are possible, in the short-term at least.

Once privatisation has occurred to a significant extent, the difficulties of imposing environmental policy measures increase. This is especially important in economies where energy demand is growing rapidly, as in much of Asia. For the more developed economies, energy demand is relatively flat, and significant over-capacity of generation exists in many areas. If environmental degradation is occurring in the short-term, through greater utilisation of cheaper installed coal fired capacity, this can be rectified before commitments are made to new plant. However, even in this situation, clear policy signals are required now, so that investment risks are more fully understood.

A VISION OF THE FUTURE

So far, the discussion has tended to consider the barriers to the introduction of new and emerging technologies, and the environmental threats posed by energy sector reform. There is a countervailing view, one, which is very optimistic about the future and the role new and cleaner energy technologies will play in it. What is remarkable about this view is that it is coming not from technology “junkies” but from some sectors of the non-governmental environmental sector, people who are normally rather pessimistic about the future.

For example, in a recent publication, the President of the Worldwatch Institute asserted that the world might be on the edge of an environmental revolution, comparable in scope and impact to the industrial revolution (Brown 1999). He believes that “the world may be approaching the threshold of a sweeping change in the way we respond to environmental threats – a social threshold that, once crossed, could change our outlook as profoundly as the one that in 1989 and 1990 led to a political restructuring in Eastern Europe”. One sign of this, according to Brown, is a growing number of high profile CEOs who are beginning to sound more like spokespersons for Greenpeace than for the bastions of global capitalism.

Although official and think-tank energy supply/demand projections routinely show a continuing reliance on fossil fuels, such forecasts may obscure a quite different reality. For example it can be successfully argued that conventional wisdom is sometimes reliable when anticipating smooth trends, but almost never anticipates major dis-continuities (Lenssen, 1996). It can be further argued that although corporations and governments are now using more powerful computers and have adjusted their assumptions to account for earlier mistakes, they still tend to look at the future through a rear-view mirror. Why is this? Basically, it is very hard to factor technological innovation into traditional modelling algorithms.

What will drive this revolution? Worldwatch believes a number of factors are merging, and the combined effect will lead to some fundamental changes in the way economies are organised (including energy technologies and consumer behaviour). Factors include: the global debate about climate change (reinforced by recent disastrous weather event patterns); the emergence of commercially viable renewable energy technologies (already showing substantial growth rates in market penetration); the changing attitudes of corporations (who are beginning to see opportunities where before, only threats were evident); the debate about nuclear power; and a wrong assumption that developing economies are doomed to repeat the history and mistakes of the developed world.

Lenssen and Flavin (1996) believe their vision of a sustainable future will unfold most rapidly in market-based economies, with governments facilitating the process by acting to eliminate subsidies. The vision is one of high efficiency levels, extensive use of decentralized technologies, heavy reliance on natural gas and hydrogen as energy carriers, and a gradual shift to renewables. A factor which will influence the pace of change, it is argued, is the fact that the important new energy technologies are relatively small devices that can be mass-produced in factories – in stark contrast to the huge oil refineries and power plants that dominate the energy economy today. The economies of mass manufacturing will quickly bring down the cost of the new technologies (this is already happening), and ongoing innovations will be rapidly incorporated in new products, in much the same way as happens in the consumer electronics industry.

CHAPTER 8

CASE STUDIES

AUSTRALIA

INTRODUCTION

Australia is a Federation, comprising six states (Victoria, New South Wales, Queensland, South Australia, Western Australia, Tasmania), and two mainland territories (Australian Capital Territory, Northern Territory).

New South Wales (NSW), Victoria and Queensland, where the majority of the population is concentrated, account for most of Australia's electricity demand.

The predominant fuel used to generate electricity is coal, which accounts for 80 percent of capacity. Natural gas, with an increasing share (now over 10 percent), and hydropower account for the rest. Despite large deposits of uranium, Australia has no nuclear power plants. In 1997, electricity generation was 169 million kWh from an installed capacity of 42,547 MW. Australia has a population of 18 million.

As a result of Australia's past political history, its demographics and geographic circumstances, the electricity sector is characterised today by regional markets and limited interconnections. This is demonstrated in Figure 24, which is a map of the continent showing transmission lines and areas served by distribution networks. Currently, Tasmania, Western Australia and the Northern Territories are not connected to the eastern states, and Queensland currently has limited interconnections with the other states on the east coast.

The provision of electricity services has traditionally been the responsibility of individual state governments, and this has been achieved historically through vertically-integrated and publicly owned statutory utilities characteristically operated in a monopoly market.

During the 1980s, there was growing concern about the domestic and international competitiveness of Australian manufacturers. As well, it was becoming increasingly clear that major micro-economic reforms were required in many sectors of the economy.

Because electricity sector regulation is under state jurisdiction, with limited Commonwealth Government responsibility, any reforms at a national level require agreement between the states and the Commonwealth Government.

Figure 24 Transmission lines and areas served by distribution grids in Australia

Source: IEA (1997)

In 1990, the Commonwealth Government asked the Industry Commission (an independent government economic research agency) to conduct an inquiry into the generation, transmission and distribution of electricity to examine the scope for improved efficiency.

In May 1991, the commission recommended the restructuring of the industry, including:

- Vertical separation of generation and retail activities from the natural monopoly elements of transmission and distribution;
- Corporatisation of the utilities;
- Introduction of competition into generation and retailing, with non-discriminatory access to transmission and distribution networks; and
- Enhancement and extension of interconnections between states.

The National Grid Management Council (NGMC), an intergovernmental advisory body, was established in July 1991 to progress electricity sector reform in the southern and eastern states. The key structural reforms required to establish the National Electricity Market (NEM) were initiated at this time. The task was bigger than anticipated, and it wasn't until December 1998 when the NEM became fully operational, almost 8 years after the decision to undertake reform of the sector.

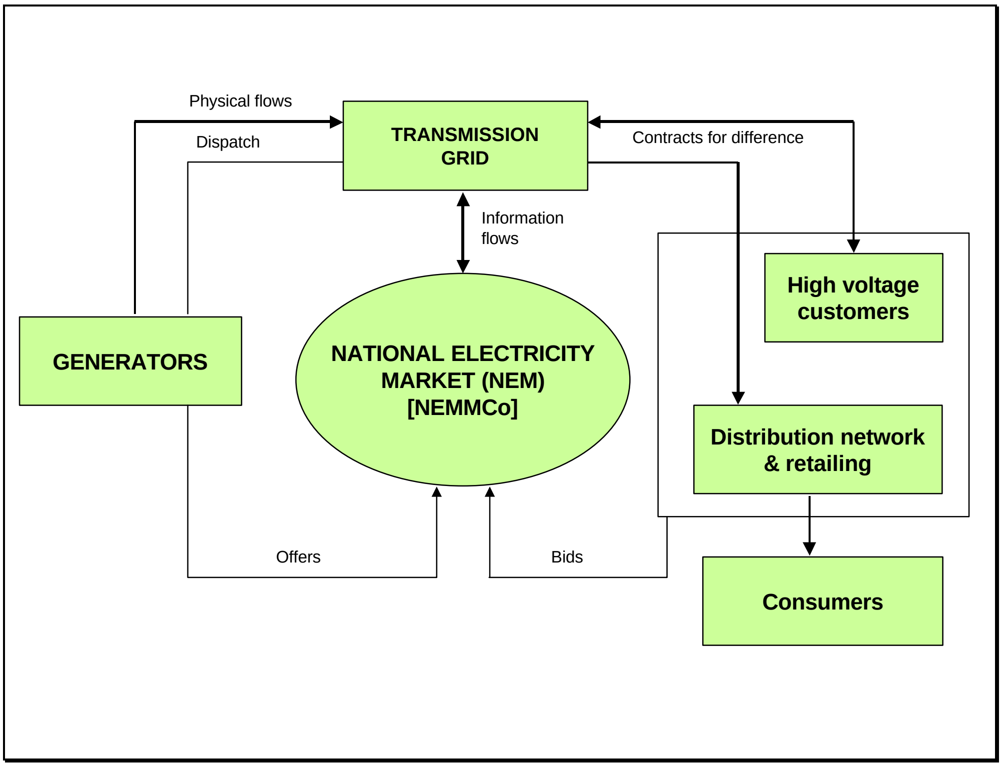
In parallel with the NGMC process, the states of NSW and Victoria introduced their own state wholesale electricity markets. These were linked by aligning rules for pricing and generator dispatch in 1997.

The NEM is an integrated competitive wholesale market for the trading of electricity, which operates across the eastern and southern mainland states of New South Wales, Victoria, the Australian Capital Territory and South Australia. The same system was concurrently implemented in Queensland.

The operations of the national electricity market are shown depicted in Figure 25. Generators compete in the spot market by electronically submitting offers for dispatch. The National Electricity Market Management Company (NEMMCo) operates the system by dispatching generation to meet the demand at any instant in time, as determined by the bids being made by power retailers and large, high voltage industry customers. The price established by the pool is the spot market price for wholesale electricity. This is calculated as a time weighted average of the six (5 minute) dispatch prices for each half hour of the trading day. A separate financial contracts market also operates on two levels to manage wholesale spot market trading risks.

For that part of the retail market that is contestable - typically large industrial users able to choose their electricity supplier – the NEM allows negotiation of competitive contracts, including hedging and other risk management contracts.

Figure 25 The Australian wholesale electricity market



The Australian Productivity Commission recently estimated that energy market reforms have led to real falls in electricity prices of some 24% on average for all end-users since 1991-2.

Each jurisdiction participating in the NEM has a defined timetable for when a franchise customer will be eligible to choose their electricity supplier. These timetables are based on their level of electricity consumption or demand. From January 2000 all customers who consume more than 160 MWh in participating jurisdictions have been contestable. From January 2001 all customers in participating jurisdictions apart from SA will be contestable. Customers in SA will be contestable from 1 January 2003.

Table 12 Electricity consumption, production and capacity by Australian state in 1997

	Consumption (TWh)	Generation (TWh)	Net Imports (TWh)	Capacity (MW)
ACT[1]	2.3		2.3	
New South Wales	53.7	62.9*	4.5	16,802**
Northern Territory	1.4	1.5		433
Queensland	28.7	34.3	-0.3	8,040
South Australia	9.5	6.8	4.0	2,529
Tasmania	8.9	8.8		2,543
Western Australia	10.8	12.8		5,084
Victoria	33.9	39.2	-3.2	8,465

Notes: 1 Australian Capital Territory
* Includes 5.6 TWh from the Snowy Mountains hydro scheme
** Includes 3,756 MW from the Snowy Mountains hydro scheme
Source: Department of Industry, Science and Resources. Canberra.

SNOWY MOUNTAINS HYDRO-ELECTRIC SCHEME

The Snowy Mountains Hydro-electric Scheme is a cooperative venture between the Commonwealth, New South Wales (NSW) and Victorian governments. It comprises a vital part of the supply and market stability arrangements for south-east Australia. Generation and transmission of electricity is the responsibility of the Snowy Mountains Hydro-electric Authority. A separate government owned company, Snowy Hydro Trading Pty Ltd, sells the electricity into the wholesale market.

REFORM AT STATE LEVEL

VICTORIA

The state of Victoria was the first to begin energy sector reform, and this is almost complete. The State Electricity Commission of Victoria was vertically separated into three sectors (generation, transmission and distribution) in late 1993. The generation sector was divided into 5 companies (which have subsequently been privatised), and the Victorian Power Exchange was established to operate the wholesale market until it became part of the NEM at the end of 1998.

The transmission company has also been privatised. The former 29 electricity distribution companies were reduced to five, and have been privatised. These have monopoly rights with respect to their customer franchise areas, but this provision will be phased out by December 2000.

A transition tariff structure has been developed through to the year 2000. Tariffs include the maximum uniform tariffs for franchise customers and maximum network tariffs for transmission use and distribution use of system. The five distribution companies in Victoria in collaboration with NEMMCo and the Victorian Government are in the process of developing the trading arrangements for the final tranche of retail customers.

NEW SOUTH WALES

New South Wales has instituted a similar reform process to Victoria, but has not taken the step of privatising the state owned generation companies. Instead, these were corporatised, and operate as state owned firms operating under normal business laws.

The high voltage transmission grid is the responsibility of the state owned company TransGrid. The former 25 distribution boards have been aggregated into 6 corporatised businesses that also continue to operate as state owned enterprises.

QUEENSLAND

In early 1995, the Queensland Electricity Commission was initially restructured and corporatised to form two new government corporations, one responsible for all generation and the other responsible for all other functions. In 1998, the industry was entirely disaggregated into competing state owned businesses at all levels.

Queensland has private sector investment in the generation sector. In 1997, 30 percent of the sector was privately owned, and this share will rise as investors move to build new capacity in the state. In that year, the industry was entirely disaggregated into 14 competing state owned businesses including three generation companies, an engineering services company, a transmission company, seven regional distribution companies and two new retail corporations. Two new interconnectors are being commissioned between Queensland and NSW that are expected to be operational in 2000 and 2001.

Although committed to becoming part of the NEM, Queensland does not yet enjoy interconnection with New South Wales and other, more distant states.

SOUTH AUSTRALIA

In 1995, the vertically-integrated state utility Electricity Trust of South Australia was corporatised, and four subsidiaries formed: ETSA Generation, ETSA Transmission (transmission, system control and system planning), ETSA Power (distribution and marketing), and ETSA Energy (gas trading).

ETSA Generation was separated from ETSA Corporation in 1997 to form SA Generation. In 1998 the power assets were reorganised into seven businesses in preparation for privatisation of the industry. The new entities included three power generation companies, a gas trading corporation and a transmission business, a retail business ETSA Power and the distribution company ETSA Utilities. ETSA Power and ETSA Utilities were subsequently sold in late 1999 and the remaining businesses are expected to be sold by the end of 2000.

WESTERN AUSTRALIA

In 1995, the vertically-integrated State Electricity Commission of Western Australia was divided into two independent state-owned electricity and gas corporations, trading as Western Power and Alinta Gas.

Like Queensland, Western Australia has encouraged private investment in the generation sector. The state intends to privatise the gas network.

TASMANIA

In 1998, the Hydro-Electric Corporation was disaggregated into 3 separate businesses to take responsibility for generation, transmission and distribution functions. They all remain state owned.

THE FUTURE?

Australia is focusing on the creation of a fully competitive national market in the generation and marketing sectors, and to provide for efficient outcomes at the state level in the transmission and distribution sectors. The target date to achieve these outcomes (with at least New South Wales, Victoria, South Australia, ACT, and Queensland fully interconnected) is late in the year 2000.

Australian policy-makers in most states consider that a fully competitive energy sector can be substantially achieved without full privatisation of the competitive elements, although individual states may pursue this path. They consider that the successful operation of the wholesale market is not necessarily dependent on the assets being privately owned, provided governments do not take actions that distort market behaviour and instead allow their enterprises to operate independently in a commercial manner (Tucker, 1999). Victoria and South Australia have however opted for full privatisation.

LESSONS

With the right regulatory controls and incentives, competitive wholesale and retail electricity markets can be achieved without full scale privatisation – provided state owned companies are set up to operate commercially on a level playing field with private sector firms.

Table 13 Australia's electricity sector reform history

Year	Reform initiative	Comments
1991	Industry Commission reports. National Grid Management Council (NGMC) established.	Industry Commission report recommends vertical separation (unbundling) of generation, transmission and distribution. Also corporatisation of each entity and privatisation of generation capacity.
1993		Disaggregation and corporatisation of state electricity utilities commences in Victoria.
1994		Victoria becomes the first state to introduce a wholesale electricity market, competition between generators and retail contestability.
1995		Commonwealth (COAG) agrees that each jurisdiction should introduce competition into the industry, with transition to a fully competitive national electricity market. Victoria commences privatisation of state electricity assets, with distribution followed by generation assets.
1996	National Electricity Code (NEC) developed.	Code submitted to Australian Competition and Consumer Commission (ACCC) for approval. Code defines rules for network pricing, connection and access, market rules and operation, and system security. A wholesale electricity market commences in New South Wales.
1997	National Electricity Market (NEM) commences operation. National Electricity Market Management Company (NEMMCO) established.	Phase 1 of the NEM commences, with the linking of the Victorian, New South Wales and Australian Capital Territory markets. NEMMCO operates and administers market, and is responsible for power system security.
1998		NEM comes into force fully, also encompassing South Australia and Queensland.

CHILE

INTRODUCTION

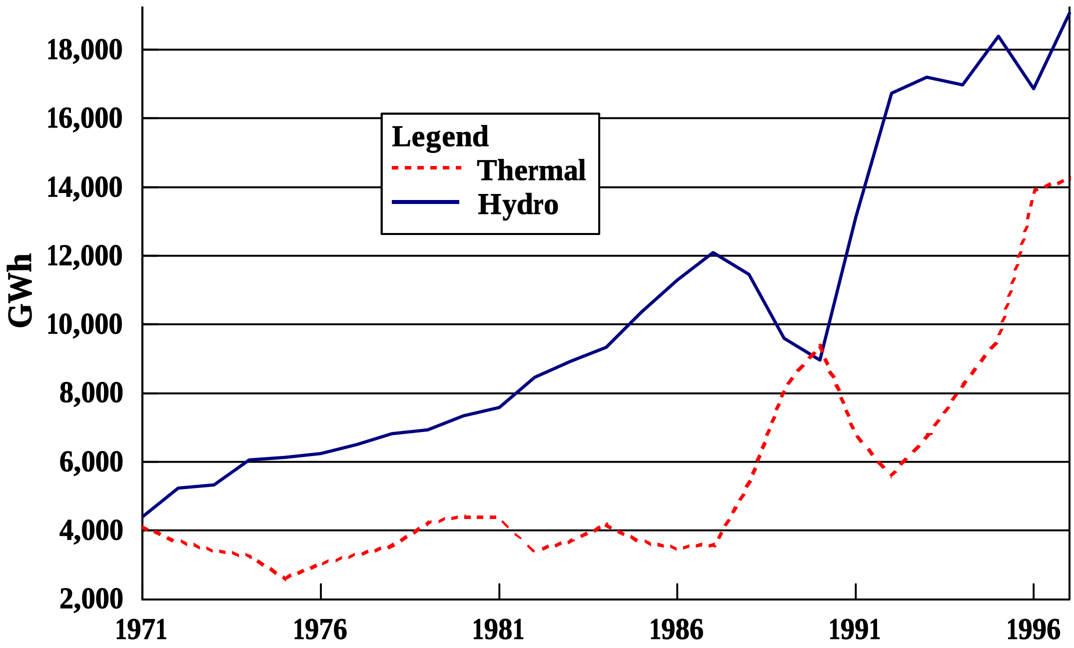
Chile's power sector was one of the first in the world to be deregulated. Given the common characteristics with other developing APEC economies and the time that has passed since the beginning of the process, its study can provide insights into issues that economies who plan to restructure will probably face[20].

GENERAL BACKGROUND

Chile's electricity demand is closely linked to GDP. In the last 20 years (1977 to 1997), electricity demand has grown at an average annual rate of 7.4 percent.

Under normal hydrological conditions, this demand is supplied mainly with hydropower and to a lesser extent with thermal generation (see Figure 26).

Figure 26 Generation by energy source in Chile



Source: EDMC database

However, the share of thermal generation is expected to increase significantly with the construction of combined cycle plants, as a result of the introduction in 1997 of natural gas from Argentina. In fact, prior to this date, generation from this source was almost negligible. According to the 1999 indicative planning of the Chilean National Energy Commission (CNE, 1999), of the total 4,831 MW that are planned to be installed until the year 2008[21], 83.2 percent will be of natural-gas-fired power plants and 16.7 percent of hydro stations. Thus, it has been estimated (US EIA,

20 The base information for this case study comes mainly from PRIEN (1995).

21 This date corresponds to the indicative planning for the Central Interconnected System (SIC). For the other systems it is 2000 (SING) and 2001 (Aysen and Magallanes). The power plants in Argentina that will supply the InterAndes cross-border interconnection are not included.

1999), that natural gas could account for nearly 43 percent of the total generation by the year 2020. The following table shows the installed capacity in 1999 by energy source.

Table 14 Installed capacity by energy source in Chile (1999)

	Hydro	Natural gas	Coal	Oil	Other	Total
MW	4,027	2,321	2,073	1,255	211	9,887
Percentage	40.7	23.5	21.0	12.7	2.1	100.0

Source: National Energy Commission of Chile (CNE)

THE POWER SECTOR BEFORE RESTRUCTURING

Before the restructuring of the electricity sector, ownership was mixed with dominant state presence in generation, transmission and distribution through vertically-integrated utilities. Regulation and long-term planning were undertaken by the state.

The main actors in the system were:

- ENDESA: A state-owned utility created in 1943 with the objective of carrying out the National Electrification Plan. It developed into Chile's major vertically-integrated utility, responsible for not only constructing and operating most of the system, but also –amongst other tasks– of prospecting hydrological resources and developing a long-term electricity plan;
- CHILECTRA: The major distribution company, supplied by ENDESA and by its own generation facilities. Privately-owned until 1970, when it was nationalised;
- AUTOPRODUCERS: Mainly of the mining sector in the North. Especially relevant was the Tocopilla thermal plant, which supplied power not only to the state-owned copper company, but also to other industrial and residential customers;
- THE STATE: Implemented its policies mainly through ENDESA.

Price regulation considered cost recovery plus a 10 percent margin. Cross-subsidies favoured rural and remote areas.

MOTIVATION FOR RESTRUCTURING

The main motivation for the deregulation and privatisation process in Chile was restructuring of the economy, and to a lesser but nonetheless important degree, the investment requirements in and outside the power sector that demanded significant resources, which the state had difficulty in providing (PRIEN, 1995).

In the years following 1973, profound changes were introduced in Chile. The main philosophy was that through markets, the private sector should be the main actor in the economy, with the State serving in a subsidiary role. In concrete terms, this meant the opening of the economy to the outside world, the reduction of state participation in the economy and liberalisation of prices. The state, which had been the determinant agent in the development of Chile, restricted itself to promoting and overseeing the functioning of markets.

In this context, the restructuring of the electricity sector was part of a major process that included labour, pensions, finance, health, taxes and others. The privatisation of public enterprises included the participation of its workers and of the general public, through what was called "popular capitalism", in order to gain acceptance to the process and to impede or reduce the possibility of its reversal.

Thus, some reviewers of the Chilean process state that the main drivers for the restructuring of the electricity sector lay outside of the sector itself, being heavily influenced by a wider economic and political reform process (PRIEN, 1995).

From the middle of the seventies, and in accordance with the principles of the "market social economy" philosophy held by the government, a rationalisation of electricity prices in particular, and energy prices in general, was commenced together with a financial and administrative normalisation of public enterprises. Among the problems identified in the electricity sector were:

- A strong commitment of the state in the development of the sector, which meant investment requirements in the order of 200 million US dollars per year;
- Increasing monopolisation of the sector and concentration in the hands of one public utility, ENDESA;
- Confusion over the normative and entrepreneurial roles of the state, which hindered the entrance of other actors; and
- A lack of sufficiently-transparent and economically efficient principles and mechanisms to set electricity tariffs. (The use of accounting principles to set tariffs did not recognise the present value of the opportunity costs of producing, transmitting and distributing electricity. Rather, they reflected what each company had invested in the past, independent of its efficiency).

The regulatory framework showed weaknesses regarding the procedures to undertake tariff studies and the lack of uniform criteria to establish tariff structures. The Tariff Commission had been losing importance with respect to the Ministry of the Economy, which increased the influence of non-technical and non-economic factors in the determination of tariffs. These elements, in a high inflation setting, led to a situation where the rate of return of the companies was lower than what they theoretically could obtain (under prevailing law).

It was concluded that these problems could not be dealt with internally within the electricity sector, but needed a comprehensive strategy encompassing the whole energy sector. The central elements of the strategy were designed to encourage economic efficiency in the electricity sector, in a framework in which the state played a subsidiary role. With respect to the electricity sector, the actions and policies undertaken included:

- The design of a regulatory framework that would decentralise and disaggregate the sector;
- The formulation of a price policy that would reflect the real costs of producing, transmitting and distributing electricity efficiently;
- The assignment of the state to the role of assessment of hydraulic resource availability;
- The development of an investment planning and coordination policy (the criteria used to plan the expansion of the system should permit the

identification of those options – sequences of projects – that represented the minimum present cost of investment, operation and outage); and

- A policy to coordinate the operation of generation units and transmission systems of different suppliers, in order to have an efficient and secure operation.

In sum, the goals were to allow for the efficient development of the electricity sector, including social efficiency in the allocation of resources, and the promotion of competition. This would be achieved through privatisation, accompanied by the decentralisation and desegregation of the ownership structure.

An additional element reinforcing the reasons to privatise the sector, though not defining the process, was an economic crisis during 1982-83. As discussed above, the previously defined restructuring framework included privatisation as part of the process. The crisis deepened the need to relieve the state of its investment requirements in the sector, as well as the necessity of obtaining funds for other infrastructure and social investments. The sale of public assets was seen as a solution to both problems. However, at the time, the private sector was also struck by the crisis and was not prepared to invest the amounts required.

DEREGULATION PROCESS

The process began in 1978, with the creation of the National Energy Commission, which designed the new framework, enacted by law in 1992. The law established competition in generation and recognised transmission and distribution as natural monopolies. It is important to note that no restrictions were imposed as to the property of transmission lines. Transactions among generators would follow marginal cost pricing practice, while prices charged to distributors and retail consumers would be regulated. Large consumers (with a power demand greater than 2 MW) were allowed to freely choose their supplier and negotiate prices. The Economic Dispatch Load Centre (CDEC), created in 1985, would coordinate the generation, operating under a merit order rule.

The unbundling of companies started in 1981, and their privatisation commenced in 1985. Major actors in the privatisation process were the AFP (private pension funds) that bought shares in the stock market. The following tables summarise the main events and some key elements of the Chilean reform process.

Table 15 Chile's electricity sector reform history

Year	Reform initiative/Related event	Comments
1978	Creation of the National Energy Commission (CNE)	Designed the basic institutional, legal and policy framework that changed the energy sector during the eighties
1980	Change of tariff calculation criteria	The criteria to determine tariffs based on minimum return on investment of 10% is changed to marginal cost pricing.
1981	Unbundling of distribution from ENDESA (major utility)	The distribution business was separated into 9 companies.
	Unbundling of Chilectra (major distribution company)	The company was transformed into a holding composed of: Chilgener (generation, now Gener), Chilectra Metropolitana (distribution) and Chilectra V Región (distribution)
1982	Electricity Power Services Law (DFL 1) was enacted	Legal framework for the restructuring process.
	ENDESA registered as a per-share society	The stock market, especially through institutional buyers (AFP[1], international investment funds, etc.) would play a key role in the privatisation process
	Separation of some of ENDESA's generation facilities	Three generation units were separated from ENDESA, but remained as subsidiaries
1982-83	Economic recession	Delayed the privatisation process
1985	Separation of two of ENDESA's generation subsidiaries	The subsidiaries remained as state-owned companies under CORFO (state development agency)
	Creation of CDEC-SIC[2]	All major generators became subject to central cost-based dispatch. Application of marginal cost wholesale pricing regulation.
1985-87	Privatisation of Chilectra	The shares were sold to its employees and in the stock market
1986	Introduction of retail supply competition	Limited to consumers with a demand over 2 MW (the so-called "free clients")
		The state absorbs US$ 500 million of ENDESA's external debt
1987-90	Privatisation of ENDESA	Shares were initially sold or exchanged for indemnisation compensations to selected groups[3] and later floated in the stock market[4].
1988	Creation of ENERSIS	Created from the transformation of the Compañía Chilena de Electricidad S.A. Will later become a major actor in Chile and Latin America[5].
1990	Privatisation process practically completed	
	ENERSIS single largest shareholder of ENDESA	ENERSIS has interests in generation, transmission and distribution.
1993	Separation of Endesa's transmission business	Created a separate company (Transelec) and transferred the ownership to its shareholders.
1997	Privatisation of EDELAYSEN	With the sale of this small utility, privatisation reaches 100%.
1999	ENDESA-Spain single largest shareholder of ENERSIS and ENDESA-Chile	ENDESA-Spain owns 63.9% of ENERSIS, which owns 60% of ENDESA-Chile. In Latin America, its interests in generation, transmission and distribution, are located in Argentina, Chile, Brazil, Peru and in the SIEPAC project, which will interconnect 6 Central American economies.

Notes: 1) Private pension funds.

2) Economic Load Dispatch Centre of the Central Interconnected System, initially a generator's pool; changes to the regulation incorporated transmission companies.

3) ENDESA workers, public sector workers, Armed Forces.

4)The shareholders as of December 1990 were: AFP (private pension funds) (26.3%), public sector workers (13.8%), Armed Forces personnel (13.0%), individuals (12.0%), foreign investment funds (7.3%), ENDESA personnel (3.3%), CORFO (1.0%), others (23.3%).

5) As of June 1999, the ENERSIS Holding had interests in the following businesses and companies (in the case of electricity generation and distribution, the percentage indicates the share in property):

Electricity generation and distribution: ENDESA (Chile) 63.9%, CHILECTRA (Chile) 74%, Rio Maipo (Chile) 84%, EDESUR (Argentina) 51%, EDELNOR (Peru) 29%, CERJ (Brazil) 38%, COELCE (Brazil) 21%, CODENSA (Colombia) 21%. This represents 10,700 MW of generation capacity and 8.8 million customers in distribution, making ENERSIS the largest private electric group in Latin America. However, currently ENDESA-Spain controls ENERSIS and ENDESA-Chile.

Water utility sector: Aguas Cordillera and Esval (Chile)

Related businesses: computer and information services (SYNAPSIS), electric engineering services and real estate (I.I. Manso de Velasco), sales of electrical equipment and products (DIPREL)

Sources: PRIEN (1995), Yajima (1997), Enersis website, ENDESA-Spain website.

Table 16 Key reform elements in the Chilean electricity sector

Element	Comment
Reform model	Retail wheeling with cooperative generators' pool
Treatment of monopolistic functions	Transmission: separation Distribution: bundled with monopolistic retail supply (< 2 MW)
Restructuring and privatisation	Important state-owned companies, Endesa and Chilectra, split and privatised
Vertical disintegration	Split-up designed to secure disintegration among competitive generation, transmission, and distribution (bundled with regulated retail supply). No restrictions as to the property of assets in the value chain
Liberalisation	Removal of legal entry barriers in generation and transmission (no licensing requirements); distribution subject to licensing
Access to the grids	For all generators and for all retail consumers larger than 2 MW, based on grid tariffs
Mandatory generator's pool (CDEC)	Generators are cost-based dispatched; differential energy quantities (trade) are settled based on the short run marginal cost of the system; short-falls in capacity between contractual obligations and available capacity are settled based on the regulated long run marginal cost (LRMC) capacity premium (generators' pool gives generalised access to back-up and top-up supplies)
New price regulation	Prices between generators and distributors are based on actual pool prices for energy and regulated LRMC capacity premium; retail supply based on regulated tariff, which is the sum of pool price forecast-derived energy price, the regulated capacity premium, and transmission and distribution costs
Competitive mechanisms	Full competition in generation; in supply, there is retail competition where generators compete in concluding supply contracts with distributors (regulated conditions) and retail consumers larger than 2 MW (unregulated conditions)

Note: The table shows the initial formulation of the model. Changes to the regulation incorporated transmission companies into the CDEC's.

Source: Yajima (1997)

PRICING SYSTEM

Electricity tariffs in Chile are designed to approximate a free market. Generators may sell electricity to other generators, to distribution companies, and to some large customers - the so-called "free clients"[22]. Sales can be made pursuant to short- or long-term contracts or on the spot market. Contractual sales to other generating companies or free clients are not regulated, whereas those on the spot market are. These latter transactions among generators are valued at the system marginal cost of the interconnected system in which the companies are located[23]. Transmission tolls are fixed according to a formula that reimburses the owner of the transmission lines for a portion of its investment and operating cost for the transmission lines used. Prices for regulated consumers, who have no negotiation capacity and are supplied by distribution companies resembling natural monopolies, are determined in two stages:

1) PRICES BETWEEN GENERATORS AND DISTRIBUTION COMPANIES, the node prices. Node prices for energy are calculated every six months and are based on the projected short-term marginal cost of satisfying the demand for energy at a given point in the relevant interconnected system over the next 48 months, in the case of the SIC[24], and 24 months, in the case of the SING[25]. A tariff formula is used which takes into account projections of the main variables in the cost of energy at each substation in the system over the relevant time period[26]. Indexations allow adjustments during the six-month period if changes in the underlying assumptions used to project the node prices in effect would result in a change of more than 10 percent in the node price calculation. Regulation requires that the difference between node prices and the actual prices charged to non-regulated customers in the prior six-month period may not, on average, exceed 10 percent. If this requirement is not met, the National Energy Commission must make the necessary adjustments;

2) FINAL PRICES BETWEEN DISTRIBUTION COMPANIES AND END-USERS reflect the applicable node price plus an additional charge for the electricity distribution service, which is known as the distribution value added. The tariffs to end-users are based on the operational costs (including expansion requirements) of model companies operating efficiently in typical electrical distribution zones. Inefficiencies that may exist in the operations and investments of real distribution companies cannot be passed on to consumers; rather, companies have incentives to increase the efficiency of their operations. The regulations state that the tariffs should allow the distribution companies of the respective typical distribution zone

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22 The so-called "free clients" must have a demand in excess of 2 MW. The prices they obtain in the market are called 'free prices'.

