



**INTERNATIONAL
ENERGY AGENCY**

**ENERGY
MARKET
REFORM**

COMPETITION IN ELECTRICITY MARKETS



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INTERNATIONAL ENERGY AGENCY

9, rue de la Fédération,
75739 Paris Cedex 15, France

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

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- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations ;
- To operate a permanent information system on the international oil market ;
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use ;
- To assist in the integration of environmental and energy policies.

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FOREWORD

Most OECD countries, and many countries outside the OECD, are introducing competition into their electricity markets. This is a challenging process. Promoting effective and sustainable competition requires action on a number of related issues and an overhaul of traditional market structures and regulatory frameworks.

This book considers the experience of OECD countries in the reform of their electricity markets. Its main focus is the introduction of competition. Reform also has significant implications for other key policy issues such as security and the environment, but it is not the main purpose here to analyse these.

Reform experience so far highlights a converging trend towards introducing consumer choice of electricity supplier as a fundamental pillar of effective reform. This means stimulating competition not only in generation, but also in electricity trading and supply as a service to consumers. At the same time, the need to regulate transmission systems effectively is becoming evident, so as to ensure a level playing field for market participants and sustain efficient investment in transmission. Many countries are also engaged in a major overhaul of regulatory institutions to oversee the new markets.

As well as providing a strategic and comprehensive overview of the reform process, this book contains a detailed analysis of key elements, including unbundling the network from potentially competitive activities, the evolution of competitive electricity spot markets, the regulation and pricing of transmission, and the role of system operators. These issues are in full evolution and approaches continue to be improved and refined. The book will therefore be of interest to energy policy makers, legislators and electricity specialists.

It is important for reforming countries to keep track of developments and best practices. The IEA monitors, and will continue to monitor, the evolution of electricity market reform. Developments are reported regularly in the IEA's Annual Energy Policy Review Book.

This book has benefited enormously from discussions at meetings of the IEA's Electricity Regulatory Forum on such issues as electricity trading and transmission pricing. I would like to thank the IEA member country participants of these meetings. The main author of the book is Carlos Ocaña. Caroline Varley directed the work and provided editorial oversight.

This book is published under my authority as Executive Director of the International Energy Agency.

Robert Priddle
Executive Director

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INTRODUCTION AND EXECUTIVE SUMMARY

Virtually all OECD countries have decided to open up their electricity markets, at least to their big industrial users. In many countries electricity markets will be open to all users, including households. This is already the case in Finland, Germany, New Zealand, Norway, Sweden, England and Wales in the UK, and several states in the US and Australia. By the year 2006, more than 500 million people (and all large industrial users) in the OECD area will be entitled to choose their electricity supplier. This accounts for nearly 50% of the population of OECD countries.

This book analyses the development of choice and competition in the Electricity Supply Industry (ESI). Drawing on a review of the international experience, it describes the main approaches that are being developed, discusses the key issues in the effective reform of electricity markets and provides an assessment of the emerging approach to reform. The book is written from the perspective of regulators and policy makers. It seeks to answer the question: what is an effective regulatory framework for competition in electricity markets?

A common Approach to Reform is Developing

In principle, many different approaches to ESI reform are possible depending on which activities are liberalised (e.g. generation), how the non-liberalised activities (e.g. transmission) are regulated and which agents are allowed to participate in the different markets. However, in practice, there is increasing convergence in the approach to reforming electricity markets in the OECD area. Recent ESI reforms often share these four elements:

- Rapid introduction of full consumer choice;

- An obligation to provide non-discriminatory Third-Party Access (TPA) to the transmission and distribution networks;
- Unbundling of transmission; and
- Liberalisation of electricity trade so that electricity can be traded both through organised power exchanges and on a bilateral basis

This combination of full market opening, unbundling of transmission activities, regulated access to the network and liberalisation of electricity trade is known as “retail competition”. Under retail competition, transactions among generators, end users and a number of possible intermediaries, such as retailers, power exchanges and brokers take place freely (within the “physical” constraints imposed by the network). Thus, on the demand side, end users are free to choose their supplier and to negotiate their contracts; on the supply side, generators can sell their electricity to any other market players. Retail competition has inspired reforms in Finland, Norway, Spain, Sweden, UK, US and, with some variations, in Australia, Denmark, Germany and New Zealand.

A Review of Reforms to Date

Electricity reforms are expected to increase the efficiency of the ESI. However, the most significant impacts of reform are only expected to emerge in the long-term as a result of better investment decisions. In most countries competition started very recently, so it is still too early to evaluate the performance — in terms of costs, prices, and global social benefits — of the new electricity markets.

In a short-term perspective, reforms have generally delivered their expected benefits. Large productivity increases have been reported in a number of countries, largely linked to the corporatisation and privatisation of the utilities. Final electricity prices have decreased or remained stable in all countries examined and wholesale

electricity prices have been low (e.g. relative to the cost of new generation) whenever market power has not been an issue. However, as a result of lower costs, electricity prices have also decreased in many OECD countries that did not introduce reforms until very recently, making it difficult to quantify the actual impact of competition on prices.

Market structure is a key determinant of prices in the new electricity markets. High concentration of generation assets has resulted in weak competition in the wholesale market (e.g. early UK and Spain), while more intense competition has taken place in less concentrated markets (e.g. the Nordic electricity market and Germany). The implication for policy is that reforms need to pay attention to structural competition policies such as divestitures and/or the opening of national markets to international (or interstate) trade and competition. Regulatory reform alone is not enough for competition to emerge.

A key issue for the progress of reforms is the distribution of the costs and benefits of reform among end users, investors and other parties such as tax payers and ESI employees. The distribution of costs and benefits has a large impact on the social and political acceptability of reforms, in addition to its impact on efficiency. For instance, in a number of countries cost and price reductions along the supply chain have not been fully reflected in end-user prices. This has raised concerns about the fairness of reforms and encouraged the introduction of retail competition and other measures to lower electricity prices. Also, the treatment of stranded costs and, where applicable, the form of privatisation, have had a significant impact on the distribution of the benefits of reform.

The transition from the old to the new regulatory regimes poses a major challenge for policy makers. Regulatory uncertainty during or immediately before the transition may have a negative impact on investment as potential investors delay their decisions until the new framework is defined. Also, the reliability of electricity supply may decrease if the rules and responsibilities of the new actors are

not clearly and consistently defined. Experience shows that reliability problems have been at most sporadic in reformed markets and are only partly attributable to transition issues. However, experience also shows that these problems, whenever they have materialised, have a large negative impact on the public perception of reforms. Thus, governments have a key role during the transition in ensuring that the appropriate safeguards to sustain reliability are in place and in minimising regulatory risk.

Key Issues: Unbundling

In order for competition to develop in electricity markets, monopolistic activities such as the operation of the transmission network need to be effectively separated from the potentially competitive activities (e.g. generation). The main objective of unbundling is to avoid discrimination in the competitive segments of the ESI. Thus, some degree of separation is needed between transmission and generation, distribution and generation, and distribution and end user supply.

Ownership separation or “divestiture” — requiring different owners for different activities — has the greatest potential to eliminate discrimination, because it eliminates the incentive to discriminate. Functional separation and accounting separation have a limited potential to prevent discrimination because the incentive to discriminate and some of the ability to discriminate remain. If applied, these forms of separation require significant regulatory oversight and vigorous enforcement of competition law. Operational separation of transmission — separating system operation from the ownership of transmission assets — may provide a workable alternative to divestiture when transmission ownership is fragmented among several parties. However, the establishment of effective independent system operators requires the development of complex and still largely untested governance structures.

Key Issues: Empowering the End User

Despite its relatively small weight in the supply chain, end user supply has a disproportionately large importance in getting competition to work for the benefit of consumers. The ability of end users to choose a supplier creates a fundamental pressure on all the players along the supply chain that is virtually impossible to replicate by regulation. The value of consumer choice in disciplining market players is that it provides consumers with an effective bargaining tool; the tool may be effective even if the options that it provides (e.g. switching supplier) are not systematically used. Even if this pressure is not directly observable (many consumers may choose to remain with the same supplier), indirect effects on price structures, price levels, product diversity and service conditions are potentially significant.

Introducing competition in end user supply requires unbundling it from distribution, a critical mass of suppliers to enable genuine choice, and the development of an appropriate technical framework related to metering and billing. In addition, there are techniques, such as load profiling, that significantly reduce the cost of introducing competition for small consumers.

Key Issues: Meeting Security of Supply, Environmental and Social Goals

In addition to economic efficiency, energy policy aims to meet other objectives such as security of supply, environmental protection and social goals. The old command and control mechanisms traditionally applied to pursue these goals are generally neither the best approach nor feasible in the new context. In a competitive ESI, policies have to be implemented with competitively neutral instruments that do not discriminate among market players and minimise market distortions. Implementing suitable instruments has proved to be a difficult task.

Key Issues: Reforming Regulatory Institutions

Regulatory institutions need to adapt to meet the new challenges posed by reforms. In particular, regulators need to be independent from the regulated. Otherwise, conflicts of interest inevitably arise. Independence from government helps to ensure stability of regulatory policies, to avoid the use of electricity policy to achieve general policy goals and, where government is also the owner of utilities, to ensure impartial treatment of market players. However, ensuring the accountability of independent regulatory agencies is a difficult issue, and the choice of approach may depend on specific country features — for example, the role of the courts. In addition, the active role of competition authorities is needed as competition develops. Two areas in which competition plays an important role are merger control and the elimination of subsidies.

Designing Markets and Regulation

Together with the “big” strategic issues, the development of electricity markets necessitates addressing other more technical issues concerning the regulation of transmission and distribution, and the organisation of the market. Chapters 6 and 7 provide a non-technical introduction to these issues along with a brief survey of current approaches in OECD countries.

A key aspect of the regulation of the network is the pricing of transmission. Nodal pricing provides incentives for an efficient use of generation and transmission assets. Experience shows that nodal pricing is workable, and its use may be expected to increase progressively. Postage stamp pricing does not generally provide adequate incentives for efficiency. However, inefficiencies may be small in systems with a strong grid and large reserve generation margins and postage stamp pricing has the advantage of being relatively transparent and easy to implement.

Two issues have polarised the debate on the organisation of wholesale electricity markets. First, there is the question of whether mandatory or voluntary electricity pools should be preferred. There is a growing consensus that competitive bilateral electricity trading is an essential part of an efficient modern electricity market. Voluntary pools or power exchanges are increasingly dominating the scene, and mandatory pools are receding. Although pricing and scheduling rules show significant variation across systems, these differences do not seem to have a significant impact on the functioning of electricity pools or power exchanges. Second, some electricity markets have instituted so-called capacity payments to provide additional incentives for investment in generation while, in other markets, generators are paid only for the energy actually provided. This study concludes that, under most circumstances, market incentives to invest are sufficient to ensure adequate investment and that capacity payments are not generally needed.

Outlook

Electricity market reform is a moving target. One key development is the market itself. The ESI is rapidly expanding its boundaries. Generation is increasingly integrated with gas and oil companies. At the same time, distribution and end user supply activities in network industries, such as gas, electricity, telecommunications or water, are likely to become more integrated across industries. The geographical boundaries of the ESI, once coincident with national or state boundaries, are also changing. More and more, electricity systems are becoming integrated within regional markets. Liberalisation is also opening the way for significant direct investment by foreign companies in national markets. The implication for policy of this expanding industry boundary is that regulation will have to be managed at a multi-sectoral and multinational level. This evolution towards greater dependence on competition law and common rules for international trade is a

process that has already occurred in many other industries opened to competition.

The emergence of non-centralised dispatch is also changing the ESI. Autoproduction and distributed generation are rapidly growing in many countries due to the development of efficient small scale generation. Environmentally these developments are very positive to the extent that they make use of renewable sources of energy. Distributed generation and autoproduction are both substitutes for electricity transportation services. This has the effect of weakening the effectiveness of natural monopoly regulation of the network. In due course, if new generation technologies become a profitable substitute for transportation, transportation will cease to be a natural monopoly. Such a development would have a crucial impact on the future economics, market structure and regulation of the ESI.

THE BACKGROUND TO REFORM

Defining Electricity

It is helpful to start by considering the different functions that make up electricity delivered to the consumer. Some of these functions can be supplied competitively, whereas others are more difficult to liberalise. Electricity delivered to the consumer is made up of energy (a non-storable commodity), and transportation (a service) which includes transmission, distribution and system operation. Ancillary services supply some special forms of energy needed by the system operator to secure the short-term balance, security and reliability of the system. Electricity is supplied to end users by bundling it with end user services (e.g. billing). Finally, there are other associated services (e.g. construction and maintenance). The functional structure of the ESI is summarised in Table 1.

■ **The Commodity: Energy**

The commodity component of electricity is similar to many other commodities although it has some special features. Electricity demand fluctuates in the various time horizons (in a day, a year, or in the business cycle) both randomly and non-randomly. In addition electricity, at present, cannot be economically stored. This means that:

- Generation (and transmission) capacity needed to cope with peak demand is partly unused in periods of lower demand;
- Reserve capacity may be required to cope with random demand fluctuations or generation shortfalls; and
- A diversified portfolio of electricity generating technologies is needed to provide the different loads of electricity at least cost.

Table 1*Functional Structure of the ESI*

Function	Key Economic Characteristics	Implications
Generation	<ul style="list-style-type: none"> • Limited scale economies at plant level • Co-ordination economies at system level • Complementarity with transmission 	Potentially competitive
Transmission	<ul style="list-style-type: none"> • Network externalities • In general not a natural monopoly • Large sunk costs 	<ul style="list-style-type: none"> • Investment incentives need special attention • One grid but possibly several owners
Distribution	<ul style="list-style-type: none"> • Often a natural monopoly • Large sunk costs 	No competition
System Operation	<ul style="list-style-type: none"> • Monopoly (due to technical constraints) 	No competition
End user Supply	<ul style="list-style-type: none"> • Limited scale economies • No special features 	Potentially competitive
Related Services: <ul style="list-style-type: none"> • Power Exchanges • Financial Contracts • Construction and maintenance of assets 	No special features	Potentially competitive

Since the costs of electricity production from generating plants vary, electricity generation is characterised by a merit order of generating plants. There are related economies of co-ordination at the system level. In varying degrees, generating technologies are also characterised by their relatively high capital intensity, and technical and economic longevity, including long lead and construction times. However, some recent innovations are dramatically lowering capital intensity and shortening lead and construction times for some technologies (e.g. combined cycle gas turbines). Overall, economies of scale in generation do not seem to be significant at the plant level.

■ **Transportation: Transmission and Distribution**

It is customary to distinguish between two types of transportation: transmission is transportation at very high voltage levels and distribution is transportation at lower voltage levels. Transmission refers to transportation over an interconnected network, which is shared by all end users, whereas distribution refers to transportation from the interconnected network to a specific group of end users; a transmission line thus provides security of supply to all end users while a distribution line benefits only some.

Distribution lines are often considered a natural monopoly since duplication of distribution lines would be inefficient due to the large fixed costs of the investment. There are exceptions such as buildings and factories that have two connections to the distribution grid to ensure security of supply.

The transmission network also has some special characteristics. First, there are so-called network externalities, i.e. investments benefit all interconnected parties by increasing reliability and security and reducing the cost of generation. Network externalities may result in the additional value of investments in grid augmentation being reduced by successive investments. This may discourage investment. Second, there are system-wide economies of scale as in the case of distribution.

However, transmission lines within the grid are not, in general, natural monopolies. Two transmission lines may run more or less in parallel and still be economical; and two nodes within an interconnected grid are often connected through several paths as a means to increase reliability. Thus, transmission services can be provided by different owners within a single interconnected network.

■ System Operation

System operation refers to the co-ordination of transportation services to ensure that the system is constantly in state of static electrical equilibrium. In particular, equilibrium requires that power supplied equals power demanded at each node of the network. This state is achieved by controlling inflows and outflows of energy over the network and by procuring the complementary ancillary services necessary to maintain the technical reliability of the grid. The scope of system operation changes with the regulatory framework. Decisions made at the time of delivery are always controlled by the system operator, while decisions made some time in advance of actual delivery can be made either by the system operator or by market participants. The development of information technology is quickly shortening the period over which decisions have to be made by the system operator. For instance, the Australian electricity market is open up to five minutes before delivery.

Regardless of the market framework (monopoly or competitive), system operation always remains a monopoly. Interconnection and its associated benefits of increased reliability and lower costs are only possible under a centralised system operation. However, this intrinsically monopolistic function can be unbundled from transmission ownership, in which case an independent system operator is in charge of system operation.

■ End-user Supply and Services

End-user supply refers to the delivery of electricity to end users. It includes the procurement of energy and transportation services and the metering and billing of consumption. End-user supply was traditionally bundled with distribution but can be performed separately. There is an increasing number of “value-added services” linked to end-user supply such as supplying differentiated electricity (e.g. green energy), packaging electricity (e.g. with other utility services such as gas) and supplying differentiated reliability and quality (e.g. interruptible supply). End-user services are potentially competitive.

Suppliers to end-users thus perform two functions. First, they act as brokers who buy and sell energy and try to make a profit from assuming the risk of price volatility and from adjusting prices to consumption patterns¹. Second, suppliers may provide the services to end-users mentioned above.

■ Related Services

Electricity supply involves other activities. Construction and maintenance services provide and maintain the generating plants and grid assets needed to supply electricity. There are also many new financial services, such as those offered by a growing number of power exchanges, that facilitate trade in electricity. Financial instruments (e.g. electricity futures) are also being developed to provide for a better management of risks. These services are potentially competitive subject to the same type of regulation that applies to similar services in other sectors (e.g. regulations on financial contracts), and specific electricity regulation is not generally needed. However, these activities have generally been performed or controlled by the vertically integrated electricity

1. For instance, consumers with flat loads may be offered lower prices than consumers whose peak demand coincides with the system's peak load. Retailers can make a profit from adjusting prices for individual consumers. However, as time of use metering is becoming widespread, opportunities for profitably performing this activity tend to disappear.

monopolies. As a consequence, the unbundling and liberalisation of these services is often part of electricity market reform.

The disaggregation of functions and the introduction of competition is reflected in the changing shape of the market and market participants. Under competition the vertically integrated utility gives way to a number of different and more specialised market players including generation, transmission, distribution and supply companies. The unbundling of the various functions, often mandated or facilitated by regulations, is a key factor in the development of these new markets (unbundling considered in more detail in Chapter 5).

What are the Benefits of Reform?

Reform primarily reflects a concern that economic efficiency is not as good as it might be in the ESI, and hence prices to consumers are higher than what they might be. The inefficient performance of the old regulatory framework has given cause for concern. Widespread excess generating capacity, unexplained national and international cost differentials (e.g. between plants or between companies), and persistent international (or inter-state) electricity price differentials imply that there is scope for improvement. Inefficiencies have become more obvious and relevant in the current context of slower demand growth and globalisation.