23 System marginal costs are set twice a year in the case of sales of power and each week (with a daily review) on an hourly basis in the case of energy sales. These marginal costs are set by the CDEC (Economic Load Dispatch Centre) of each system, taking into account the main variables in the cost of capacity and energy. For capacity, the system marginal cost is based on the cost of a new diesel gas turbine generation facility. The determination of the system marginal cost for energy is based on: demand forecasts, reservoir levels, fuel costs for thermoelectric generating facilities, maintenance schedules and others.

24 Central Interconnected System, which supplies electricity to over 90 percent of the population.

25 Interconnected System of the Great North.

26 The variables considered include: projections of demand growth; reservoir levels, which determine the availability and price of hydroelectricity; fuel costs for thermoelectric facilities; variations in exchange rates of foreign currencies relevant to raw materials; planned maintenance schedules or other factors that would affect the availability of existing generating capacity; and scheduled new additions to generating capacity during the relevant period. These marginal cost projections assume efficiency in operations and future investment.

to have a nominal rate of return in the range of 6 to 14 percent. Distribution tariffs are calculated every four years, with monthly indexation to allow adjustments due to variations in node prices and other factors affecting distribution costs.

OUTCOME

Almost twenty years have passed since the enactment of the law that restructured the Chilean power sector. It has served as a model for many economies that have improved the basic - and pioneering - conception.

Although some indicators show that the efficiency of the system increased, investments have kept pace with the demand, and that the sector has been successful in its internationalisation process, no definite conclusion can be made regarding retail prices, especially in the Central Interconnected System where the majority of the population lives.

As for the lessons that can be obtained for other developing economies, it is interesting to recall the concerns that several reviewers of the Chilean restructuring process have raised, including the price at which assets were sold and the lack of consumer protection[27]. However, one of the major criticisms has been the feasibility of true competition. These criticisms have highlighted – among others – the importance of the ownership of water rights, clear pricing mechanisms (especially in transmission), and above all the high degree of concentration.

As was mentioned earlier in this case study ENDESA, the main state utility before the restructuring process began, was responsible for prospecting hydro resources. As part of the assets included with the privatisation of this utility, were water rights to most of the technically and economically interesting exploitable hydro resources in Chile. It must be noted that under Chilean law, holders of water rights are not required to use them. Therefore, it has been argued that this represented an entry barrier to the generation market. Furthermore, given the low –and sometimes zero– marginal cost of hydro generation as compared to thermal generation, and the pricing system used by the CDEC to dispatch, it was argued that this utility delayed investments in hydro facilities so the prices would not decrease. After the introduction of natural gas from Argentina and the simultaneous construction of natural gas combined cycle plants, this issue lost momentum.

As stated earlier, the major issue that the Chilean electricity sector restructuring process has faced is the degree of concentration, with its accompanying threat of monopolistic practices. This has confronted in numerous occasions the regulatory bodies with the utilities.

One of the objectives of the reform was to reduce the concentration present in the industry. However, the legislation enacted to support the process did not impose restrictions as to the property of each section of the value chain. In particular, property of the main transmission system remained in ENDESA, which had the majority of the generation facilities. Furthermore, ENERSIS, a holding that emerged from the major distribution company, acquired an increasing percentage of shares in each of the segments of the industry. Some of these acquisitions were questioned by the antitrust bodies. ENERSIS ultimately acquired a controlling position in the Chilean electricity sector.

The consequences of this concentration, together with unclear pricing mechanisms in transmission, gave rise to a disadvantageous market position for those companies not part of the holding. Many disputes ended in trial.

In 1993 the antitrust bodies ordered that transmission should be separated from ENDESA. A new company was formed, TRANSELEC. In practice however, the results of this separation were not clear, given the connections between both companies.

27 For an expanded discussion see PRIEN (1995), Blanlot (1993) and Moguillansky (1997).

Considering the problems that the industry was facing, the National Energy Commission undertook a partial revision of the legislation in 1997. Some of the changes involved the transmission pricing system and the composition of the CDECs, incorporating transmission companies to these latter bodies.

During the 90's, Chilean companies invested heavily in the power sector of many Latin American economies, such as Argentina, Brazil, Colombia and Peru. In this process, ENERSIS transformed itself into the major electricity holding of South America, with interests in generation, transmission, distribution and retail.

In tandem with the Chilean expansion to Latin America, foreign companies acquired shares of Chilean utilities. However, the end of the 90's brought a major actor into the Chilean market, namely ENDESA ESPAÑA. In a first step, it bought a percentage of ENERSIS, but soon it would be evident that it was not enough to have a controlling position. Ultimately ENDESA ESPAÑA increased its property in ENERSIS as well as ENERSIS' property in ENDESA (Chile). This operation was highly opposed by the antitrust regulatory bodies, but nevertheless the takeover proceeded.

FUTURE DEVELOPMENTS

The main elements of the Chilean model remained in essence unchanged since its adoption almost twenty years ago. Given the difficulties that arouse, some changes were made, nevertheless they were insufficient.

However, given the persistence of serious difficulties, currently some important changes to the legislation are being discussed. A draft proposal to reform the regulatory framework was opened to public discussion on the 25th of January, 2000 [28]. The draft, formulated by the National Energy Commission and the Senate, can be summarised in the following points[29]:

"Objectives

1) ***Strengthen the mechanisms leading to a dynamic and efficient development of the electricity sector****, keeping adequate incentives for productive investments in all its sectors and assuring forms of competition and regulation that guarantee adequate coverage, quality and supply prices, in order to achieve a better quality of life for residential customers and an increase in the international competitiveness of industrial consumers.*

2) ***Strengthen the loyal competition in the segments of the electricity market where it is feasible****, particularly in generation and commercialisation of energy and power to free clients and distribution companies.*

3) ***Preserve and protect the rights of consumers****, especially of the smaller ones, both residential and industrial.*

4) ***Establish the preventive mechanisms to avoid or reduce the probability of electricity rationing****.*

5) ***Improve the regulatory framework of the electricity sector trying to avoid a prolonged uncertainty period****.*

Main proposals

1) *Advance towards a vertical disintegration of the major interconnected systems (SING and SIC), desegregation of transmission, limits to the concentration in the supply of free markets and distribution. This should contribute to the strengthening of competition, in benefit of economic efficiency and of users, and*

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28 The proposal ("Propuesta de Bases de la Reforma del Marco Regulatorio del Sector Eléctrico"), can be consulted in the website of the National Energy Commission (http://www.cne.cl).

29 The text corresponds to our own and unofficial translation of the proposal.

seeking that the processes of disintegration and desegregation will generate a maximum competitive effect and a minimum negative effect over investment in the sector. (Several prohibitions and limits are proposed, as well as an implementation period of 5 years)

2) *Introduce the marketer, a new type of specialised agent in the segment of commercialisation of electricity to free clients, activity which is now performed in generation and distribution companies.*

3) *Grant access to the spot market to the marketer, free clients and distribution companies, at instantaneous marginal cost, but for the latter ones, only in what refers to the supply of free clients, not subject to price regulations.*

4) *Perform a bidding process of all the contracts of concessionary distribution companies that correspond to the supply of regulated customers.*

5) *Expand the market of free clients, to contribute to the creation of competitive conditions, but avoiding that the new clients, which are smaller, face insufficient competitive conditions. The category of free clients will be expanded from the current 2000 kW to 500 kW of connected power, at the publication of the law (with two years of voluntary adoption of this status for those customers that prefer to stay as regulated) and from 500 kW to 100 kW five years later.*

6) *Develop an institutional framework and regulations that permit the achievement of maximum possible transparency and predictability in the establishment of tolls corresponding to the transmission, subtransmission and distribution segments, keeping direct negotiations among the companies involved as an initial option, but establishing reference parameters, peremptory terms and expedite and consistent arbitral procedures, that is, based on permanent instruments and in stable methodologies.*

7) *Improve the institution that coordinates the operation of the electric systems, that is the Economic Load Dispatch Centres, ratifying the autonomy reached with the modifications to the original law and permitting the incorporation of concessionary public service distribution companies and the marketers. Include the free clients that have purchased at least 70 GWh in the spot market, at instantaneous marginal cost, in the last 12 months.*

8) *Maintain the dispatch of generating units based on short-term marginal costs, but permitting the supply of electricity coming from international interconnections[30].*

9) *Improve the regulation of tariffs pertaining to generation-transmission and gradually approximate it to free prices.*

10) *Simplify tariff regulation at the distribution level, eliminating the necessity of determining tariffs every 4 years. Tariffs will vary according to their indexer minus a discount for efficiency gains, in the same manner the mechanism currently operates between tariff determination processes."*

As seen, the proposal addresses some of the major problems of the system.

LESSONS

Economies with small power markets subject to takeover by big trans-national companies after privatisation need to carefully craft power sector regulations and enforcement bodies – both specific to the sector as well as of general application to markets – to effectively limit market power, balancing efficiency, investment attractiveness, and consumer protection.

30 The regulatory framework for cross-border power interconnections is currently being discussed. It can be consulted in the web of the National Energy Commission.

JAPAN

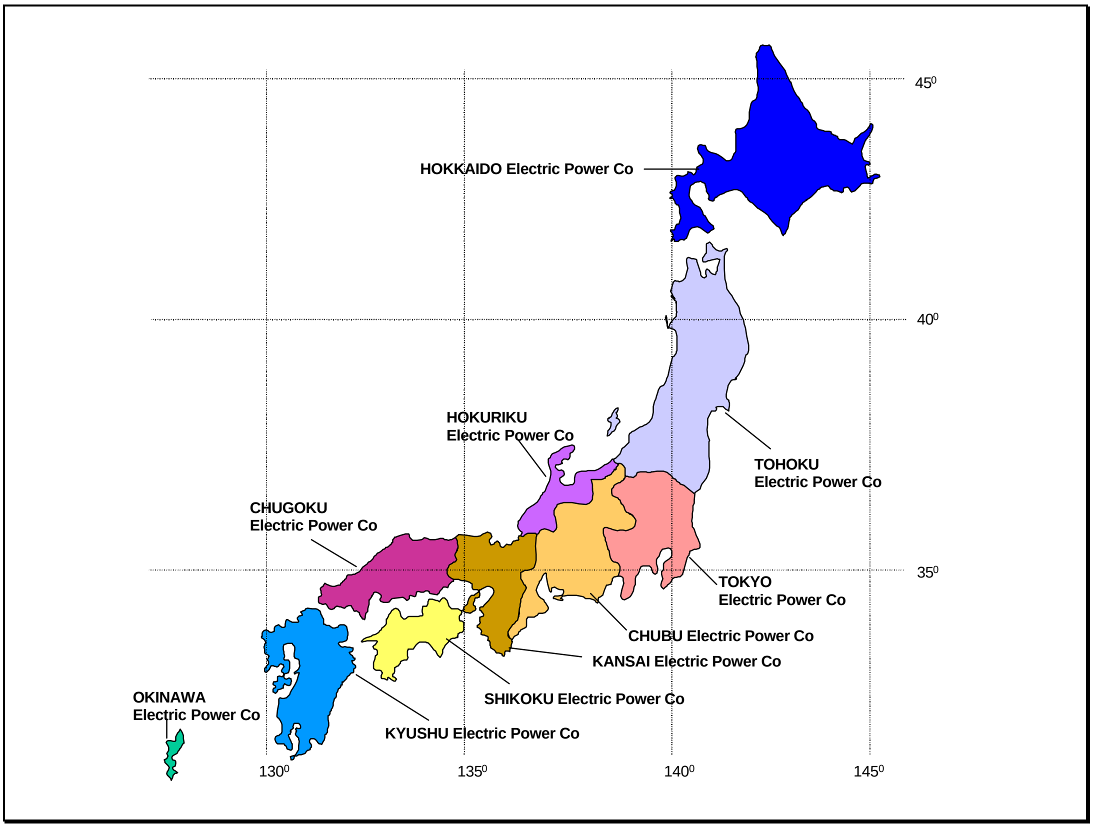
INTRODUCTION

INDUSTRY STRUCTURE

In Japan there are 10 private electric utilities, all vertically-integrated (from generation to retail supply). They are all regional monopolies, with their own franchise areas. Between generators, inter utility trade is carried out to ensure security of supply.

There are three wholesale suppliers of power: the Electric Power Development Co Ltd (EPDC); the Japan Atomic Power Company (JAPC), and the Joint-Venture Power Utilities.

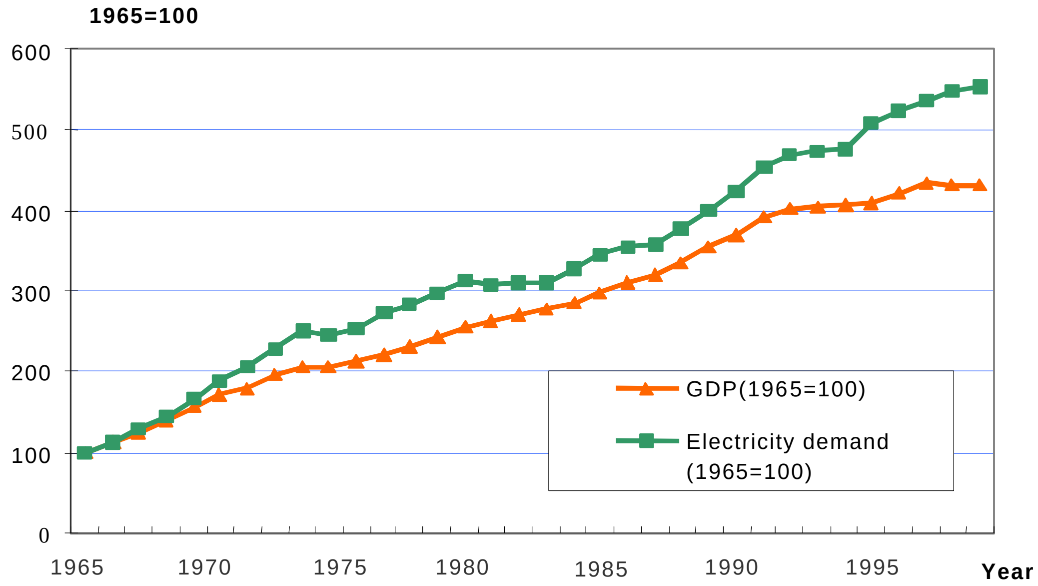
Figure 27 Electric power utilities in Japan



DEMAND

Japanese electricity demand has shown a steady increase from 1965 to 1998, with a 5.3 percent average annual growth (EDMC/IEEJ 2000). As Figure 28 shows, demand is increasing with GDP growth. In response to the public trend for greater comfort and more sophisticated amenities, the use of convenient electrical products is rapidly increasing. Subsequently, commercial and consumer demand for electricity now exceeds industrial demand, and the gap is expected to widen even further in the future (Federation of Electric Power Cooperation, 1999)

Figure 28 Trends in GDP and electricity demand for Japan



FUEL MIX CHANGE

Table 17 shows the fuel mix change from 1970 to 1998 for 9 major electric utilities, indicating that reliance on hydro and oil is decreasing, while reliance on LNG and nuclear is increasing. After the two oil crises in 1973 and 1979, the Japanese government tried to reduce its dependence on oil. Fuel source diversification became an important policy goal in an attempt to ensure energy security. As a result, oil-fired power generation, with a share in 1970 of 50 percent of total electricity generated by 9 major electric utilities, decreased to 9 percent of total electricity generated in 1998. On the other hand, the share of LNG-fired and nuclear power generation increased greatly, from a zero base. In 1998, the share of LNG-fired generation was 27 percent, and nuclear was 46 percent[31].

31 Figures shown are the share of total electricity generated by the 9 mainland electric utilities. Of the total electricity generated - including the wholesale electric utilities and IPPs - hydro accounted for 9.8%, thermal for 58.1% and nuclear for 31.8% in 1998.

Table 17 Electricity generation by fuel in Japan

Year	Hydro	Oil	Coal	LNG	Nuclear	Total (M kWh)
1965	55,335	36,797	48,814			140,946
1970	60,848	124,320	63,913		1,293	250,374
1980	63,871	175,780	12,827	84,647	71,950	409,075
1990	65,433	162,810	37,258	181,674	181,063	628,238
1998	69,448	74,399	64,127	230,160	310,593	775,385
	%	%	%	%	%	%
1965	39	26	35	0	0	100
1970	24	50	26	0	1	100
1980	16	43	3	21	18	100
1990	10	26	6	29	29	100
1998	8	9	10	27	46	100

Note: For 9 Major Electric Utilities

Source: EDMC (2000)

ELECTRICITY SECTOR RESTRUCTURING

Deregulation of the electricity sector began only recently. In 1995, the Electricity Utilities Industry Law, the main legislation covering the electricity industry, was amended as a result of a number of pressures, including:

1) The global energy sector reform trend;
2) The comparatively high electricity tariffs in Japan; and
3) The deteriorating load factor (due to a sharp increase in demand in the summer).

1995 AMENDMENTS

The main provisions of the amendments made in 1995 to the Electricity Utilities Industry Law are as follows:

1) Liberalisation of entry for Independent Power Producers (IPPs);
2) Granting of permission to allow special electric utilities to supply directly to their customers (Retail sales).

The 1995 amendments of the Electric Utilities Industry Law is mainly characterised by the liberalisation of entry by IPPs. Although direct retail sales are now allowed for special electric utilities, they are limited to the suppliers with small capacities. The key amendment is that utilities can now conduct tenders for IPP investment in generation to cover short-term thermal power requirements.

As is shown in Table 18, in 1996, proposed projects amounted to 10,813 MW, four times larger than the original utility solicitation plans of 2.805 MW. Finally 20 projects were accepted, with a capacity of 3,046.9 MW. In 1997, proposed projects amounted to 4,254 MW, while 16 projects were accepted for a total of 3,118.3 MW. A variety of companies are involved in IPP ownership, including iron and steel companies, oil companies, and trading companies.

Table 18 Result of IPP bidding in Japan (1996-1999)

	Original Solicitation (MW)	Proposals (MW)	Number of Projects Proposed	Total Offers Accepted (MW)	Projects Accepted	Projects Withdrawn (MW)
First Round (1996)	2,805	10,813	100	3,047	20	
Second Round (1997)	2,855	14,254	92	3,118	16	547.5[a]
Third Round (1998)	150	764		215		109.5[b]
Fourth Round (1999)	1,000	2,510	11	804	4	

Notes: (a) General Sekiyu K.K. project. (b) Shinagawa Refractories project.

Source: CERA, IEEJ.

The major source of fuel used by industries that generate electricity in excess of their own requirements (or which plan to build IPP capacity) is coal and oil. The steel industry uses mostly coal-fired generation, and the petroleum refining industries use mostly oil-fired generation. A number of firms in those industries are already auto-producers, possessing idle land on which they can construct generation plants, and having relatively easy access to fuel.

Gas plays a relatively limited role in independent power generation. Of the 40 successful IPP projects so far accepted, only five will use natural gas. This is due to lack of indigenous gas supply, the limited gas infrastructure, and the relatively high cost of LNG (liquefied natural gas).

Table 19 Planned sources of fuel for IPPs in Japan (1996-1999)

	Number of projects	Capacity (MW)	Share (%)
Coal	17	3,674	56
Oil	17	1,834	28
Gas	5	985	15
Other	1	55	1
Total	40	6,748	100

Source: IEEJ

In addition to allowing IPPs entry to the wholesale market, there is an important factor that affects the future Japanese electricity industry, namely the greater competition in the gas market.

IMPACT OF GAS MARKET COMPETITION

In 1995, the Gas Utilities Industry Law was revised to allow parties other than gas suppliers, the ability to supply gas directly to industrial customers. Also, it allows general gas suppliers to sell gas to customers outside their service territory. Large volume customers, whose contract supply volume is at least 2 million cubic metres, are allowed to negotiate prices directly with suppliers. These amendments have had significant impacts on the Japanese gas sector and other energy sectors, by allowing the breakdown of a once very rigidly structured industry.

For example, Tokyo Electric Power Company (TEPCO), the largest electric utility in Japan, proposed to supply gas to Ube Industries for an IPP project. TEPCO was supposed to supply gas to Ube Industries by way of the city gas company, Ohtaki gas. Although Ube Industries' IPP project was not selected in the second round bidding, the implication is that in the foreseeable future electric utilities will enter the gas supply business. The gas industry will be liberalised in 2001, and this will promote a breakdown of the industry barriers between the electricity and gas sectors.

TOWARDS PARTIAL LIBERALISATION

Even after the 1995 amendment, the Japanese electric industry has been waiting for more changes to take effect. The Program for Economic Structure Reform, which attempts to reduce costs to industry and pursue efficiency improvement, was adopted in December 1996. Subsequently, the Japanese Cabinet adopted "the Action Plan for Economic Structure Reform" in May 1997. The electricity industry has attracted increasing attention, as policymakers have come to realise that there is still more room for cost reduction and efficiency improvement through deregulation.

MITI has undertaken an inquiry into the Electric Utility Industry Council (EUIC), by establishing the Basic Policy Committee in July 1997, to determine the optimal structure of the electricity supply industry. Through discussions between these parties consideration has been given to the introduction of competition - including retail competition – to promote improved energy efficiency. At the same time, it has been recognised that competition should go hand in hand with the requirement to meet public needs, such as universal service, maintenance of high reliability standards, energy security and preservation of the natural environment. In January 1999, the Committee released its report, and put forward recommendations for partial liberalisation of electricity retailing. Subsequently, in May 1999, the Diet passed a bill to amend the Electric Utilities Industry Law. In the revised legislation, there will be introduction of partial retail market competition. From March 21, 2000, extra-high voltage customers will be able to select their supplier. This partial liberalisation is expected to bring about a significant impact on the Japanese electricity sector, since 27.7 percent of total electricity demand will be affected.

Table 20 Reform history of the electricity sector of Japan

Year	Month	Reform Initiative	Comments
1995	December	First amendment of Electric Utilities Industry Law	Wholesale IPP entrance is allowed.
1996		The Program for Economic Structure Reform was adopted by the Cabinet	Aiming at the further electricity tariff reduction
		First Round of IPP bid results were announced	20 projects were accepted. Total capacity amounts to 3,046.9MW.
1997	May	The Action Plan for Economic Structure Reform was adopted by the Cabinet	
	July	Electric Utilities Industry Council (EUIC) established the Basic Policy Committee	EUIC is the advisory body to the Ministry of International Trade and Industry (MITI).
		Second Round of IPP bid results announced	16 projects were accepted. Total capacity amounts to 3,118.3 MW.
1998	May	The Committee released an interim report.	
		Third Round of IPP bidding	2 projects were accepted. Total capacity accounts for 215 MW.
1999	January	The Committee completed a report recommending partial liberalization.	It is recommended that partial liberalisation should go along with ensuring universal service, reliability, energy security and preservation of natural environment.
	May	Second amendment of the Electricity Utilities Industry Law	
		Fourth Round of IPP bidding	4 projects were accepted. Total capacity accounts for 804.1MW.
2000	January	Announcement of wheeling tariff	
	March	The Amended Electric Utilities Industry Law	Partial retail competition takes effect.

Source: Cambridge Energy Research Associates and other sources.

PARTIAL LIBERALISATION OF THE RETAIL MARKET

On May 21, 1999, the Electric Utilities Industry Law was amended with the revisions scheduled to take effect in March 2000. The Amended Electric Utilities Industry Law will allow partial liberalisation of retail sales, applicable to the special high-voltage customers. The eligible customers are either high voltage (20 kV) or with contracted demand over 2,000 kW. They can freely contract with power suppliers, including IPPs. This is made possible with retail wheeling by opening access to transmission and distribution lines. For new IPPs there is no legal supply obligation, their tariff and their entry to the market are not subject to any regulations. However, in the case that an eligible customer does not settle a contract with any supplier, as a last resort, it is ultimately possible that incumbent electric utilities are obliged to supply at the rate reported to MITI.

Table 21 shows the number of eligible customers by sector and by franchise area of incumbent utilities. In terms of total electricity demand, the share of eligible customers is 27.7 percent.

Table 21 Consumers able to negotiate tariffs in Japan after partial reform

	The number of eligible customers and its share in total electricity demand			
	Commercial	**Industry**	**Total**	**Share (%)**
Hokkaido	35	87	122	
Tohoku	68	505	573	
Tokyo	1,161	2,154	3,315	
Chubu	164	910	1,074	
Hokuriku	12	151	163	
Kansai	647	1,252	1,899	
Chugoku	47	446	493	
Shikoku	7	123	130	
Kyushu	106	375	481	
Okinawa	29	46	75	
Total	2,276	6,049	8,325	27.7%

Source: IEEJ

Among the total 8,325 eligible customers, most are industrial customers (6,049), while the rest are commercial users, such as large office buildings, hospitals and schools. By area, the largest number of eligible customers are located in TEPCO's franchise area, where the share of the commercial sector (such as large office buildings) is much higher than other areas.

Electricity tariffs for end users will be decided through negotiation between suppliers and users, since end user tariffs will not be subject to permission from MITI. Even though electric utilities are not subject to submit tariff menus, voluntarily standard tariff menus are published and presented to MITI.

The purpose of the partial liberalisation of retail markets is to improve efficiency through the introduction of competition. However, there are several issues inherent in the Japanese electricity market that may hinder the efficiency gain through liberalisation. Examples include:

1) The share of incumbent utilities in franchise area is almost 100 percent,

2) The possibility that incumbent utilities will take unanimous action. Because of these considerations, it is desirable that the incumbent electric utilities take fair action to open their transmission line equally to new entrants. Thereby, it is important to consider the following two points to facilitate the functioning of the market:

1) Designing a system for wheeling power

2) Determining a fair wheeling price.

The approach to allow equal access to transmission lines will rely on utilities' own design, rather than rely on a regulatory framework, as there is concern that governmental intervention (with setting of a regulatory framework) might hinder free competition. Therefore, it has been decided that government intervention should be minimised, except when actions taken by incumbent electric utilities are against the Anti-monopoly Act and Electric Utilities Industry Law.

Regarding wheeling price, it is proposed by the Basic Policy Committee under the Electric Utility Industry Council that the wheeling price should be based upon the possible efficiency improvement through the future technological development as well as the cost incurred from building systems.

CONCLUSIONS

The Japanese electricity sector is on track for further deregulation measures to be taken. These are likely to occur at a steady, and somewhat slow pace. From March 2000, partial liberalisation of the retail market will take effect. The results are to be reviewed after three years, although the criterion for assessing results has not been yet decided. Depending on the success of this step, further steps may be taken to further liberalise the sector.

There are some important issues to be resolved in the Japanese electricity market. For example, the universal service obligation will no longer be a requirement under competitive environment, because such an obligation creates serious distortions in the market. The universal service supply obligation enables all citizens to have an electricity supply at a reasonable cost. This results in remotely located consumers being charged a similar tariff to urban dwellers. With the introduction of competition, where pursuit of efficiency is the primary aim, consumers in remote areas will suffer a disadvantage because of the higher cost to supply them.

Another important issue in the Japanese market is the potential for stranded costs to be incurred as a result of deregulation. Private investors will tend to invest in less capital intensive, smaller scale generation plant. This may lead to lower generation costs for these suppliers, making some existing plant uneconomic. This is an issue for Japan because of a consensus among key government and industry leaders that nuclear power should continue to be a part of Japan's energy mix (Evans et al, 1998). To avoid the potential for huge stranded costs being faced, some framework to deal with the issue will need to be established.

An efficient wheeling system and reasonable wheeling price setting will also constitute an important element of a deregulated electricity industry. It will be important to set up a transparent system that fosters fair access to the transmission grid.

STRUCTURE OF THE ELECTRICITY SECTOR

Figure 29 Structure of the electricity sector in Japan – Pre 1995

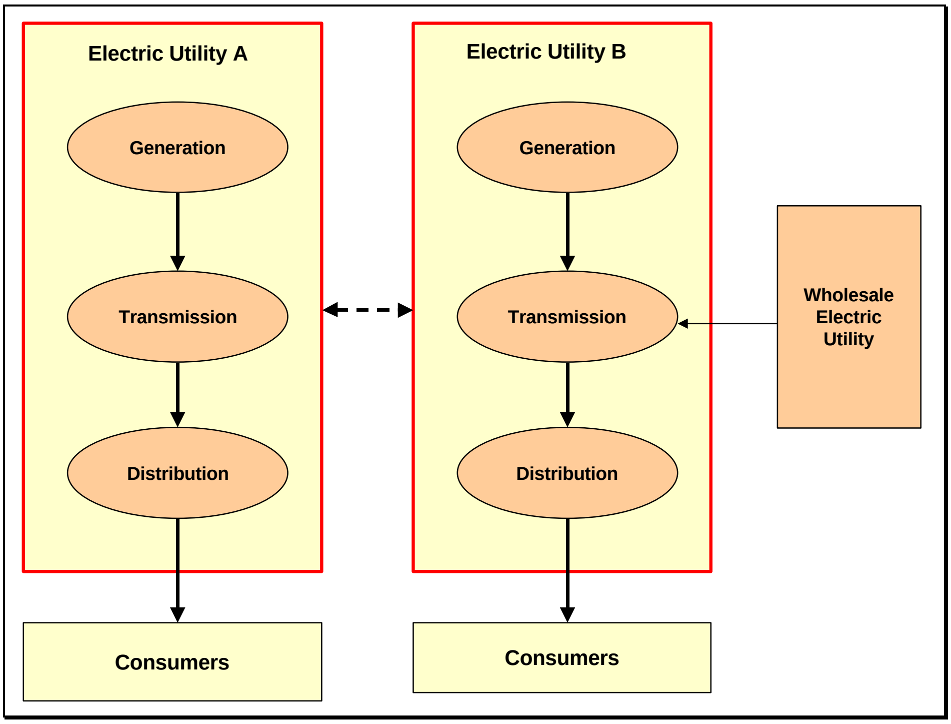


Figure 30 Structure of the electricity sector in Japan – Post 1995

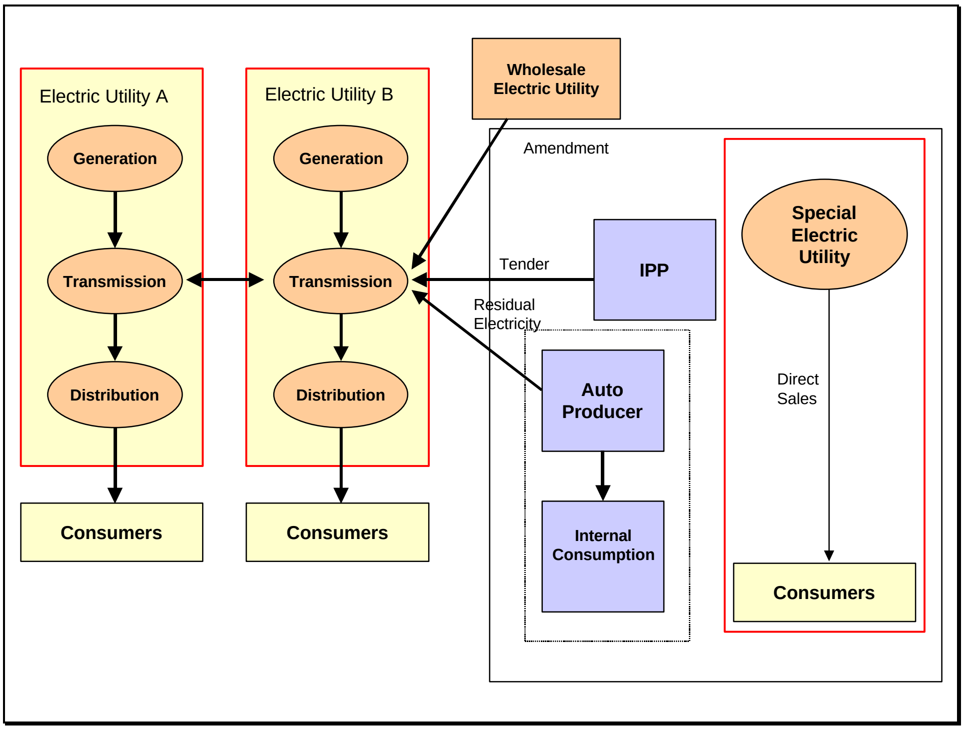
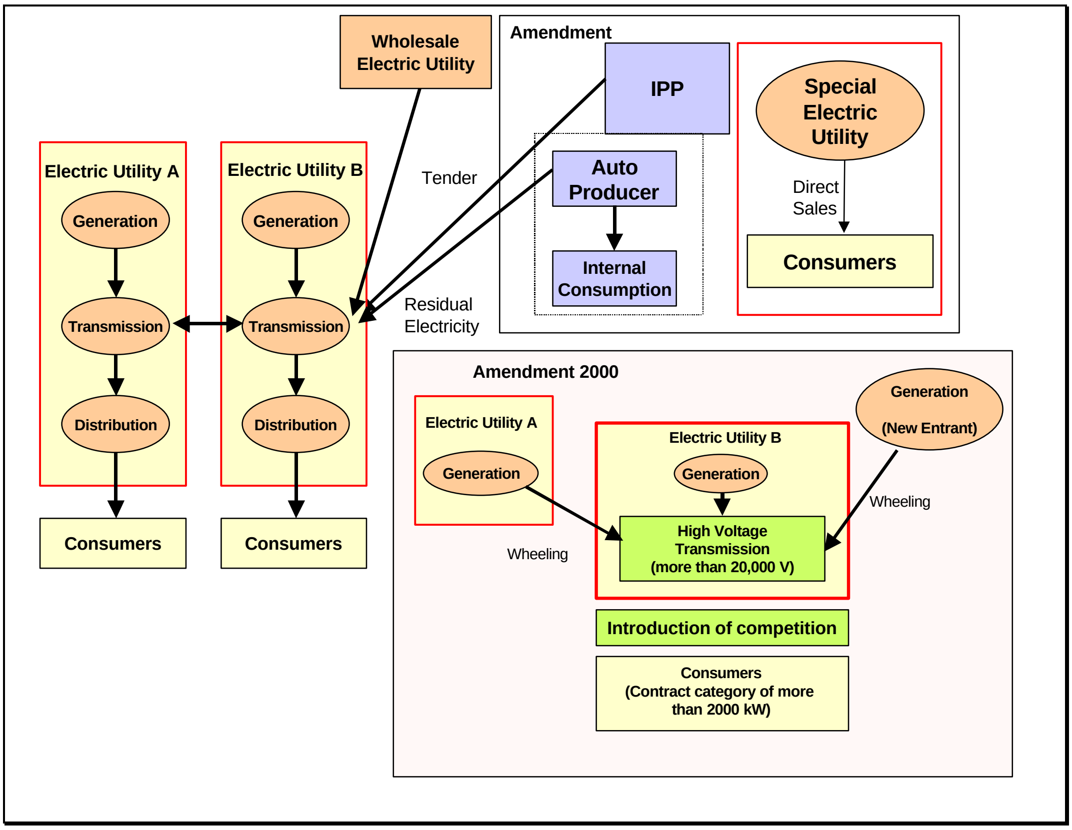


Figure 31 Structure of the electricity sector in Japan – Post 2000



LESSONS

In economies with a large private sector involvement in the electricity supply industry, substantive reform requires a high degree of consultation between government policy-makers and private firms, and faces stiff legal and political hurdles.

An industry structure comprising many vertically-integrated private companies with limited interconnections is difficult to reform, as vertical unbundling (divestiture) is required, as is the encouragement of horizontal competition.

THE REPUBLIC OF KOREA

INTRODUCTION: INDUSTRY OVERVIEW

The Republic of Korea has in recent years experienced rapid economic growth, a trend that should continue for the coming decade, despite the 1997/1998 financial crisis. Korea's economic growth has been accompanied by a substantial increase in energy demand - at a rate unsurpassed by most economies in the world. The most recent forecast in the aftermath of the financial crisis indicates that the economy will recover quickly and grow at about 8.8 percent in 1999[32], a trend that will continue well into 2000[33].

Much of the energy demand growth is focused on electricity – with electricity demand growing from 32.7 TWh in 1980 to 200.8 TWh in 1997 (exceeding the GDP growth rate of 8.5 percent). To meet this demand increase, generation capacity increased from 9,391 MW in 1980 to 41,041 MW in 1997. Until 1980, oil was the major fuel for power generation, accounting for 77 percent of the total for that year. Since then, oil fired generation has declined substantially (to 18.4 percent of the total in 1997). The first bituminous coal-fired power plant was completed in 1983. Since then, coal-fired generation has grown strongly, accounting for 26.7 percent of the total in 1997. Nuclear power is now also a major source of electricity, accounting for 37.0 percent of total power generated in 1997.

Table 22 Electric power generating facilities in Korea

Year	Hydro (MW)	Nuclear (MW)	Thermal (MW)					Total
			Coal Mix	Oil	LNG Cogen	Combined Cycle	Internal Combustion	
1980	1156.7	587.0	750.0	5524.8	0.0	920.0	314.8	9390.8
1985	2223.2	2865.7	3700.0	6212.3	0.0	920.0	215.5	16136.7
1990	2340.0	7615.7	3700.0	3662.3	2550.0	840.0	213.1	21021.1
1997	3114.6	10315.7	10200.0	4340.0	1537.5	11268.5	265.4	41041.7

Source: KEEI (1998)

Since its first commercial operation in 1978, nuclear power has played an important role in electricity generation, particularly for base load generation. During the period 1980-97, nuclear generation increased from 3.5 TWh to 77.1 TWh, and its share in Korea's total primary energy consumption increased from 2.0 percent in 1980 to 11.0 percent in 1997.

The Korean Electricity Market has been run by the Korea Electric Power Corporation[34] (KEPCO), which controlled generation through Chosun Electricity and distribution through Kyongsung Electricity and Namson Electricity in 1961. Under the auspices of the government, KEPCO established and operated a vertically-integrated electricity power supply network from generation to retail. The electricity supply system in Korea has a high thermal efficiency and low transmission and distribution losses. In 1997 the average gross thermal efficiency of KEPCO was 38.73 percent and the transmission and distribution loss factor was 4.85, which is less than half of what it was in 1971, namely 11.42.

32 The Bank of Korea announcement in October 1999.

33 Korea Development Bank's forecast in Yonhapnews (Korean), December 15, 1999.

34 This official name was established in 1982.

KEPCO made great progress in achieving universal service, low tariffs, high labour productivity, and social policy objectives, including rural electrification.[35] However there was a downside to KEPCO's monopolistic dominance of the electricity sector, including systematic errors in demand and supply projections creating instability, a strong inclination toward expanding and retaining market power, and excessive contributions to non-economic government activities.[36]

ELECTRICITY TARIFFS

Currently, KEPCO applies a uniform tariff to all consumers within one consumer class, regardless of location. However, in support of some sectors (industry, agriculture, and fisheries), electricity tariffs differ between consumer classes. As seen in Table 23, commercial and household users are paying 30 percent to 40 percent more than the average for all types of end users.

Table 23 Electricity tariff structure by end users in Korea

Use	Household	Commercial	Education	Industry	Agriculture	Streetlights
Rate (KRWon/kWh)	97.00	105.55	87.91	55.11	43.00	62.91
Share in terms of total sales	18.3%	19.1%	0.8%	58.7%	2.2%	0.8

Source: KEEI (1998)

Over the last two decades, electricity prices rose steadily until the middle of 1980's - due to increasing demand and the rising prices of fuels for generation. After 1985, the government reduced electricity tariffs, reflecting a decline in fuel costs, and operational and management costs. In the early 1990's inflation control and improving industry competitiveness became important government goals as the economy started showing signs of over-accelerating growth.[37] To these ends, electricity tariffs were revised upward almost annually to encourage rational use of energy and promote Demand Side Management (DSM).

Table 24 Trend of average electricity sales price in Korea (KRWon/kWh)

Year	Lighting	Power	Average of the Total
1980	59.55	49.28	50.88
1985	73.58	66.64	67.92
1990	68.11	49.51	52.94
1997	90.69	59.62	65.26

Source: KEEI (1998)

HISTORY OF ELECTRICITY SECTOR RESTRUCTURING

Between the late 1970s and early 1990s, discussions about restructuring the electricity sector had gone on, but without much attention being paid. Rapid growth in electricity demand (over 10 percent per annum) and accompanied capacity expansion left little room for changing the incumbent industry structure.

35 The rural electrification rate has reached 99.99% as of 1999.

36 An example is cross subsidisation by KEPCO, playing a role of a swing consumer for natural gas.

37 For example, the average annual growth rate in terms of GDP between 1985 and 1990 was about 10%. Even in 1990 and 1991 the GNP growth rates were above 9 %.

Table 25 Reform history of electricity sector in Korea

Year	Reform Initiative	Comments
Late 1970's	Initial discussions on electricity sector restructuring	Rapid demand growth did not allow any substantial discussion on this matter.
December 1993	The Committee for management appraisal of government investment companies decided to probe the management practices of Korea Electric Power Corporation (KEPCO)	All government investment corporations were subject to this decision.
1994 - 1996	Implementation of evaluation of KEPCO's performance efficiency in terms of operation and management.	Privatisation was recommended in a number of phases taking into account accelerating electricity demand and market power concentration after privatisation. In addition, as a pre-requisite, deregulation was acknowledged.
June 1997	Establishment of the Committee for Electricity Industry Restructuring.	The Committee consisted of experts from government, research institutions, and industry.
July 1998	Announcement of the Privatisation Plan for Major Public Enterprises in the wake of the financial crisis.	As a part of the Plan, October 1998 was set as a deadline for finalising the electricity industry restructuring plan
January 1999	The Base Plan was finalised and announced.	Under the Ministry of Commerce, Industry and Energy (MOCIE), the Electricity Industry Restructuring Bureau was created.
September 1999	A plan for initial grouping of KEPCO's power plants for divestiture was announced.	The 42 thermal/hydro plants currently in operation or under construction will be divided into 5 subsidiaries of KEPCO and nuclear plants will remain under an additional subsidiary.

In 1993 the government decided to review the management practices of all government investment corporations in an effort to increase the efficiency of the public sector. Among those selected for evaluation were Pohang Steel Corporation and KEPCO. The evaluation process went on for two years until June 1996. The main recommendation was a multi-phased privatisation of KEPCO in view of the fast electricity demand growth at that time and the potential economic concentration in case of a swift full-scale privatisation. In addition, electricity sector deregulation was viewed as an essential prerequisite for privatisation.[38]

On June 3, 1997 the government created the Committee for Electricity Industry Restructuring to set the phase and delineate guidelines for the restructuring process. The committee helped shape the government privatisation plan for KEPCO, which was announced in July 1998 and which led to the Base Plan for Electricity Industry Restructuring in January 1999. In September 1999 a plan for the initial grouping of KEPCO's power plants for divestiture was announced. Under the plan, 42 thermal/hydro plants currently in operation or under construction will be divided into 5 subsidiaries of KEPCO and nuclear plants will remain under an additional subsidiary.

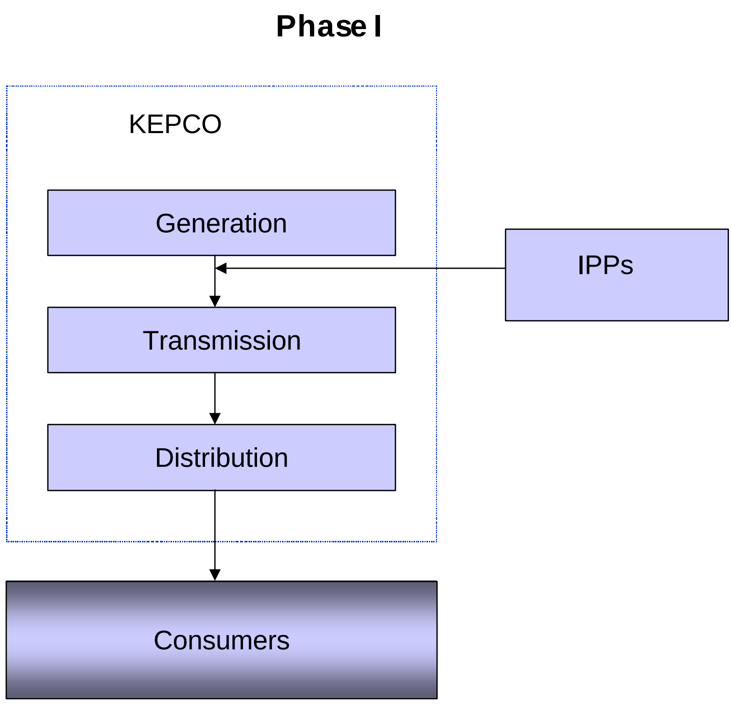
38 The team consisted of a government research institute and two accounting firms.

FUTURE OF KOREA'S ELECTRICITY SECTOR

THE RESTRUCTURING PLAN[39]

The Base Plan involves a phased restructuring program for the electricity sector. The plan proposes four phases of reform. The first aims to set the scene for reform by the end of 1999. This phase has a crowded agenda that includes legal due diligence and institutional rearrangements, due diligence of the KEPCO assets, divestiture of KEPCO's generation business into generation subsidiaries, and preparation for a wholesale power market operated basically by price bidding. In addition, efforts should be put into establishing operating rules, training market-operating personnel, and building up the hardware and software of an IT system to control market transactions. From an institutional point of view, amendment of the Electricity Enterprise Law and enactment of a special law to facilitate the restructuring process is now well under way. Also, the plan for grouping KEPCO generation plants into suitable commercial subsidiaries was announced on September 2, 1999.

Figure 32 Phase I of the electricity reform process in Korea

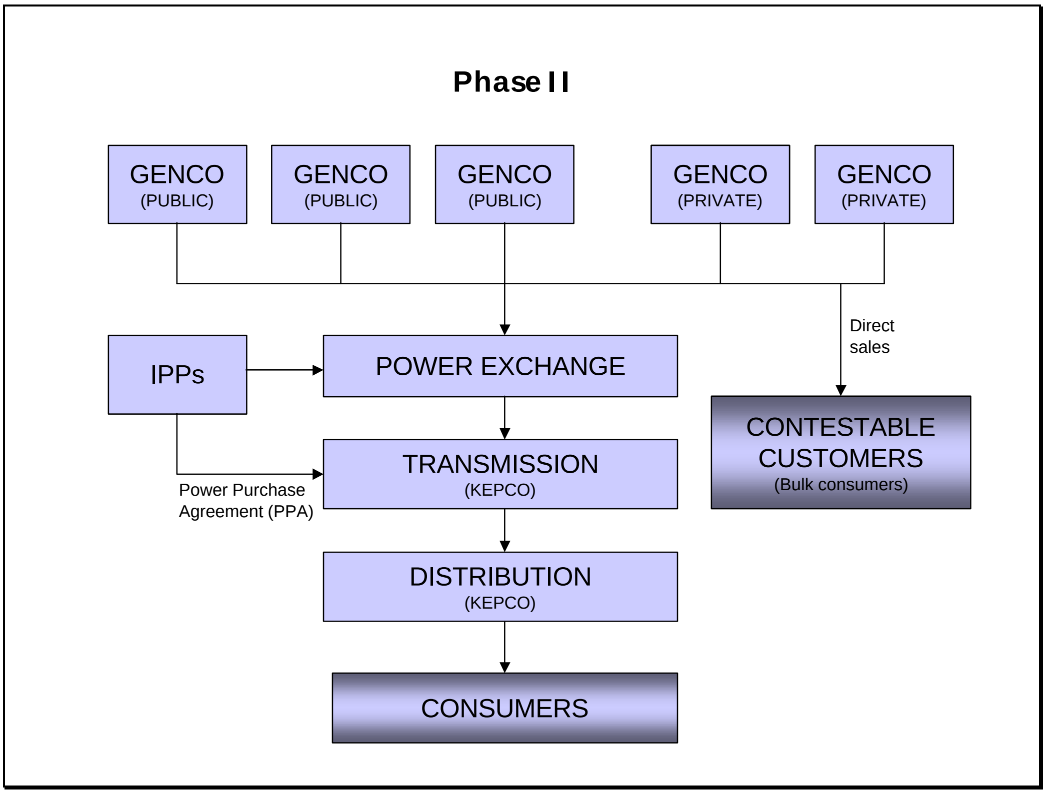


The second phase is set to introduce competition in power generation, with the newly established KEPCO generation subsidiaries competing against each other and new entrants. They will sell electricity to the Korea Power Exchange through a price bidding system. Independent power producers (IPPs) bound by a power purchase agreement (PPA) with KEPCO will be allowed to choose between selling power directly to the Power Exchange and selling under the terms of existing PPAs. Generators will also be able to sell power directly to some large-scale consumers. The time period for the second phase was set between October 1999 and 2002.

[39] For this section, we have greatly benefited from a paper, "Deregulation and Privatisation of the Electricity Sector in Korea: Issues and Lessons" written in 1999 by Dr Ki-Joong Kim.

During this period KEPCO's generating subsidiaries will be privatised and become independent from KEPCO. In the meantime KEPCO's distribution arm will be divided into several distribution subsidiaries, which will be privatised later. According to the plan, a committee or council for licensing, market operating rules and dispute settlement among market participants will be established before the end of 1999. It will be developed into an independent regulatory body in 2001. In this phase, preparatory work will be undertaken for two-way bidding wholesale competition.

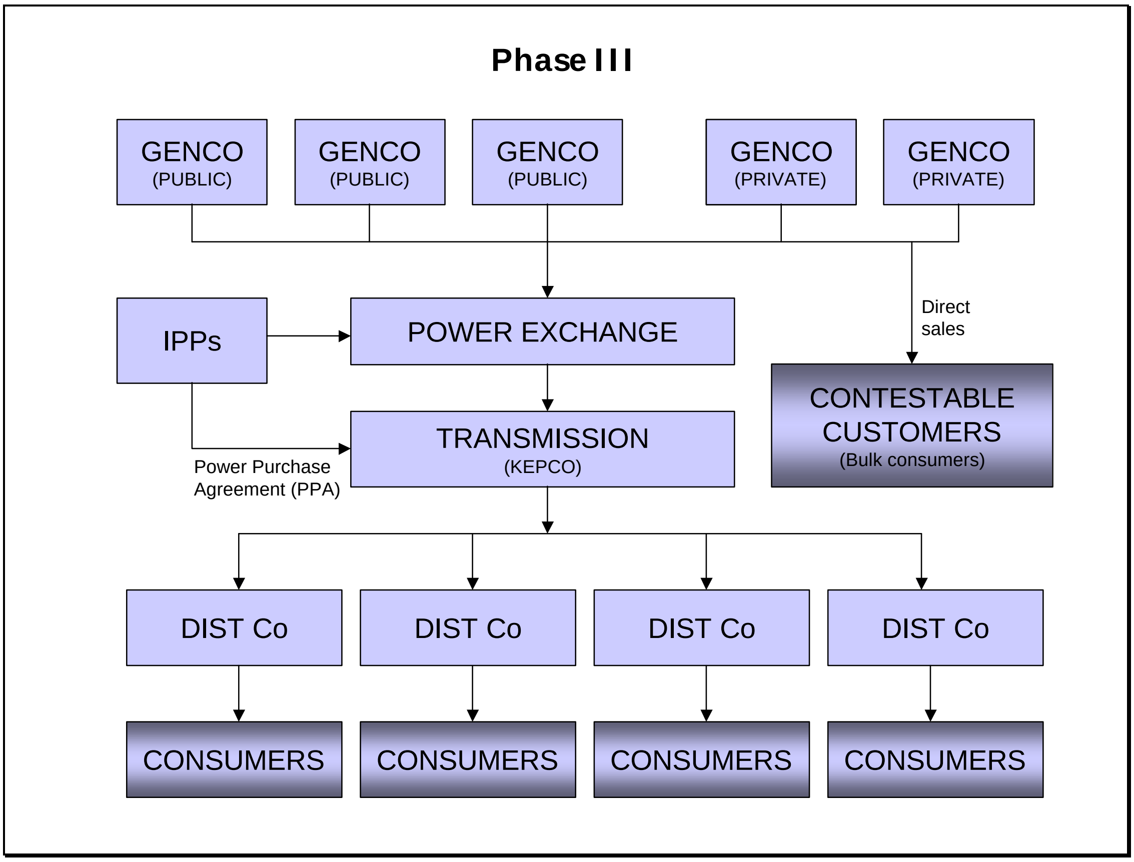
Figure 33 Phase II of the electricity reform process in Korea



The period from 2003 to 2009 is set for the third phase, which is intended to introduce wholesale competition. The power trading arrangements envisaged are such that generating companies and distribution companies bid for terms of power trade in the market. However, distribution companies will still remain monopoly suppliers within their service territories. The scope for direct power sale by generators will be widened continuously during this period.

In the final phase after 2009 full-fledged competition at every level will be made possible, where even small consumers can choose their suppliers. Distribution companies will have mandatory requirements to open their distribution networks to any market participant who wants access. Consumers may buy electricity on their own, through a marketer, or from their co-operative as a power-purchasing agent. Specialised marketers will play an important role to match suppliers and consumers. However it is not clear at the moment when and to what degree effective retail competition will be available as the plan only says "after 2009."

Figure 34 Phase III of the electricity reform process in Korea



The restructuring plan envisages evolutionary steps[40] that start with a vertically-integrated monopoly utility, where KEPCO is the sole supplier who generates, transmits, distributes and sells electricity to all consumers. In the second phase, KEPCO as transmitter and distributor will become the single purchaser of electricity for resale, although there will be some room for direct sale from generators to large-scale consumers. And then the next phase will allow wholesale competition and retail competition. The rationale behind this approach is that the transition from one phase to the next can be made only after many technical and institutional obstacles are overcome.

DIVESTITURE OF GENERATION FROM KEPCO

KEPCO announced the preliminary power plant groupings for divestiture on September 2, 1999. The plan was developed as an outcome of a consulting contract between Andersen Consulting and the government. According to the announcement, 42 thermal and hydro plants in operation or under construction will be grouped into five clusters. Each will belong to one of five KEPCO subsidiaries. Nuclear power plants will be owned and operated by a newly established nuclear power generation subsidiary. The basic rule applied to grouping plants was to level the playing field as far as possible. The plants have been grouped as shown in Table 27. The average capacity of each subsidiary is around 7,700 MW.

The scale of personnel transfer to the generating subsidiaries is estimated at about 16,000 people out of the current 35,000. The total value of the plants seems to be around 34 trillion

40 For a good textbook for this type of electricity market evolution, see S. Hunt and G. Shuttleworth, *Competition and Choice in Electricity*, John Wiley & Sons, 1996.

Korean Won, amounting to 55 percent of the total asset value of KEPCO, 62 trillion Won (US$52.6 billion dollars).

Figure 35 Phase IV of the electricity reform process in Korea

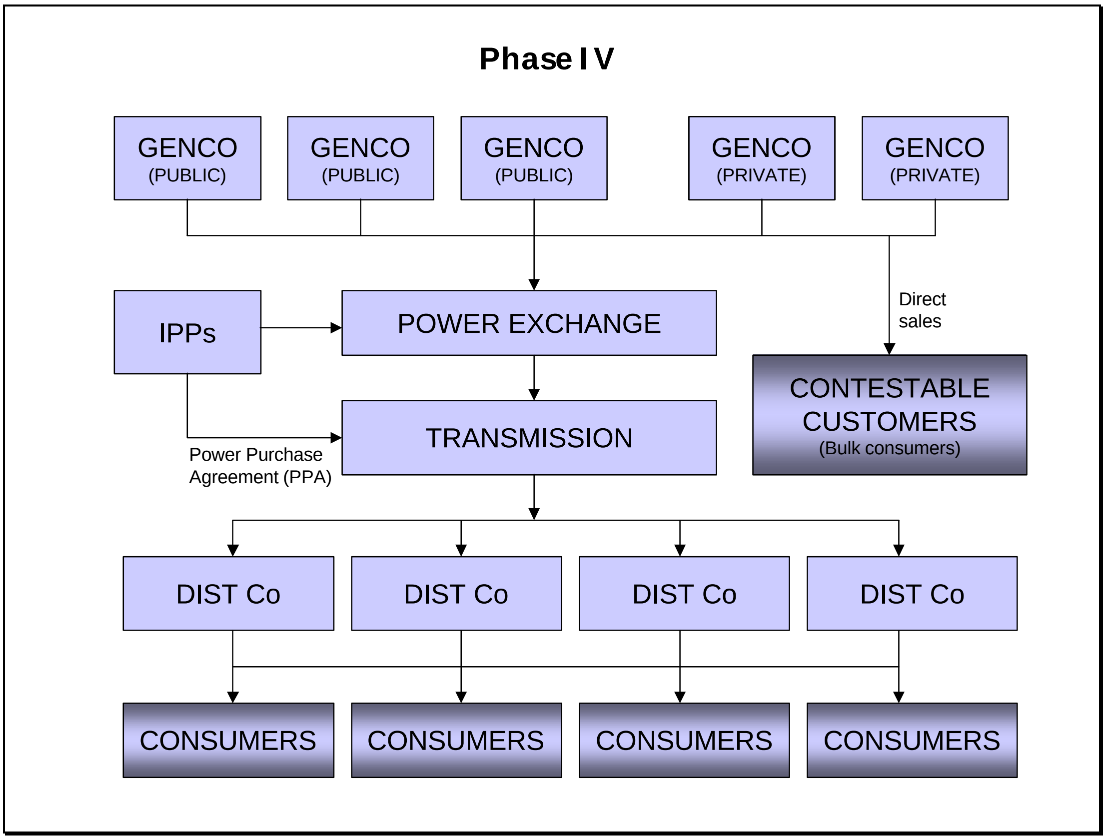


Table 26 Korean electricity restructuring plan

	Period	Activities
Phase 1	Jan. 1999 – Dec. 1999	· Preparation for Competition in Generation · Start of Competition in Generation · Divestiture and Privatisation of Distribution
Phase 2	Oct. 1999 – 2002	· Establishment of Independent Regulatory Body · Preparation for Two-Way Bidding Market · Direct Sale to Large-Scale Consumers
Phase 3	2003 – 2009	· Wholesale Competition · Widening Scope of Direct Sale
Phase 4	After 2009	· Retail Competition

Source: MOCIE (1999b)

Table 27 Groupings of KEPCO plants for splitting into subsidiaries

Subsidiary		Thermal and Hydro (MW) A	B	C	D	E	Nuclear (MW)
In Operation	Base	3,240	3,000	2,000	2,000	1,500	
	Intermediate	825	1,938	1,466	710	2,200	
	Peak	2,035	1,200	2,880	2,200	2,100	
	Subtotal	6,100	6,138	6,346	4,910	5,800	12,016
Under Construction	Construction Started	-	1,600	1,000	1,000	1,700	
	Construction Not Started	1,600	-	600	1,800	-	
	Subtotal	1,600	1,600	1,600	2,800	1,700	5,700
Capacity Total		7,700	7,738	7,946	7,710	7,500	17,716

Source: KEPCO, Press Release on the Divestiture of KEPCO's Generation Sector, September 2, 1999.

STATUS OF IPP PROJECTS

The 4th long-term electricity supply and demand plan was finalised in the summer of 1998 after a long revision process. Approval of IPP projects was included in the plan to enhance the competitiveness and efficiency of the electricity industry. In the plan, IPP projects are only considered up to 2010. After 2010, the plan will be adjusted in accordance with the pace of the restructuring process. One noteworthy development is the repeal of restrictions on foreign capital participation in the electricity sector including IPPs, except with respect to nuclear generation, which is excluded in this plan.

Aside from nuclear plants and the six contracted IPP plants, twelve new plants out of seventeen have been allocated to IPPs, amounting to 5,400 MW or 65.5 percent of the 8,250 MW of total new capacity currently being planned. The total capacity of IPPs to be added to the system up to 2010 is 8,320 MW - 1,970 MW greater than that allocated to IPPs in the 3rd plan in 1995.

ESTABLISHMENT OF IMPLEMENTING BODY OF THE PLAN

In order to meet the complex administrative needs of the restructuring process, the Base Plan for Electricity Industry Restructuring stipulated that an implementing body be established within MOCIE in January 1999, headed by the Deputy Minister for Energy and Resources. It was also planned to establish a ruling body for the restructuring process, to consist of experts from both the private and public sectors. The committee will handle mainly legal and institutional rearrangements. An independent regulatory body like OFFER in the UK will be put in place by the end of 2001, as the restructuring advances.

The Electricity Restructuring Bureau was established in May 1999, a few months behind schedule, as part of a reorganisation within the government structure. The Bureau has two branches, the Restructuring Policy Division and the Market Creation Division. The Bureau is headed by an official at the Director General level within the organisation scheme of the Korean government. According to the Draft Amendment of the Electricity Enterprise Law, the ruling body described above is to become a committee or a council that deliberates but does not decide about matters related to licensing and trading arrangements, and resolves disputes between market participants. Authority for decision-making with regard to trading arrangements and licensing will be vested with the Minister of Commerce, Industry and Energy (MOCIE).

Table 28 Korean IPP plant construction plan until 2010

	3rd Plan (1995) (MW)		4th Plan (1998) (MW)			
	KEPCO	IPPs	KEPCO	IPPs		
				Contracted	New	Total
Coal (800 MW)	3,200 (4)	-	1,600 (2)	-	-	-
Coal (500 MW)	1,000 (2)	1,000 (2)	-	1,000 (2)	1,000 (2)	2,000 (4)
Gas	4,500 (10)	4,850 (11)	450 (1)	1,920 (4)	1,800 (4)	3,720 (8)
Oil	1,000 (2)	-	-	-	2,000 (4)	2,000 (4)
Pumped Storage	500 (2)	500 (2)	800 (2)	-	600 (2)	600 (2)
Total	10,200 (20)	6,350 (15)	2,850 (5)	2,920 (6)	5,400 (12)	8,320 (18)

Notes: 1) Numbers in parentheses are the number of generator units.
2) Contracted projects are as follows: LG: one gas-fired unit, 500 MW; Hyundai: one gas-fired unit, 470 MW; POSCO: two coal-fired units, 1,000 MW; Daegu: two gas-fired units, 950 MW.

Source: MOCIE (1998a).

LEGISLATIVE ARRANGEMENT

There are two major legislative activities currently under way. The first is to amend the Electricity Enterprise Law and the second to enact a special law to facilitate the restructuring process. The administration is advancing the legislation in the hope that both laws will pass the National Assembly in the fall of 1999[41]. If they are enacted, the amended law will be effective from January 1, 2000 and the special law effective as soon as its promulgation. The main features of the Electricity Enterprise Law are as follows:

- UNBUNDLING. This will lead to generators, a transmission agency, distributors, and suppliers. Currently, KEPCO undertakes all these functions, with some auto-generators and IPPs selling to KEPCO for resale. KEPCO will retain only the transmission and distribution functions, with distribution unbundled into subsidiaries of KEPCO in 2000 or 2001. Transmission and distribution companies will have to allow open access to their lines. Another new market player will be the electricity marketer who will sell power to the market on behalf of small-scale generators. The Korea Power Exchange will operate the wholesale electricity market. According to the draft law, the Power Exchange will play the roles of system operator and market operator, and take over from KEPCO the existing PPAs between KEPCO and IPPs.

- TRANSFER OF SOCIAL POLICY OBLIGATIONS. Non-profit, public interest businesses will be transferred to the government and financed by a new fund called the Electricity Industry Infrastructure Fund. KEPCO's major non-profit businesses include the support program for local residents near

41 As of December 1999, it is not likely that the legislation will pass the national assembly.

power plants, rural electrification, promotion of renewable energy sources, electric technology development, accumulation of human capital for the electric industry and support for such industries as coal, natural gas and district heating. The resources for this fund will come from a surcharge on electricity rates, contributions and loans from the government, a dividend from KEPCO shares and other government revenues.

- CREATION OF AN INTERIM INDEPENDENT REGULATORY BODY. A committee or council to deliberate on licensing matters and handle dispute resolution will be established and operated within MOCIE until an independent regulatory body can be established. Every market participant will keep separate accounts for each licensed business.