The main objective of ESI reform is to increase economic efficiency. This requires minimising the cost of electricity supply and ensuring that electricity prices are in line with costs. Experience from other industries shows that competition is the most effective way to establish sustained incentives to keep costs and prices down. Under competition, productivity grows, costs and prices decrease, and innovation and product diversity flourish. The expectation is that these benefits will also result from the introduction of competition in the ESI. The largest expected benefits of reform in the ESI are:

- Lower prices resulting from competition: Competition puts a downward pressure on the profit margins of generators and suppliers and provides an incentive to reduce costs. As a result, electricity prices under competition tend to be lower.
- Lower prices resulting from increased electricity trade: Reform facilitates inter-system competition and trade in electricity, resulting in a better allocation of resources and, ultimately, a reduction in the cost of supplying electricity. This is an important benefit of reform in many regions. In the EU, the Electricity Directive aims to develop the EU internal electricity market by integrating the national EU electricity systems. In the US and Canada, reform is expected to reduce the large (and inefficient) electricity price differentials that exist across regions. For instance, the average price in 1995 ranged from about 4 cents per kWh in Oregon to more than 10 cents per kWh in California and New York. In Australia, the National Electricity Market facilitates inter-state trade and therefore has a similar effect on price differentials. Even though no precise estimates are available, some preliminary research suggests that the gains from inter-system electricity trade may be substantial (IEA, 1995).
- Savings in investment costs: better investment decisions are expected, particularly in generation, as investors assume the risks of their investments, and incentives to over-invest correspondingly disappear. The large generation capacity reserve margins now observed in some countries, as large as 50%, can be expected to adjust to more normal levels as the costs of non-economical investments cease to be borne by consumers. Reserve margins in the order of 20%, which are observed in countries like the US and the UK, may become more common.
- Higher labour productivity: better use of manpower is expected, particularly in distribution activities, as increased regulatory oversight, incentive regulation and, in some cases,

privatisation, build up pressure for a more efficient use of resources. Experience from the UK and Australia indicates that labour productivity increases in distribution can be large, reaching levels as high as 40 to 50% in some cases.

■ Development of new energy services.

Competition also means that regulators do not need to provide regulatory incentives to promote efficiency. The evidence from many regulated sectors suggests that regulation is an imperfect substitute for competition in providing incentives for efficiency. A number of factors seem to cause this, including information asymmetries between the regulator and the regulated firms and regulatory capture.

Reform needs to be carefully targeted at the largest inefficiencies in electricity supply. Historically, power generation became the first target of reform because it offered the largest potential for improvement. Costly planning errors, leading to excess generating capacity suggested that efficiency could be improved. Generation accounts for about half of the total cost of electricity and it does not exhibit significant economies of scale so that competition is a possibility.

More recently, distribution and retail supply have also become areas for reform. Experience with the corporatisation and privatisation of distribution systems indicates that potential cost savings in distribution, which accounts for about 30-40% of total costs, could also be significant. Experience gathered in competitive electricity markets also suggests that consumer choice is needed in upstream activities and that a level playing field for competition requires eliminating distortions in end user tariffs. Many recent reform programmes aim to unbundle distribution networks from supply, introduce consumer choice and re-regulate distribution networks.

The remaining link, transmission, is also now an object of reform, even if for a different reason. The direct potential savings in transmission are relatively small — its share of total cost is just

about 10% — and there is limited scope for competition. But transmission can easily become a bottleneck for the development of competition in the other ESI functions. Electricity regulators around the world are now struggling with the regulation of transmission, including transmission pricing, governance and unbundling from other activities.

What are the Costs of Reform?

A monopolistic electricity network remains essential to supply a large majority of end-users. In consequence, extensive resources have to be devoted to the regulation and restructuring of the network. Regulating the grid is a costly activity. Resources are needed both to develop new regulations and to implement them in areas such as pricing, allocation of access rights and antitrust enforcement. Regulation also commits the resources of market players as they try to influence the design of regulations and enter into legal battles regarding their implementation. In addition, a detailed regulation of the electricity grid has costs in terms of foregone economic efficiency: regulatory loopholes and imperfections seem almost unavoidable given that regulators have limited access to information in key areas such as costs or technical constraints (e.g. capacity and availability of lines).

The unbundling of activities along the vertical supply chain also results in transaction costs. A web of contracts and intermediaries replaces the previously vertically integrated structures. Some of the costs of contracting and intermediation already existed or have their counterparts in the integrated model. However, the total cost of these activities is expected to increase.

It has been suggested that structural policies, such as unbundling and divestitures, may lead to foregone economies of scale and coordination but the evidence suggests that foregone economies may not be significant. For instance, there are economies of vertical integration that may be lost when transmission is unbundled from generation. Generation and transmission can be substitutes for

each other since the services provided by a transmission line can also be provided by a power plant located where the line would deliver energy. Unbundling generation from transmission has the potential cost of yielding sub-optimal investment decisions in either activity. However, these indirect costs of vertical de-integration seem small in the light of the international experience discussed in Chapter 3.

Likewise, the horizontal restructuring of the ESI does not seem to have a significant impact on the internal efficiency of electricity companies. It is sometimes claimed (e.g. in antitrust cases) that horizontal restructuring may have efficiency costs because of foregone economies of scale. While there is general agreement that a minimum efficient scale exists for each ESI activity, this minimum generally allows for several companies to compete within the same market. As an example, studies of generation costs for US vertically integrated utilities suggest that scale economies are exhausted for production levels in the 12 000 to 30 000 GWh range. Similarly, distribution costs (including end-user supply costs) in the US do not seem to decrease with size, at least for utilities serving 750 000 customers and above. Other studies find that the hypothesis of constant returns to scale cannot be rejected and that economies of scale at the generating unit level are exhausted at a unit size of about 500 MW².

What is Driving Reform?

While the main expected benefit of reform is increasing efficiency, this is not a new policy objective and, therefore, it may be suspected that other factors are triggering reform. Some experts believe that country specific factors have a significant weight in promoting electricity reform. In the US, the significant gap between electricity prices and (long-term marginal) costs has been a key contributing factor in the increasing pressure

2. See Wolak (1997), Frankena and Owen (1994), Lee (1995) and Joskow (1987).

for reform, especially in high price states like California and Massachusetts³. In the EU, political pressure for the development of the internal European market is a major factor in the process of reform. In Japan, high electricity prices and low generating capacity utilisation, resulting from a very uneven load curve, are encouraging reform. And in a number of countries (e.g. the UK, Chile, Argentina) reform has been linked to privatisation programmes and a wider reform of the economy.

In addition, there are a number of shared factors that may be encouraging reform but whose actual weight is somewhat disputed. Current technological trends reinforce the advantages of introducing competition into the ESI. Economies of scale in electricity generation are not significant enough under the current conditions, thus paving the way for competition among electricity generators. In addition, cheap and abundant gas supplies have encouraged the development of gas fired plants that are efficient on a relatively small scale.

Increasing economic globalisation also encourages electricity reforms. In a closed economy, inefficiencies in any part of the economy can be more easily absorbed by other economic sectors to the extent to which they are also shielded from competition, and excess costs can be passed on to consumers in the form of higher prices. In an open economy, industries exposed to competition cannot remain competitive if they pay more for their inputs than their (“foreign”) competitors. Globalisation thus creates extra pressure to increase efficiency in electricity supply. Also, a global economy helps reform by fostering the emergence of international energy companies that have the resources, the willingness and the dynamism to compete in the newly liberalised electricity markets, and to introduce new ideas.

Finally, the fact that reform has been successful in some countries provides an impetus for reform in other countries. Regulatory know-how can be imported, at least partly, and the biggest uncertainties and concerns that surrounded the first reform experiments are no longer present.

3. Joskow (1997).

A REVIEW OF ESI REFORMS IN OECD COUNTRIES

A Brief History

The origins of the current wave of reforms in the ESI can be traced back to the late 1970s. The first step came with a partial opening of electricity generation to new entrants. In 1978, the US adopted the Public Utility Regulatory Policies Act (PURPA), requiring the utilities to buy electricity from “qualified facilities”, mostly co-generators and small power producers. Four years after the PURPA, in 1982, Chile enacted a law introducing some competition into electricity markets by allowing large end users to choose their supplier and freely negotiate prices. A second step came with the establishment of explicit market mechanisms to determine the dispatch of generators and the wholesale price of electricity, thereby permitting competition between generators. The England and Wales electricity market, or “pool”, established in 1990, was the first such market mechanism. It was followed in 1991 by Norway which established a competitive electricity pool. This pool was extended in 1996 with the incorporation of Sweden, and NordPool was formed, which now also includes Finland and Denmark. The National Electricity Market of Australia was created in 1997 from the merger of the Victoria Pool, in operation since 1994, and the New South Wales Pool, established as a daily pool in 1996. In New Zealand, after ten years of reforms, a voluntary Wholesale Electricity Market was established in 1996, following the corporatisation of generation in 1987, and the corporatisation of distribution and the introduction of consumer choice in 1994⁴.

Competitive power exchanges started operation in 1998 in Spain and, within the US, in California and the “Pennsylvania-New Jersey-Maryland Interconnection”, opening the way for a number of

4. Other more tightly regulated pools were also created during the 90 (e.g. Argentina, 1991; Colombia, 1995; Alberta (Canada), 1996).

regional electricity markets within the US such as the New York Pool and the New England Pool. In the Netherlands, the Amsterdam Power Exchange began operation in 1999. In the UK, an in-depth reform of the England and Wales Pool, known as NETA (New Electricity Market Arrangements) was approved in 1999 and implementation is expected in early 2001.

In parallel to the development of wholesale markets, electricity markets have been progressively opened up to end users. In some countries and states all end users are legally permitted to choose their supplier (Norway since 1991; New Zealand since 1994; Sweden since 1996; Finland since 1997; California since 1998; England and Wales since 1999; New South Wales since 1999). There is also some degree of market opening in many other OECD countries even if no organised electricity market has been established.

Early Reforms

This section summarises the approach adopted by early OECD reformers, those for which an open market has been in operation four or more years. They are the UK, Norway, Sweden, Australia and New Zealand (more recent reforms are considered in the following section).

Key elements of early reforms are summarised in Table 2 below. All early reformers took some action to separate potentially competitive from non-competitive activities and to stimulate competition in the competitive activities. In essence, this meant the separation or “unbundling” of transportation from other activities, and the introduction of third party access to the grid. Early reformers also introduced an organised wholesale market. However, many detailed aspects of reform varied significantly, including the separation — or not — of generation from distribution, the governance of the grid, transmission pricing, the organisation of the wholesale market, ownership, and the institutional framework.

Table 2*Key Characteristics of Some Early Reformers*

Industry Structure			
Country	Ownership of Utilities	Vertical Integration of Generation /Distribution	Common Elements
UK	Private	No*	Full Consumer Choice (Target) Unbundling of Generation from Transmission Regulated TPA to the Grid**
Norway	Largely Public	Yes	
Sweden	Mixed	Yes	
Australia	Mixed	No	
New Zealand	Largely Public	No	

* Distribution companies are allowed to own some generation assets.

** Except in New Zealand where TPA is negotiated.

Wholesale Markets			
Country	Pool Participation	Pool Capacity* Payments	Pool Pricing**
UK	Mandatory	Yes	<i>Ex ante</i>
NordPool	Non-Mandatory	No	<i>Ex ante</i>
Australia	Mandatory	No	<i>Ex post</i>
New Zealand	Non-Mandatory	No	<i>Ex post</i>

* Capacity payments: payments made to generators in order to guarantee their availability to generate electricity in case of need.

** *Ex ante*: pool purchasing price determined from scheduled demand and supply.
Ex post: pool purchasing price determined from actual demand and supply.

Institutional Framework		
Country	Electricity Regulator	Regulator Also Enforces Competition Law
UK	Independent	No
Norway	Ministry	No
Sweden	Independent	No
Australia	Independent	Yes
New Zealand	No Specific Electricity Regulator	Yes

■ Structural Policies

The purpose of horizontal restructuring is to mitigate market power in the potentially competitive functions in electricity supply, especially generation and end user supply. Many reforming countries have adopted measures to reduce horizontal concentration in generation and in end user supply. These measures include mandated divestiture of generation assets and the split of generation companies at the time of privatisation, generally intended to reduce market power. There have also been some mandated splits of regulated distribution companies. This policy aims to establish a critical mass of competitors and often also a sufficient number of “comparators” for regulatory purposes (e.g. for setting price caps in the UK). An added benefit of divestiture is to set the market value of assets, which helps to handle the transitional issue of placing a value on stranded assets.

The feasibility of structural measures to increase competition depends on whether the utilities are publicly or privately owned. If the starting point is a government-owned industry, a government-mandated split of companies may be feasible. This was the case in the UK at the time of privatisation, where generation was split into three companies and distribution was split into thirteen regional companies. In Australia, the Victorian monopoly has been privatised

and disintegrated into five generators and five distribution companies; and, in New South Wales, restructuring has resulted in two generation and six distribution companies, all kept under public ownership. In New Zealand, the dominant electricity producer was separated in 1996 into two companies accounting for approximately 60% and 30% of the generation market. In 1999, to increase rivalry among generators, the government divided the dominant company into three competing state-owned companies, and sold off the other state owned generator, reducing the share of the two largest companies to about 53%.

Similar policies have been adopted in countries outside the OECD. For instance, in Argentina, privatisation transformed the three state-owned generators, seventeen regional distributors and a number of smaller regional generators into a vertically disintegrated structure in which no generator has a market share larger than 10%.

Government-mandated divestiture policies may be difficult to implement when there is private ownership of the utilities. However, restructuring policies may still be implemented on the basis of either antitrust laws or financial incentives. In 1997, the UK electricity regulator encouraged divestiture of 6000 MW of generating capacity owned by the two largest generators, threatening to refer them to the Mergers and Monopolies Commission. In California, financial incentives, in the form of a higher allowed rate of return on certain investments, have been used to induce divestiture of 50% of the fossil-fuel generation assets owned by the largest (privately owned) utilities. However, the three utilities involved voluntarily decided to divest all but nuclear generation.

In some countries, horizontal restructuring has occurred implicitly through the integration of national (or regional) electricity markets. Integration of various national markets yields a less concentrated market because it increases the number of players and the relative size of all players is smaller in the larger market. In the NordPool member countries, horizontal restructuring has

taken the form of unrestricted international trade. The Australian National Electricity Market integrates previously separated state markets. The EU aim to create an internal market in electricity goes in the same direction.

Horizontal restructuring has led to a significant decrease in market concentration. However, concentration may still be too high in some markets. Table 3 provides measures of concentration in power generation.

Table 3

Horizontal Concentration

Market	Market Share of the Two Largest Producers (C2)	
	1996	1998
UK (England and Wales)	55	41
NordPool	40	35
Australia (National Electricity Market)	40	36
New Zealand	90	53

■ Ownership

Another element linked to structure is ownership. There is no clear ownership pattern among the early reformers (see Table 2). This mixed configuration of ownership can also be observed in the unreformed ESI. Nevertheless, there is a worldwide trend towards more private ownership due to both privatisation programmes and to the entry of new privately-owned competitors. The sequence in which liberalisation and privatisation measures have been adopted also varies among countries. Privatisation of electric utilities has preceded liberalisation in the UK, while liberalisation has preceded some partial privatisation in the Nordic countries. In Australia, some privatisation has taken place both before and after

liberalisation. In New Zealand, while most of the industry has remained under public ownership, some privatisation has occurred with more expected in the near future.

■ Regulation

Early reforms sought to establish market mechanisms to determine the dispatch of generators and the wholesale price of electricity. This can be done by either an organised wholesale market (also known as a power exchange, or pool) or by buyers and sellers of electricity engaging in bilateral trade. A mandatory power exchange jointly manages system operation and dispatch in England and Wales (the introduction of new non-mandatory arrangements is in prospect) and in the Australian National Electricity Market. A non-mandatory power exchange that establishes a merit order of bids among participants⁵ and a separate system operator exist in the Nordic countries and in New Zealand (see Table 2).

The operation of electricity pools varies. Some incorporate capacity (or availability) payments to generators in addition to electricity payments while others only pay for electricity. Pool purchasing prices are sometimes determined by scheduled supply and demand, in which case selling prices have to add a correction for the cost of balancing actual supply and demand. In other cases they are determined by actual supply and demand and then purchasing and selling prices coincide (see Table 2).

Pricing of access to and use of the grid also had to be tackled alongside industry restructuring and the establishment of a wholesale market. Without effective regulation of transportation these other reforms would have been quite ineffective. A variety of transmission pricing systems have been developed among the early reformers. In Europe — Norway, Sweden, England & Wales and Finland — pricing is based on a postage stamp tariff that is not sensitive to congestion. Within each of these systems, congestion

5. As will be seen later, in other countries there is no power exchange (e.g. Germany) so that all trade is “bilateral”.

leads to re-dispatching. In Norway and Sweden, transmission prices vary according to a loss factor — intended to capture marginal losses — that changes from region to region. In New Zealand, a nodal pricing system is in operation so that prices of electricity and transmission are calculated to equate supply and demand at each node of the grid. In Australia, a zonal pricing system has been adopted. Prices are set to equate supply and demand in each of a number of pre-specified zones. Congestion between regions is addressed by operating separate markets in each region. All these pricing systems set a fixed charge to raise the required level of revenue.

Incentive regulation of grid activities has been introduced in some reforming countries. Traditionally, regulated activities have been subject to cost of service regulation so that the revenue of a regulated company is set to cover costs, including a competitive return on investment. Under incentive regulation, allowed revenues are still determined, initially, to cover cost of service. However, regulated companies are allowed to keep a fraction of any cost reductions they achieve. In the UK, incentive regulation has been implemented through “CPI-X” (Consumer Price Index-X) price caps. Under this arrangement, the remuneration of grid activities is updated yearly by a factor equal to consumer price inflation (measured by the CPI) minus a pre-specified X factor; currently the X factor is 3% for distribution and 4% for transmission. In addition, there have been one-off cuts, in the order of 20%, in transmission and distribution charges. Overall, revised price controls have resulted in substantial cuts in network charges. Transmission revenues in some Australian states are also subject to CPI-X regulation.

Recent Reforms

Many other OECD countries are now embarking on reform. Reform is now underway in all the EU member countries, the US, Canada and Japan.

■ European Union

The Council of the EU adopted a Directive on the internal market for electricity (EC 96/92) on 19 December 1996 (EC, 1996). EU member states, with some exceptions, implemented the Directive into their national laws by 19 February 1999. Ireland and Belgium have one additional year, and Greece has two additional years to comply with the Directive.

Under the Directive, increasing shares of electricity markets must be opened to competition, based on size of user. For 1999, the group of largest users, accounting for at least 26.48% of the market had a choice of supplier. This percentage increases to 30% in 2000 and 35% in 2003. In practice, the minima mean that only large users have the opportunity to choose their supplier, although member states can go — and often have gone — further.

Table 4

Market Opening under the EU Electricity Directive

Date*	% of the national market open to competition (consumption of eligible consumers relative to National Electricity Consumption)	Minimum size of Eligible Consumers (EU Average) GWh per year
February 1999	26	40
February 2000	30	20
February 2003	35	9

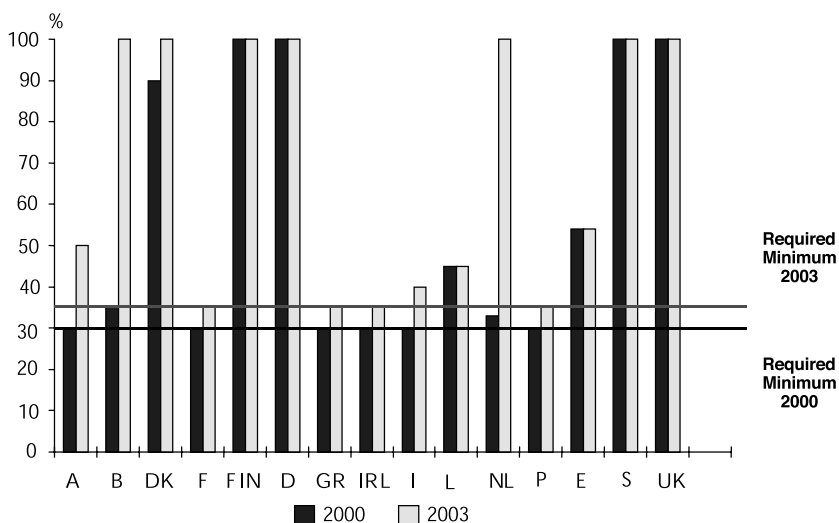
* Exceptions: Belgium and Ireland had one additional year to comply with the Directive. Greece has two additional years.

A number of countries have opened, or will open, their markets beyond these limits. As of August 1999 there is full market opening in Finland, Sweden, the UK and Germany. Denmark will be in the

same situation by 2003, and Spain and the Netherlands by 2007 or earlier. The remaining EU countries have not announced plans to go further than required by the Directive. Current and planned market opening in EU member countries is summarised in Figure 1.

Figure 1

Planned Electricity Market Opening in EU Countries



Source: IEA

Access to the grid is via a transmission system operator (TSO) who must be a separate business from the generation and distribution businesses. Several EU countries (Austria, Belgium, Denmark, Ireland, the Netherlands and Portugal) have met this obligation by requiring the TSO to be a legally separated company that remains under the control and ownership of the incumbent utility. An even weaker form of separation (managerial separation) has been adopted in France, Germany and Greece. In some countries, however, transmission is not vertically integrated with

the other electricity functions. There is operational separation in Italy and ownership separation in Finland, Spain, Sweden and the UK⁶.

EU member states can choose from three different procedures for access. Under regulated third party access, tariffs are regulated, published and available to all parties. Under negotiated third party access, eligible consumers or generators/suppliers can negotiate network access with the incumbent utility. Prices and access terms are agreed freely among them and are confidential. The system operators must be involved in the negotiations and must publish an indicative range of transmission and distribution prices on an annual basis.

The third possible approach is the single buyer system, where a designated single buyer (expected to be the incumbent utility) sells all electricity to final consumers. Eligible consumers are free to conclude supply contracts with generators/suppliers both inside and outside the incumbent utility's territory. The electricity contracted by an eligible customer is purchased by the single buyer at a price which is equal to the sale price offered by the single buyer to eligible customers minus a tariff for network services.

Most EU countries have chosen a regulated third party access model as the primary form of grid regulation (see Table 5). The European experience with negotiated third party access (i.e. in Germany) has not been satisfactory. There are concerns that negotiated third party access is not effective in preventing discrimination and places a burden on the companies willing to access the network⁷.

The EU Directive provides two options for generating capacity additions. Under the tendering procedure, the monopoly utility determines when new capacity is required and conducts a tender for this requirement. Under the authorisation procedure, the

6. Definitions of the different forms of unbundling are provided in Chapter 5.

7. EU Commission (2000).

Table 5*Network Access in EU Countries*

Regulated Third Party Access	Negotiated Third Party Access	Single Buyer
Austria	Germany*	Germany (Transitional)
Belgium*	Belgium*	
Denmark	Greece	
Finland		
France		
Ireland		
Italy*		Italy*
Luxembourg		
Netherlands		
Portugal*		Portugal*
Spain		
Sweden		
United Kingdom		

* Combines the two systems.
Source: EU DG XVII.

timing of generating capacity investments is the responsibility of individual investors, provided that they meet criteria specified in advance by the member state (e.g. environment, land use, public safety) for granting an authorisation to construct. Member states may also opt not to require a procedure and leave the addition to market forces.

The Directive also contains significant provisions that may delay or affect the development of open markets. Member states may impose public service obligations to ensure “security, including security of supply, regularity, quality and price of supplies and...

environmental protection”. Furthermore, “to avoid imbalance in the opening of electricity markets” the Directive permits the imposition of reciprocity requirements. This means that a customer who has choice in one member-state may be prohibited from obtaining supply from a supplier in another member state where customers of the same type do not have choice. In addition, the Directive also permits member states to impose a requirement that up to 15% of fuels to be used in the generation of electricity come from indigenous sources. A summary of how EU member countries have complied with the main requirements of the directive is provided in Table 6.

In some countries, the implementation of the Directive has resulted in a major overhaul of the ESI. In Spain⁸, a competitive electricity market began to operate in January 1998. Main features of the new system are functional unbundling (i.e., separate accounts) of distribution from both supply and generation; creation of an independent transmission system operator; arrangements for a non-mandatory power exchange set up to co-exist with bilateral transactions outside the exchange; provisions to phase in full consumer choice over a period of ten years; and an extension of existing policies on coal and renewables. Overall, the long-term regulatory options are similar to those adopted by the Nordic countries and some US states. However, there are some transitional arrangements, such as the gradual opening of the market, the introduction of a cap on wholesale prices and an agreement to gradually reduce end user tariffs over a five year period, which are country specific.

In April 1998, Germany⁹ issued a new Act on the Supply of Electricity and Gas. Utilities are required to provide negotiated TPA, and all consumers are given free choice of supplier. A transitional arrangement allows the Single Buyer Model to be applied until 2005 in some municipalities. Until the end of 1999,

8. A detailed analysis is contained in the OECD/IEA Review of Regulatory Reform in Spain (1999).

9. A detailed analysis is contained in the IEA Review of Energy Policies of Germany 1998.

Table 6*European Electricity Market Reform*

Country	Separation of Transmission	Entry into Generation	Market Opening %		Generation Ownership
			2000	2003	
Austria	Legal	Authorisation	30	50	Mixed
Belgium	Legal	Authorisation	35	100	Privatised
Denmark	Legal	Authorisation	90	100	Municipal/ coop
Finland	Ownership	Authorisation	100	100	Mixed
France	Management	Authorisation	30	35	Public
Germany	Management	Authorisation	100	100	Private/ länder + municipal
Greece	Management	Authorisation	30	35	Public
Ireland	Legal	Authorisation	30	35	Public
Italy	Operational	Authorisation	30	40	Mixed
Netherlands	Legal	Authorisation	35	100	Municipal/ privatised
Portugal	Legal	Tendering	30	35	Mixed
Spain	Ownership	Authorisation	54	54	Privatised
Sweden	Ownership	Authorisation	100	100	Mixed
UK	Ownership	Authorisation	100	100	Privatised

Source: EU Commission and IEA.

there was an agreement between the utilities to set transmission access prices on the basis of the distance between generator and consumer. A uniform postage stamp tariff was charged for distances less than 100 km, and a surcharge was added for longer distances.

Since the beginning of 2000, there is a postage stamp tariff combined with a surcharge applied to all international and some domestic transactions. These approaches to transmission pricing have been widely criticised for being discriminatory and erecting barriers to trade. They also raise concerns about the viability of a negotiated approach to transmission pricing. Despite these problems, the German reform has been successful in quickly promoting price competition and significant price reductions.

In the UK a second wave of reforms is to be implemented in early 2001. Under the New Electricity Trading Arrangements (NETA) there will be no central dispatch of generation. Instead, all trading will be made on a voluntary basis. In addition, capacity payments will be abolished, demand will play a more active role and the bidding structure in the new voluntary market will be reformed. The guiding principles of NETA are thus similar to those inspiring retail competition in other markets in Europe (e.g. NordPool) and North-America (e.g. California).

Despite recent reforms, cross-border transactions are a major bottleneck in the development of the internal EU electricity market. The old pricing and capacity allocation mechanisms for international transmission lines are grossly inadequate in the new framework. For instance, cross-border tariffs discourage trade and do not generally reflect the cost of transmission. Also, non-discriminatory TPA to the network is undermined by long-term contracts and agreements granting access to cross-border transmission capacity to certain companies. The EU Commission has launched a process — known as the Florence process — to establish common rules for cross-border transmission within the EU that are consistent with the development of the internal market. It is expected that a decision will be reached on this during the year 2001¹⁰.

10. See Haubrich and Fritz (1999) for a detailed discussion.

■ US¹¹

In the US, reform is taking place more or less simultaneously in generation and end user supply activities. On the generation side, emphasis is on ensuring open and non-discriminatory access to the grid. On 24 April 1996, the Federal Energy Regulatory Commission (FERC) issued wholesale open access rules requiring transmission owners to provide point-to-point and network services under the same conditions they provide for themselves, and to separate their transmission and supply activities. In order to avoid discrimination in network access, FERC encouraged, but did not mandate, the creation of Independent System Operators (ISO). These entities manage and operate the transmission grid independently from the generators and other grid users without (necessarily) owning the grid. The operational unbundling of transmission provided by an ISO is an intermediate solution between full (ownership) separation of transmission and accounting separation. ISOs are not the only solution to restructuring US wholesale electric markets. On December 1999, FERC issued Order 2000 that examines a wide range of Regional Transmission Organisations (RTO), including Independent System Operators (ISO) and Transmission Companies or “Transcos”. A Transco generally owns transmission, rather than giving the ISO operational control of transmission. Order 2000 requires utilities to file a proposal for a RTO but falls short of requiring the utilities to establish a RTO. The US is still struggling with transmission pricing and how to ensure long-term planning and expansion of the transmission system.

On the end user side, new regulation is concentrated on the following: enabling supply choice for all consumers; leveling the playing field for supply competition by means of unbundling and transparency obligations imposed on utilities; and support of public policy objectives and consumer protection.

11. A detailed account and assessment of electricity regulatory reform in the US can be found in the IEA Review of Energy Policies of the US (1998) and in the IEA/OECD (1998) study on Regulatory Reform in the US.

■ Canada

There are significant differences among Canadian provinces. Only Alberta and Ontario have firm plans to implement full retail access in 2001. Both provinces have regulated third party access and

Box 1

Main Lines of Reform in the US

Electricity reforms in the United States are distinct from those in most other OECD countries. First, they vary significantly from state to state. The state-to-state variation is greater than, for instance, in Australia, another federal country, but is comparable to that among member states of the EU. Second, where end users get direct access to the electricity market, they typically all get access simultaneously (or over a very short period), unlike in Australia, New Zealand, and the EU member states, where access is phased in over several years, and not always to all end users. Third, the reforms do not start from a unified, publicly owned system as they do, for example, in France, New Zealand, and England and Wales. Having private rather than public initial ownership implies a much greater concern in the US about stranded costs. On the other hand, as in many other countries, the reforms in the US have not included privatisation of publicly owned utilities.

A major part of the overall reform effort is to intensify competition between generators to supply electricity. Among the requirements for such competition in generation is non-discriminatory access to the transmission grid and ancillary services. Some states, such as California, are providing powerful financial incentives to partially divest generation to owners from outside the present market. As an alternative to divestiture of all generation, California, the states of the Northeast and Pennsylvania, New Jersey, and Maryland have established “independent system operators”. Competition in generation also requires sufficiently unconcentrated

Box 1*Main Lines of Reform in the US (continued)*

ownership of generating plants. In California, the divestiture of generating capacity was to multiple owners in order to deconcentrate generation. Independently run power exchanges have also been established in the more liberalised jurisdictions.

The second major reform element in the US is the promotion of competition to supply all end users, which is allowed, but not required, under the Energy Policy Act of 1992. The Administration proposes that each utility be required to permit all end users to choose their own electric power supplier by 1 January 2003, except where states or non-regulated utilities find, on the basis of a public proceeding, that an alternative policy would better serve consumers.

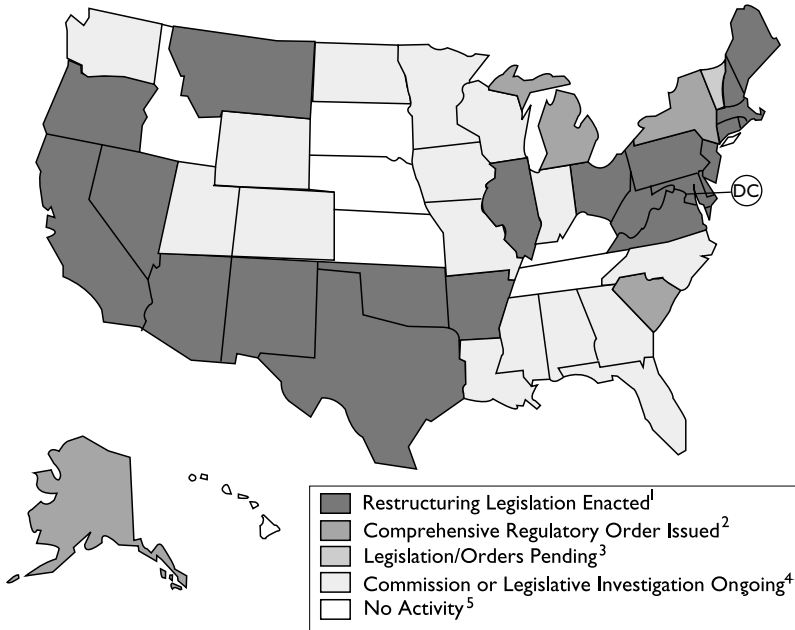
The third major element of the US reform is the mitigation, measurement, and compensation for stranded costs. Mechanisms used to recover stranded costs include lump-sum exit fees and non-bypassable charges on end users. Stranded costs are mostly attributed to investments in nuclear generation and in long-term power purchase agreements under the Public Utility Regulatory Policies Act of 1978. The range of stranded cost estimates is US\$70 billion to US\$500 billion; an often-quoted likely mid-range is US\$135 billion to US\$200 billion.

Source: "Regulatory Reform in the US" (OECD/IEA, 1998).

transmission is operated by separate entities. Alberta has set up a mandatory spot market and a voluntary spot market is planned to start operation in Ontario in 2001.

■ Japan

In 1998, the Government of Japan adopted a programme of partial liberalisation of its ESI. Large consumers, who use more than 2 MW

Figure 2*Status of State Electric Industry Restructuring as of May 2000*

1: Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.

2: Michigan and New York.

3: Alaska and South Carolina.

4: Alabama, Colorado, Florida, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.

5: Georgia, Hawaii, Idaho, Kansas, Kentucky, Nebraska, South Dakota, and Tennessee

Source: Energy Information Administration.

and take power at 20 000 volts or above, will be eligible to choose their supplier. These consumers account for about 30% of total electricity demand. In addition, there will be negotiated third party access to the grid. Other related measures include a re-examination of the electricity rate (tariff) system, the introduction of a full scale bidding system for the development of thermal power, and the removal and simplification of some administrative procedures and rules to ensure transparency in transactions. Reform was implemented in March 2000 and will be reviewed three years later.

Performance

It is still too early to evaluate the performance — in terms of costs, prices, and global social benefits¹² — of electricity reforms. The experience so far indicates that there are significant differences among reforming countries. For instance, in some countries intense price competition has developed quickly while in others the initial impact of reform on prices has been modest.

Significant time series are only available for the UK. Since 1990, the productivity of the industry has skyrocketed. Output rose by 8% from 1988 to 1995 and, in the same period, employment was reduced by roughly 50%. Final electricity prices in the UK have experienced a substantial decrease over the 1990-1997 period. In real terms, domestic rates have decreased by 20%, equivalent to a 9% reduction in nominal terms; non-domestic tariffs have fallen in the range of 19 to 27% in real terms during the same period¹³. Electricity generators have remained profitable, with a return on capital employed that has stayed above 25% for the two largest generators in the 1993-99 period¹⁴.

12. Other key aspects of performance such as environmental impact and reliability will not be considered in this book.

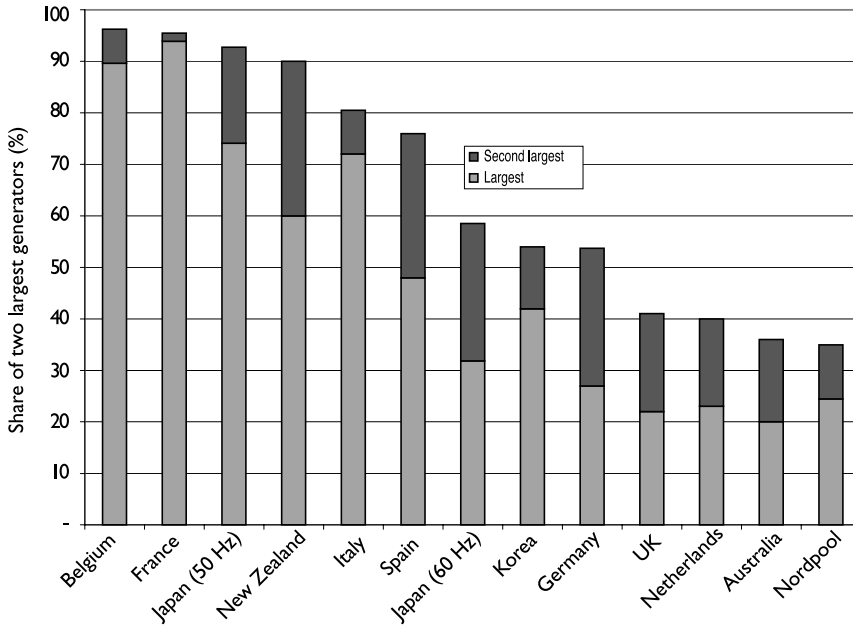
13. Littlechild (1998).

14. Ofgem (2000).

The reduction of (end user) electricity prices in the UK has resulted from both the adoption of regulatory measures (e.g. RPI-X caps on transmission and distribution charges) and competition. Decreasing pool prices¹⁵ have contributed to the decrease in final prices. Time weighted pool selling prices have dropped nearly 10% in real terms in the 1990/91 to 1997/98 period¹⁶ reflecting significant reductions in the cost of power generation, estimated in the 40-50% range¹⁷. However, the changes in costs have not

Figure 3

Market Share of Two Largest Generators in Selected OECD Markets (1998)



Note: US and Canada not included as each comprises various separate markets. Share in New Zealand was reduced to 53% in 99. Share in UK (England and Wales) was reduced to approximately 28% in 99.