The legislation is intended to facilitate the process of unbundling and privatisation of KEPCO, by freeing the new companies from a variety of duties, granting special rights, and streamlining the restructuring procedures. In the process of restructuring, KEPCO's relevant licenses[42] will be automatically taken over by KEPCO subsidiaries. There are many provisions in the law to help these companies, including:

- EXEMPTIONS. Individual subsidiary companies will be exempted from joint liability for outstanding KEPCO debts at the time of divestiture. Furthermore, these companies will be exempted from corporate registration tax, the special tax for rural development, and will not be required to purchase government bonds. Allowances for nuclear decommissioning and waste disposal will also be exempted from corporate tax. KEPCO's dividend income from its generation subsidiaries will be tax-free, and as a holding company, KEPCO will be allowed to carry a liability of up to two times its net asset value.

- INTERIM ARRANGEMENT FOR FACILITY UTILISATION, METERING AND ANTI-TRUST. For the sake of continuity, the newly established companies will be able to use existing communications equipment and KEPCO network for up to six months after the enactment of the law. Rather loose MOCIE metering standards (different to those applied for final consumers) will be applied to KEPCO subsidiaries for three years from the day the law becomes effective. In order to save time and resources required posting periods would be shortened for general meetings of stockholders. Finally, to maintain system security and the new companies' financial health, mutual support mechanisms will be allowed between the parent company and subsidiaries, as well as between subsidiaries (relating to financing, personnel, real estate, movables and intangible property rights).

ISSUES AND LESSONS

There are many issues to be faced by the electricity industry in Korea during the process of deregulation and privatisation. Many important issues have surfaced, after a rigorous evaluation of the electricity sector and deregulation proposals by many experts in the public and private sectors. Below, some of the major issues pertinent to the Korean situation are discussed.

42 Also, the draft law says that the government may guarantee financial liabilities of KEPCO, its subsidiaries and the Korea Power Exchange.

GOVERNMENT GUARANTEED DEBT

As of the end of July 1999, KEPCO's foreign debt stood at 8.1 trillion Won (US$6.87 billion dollars). Yankee bonds represent 47.5 percent of the total, Eurobonds and Samurai bonds 22.0 percent and 10.2 percent, respectively. KEPCO's debts are shown in Table 29 and Table 30.

Table 29 KEPCO's debts

Total	Debt in Domestic Currency	Debt in Foreign Currency		
		Domestic	Foreign	Subtotal
25.4	14	3.3 (2,730)	8.1 (6,870)	11.4 (9,600)

Notes: Units are in trillion Korean Won and those in parentheses are US$ millions as of July 31, 1999.

Source: MOCIE (1999a).

Table 30 KEPCO's foreign debt

Yankee Bonds	Samurai Bonds	Eurobonds	Euro CB	Loans	Total
3,260 (47.5)	1,020 (14.8)	1,510 (22.0)	280 (4.1)	800 (11.6)	6,870 (100)

Notes: As of July 31, 1999. Units: US$ million (percent)

Source: MOCIE (1999a).

One of the major difficulties in the restructuring process seems to be the possibility of KEPCO defaulting on its loans. It has been relatively easy[43] for KEPCO to raise funds by issuing bonds - mostly because of KEPCO's monopoly position in the Korean electricity market and the 58.2 percent shareholding by the government.[44] However, as KEPCO is to be divested and subsidiaries will operate at arm's length, there arises the issue of whether KEPCO's debts will be in default status. Technically if KEPCO's generation business is sold at once, lenders could opt for a one time full recovery of the debt. In that case, KEPCO could be put in a state of default. The conditions for KEPCO's technical default include: when the government's share in KEPCO becomes less than 51 percent; when KEPCO sells off or disposes of its major assets; and when KEPCO gives up or ceases to run major businesses.

In terms of divestiture of the generation assets and establishment of 100 percent holding subsidiaries, most legal experts believe KEPCO will not be brought into default status, as it is merely a change in mode of operation. There are experts with a different view. The risk of default seems to be very low with regard to Samurai bonds, JEXIM loans, and Yankee bonds, while this is not the case with Euro bonds. A US$300 million commercial loan faces the possibility of an increase in the borrowing rate. Although a US$90 million Eurocurrency bond has already been in technical default, it seems possible that KEPCO will come out of the default status under the condition that KEPCO remains the bond issuer, and there is no change in tax treatment. Opponents to the establishment of generation subsidiaries hold the prevalent view that selling off of the subsidiaries will put KEPCO into a default status.

There are three responses to this potential problem being contemplated. Firstly, KEPCO and the Korean government will try to persuade lenders to hold interest rates. The second option would be to buy back less secure bonds with funds from an emergency credit line. This alternative

43 As the KEPCO subsidiaries will have to bear joint liability with the parent company for KEPCO's existing debts according to the Korean Commerce Law, their ability to raise funds will be affected adversely.

44 As of the end of 1998 fiscal year. The number of stocks is 628,219,813 and the paid-in capital amounts to 3,141.1 billion Won.

may be effective in dealing with Eurobonds, which are opposed to the Korean electricity restructuring. As a last resort, a government guarantee could be provided if the above two options are exhausted in the renegotiation process.

Moreover, there is the problem of joint liability held by KEPCO and its generation subsidiaries for debts raised before divestiture. It has been argued that the financial credit-worthiness of the newly established subsidiaries will be adversely affected by joint liability, which will eventually make it difficult to finance new generation facilities. The government appears to be of the opinion that, even though only buying back some of the foreign bonds will be sufficient to solve the default problem, the best way to cope with the problems of default and joint liability might be for the government to guarantee the debts of KEPCO and its subsidiaries. The government has demonstrated an inclination to retain lower interest rates with the default risk spread to its citizens.

Reflecting the government's view, the draft of the special law stipulates that KEPCO and its subsidiaries do not bear joint liability for the debts incurred before the divestiture. If it turns out that this is the case when the law passes the National Assembly, a government debt guarantee may end up being a disincentive to these organisations with respect to the development of financial health. The Draft Amendment of the Electricity Enterprise Law also says that market participants shall pay an incentive price to generators to induce investment in generation plant construction. Thus inefficiency in these companies would be passed on to the captive consumers. And the government guarantee for debts will be borne by the general public or taxpayers.

The debt may be cleared at once by selling off generation assets and other operations, such as the communications business and existing subsidiaries. This process would need to be handled carefully, to maximise the return from the sale process and to diminish any public backlash against sale of public assets to foreign investors. A large inflow of foreign equity capital could make it difficult for the Korean government to push the restructuring program forward. A case in point is a failed attempt by the Korea Gas Corporation (KOGAS) to increase its capital by share issue. Although the shares were not put on offer in the end, a controversy erupted over KOGAS plans for a capital increase by mobilising foreign capital. Many argued that once foreign capital had obtained a significant equity in KOGAS, it would become very difficult to reform the natural gas industry in Korea.

EXISTING PPAs AND SELECTION OF IPPs

The Base Plan for Electricity Industry Restructuring allows IPPs with existing PPAs to sell electricity either to the Power Exchange under the same terms as the existing contract with KEPCO, or directly to the market on a competitive basis. The Draft Amendment of the Electricity Enterprise Law stipulates that KEPCO's rights and duties under existing PPAs be taken over by the Korea Power Exchange. The government claims that this option will provide IPPs with more freedom in the liberalised power market.

If IPPs choose direct sale on a competitive basis, the restructuring program will have been proved a success, at least with regard to the goal of achieving a competitive market. On the other hand, if they choose to stick with existing PPAs (because they offer higher returns), captive consumers will have to bear the burden of the extra costs. IPPs have been arguing for a rise in the rate of return in PPA agreements, an action that would aggravate this potential problem. Perhaps an incentive mechanism should be developed to encourage IPPs to choose the open market.

Some experts have alleged that the encouragement of IPP investments in Korea has been used by KEPCO as a means to discourage its privatisation and the introduction of competition in the power market. There seems to be some shred of truth in the allegation. When IPP projects were first proposed, it was a time when arguments about economies of scale in the electricity industry were becoming popular. As a monopoly, KEPCO has been in full control of industry information and has had a large influence on government policies and supply plans. KEPCO is authorised to select fuel type and plant size for IPP investment, as specified in the Long-Term Electricity Supply and Demand Plan. KEPCO evaluates the design and capability of IPP plants without making public details of the evaluation standards. A benchmark cost of plant construction is determined on the basis of KEPCO's comparable plants, which are used for the evaluation of bidders (who don't know the true cost of KEPCO plants). The price bid of a potential IPP earns the highest evaluation score when it is closest to 88 percent of KEPCO's price. But this method is criticised as a defensive strategy for KEPCO discouraging potential competitors in generation.

INDUSTRIAL RELATIONS WITHIN THE ENERGY SECTOR

As mentioned in the previous section, the Draft Amendment of the Electricity Enterprise Law stipulates that a fund will be established to support various non-economic businesses in the public interest. They include support for local residents in the vicinity of power plants, rural electrification, promotion of utilising renewable energy sources, electric technology development, accumulation of human capital for the electric industry and support for industries like coal, natural gas, and district heating. There has been a view that the electricity industry has been subsidising industries such as coal, natural gas and district heating, and it is difficult to prove otherwise.

Currently restructuring programs for natural gas and district heating are under way, including privatisation. Considering that one of the main rationales for privatisation is to create competitive markets and raise finance, the ongoing existence of subsidies or support from electricity consumers to these industries is a problem.

Korea is poorly endowed with indigenous energy resources and it is natural that the government will wish to maintain a role in securing a stable and secure energy supply, and will want to maintain some non-profit social policy obligations. However, continued support by the government may reduce private participants' incentives to become efficient. Also, this form of government initiative may be seen as an intention by the government to maintain a strong presence in the future energy market. It may increase the policy risk to the business community and reduce the flow of private capital into the energy sector. Another foreseeable outcome is that new entrants may demand government support.

Another interesting issue concerns the time frame and the manner in which the natural gas industry will be restructured. A policy report was prepared, stating that the government would announce a plan for restructuring the natural gas industry by November 1999 and it will cover the industry structure, ownership structure, basic gas trading arrangements, and the time frame of the restructuring. But, considering the experience in the process of preparing the report, it is probable that the privatisation and introduction of gas-to-gas competition will come far later than competition in power generation. In this case, effective competition in generation will be harder to achieve in the foreseeable future. At the core of competition in generation lies the ability of investors to compete on fuel price.

Until now the amount of natural gas consumed for power generation has been coordinated partly through government long-term supply and demand plans. The government has influenced KEPCO's fuel mix decisions to achieve energy security and environmental policy objectives. Without the environmental benefits of natural gas fully reflected in the price, natural gas is the most expensive fuel in Korea. As a result, gas fired plants tend to have a low load factor. This is clearly demonstrated in the Long-Term Electricity Supply and Demand Plan. However, many believe that as the load factor improves, gas-fired plants will become more competitive against other types of plant and technology development in the thermal efficiency of gas turbines will also increase the economic feasibility of this type of power plant. The high price of gas limits the competitiveness of gas-fired plants in a fully deregulated market in the near future, as investors are likely to choose dirtier but cheaper fuels. This outcome will lead to greater environmental damage and less overall benefits to consumers. Once true competition has been introduced in the generation sector, it will be neither desirable nor possible for the government to dictate the types of fuels to be used for power generation.

Table 31 Share of natural gas in the Korean power sector

	1997	1998	2000	2005	2010	2015
Capacity	8,551 (20.8)	9,518 (21.9)	13,440 (26.9)	16,900 (26.8)	17,550 (23.6)	19,800 (24.5)
Generation	31,823 (14.2)	26,302 (12.2)	22,528 (9.1)	39,534 (12.0)	41,234 (10.6)	49,309 (11.5)

Note: Actual figures for 1997 and 1998.
Units: MW, GWh, percent
Source: MOCIE (1998) and KEPCO Website, www.kepco.co.kr/en/static.html.

LESSONS

Reviewing the recent development in the Korean electricity sector, there are a few lessons that could be learned.

A rigorous assessment process has to be put in place before implementing any restructuring plan. In Korea, the more than 6 years of deregulation preparation work has uncovered many important issues, which may have been overlooked and could have incurred unnecessary costs.

In order to maximise the benefits of deregulation, other fuel sectors should be deregulated simultaneously, so that power generators can choose the most economic fuel for power generation, and avoid the risk of stranding their assets at a later date when other fuel sectors do become more competitive due to market opening.

The environmental consequences of deregulation must be taken into account in parallel with the deregulation process, to avoid the environmental costs that may result from investment in fuels, which do not incorporate their full environmental costs in their market price.

MALAYSIA

INTRODUCTION

Electricity infrastructure growth - which has been regarded as indispensable to economic development - is now the impetus and stimulus for greater growth and industrialisation in Malaysia. The electricity sector is undergoing substantial change, from a monopolistic, vertically-integrated industry managed by government utilities, to a sector comprising government owned utilities as well as private sector players.

In line with the government privatisation policy of the mid 1980s, the electricity sector is being privatised, beginning with the largest utility, the National Electricity Board, serving Peninsular Malaysia (more than 80 percent of the total population of Malaysia). Table 32 explains the history of electricity sector restructuring.

Table 32 Malaysia's electricity sector reform history

Year	Reform initiative	Remarks
1990	Corporatisation of the national utility	The NEB incorporated as a company – the company still remain as a vertically-integrated utility
	Electricity Supply Act. Electricity Supply Regulations Licensee Supply Regulation	To ensure the electricity supply industry will function effectively and efficiently, a framework was established to regulate the privatised power sector.
1992	27% of NEB ownership was offered to public Generation opened to private players	At the same time it was listed on the Kuala Lumpur Stock Exchange (KLSE) IPPs introduced on a direct negotiation basis
1994	Electricity Regulations	To regulate the operation and enhance the efficiency of the privatised power sector
1997	Formation of TNB Generation	TNB no longer a player in generation. TNB Generation takes over all the major TNB power stations and sells power to TNB through PPAs just like other IPPs TNB is responsible on transmission and distribution sides
1998	Privatisation of Sabah Electricity Board	
2000	Establishment of Energy Commission Establishment of IGSO Establishment of power pool	

The reform process in Malaysia is driven by the government belief that the industry is best driven by free market principles, and this will lead to more investment in the industry to meet the challenge of rapid demand growth.

The rapid electricity demand increase due to high economic growth in the late 1980s and early 1990s has led to acute power shortages. In recognition of the severity of this situation, the government passed the Electricity Supply Act (1990) and subsequently created the Department of Electricity and Gas Supply to deal with the problem.

Subsequently, the National Electricity Board (NEB) was corporatised and became the Tenaga Nasional Berhad (TNB) in 1990. In 1992, TNB was partly privatised, with the government holding the majority of shares. Independent power producers were also encouraged to invest in 1992, on a direct negotiation basis to supply additional electricity to TNB to cope with the power shortages. All IPPs have entered into long term Power Purchase Agreements with TNB.

PRESENT SCENARIO

POWER DEMAND

Between 1987 and 1997 Malaysian electricity demand grew at around 12-15 percent per annum. Peak demand increased from 3,000 MW in 1986 to about 9,200 MW in 1997, and is expected to grow at a modest rate during the financial crisis period and pick up again when the economy recovers. Overall electricity consumption increased from 21 TWh in 1990 to 49.1 TWh in 1997, representing a growth of 8-15 percent per annum. Electricity consumption per capita increased from 1,120 kWh to 2,320 kWh during the same period.

STRUCTURE

The Peninsular Malaysia electricity supply industry today is structured as follows. TNB and its wholly owned subsidiary, Tenaga Nasional Generation Sdn Bhd are involved in electricity generation, transmission and distribution activities. There are 5 IPPs in the generation sector, and one licensed mini utility, the Northern Utility Resources Sdn Bhd (NUR) involved in generating and distributing power to a franchised area in the north of Peninsular Malaysia. There are also a number of cogeneration and distribution licensees for specific areas. All the IPPs are privately owned and have entered into long term PPAs with TNB. Figure 36 shows the current structure of the industry.

Sabah Electricity Sdn. Bhd. - SESB (Sabah) and Sarawak Electricity Supply Corporation-SESCo (Sarawak) are involved in generation, transmission and distribution activities in East Malaysia. SESB is also being privatised and controlled by a consortium of companies at the end of 1998. Meanwhile, SESCo is still a statutory body, owned by Sarawak State Government. However, part of its equity is held by private sector. It will remain as its present status to cater for generation, transmission distribution and use of energy in the two states.

For the purpose of this study, we only examine the restructuring process that is taking place in Peninsular Malaysia where more than 93 percent of the total electricity is consumed as of 1998. The present structure of the industry is shown in the figure below.

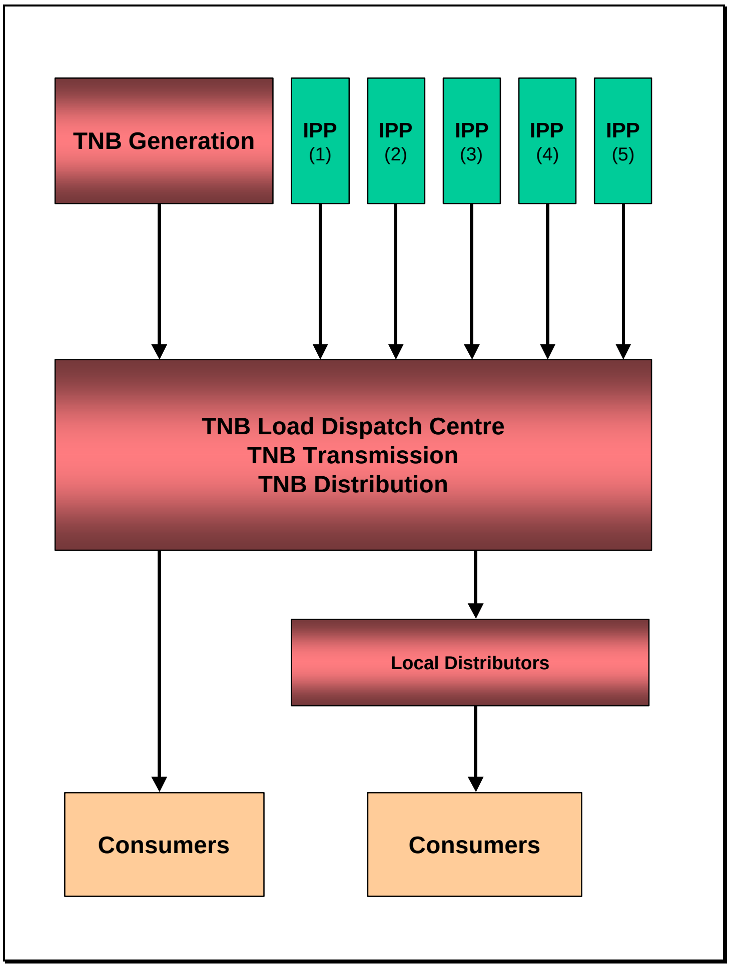
Under the present structure, almost 100 percent of the Peninsular Malaysia population - with the urban population representing more than 60 percent (1998) - is supplied with electricity. This is achieved by having a tariff structure that allows the TNB to cross-subsidise the electricity price.

Table 33 Malaysian electricity tariff structure by end users (1998)

Use	Household	Commercial	Industry	Streetlights	Overall
Rate (RM/kWh)	0.231	0.277	0.215	0.203	0.235
Share in terms of total sale (MW)	8516	13,177	24,515	358	46,466
Percentage	18.3	28.4	52.8	0.5	100

Source: Department of Electricity and Gas Supply Malaysia

Figure 36 Current electricity supply market structure (Peninsular Malaysia)



Source: Department of Electricity Supply, Malaysia

The determination of the tariff is subject to the approval of the government based on the information in the table below.

Table 34 Objectives for determination of Malaysian electricity tariff

- Energy prices shall reflect the economic cost or true cost of supply;
- Adequate revenues to allow for the development of the power sector;
- Competitiveness of Malaysia's industries and services;
- Diversification of energy resources, with greater use of indigenous resources; and
- Aligned with social and economic objectives of the government

Source: Department of Electricity and Gas Supply Malaysia

An Electricity Trust Fund was established in 1997 as a result of a voluntary commitment by TNB and the 5 IPPs. The table below explains the objectives of the trust fund.

Table 35 The objectives of the Malaysian Electricity Trust Fund

- Maintain rural electrification projects under the Rural Electrification Programme;
- Support R&D projects for the electricity supply industry;
- Undertake human resource development programmes for the industry;
- Support energy efficiency projects; and
- Develop and promote the electricity supply industry.

Since the privatisation of the electricity supply industry in 1990, the grid connected generation capacity in the peninsula has increased from 6,030 MW in 1990 to 12,250 MW in 1998 with 4,115 MW being contributed by independent power producers. By the year 2000 the total grid-connected generation capacity in the peninsula will increase to 13,250 MW.

THE FUTURE OF THE INDUSTRY

The main objectives of the privatisation and deregulation of the electricity sector are to promote competition and to improve economic efficiency, so that lower supply costs are achieved and consumers, especially major industrial customers are able to benefit from cheaper energy prices and better quality of service.

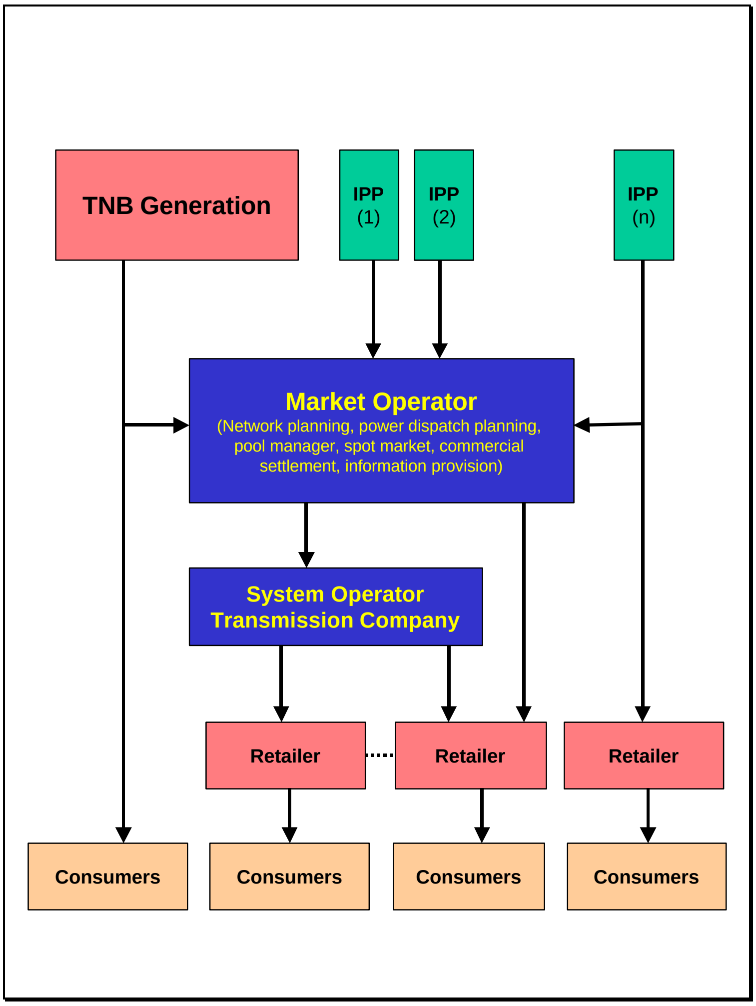
However, the social, political and economic circumstances of Malaysia differ from those of some economies that have already deregulated their markets. Malaysia is a multi racial, developing economy desiring to create an investment environment for all kinds of businesses and industries, but also wishing to provide for the basic needs of all its citizens. With these objectives in mind, the restructuring is designed to:

- Allow the industry to change from one in which there is no competition to one where there is effective competition;
- Attract more investment into the industry to meet future demand;
- Achieve the social objectives of providing electricity at prices which are universal to all areas, and to ensure no discrimination among consumers in the same category;
- Provide for the need to cross-subsidise, especially in distribution to ensure universal pricing;
- Ensure that the values of the incumbent utilities and other players are not seriously affected and to ensure that their loan covenants are not breached;
- Provide for prudent long term planning of electricity supply to cater for growing electricity demand; and
- Allow a smooth transition of human resources, particularly in incumbent utilities into the new restructured industry.

Source: Ministry of Energy, Communications and Multimedia, TNB (1999)

A new set of legal and regulatory frameworks is currently being prepared to pave the way for the establishment of an independent Energy Commission, a power pool system and an independent market operator. It has been proposed that in the year 2000 a single buyer model will be introduced, with the independent market operator as buyer. This will eventually evolve into a multi buyer system when the market is more mature. Thus, from the above objectives the government, in promoting the industry to grow and become mature, will at the same time need to achieve the overall objectives and policies of the nation, not only in the power supply industry but also in the other sectors.

Figure 37 The possible future electricity supply market structure for Malaysia



Source: Department of Electricity Supply, Malaysia (Nor 1999)

LESSONS

In some developing economies, the potential benefits of opening energy markets to full competition must be balanced against competing political, social and economic policy objectives, such as extension of electricity networks to all communities, and maintenance of tariffs at prices poorer consumers can afford.

NEW ZEALAND

INTRODUCTION

In the mid 1980s, electricity generation and transmission were the responsibility of the Electricity Division of the Ministry of Energy. Up to that time, Government Ministers made generation capacity investment decisions. They were assisted by officials, who modelled supply and demand and planned new generation facilities. Large-scale hydro was traditionally a popular option, the construction projects being managed and in the main part undertaken by the Ministry of Works and Development.

The reforms were driven by a government firmly of the view that future energy sector investments would be better made by people driven by strong profit incentives, and not by public servants and Ministers with more obscure lines of accountability.

Two key pieces of legislation were needed to begin this process. These were the Commerce Act 1986 and the State Owned Enterprises (SOE) Act 1986. The Commerce Act provided a framework for limiting monopoly powers and promoting the development of competitive markets. It also affirmed the Government's intention to operate a general framework for competition, as opposed to industry-specific mechanisms favoured overseas.

The SOE Act would allow a transition phase towards private ownership and control – Government owned, limited liability businesses governed by general business laws, and accountable to a "return-on-investment" driven Board of Directors. Under the SOE Act, nominated Ministers hold shares, the enterprises provide annual Statements of Corporate Intent, and they operate with commercial structures and incentives and with the principal objective of being successful businesses.

With the SOE Act in place, a process of commercialisation of the Government's trading activities began to occur. Non-commercial activities, such as energy policy advice, were transferred to government departments.

If one were to characterise in a few words some of the deficiencies of the New Zealand electricity sector in the mid 1980s, a number of observations could be made. Firstly, notable inefficiencies existed within the system, largely resulting from poor investment decisions, but also from the lack of incentives to improve service and lower costs. On top of this, there was a general lack of consumer choice and also cross-subsidisation between the industrial, commercial and residential sectors.

The energy sector situation coincided with a general and increasing concern about New Zealand's overall economic performance. This was a country that in the 1950s had one of the highest living standards in the world. The concern over New Zealand's long-term declining economic performance brought about a wave of strong micro-economic reforms, more predictable macro-economic policy formation, and strengthened public sector accountability arrangements. The desired outcomes were strong economic growth through efficient resource use driven by clearer price signals, and, where possible, by competitive markets.

With the SOE Act in place, the Electricity Corporation of New Zealand (ECNZ) could be set up as a state owned enterprise, and this action was taken with effect from 1st January 1988.

To begin moving the Electricity Supply Associations (ESAs) towards competitive structures, ESAs were made subject to income tax in April 1987, and the Electricity Amendment Act 1987 repealed existing provisions under which the consent of the Minister of Energy was necessary before any person (including ESAs) could commence new hydro generation.

Trans Power was set up at this time as a separate corporate entity, a subsidiary of ECNZ. This action recognised the monopoly status of the transmission grid, and initiated the transition to a separate monopoly enterprise. An Electricity Task Force (ETF) established in 1987 to consider various options, did recommend that the transmission network should be vested in the generation and distribution sectors under a "club" ownership arrangement. The Government eventually declined to accept this recommendation, preferring to keep transmission under government ownership and control.

A number of the recommendations of the ETF were accepted however. These included the corporatisation and privatisation of the ESAs, removal of statutory franchise areas and obligation to supply, and a "light-handed" regulation model drawing on the general provisions of the Commerce Act and information disclosure regulations. A recommendation to keep the generation structure largely intact under the ECNZ umbrella was honoured for a time, but it eventually became clear that active competition in this sector would only occur once the monopolistic power of ECNZ was significantly reduced.

As an example of ECNZ's monopoly power, in 1992 when the International Energy Agency undertook an in-depth review of New Zealand's energy policies ECNZ owned 95 percent of the nation's total generation capacity. In 1997, when the IEA undertook its latest in-depth review, (IEA, 1997). ECNZ still owned around two thirds of generation capacity. Most of the remaining capacity at that time (28 percent) was owned by Contact Energy Ltd, a separate State Owned Enterprise formed in 1996 by splitting off some of ECNZ's generation capacity.

By 1990, the key foundations for the electricity sector reforms were in place. There was considerable distance to be covered, but key principles had been hammered out and it was only a matter of time before this began to work out in practice.

Some key milestones in the early 90s were the inauguration of the Energy Companies Act 1992, the Electricity Act 1992, and the investigation into the development of a wholesale electricity market.

The Energy Companies Act opened the way for the corporatisation of the ESAs. In time, this would lead to the privatisation of some supply authorities, and the entry of foreign capital into the energy sector. The key provisions of the Electricity Act were the removal of statutory monopolies and the obligation to supply, and information disclosure focused on natural monopolies.

The Wholesale Electricity Market Study, a private sector initiative, recommended a major transformation of existing arrangements to provide a predictable price path for wholesale electricity, and to enable some trading at marginal prices. A government critique of this study agreed with the broad precepts, and opened the way for the establishment of the Wholesale Electricity Market Development Group in June 1993. The Terms of Reference included the development of specific, cost effective proposals for a wholesale market that, consistent with sustainable development, would ensure that wholesale electricity was delivered at the lowest cost to the economy.

THE WHOLESALE MARKET

The Electricity Market Company Ltd (EMCO) was set up by the Electricity Supply Association (ESANZ) and ECNZ later that year to develop a market framework for wholesale trading. Key steps were: commencement of an on-line secondary market in trading of ECNZ's hedge contracts, including provision of market information; establishment of a market surveillance committee to admit new entrants and supervise conduct; and administration of the new Metering and Reconciliation Information Agreement (MARIA), to record and reconcile flows to meet the needs of parties contracting in the wholesale and retail markets. Under the MARIA agreement, Trans Power, as National Reconciliation Manager, would reconcile information against contracts and pass information for billing back to market participants.[45] The wholesale New Zealand Electricity Market (NZEM) became fully operational in October 1996.

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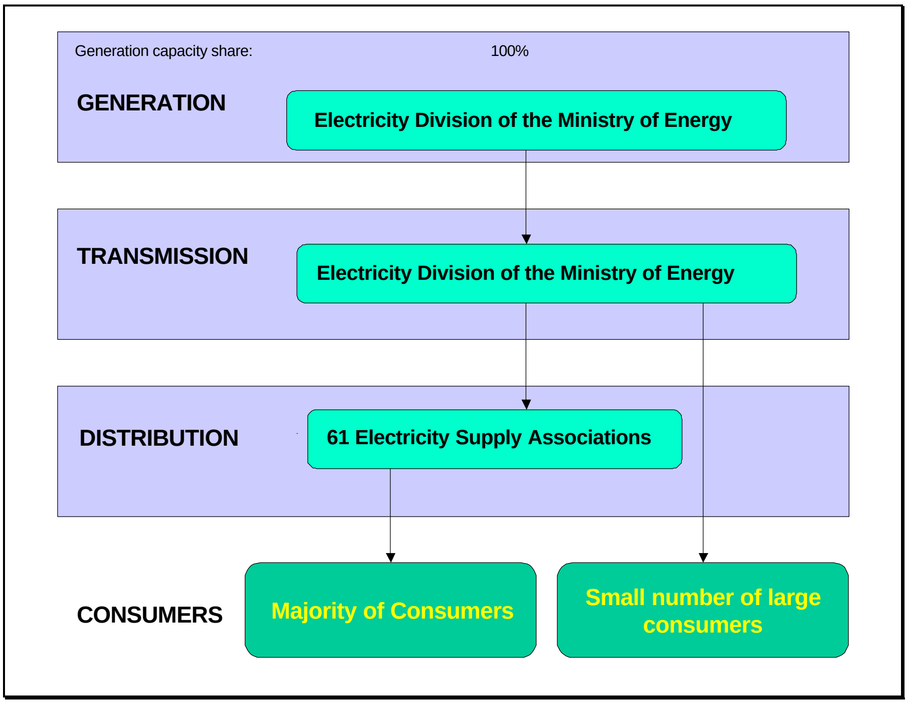
45 Trans Power's role as National Reconciliation Manager is fully contestable, it is put up to tender every three years.

The Market Company administers the rules for the NZEM, which were decided by energy sector participants without government intervention. There are two different markets:

- A PHYSICAL SPOT MARKET (POOL). Competing generators offer electricity, and buyers submit bids, into the pool for each half hour period, resulting in clearing prices and quantities for dispatch by the scheduler, Trans Power.
- A CONTRACTS MARKET. Buyers and sellers can trade contracts for supply, one day ahead, which hedge against spot prices in the pool.

There are four characteristics of the NZEM that are unusual, if not unique in comparison to other electricity markets: (1) the commodity traded is energy plus losses at the grid exit point or node[46]; (2) both generators and retailers are involved in the market; (3) payment for all electricity bought on the market is settled monthly, without argument; and (4) there is no specific government legislation relating to the governance or operation of the market.

Figure 38 Pre-reform structure of the New Zealand electricity sector



REGULATION

Market power is controlled in New Zealand by the Commerce Act. This has features in common with competition legislation in other parts of the world, but some important differences with some regimes exist:

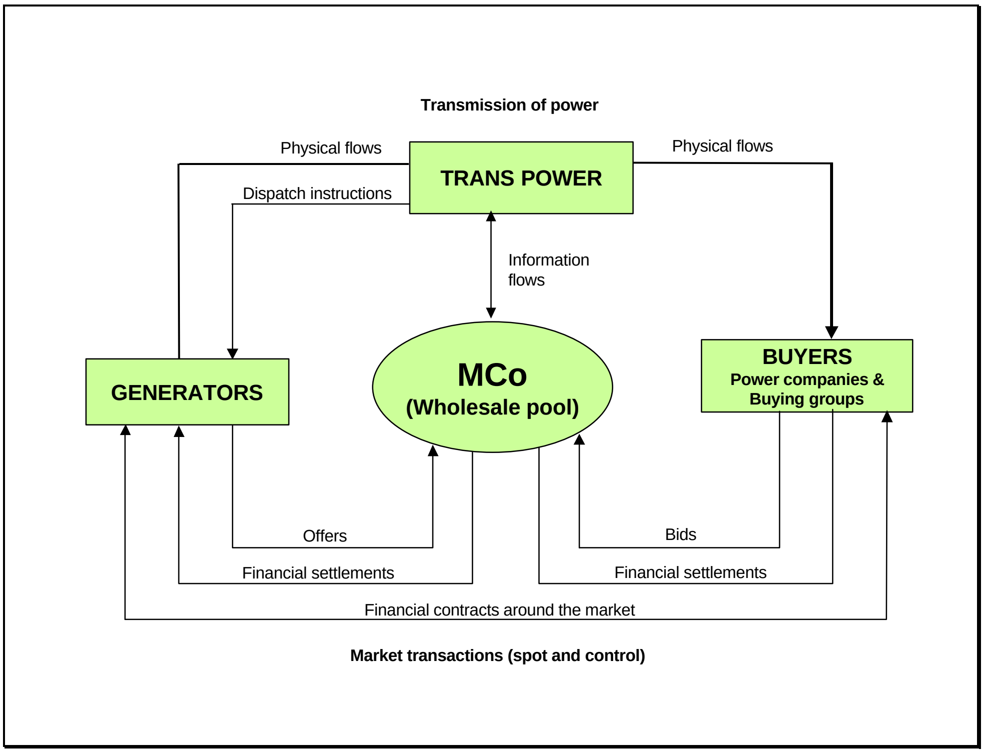
1) IT FOCUSES ON HOW FIRMS BEHAVE. Monopoly and other forms of market structure are not specifically outlawed.
2) IT IS LIGHT-HANDED. It does not intervene closely in the operations of firms, but monitors for anti-competitive behaviour.
3) IT IS BROAD SPECTRUM. It covers almost all markets, irrespective of the industry.

46 There are around 240 nodes on the national grid.

The natural monopoly elements of the electricity sector are controlled through the Information Disclosure Regulations, which were promulgated in July 1994. These called for: separate audited financial statements for natural monopoly and potentially competitive businesses (and methodologies); prices and other main terms and conditions of contracts; financial performance measures, based on standard asset values (ODV)[47] and with removal of any elements of double counting of asset related expenditure; efficiency and reliability performance measures; costs and revenues by tariff category (and methodologies); and line charges (and methodologies).

By 1997, the overall pattern of New Zealand's energy sector reform legislation was in place. The political landscape had changed somewhat by this time, with the acceptance, after a 1993 national referendum, of a Mixed Member Proportional (MMP) representation governance style. This had put a National – New Zealand First coalition government into power in 1997, one of the conditions being that further government-owned "strategic" assets such as ECNZ would not be privatised.

Figure 39 The New Zealand wholesale electricity market



An MMP government did not prevent an assessment of ECNZ's dominant market position, and this led, in time, to the Electricity Industry Reform Act 1998. This legislation paved the way (with effect from 1 April 1999) for splitting ECNZ into three competing entities: Genesis Power Ltd (18 percent of total generation capacity); the Mighty River Power Ltd (13 percent); and Meridian Energy Ltd (30 percent).[48]

Contact Energy Ltd, the fourth state-owned generator, with 25 percent of total generation capacity, was floated on the share market in mid-1999. One block of shares (40 percent) was sold to Edison Mission Energy Ltd, and the rest were offered to the public.

47 Optimised Deprival Value, that is, the lesser of Optimised Depreciated Replacement Cost (ODRC) and Economic Value (net present value of future cash flows).

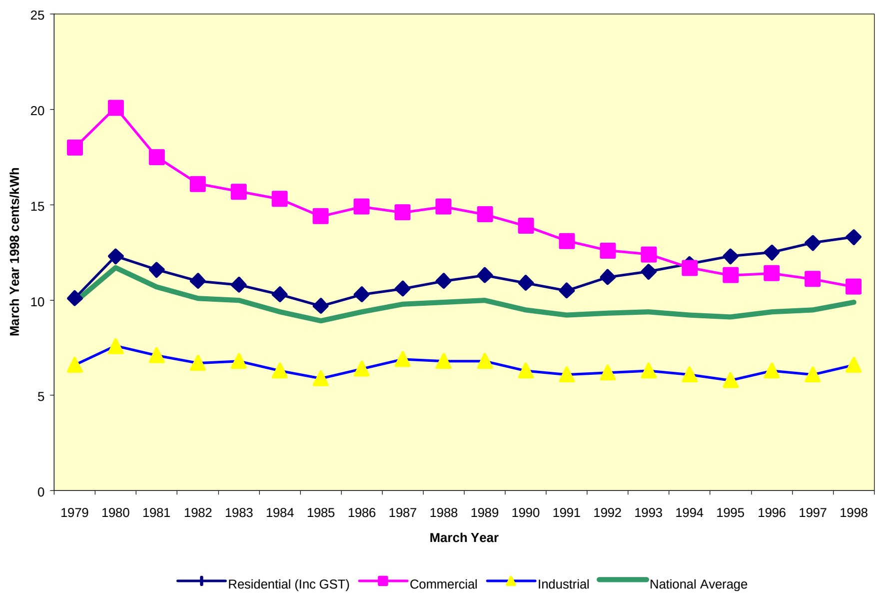
48 Genesis Power Ltd acquired the 1000 MW Huntly thermal station and 4 hydro stations; the Mighty River Power Ltd acquired 9 hydro power stations on the Waikato River (North Island); and Meridian Energy Ltd acquired 10 hydro stations in the South Island.

The other key feature of the Electricity Industry Reform Act was the requirement for a split in ownership between electricity distribution ("lines") activities and electricity retailing and generation activities. Electricity distribution companies were given until 1 April 1999 for corporate separation and until 31 December 2003 for complete ownership separation. However, very rapid progress towards ownership separation occurred, and by 1 April 1999 all had completed the process. As of 1 April, there were 10 electricity retailers and 31 lines companies.

THE BENEFITS?

It is too soon to be able to measure the overall benefits of electricity reform in New Zealand, although some early signs can be identified. One sign that the outcomes have been positive is the willingness with which some large international energy companies have invested in the New Zealand energy sector. For example, TransAlta a Canadian power company has, over the last five years, built up a large integrated generation and retail business with an asset value of NZ$1.1 billion (Nelson, 1999). When the recent split of lines businesses from retail was forced on the industry, the health of the sector was further evidenced in the prices paid for retail customers and distribution assets. In some cases, these exceeded the Optimised Deprival Value of the assets by two to three times.

Figure 40 Electricity consumer prices (real)



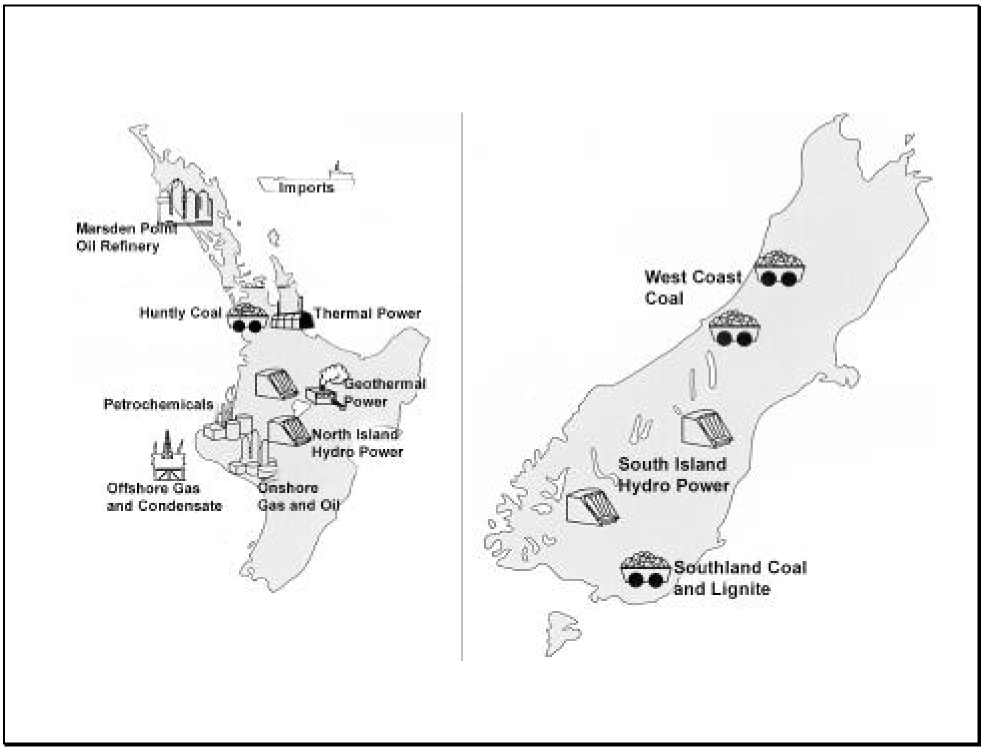
Notes: The residential prices include the 12.5 percent Goods & Services Tax. This is omitted from the commercial and industrial sectors because they are more able to avoid paying this tax. Prices have been adjusted using different price deflators, so definitive inferences about relative movements in real electricity prices between different sectors are not possible.

Source: New Zealand Ministry of Commerce (1999).

One complaint private firms in particular have expressed, is that the final structure of the sector and the rules to govern it were not clearly established at the beginning of the process, the time-frame was not clear, and the regulatory regime has tended to change with time. To some extent, this may be explained be arguing that policy officials and the Minister were moving into uncharted waters. The concept of "light-handed" regulation is somewhat novel, and untested. The doctrine that forced (and complete ownership) separation of lines and retail businesses would lead to overall benefits for the industry, and for consumers is also uncertain - given the significant structural costs involved in achieving this at a late stage in the reform process.

In the aftermath of the Auckland Central Business District (CBD) power failure in February 1998, questions have been raised about the security of supply in a deregulated market. However, a Parliamentary Commission of inquiry established that the failure of the four underground power cables feeding the CBD resulted from a number of compounding factors, principally inappropriate installation procedures and poor quality maintenance over an extended period of time.

Figure 41 Map of New Zealand showing energy resources



The Electricity Reform Transition Unit, which advised the government on the split of ECNZ, stated in April 1999 that average wholesale prices should drop by 14 to 20 percent. Wholesale prices have halved on average since that time, but it is commonly believed that such low prices are unsustainable.

What concerns consumers the most, is the price they pay for electricity. This is where clear evidence of the beneficial outcomes of the New Zealand energy sector reforms is more problematic. As shown in Figure 40, the national average real consumer price of electricity has remained relatively stable for the last decade. There have been relative shifts between sectors as cross-subsidies have been removed. This is not good news for domestic consumers, who have faced increasing prices, but has been beneficial to the commercial sector of the economy.

THE FUTURE?

New Zealand has gone further than most Asia Pacific economies in undertaking a comprehensive reform of its energy sector. The only major step remaining is the privatisation of all generators. This step may well be taken over the next few years, although the recent election of a centre-left government may result in a reluctance to take this last step.

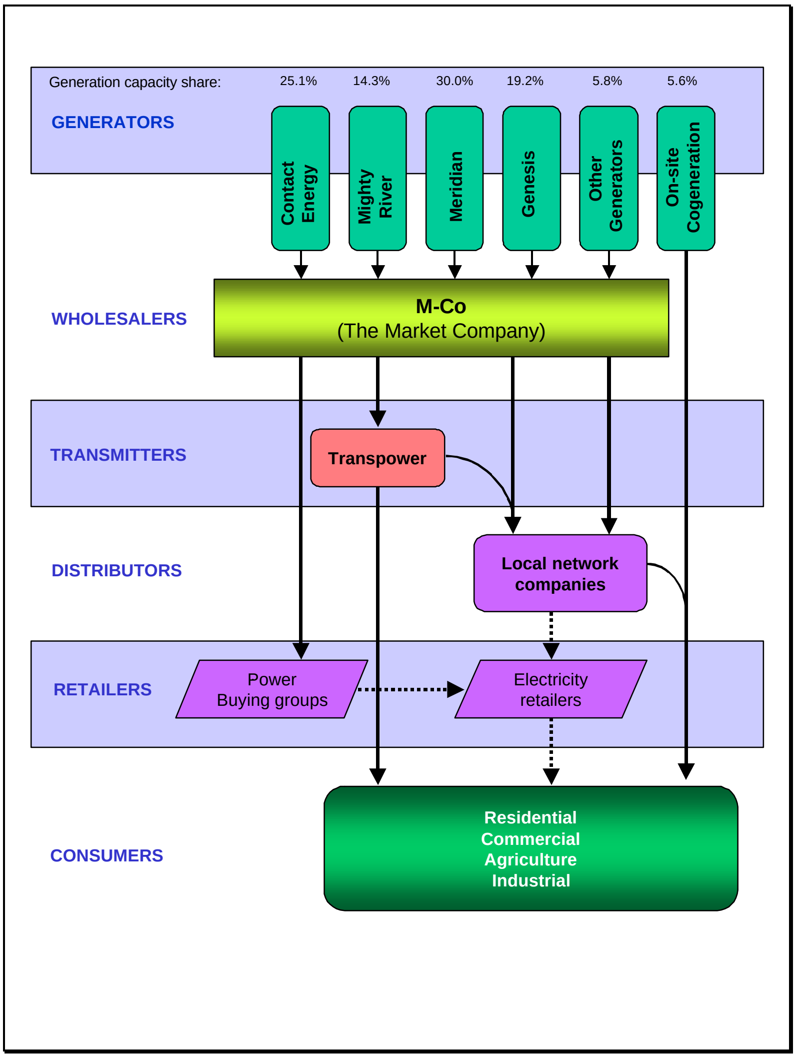
It is envisaged that Trans Power will always remain a state owned corporation, unless some pressing evidence suggests that private ownership of the transmission network would reap substantial benefits over the current arrangement.

Table 36 Electricity sector reform history in New Zealand

Year	Reform initiative	Comments
1986	First government decisions	Decision to reform generation and transmission sectors, and look at distribution.
1987	Electricity Corporation of NZ (ECNZ) established.	ECNZ set up under the new State-Owned Enterprises (SOE) Act[1], incorporating generation and transmission assets of the former NZ Electricity Division of the Ministry of Energy.
1988	Electricity Task Force established.	To advise government on structure and regulatory environment.
1989	Electricity Amendment Act.	Repeal of existing provisions requiring consent for construction of new hydro dams.
	Trans Power set up.	Established as a subsidiary of ECNZ.
	Task Force recommendations announced	Key recommendations include: separate ownership of generation and transmission; no large-scale break-up of generation; Electricity Supply Authorities (ESAs) should be corporatised and privatised; removal of statutory franchise areas and obligation to supply; and light-handed regulation.
1991	Energy Sector reform Bill introduced.	Encompassed corporatisation of ESAs and a wide range of regulatory issues[2].
1992	Energy Companies Act.	Provided for corporatisation of ESAs[3].
	Wholesale Electricity Market study released.	A private sector initiative to consider wholesale market developments.
	Energy Efficiency & Conservation Authority set up.	To develop, implement and promote energy efficiency strategies.
1993	Electricity Act 1992 comes into effect.	Provided for: removal of statutory monopolies and obligation to supply, information disclosure, and compulsory maintenance of lines until 2013.
	Electricity Market Company (EMCO) set up.	Purpose to develop an electricity market framework for wholesale trading.
1994	Information Disclosure Regulations promulgated.	Call for public disclosure of: separate audited financial statements for natural monopolies; prices and contract conditions; financial performance measures[4]; and removal of double counting of asset related expenditure.
1996	ECNZ split into two competing SOEs.	Contact Energy (with 28% of total generation capacity) split from ECNZ.
	Wholesale electricity market becomes operational.	Pool price based on 30-minute aggregation, with matching of buyer and seller bids.
1998	Electricity Industry Reform Act 1998.	ECNZ to be split into three competing state-owned generators[5]. Ownership split required for electricity lines businesses and electricity retailing function.
1999	Contact sold.	Contact Energy Ltd sold to one large investor (Edison Mission Energy ltd) and the public.

1 Nominated Ministers hold shares in SOEs, which must provide Statements of Corporate Intent and operate with commercial structures and incentives.
2 The Bill was later split into five separate Acts, including the Energy Companies Act 1992 & the Electricity Act 1992.
3 A diverse ownership pattern resulted, including: trust ownership; private shareholding; local government ownership, and combinations of these.
4 Based on standard asset values – i.e. Optimised Deprival value (the lesser of Optimised Depreciated Replacement Cost (ODRC) and economic value).
5 Mighty River Power Ltd (Nth Island hydro -14% of generation), Meridian Energy Ltd (South Island hydro – 30% of generation), and Genesis Ltd (hydro, thermal – 19% of generation). The split came into effect in 1999.

Figure 42 Post-reform structure of the New Zealand electricity sector



LESSONS

Light-handed regulation is possible with the right regulatory framework of incentives and controls (such as information disclosure requirements).

The wholesale market does not need to be designed or imposed from above; the industry should be free to implement a market structure most suited to the workings of the electricity sector (with safeguards to ensure fair play)

Full privatisation of the competitive elements of the sector is not necessary, provided state owned corporations operate under the same business laws as private firms, and are independent of political influence.

RUSSIA

PRESENT STATE AND DEVELOPMENT OF RUSSIAN POWER SECTOR

The current state of the Russian power sector is strongly influenced by Russia's past and present political history, and the recent economic transition of an emerging economy. The situation is characterised by the combined effects of a number of serious problems: non-payments (amounting to almost 77 percent of sales in 1998); financial problems; degradation in the value of capital (more than 1/3 of productive capital is obsolete); insufficient investment levels; a significant decline in power demand in Former Soviet Union countries and Eastern Europe; flaws in state pricing policy; cross-subsidies; and the conflicting policies of federal and regional government bodies.

In spite of the more than 50 percent decline in industrial production between 1990 and 1997, electricity consumption dropped only 25 percent over the same period. Russian electricity consumption in 1997 was 813.3 TWh. Installed power generation capacity in Russia was 215.9 GW in 1998. A breakdown by fuel type is shown in Table 37. Electric power output in Russia in 1997 was 834 TWh compared to 1082 TWh in 1990.

The Russian electricity sector is controlled by the Unified Energy System (52.7 percent-state-owned), which produces and distributes more than 94 percent of the total electric power demand. The rest is produced by a number of small local companies.

Table 37 Russian power generation capacity by fuel type (1998)

Total Capacity (GW)	Thermal	Hydro	Nuclear
215.9	150.7	43.9	21.3
	69.8%	20.3%	9.9%

THE RUSSIAN UNIFIED ENERGY SYSTEM

The Unified Energy System of Russia (UESR) is comprised of:

- 440 electric power stations with a total installed capacity of over 197,000 MW, including 21,000 MW of nuclear power producing 787 billion kWh of power a year;
- a total of 3,018,000 km of electric power lines; and
- a supply regulation system that unites physically all power installations with a single 50 Hz current frequency.

The organisational structure the UES is comprised of:

- RAO-UESR, which acts as a central locus to implement the functioning and development criteria established by the government, and it provides operational supply management aimed at increasing the economic efficiency of the UESR;
- 74 power suppliers that supply heat and power to consumers throughout the Russian Federation; and
- 34 large electric power stations that operate independently in the federal (national) wholesale electric power market.

Over 300 organisations provide technological back up and development for the UES, and also ensure the viability of the industry as a whole.

DEREGULATION AND PRIVATISATION IN THE RUSSIAN POWER SECTOR

The capacity of the electric power industry is sufficient to meet the demands of Russian electricity consumers, as well as provide for the export of electricity under existing agreements.

The history of the electric power industry in Russia has consisted of several consecutive stages of unification and re-organisation of the regional power systems, and the establishment of inter-regional unified power systems and their final incorporation into the Unified Power System. The establishment of the integral system has been viewed within Russia as relatively successful, in spite of the fact that the connections between the European and Siberian parts, and Siberia and the Far East are limited. Russia's transition to a market economy has brought about the necessity for the electric power industry to undergo restructuring and the development of new forms of internal and external economic relations.

The development of the Unified Power System began in 1992, along with the partial privatisation of industrial enterprises. Before putting this programme into effect, a preliminary restructuring of the power industry was carried out in an attempt to allow for the peculiarities of the existing system, such as: uneven location of the generation capacity with respect to demand, relatively low reserve capacity, the high concentration of electric and heat loads in big industrial centres separated from each other by long distances (from 500 to 1,000 km); and the dependence of the majority of the Russian regions on inter-system over-flows of electricity. In 1992, only about 13 regions were self-balanced within +/- 10 percent of the total volume of electric power needed, while 19 regions were in surplus and the rest of the regions were in deficit.

To preserve a reliable power supply, control of the established wholesale market was centralised. The Russian Joint Stock Company (RAO) and the Unified Energy System of Russia (UESR) were set up in December 1992 by Presidential Decrees ¹ 922, 923 and 1334. Cooperation between the Unified Power System and regional utilities allowed the coordination of investment programmes in the electric power industry.

A key inter-system objective was the co-ordination of all big thermal power plants (with a capacity of 1000 MW or more) with hydro power plants of 300 MW or more, (a total capacity of 95,000 MW – about 50 percent of the total installed capacity), along with the high voltage network, as well as the Central Dispatcher Board and dispatcher boards of the regional utilities, and other enterprises and institutions in the electric power sphere.

All these structures became subsidiary companies of RAO-UESR with 100 percent of the shares belonging to the mother-company. In addition, every regional utility (AO-Energo) handed over 49 percent of their shares to RAO-UESR. These regional utilities were set up on the basis of former regional power amalgamations, except for big power plants and network assets that were incorporated into RAO-UESR. To preserve its control over the electric power industry, the state retained a controlling number of RAO-UESR ordinary shares.

The main challenge for RAO-UESR has been the establishment of a federal wholesale electricity market (FOREM), which would work on the principles of competition and hence ensure truly cost-reflective electricity and heat prices through competition between the market participants.

The preliminary power industry-restructuring plan was not fully implemented. As a result of compromises arising during the course of difficult talks between RAO-UESR and federal and local administrations, only 34 of the 51 power plants included into the Annex of Presidential Decree ¹923 became part of the integrated system. Seven power plants out of the 34 (with a total installed capacity of 12,000 MW) were leased by RAO-UESR to regional utilities (AO-Energos) that independently manage the plants and pay rent to RAO-UESR. The rest of the power plants retained by the regional utilities became joint stock companies (as a compromise), handing over more than 49 percent of their shares to RAO-UESR.

On the whole and despite all the difficulties RAO-UESR has experienced, the resources existed to set up an inter-regional wholesale electricity market, putting an end to the monopoly position of the majority of the regional power systems. 23 power plants with a total installed capacity of 43,000 MW are involved in the wholesale market, as well as 9 state-owned nuclear power plants with a total installed capacity of 21,000 MW.

Setting up RAO-UESR as a holding company made it possible to preserve the principles and methods of a unified power system despite the disintegration of the USSR power system into separate national power systems. Along with this, the Russian system provides for a sustainable power and heat supply to consumers in the period of transition from centralised planning to a market economy. There is almost no state financing, despite a very high rate of inflation and the difficult issue of non-payments of electricity bills. At the same time the structure has facilitated the integration of the economy's regions and the social support of the population.

LESSONS

Russia has taken the initial steps towards the creation of a market structure in the power sector. This includes partial privatisation of a state monopoly, regional restructuring and introduction of a wholesale power market. However the previous state monopoly structure has been replaced by a set of regional monopolies controlled by the RAO-UES, with the state maintaining a golden share, and consequently wholesale competition is not actually occurring.

Power sector reforms are being impeded by the ineffective operation of general market institutions in the Russian economy. Therefore the major barriers to electricity industry reform lie outside the sector.

THE UNITED STATES OF AMERICA

INTRODUCTION

The US electricity sector, when compared with those in other Asia Pacific economies, is unusual for a number of reasons. Firstly, the US Federation of 51 states encompasses a large area geographically, and the electric power industry is large. For example, at the end of 1996, the net generating capability stood at more than 776,000 MW, with total sales to consumers of more than US$210 billion (EIA, 1998)

Two states are isolated from the rest, leaving 49 that could technically be part of one large interconnected grid system. In reality, the bulk power system has developed into 3 major networks (the interconnected Eastern, Western and Texas power grids) that consist of extra-high voltage connections between individual utilities designed to permit the transfer of electricity from one part of the network to another (EIA, 1996)

Each state historically developed its own electricity supply industry, controlled by state, as well as federal regulations. The sector has also always been dominated by private sector investment and control. This goes back to 1882, when Thomas Edison's first central station power plant went into operation in New York City (Joskow & Schmalenesee, 1983)

Because the US is one of the wealthiest nations on earth, and one of the most advanced industrially, there is a high level of electrification. The electric power industry is consequently quite complex and diverse, with a mix of private and public ownership. In the early 1980s, and before the current reform process began, about 3,500 enterprises were engaged in the generation, transmission and distribution of electricity. These included private utilities, municipal and state utilities, rural electric cooperatives, and federal power systems.[49]

Table 38 Net generation by source in the US (1997 and 1998)

Energy Sources	1997 (Million kWh)	1998 (Million kWh)
Coal	1,843,831 (52.76%)	1,872,186 (51.72%)
Petroleum	92,727 (2.65%)	129,104 (3.57%)
Natural Gas	497,430 (14.23%)	544,765 (15.05%)
Nuclear	628,644 (17.99%)	673,702 (18.61%)
Hydroelectric (conventional)	358,949 (10.27%)	328,581 (9.08%)
Others (geothermal, biomass, hydroelectric pump storage, hydrogen, sulphur, etc.)	72,860 (2.10%)	71,294 (1.97%)
Total electricity generated	3,494,441 (100%)	3,619,632 (100%)

Source: Energy Information Administration. DOE

49 As of December 1996, there were 3,195 electric utilities throughout the US, but only approximately 700 of them were operating power generation facilities.

Table 39 US electric power generation capacity

	Capacity		Share	
	Utilities (net) (MW)	Non-utilities (gross) (MW)	%	%
Coal	302,421	12,122	38.6	1.5
Petroleum	70,421	3,185	9.0	0.4
Natural gas	140,002	31,024	17.9	4.0
Petroleum/Natural gas	-	10,875	-	1.4
Nuclear	101,121	-	12.9	-
Hydroelectric	73,129	3,419	9.3	0.4
Geothermal	1,622	1,346	0.2	0.2
Biomass	442	8,494	<0.1	1.1
Wind	8	1,670	<0.1	0.2
Solar thermal	-	354	-	<0.1
Photovoltaic	4	-	<0.1	-
Pumped storage	21,110	-	2.7	-
Other	-	694	<0.1	<0.1
TOTAL	710,279	73,183		

Source: Energy Information Administration. DOE

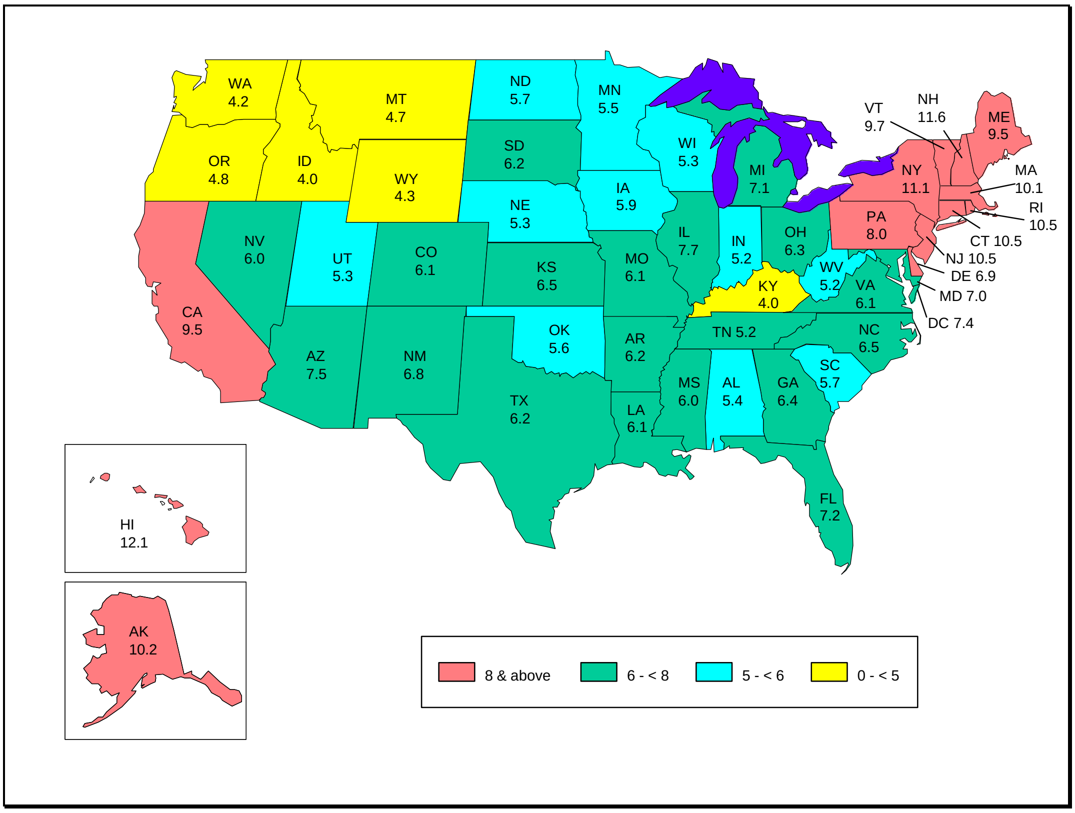
The investor-owned sector accounted for about 78 percent of both generating capacity and net electricity generation in 1980 (Joskow & Schmalensee). The majority of these were vertically integrated, with ownership and operation of generation, transmission and distribution facilities.

Just as the US electricity sector has historically been dominated by private ownership, it has also historically been characterised by pervasive economic regulation by municipal, state, and federal regulatory authorities. Because of the high degree of vertical integration created by private capital, companies would normally sell within an exclusive franchised area. State commissions regulated the prices at which private utilities could sell electricity to retail consumers. Price control was based on the principle that utilities should be able cover the cost of providing the service, and receive a fair rate of return on investment.

Although in theory it would seem a simple matter to set prices that encourage adequate and prudent investment, allow a fair rate of return, and ensure economic efficiency, this has proven difficult in practice.

Attempts to reform the US electricity supply industry actually go as far back as 1935, when the Public Utility Holding Company Act (PUHCA) was enacted to break up massive interstate holding companies and require them to divest their holdings until each became a single consolidated system serving a discrete circumscribed geographic area. This legislation, although successful in countering an undesirable characteristic of the sector at that time, had the unfortunate side effect of practically eliminating the participation of non-utilities in electric power wholesaling.