15. The evolution of pool prices is described in the IEA Review of Energy Policies of the UK 1998.

16. In nominal terms, pool prices rose during the initial four years of operation. This led to the imposition of a two year price cap. Prices have since dropped.

17. Ofgem (2000).

resulted in similar falls in pool prices which have remained well above the price that would make new investments economical¹⁸. This, and other related evidence, has been widely interpreted as a sign of insufficient competition in the England and Wales pool. It has been estimated that prices exceeded competitive levels by around 20-25% in the England and Wales pool¹⁹.

A cost-benefit analysis of the UK experience provides estimates of the overall benefit of the 1990 electricity restructuring²⁰. Depending on the scenario considered it could be £6 or £11.9 billion (values discounted to 1995). This amount is equivalent to a permanent reduction of electricity prices of 3.2% or 7.5% from 1990 levels. The distribution of benefits among the different parties is unequal with shareholders getting large benefits (£8.1 or £9.7 billion), government getting a smaller benefit (£0.4 or £1.2 billion) and (wholesale) power purchasers losing £4.4 or £1.3 billion, respectively²¹.

Evidence from other countries (see Table 7) may still be anecdotal:

- In the Nordic countries, prices spiked in 1996 roughly at the same time as NordPool began operation but this has been attributed to unusually dry weather conditions during 1995 and 1996. Since then, prices have receded to pre-95 levels. For example, in Sweden the average NordPool spot price in 1999 was 119.42 SK/MWh, down from 120.49 in 1998, 143.77 in 1997 and 260.01 in 1996. The current price level in NordPool is relatively low compared to total electricity generation costs in new plants which are estimated to be in the order of 300-350 SK/MWh for oil- gas- and coal- fired plants²². This steep downward trend is not reflected in end user prices. Pre-tax domestic prices rose around 3.5% in 1996, the year when the market was open. At the end of 1999 they were roughly at the

18. Offer (1998), Ofgem (2000).

19. Thomas (1999), Ofgem (2000), Wolfram (2000).

20. Newbery and Pollitt (1997).

21. The loss suffered by (wholesale) purchasers reflects that electricity prices have fallen less than costs.

22. See Energy Policies of Sweden 2000 Review, IEA.

level of 1996 and were expected to decrease in 2000. Industrial prices have remained more or less stable in the 96-98 period.

- In Australia, electricity prices decreased over 1% in 1998 following the establishment of the National Electricity Market. A larger price drop was recorded in wholesale prices. In the Victorian pool, prices more than halved from \$28.1 per MWh in 1995 to \$12.5 per MWh in 1997. Prices remained low on average in the Australian National Electricity Market during 1998 and 1999. This trend seems to reflect both the onset of competition and the existence of large reserve margins of generation capacity in the Australian market.
- In New Zealand, final prices have not risen significantly after the implementation of reform and some rebalancing has occurred between the domestic tariffs and other tariffs²³. Average spot prices before and after the establishment of the New Zealand Market have been fairly stable and have been below the price at which new generation capacity would become economical²⁴.
- In Spain, nominal retail prices have decreased by around 10% in the 1996-1999 period following an agreement between government and industry to gradually decrease tariffs over a five-year period. Wholesale prices have remained stable over the first two years of operation of the power exchange but have peaked in the first months of 2000. Weak competition is often attributed to the high concentration of the Spanish ESI.
- In Germany, an intense price war has been reported during 1999 and early 2000, resulting in some significant price reductions. According to Eurostat, prices fell in the 1996-1999 period by 9.6% for industrial consumers and increased by 0.8% for domestic consumers. In parallel, a wave of mergers and acquisitions is reshaping the industry. This price trend seems to

23. Read (1998).

24. Wolak (1997); New Zealand Ministry of development (2000).

reflect both the onset of competition and the atomised structure of the industry.

- In California, regulated end user tariffs decreased by 10% at the time of restructuring. Customer switching to new suppliers (presumably attracted by even lower tariffs) has been modest, particularly among domestic consumers. In some parts of California, where the cap on tariffs was abolished in 2000, there have been substantial price increases during the summer. It has been estimated that energy purchase costs in California averaged about 14% above competitive levels during 1998 and 1999²⁵. There has been significant price volatility in the wholesale market, with large price spikes during the high demand summer months. Price increases have resulted from a large demand increase, as well as from the investment slowdown that took place during the years immediately before the opening of the market. The investment slowdown has been attributed to the large regulatory uncertainty that existed at the time when reforms were planned. Apparently, investment activity has returned to normal levels since the market opened in 1998²⁶.

Reliability and environmental impact are also critical dimensions of performance. Both impacts appear so far to have been modest and, if the right institutions are in place, there is no reason to fear that this will change. However, regulatory uncertainty may have an adverse impact on reliability as illustrated by the case of California²⁷. While this is a transitional issue, it is a critical one. The acceptability of reforms largely depends on the ability of the reformed ESI to sustain a reliable electricity supply.

An assessment of environmental and reliability performance has to wait until much more information becomes available. Many factors other than competition have a large effect on reliability and

25. *Bushnell and Wolak (2000)*.

26. *CPUC(2000)*.

27. *Difficulties to attract investment in developing countries (e.g. Argentina, Brazil and India) have also been attributed to the ambiguity and risk of the regulatory regimes in those countries.*

environmental impact and therefore it is difficult to isolate the impact of competition. For instance, the average CO₂ intensity of electricity generation in the OECD countries has decreased since 1990, and reforming countries participate in this trend. However, changes in relative fuel prices (e.g. lower gas prices) are probably a more important factor in explaining this trend than the development of electricity competition and trade. Likewise, reliability depends on reform policies and decisions taken before the onset of competition and unusual circumstances (e.g. severe weather or accidents). A longer time perspective will be needed to assess reliability under competition.

Table 7

Wholesale Average Prices (US\$ per MWh)

	1995	1997
Australia (Victoria)	28.1	12.5
New Zealand (North Island)	19.1	26.0
Norway	15.6	17.9
United Kingdom (England & Wales)	39.7	40.5

Source : all data compiled by Offer (1998).

WHAT MODEL FOR THE ESI?

The review of national approaches in the previous chapter suggests the broad lines of an emerging new model for the ESI. This chapter discusses the emerging model and compares it with a number of alternatives. The focus of this analysis is on how to maximise efficiency in the ESI.

Retail Competition

The basic emerging alternative to the vertically integrated monopoly is the retail competition model²⁸. Most other approaches to reform can be described as a constrained version of retail competition. The retail competition model has the following characteristics:

- Transactions between generators, end users and a number of possible intermediaries, including retailers, power exchanges and brokers, take place freely (within the constraints imposed by the network). Thus, on the demand side, end users are free to choose their supplier and to negotiate their contracts; on the supply side, generators can sell their electricity to any other market players.
- Network activities and prices are regulated and, in particular, there are provisions to ensure non-discriminatory third party access to the network, often including some form of separation of network activities from generation and end-user supply.
- There is an independent system operator, which means that the system operator is not owned or, at least, not controlled by the owners of generation assets.

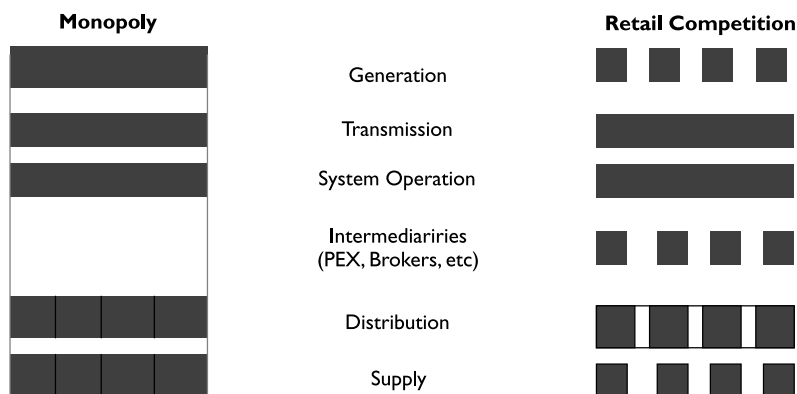
This model is the starting point for the organisation of the electricity market in Finland, Norway, Spain, Sweden and Finland,

28. Here we follow the most common terminology. See Hunt and Shuttleworth (1996) and Joskow (1996). The “retail competition” model is sometimes referred as the “bilateral contracts” model, particularly in Europe, but the precise meaning of this term can vary.

some US states (e.g. California) and, with the implementation of the New Electricity Trading Arrangements, the UK. The basic structure of the model is summarised in Figures 4 and 5. Retail competition combines deregulation, lifting constraints on the potentially competitive activities in the ESI, with re-regulation of the network and related activities which remain monopolistic.

Figure 4

Monopoly vs. Retail Competition



A comprehensive reform programme includes:

- Structural reforms designed both to separate regulated and potentially competitive activities and to promote competition within the latter;
- Institutional reforms intended to provide adequate framework conditions for the effective functioning of emerging competitive markets; performance regulation aimed at providing incentives for efficiency in the management of regulated activities;

Figure 5

Retail Competition: How Does it Work?

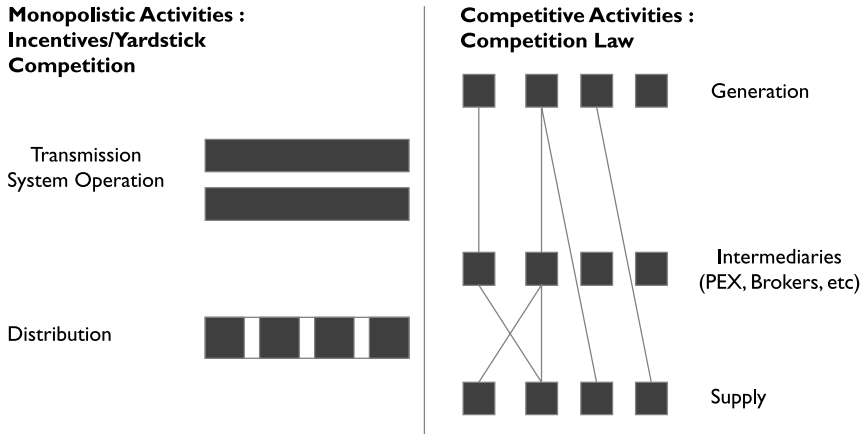
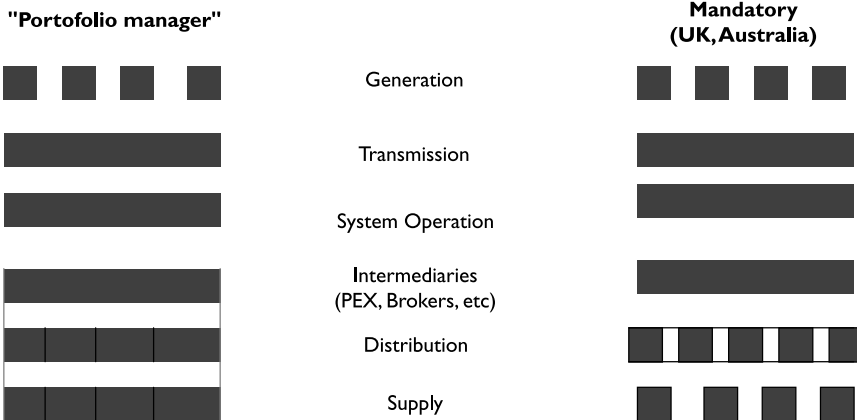


Figure 6

Other Approaches



- Transitional arrangements to implement reform, including a calendar of reforms, and, in some cases, a plan to deal with stranded assets²⁹; and
- measures to ensure competitive neutrality of general policy instruments (e.g. environment).

Alternative Approaches

Different industry configurations may be imagined combining elements of the retail competition model with elements of the monopoly model. Only a few of these configurations have actually been implemented. The first modern approaches to competition in electricity markets were based on the portfolio manager model³⁰, which is still widely applied in some regions of the world. In this model there is procurement competition, that is, the right to build and operate generation assets is assigned competitively, usually through an auction. Apart from this, all activities remain regulated, and monopoly utilities retain the obligation to supply consumers within their exclusive franchise areas with bundled retail electricity service³¹. If the tendering process is open and competitive, this model provides incentives for cost efficiency in building and managing generation plants as generators can retain any cost savings. However, the portfolio manager inherits most of the weaknesses of the vertically regulated monopoly. There are no external (market) incentives to set end user prices efficiently. Investment risks are borne by end users instead of investors. There is no day-to-day competition among generators. Finally, the portfolio manager model is risky for end users because it locks them into long-term procurement contracts that may eventually turn out to be too costly or otherwise inadequate.

29. The issue of stranded costs is discussed in the appendix at the end of this chapter.

30. The term “portfolio manager” is somewhat vague. Most often it refers to generation procurement competition as defined in this paragraph. However, a monopolistic buyer of electricity not owning any generation plants is sometimes also called a “portfolio manager” (this manager could emerge in the context of the EU Directive single buyer option).

31. See Joskow (1997).

Moving one step forward in the development of competition, generators may be allowed to compete against each other. Competition in generation is often labelled wholesale competition. It may require generators to sell through a power exchange; this yields the mandatory pool model in operation in the UK and Australia. Alternatively it may allow generators to sell directly to all or some end users or a number of intermediaries; this yields (full or partial) retail competition. Often, the restrictions on consumer choice are intended to be transitional arrangements, and are progressively eliminated. Figure 6 summarises the portfolio manager and the mandatory pool models.

Retail Competition Issues

Introducing consumer choice is costly, particularly for small end users. This raises the issue of whether the benefits of retail competition, including the indirect benefits, outweigh the costs for all consumer groups.

The cost of metering may be a barrier to the development of competition for small consumers. Currently, meters used for smaller consumers do not generally have time-of-use metering capabilities. Time-of-use metering is needed, at least in principle, for the unbundled billing of energy and grid services since energy prices (and possibly grid access prices as well) vary over time. The cost of improving metering equipment is relatively high. Table 8 shows some estimates of meter costs depending on the capabilities of the meter and the scale of its use. Rapid progress in information technologies suggests that these figures will decrease in the future and, even today, simple meters allowing for day/night differentiated metering can provide a relatively cheap proxy for the actual load profile. Metering also entails other costs such as those related to compiling and processing information.

Compared with metering costs, the gross margin of electricity commercialisation, i.e., the difference between the price paid by

end users and the price paid for energy and transportation, is relatively small. For instance, the allowed gross margin of commercialisation in 1997 in the UK for below 100 kW consumers was in the range of US\$30-\$38 per consumer per year. As a consequence, even if commercialisation margins were to decrease significantly, smaller consumers may not generally find it profitable to pay the cost of improved meters in exchange for a reduction in their annual electricity bill.

Table 8

Cost of Metering Equipment (US\$)

Meter Type	Functions	Unit Cost 100 Consumers	Unit Cost 50,000 Consumers
Meter Modifications	Limited AMR*	175-300	75-300
Existing Electronic Meters	AMR* Load Profiling	250	100
Advanced "Smart" Meters	AMR* Load Profiling Time-of-use Control	600	500

AMR* = Automated Meter Reading
Source: J. King (1997).

Reliable cost-benefit estimates of competition for small consumers are not yet available. Indirect impacts of competition on cost reductions and tariff re-balancing are difficult to estimate. The start-up costs of metering and billing systems are also uncertain, as figures provided by industry may be overstated. In the UK, the electricity regulator estimated benefits of some £6 to £8 billion over a ten year period against costs of some £20 to £80 million per year plus initial set up costs of between £150 to £520 million³². These figures suggest large welfare gains. When only direct impacts are considered and start-up costs are valued at an intermediate

32. Offer (1996).

value in the above range, one study³³ has found that costs may initially exceed some £100 million per year. Once start-up costs are amortised, costs may approach benefits. These figures may provide lower bounds for the actual welfare gains. This study also suggests that there are large welfare transfers involved in the introduction of competition, with consumers gaining significantly through lower prices, and with suppliers losing.

Box 2

Competition for Small Consumers: the Case of California

Since April 1998, Californian electricity consumers may choose between Direct Access or their existing utility service. Direct Access is the purchase of electricity from non-utility electric service providers. Furthermore, consumers below 20 kW may use load profiling to avoid new metering requirements.

There are concerns that retail competition will not easily extend to the residential consumer segment. The low retail margins may not compensate the costs of getting consumers to switch their electricity supplier. Enron, one of the largest competitors in this segment, announced in late April 1998 — three weeks after the Californian market opened — its intention to abandon this market segment. On the other hand, a number of electricity service providers remain active in this segment. Apparently their strategy is to compete through the proliferation of value-added services (e.g. green energy) instead of competing in price discounts. As of August 1999, 1.5% of all electricity consumers, accounting for 11.6% of demand, have switched supplier in California, reaching an estimated 2.2% of all electricity consumers in February 2000.

Source: Wisser, Golove and Pickle, 1998; Rivera-Brooks, 1999; and O'Rourke, 2000

33. Green and McDaniel (1998).

An increasing number of countries are adopting “load profiling” to reduce the costs of extending retail competition to all consumers. The idea is that statistical inference procedures allow precise estimates of the aggregate load of “many” small consumers. Even if metering and settlement procedures under load profiling are complex, requiring appropriate information technology, load profiling can be significantly cheaper than actual load metering.

An Assessment

Retail competition aims to promote competition as much as possible in the ESI, but acknowledges the need to continue regulating the network. Retail competition relies on end-user choice together with competition among generators as the two key forces disciplining the market. In older approaches, only competition among generators was allowed to play a significant role. By letting the demand side be an active market participant, the retail competition model seems to offer the best chances of success in addressing inefficiencies in the generation and end-user supply segments of the ESI, whilst maintaining a strong regulatory approach to transmission.

Experience with approaches that do not fully deregulate generation and end-user supply suggest that these are not sustainable in the long-term. Mandatory pools and partial market opening require substantial regulatory involvement. Mandatory pools seem particularly vulnerable to manipulation or “gaming”, and partial market opening is likely to distort prices. As a result, captive consumers may subsidise eligible consumers. These problems create pressure for removing restrictions to competition in generation and end-user supply.

Full deregulation, in essence the removal of all electricity specific rules, is occasionally developed as an alternative means of introducing competition. Full deregulation lifts constraints on the prices of electricity and grid services, allows choice to all

consumers and does not impose any constraints on the vertical structure of electricity companies. Under this approach, the vertically integrated structure of the industry remains unchanged. Network activities are not regulated. Market power and anti-competitive behaviour are controlled *ex post* (after the event), through the application of competition law. The negotiated third party access models being implemented in Germany and, with a more significant degree of unbundling, in New Zealand, contain most of the elements of this approach.