Figure 43 Average revenue from electricity sales to all retail consumers by US state (1996)



Source: Energy Information Administration.

The recent interest in electricity sector reform in the US dates back to the late 1970s and early 1980s, and results from the culmination of a number of factors. In the early 1980s, consumers became dissatisfied with the rapidly rising costs of electricity. Although these rises were largely due to rising fuel prices, increased costs of construction, interest rates and general inflation, consumers blamed the regulators. The utility industry was also critical of regulatory performance, believing that prices were not rising fast enough to compensate for increases in operating costs, construction costs, and interest rates. At the heart of this conflict, was the conviction by a growing number of people that electricity was not being supplied very efficiently (Joskow & Schmalensee).

In the early 1980s, the situation arose where under-investment in new facilities was occurring because the return on investment was less than the full cost of making the investments. This had a major impact on investment in capital intensive generation plant such as nuclear. In hindsight, this may be considered a good outcome, but at the time, there were serious concerns that lack of investment in energy infrastructure would have detrimental long-term consequences.

In line with the market economic philosophies emerging in the early 1980s, and the economic reform being wrought on various sectors of the economy, there were those in the US arguing that for decades power had not been supplied at least cost, nor priced appropriately. Underlying this argument was the view that serious inefficiencies of supply and pricing can persist in an industry in which most sellers have protected monopolies and regulated prices, so that they are insulated from the discipline of the marketplace (Joskow & Schmalensee).

Another major driver of change has been technological innovation, with the emergence of the high efficiency gas combined cycle turbine having a major impact on power generation economics. An additional benefit of the gas CCT is its clean burning aspect, with much lower emission levels, including CO_2.

The first move towards deregulation began with the enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978. This legislation stipulated that electric utilities had to interconnect with and buy, at the utilities' avoided cost, capacity and energy offered by any non-utility facility meeting certain criteria established by the Federal Electricity Regulatory Commission (FERC).

Table 40 Average electricity price in the US (1997 and 1998)

Item	1997 US¢per kWh	1998 US¢per kWh
National average electricity price	6.85	6.75
Residential	8.43	8.27
Commercial	7.59	7.43
Industrial	4.53	4.50

Source: Energy Information Administration. DOE

The next major reform initiative was the Energy Policy Act of 1992 (EPACT). This opened access to transmission networks and exempted certain non-utilities from the restrictions of the PUHCA. In 1996, FERC issued Order 888, which opened transmission access to non-utilities, thereby establishing wholesale competition, and Order 889, which requires utilities to establish electronic systems to share information about available capacity. The main objective of these orders was the elimination of monopoly power in transmission, and in particular to clearly separate the monopoly function of grid operation from the competitive elements of generation and communications.

Table 41 U.S electricity sector reform history

Year	Reform initiative	Comments
1935	Introduction of the Public Utility Holding Company Act (PUHCA)	To break up massive interstate holding companies with monopoly power over electricity supply.
1978	Introduction of the Public Utility Regulatory Act (PURPA)	To interconnect all utilities to make electricity trading possible.
1992	Introduction of the Energy Policy Act (EPACT)	To open access to transmission networks.
1996	Federal Electricity Regulatory Commission (FERC) Orders of 888 & 889	To facilitate open access transmission networks and encourage wholesale competition.
1998	Restructuring changes in California come into effect (with a transition period to 2002.	ISO to perform transmission and dispatch. Full generation and retail competition to be phased in.

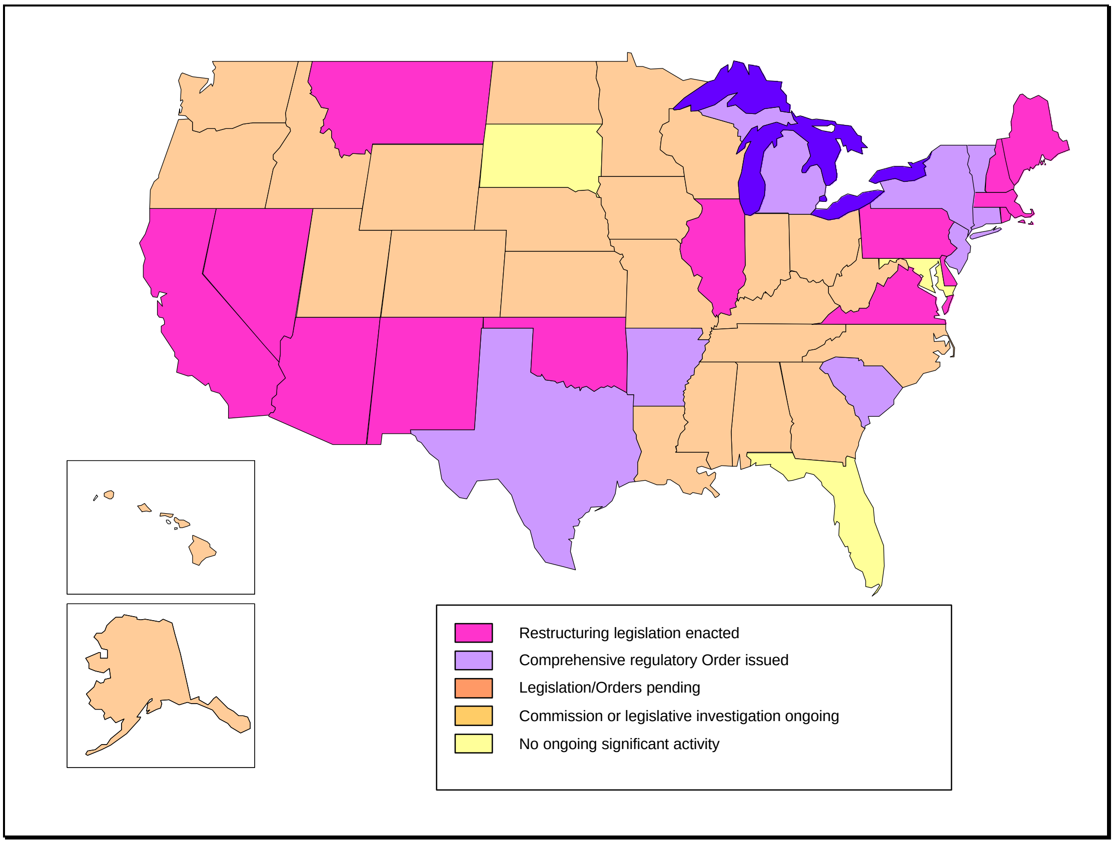
Source: Energy Information Administration. DOE

Currently, there are a host of electricity reform legislative proposals before the US Senate and House of Representatives. These include: provisions to encourage retail competition; repeal of the Public Utility Holding Company Act; measures to encourage energy efficiency and renewables; and proposals to privatise Federal energy operations.

At the state level, there has been a surge of activity in the legislatures and utility commissions in most states to examine the possibility of retail competition. This process has been quite uneven, with some of the states with relatively high power prices proceeding faster and further than states with naturally low priced energy. For example, states with high electricity tariffs, such as California and as those in the Northeast have had compelling reasons to promote competition to lower consumer electricity tariffs.

California has made the most progress to date, introducing full direct retail access for all consumers on April 1 1998. Competitive processes include both an Independent System Operator (ISO), which performs transmission and dispatch, and a power exchange, which matches customers with suppliers. All investor owned utilities in the State are required to participate in the restructured system, but the public utilities (comprising 25 percent of the market) are not required to participate (Griffin, 1998). Investor owned utilities (IOUs) have been required to divest themselves of their generating facilities, which will now be owned and operated by independent investors within a fully competitive framework. Distribution will remain in the hands of utility distribution companies, and be regulated by the California Public Utility Commission. The transition period for restructuring will run until 31 March 2002. During the transition period, customer rates of IOUs are frozen at their June 1996 levels.

Figure 44 Status of electricity industry restructuring in the US (December 1999)



Source: Energy Information Administration. DOE

States with low electricity tariffs have been much slower to adopt reform proposals, partly through a widespread fear that prices could increase in such states under a competitive environment. In the Northwest states which have particularly low tariffs (from low cost coal generation facilities), the feeling is that public utilities currently deliver low cost electricity and have good service, so why mess with a system that is working well (Golden, 1998).

To date, 24 states (representing about 65 percent of the US population) have started moves that could lead to the introduction of customer choice in electricity markets. Meanwhile, attempts to develop US national legislation to coordinate deregulation and promote competition have so far been frustrated by a powerful alliance of state administrators, regulators and utilities (Financial

Times, 1999). A federal bill, passed recently by the House of Representatives, broadly supported the rights of individual states to determine the future of their own electricity markets.

Table 42 Status of electricity industry restructuring in the US

Restructuring Legislation Enacted	Comprehensive Regulatory Order Issued	Legislature/ Orders Pending	Commission and Legislative Investigation Ongoing	No Ongoing Significant Activities
Arizona, California, Connecticut, Delaware, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Oklahoma, Pennsylvania, Rhode Island, and Virginia.	Maryland, Michigan, New York, and Vermont.	Arkansas, Ohio, South Carolina, and Texas.	Alabama, Alaska, Colorado, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, Oregon, Tennessee, Utah, Washington, West Virginia, Wisconsin, and Wyoming.	Florida and South Dakota.

Source: Energy Information Administration. DOE

ISSUES

STRANDED COSTS

In the pre-reform era when the power industry was heavily regulated, some investments made by utilities (especially in generation capacity) will be unable to compete in a deregulated, competitive market. This leads to the phenomenon known as stranded costs, where the investment cannot be fully recovered. Estimates of these stranded costs range from US$100 billion to US$200 billion nationwide (US EIA). During the transition to a competitive environment, the FERC recognised the possibility that some utilities may incur stranded costs as wholesale customers leave to purchase power from alternative sources. Consequently, Order 888 provided a mechanism for recovery of stranded costs to allow an orderly and structured transition to a market-based wholesale market.

Many states have agreed to provide an opportunity for full recovery of stranded costs, contingent on adoption of appropriate mitigation strategies that included divestiture and/or securitization.[50] This has become a contentious issue, with some arguing that utility shareholders have already been compensated for the investment risk under the traditional cost of service regulatory principles. In an analysis of this issue, Kolbe and Tye (1996) concluded that investors couldn't possibly have been compensated for the risk of stranded costs by the mechanism of equating the allowed rate of return to the cost of capital in an unbiased regulatory regime prior to the creation of stranded costs. This issue has become hotly debated because, on the one hand utilities have sought guarantees with respect to full recovery of stranded costs, and on the other many customers have sought the ability to abrogate existing wholesale contracts without payment of stranded costs.

DEVELOPMENT OF INDEPENDENT SYSTEM OPERATORS

Although the transmission network comprises only 12 percent of overall energy infrastructure investment, a comprehensive interconnected transmission system is a vitally important part of a

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50 Securitization is a financing tool employed to reduce the cost of business credit. It refers to the creation of a financial security backed by a revenue stream exclusively used to pay debt associated with that security. (see EIA. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*).

competitive energy market because it increases the potential for competition by providing customers the opportunity to purchase less expensive power from distant suppliers. The US bulk power transmission system comprises five networks: (1) the Eastern Interconnected System, consisting of the eastern two-thirds of the United States; (2) the Western Interconnected System, consisting of the Southwest and areas west of the Rocky Mountains; (3) the Texas Interconnected System, weakly interconnecting with the others by direct current lines; (4) the Canadian system with good integration with the Eastern and Western systems; and (5) the Mexico system with a limited interconnection to the Texas and Western systems.

The interconnections are divided into 152 regional “control areas” that monitor and control a regional transmission grid. Control areas are the primary units responsible for the reliable operation of the transmission system. To improve operating efficiencies, some utilities have created power pools to coordinate the operation and planning of generation and transmission services. Centrally dispatched power pools can select the least-cost mix of generating and transmission capacity at any given moment, schedule in maintenance requirements and share operating reserve requirements, and hence increase the overall efficiency of the system.

Prior to reform, access to the bulk power transmission system was limited, as owners used their market power to control access. The Energy Policy Act 1992 gave the FERC the authority to order owners to provide access to their transmission grids to third parties when requested. This legislation facilitated access to transmission networks, but owners could still use their market power to prevent full and free competition. The FERCs Order 888 includes provisions to correct this problem, by introducing the concept of comparable service. The idea of separating transmission ownership from system control arose because some regulators believed that stronger measures were required to eliminate discrimination and favouritism. California led the way in 1994, with an idea, which developed into the independent system operator (ISO) concept. Consequently, ISOs are now being formed in many regions in the US.

By sharing resources, and by having central dispatch, an ISO can achieve efficiencies in system operation similar to what wholesale power pools have experienced. Potential benefits include: elimination of discriminatory practices and reduction of other market power abuses; development of efficient transmission system pricing; efficient management of congestion problems using market-oriented approaches; simplification of procedures for transmission customers; and timely and objective dispute resolution. Some critics of the ISO concept believe a more effective approach would be the creation of independent transmission companies by physically separating generation and transmission ownership by divestiture (as has happened in other economies going down the electricity sector reform path). Other potential issues with the ISO concept include: the incentives for ISOs to perform efficiently, given their position as operator but not owner of the transmission assets; and the sufficiency of control over transmission facilities to provide fair and equitable access to the network.

However, despite this progress, substantial hurdles have yet to be overcome to the introduction of a fully competitive, and smoothly functioning electricity market in California. The two most significant obstacles are stranded costs and abuses of market power. Stranded costs, which are defined and discussed in more detail below (under Economic Policy Considerations), are being dealt with in California through the Competitive Transition Charge (CTC), an extra charge on every consumers’ electricity bill. The CTC has been designed to fully recover the stranded costs of the affected utilities over a five-year period. This adds a substantial premium to tariffs in the state in the short term, defeating temporarily one of the key rationales for the reforms – that consumers would be paying less for their power.

The other problem is abuse of market power. The incumbent utilities, holding transmission and distribution assets, must theoretically provide third party access on equitable terms. However, there are many ways for asset owners to act uncompetitively, squeezing out new entrants by making it difficult for them to compete. One or none of the competitive electric service providers (ESP's) may survive the restructuring transition period, leaving the incumbent utilities with control over distribution. Political interference and power of the unions compound the difficulties in instituting true reform in California (P. Eckert, pers. comm.).

It also appears that the wholesale pool and dispatch model introduced in California is rather complex and high cost compared with models developed elsewhere.

LESSONS

In an economy where the pre-reform electricity sector is comprised of privately owned and operated, vertically-integrated monopolies, the question of stranded costs is likely to arise where electricity supply assets that were developed under the influence of the policies of regulators and governments, may not be commercially viable in a competitive market.

It is possible to undertake reform where existing structures are not overly conducive to change, providing the costs and benefits can be clearly demonstrated in advance to those most likely to be affected by the changes

CHAPTER 9

CONCLUSIONS

IMPLICATIONS OF REFORM

Regulatory reform in the electricity sector, characterised by deregulation and privatisation is beginning to become a common phenomena amongst APEC member economies. Some are well advanced while others are still in the early stages of planning. When one takes into consideration the circumstances of individual economies, in terms of social fabric, political, legal and financial frameworks, and stage of economic development, it is easy to see how there can be substantial hurdles to the introduction of fully competitive electricity markets. Policymakers and energy industry analysts in well-developed economies may sometimes lose sight of the fact that these hurdles may prevent rapid reform - or for that matter, any significant reform. Where reform processes do take place in under-developed and emerging economies, the outcomes may well differ from what economists and industry analysts in well developed economies consider ideal. However, a number of possible models exist, and each may be appropriate to a particular set of circumstances. There is clearly no “one-size-fits-all” model for electricity supply industry regulatory reform.

One of the theoretical arguments in favour of the introduction of full-scale competition in the electricity supply industry is that the cost of generating and supplying electricity will decline, as operational efficiencies in managing generation and network assets improve, and competition leads to wider choice and higher quality services. Although it is too early to know what the long-term outcome will be with respect to the industry cost structure, available empirical evidence indicates that wholesale costs have been driven down, as have retail electricity prices, at least to larger consumers. Investment decisions with respect to new generation capacity and the upgrading and/or extending of networks have become more transparent as they have become more commercially oriented, and a host of new and improved goods and services are beginning to be offered.

Regulatory reform requires deregulation on one hand, but also requires re-regulation on the other. As reform advances, and it becomes more difficult to meet social policy objectives, new sets of regulation are required to deal with environmental impacts, rural electrification and support programs for low-income consumers. The problem of meeting social policy objectives is more difficult in those economies where electricity supply is barely keeping up with ever increasing demand.

As seen in the case studies, regulatory reform takes place over a relatively long time frame (a decade or more in many cases) and can entail costly trial and error. Although it is relatively clear what is required to introduce competition into the electricity supply industry – the separation of the competitive from the natural monopoly elements, desegregation to reduce market power etc, the design of a satisfactory regulatory framework is less straightforward. The electricity supply industry is unusual in a number of respects: the product (electrons) cannot be easily stored, there is an intimate relationship between operations at all stages in the supply chain, the assets involved are capital intensive and idiosyncratic, and there are areas of legitimate natural monopoly, as in the networks. An optimal regulatory framework needs to take into account these factors, and the likelihood that post-reform a potentially high degree of re-concentration will occur (requiring robust competition law). Also important is the flexibility to accommodate technological development, changes in industry structure (particularly if disseminated power systems become important in the industry), and the need for consumer education, especially at the household level.

Thus it is our view that regulatory reform ought to be as flexible and performance oriented as possible, so as not to inhibit competition at any level, and to foster the adaptability of the regulatory regime to both anticipated and unanticipated future events, including technological advances.

NEW DEVELOPMENTS

As previously discussed in Chapter 4, there are various models that could capture attributes of a particular regulatory regime. Moving from a command and control model (VIM) to a free competition model (FCC) is a formidable task for many member economies due to varying socio-economic circumstances. Some economies that have made significant electricity sector reform progress are now experiencing further developments that give some hint of how the industry may develop over time. Others however, have not taken any steps towards regulatory reform for various political and social policy reasons.

In some economies that have achieved an advanced level of electricity sector regulatory reform, market forces have become a strong driving force for further development of the industry. These forces have pushed the industry beyond what regulators and policy-makers envisaged with respect to market development.

In some states in the US, some extensive changes in electricity industry structure are being experienced, with the emergence of specialised companies at retail level, independent contracts between generators and large consumers, convergence of electricity and natural gas, and specialists in wholesale trading of electricity and gas (Silverman, 1999). These trends hint at the kind of developments in the electricity sector the future could bring to other economies when regulatory reform becomes more widely established.

Economies undergoing or planning regulatory reform could learn valuable lessons from current developments in market structure, regulatory regime shift, technological innovation, and consumer awareness. Regulatory reform is a process, which will continue to develop as markets run their course once fully empowered. Thus any reform policies and measures should be open ended and flexible enough to cope with that uncertain future development of the electricity sector.

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APPENDIX I

STATISTICS FOR APEC MEMBER ECONOMIES

A summary of the recent history and current status of electricity reform plans in APEC economies is provided below. The case studies provide more detailed information for selected economies (Australia, Chile, Japan, Korea, Malaysia, New Zealand, Russia and the United States).

AUSTRALIA

For details see case study on page 77.

Area	7,682,300 sq km	Installed Electricity Capacity	105,176 MW
Population (1998 est.)	18.8 million	Gross Generation	183,643GWh
GDP (June 1998)	US$347.3 billion	Population Electrified	100%
GDP per capita	US$18,473	Generation mix	
		Thermal Hydro	91% 9%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

BRUNEI DARUSSALAM

The Department of Electrical Services (DES) is under the Ministry of Development and is charged with operating the electricity sector. The DES is both a department and an integrated electric utility monopoly. As a utility, it is responsible for planning for future generation and distribution requirements, while as a service department it sets the standards for and implements electricity usage in public buildings as well as overseeing their overall electro-mechanical maintenance.

In line with Brunei's energy policies of providing a reliable, continuous, and safe supply of electric power to all consumers in the Sultanate of Brunei, the DES is looking into the possibility of engaging the participation of IPPs in power development programmes. Some services, such as metering and cable supply have been privatised to make these services more competitive and efficient.

The government controls the price. The tariff is currently not affected by changes in fuel costs, operating costs, capital expenditure, consumer price index or other indicators. Total installed capacity in Brunei Darussalam, including the private sector, is 770.2 MW. The electrification rate is 100 percent in the urban areas and 97 percent for the rural areas.

(Brunei Darussalam Cont)

Area	5,765 sq km	Installed Electricity Capacity	770.2MW
Population ('97)	305,000	Gross Generation	1,530GWh
GDP ('97)	US$4,815 million	Population Electrified	100%
GDP per capita	US$15,782	Generation mix	
		Thermal	100%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
Brunei Darussalam Statistical Year Book, 1996/1997

CANADA

The Canadian electricity industry is decentralised, with each province having its own system. Although the situation varies between provinces, most Canadian electric utilities are publicly owned. Most of the utilities in each province are vertically integrated. Inter provincial sales of electricity occur between utilities and each provincial government has a regulatory body responsible for electricity generation, transmission and distribution regulation.

A number of individual provinces are planning to establish competitive energy markets and to more fully integrate the Canadian and US power grids. Electricity regulatory reform, which is expected to increase competition and lower cost of supply, will occur at the provincial level. In the Province of Ontario, there is an effort to split its electric utility company into separate generation, transmission and distribution commercial entities, although they will remain government-owned. This plan is scheduled to begin after the year 2000.

The province of Alberta has undertaken a limited reform of its electricity sector, by using Power Purchasing Agreements to accomplish what policy-makers in the province refer to as "virtual divestiture" by the three vertically-integrated utilities of their generation and distribution assets. The reform process will also include over time the transfer of marketing rights for wholesale power from owners to independent third parties, and eventually both independent system operation and independent transmission administration.

Area	9,215,430 sq km	Installed Electricity Capacity	39,017MW
Population ('99)	31 million	Gross Generation	587,475GWh
GDP (quarter '99)	US$682.69 billion	Population Electrified	100%
GDP per capita	US$22,022	Generation mix	
		Thermal	21%
		Hydro	65%
		Nuclear	14%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
Website http://www.statcan.ca/
International Energy Agency (IEA), "Energy Policies of IEA Countries 1998 Review"

CHILE

For details see case study on page 83.

Area	756,252 sq km	Installed Electricity Capacity ('99)	9,183MW
Population ('97)	14.622 million	Gross Generation ('99)	35,858GWh
GDP ('97)	US$74.96 billion	Population Electrified (est.)	95%
GDP per capita	US$5,128	Generation mix	
		Thermal Hydro	43% 57%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. National Energy Commission of Chile, World Bank "1999 World Development Indicator"

CHINA

The electricity sector is publicly owned, with control by a mixture of central and local government. The China Electricity Council (CEC) is an organisation representing all of China's electric power utilities. The structure is vertically integrated although there are several independent power projects underway. There are no plans to privatise the distribution or transmission networks. However, there are plans to privatise the generating capacity by up to 20 percent.

One of the important milestones has been the establishment of the State Power Corporation of China (SPCC). It is expected this will have a profound influence on development of China's power industry in the future. SPCC is the owner of state assets as defined by the State Council and a main investor and asset operator. The creation of SPCC signals the separation of government functions from commercial functions. This will go a long way to resolving any conflicts of interest arising from state funds being used to finance power projects.

The SPCC also deals with inter-regional electricity transactions and undertakes overall management of the electricity grid system. One of the biggest problems has continued to be the lack of a rational price formation mechanism. Pricing is decided on a case-by-case basis for each project. This introduces confusion into price implementation. The current price structure has been adapted, along with the structural model used 20 years ago. For example, in the industry sector, the relative weight of the capacity charge to the energy charge is too low. Price management is also not clearly defined between central government and local government.

[China cont]

Area	9.6 million sq km	Installed Electricity Capacity ('98)	2770GW
Population ('98)	1,248.1 million	Gross Generation	1167TWh
GDP ('98)	US$960.9 billion	Population Electrified	95%
GDP per capita	US$770	Generation mix ('95)	
		Thermal	75%
		Hydro	24%
		Nuclear	1%

Source: State Statistical Bureau of China, "A Statistical Survey of China 1999". Using GDP in Chinese currency and the annual average exchange rate to US dollar covers GDP in US dollar term.

APEC Supply and Demand Outlook, APERC 1998

HONG KONG, CHINA

The Hong Kong Electric Company (HEC) and China Light and Power Holding Ltd (CLP) are the two private electric power utilities operating in Hong Kong. Both companies are vertically integrated. The structure of the local electricity supply industry has remained practically unchanged since Hong Kong was handed over to China in 1997. The electricity price is regulated by a scheme of controls set by the government and is asset based. The existing companies do not have franchise areas, but they are virtual monopolies.

HEC provides electricity to its customers in Hong Kong Island, Ap Lei Chau and Lamma Island, and CLP provides electricity to the New Territories, Kowloon, and Lantau Island. At present, HEC does not have any agreements with neighbouring utilities to export or import electricity. The current existing interconnection with CLP is primarily used as a mutual support for contingencies and optimisation of reserve margins for both companies. In Hong Kong all transmission lines are planned, installed and operated by private companies.

Previously, the electricity infrastructure of Hong Kong was predominantly coal-based. CLP commissioned a natural gas-fired combined cycle power station in 1996. Generating capacity of CLP 's gas-fired units currently accounts for about 23 percent of its total installed capacity, and the percentage is expected to increase to 28 percent in 2006. On other hand, HEC has proposed to commission LNG combined cycle units in a new power station starting from around 2004.

Area	1,095 sq km	Installed Electricity Capacity	10,593MW
Population ('98)	6,687 million	Gross Generation	28,932GWh
GDP ('98)	US$166.3 billion	Population Electrified	100%
GDP per capita ('98)	US$24,870	Generation mix	
		Thermal	100%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.

The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

INDONESIA

Electric power is supplied by the vertically-integrated monopoly Perusahaan Listrik Negara (PLN) the state-owned electricity corporation. PLN is responsible for the majority of Indonesia's generation, transmission and distribution of electricity. Lately, the government has exerted effort to reduce economic and political barriers to private sector participation in the energy area. The objectives of regulatory reform and development of private power in Indonesia are closely connected to mobilisation of financial resources, improvement in economic efficiency and fostering of social development. Several IPPs have been permitted under Built-Operate-Transfer (BOT) schemes. International donor organisations, such as the World Bank and the Asia Development Bank (ADB) have stepped in to provide funding for most of the planned projects.

At present, the electricity sector is structured as a single-buyer model, with PLN buying from IPPs under long-term contracts. PLNs revenues are dependent on sales and the electricity tariff.

Area	1,919,440 sq km	Installed Electricity Capacity	21,312MW
Population ('98)	212,94 million	Gross Generation	75,030GWh
GDP ('98)	US$94.2 billion	Population Electrified	55%
GDP per capita ('98)	US$442	Generation mix	
		Thermal	84.8%
		Hydro	13.4%
		Geothermal	1.8%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. Statistic Indonesia of the Badan Pusat Statistik (BPS), Republic of Indonesia.

JAPAN

For details see case study on page 93.

Area	377,765 sq km	Installed Electricity Capacity	215GW
Population ('98)	126 million	Gross Generation	1,003TWh
GDP ('97)	US$3.08 trillion	Population Electrified	100%
GDP per capita	US$24,500	Generation mix ('98)	
		Thermal	52%
		Hydro	11%
		Nuclear	36%
		Geothermal	0.4%
		Other	0.15%

Source: The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

KOREA

For details see case study on page 103.

Area	98,480 sq km	Installed Electricity Capacity	41,042MW
Population ('98)	46.4 million	Gross Generation	224,444GWh
GDP ('97)	US$631.2 billion	Population Electrified	100%
GDP per capita	US$13,700	Generation mix	
		Thermal Hydro Nuclear	90% 2% 8%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book)
Year Book of Energy Statistics, Korea Energy Economics Institute (KEEI), 1998

MALAYSIA

For details see case study on page 117.

Area	329,733 sq km	Installed Electricity Capacity	13,540.5MW
Population ('98)	20.93 million	Gross Generation	60,593GWh
GDP ('97)	US$227 billion	Population Electrified Peninsula Sabah / Sarawak	 99% 75%
GDP per capita ('97)	US$11,000	Generation mix	
		Thermal Hydro	85% 15%

Source: National Energy Balance, Malaysia 1997, Ministry of Energy, Communication and Multimedia, Malaysia.
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book)

MEXICO

The Federal Electricity Commission (CFE) and Luz y Fuerza del Centro (LFC) are the two public utilities responsible for providing electricity, with obligations to supply. In 1992, the Electricity Public Service Law was reformed, and reduced CFEs legal monopoly in power generation. The objectives of the reform were to foster private participation in electricity generation, to entitle open access to the transmission grid for all participants in the sector, and to optimise short and long-term costs.

Currently, the CFE is carrying out bidding processes to develop major electricity generation projects. These processes include Build, Lease and Transfer (BLT) projects and IPP schemes. In addition, the Energy Regulatory Commission (CRE) issues generation permits for self-supply, cogeneration, small-scale production, independent power production, and permits for imports and exports.

[Mexico cont]

Area	1,909,000 sq km	Installed Electricity Capacity	35,850MW
Population ('97)	94.3 million	Gross Generation	161,326GWh
GDP ('97)	US$403.0 billion	Population Electrified	95%
GDP per capita	US$4,274	Generation mix	
		Thermal	66%
		Hydro	28%
		Nuclear	4%
		Geothermal	2%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. World Development Indicator, 1999.

NEW ZEALAND

For details see case study on page 122.

Area	268,680 sq km	Installed Electricity Capacity	7,900MW
Population	3.8 million	Gross Generation	35,656GWh
GDP ('98)	US$45.72 billion	Population Electrified	100%
GDP per capita	US$12,032	Generation mix	
		Thermal	29%
		Hydro	64%
		Geothermal	5%
		Other	2%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book)
MEGABARE GDP Projection, 1987US$ (New Baseline'98)

PAPUA NEW GUINEA

Electricity is provided and controlled by government. The Papua New Guinea Electricity Commission (Elcom) is the commercial statutory authority responsible for planning, generation, transmission, distribution and selling of electricity throughout Papua New Guinea. The state owned monopoly maintains 19 discrete power networks. At the moment, there is no plan to liberalise the sector.

Area	462,840 sq km	Installed Electricity Capacity	262.8MW
Population ('98)	4.6 million	Gross Generation	608.7GWh
GDP ('96)	US$11.6 billion	Population Electrified	7.5%
GDP per capita ('96)	US$2,650	Generation mix	
		Thermal Hydro	38% 62%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

PERU

Peru has followed a similar restructuring route to Chile. Assets sales were implemented in the period 1993 to 1996, principally by selling majority stake holding shares (around 60 percent) to large investors, keeping 10 percent for employees, and releasing 30 percent to the local stock market. Peru has a mixed electricity structure. Electricity distribution has been fully privatised, and a major generation company has also been privatised. Peru has seen significant investment in power distribution, in addition to generation. Most of the investment has been in hydro-electricity. Once full privatisation has been achieved, the industry will be completely unbundled.

Area	1,280,000 sq km	Installed Electricity Capacity	5192MW
Population ('97)	24.4 million	Gross Generation	17,950GWh
GDP ('97)	US$63.8 billion	Population Electrified	72%
GDP per capita	US$2,614	Generation mix ('97)	
		Thermal Hydro	51.6% 48.4%

Source: Plan Reference of Electricity 1998, Ministry of Energy and Mines, Republic of Peru.
World Development Indicator, 1999

PHILIPPINES

The government-owned and controlled National Power Corporation (NPC) provides about half of the electricity generated in the Philippines, and a significant portion (around 49%) is provided by IPPs. NPC controls the transmission system, and distribution is handled by private electric utilities and rural electric cooperatives. Some private and government industries buy power directly from NPC, and cross-subsidies exist in the current tariff structure.

The past and the current administrations have been exerting efforts to reform the economy, and the power sector is one of the high priority areas. Given the limited resources and the economy's growth and development objectives, the Philippine government has been paving the way to attract greater private sector capital infusion and participation in the power sector.

The enactment of the Build-Operate-Transfer (BOT) law in 1987 marked the beginning of private sector participation in major power projects, and has resulted in a substantial amount of IPP power capacity coming on stream. The Foreign Investment Act now allows 100 percent foreign equity interest in power generation projects. However, attempts by the government to encourage the immediate entry of IPPs in the early 1990s, to end the severe power shortages, has resulted in higher tariffs because of the agreed "take-or-pay" provisions of agreements between NPC and IPPs. IPPs sell electricity to NPC under long-term PPAs. The tariff is composed of demand and energy charges, and includes foreign currency adjustments.