Full deregulation is often the reform choice in other network industries, including telecommunications and air transport, and it cannot be ruled out in the ESI. However, it is complicated by the central role that the network plays in most electricity systems and the consequent need which most reformers perceive to regulate it. In addition, many countries traditionally rely on *ex ante* regulation more than on *ex post* application of antitrust to pursue policy goals. Full deregulation in these countries would require strongly reinforcing their competition authorities and laws. This approach could become a focal point of reform if changes in technology or prices of generation reduce the importance of the network in supplying electricity efficiently.

Partial or gradual reforms may have an important place in the overall reform path. A gradual approach may favour the political and social acceptability of reforms. In addition, a partial reform may be the only feasible option when governments seek to maintain some direct control over the ESI, at least for some time. Reasons include the desire to maintain or develop a technological option such as nuclear, to keep a direct control over electricity prices or to promote national energy security beyond the levels that might be achieved by the market. Even when political constraints limit the extent and the potential benefits of reform, partial reforms can improve upon the existing situation and can be built on in due course when political conditions allow. Examples of partial reforms are:

- Institutional and procedural reforms to increase transparency and to minimise undue influence in the regulatory process (e.g. establishing an independent regulator);
- Vertical and horizontal separation of activities to increase transparency and to facilitate regulation;
- Dismantling subsidies and cross subsidies to eliminate distortions in other economic sectors (e.g. end user tariff reform to eliminate cross subsidies);
- Corporatisation possibly followed by privatisation of the ESI;
- Incentive regulation of ESI activities and yardstick competition;
- Limited competition in generation (e.g. procurement competition to create an external incentive for cost minimisation on the utilities, and a mandatory spot market based on costs or, preferably, a generator's bids to make dispatch decisions and to remunerate variable costs; and
- Limited competition in retail supply (e.g. limited consumer choice to facilitate some retail supply competition) or opening the electricity market to international trade.

A number of case studies³⁴ show that piecemeal reforms are potentially costly. Regulatory mismatches expose governments and, ultimately, end users to substantial risks during the transition. For instance, competitive generation procurement coupled with monopolised supply may result in a build up of potentially stranded assets or potentially uneconomical long-term contracts. In addition, the eventual implementation of delayed reforms may be obstructed or blocked by early reforms. For instance, vertical and horizontal restructuring are much more difficult after privatisation. Also, there is evidence that regulatory intervention in the potentially competitive activities (e.g. through a mandatory pool) distorts the behaviour of market players. This

34. The UK experience has been extensively documented; see, for instance, Newbery (1995) and Green (1996). For an account of the early US experience, see Joskow (1997) and the references therein. See Rosenzweig and Voll (1998) for an analysis of reform in New Zealand, Argentina, Brazil, Chile and India. The case of Colombia is reviewed in Gray (1997). Bond (1998) points out some lessons from the Asian experience.

does not exclude gradualism nor flexibility in the implementation of reforms as long as reform progresses along a coherent plan.

Appendix

■ Transition Issues: Stranded Costs

This appendix reviews stranded costs, which are a significant transition issue in some countries. An asset is stranded if its sunk costs cannot be completely recovered under competition. Stranded costs are the difference between the sunk costs of an asset and the expected remuneration under competition (net of variable costs and salvage value). The potential for stranded generation assets seems to be significant in some countries resulting from a number of factors, including excess generating capacity investment, lower than expected demand growth, and technological obsolescence. The concept of stranded costs has been developed only recently in the context of the liberalisation of the US power industry. Explicit stranded cost payments have only been set in the US and Spain.

Stranded costs raise three important issues. The first is the question of who should pay the stranded costs: consumers, taxpayers or investors? This is essentially a fairness issue. Since allocating stranded costs has distributive implications, no solution can be satisfactory to all parties. In countries evolving from a publicly-owned ESI, stranded costs can be amortised at the time of flotation, and are implicitly absorbed by taxpayers. This does not distort the market and leaves firms' finances unaffected. However, this option may not be feasible when companies are already privately owned and taxpayers do not assume payment of stranded costs. In this case, other arrangements between investors and consumers will need to be made. In addition, legal considerations may determine the allocation of stranded costs (e.g. regulatory commitments to finance certain investments and long-term contracts). Stranded costs may also have implications

for the performance of the industry. In particular, stranded cost payments may have an unequal impact on competing electricity companies, distorting competition.

Second, there is the question of how to measure stranded costs. This is complicated by two interconnected features:

- Competition creates incentives for firms to inflate their stranded costs by either declaring more of their assets stranded or by claiming a low market value for their stranded assets. If payment for stranded costs is made outside the competitive market, this strategy allows firms to improve their financial position. The resulting inflationary pressure is sometimes called the snowballing effect of stranded costs.
- The market value of a stranded asset under competition is not known with certainty unless the asset is actually sold³⁵. The option of selling the assets is sometimes a natural step in the reform process, namely when utilities are privatised at the onset of competition or when divestiture is sought for vertical restructuring to enhance competition. There can also be a policy decision that each stranded asset be sold by means of an auction in which the former owners are not allowed to participate. Otherwise, the market value of the assets has to be approximated following one of the several methodologies that have been proposed.

If the stranded assets are sold, the measurement problems are resolved. However, this option may be unfeasible due to private ownership of the assets or to other reasons, in which case stranded costs have to be valued following *ad hoc* procedures.

35. The selling price will depend not only on the asset itself but also on the regulatory framework (e.g. whether there are capacity payments) and on the structure of the market (e.g. whether market power is expected to keep prices at high uncompetitive levels). This further emphasises the fuzziness of the stranded cost concept.

36. For instance, a firm with many stranded assets may have a greater incentive to set low prices since this will result in more stranded costs being recognised; a firm that owns no stranded assets will have "standard" pricing incentives. These asymmetries may negatively affect the performance of the market.

Third, related to the difficulty of obtaining reliable estimates of stranded costs, there is the issue of when stranded costs should be valued. One possibility is to establish their amount at the onset of competition. Another is to wait and link the assessment of stranded costs to the actual value of the assets observed in the market. The wait-and-see option imposes a financial cost on firms due to the increased uncertainty of future revenues. It may also distort prices and competition. The behaviour of the utilities will be affected by the fact that market prices will be used by the regulator to assess the magnitude of stranded costs³⁶. Valuing stranded costs at the onset of competition does not create this distortion.

On the other hand, it has been argued³⁷ that the wait-and-see option may result in less stranded costs being ultimately paid. *Ex ante* estimates of stranded costs may be biased upwards. This bias can be corrected once market prices and the actual performance of the assets under competition can be assessed. In addition, stranded costs will most likely be reduced as the depreciation of assets continues over time. Whether the wait-and-see option yields any real benefits depends largely on the political and institutional factors surrounding the bargaining process in which the amount of stranded costs is determined. These factors vary from country to country. In any case, delays in the valuation of stranded costs can be costly and potentially distortionary and, therefore, have to be limited in time.

37. In the context of the Spanish and Dutch reforms, for instance.

UNBUNDLING

This and the following three chapters consider the four key areas of change that underpin an effective reform of the ESI aimed at maximising competition. These are:

- The separation of the functions that make up the ESI or unbundling (Chapter 5);
- The organisation of wholesale electricity markets (Chapter 6);
- The regulation of the transmission network and, particularly, the pricing of transmission (Chapter 7); and
- The institutional and policy framework, which needs to be adapted to oversee the new market conditions effectively (Chapter 8).

Why Unbundle?

The main reason to unbundle is to avoid discrimination by vertically separating monopoly from competitive activities. Transmission, system operation and distribution remain monopolies in a liberalised ESI. If these monopolies are vertically integrated with the competitive activities of generation and end user supply, they have an incentive to use their monopoly power against competitors. A grid monopolist can distort competition in many ways. For instance, discriminatory access conditions, high or discriminatory access charges and “strategic” investment in grid augmentation may put competitors at a disadvantage.

Competition law makes discrimination illegal in most countries, and discriminatory behaviour is punishable by competition authorities. However, this may not be a fully effective remedy to counter discrimination. Showing that a certain practice is discriminatory may be difficult and costly, and requires the affected parties to engage in lengthy antitrust procedures with no guarantee that they will win.

Vertical separation thus aims to limit the ability as well as the incentive of grid monopolies to distort competition. In particular, reforming countries have to deal with separation of:

- Generation and transmission/system operation;
- Generation and distribution; and
- Distribution and end user supply.

A second and related reason to introduce unbundling is to improve the effectiveness of regulation. Some degree of separation between regulated and competitive activities is needed to regulate effectively. For instance, the regulation of transmission revenues requires, at least, separate and transparent accounting of transmission. Stronger separation facilitates a more effective ring-fencing of regulated activities and, therefore, a more cost reflective pricing of grid services.

Vertical Separation of Generation and Transmission

A transmission owner who also owns generation assets has the incentive to discriminate against the other generators and to favour his own generating units. To the extent that competing generators have to access the network to deliver their electricity, the transmission owner also has the ability to discriminate by setting high access prices, reserving transmission capacity for its own generation units, providing unequal access to technical information (e.g. changes in available capacity over time), or imposing abusive technical requirements. He can also enter into long-term contracts that block transmission capacity or even favour a biased development of the transmission grid.

■ Forms of Separation

Vertical separation of generation from transmission and system operation activities may reduce or eliminate self-dealing or other forms of discriminatory behaviour, but the architecture of

separation can be quite complex. Four basic approaches to vertical separation have been proposed:

- Accounting separation: keeping separate accounts for generation and transmission activities within the same vertically integrated entity. On this basis a vertically integrated entity charges itself the same prices for transmission as it does others and offers separate prices for generation and transmission services.
- Functional separation: accounting separation, plus (1) relying on the same information about its transmission system as the other market players when buying and selling power, and (2) separating employees involved in transmission from those involved in power sales.
- Operational separation: operation of, and decisions about, investment in the transmission grid are the responsibility of an entity that is independent of the owner(s) of generation; however, ownership of the transmission grid remains with the owner(s) of generation.
- Divestiture or ownership separation: generation and transmission are separated into distinct legal entities with different management, or operations, and there is no significant common ownership.

Some countries (e.g. Denmark) require corporate unbundling, i.e., creating separate legal entities for generation and transmission, whilst preserving common ownership. This is a legal concept that does not conform exactly to any of the four forms of separation defined above. In practice, corporate unbundling may be similar to accounting separation since it allows firms to share owners, management, staff and information while requiring a separate accounting of the different functions.

The transmission function may be disaggregated into ownership of grid assets and system operation. Electricity trade through a power exchange, which is sometimes bundled with transmission, can also

be performed separately. Transmission related activities may thus be organised in many different ways depending on the form of unbundling (from accounting separation to divestiture) and on which activities, among ownership, system operation and trade, are unbundled. Table 9 provides examples of the different approaches to unbundling transmission.

Table 9

*Organisation of Transmission-related Activities
in Competitive Electricity Systems*

Type of Unbundling		Examples	Structure of Companies
Ownership Separation	Separate Power Exchange	Finland, Norway, Spain, Sweden, UK (planned)	One Transmission Company ("Transco") owns and operates transmission One or several Power Exchanges (PX) facilitate trade
	No Separate Power Exchange	England and Wales (until 2000)	One Transmission Company ("Transco") owns and operates transmission, and facilitates trade
Operational Separation	Separate Power Exchange	California New Zealand	One or several Grid Companies own the grid System Operator (ISO) operates the grid Power Exchange (PX) facilitates trade
	No Separate Power Exchange	PJM Interconnection	Grid Companies own the grid System Operator operates the grid and facilitates trade
Functional and Accounting Separation		Austria, Belgium, Denmark, Germany, Greece	Vertically Integrated Companies

■ Ownership Separation

Ownership separation solves nearly all concerns about discrimination because it eliminates the incentive as well as the ability to discriminate. The weaker forms of separation limit the ability to discriminate but do not eliminate the incentive to engage in discriminatory behaviour.

Imposing ownership separation of transmission on vertically integrated companies may be difficult due to legal obstacles or opposition from the utilities. Inducing divestiture by means of financial incentives may be costly. This issue is particularly significant when the vertically integrated companies are privately owned, as in the US and Japan.

Some analysts have expressed concern that ownership separation of transmission and generation may distort investment decisions in generation. The reason is that generation and transmission can be substitutes for each other³⁸. For example, an alternative to building new generation capacity is to build a transmission line to bring electricity generated somewhere else by an existing plant. Investment decisions that are limited to either generation or transmission assets may not be globally optimal. For instance, weak transmission links in a given area may discourage investments in generation that would be cost efficient in that area because of the proximity of a gas pipeline that could provide fuel cheaply. The cost savings for generation that would result from reinforcing the grid in that area may be ignored by a transmission company that is only concerned with transmission investment.

However, the practical relevance of this issue may well be small. Ownership separation of transmission assets seems to have worked satisfactorily for several years in a number of countries, including the UK, Sweden, Norway and Finland and no significant problems have been reported. Regulatory measures, such as allocating the cost of congestion to the transmission company, can

38. They are also complementary as they are combined to supply electricity.

provide strong incentives to invest and eliminate congestion. This approach, adopted for instance in Finland, may work even if transmission investments are reserved to a monopolistic transmission company. Nodal prices, that reflect the true cost of using the network, also provide incentives for third parties to invest and eliminate distortions. For price signals to be effective it is necessary that transmission investment be open to third parties (with appropriate limits on the participation of generators).

■ Operational Separation

Operational separation works through Independent System Operators (ISO) that operate but do not own the transmission grid. In effect, ISOs interpose themselves between transmission owners and generators. ISOs may be effective in reducing discrimination, provided there are many competing owners of generating units and transmission assets.

Operational separation raises other issues. First, incentives for efficient management of ISOs may be weak. The ability to control ISO management is reduced by the limited rights of the owners of transmission assets. In addition, most ISOs are not-for-profit. Their performance will depend critically on the ISO governance structure and how it combines objective independence and operational expertise. Stakeholders can provide operational expertise but do not have the right incentives to act independently, as they tend to favour their narrow interests. For instance, the US experience shows that weighted voting allowed abuse (in one of the old system operators, the NEPOOL), while requiring unanimous decisions made it difficult to reach decisions to correct market imperfections (in another of the old system operators, the PJM). Independent boards, on the other hand, lack operational expertise.

Existing ISOs have taken different approaches to governance. In California, the ISO is governed by stakeholders, but its functions are restricted to the technical operation of the system. In NEPOOL and PJM, there is a two tier approach to governance, half

way between “all stakeholder” and “no stakeholder” governance. In this approach, an independent board, which has ultimate decision-making authority, co-exists with a committee of stakeholders, which makes decisions but the board does not review every decision of the committee. The design of effective governance structures for ISOs is still an open issue³⁹.

A further issue is that incentives to invest in transmission may be distorted to some extent. An ISO that controls, but does not own, transmission assets weakens the property rights of the transmission owners. This may distort investment incentives as the value of the asset to investors may be reduced by their lack of control over it (owners can sell the assets but cannot control their operation). Experience with ISOs is still limited, so the significance of property rights remains uncertain.

■ Functional and Accounting Separation

The two more limited forms of separation are relatively easy to implement. Legal difficulties are minimal, opposition from industry is typically weak, and set-up costs are modest compared with those of setting up an ISO. However, the constraints on the ability of transmission owners to discriminate are less effective even if they may contribute to increase transparency. This implies that functional and accounting separation, whenever adopted, needs to be complemented by strong regulatory oversight, vigorous antitrust enforcement, and preferably both. These complementary measures are costly to administer and drain significant resources from the regulated parties. These costs have to be weighed against the benefits of a relatively simple and lower cost implementation. In addition, it is unclear whether increased vigilance by regulatory and competition authorities would be enough to prevent discrimination.

The foregoing analysis shows that there is no perfect solution:

39. See CPUC (2000).

- Ownership separation is the only option that eliminates concerns about anti-competitive discrimination by transmission owners. Thus, there is a strong presumption that divestiture of transmission should be required in a competitive electricity market. However, if electricity companies are privately owned, ownership separation may be difficult to implement and, in practice, other options may be more attractive.
- Operational separation may be effective in preventing discrimination if there are many transmission owners. However, in order to promote efficiency, operational separation requires the development of sophisticated and still largely untested governance structures.
- Weaker separation forms (functional and accounting) require a large and costly involvement of regulatory and competition authorities and may fail to prevent discrimination.

Vertical Separation of Generation and Distribution

Discrimination is also possible at the distribution stage. The owner of distribution assets may favour his own generation and discriminate against other competing generators (e.g. charging high access prices to the distribution grid). The issues raised by discrimination in the provision of distribution services and the possible approaches to deal with them are similar to those considered in the separation of transmission and generation⁴⁰. However, operational separation of distribution is not considered an option in practice because the costs of setting-up and operating ISOs are large relative to the size of a typical distribution area.

Divestiture is the only effective way to eliminate concerns with discrimination in distribution as it removes incentives to discriminate. This is the approach taken in the UK and in some US

40. A difference is that the substitutability between generation and distribution is more limited.

states. Integration of generation and distribution is nonetheless permitted in some reforming countries that have divested transmission (e.g. Norway, Sweden and Spain), but this may be an obstacle to competition.

Vertical Separation of Distribution and End-user Supply

Another possible form of discrimination arises when the owner of the distribution grid is also a competitor in the end user supply market. Abusive distribution pricing, cross subsidisation, unnecessary technical requirements (e.g. related to metering) and procedural and implementation delays can be used to put competitors in the end-user supply market at a disadvantage.

The incumbent supplier (“utility affiliate”) benefits from a significant competitive advantage vis-a-vis new independent (unaffiliated) entrants. Initially, the incumbent supplier covers the entire market. Thus, incumbents benefit from horizontal market power. Consumers may perceive risks and costs when switching electricity supplier. In addition, incumbents have an established reputation and recognition attached to the name and logo of the parent utility and they also have access to valuable information about their consumers. These structural barriers to the development of retail competition, particularly in the small consumers segment, reinforce the case for unbundling distribution and end-user supply.

The options for unbundling distribution and end user supply are essentially the same as those discussed above: separate accounts, functional separation (e.g. through the development of standards of conduct to govern relationships between distribution companies and their supply “affiliates”) and ownership separation. In addition, there are proposals for equalisation measures (e.g. in the US) to compensate for the competitive advantage inherited by the incumbents. These include restrictions on the use of the name or

the logo of an utility by its affiliate and banning or restricting affiliate sales of electricity in the utility's historic area⁴¹.