Area	300,000 sq km	Installed Electricity Capacity	12,066MW
Population ('98)	75.15 million	Gross Generation	41,065GWh
GDP	US$82,241 billion	Population Electrified	79.89%
GDP per capita	US$1,094	Generation mix	
		Thermal	65.12%
		Hydro	19.07%
		Geothermal	15.81%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

RUSSIA

For details see case study on page 130.

Area	16,889,000 sq km	Installed Electricity Capacity	250,900 MW
Population	147 million	Gross Generation	834,000GWh
GDP	US$735.0 billion	Population Electrified	99%
GDP per capita	US$4,950	Generation mix	
		Thermal	70%
		Hydro	20%
		Nuclear	10%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. World Development Indicator, 1999

SINGAPORE

Until 30 September 1995, the Public Utilities Board (PUB) was responsible for supply of electricity in Singapore. Following a decision by government on 1 October 1995 to privatise the PUB, the electricity industry was restructured with the break-up of the formally vertically-integrated industry into four organizations (generation, transmission and distribution, and supply business). The restructuring was introduced to provide a framework for competition in electricity generation and supply. PUB plays the new role of regulating the electricity industry.

As of 1 October 1995, Singapore Power Ltd (SP) took over the PUB electricity operations. SP is a wholly owned subsidiary of Temasek Holdings, the investment arm of the Singapore government, and is run as a private business entity. SP has been structured as a holding company with eight subsidiary companies - four electricity companies and four others. In October 1995, electricity operations were corporatised as the first move towards privatisation, and Singapore Power began to prepare for public listing.

However, in February 1996, the Government took a decision to defer the public listing of SP indefinitely. According to the Government, the company needs more time to make the transition from a monopoly statutory board to a commercial business. In addition, SP is not earning an adequate rate of return. Low tariffs are one of the main causes. In April 1998, The Singapore Electricity Pool (SEP) was launched with the objective of introducing competition and increasing efficiency in the generation and supply of electricity. SEP's pooling and settlement system provides the means for trading electricity between power generation and distribution companies through a common pool, thereby allowing market forces to determine the price of electricity. On 1 January 1999, a new electricity tariff was introduced, that extra high tension and low tension customers now pay lower charges for the use of the delivery system, while high tension customers pay more, as they are no longer subsidised by the other categories.

At present, there are six public electricity licensees, namely: PowerSenoko Ltd, PowerSeraya Ltd, Tuas Power Ltd and SembCorp Cogen Pte Ltd, (generation companies); PowerGrid Ltd (T&D company; and Power Supply Ltd (supply company). PowerSenoko and PowerSeraya are both subsidiaries of SP, and both will be come under the direct ownership of Temasek Holdings, the government's investment arm with effect from April 2001.

Area	646 sq km	Installed Electricity Capacity	5,600MW
Population ('98)	3.87 million	Gross Generation	27,685GWh
GDP ('97)	US$79.5 billion	Population Electrified	100%
GDP per capita	US$20,452	Generation mix	
		Thermal	100%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

CHINESE TAIPEI

The Taiwan Power Company (Taipower) is moving towards deregulation and privatisation by the year 2001. Currently, Taipower has been responsible for the development, generation, supply, and marketing of electricity for the island. Chinese Taipei's electric power sector is an independent vertically-integrated network, and 90 percent of its fuel supply is imported. The Energy Commission of the Ministry of Economic Affairs (MEA) is the regulatory body in charge of national energy policy and other related areas, except nuclear energy, which is regulated by the Atomic Energy Council. As Chinese Taipei lacks indigenous energy resources, it relies on imported coal, oil and natural gas. A rapid increase in demand for power is proving difficult to manage. Currently, the reserve margin is too low to manage peak load situations.

Chinese Taipei's economy is very closely interlinked with international markets. It is a major exporter of products, which rely heavily on imported energy for manufacturing. Under the impetus of international economic liberalisation and political democratisation in Taiwan, the government has developed a deregulation policy for the generation sector. This will include encouraging investment by IPPs. The Energy Commission has granted permission to 11 companies to build power plants under IPPs programme with limitations on foreign ownership restricted to 50 percent in order to increase the attractiveness of such projects to foreign firms. Initially, IPPs will be confined to development of thermal and hydropower generation, and will be excluded from building nuclear power capacity. IPPs will sell electricity to Taipower pursuant to Power Purchase Agreements (PPAs). The capacity to be purchased by Taipower has been set at less than 20 percent of the corresponding future system capacity. The prices offered by the IPPs must be lower than the avoided costs of Taipower's own similar units.

Like all other regional utilities, the biggest influence on tariffs is fuel costs. For sole and bundled power systems, Taipower's price structure is configured to reflect the cost of supplying energy at different times of the day and in different seasons. Taipower pricing strategy is also influenced by: economic objectives (efficiency and fairness); financial objectives (maintenance of financial viability and a fair rate of return on investment, and ability to investment in further generating capacity); and social objectives (maintenance of rate stability and social obligations).

Area	35,980 sq km	Installed Electricity Capacity	26,680MW
Population	21.9 million	Gross Generation	142,964GWh
GDP ('97)	US$308 billion	Population Electrified	99.97%
GDP per capita ('97)	US$14,200	Generation mix	
		Thermal	64%
		Hydro	17%
		Nuclear	19%

Source: Energy Commission, Ministry of Economic Affairs, Republic of China, June 1999, "Energy Statistical Data Book, 1998".

The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book)

THAILAND

The Thai electricity generation industry has until recently been controlled by the Electricity Generating Authority Thailand (EGAT). EGAT is a wholly state-owned monopoly enterprise under the office of the Prime Minister. The National Energy Policy Council (NEPC) chaired by the Prime Minister, is the highest government council responsible for energy policy. The National Energy Policy Office (NEPO) acts as the secretariat to the NEPC.

The electricity supply sector in Thailand is mainly composed of three government-owned utilities, the Electricity Generating Authority of Thailand (EGAT), the Municipal Electricity Authority (MEA), and the Provincial Electricity Authority (PEA) both are under the Ministry of the Interior. EGAT is responsible for the country's electricity generation and transmission and sells electricity through the two major distribution companies, MEA and PEA. EGAT also sells power directly to a few large customers and neighbouring countries, such as Laos and Malaysia (Peninsular). EGAT's controls about 87 percent of the country's electricity generating capacity, with the reminder generated by IPPs.

In March 1992, the EGAT Act ended EGAT's monopolistic position in generation. The Government approved a plan to permit majority equity participation. It allowed private companies to produce and sell electricity, in an effort to encourage private participation through either the Small Power Producer (SPP) program or Independent Power Producer (IPP) program. The law allows a single SPP to sell up to 90 MW of capacity to EGAT under either a form contract - with duration of more than five years and allowing capacity payments. Non-form contracts are offered for less than five years and do not allow capacity payments. Electricity tariffs are under the control of the NEPC and the cabinet. The tariff rate for electricity sold by SPPs is to be determined by market forces. They can also sell electricity directly to industrial customers.

IPPs sell electricity to EGAT pursuant to a PPA. The objectives of the Thai Government's priorities in privatising the country's electricity generation business are to introduce competition in order to encourage efficiency, and to reduce the government's massive financing burden for infrastructure development.

Area	514,000 sq km	Installed Electricity Capacity	18,174MW
Population ('98)	61 million	Gross Generation	93,253GWh
GDP ('97)	US$525 billion	Population Electrified	82%
GDP per capita ('97)	US$8,600	Generation mix	
		Thermal Hydro	84.2% 15.8%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998. The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).

USA

For details see case study on page 133.

Area	9,159,000 sq km	Installed Electricity Capacity	775,861MW
Population	274.1 million	Gross Generation	3,526,756GWh
GDP	US$7,834 billion	Population Electrified	100%
GDP per capita	US$28,580	Generation mix	
		Thermal	71%
		Hydro	10%
		Nuclear	18%
		Geothermal	0.5%
		Other	0.3%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
World Development Indicator, 1999

VIET NAM

The central government owns and controls the electricity sector in Viet Nam. The control and regulation of the sector is the responsibility of the Ministry of Industry (MoIN). The state-run Electricity Corporation of Viet Nam (EVN) is responsible for all industry development and regulation. EVN holds a monopoly on generation, transmission and distribution of power. The principal activities of EVN are to produce, transmit and supply electricity, to design and construct projects, to make electrical equipment and to render related services for all customers.

Area	329,560 sq km	Installed Electricity Capacity ('99)	5,559MW
Population ('98)	76.24 million	Gross Generation ('98)	21,654GWh
GDP ('97)	US$128 billion	Population Electrified	71%
GDP per capita ('97)	US$1,700	Generation mix ('98)	
		Thermal	22%
		Hydro	51%
		Other	27%

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998.
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Gold book).
Institute of Energy, Viet Nam 1999.

APPENDIX II

THE IMPORTANCE OF IPPS

Developing economies began opening their power sectors to investment by Independent Power Producers (IPPs) around a decade ago, and now IPPs are a well-established feature of the energy scene in the APEC region. The boom period was 1992-1996. East Asia and Southeast Asia have the lion's share of IPP investment, with 103 contracts worth US$54 billion. (Albouy & Bousba, 1998).

The IPP business is principally concentrated in China, Indonesia, the Philippines, Malaysia and Thailand. All these economies have experienced rapid economic growth over the last decade, and demand for electricity has grown strongly along with it. Local state-owned utilities are usually minority shareholders in IPP projects in Malaysia, and majority venture partners in a score of Chinese projects. IPPs generally sell to single state-owned buyers through a power purchase agreement (PPA).

The opening of the market to IPPs has raised a number of questions. Analysis by the World Bank Group shows that IPPs have allowed the transfer of a significant share of project risks to the private sector. IPPs have accepted construction and operating risks, and they share fuel availability risks for 52 percent of the IPP market – by signing third-party agreements for 31 percent and by enlisting the fuel supplier as an equity holder for 21 percent. Most IPPs have made compensation for fuel price variations over time, and recovery of their fixed cost is protected against market risks by take-or-pay contracts or capacity charges. Except in Malaysia, denominating prices in, or indexing them to, hard currencies covers currency risks. Many IPPs are also protected against political risks – including regulatory ones – often by explicit government guarantees. The risks are passed on to the off-taker, but for 20 percent of the market the off-taker also owns the IPP.

External debt finance and fuel imports can have a significant impact on foreign exchange exposure. Mostly, a few global developers hold equity. IPPs rely overwhelmingly on fossil fuels, which typically accounts for 50 to 70 percent of total operating costs. In general, the sector's exposure to foreign exchange risk has stayed the same or increased with the introduction of investment by IPPs.

Sudden blackouts (as in the Philippines and Malaysia) put an additional financial burden on developing economies. Without IPP investment, state-owned utilities would have been able to finance and build significantly less capacity, and valuable demand would have remained un-satisfied. In such cases, investment by IPPs leads to short-term benefits.

However, there are cases where IPP investment has not had the anticipated effect of improving security of supply, and in addition has inflated reserve margins. In Indonesia and Malaysia IPPs brought fuel savings of US$10 to US$20 per MWh - too low to have justified the investment. In addition, IPP investment did not displace expensive existing generation.

Analysis by the World Bank Group on IPP capacity costs shows they vary widely, even for similar technologies. For example, the average price of installing gas turbines in China is 40 percent less than in Indonesia. Moreover, IPPs' capacity costs are sometimes higher than those achieved by state-owned utilities with World Bank financing. In addition, PPAs often include take-or-pay quotas – a costly straightjacket when demand for plant output is weak. Those economies that were badly affected by the crisis are now facing difficulties to finding financial support for power development projects. As a result, power development plans, especially for new power plants have been revised or deferred indefinitely.

APPENDIX III

THE 1997 FINANCIAL CRISIS - IMPACT ON SELECTED ECONOMIES

The Asian financial crisis casts a dark shadow over the power sector. Currency devaluations have caused power costs to rise dramatically because of their high foreign exchange content. The crisis also restricts access to foreign funds and threatens to dry up capital markets. While prescriptions for the future vary for each economy, the common prescription must be an improved climate for private generation by strengthening sector cost recovery, developing local capital markets, and optimising the capital structure of the sector.

Below, we examine electricity sector restructuring experiences for some APEC economies. These economies have been chosen because most anticipate that the private sector will play a significant role in generation development in the future.

INDONESIA

The currency crisis that crippled the Indonesian economy caused severe problems for the energy sector. Facing a decline in the value of the Rupiah, the Indonesian government has been forced to limit the fiscal impact of energy subsidies. As a result, eight power projects have been either cancelled or delayed.

In response to pressures from the International Monetary Fund (IMF), the government of Indonesia has agreed to eliminate electricity subsidies. This move would lead to a fundamental change in the energy industry if Indonesia follows through on its commitment to the Fund.

The state-owned company “Perusahaan Listrik Negara” (PLN) currently purchases approximately 80 percent of the power produced by IPPs at prices more than twice that charged to domestic consumers. The government has also announced plans to delay construction of eight power plants. These projects had initially been postponed at the time of the government’s September agreement with the IMF, but had been reinstated by presidential decree in November. In January, following the firestorm surrounding the release of the poorly received 1998/99 budget; the projects were postponed once again. Rating agencies have also concluded that debt on three Indonesian IPP projects should be written off – highlighting the difficulties that developers will face in financing power projects in Southeast Asia in the years to come. Lower debt ratings will translate into higher costs for capital and thus higher power prices.

Table 43 Indonesian power projects on hold

Project	Technology	Location	Capacity (MW)	Status
Karaha	Geothermal	Java	220	Postponed
Sarula	Geothermal	North Sumatra	300	Postponed
Darajat 1,2	Geothermal	West Java	270	Postponed
Palembang Timur	Combined cycle	South Sumatra	130	Postponed
Patuha	Geothermal	West Java	80	Reviewed
Asahan 1	Hydro	North Sumatra	60	Reviewed
Tanjung Jati A	Coal	Central Java	1320	Reviewed
Tanjung Jati C	Coal	Central Java	1320	Reviewed

Source: Perusahaan Listrik Negara (PLN), Ministry of Mines and Energy, Indonesia.

The government's failure to publicly restate its support for PLN and for the off take agreements of IPP projects heightens foreign investor worries concerning the future of the Indonesian power industry. Under existing Power Purchase Agreements (PPAs), PLN has assumed substantial convertibility risk by agreeing to pay IPPs in dollars if the companies are unable to secure dollars through foreign exchange contracts within Indonesia. The projects affected are all under construction or operating. The PLN is caught between a US dollar commitment to IPPs in the range of 5 to 8 cents per kWh and Rupiah denominated prices to local consumers of less than 2 cents per kWh (using an exchange rate of 10,000 Rupiah to one dollar).

Further, coal-powered IPP projects, such as the Paiton project in East Java, purchase coal supplies denominated in US dollars, whereas PLN purchases coal for its own plants from domestic mines under medium-term Rupiah-denominated contracts. This has led to a wide differential, in Rupiah terms, between the fuel costs faced by IPPs and those faced by PLN-owned power plants.

This creates a disincentive for PLN to purchase power under previous agreements that called for up to 80 percent off-take from IPPs. Intense pressure on PLN's profits and on Indonesia's balance of trade creates a huge incentive for PLN to reduce its off-take of power from IPPs regardless of the terms of the PPAs.

Both the IMF and the World Bank have expressed extreme concern over the financial strength of PLN and the potential for a substantial oversupply of power. PLN forecasts losses approaching US$1 billion in 1998, attributable to low end-use electricity tariffs. PLN is also highly leveraged – in early December; the company estimated its total domestic and external debt position at approximately US$9 billion. Given the rapid decline in the Rupiah since then, PLN's debt position has undoubtedly worsened significantly.

KOREA

Challenges faced by Korea include a credit crunch, financing resolution cost, and unemployment eroded market confidence. Debt financing for KEPCO's enormous capital expenditure program is becoming more expensive and more difficult. This has changed the climate for IPP investment, with private capital now reluctant to assume risks associated with regulation uncertainty, currency fluctuations, contract default and capacity utilisation rates. This can be seen in the delays in anticipated completion dates for power plants under construction. The delayed construction plans are summarised in Table 44. According to the 1995 plan, 60 plants were under construction. The completion dates for 42 of the 60 power plants were delayed more than 3 months. The delayed capacity is around 17,435 MW; with an average 15 months delay period. A total of 6 nuclear power plants (5,700 MW) have been delayed by an average of 9.2 months. Eleven coal-fired plants have been delayed by an average of 10.5 months.

Table 44 Delayed construction plans for Korean power plants

	1995 plan	1998 plan	
	Capacity (MW)	Capacity (MW)	Total Month
Nuclear	7,400	5,700	55
Oil	151	150	15
Domestic Coal	400	400	6
Imported Coal	8,100	6,100	155
LNG	4,970	3,474	143
Pumped	2,300	1,700	112
Hydro	81	61	159
Total	23,402	17,435	645

Sources: Electricity Policy Research Division, Korea Energy Economic Institute (KEEI).

MALAYSIA

The impact of the crisis has resulted in a substantial reduction in energy demand. As of October 1998, 48 percent of total installed power capacity is surplus to current requirements. The situation has arisen from the closure of a number of factories and reduction in operations by other energy intensive industries.

Another impact is the rescheduling and deferment of several 'non-critical' major projects. For example, The Bakun Hydro Electric project, which was expected to increase the generation capacity of the economy by 2400 MW in 2003, was shelved at the end of 1997 due to the financial crisis.

Although the current crisis has severely curtailed demand in the short-term, Malaysian energy demand is expected to grow again after the year 2000. For example, peak demand for electricity is expected to grow from 8,471 MW in 1998 to 14,095 MW in 2007.

It is believed that the current installed capacity will not be enough to cater for the needs of the economy after the year 2000. Therefore, the government has taken several actions to reduce bottlenecks that may prevent rapid economic recovery.

Effort has been made to improve the efficiency and productivity of utilities, and it is planned to implement a power pooling system after the year 2000. The government has also adopted expansionary macroeconomic measures and eased monetary policy so that the economic crisis will have a lessened impact on economic activities including energy sector.

However, it is quite interesting that the severe economic crisis has had no impact on existing IPPs. This is due to the fact that the present PPAs will not be renegotiated and all IPP debt financing thus far has been raised locally, amounting to over RM8 billion. Five funding options have been developed: debt markets; equity markets; private debt security markets; cross border lease markets; and future financing in the form of 'merchant' power plants.

THE PHILIPPINES

The financial crisis has not spared the Philippine electricity sector. The projected growth in Gross Domestic Product (GDP) of 1.0 percent growth in 1998 (from 5.3 percent the previous year) has resulted in a lower electricity demand, and deferment in projected power generation investment.

Table 45 Deferred Philippine power development programmes (1998)

No.	Plant	Capacity	Fuel	Target Commercial Operation
(1)	Casecnan	140	Hydro	Deferred (1999-2000)
(2)	Villasiga	32	Hydro	Deferred (2003-2004)
(3)	Mindanao	200	Coal	Deferred (2002-2004)
(4)	Bulanog-Batang	132	Hydro	Deferred (2004-2005)
(5)	Leyte-Bohol Interconnection			Deferred (1999-2000)
(6)	Leyte-Cebu T/L Uprating			Deferred (2001-2002)

Notes: 3,019 MW total power plant capacity for retirement between 1998-2010; some of these power plants may be put back on stream in the event of sudden power supply/capacity shortfall.

Source: Department of Energy (DOE), Philippines.

These projects are financed either under a Build-Operate-Transfer (BOT) arrangement or handled by IPPs. It is now expected that a total of 574 MW of capacity will be delayed. This includes the deferment of an interconnection project and a transmission line-upgrading project. Meanwhile, a total of 3,019 MW of power plant capacity (largely oil-based) is being considered for retirement between 1998 and 2010. However, some of these power plants may have to be kept operational, in the event of a sudden power capacity shortfall.

THAILAND

The economic crisis has greatly affected the shareholder structure in IPP and Small Power Producer (SPP) projects by forcing them to seek new partners. However, international energy companies have shown some reluctance to participate in these projects. The economic problems have caused delays in obtaining financing and as a result some IPPs may seek to delay the completion schedules of some projects.

After the Baht currency depreciation in July 1997 the government amended the terms and conditions for IPPs and SPPs, particularly by indexing a part of the payments to the exchange rate in order to cushion the impact of the economic crisis.

As a result of the economic slowdown and diminished power demand growth, EGAT has decided to reduce substantially its generation capacity growth plans and to reduce imports of electricity. Purchases from independent and small power producers, as well as electricity imports on Laos have been cut back, as well as generation from EGAT's own plants.

Table 46 EGAT power development plan – pre and post crisis

Fiscal year	Pre-crisis plan PDP 97-01		Post-crisis Plan PDP 99-01		Difference			
	MW	GWh	MW	GWh	MW	%	GWh	%
1998	19,459	108,234	18,444		-1,015	5.21	-108,234	-100.00
1999	23,104	118,797	14,499	93,178	-8,605	37	-25,619	-21.57
2000	25,979	129,601	15,254	97,858	-10,725	41	-31,743	-24.49
2001	29,202	141,598	16,214	103,685	-12,988	44	-37,913	-26.78
2002	30.660	153,141	17,308	110,436	-13,352	44	-42,705	-27.51
2003	33,501	165,460	18,399	117,341	-15,102	45	-48,119	-28.80
2004	34,901	179,206	19,611	124,532	-15,290	44	-54,674	-31.00
2005	36,551	193,097	20,818	132,228	-15,733	43	-60,869	-32.00
2006	39,241	206,566	22,168	143,300	-17,073	44	-65,266	-32.00
2007	41,560	221,170	23,728	153,322	-17,832	43	-69,848	-32.00
2008	44,370	236,964	25,450	162,438	-18,920	43	-74,526	-31.00
2009	46,982	251,909	27,232	173,532	-19,750	42	-78,377	-31.00
2010	50,282	267,557	28,912	184,213	-21,370	43	-83,344	-31.00
2011	52,907	283,858	30,587	194,930	-22,320	42	-88,928	-31.00

Source: Electricity Generating Authority of Thailand. (EGAT), Thailand Load Forecast Sub-Committee, September 1998.

APPENDIX IV

WHAT IS TRANSACTION COST ECONOMICS?

Transactions are the actions, such as searching, coordination and monitoring, undertaken by people or firms when exchanging goods, services and ideas. Transaction costs are the costs accruing from transactions: negotiation, monitoring, enforcing contracts, or the cost resulted from contract failure (Joskow & Schmanlensee, 1983).

In order to provide a criterion for evaluating organisational structure[51] or to give a concrete rational ground for an efficient organisational structure, it is important to understand the following basic concepts associated with transactions; (1) the characteristics of transactions, (2) the human behaviours which effect transactions.

CHARACTERISTICS OF TRANSACTIONS

Williamson (1997) identifies three characteristics of transactions which are important with respect to transaction costs: (1) **idiosyncrasy,** (2) **frequency**, and (3) **uncertainty and complexity**.

(1) Idiosyncrasy

Idiosyncrasy can be explained as "transaction-specific investments", meaning they are only valuable with respect to the specific relationship between a particular seller and buyer. The notion of "transaction-specific investments" is closely related to the concept of "sunk cost" in a sense that if a party investing in an asset leaves that particular activity or transaction, those costs cannot be recovered. The larger the transaction-specific investments with respect to the total costs of a particular set of related transactions, the greater their importance.

In terms of the electricity sector, electric utility assets such as power plants, power lines, transformers and other utility hardware are idiosyncratic in that they are generally made for only one purpose. Electric utility assets require a very large investment, and hence the level of idiosyncrasy is high.

(2) Frequency

In the context of transactions cost economics, "frequency" can be explained as the number of transactions for one purpose. Other things being equal, if the frequency of transactions is high, the relationship tends to be self-enforcing (Joskow and Schmanlensee). The frequency with which transactions are made can be subdivided into the two categories "occasional" and "recurrent" for convenience.

If both parties involved in a transaction act reasonably, there should be no great need to settle details in a complicated contract, but rather rely on trust, (usually reinforced through experience).

In the electricity sector, the frequency of transaction is high between generation and transmission, transmission and distribution, and distribution and final customers. In order to meet demand fluctuations, while ensuring security of supply, dispatching or retailing of electricity happens on a moment-by-moment basis. Therefore, transaction costs can potentially be high when the trading is between different firms, rather than within one vertically-integrated firm.

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51 The concept of a contract has a broad meaning. It can be a market, where no formal written contract is developed before a transaction takes place. Or it can be short-term or long-term, periodic or frequent.

(3) Uncertainty and complexity

When the uncertainty and complexity of transactions are high, the costs of negotiation, monitoring and enforcing contracts are of significance. Also, when there is a need to settle a contract between two parties, it is hard to incorporate all the contingencies that will take place in the future, especially if uncertainty is high and the transaction complex. Therefore, unless transactions are internalised into one firm, the transaction costs to settle such a contract will be high.

Electricity is unusual in a sense that the demand load changes constantly, and inventory cannot be stored as with most commodities. Also, electricity demand patterns are influenced by the weather, human behaviour, and industrial production levels on a day to day basis. To provide a secure and stable electricity supply that meets an uncertain demand pattern, a complex system of command and control is required.

To meet contingencies, a system of close coordination between power plants, networks and consumers must be maintained so outages are minimised. Because electrons cannot be stored like normal commodities, a certain amount of reserve generation capacity has to be created and maintained.

HUMAN BEHAVIOUR

To make a transaction, the involved parties (people or firms) undertake a contract. A strong incentive exists to minimise transactions costs, to keep overall costs down. If all contingencies were understood, the contracting process would be straightforward and unremarkable. However, in the real world, contracts cannot cover all possible future contingencies, partly because of “bounded rationality”. Economists argue that the ultimate aim of humans engaged in economic activity is the maximisation of economic welfare. Although this can be held as a valid argument, the inability of people to obtain all the information needed, or to plan for all possible contingencies (bounded rationality), leads to the importance of the concept of transaction costs.

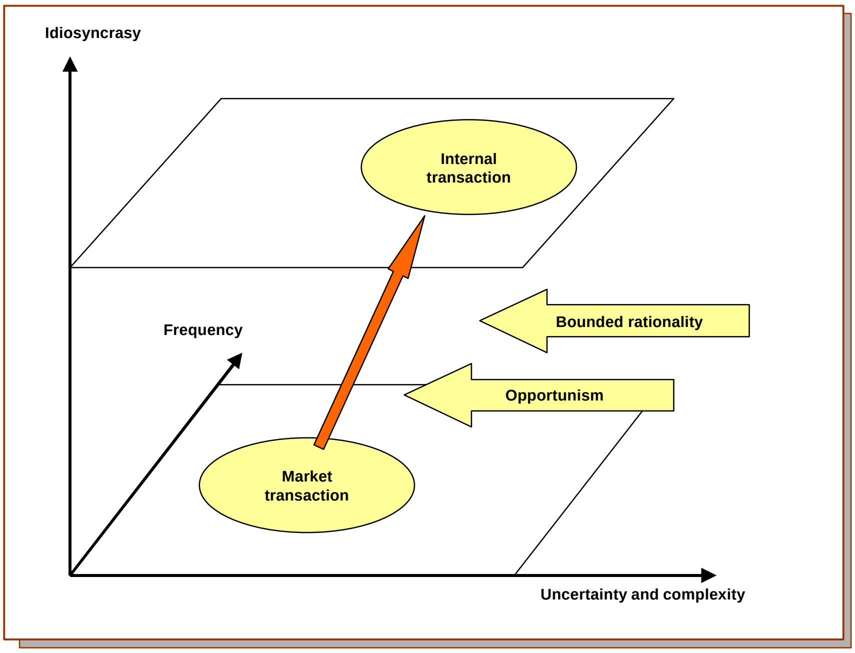
Because transactions involve two parties seeking their own self-interest, the opportunity also exists for economic agents to engage in opportunistic behaviour, in attempting to find any loopholes in negotiating contracts, or to behave within the terms of the contract in a way that maximises self-gain.

OPTIMAL ORGANISATIONAL STRUCTURE

Williamson’s argument is that the optimal form of transaction - ranging from a transient exchange in a spot market, to long-term exchanges through internal transactions within one organisation - is determined by the transaction costs incurred with respect to idiosyncrasy, frequency, uncertainty and complexity. Here, it is important to recognise that there is no simple division between market transactions at one extreme, and internal organisation at the other. Rather there is a continuum between them (Joskow & Schmanlensee, 1983).

As shown in Figure 45, transactions are efficiently executed in a transient market where uncertainty, complexity and idiosyncrasy are minimal. On the other hand, where there is much uncertainty, complexity and idiosyncrasy, transactions may be more efficiently conducted internally within one organisation. It is argued that internal transactions are one way to reduce risks associated with the contingencies resulting from human bounded rationality, and lowers the risks associated with opportunistic behaviour.

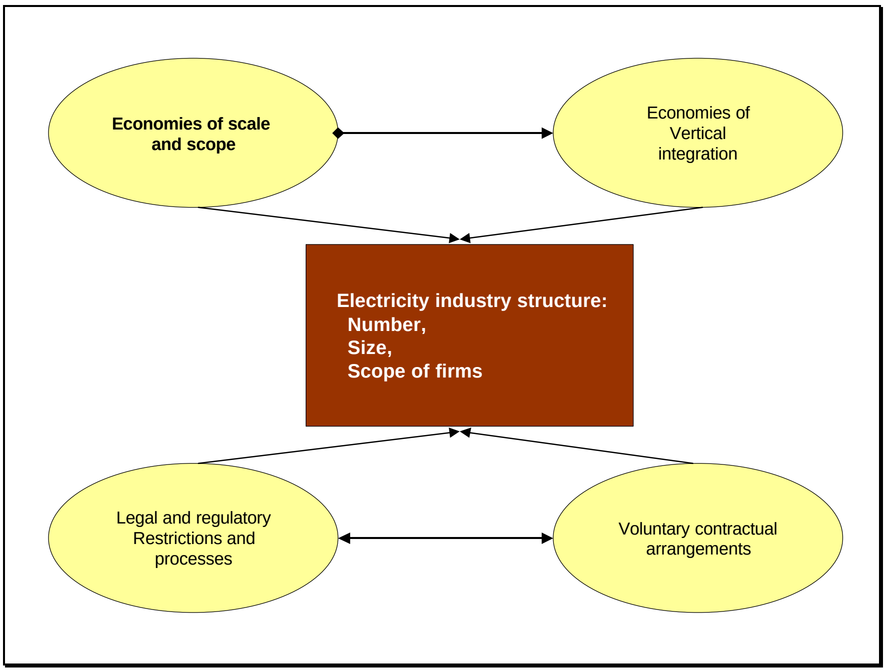
Figure 45 Optimal forms of organisational structure in relation to type of contracts involved



DETERMINANTS OF ELECTRIC INDUSTRY STRUCTURE

As Williamson argued, the ability to lower transactions costs is a primary reason firms are created. Regarding the electricity industry, four factors are considered the determinants of industry structure.

Figure 46 The determinants of electricity industry structure



Source: Kahn, (1988) "The economics of Regulation", MIT Press

Taking everything into consideration, it is understandable that a vertically-integrated electricity industry has traditionally been considered to be the most efficient system of operation. It is argued that internalisation of transaction costs by integrating generation, transmission and distribution into one organisation creates significant savings in transaction costs, while ensuring that requirements such as reliability, stability, and contingency planning are met. The reason for vertical integration is that for meeting the requirement, the high degree of interdependence in power systems can result in information overload.