The actual approaches to unbundling distribution and end user supply are typically functional or accounting separation, often implemented on the basis of corporate unbundling. Ownership separation is required in New Zealand. The lack of unbundling between the distribution and end-user supply businesses may slow down the development of competition in end user supply, but a stronger approach has not evolved for a number of reasons. First, implementing ownership separation is often difficult. Second, the direct benefits of promoting competition in end user supply are relatively small because it accounts for a small share of total costs (even if the indirect and long-term benefits are potentially crucial to reform success, as discussed in Chapter 4). Third, it is sometimes argued that there are vertical economies of integration between distribution and supply.

41. The issue of the appropriate relationship between a utility and its marketing affiliate has been addressed in the US by several state regulators in the context of gas distribution. Standards of conduct in gas distribution typically involve the prohibition of preferential treatment to the affiliate, structural separation of functions and related monitoring and enforcing procedures. In this vein, the California Public Utilities Commission requires non-discriminatory access to local distribution information; specifies separation standards (e.g. office space and information systems cannot be shared); mandates separate accounting; and establishes billing procedures in which cost is separated by function and charges are the same for Direct Access and the utility service, except for energy costs (K. Costello, 1998). The much debated question of whether affiliates should be allowed to use the logo of their parent utility has been resolved by allowing them to do so. They are required, however, to inform their clients about their structural separation from the utility.

MARKETS

The development of competition in the ESI results in a large increase in transactions in electricity as well as in the development of related financial contracts. This chapter provides an introduction to organised electricity markets and related financial instruments. First, it provides an overview of organised electricity markets in OECD countries. Second, it discusses two key market design areas: bilateral transactions and capacity mechanisms. Third, the structure and function of financial contracts is analysed.

“Spot” Electricity Markets

The physical nature of electricity does not allow for a true electricity spot market, that is, a market for immediate electricity delivery. Instead, transactions are scheduled some time in advance of physical delivery (e.g. one day, one hour or five minutes in advance). Imbalances between scheduled and actual supply and demand that inevitably arise are handled following some predetermined procedures, which may or may not be competitive.

Competitive pools or power exchanges are a substitute for a true spot market. In most existing pools, pool purchasing prices and scheduled supply are set by auction some time in advance of physical delivery. Pool selling prices are established by adding the cost of imbalances, ancillary services, and possibly other demand related charges such as capacity payments to the pool purchasing price. Since prices are determined from scheduled supply and demand, these are known as *ex ante* pools. Alternatively, there are *ex post* pools, like the Australian National Electricity Market, in which prices are determined *ex post* from actual generator schedules and demand. In an *ex post* pool, the pool purchasing and selling prices coincide. Information technology is quickly shortening the period in which system balancing needs to take place — though not eliminating such a need.

Box 3 below introduces the logical foundations of «spot» electricity markets.

Box 3

How an Ideal Spot Electricity Market Would Work

In an electricity market, prices are used both to co-ordinate the decisions of generators and electricity buyers, so that supply equals demand, and to ensure that these decisions are feasible given the physical constraints of the system.

Prices

Spot prices for electricity would be set for each node of the grid. A number of cases will be considered in increasing order of complexity:

- **Base case:** *In the simplest case, when there is enough generation and transmission capacity to cover demand and transmission losses are ignored, there would be a single price for electricity for each time period:*

Price of energy (P1) = Marginal cost of highest cost unit in operation

- *At price **PI** there is a **generating capacity shortage**: If setting price equal to the marginal cost of the highest cost unit available would result in a generating capacity shortage, the above rule cannot be applied. The price of energy has then to be increased in order to decrease demand. The price increase **S** needed to make demand equal to available generation capacity is the difference between the marginal cost of generation and the marginal benefit of consumption. The price of energy is then:*

Price of Energy (P2) = PI + S

S can be interpreted as the scarcity rent that covers the fixed costs of generation.

Box 3*How an Ideal Spot Electricity Market Would Work (continued)*

Therefore, S provides incentives for investment in generation.

- *There are transmission losses: the price of energy (either P1 or P2, as it applies) would increase by a factor of (1 + Marginal Loss) at each node, reflecting that, in order to supply 1 kWh, it is necessary to produce (1+Marginal Loss) kWh. Thus:*

$$\text{Price of Energy (P3)} = P2 (1 + \text{Marginal Losses})$$

- *There are transmission constraints: the price at congested consumption nodes has to be increased so as to discourage consumption; the price at congested injection points has to be decreased so as to discourage consumption. The magnitude of the adjustment, known as the “shadow price” of the constraint is such that, at no point of the grid, supply exceeds transmission capacity. The resulting prices are nodal electricity prices, discussed in detail in chapter 6. They include all the cases considered above as particular cases:*

$$\text{Nodal Price} = P3 + \text{Shadow price of the constraint at that node}$$

Generation and Consumption

Because of the way wholesale prices are constructed, supply equals demand at each node and time period, and feasibility is ensured. Generators will produce energy if their marginal cost does not exceed the price of energy at their injection point, but not otherwise. Consumers will buy electricity up to the point where the price of electricity equals the marginal benefit of consumption.

Power Exchanges: Review of the International Experience

This section provides some examples of the actual organisation of competitive electricity markets. A summary of how trading is organised is provided in Table 10. The review of the international experience shows that pricing and scheduling mechanisms widely vary. For instance, bidding can be iterative or one-shot and may allow for demand side bidding or not. Bids can be firm or non-firm and can be simple, containing just a price per kWh, or may include several terms. Prices can be determined *ex ante* or *ex post* and may include capacity payments to generators. There can be pool price ceilings or other constraints on bidding behaviour; and transactions can be settled in a number of ways. More generally, electricity exchanges differ in the degree to which optimisation by market players — as opposed to optimisation by the “exchange” — is allowed.

Knowledge of the relative performance of different rules is still quite limited but can be expected to improve in the near future as the number of power exchanges is increasing rapidly. Two exceptions are the following:

It has been found⁴² that “electricity spot markets with mandatory participation...tend to have more volatile prices than systems with voluntary participation”. This study also considers market structure and technology. Price volatility is higher in fossil fuel-based systems than in hydroelectric based systems; and prices tend to be lower, but more volatile, when the companies are privately owned than when they are publicly owned.

A comparison of the performance of two US markets⁴³ — California Power Exchange and “PJM Interconnection” — finds that average prices and price differentials between constrained zones

42. Wolak (1997).

43. Van Vactor (2000).

Table 10*Organisation of Electricity Exchanges in the OECD Area*

Market	Participation	Demand side Bidding	Simple bids*	Pricing**	Capacity Mechanisms	Integrated Dispatch***
England and Wales	Mandatory	No	No	Ex ante	Yes	No
NordPool	Voluntary	Yes	Yes	Ex ante	No	No
Australian NEM	Mandatory	Yes	Yes	Ex post	No	Partially Integrated
New Zealand Electricity Market	Voluntary	Yes	Yes	Ex post	No	Yes
Spanish Electricity Market	Voluntary	Yes	No	Ex ante	Yes	No
California PX (US)	Voluntary	Yes	Yes	Ex ante	No	No
PJM ISO (US)	Voluntary	No	No	Ex post	Yes	Yes

* "Simple" means that bids are price-quantity pairs; "not simple" means that prices may have additional terms.

** Ex ante means that prices are calculated for scheduled supply and demand; ex post means that prices are calculated for actual supply and demand.

*** Integrated dispatch means that the system optimises joint use of generation and grid resources; otherwise there is unconstrained dispatch that ignores possible transmission constraints.

were similar in the two markets in the period until April 2000, but price volatility was higher in PJM.

■ England and Wales Pool

In 1990, the ESI in England and Wales was unbundled into three generation companies, one transmission company and twelve distribution companies. All these companies are now privately (and separately) owned. Generation and, gradually, end user supply were

opened to competition, with the smallest consumers getting the right to choose their supplier by 1999.

The centralised wholesale market is the England and Wales pool. It is mandatory: generators are obliged to sell their production to the pool and electricity buyers to buy from it. The pool sets prices for energy for each half-hour period on the basis of a daily, one-day ahead auction. Generators submit bids specifying the capacity available for the next day and the price at which it is willing to sell output from each capacity unit. Bids are fixed for the day so that the same price bids apply to all half-hour periods). With some limited exceptions, there is no demand side bidding. Bid prices contain several terms, such as a fixed start-up rate, a no-load rate for each hour that the unit is running at its technical minimum, and various energy rates for different loads. The pool combines the bids to construct an unconstrained merit order of generating plants that minimises the cost of serving the scheduled demand for each period. Price bids are firm, but capacity bids can be withdrawn up to the moment of operation.

Scheduled generators receive the Pool Purchasing Price defined as the system marginal price plus a capacity payment. The system marginal price is defined as the price of the highest bid needed to cover scheduled demand (where prices for start-up and no-load are averaged and added to energy prices).

The capacity payment is intended to reward generators for availability, thus providing “security of supply”. This value is fixed administratively. Capacity payments are defined through a complex set of rules that ultimately aims to reflect the expected cost to the user of a supply interruption or the value of capacity. This value is calculated as the product of two quantities: the Value of Loss Load (VOLL) measured in pounds per kWh, and the Loss of Load Probability (LOLP). VOLL is set administratively as there is no demand side bidding from which the actual figure could be inferred. LOLP is set to take into account how much capacity is available relative to forecasted demand. It is higher when capacity is scarce. The amount (LOLP x VOLL), measured in pounds per kWh, is

charged on all energy sold and paid to all capacity that has been declared available but has not been scheduled. The size of capacity payments varies significantly depending on available capacity relative to demand as measured by LOLP values.

The unconstrained merit order may not be feasible due to network capacity constraints ignored by the pool. If needed, the system operator calculates a constrained merit order. “Constrained on” units are paid their bid price plus the capacity payment, and “constrained off” units receive the pool purchasing price minus their bid.

Electricity buyers pay the pool selling price, defined as the pool purchasing price plus the uplift. The uplift is the cost of the various services provided by the system operator, such as ancillary services, reserve and constraints costs, plus transmission losses.

A financial market runs in parallel to the pool. Contracts for Differences may be used by generators and buyers of electricity to hedge the risk of price fluctuations.

There are plans to reform the wholesale trading arrangements in the England and Wales pool. The reform proposals released by the Electricity Regulator in July 1998 and to be implemented in early 2001, will abolish the mandatory pool, introduce a series of voluntary organised markets and allow for bilateral transactions. The bidding and price setting mechanism will be reformed on the basis of three main building blocks:

- First, the demand side will be incorporated into the price setting process. Incorporation of the demand side should encourage greater demand responsiveness and enable the system operator to balance the system at lower cost. It should provide an incentive for suppliers to understand better their customers’ needs and enable them to manage demand better.
- Second, offers and bids into the market will be firm. Participants will be exposed to the costs and consequences of not meeting the commitments in their offers and bids. Placing the risks and

responsibilities on those best able to deal with them should sharpen the incentives to manage and reduce risks.

- Third, bids and offers will be in a simple form. Simple bids and offers will be more conducive to transparency in price setting, incorporation of the demand side and management of dispatch costs and risks.

These principles are to be delivered through the establishment of a series of sequential markets that have much in common with other commodity markets. A forward market will operate long in advance of real time delivery — perhaps a year or more ahead. This market will enable parties to enter into contracts for the physical delivery of electricity. Closer to real time, a short-term bilateral market will operate. This will enable market participants to modify their long-term contractual position close to real time in order to take account of current information on matters such as the weather. From around four hours ahead, a balancing market will operate. In this market, the system operator will buy offers of increased or decreased output, or decreased demand, in order to balance the system. As with other commodity markets, there will also be a derivatives market and a settlement process. There will be no capacity payments in the new system.

The reasons for these proposed changes can be more easily understood in a historical perspective. “The pool in England and Wales was the first mechanism of its kind...[and]...it was developed in a process that gave considerable weight to the then existing arrangements...” (Offer, 1998). The proposals reflect a gradual convergence of thinking in different countries about the appropriate organisation of generation in competitive electricity markets.

■ NordPool

NordPool is a voluntary electricity exchange open to traders from Norway, Sweden, Finland and parts of Denmark. As of 1997, over 40% of electricity trade in the area was handled by the pool. There is a spot market, Elspot, and a futures market, Eltermin, which deals

with futures contracts for up to three years ahead. Elspot is a one day ahead auction market. Bids are made for each of the twenty four hourly markets and consist of price-quantity pairs specifying how much the bidder is prepared to buy or sell at different prices. Supply and demand schedules are constructed from selling and purchasing bids and, in turn, this determines a market clearing price. Bids are firm, entailing a commitment to physical delivery or withdrawal. All scheduled bids are settled at the market clearing price.

A balancing or regulation market operates in each NordPool member country to manage transmission bottlenecks and imbalances resulting both from trade in the pool and from bilateral trade. In Sweden, Svenska Kraftnät and in Finland, Fingrid make use of the countertrade principle. In other words, they balance the market by re-dispatching generating units contracted for in a separate balancing market. Svenska Kraftnät and Fingrid pay for the downwards balancing of the surplus area and for the upwards balancing in the deficit area. The costs connected with the counter purchase are regained through tariffs for transmission. In Norway, a split-the-market approach is used. The price of energy is reduced in the surplus area and increased in the deficit area until the transmission demand is reduced to the capacity limit. The costs are recouped from the market participants through the capacity fee in the market settlement.

NordPool arrangements are the blueprint for other more recently organised markets, including the Spanish and Californian markets discussed below.

■ Australian National Electricity Market

The National Electricity Market (NEM) is a mandatory auction market in which generators of 30 MW or larger compete. Wholesale market customers can also bid to the pool. Bids are simple price-quantity pairs and ten such pairs can be submitted per day. Two additional “revenue bids” are also permitted specifying a minimum payment if the generator is forced to run below a certain

level. In principle, bids are firm. However, capacity bids can be altered under certain specified conditions.

Bids are used to construct a merit order of generation and a demand schedule. Dispatch minimises the cost of meeting the actual electricity demand, taking into account « generic » transmission constraints. Thus, it approximates a fully integrated dispatch. Generation is scheduled according to this merit order and regional spot prices are calculated *ex post* for each five-minute period from actual supply and demand. Generators are paid the spot price. These arrangements eliminate the need for a separate balancing market. Capacity payments are set equal to zero because, at the time prices are set, the probability of loss of load (LOLP) is also zero.

A financial contracts market has developed in parallel to the NEM. Contracts for differences are bilaterally traded between the parties to each arrangement. In addition, the Sydney Futures Exchange is trading two electricity futures contracts.

■ **New Zealand Electricity Market**

This is a voluntary market in which prices are determined on the basis of simple (price-quantity) generator and consumer bids. Bids are used to compute one day ahead optimal scheduling as well as real time dispatch. Spot prices are determined from actual supply and demand for virtually each node of the grid and for each half-hour period. Overall, the operation of the market is similar to that of the Australian NEM, with the important difference that trade outside the pool is permitted in New Zealand.

■ **Spanish Electricity Market**

The general architecture of the Spanish market (Omel) is similar to NordPool, based on voluntary participation and firm bids. However, it incorporates an intra-day spot market that allows traders a sequential adjustment of their trading portfolios at times increasingly closer to the time of operation. There are other

differences between the Spanish market and NordPool. Bidding procedures are different since complex bids are allowed in Omel, and there are administratively set capacity payments.

The one-day ahead market sets prices for each of the twenty-four hourly periods of the next day. Generators and buyers send bids to the market operator who matches the bids. If the resulting basic daily schedule is not feasible due to transmission constraints, the market operator incorporates offers for congestion relief to establish the definitive feasible daily schedule. Scheduled bids are firm. On the day of operation, the intra-day spot market can open several sessions of trade (up to 24) for the remaining one-hour periods of the day. Each session is similar to a one-day ahead market session. The outcome of this session is the basic intra-day schedule, which subsequently becomes the final scheduling when any possible modifications prompted by technical restrictions have been added into it.

Due to transitional issues, a financial contract market has not yet developed.

■ **US: California Electricity Market**

The Californian Power Exchange (CalPX) conducts daily auctions to allow trading of electricity in the forward day-ahead and hour-ahead markets. It is a voluntary pool and there is a large number of competing power exchanges (known as Scheduling Coordinators in California). However, the major Californian utilities are committed to sell and buy only through the pool for the first four years of operation, until mid 2002.

The PX accepts demand and generation simple bids (price-quantity) from its participants, determines the market clearing price at which energy is bought and sold, and submits balanced demand and supply schedules for successful bidders to the system operator. It also submits bids for ancillary services, real time balancing and congestion management. It is an energy only market with no capacity payments.

The trading procedures in the day-ahead market are as follows. For each hour of the 24-hour scheduling day, the PX constructs aggregate supply/demand curves. Their intersection determines the market-clearing price (MCP)⁴⁴. The independent system operator (ISO) determines — based on all unit specific supply bids and location-specific demand bids — whether there is congestion. If there is congestion, the ISO uses adjustment bids to submit an adjusted schedule to the PX. These adjusted schedules and ISO-determined usage charges become the foundation for zonal MCPs and for the final schedule submitted to the ISO. In the Hour-Ahead market, bids are submitted to the PX at least 2 hours before the hour of operation. The MCP is determined the same way as in the Day-Ahead market.

■ US: PJM Interconnection Electricity Market

PJM (Pennsylvania/New Jersey/Maryland) is both a voluntary power exchange and a system operator in the US. It operates a one-day ahead market in which generators submit offers that may include a number of price terms. However, only one price bid per day can be submitted, and dispatch is determined on the basis of these offers. PJM sets nodal prices for energy, also known as locational marginal prices. These prices are computed for the actual dispatch and, when transmission constraints are binding, prices are differentiated by location.

PJM also operates a capacity market. This approach is followed by other US system operators such as NeePool and New York ISO, but not in California. The capacity market results in capacity payments to generators, just as in the England and Wales pool, but the payments are determined by the market instead of administratively.

All load-serving entities (LSE) are required to purchase installed capacity (ICAP) in addition to energy. This requirement is a

⁴⁴ Bids initially submitted into the day-ahead market auction need not be attributed to any particular unit or physical scheduling plant. Such a bid is referred to as a portfolio bid. Portfolio bids that are accepted into the day-ahead market are then broken down into generation units.

function of the annual peak load served by each entity. ICAP is bilaterally traded between generators and LSE. LSEs that are short on ICAP must pay a penalty to the system operator which is then redistributed among generators. In addition, there is a monthly and a one-day ahead ICAP market created to facilitate ICAP trading. Generators with unsold ICAP are obliged to offer it in the one-day ahead market.

PJM also operates a Fixed Transmission Rights market to provide insurance against price volatility caused by transmission congestion.

Trading Outside the Pool

There is a growing consensus that electricity trade should be allowed to take place outside organised markets. Bilateral contracting is expected to be efficient since it is a standard, if not the unique, way of trading in many markets. Bilateral trading is, by definition, more flexible than centralised pool trading since it may co-exist, and it does in practice, with a non-mandatory pool. A non-mandatory pool also lessens concerns about discrimination and is a necessary condition for individualised pricing and provision of security and reliability, adapted to individual consumer needs.