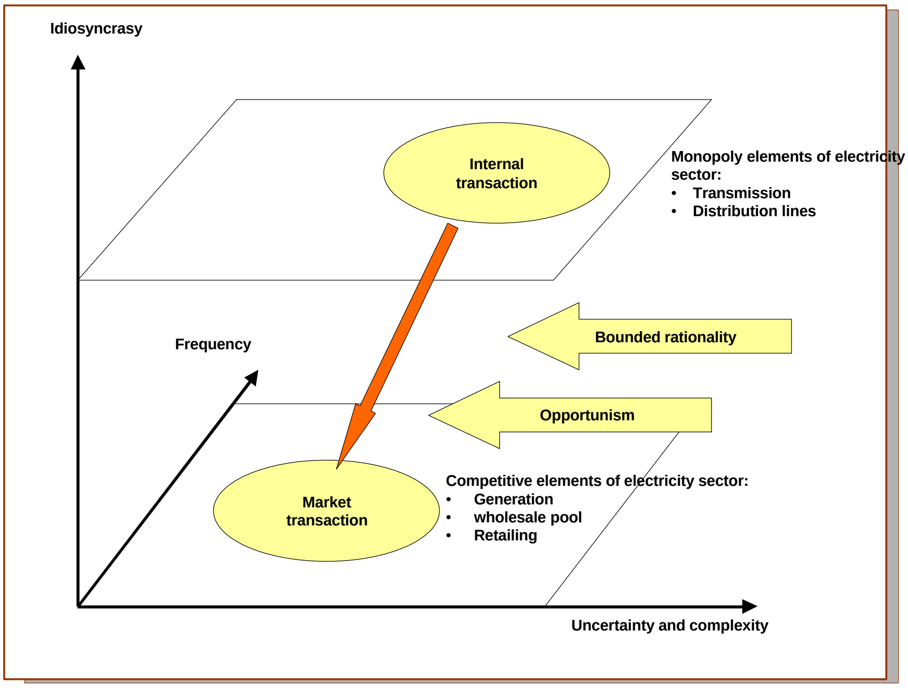
Table 47 The electricity industry from a transactions cost perspective

	Generation, transmission, distribution
Idiosyncrasy	High sunk cost, profound asset specificity, economies of scale and density, site specific economic dependencies
Frequency & duration	Infrequency of orders
Uncertainty	Contingencies, future demand (related to investment), market evolvement (under regulation), construction and operation (related to investment)
Complexity	Stable supply, capacity mix

Electricity sector reform usually leads to vertical and horizontal desegregation of the previous monopoly structure. This goes against economic (transaction cost) theory, which suggests that increased transactions costs would result from the separation processes involved and lead to decreased economic efficiency overall.

The reason electricity sector reform may not lead to increased transaction costs lies in a re-evaluation of Figure 45, as shown below in Figure 47. The argument is that substantial areas of natural competitiveness exist within the sector, and these can be exploited to best advantage by separating these elements from the monopoly elements. Advocates of electricity reform argue that restructuring and deregulation lead to significant cost reductions, and the empirical evidence available has backed this up to date (discussed elsewhere in the report).

Figure 47 The electricity sector from a transactions cost perspective



APPENDIX V

ELECTRICITY SYSTEM RELIABILITY

[This discussion is based on standard practice in the United States of America]

System regulators define and enforce reliability standards to ensure that a continuous supply/demand balance is maintained and that transmission systems are operated within security limits.

The whole electric power network is divided into "control areas" to keep the regional electric power system in momentary balance. Each area has an energy control centre (ECC) monitoring the regional system. Most of the generators, power lines, transformers and other parts of the system are under permanent control by the ECC, which is maintaining the electrical balance and restoring it in the case of emergencies. All the neighbouring ECCs co-ordinate their operations.

Control centres provide the technical services of Automatic Load-Frequency Control (ALFC) and Automatic Voltage Regulation (AVR).

POWER OUTAGES

Distribution outages are usually isolated physical disconnections of a small part of the system, due to a disruptive event or to failure of a nearby transformer. Bulk power outages can be caused by failures in large plants or transmission networks, and affect more customers. Distribution failures are a much more common occurrence than a major bulk outage. In the US in the 1970's there were about 60 bulk power system outages per year, with loss of power to an average of 110,000 consumers. Over the same period, 81,000 distribution outages per utility occurred, affecting 156 customers per outage on average.

Distribution outages are mainly treated as an individual-utility issue. This kind of reliability could be better improved by measures within the control of a local utility.

RELIABILITY MEASURES

Based on operational practice, several quantitative measures of reliability can be defined (Table 48). These measures describe past levels of system reliability. There are also normative indicators for system design.

Table 48 Measures for reporting electricity outages

Measure and Definition	Comment
1. Customers Losing Service	Most commonly reported statistics in press
2. Capacity of Load Lost (Shed, Disconnected, Interrupted)	Capacity of Load shed
3. Duration of Outage	Refers to period from beginning of outage to complete restoration of service to all customers
4. "Customer Minutes": number of customers losing service times average duration of outage	Measure of severity
5. "Load-Minutes": number of MW of load disconnected times average length of time each MW was out off system	Measure of severity

Source: Peter Fox-Penner, 1998.

RELIABILITY COUNCILS

Both government regulation of reliability and voluntary cooperation among the power market participants control the operation of regional reliability councils, of which all utilities that own generation or transmission are members. These councils each perform studies of their systems, engineer them to prevent large outages, and put in place voluntary standards for system design and operation decreasing the chance of major outages. Such standards allow system controllers to preserve bulk power reliability.

For example, the North American Electric Reliability Council coordinates the operation of the regional councils. Short-term reliability can be achieved by voluntary agreements that meet regional reliability council standards.

TRANSMISSION SYSTEM ROLE

Coordinated transmission planning, operation and interconnection makes it possible to meet any particular level of system reliability with less generating capacity. Interconnection makes it less costly to achieve a given level of bulk power reliability than operating independently. Interconnection enhances system reliability – benefits from maintaining a suitable reliability level with less generation reserves and from improved reliability through coordinated transmission planning. It generates savings in operating reserve, both spinning and non-spinning, resulting from sharing the reserve required to cover contingencies.

POOLS AND RELIABILITY

Power pooling could be an effective form of providing for a sufficient reliability level at a least cost. Power pools are partnerships among electric utility companies, formed to realise cost savings through mutual cooperation, usually the pool-wide cost of generation is decreased.

System controllers have to check the pool's dispatch practice on the matter of vulnerability to a large failure in the total control area. In deregulated markets, efficient contractual pooling could decrease the cost of spinning reserves, designed to operate in emergency cases.

APPENDIX VI

THE ENVIRONMENTAL IMPACTS OF EACH FUEL CHOICE

Coal: Of all the fossil fuels, coal contains the highest percentage of carbon on a weight for weight basis, as well as in terms of energy produced upon combustion. Coal releases 20 percent more carbon per unit of energy than oil, and 40 percent more than natural gas (ignoring fugitive emissions). (Worldwatch News Release, 1999)

Apart from the high carbon content (which results in high CO_2 emissions when coal is burned), coal often contains high levels of sulphur and nitrogen, leading to significant SO_X and NO_X emissions upon combustion. In addition, burning of coal leads to emissions of significant quantities of fine particulates and other pollutants.

In the US alone, it has been estimated that electricity generation results in 70 percent of the sulphur dioxide, 30 percent of the oxides of nitrogen, and 40 percent of the fine particulates emitted as the result of energy use. (Bernow et al, 1998) Coal burning also contributes to the release of myriad toxins, which are hazardous to health. It has been estimated that particulate and sulphur dioxide pollution from coal smoke causes 500,000 premature deaths and millions of new respiratory illnesses each year in urban areas worldwide. Several cities, including Beijing and New Delhi, are near the pollution levels that London experienced during its famous smog that took 4,000 lives in 1952. (Worldwatch Institute, 1999). With current technology, coal generation has a conversion efficiency of approximately 33 percent, and an emission rate close to 1.0 tonne of CO_2 per MWh. (Bernow et al, 1998). New generation coal burning technologies are becoming available with thermal efficiencies as high as 42 percent.

Oil: Oil is intermediate between coal and gas with respect to carbon content. Oil power generation leads to significant sulphur and carbon emissions, but this is mitigated by the fact that oil fired plants, where still used, tend to be used mostly for peak load or stand-by generation. During the 1980s, a large number of oil-fired plants were converted to gas or decommissioned, due to the high fuel cost at that time.

Gas: Natural gas as a fuel for electricity generation is experiencing substantial growth, driven on the one hand by an abundant supply, and on the other by technological innovation in transportation and handling technologies and turbine design. The Asia Pacific region has been at the centre of this development. A number of economies (Australia, Indonesia) are major suppliers of natural gas, either delivered to local customers through pipelines or exported as LNG. Other economies are becoming major users, with strong projected growth in demand for gas to fuel power stations and supply reticulated demand to consumers.

First generation, single cycle power plants were relatively inefficient, operating at around 30 percent efficiency of conversion of fuel to electricity. Natural gas combined cycle (NGCC) plants are currently able to operate at around 45-50 percent efficiency, and could reach around 60 percent with further refinements. A NGCC plant emits around 0.27 tonnes of CO_2 per MWh, or about one-quarter that of a current generation coal plant (Bernow et al, 1998). Gas fired power stations emit negligible amounts of sulphur oxides, and no ash, but can emit significant amounts of NO_x (new turbines have low NO_x emissions).

Nuclear: Of all energy sources, this is the most controversial and hotly debated. With the advent of the political debate over climate change, supporters of nuclear power point to the absence of CO_2 emissions, and the relatively good safety record of plants of modern design operated according to internationally accepted safety standards.

The environmental impacts of nuclear power can be divided into two broad categories. The first would be the impacts resulting from mining, transportation, and the operation of nuclear plant. The second, and the one that evokes images of disaster in the public mind, is the possibility of a major mishap, such as a meltdown, or a major release of radiation to the environment. Despite the fact that for a well maintained, modern plant, the day-to-day environmental impacts of operation are relatively modest, and the likelihood of a major disaster remote, the fact that such accidents have happened (Three Mile Island, Chernobyl) are sufficient to make many people strongly opposed to nuclear power.

Apart from the day-to-day operation of power plants, the life cycle of nuclear fuels must be taken into consideration. Firstly, mining uranium has significant impacts on the environment. Of more importance to those who oppose the nuclear option, is the fate of spent fuel after it has been extracted from the reactor core. High-level waste is of major concern (although volumes are relatively small), but so is the substantial volume of low-level waste produced.

From a technical point of view, it is not prudent to place highly radioactive waste in a final repository during the initial period of extremely rapid radioactive decay (around 40 years), so to-date no high level waste has been permanently stored anywhere in the world. This has reinforced a growing public opposition to nuclear power, with stories of waste leakage from temporary on-site storage facilities, and growing resistance to the creation of final repositories because of fears of leakage to underground reservoirs.

Hydro: Hydropower evokes images of glistening waters in remote locations spilling through huge penstocks to generate low cost, environmentally clean electricity. In some Asia Pacific economies, particularly Canada, New Zealand and the United States, hydropower has been a traditionally favoured option in suitable localities. Today, hydro generation comprises 67 percent of total New Zealand capacity, around 60 percent of Canadian capacity, and around 10 percent of US capacity.

To imagine that hydropower is devoid of environmental impacts is to ignore the reality. Hydropower has significant impacts, including: loss of fertile silt to downstream flood plains, loss or diminution of fish habitats (especially access to spawning grounds); and loss of amenity (wild habitat) values. In the more heavily populated parts of Asia, the construction of new, large scale hydro projects has also led to major relocations of communities affected by the rising waters.

Another impact not widely understood is the fact that hydro lakes can emit substantial quantities of greenhouse emissions over their lifetime. Recent research (Pearce, 1996) in both Brazil and Canada demonstrate that, regardless of climate, hydro lakes can emit large quantities of CO_2 and CH_4. In the worst case studied, it is estimated that to date the Balbina reservoir on the River Uatumoã, a tributary of the Amazon, has had about 16 times as potent a greenhouse impact as an equivalent fossil-fuelled power station.

Even in less extreme situations (where the average depth of the reservoir is much greater, the area inundated correspondingly less, and large areas of vegetation are not inundated), greenhouse emissions can still be significant. For example, in Canada it has been found that the two main habitats flooded are sites of intense microbial decomposition and greenhouse gas production when they become inundated. Although opinions differ regarding emission levels from an average reservoir, and the calculation used to determine greenhouse impact, there is general agreement amongst experts that hydro reservoirs could prove to be a significant part of many nations' outputs of greenhouse gases.

Geothermal: Geothermal energy is considered renewable, and is commonly thought of as a relatively clean source of energy. Geothermal energy, relative to fossil fuel derived energy, is non-polluting, provided that the hydrothermal fluid is re-injected back into the thermal reservoir. If discharged to local waterways, significant negative impacts occur, more so if the fluids are still hot. Geothermal fluid typically contains substantial quantities of soluble salts, as well as concentrations of environmentally harmful chemicals such as heavy metals and other mineral elements.

In the Philippines in the early 1980s, rice crops downstream of geothermal exploration developments were severely impacted by the fluids discharged to local streams. The responsible element was identified as boron, which is toxic to rice plants even at low concentrations.

Geothermal steam also contains small amounts of CO_2 and H_2S. While sulphur emissions are relatively minor and non-harmful, CO_2 concentrations can average up to 5 percent of fluid volume for some fields. Given the modest amount of power generated by geothermal, and the relatively small amounts of CO_2 involved, the impacts are not substantial.

Biomass: Biomass is a renewable resource, so if burned will result in no net increase in carbon dioxide emissions to the atmosphere. Where peat or wet wood is burned for heating or cooking, or to generate electricity, biomass suffers similar environmental disadvantages to fossil fuels, unless care is taken to eliminate SO_x, NO_x and particulate emissions. Peat accumulates so slowly that it is a non-renewable fuel when burned in significant quantities, resulting in net CO_2 increases in the atmosphere.

On a global basis, biomass is a major source of energy, mainly in the developing world. The major negative environmental impact resulting from the use of biomass for energy is the extensive denudation of land resulting from the unsustainable harvest of biomass, mostly in the form of wood, in the desperately poor, densely populated areas of the world.

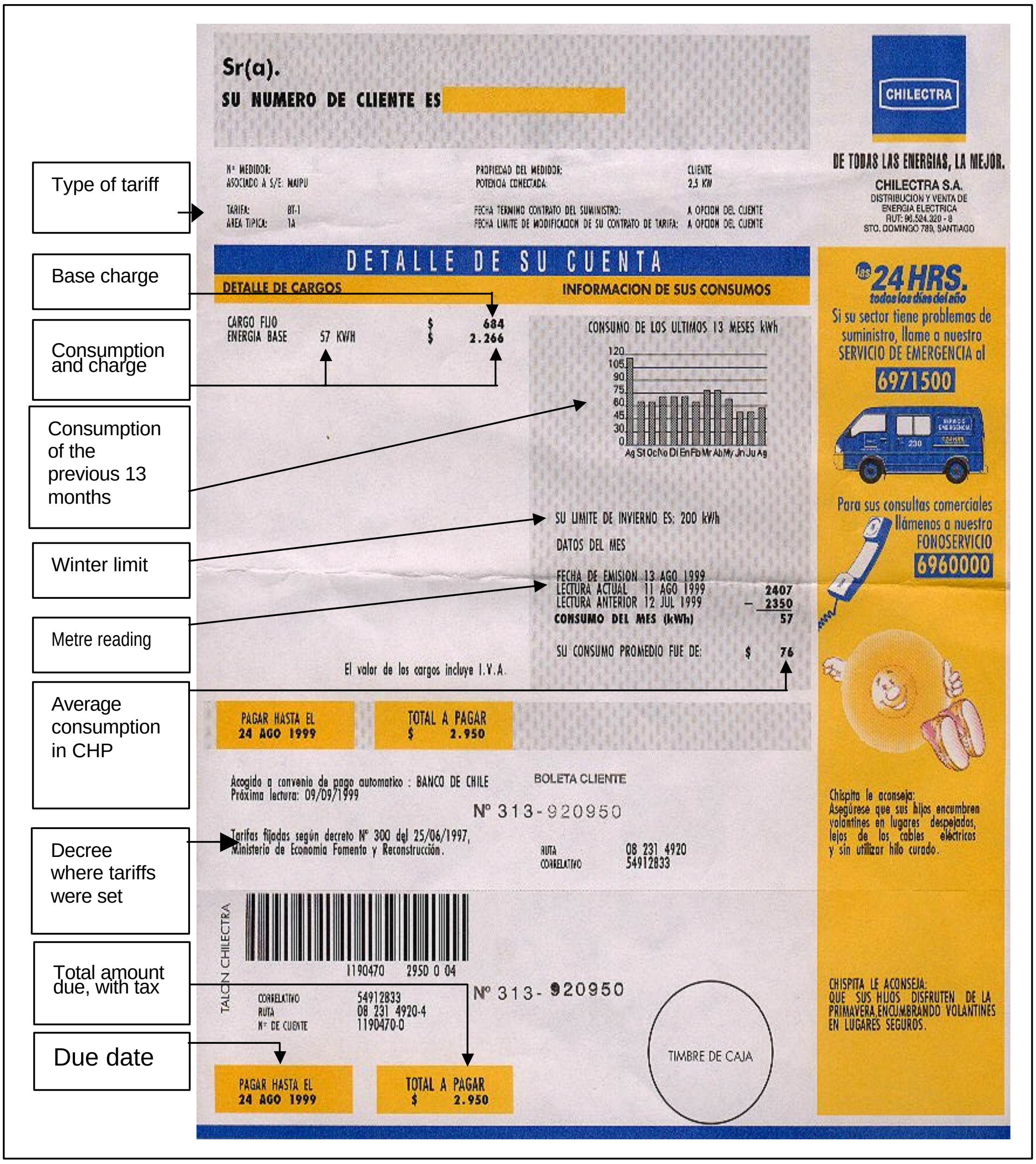
Wind: Apart from the visual pollution and noise issues raised by some objectors to this technology, the only real hazard identified is that to certain types of migratory birds. This appears to be a significant issue in the US, but not in other areas in the Asia Pacific where wind turbines have been installed.

Solar: Direct solar thermal power generation technologies, passive solar heating technologies, and solar photovoltaics would appear to be almost entirely environmentally benign. Currently commercialised solar cells are comprised of silica, a non-toxic compound, and the most abundant mineral in the crust of the earth. The impacts of the production of solar cells are not negligible however, and were solar powered cars to become commonplace, the disposal of old batteries could become a significant environmental issue needing to be dealt with, as batteries tend to contain very toxic materials.

APPENDIX VII

URBAN ELECTRICITY BILLS OF SELECTED ECONOMIES

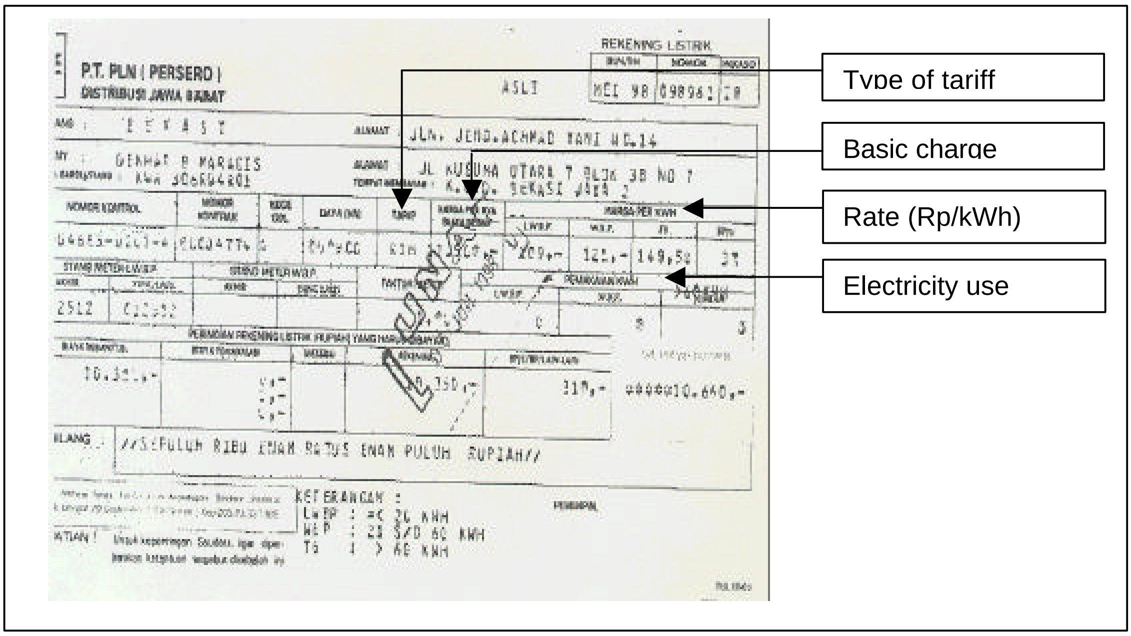
CHILE



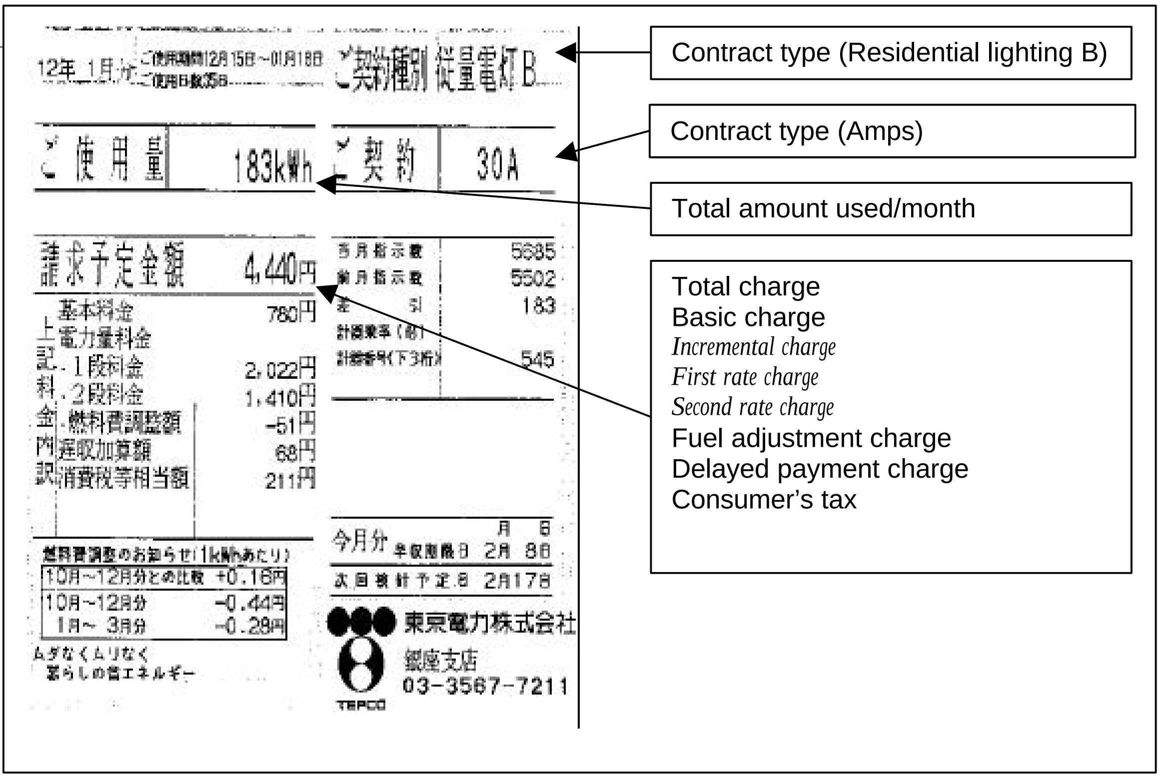
The electricity bill shows the fixed base charge and the charge for consumed electricity for a period of one month, inclusive of a value-added tax. The calculation of the tariff covers the operational costs of efficient model companies operating in typical electrical distribution zones. This calculation is the responsibility of the National Energy Commission, enacted by the decree of the Ministry of Economy, which is referred to in the bill.

It is interesting to notice that the bill also includes consumption of the previous thirteen months, which is intended to show the average monthly consumption and whether a customer exceeds the winter limit, which entails a higher charge.

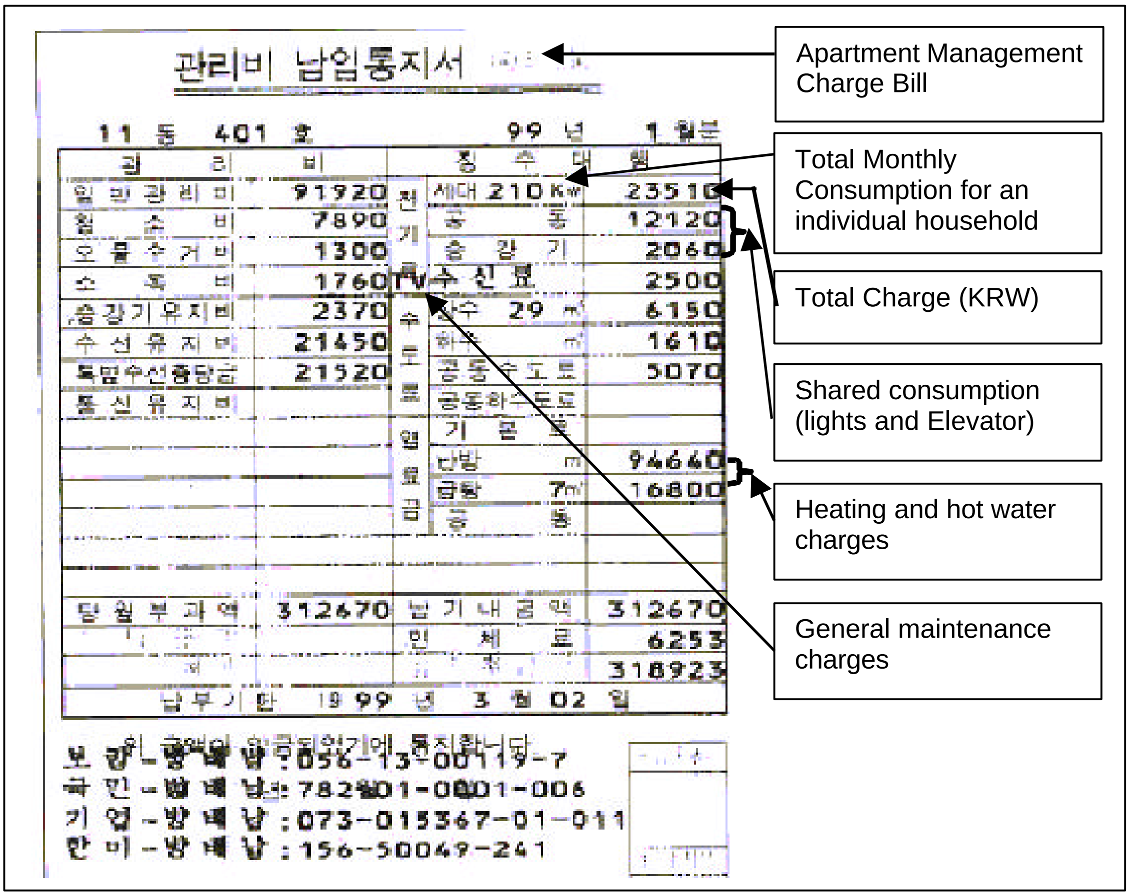
INDONESIA



JAPAN



REPUBLIC OF KOREA



Indonesia

The electricity tariff is determined based on the projected production cost by the state electricity company and subject to the government approval according to the state law. The government then determines the size of subsidy to certain types of consumer, though the electricity bill does not show the calculation. It only shows the electricity used for the past month according to its breakdown of levels of use, their progressive charge and the total charge.

Japan

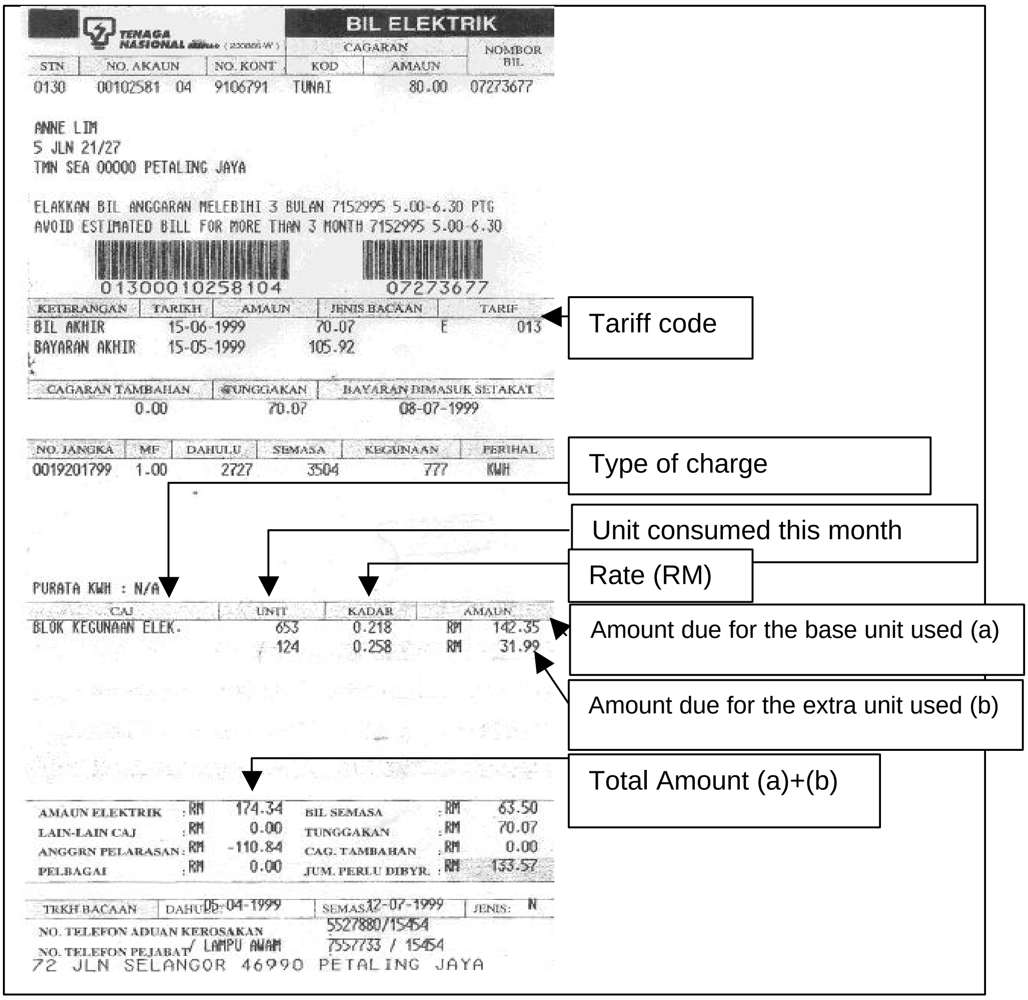
Basic charge, electricity consumption of the previous month, total charge (incremental), fuel adjustment charge, and consumer's tax are displayed in the bill. The calculation of the total charge is simply the addition of the basic tariff to the total charge and fuel adjustment charge.

Republic of Korea

The bill shown is the apartment management charge bill for residential customers, which collects into one all utilities charge, such as cable television, water and gas. The electricity part does not have any detail calculation of composition of the charges, though it mentions the electricity consumption of the month.

Different from the household electricity bill, the electricity bill for industrial customer has more detailed description of charges, and is charged separately from the bill for other utilities.

MALAYSIA



TENAGA NASIONAL (200866-W)

BIL ELEKTRIK

STN	NO. AKAUN	NO. KONT	CAGARAN KOD	CAGARAN AMAUN	NOMBOR BIL
0130	00102581 04	9106791	TUNAI	80.00	07273677

ANNE LIM
5 JLN 21/27
TMN SEA 00000 PETALING JAYA

ELAKKAN BIL ANGGARAN MELEBIHI 3 BULAN 7152995 5.00-6.30 PTG
AVOID ESTIMATED BILL FOR MORE THAN 3 MONTH 7152995 5.00-6.30

01300010258104 07273677

KETERANGAN	TARIKH	AMAUN	JENIS BACAAN	TARIF
BIL AKHIR	15-06-1999	70.07	E	013
BAYARAN AKHIR	15-05-1999	105.92		

CAGARAN TAMBAHAN	TUNGGAKAN	BAYARAN DIMASUK SETAKAT
0.00	70.07	08-07-1999

NO. JANGKA	MF	DAHULU	SEMASA	KEGUNAAN	PERIHAL
0019201799	1.00	2727	3504	777	KWH

PURATA KWH : N/A

CAJ	UNIT	KADAR	AMAUN
BLOK KEGUNAAN ELEK.	653	0.218	RM 142.35
	124	0.258	RM 31.99

AMAUN ELEKTRIK	: RM 174.34	BIL SEMASA	: RM 63.50
LAIN-LAIN CAJ	: RM 0.00	TUNGGAKAN	: RM 70.07
ANGGRN PELARASAN	: RM -110.84	CAG. TAMBAHAN	: RM 0.00
PELBAGAI	: RM 0.00	JUM. PERLU DIBYR.	: RM 133.57

TRKH BACAAN DAHULU: 05-04-1999 SEMASA: 12-07-1999 JENIS: N
NO. TELEFON ADUAN KEROSAKAN 5527880/15454
NO. TELEFON PEJABAT / LAMPU AWAM 7557733 / 15454
72 JLN SELANGOR 46990 PETALING JAYA

In Malaysia, electricity prices charge must be approved by the government based on energy policies, and economic and social objectives of the country. Electricity bill shows the amount of electricity consumed in a particular period, its fixed basic rate and its progressive consumption rates.