In bilateral trade systems, market and system operation are often conducted by separate organisations. The system operator (SO) assumes most technical co-ordination functions for balancing of the system, including time of operation dispatch. The power exchange (PX) organises trade among participants. This dual SO/PX structure reduces concerns that a joint SO and PX could discriminate against traders engaging in bilateral transactions. Separate SO and PX exist, for instance, in NordPool, Spain and California, but not in PJM.

Bilateral contracting in electricity markets has, however, been criticised on three counts:

- First, bilateral contracting is not compatible with a centralised optimisation of dispatch. It does not guarantee dispatch based on a merit order of bids or costs. However, as in most other markets, the lack of a central optimiser does not preclude markets from being (potentially) efficient. This argument was probably a factor in the preference for a mandatory pool in early reform models (England and Wales) but, since the NordPool experience has proved that a non centralised dispatch may work efficiently, this argument is now less compelling.
- Second, there are concerns that electricity prices to end users may not be transparent and/or pool prices may be distorted if a large fraction of traders enters into bilateral contracts. Setting regulated tariffs to end users when the price of wholesale electricity is not clear may be difficult. The aim of reform is to let market forces, instead of the regulator, set end-user prices. However, greater transparency may facilitate the transition to a competitive market and a transitional requirement on large suppliers to buy from the pool may be justified. Concerns about bilateral trading resulting in the exercise of market power have been addressed in California by means of transitional arrangements that limit, but do not prohibit, bilateral transactions. The utility distribution companies are required to use the PX during a four-year transitional period. For non-utility buyers and sellers of electricity, the use of the PX is optional. This strategy excludes the largest market players from entering into bilateral contracts without imposing constraints on smaller players.
- Third, long-term bilateral contracts may facilitate the exercise of market power, if market players already enjoy market power. In particular, bilateral contracts can result in an implicit form of vertical integration between generators and distributors in systems where explicit vertical integration is not allowed. But in a sufficiently atomised market place with many potential buyers

and sellers, there would be little incentive to enter into bilateral contracts at uncompetitive prices. This suggests that the potential problem is market power in itself and that uncompetitive bilateral contracts would only be a symptom.

Bilateral electricity trade has been allowed successively in the NordPool countries, New Zealand, Spain, the US and Germany. The UK has proposed new trading arrangements that will allow bilateral trade. In California and (implicitly) in Spain, there are time-limited restrictions on bilateral trading imposed on the largest incumbent utilities. The trend is not universal, however, as Australia maintains a mandatory pool. Power exchanges outside the OECD area are often mandatory.

Capacity Mechanisms

Capacity payments are money transfers to power generators given in exchange for making their generation capacity available. They are also known as availability payments. With capacity payments, the price of electricity paid to generators has at least two components. One component is related to actual energy production; the other is determined by the generating capacity made available by the generators. Capacity payments may be set administratively, as in England and Wales and Spain, or through market mechanisms, as in PJM.

The broad policy objective of capacity payments is to induce greater reliability of electricity supply than the market is expected to provide. Capacity payments are ultimately intended to improve security by encouraging a higher reserve margin, or by reducing the variability of the reserve margin over time, or both. In a historical perspective, however, capacity payments may be seen as the inheritance of planning methods applied before the introduction of competition.

In principle, capacity payments could be expected to contribute to greater and more stable investment provided some conditions are

met. A key condition for capacity payments to induce investment in the long run is credibility. Investors are not likely to modify their investment decisions if capacity payments are perceived as a transitional measure that will be eventually abolished. The fact that capacity payments are being challenged and reviewed by regulatory authorities in both the UK and Spain suggests that the impact on investment decisions may be low. Another key condition is that capacity payments be reflective of the long-term value of capacity. If prices are, or can be, distorted they do not provide an appropriate signal for investment. In current practice, it is unclear whether capacity payments reflect the economic value of capacity.

Regulated capacity payments, that is to say payments imposed by the regulator, are introduced to modify the performance of electricity markets. Their introduction is linked to the belief that there may be some form of market failure resulting in a reliability level that is too low. Four main types of potential market failure have been suggested⁴⁵:

- “Investment cycles”: It is sometimes argued that investment may go through cycles. If, for instance, investors are “myopic” and too concerned with short-term price levels, then investment could go through pronounced cycles⁴⁶. If, more plausibly, investors have a longer time horizon, then investment cycles may be less pronounced or negligible. Appropriate incentives, such as financial penalties in case of non-delivery, could reinforce this. In practice, mitigating factors can compensate for any investment lags, such as new technology which is shortening construction times, the scope for repowering existing plants, and the “demand-smoothing” potential of peak load pricing.
- “Investing in reserve capacity is too risky”: Some electricity systems, particularly those largely based on hydro generation, need substantial investments in reserve capacity that is only

45. Some observers (e.g. Ruff, 1999) argue that insufficient demand participation makes prices and revenues inadequate. However, an artificially inelastic demand response should result in higher, not lower, prices.

46. Ford (1999) and Ford (2000).

rarely and unpredictably used. These investments may be seen as too risky by investors. It is also argued that the prices that would have to be paid to make these investments profitable on the “few” occasions the assets are actually used are too high. This may be a significant issue in some electricity systems. However, it is unclear that the appropriate solution would always require regulatory intervention. For instance, generating companies can diversify risks by owning a diversified asset portfolio; and both generators and suppliers can enter into financial contracts to reduce or eliminate risks. Increased international trade in open electricity markets can also make a significant contribution to diversifying the overall generation base on which a country depends (for example, the NordPool does this in relation to Norway’s high dependence on hydro).

- “High cost of capital discourages investment”: It has been argued that the cost of capital for generating assets could be undesirably high in a competitive market due to the capital-intensive and long-lived nature of the assets. The result could be under-investment and low security of supply. Another variation of this argument is that more capital-intensive technologies such as nuclear would be at a disadvantage in a competitive market. The cost of capital is certainly likely to be higher in competitive markets. In the past, the return on investments in the electricity supply industry was guaranteed by regulation, so the owners’ investment risk was correspondingly low. Under competition, investment risk is shifted from electricity consumers to owners, raising the cost of equity and possibly inducing a decline in the share of debt used to finance the assets. Thus, the cost of capital for generation assets can be expected to increase as it approaches its “normal” market level reflecting the cost of capital in other, similar industries. The adjustment in the cost of capital to reflect normal market conditions should improve efficiency. In addition, various financial techniques available in competitive markets allow companies to reduce their investment risks. Indeed, the

evidence suggests that investment in merchant plants⁴⁷, which arguably face a higher cost of capital, is not deterred by the opening up of markets to competition.

- “Unsustainable prices”: It is sometimes argued that prices in competitive electricity markets would tend to be below cost, discouraging investment. This argument rests on a misunderstanding of how competitive markets work and is not supported by the evidence. Competitive prices can be expected to cover all costs. Wholesale electricity prices have not generally fallen to unsustainable levels. In some instances, there is concern that prices are actually too high.

Beyond their potential impact on investment activity, capacity payments may distort market performance in a number of other ways:

- Capacity payments may induce inefficient strategic behaviour by generators. Many analysts have concluded that, in the England and Wales pool, there has been “gaming” by generators, that is, strategic manipulation of availability declarations to increase the capacity payment.
- Capacity payments generally increase wholesale and final electricity prices.
- Capacity payments may distort competition and, particularly, the entry of new competitors, because they provide revenues to incumbent generators regardless of whether they are actually selling electricity.
- Capacity payments treat all or most buyers and sellers of electricity homogeneously, regardless of their actual demand for, or contribution to, security of supply. This is inefficient. Consumers range from small domestic users to large industrial companies and are likely to have widely different valuations for security of supply that are not reflected in what they pay.

47. Merchant plants are those that must find a buyer for their output.

Capacity payments may fail to discriminate among investments that make a significant contribution towards security and investments that do not make such a contribution (e.g. gas fired plants to cope with seasonal variations in a hydro-based system versus additional hydro units).

- Capacity payments can be used as a convenient way to mask the payment of stranded costs resulting from the pre-reform system.

There are regulatory alternatives to capacity payments including:

- Obligations to ensure supply, with penalties on supply companies for non-delivery;
- Direct ownership of generation units facing severe revenue uncertainty by the system operator (e.g. some peaking plants that are only rarely used, as in Sweden);
- Monitoring of investment by the regulator with the possibility of regulatory intervention if and when problems are anticipated;
- A voluntary organised market for capacity to ensure both transparency and an efficient pricing of capacity; and
- Interruptibility discounts to end-users.

Financial Markets

Financial contracts have a key role in providing insurance for market players against price volatility in electricity markets. Prices in competitive electricity markets quickly move in response to changing demand and supply conditions and, as a result, are volatile. Price movements have a healthy effect in efficiently accommodating supply and demand but may have a negative effect on market players. Electricity contract markets reallocate price and quantity risks.

In the past, the risks involved in electricity supply were bundled with electricity itself. One of the benefits of reform is that risk is unbundled from the provision of the basic good and can be, to a certain extent, separately and flexibly managed and priced.

Electricity contract markets are primarily financial markets and do not require specific electricity regulations. However, as in other commodity futures markets, financial electricity contracts may need to be backed by financial penalties and guarantees to ensure that the contracts are honoured.

It has been suggested that contracts may help to curb market power. The idea is that financial contracts reduce the incentives of generators to set high prices in the wholesale market because the price that a generator receives is set in the contract, not in the wholesale market⁴⁸. Unfortunately, the evidence from the England and Wales pool suggests that financial contracts do not mitigate market power, at least not significantly.

How do electricity contracts work? Most contracts take the form of forward contracts, futures contracts, option contracts, or Power Purchase Agreements (PPA). The first three are sometimes described as financial contracts, because they do not need to specify which plant will provide the power. PPAs are also called physical contracts, because they do specify the plant that will provide the power. They are commonly used by independent power producers (IPPs) selling to a monopolistic buyer but can also be applied in other contexts.

Forward contracts are bilateral agreements to deliver energy at a given price. They work in combination with a competitive wholesale market and are one of the simplest forms of derivative instruments that are used to transfer, or “hedge”, price risk. The parties involved agree to a price today (the “strike” price) for “delivery” of a certain amount of energy later. The settlement of a forward contract can be made without physical delivery. If the market price at “delivery” is higher than the strike price, the seller of the contract compensates the buyer for the difference; if it is lower, the buyer of the contract compensates the seller. A forward contract settled in this way is called a contract for differences.

48. However, since contract prices reflect expected wholesale prices, generators will generally make a higher profit if prices are “high”.

Futures contracts are analogous to forward contracts with the only difference that they are standardised and traded in an organised market.

Option contracts give the right, but not the obligation, to buy or sell electricity at a certain price. The price has two components: an option fee equivalent to a kW charge payable when the contract is signed, and an exercise price to be paid for each kWh actually delivered. An option contract does not need the reference of a spot electricity price to be implemented. Compared with forward contracts, option contracts have the advantage (to the seller) of partially hedging quantity risk as fixed generating costs can be covered by the option fee.

Financial contracts are currently in use in electricity markets. For instance, forward and option contracts are extensively used among traders in the England and Wales pool, NordPool and Australian NEM. These contracts are settled for differences. Electricity futures are traded in NordPool, the US (NYMEX, PJM) and Australia (Sydney Futures Exchange). There is a plethora of far more complex and advanced derivatives which can be used to hedge all kinds of price risk.

PPAs are similar to the financial contracts described above but, since they specify the plant that will provide the power, they require the generator to be excluded from any centralised pool. In countries with a mandatory electricity pool these contracts are either restricted or banned.

NETWORKS

Means and Ends of Network Regulation

Transmission and distribution lines provide the critical physical link that makes competition feasible. Thus open access to the network and adequate pricing are essential for the development of competition. In addition, to the extent that reforms also aim to integrate previously separated (national and state) markets, the regulation of cross-border (or inter-state) transmission links is a major issue in many countries.

This chapter considers the management of the grid. It focuses first on the role of prices in promoting efficiency. In the short-term the main regulatory issue is how to allocate scarce transmission and distribution capacity efficiently. In the long-term, regulation is confronted with providing adequate incentives for investment and cost efficiency without compromising the financial sustainability of the regulated companies. Further on, the institutional framework with a focus on the role of system operators is considered. An additional pricing issue is how to allocate the large fixed costs of the network to different users. This is discussed in the appendix.

Prices are the main tool in network regulation. The pricing of network services pursues a number of complementary objectives:

- Allowing sunk investment costs to be recovered (financial sufficiency);
- Providing adequate incentives for future long-term investment (long-term efficiency);
- Providing adequate signals for efficient network operation, or in other words, for the allocation of capacity to manage congestion efficiently (short-term efficiency);
- Avoiding discrimination among users of transmission (competitive neutrality); and
- Promoting simplicity and transparency.

The third of these objectives (short-term efficiency) is particularly important as well as difficult to manage. Efficient pricing for the allocation of capacity to deal with congestion may appear to be a technical issue, with limited implications. However, it is a key issue in the overall design of efficient electricity markets because in addition to its direct role in the allocation of transmission capacity, it affects the dispatch of generation units. The impact of transmission prices on the distribution of revenues and profits among generators can thus be significant. In addition, transmission pricing may have an impact on competition in the generation function, either facilitating or distorting it.

Many pricing methods have been developed in order to meet the various objectives. The average price level (or the revenue allowed to the regulated company) can be set to cover different cost and profit definitions and adjusted to provide incentives for efficiency. Prices are usually charged through a multi-part tariff structure that may include fixed connection charges, as well as capacity and energy charges that may depend on time of use. Each part of the tariff can be determined separately for each location, or alternatively for each user. In this way, many different combinations of an average price level, charges by location and charges by user, are possible.

In practice, to achieve the different objectives transmission prices combine a number of pricing and non-price methods. Table 11 summarises the approaches adopted by a number of reforming countries.

Table 11*International Comparison of Transmission Pricing*

Country	Average Price Level	Pricing by Location	Dispatch	Charges for Recovery of Sunk Costs
Australia	CPI-X applied to optimised deprival value	Zonal	Integrated dispatch (model differentiated by regions)	Fixed connection plus postage stamp energy charges
Finland	Cost Based	Postage Stamp	Unconstrained Market Clearing + Countertrade	Energy Based Fees
New Zealand	Optimised Deprival Value + Revenue cap	Nodal	Fully Integrated Dispatch	Connection and Capacity Charges
Norway	CPI-X	Postage Stamp (Differentiated by Regions)	Unconstrained Market Clearing + "Split the Market"	Capacity Charge for Peak Usage
Spain	CPI-X	Postage Stamp	Unconstrained Market Clearing + Countertrade	Capacity and Energy Charges
Sweden	Cost Based	Postage Stamp (Differentiated by Regions)	Unconstrained Market Clearing + Countertrade	Capacity Charge
US (California)	Historical Cost	Zonal	Unconstrained Market Clearing	Surcharge to End Users to Cover Sunk Costs
US (PJM)	Historical Cost	Nodal	Fully Integrated Dispatch	Capacity Charge for Peak Usage
UK (England & Wales)	CPI-X	Postage Stamp	Unconstrained Dispatch + "Countertrade"	Zonal Capacity Charges

Source: Putnam, Hayes and Bartlett (1997) and IEA.

Short-term Pricing Issues: Managing Congestion

■ Overview

There are two main competing approaches to the pricing of transmission services. There are non-transaction based, or point tariffs, which are independent of the commercial transactions that originate the transport of electricity. Point tariffs only depend on the energy injected or taken in each node. Point tariffs may be designed to reflect the costs of using the grid. In addition, point tariffs that are sensitive to location — nodal and zonal tariffs — serve to manage congestion.

Alternatively, there is a transaction-based approach to tariff setting. It consists in setting point-to-point tariffs that depend on the source and sink of each individual transaction. Contract path and distance related tariffs are two common examples of this approach. Transaction based tariffs are not in general cost reflective⁴⁹ and do not serve to manage congestion. However they have been — and still are — widely used. Table 12 lists the main pricing techniques within each group, which are discussed and compared below.

Table 12

Pricing of Network Services

Non-Transaction Based Pricing (Point Tariffs)	Nodal
	Zonal
	Postage Stamp
Transaction Based Pricing (Point-to-point Tariffs)	Contract Path
	Distance-related
	Etc.

49. This is neatly illustrated in the following example. Consider two simultaneous transactions for the same amount of energy. In one transaction energy is generated in location A and delivered in location B. In the other transaction energy goes from location B to A. Clearly the two transactions cancel out and no transmission services would be needed. However, if the transmission tariff is transaction based, it will be charged twice.

■ Nodal Pricing

Nodal prices equate supply and demand of electricity at each node of the transmission grid. Nodal prices are continuously adjusted over time and are set for delivered energy, including both the price of energy and the price of transmission. The price charged for transmission is therefore implicit in nodal prices. Nodal pricing is also known as locational market clearing pricing and as the split the market approach. The conceptual foundations of nodal pricing are summarised in Box 3 (Chapter 6).

Until recently, nodal prices were not used to allocate transmission capacity and to deal with congestion. Instead, most electricity systems have relied (and still rely) on other pricing techniques combined with non-price mechanisms. Nodal prices are now being used in some US pools and in New Zealand, often in tandem with operational separation of transmission and generation.

How does nodal pricing match up to the various objectives set out at the beginning of this chapter? Several criteria are relevant: financial sufficiency, efficiency, implementation and competitive neutrality.

As regards financial sufficiency, in practice nodal prices generate revenues well below historical cost. In an “optimally planned” system, there should not be such a discrepancy⁵⁰. However, existing grid and generation assets are the result of incremental investments over long time periods and under changing technical and economic conditions. Thus, in practice, nodal prices have to be complemented with a fixed charge on transmission to collect the additional revenue.

As regards efficiency, nodal prices reflect the relative scarcity of transmission capacity at each point of the grid. This provides incentives for efficiency both in the short and in the long-term.

50. Nodal prices would provide the right amount of revenue if (1) generation and transmission assets were optimally planned so that, in particular, there would be no excess generation or transmission capacity and the location of assets would satisfy a total cost minimisation criteria; and (2) supply were competitive.

With nodal pricing, transmission is relatively expensive at those nodes in which there is not enough transmission capacity available to accommodate all scheduled transmission. Higher prices decrease demand for electricity, thus resolving congestion (short-term efficiency). Higher prices also provide incentives to invest in interconnections to high price areas (long-term efficiency). Whether the incentives to invest under nodal pricing are sufficiently strong to eliminate all un-economical bottlenecks will be discussed below.

Finally, there are the issues related to implementation and competitive neutrality. Creating a market for transmission services raises concerns about the exercise of market power by the owners of transmission assets and the system operator. The main concern is that the owner(s) of transmission assets may manipulate prices. For instance, holding transmission capacity may artificially create congestion and thus raise prices. An additional concern is that setting nodal prices requires centralising information to calculate prices and to re-dispatch generation in an efficient way. Thus, the system operator has considerable power in shaping market decisions, which creates opportunities for monopolistic abuse.

It has been argued that a decentralised implementation of Tradable Congestion Contracts (TCC) may provide protection against monopolistic abuse. Under this approach, TCCs are sold to market participants through an auction and are then traded in a secondary market. TCCs protect market players against changes in the price of transmission and the secondary trading limits the role of the system operator in setting prices. However, it has been shown that this approach may exacerbate market distortions when there is market power, its performance is not proven and may be inadequate in some realistic situations⁵¹.

Nodal prices allow for an efficient management of congestion, but they are not immune to manipulation when there is market power.

51. These criticisms are discussed in Henney (2000), Joskow and Tirole (2000), Hogan (1999), Hogan (2000) and Joskow (1997).

In addition, most often, nodal prices need to be complemented with other charges in order to raise enough revenue to cover historical costs.

■ Zonal Pricing

Zonal pricing is a simplified version of full nodal pricing. The control area of the system operator is divided into zones, and prices are set for each zone averaging the cost of congestion of the nodes within the zone. It relies on the assumption that congestion tends to occur in just a few nodes of the grid. Its main appeal is that it is easier to implement than full nodal pricing.

Other aspects of the performance of zonal prices are similar to nodal prices. Zonal prices also fail to provide enough revenue (thus needing to be complemented with other charges), impose risks on market participants (that can be hedged by means of TCCs) and are subject to manipulation when there is market power.

Does the simplicity of zonal pricing outweigh the presumably higher efficiency of nodal pricing? As experience with zonal and nodal pricing grows, the case for nodal pricing is gaining momentum. Zonal pricing may perform well in some circumstances, but its apparent simplicity can be misleading. Zonal pricing requires setting mechanisms to deal with intra-zone congestion in addition to setting prices to deal with inter-zone congestion, which adds significant complexity. Also, as « know-how » improves, concerns about the complexity of nodal pricing are gradually vanishing. Furthermore, zonal pricing has not performed well in some instances. It was tried in 1997 in the PJM. Congestion was underpriced, so market participants scheduled more bilateral transactions than could be accommodated by the grid. Hence, the system operator had to intervene administratively to preserve reliability, constraining choice in the market⁵².

52. OECD/IEA (1998).

■ Postage Stamp Pricing

A flat rate is set over pre-specified time periods. It gives the right to inject energy at any node of the grid and to take it at any other. This implies that non-price methods have to be applied to manage congestion whenever it arises. Nevertheless, postage stamp pricing has the advantage of simplicity and transparency: prices are known in advance and are easily controlled by the regulator, and the market for generation is separated from the market for transmission. This approach is widely applied in EU countries.

Postage stamp pricing, while institutionally simple and transparent, is generally inefficient. Other pricing methods such as nodal pricing have a clear advantage over postage stamp pricing whenever congestion problems are significant. However, this can be a reasonable approach whenever congestion problems are small. A strong grid and large reserve capacity in generation are not unusual in many OECD countries. In these countries, congestion may be rare, and the benefits of optimal pricing relative to a flat rate may be small and not compensate for the costs and increased complexity of full nodal pricing. For instance, it has been estimated⁵³ that the losses created by inefficient transmission pricing in the UK are small (some 0.6% of generators' revenue). This argument could justify the use of postage stamp pricing in several EU countries.

■ Transaction-based Approaches

Two common forms of point-to-point tariffs are:

- **Contract Path Pricing:** Prices are set for each transmission line in the grid. Each transaction is assigned a “contract path” over the grid joining the location of the buyer and the seller. The price charged to the transaction is the sum of the prices of the transmission lines crossed by the contract path. While this method may seem simple and intuitive, the contract path does not reflect the actual flow of electricity over the network or its

53. Green (1998).

cost. Thus, contract path pricing does not provide an efficient management of congestion. This method is sometimes used in the US.

- **Distance-Related Pricing:** Prices are set as a function of the distance between buyer and seller. The method is similar to contract path pricing and has the same pitfalls. Distance related pricing of transmission is applied in Germany.

In general, transaction based approaches are unsatisfactory because they result in prices that do not reflect costs and do not serve to manage congestion efficiently. In addition, they may also have anti-competitive effects. Their implementation requires the communication of information on commercial relationships that may be strategically sensitive. They may also favour discrimination against some competitors. For instance, distance related prices tend to impose a larger cost on far away and foreign generators that does not necessarily reflect the cost of transportation.

■ Other Methods to Deal with Congestion

In the absence of full nodal pricing, additional mechanisms are needed to allocate transmission capacity. Capacity can be allocated on the basis of priority rules that determine a pecking order among generators and buyers of electricity. Also, the right of access can be allocated by means of long-term contracts. However, these two mechanisms are generally inefficient and possibly discriminatory.

Non-discriminatory mechanisms can also be designed. An example of a non-discriminatory mechanism is the so-called “counter-trade” approach in which a parallel generation market — the balancing market — is run to deal with congestion. The system operator directly balances the market making use of the balancing market. This is achieved by re-dispatching generation units contracted for in the balancing market. The prices of energy and transmission are those that would have resulted in the absence of congestion, and sellers and buyers conduct their transactions as if

there were no congestion. As a result, counter-trade does not give adequate signals to market players (who ignore transmission constraints) and some short-term efficiency losses may occur. On the other hand, counter-trade may encourage competition in the electricity market because, from the players' point of view, the market is not segmented by transmission constraints, thus limiting the scope for the exercise of market power.

Another non-discriminatory approach consists of conducting an auction whenever transport capacity becomes scarce. This may yield an efficient outcome provided the auction is appropriately designed. It is, however, impractical when congestion arises frequently.

Setting Price Levels: Cost of Service Versus Incentive Regulation

Network tariffs are set to provide a certain amount of revenue to the network service provider. Traditionally, regulated firms have been allowed to earn just enough revenue to cover their historical costs including a return on investment that corresponds to the cost of capital. This is known as “cost of service” or “rate-of-return” regulation. It relies on the book value of assets, allowing companies to recover accounting costs and to earn a “fair” return on investment. Inflation adjustments and depreciation schedules can be superimposed. Cost of service regulation is fair, in the sense that it does not allow the regulated company to make any “extraordinary” economic profits, and is (by definition) financially sustainable. In addition it provides strong incentives for investment as prices are adjusted to ensure that investors recover their investments (plus a profit). Cost of service regulation has, however, some well-known drawbacks. This approach provides no incentives for cost efficiency and, indeed, it provides incentives to overinvest and to overspend.

Incentive regulation is an alternative to cost of service regulation that aims to provide incentives for cost efficiency. Incentive regulation allows the regulated firm to retain temporarily some (or all) of the benefits resulting from efficiency improvements. This provides regulated firms with an incentive to reduce costs but it allows prices and revenues to temporarily exceed costs.

Incentive pricing in transmission and distribution (as well as in other regulated industries) is usually implemented by means of price caps. Prices are set to cover historical costs, including a return on investment, minus a given fraction, X , of this cost. The regulated company is allowed to retain all the additional profits if costs are reduced by more than X . However, it has to assume all the losses if costs are reduced by less than X . Incentive regulation is typically implemented by means of a “RPI- X ” formula that allows yearly price increases of $X\%$ points below inflation (so if inflation equals I , transmission prices increase by $I-X$). This method is applied to a number of transmission companies.

There are other incentive pricing mechanisms, including:

- **Yardstick and benchmark pricing:** Price is set equal to the estimated cost of providing the same service by other companies. It has a practical advantage over some other methods such as price cap regulation where X is very difficult to calculate. This “competition by comparison” approach is intended to provide a benchmark that is not influenced by the regulated company. It is more widely applicable in the distribution of electricity (and other services like water supply), where several comparable companies operate, than to transmission. However, an international (or interregional) benchmarking of transmission companies can be applied in some circumstances.
- **Sliding scale regulation:** This is similar to price cap regulation but the company is allowed to retain only a fraction of the profits obtained from efficiency improvements. The fraction of retained

profits decreases with the amount of profits obtained, and they are typically shared between the regulated company and consumers⁵⁴. This method is intended to reduce the profits made by firms under price cap regulation which are sometimes deemed excessive but it has not been actually applied.

Experience with incentive regulation suggests that the potential for cost reductions in transportation activities is large. For instance, in the UK the introduction of incentives for the National Grid Company to reduce the cost of “uplift” (i.e., ancillary services) resulted in a decrease in costs from £800 million in 1994/95 to £360 million in 1998. Despite its apparently good performance, incentive regulation has been subject to criticism on several counts. First, some companies subjected to a price cap have been highly profitable suggesting that price caps could have been lower. More frequent regulatory reviews to set price caps and “sliding scale” regulation allow for a more rapid transfer of cost reductions to consumers at the expense of incentives. Second, incentive regulation has been criticised for relying too heavily on regulatory discretion (e.g. there is some inevitable degree of discretion in setting the “X” factor in a price cap). Regulatory discretion may run against the interest of investors if “X” factors are high or, more plausibly, against the interest of network users if pressure on regulators results in low “X” factors.

In addition to incentives, a related issue is that cost of service regulation is based on historical costs. Historical costs reflect expenditures that were made in the past and that may not be economical under current conditions. As a result, when prices are based on historical cost, they may fail to provide adequate signals to investors and buyers and sellers of electricity. Ideally, prices should be based on the marginal cost of providing the service under current conditions, instead of looking backwards.

54. In other words, a sliding scale is a price cap in which the “X” factor grows with profits.

The Institutional Framework: the Role of System Operators in Investment

A key and partly unsettled issue is defining the role of the system operator in managing transmission in the long-term, that is, the planning and implementation of investment in the network. There is a broad consensus that the system operator (or other appropriately designed entity) needs to retain some responsibility in grid planning and augmentation. Incentives for grid investment may be distorted in a number of ways:

- Market power may reduce incentives to invest (e.g. bottlenecks create rents for generators).
- The risk of free riding may discourage investment. For instance, future incremental investments may significantly decrease the return on past investments, due to large price changes, discouraging grid augmentation.
- Incentives for maintenance and replacement of assets may be weak unless appropriate rewards and penalties for security and reliability are designed.
- Opposition from environmental groups, lengthy administrative procedures and other non-economic factors, may impose additional costs and delays in the development of transmission assets.

This suggests that market-driven investment alone could result in underinvestment in grid expansion and that the system operator (or other appropriately designated party) should retain some responsibility in grid planning and augmentation. Inappropriate or untimely grid investments may significantly decrease the efficiency of the ESI and have a negative impact on the development of competition. The strategic value of the grid in facilitating competition implies that an effective approach to competition should prioritise efficient and timely investments in transmission assets and should establish the appropriate incentives to eliminate transmission bottlenecks as quickly as possible. Accordingly,

virtually all liberalised systems assign some responsibility for transmission planning to the system operator⁵⁵.

Approaches diverge, however, in what other responsibilities are assigned to the system operator. There are two broad approaches to defining his role⁵⁶:

- On the one hand, the system operator can be defined as a transmission monopoly that owns the whole transmission network and takes on the obligation to provide unlimited transmission service, that is, the services that are required for effective system operation. This is the approach taken in most competitive electricity systems in Europe including the UK, Norway, Sweden, Finland and Spain. In this approach, the system operator is responsible for planning grid augmentation and managing it. In practice, this approach corresponds to the ownership separation model.
- On the other hand, the system operator can be defined as a residual provider of services that is not the owner of the network and allows market participants to trade transmission rights and to invest in transmission assets. This is the approach that dominates thinking in the US. In this approach, the system operator may still have a role in planning but does not undertake investment or does it only as a last resort. In practice, this approach corresponds to the operational separation model.

Appendix

■ Allocating Costs to Users

An additional issue in the pricing of network services is the allocation of charges to transmission users in order to collect the allowed revenue for transmission. These charges are often needed

55. Henney (2000).

56. Hogan (1999). See chapter 5 for a comparison of these two approaches.

to cover the deficit in revenues that results from fixed costs not included in congestion costs. In the absence of nodal pricing, the under-pricing of congestion also contributes to generate a revenue deficit.

Costs provide little guidance in allocating these charges to network users due to their fixed nature. Other criteria have to be applied. A number of mark-up rules can be used to set prices for network services. These rules consist in setting charges proportional to the demand of each user (uniform pricing), the price-elasticity of each user (Ramsey-Boiteaux Pricing), the marginal cost imputed to each consumer (Allais Rule), or the foregone profit or “access deficit” originated by each user (Of tel rule). The proportionality factor is adjusted to yield the desired amount of revenues. For this reason, mark-up rules are also known as fully distributed cost pricing. These rules are relatively easy to implement. However, the artificial linkage between costs and charges may well result in lack of sustainability, cross subsidies and other distortions.

A number of special rules have been proposed to apply to vertically integrated companies that provide network services together with generation or end user supply. In this context, the regulation of prices has to take into account the incentives provided across the vertically related markets (in particular, generation). These rules include:

- **Efficient components pricing (or Baumol-Willig rule):** This rule is designed to promote productive efficiency among access seekers. The transmission owner can sell access at a price that not only recoups his costs, but also compensates him for any foregone profits from final sales due to the additional competition from access seekers. This rule, if applied in isolation, is the same as allowing unconstrained monopoly pricing of access, thus, it has to be applied in conjunction with a price cap for delivered energy.
- **Global Price Caps:** It has been argued that capping the price of transmission in isolation may distort the pricing of energy by an

integrated transmission company. A global price cap defines a basket of goods, including transmission, sold by the regulated company. Weights are assigned to each good proportional to the « quantity » sold of each good, and a ceiling is imposed on the average price of the basket.

INSTITUTIONS AND THE POLICY FRAMEWORK

The Need for Regulatory Institutions to Adapt

Regulatory institutions need to adapt to meet the new challenges posed by reform of the ESI:

- First, in the new environment, regulatory procedures must be transparent and competitively neutral in order to sustain a level playing field for competition. This results in new regulatory procedures and, often, in the establishment of new regulatory agencies independent of the companies which they regulate.
- Second, the introduction of competition implies that competition law has to be applied to the ESI. This requires either competition authorities and electricity regulators to take on new roles to enforce competition law. The relationship with competition authorities has to be clarified and effective communication channels between electricity regulators and competition authorities, if they are not the same institution, have to be built up. This often means that, during the transition, regulatory capabilities have to be reinforced and more resources have to be engaged in regulatory activities than in the past. In the longer term, as these needs recede, competition authorities may gradually take over electricity regulation, perhaps retaining a specialised regulatory section for electricity and other network utilities.
- Third, structural obstacles and political resistance to the development of a competitive market in electricity often result in regulatory agencies actively promoting pro-competitive reforms. Indeed, competition advocacy by regulators appears to have contributed significantly to the advancement of reform in

electricity and in other previously regulated sectors (e.g. air transport and natural gas).

- And fourth, electricity markets benefit from a stable or, at least, predictable regulatory framework. The expectation of a stable regulatory framework may be favoured by independent regulatory agencies within government which are less subject to political change than other parts of government⁵⁷.

Regulatory Independence

A crucial issue in the regulation of any industry is the independence of the regulator. The basic principle is that regulators have to be independent from the regulated. Otherwise, conflicts of interest are unavoidable, and regulation is bound to deteriorate. Careful design of regulatory institutions is needed to ensure effective independence of the regulator from the regulated entities.

Independence from government and political actors may also be beneficial. It helps to ensure stability of regulatory policies, to avoid the use of electricity policies to achieve general policy objectives (e.g. more revenues from taxation or lower inflation from lower tariffs) and, generally, to protect investors and utilities from short-term political pressures that may undermine the stability of the regime. The importance of political independence for an adequate regulatory performance is likely to depend on a number of country specific factors. The crucial issue is to what extent political interference is a real threat. This is influenced by the institutional design of each country. For instance, the role of courts in reviewing regulatory decisions, which is critical in this regard, varies across countries.

Political independence of the regulator is particularly important whenever there is public ownership of electric utilities. In this case,

57. This was generally the case of regulatory agencies in the US before liberalisation. However, to the extent that regulators also act as advocates of pro-competitive reforms, the impact of their actions on the expectations of market players is ambiguous.

the government simultaneously faces responsibilities as owner and as regulator. Instituting a politically independent regulatory body avoids potential conflicts of interest between these two areas of responsibility.

The independence of the regulator needs to be differentiated from lack of accountability. Regulatory agencies, like any other public body, must be held accountable for their actions and be subject to adequate efficiency controls. Regulatory agencies built on the principles of independence (from the regulated) and on accountability have the highest potential to deal effectively with the new regulatory challenges. However, combining accountability and independence is a difficult task. A review of the regulatory structure must accompany regulatory reform since regulatory institutions designed in the past to deal with other issues may not satisfy these general principles.

A Review of Institutional Approaches⁵⁸

Regulatory institutions do not follow a clear pattern across countries. Electricity regulatory agencies that are independent, to some extent, from other parts of government have existed for over half a decade in the US: the Federal Energy Regulatory Commission (FERC) at the federal level deals with wholesale transactions while the different state Public Utility Commissions (PUCs) deal with retail transactions. Many other electricity regulatory agencies have been created more recently, often at the time of the restructuring of the ESI in Australia, Belgium, Canada, Finland, France, Hungary, Ireland, the Netherlands, Norway, Portugal, Spain, Sweden and the UK.

The division of jurisdictional powers among government, the courts, the general competition authorities, the national regulator and, in federal countries, the state regulators largely varies from

58. A detailed analysis of regulatory institutions can be found in the forthcoming IEA book *Regulatory Institutions in Liberalised Electricity Markets*.

country to country. In most countries, the scope of the activities of the regulatory agency is limited to specific aspects of the industry. Many regulatory agencies have powers to set tariffs, to grant licences or authorisations, to monitor the regulated companies and to act as arbitrators between private parties. However, in some countries, the scope of the regulatory agency's activities is relatively large, covering most aspects of the specific industry regulation⁵⁹.

Regulatory agencies are generally set up to be independent from the regulated parties and to maintain an arm's length relationship with the political authorities. The regulatory agencies also have attributes of institutional autonomy, usually including ear-marked funding and exemption from civil service salary rules⁶⁰. Funding is often obtained from levies on regulated firms which, for control purposes, is sometimes administered through the general budget (e.g. FERC⁶¹).

In most countries, competition agencies are not specifically in charge of ESI regulation, the exception being Australia, where the competition authority is also the national electricity regulator. In addition, advocacy of competition, the promotion of competition and defence of pro-competition reforms, is a significant activity for a number of electricity regulators.

The Important Role of Competition Policy

The role of general competition law has to be clarified at the time competition starts in the ESI. An active role of competition authorities is needed. Oligopolistic conditions prevailing in electricity generation in many countries require intense

59. Regulation which is not industry specific may be handled by a different agency (e.g. the Environmental Protection Agency in the US).

60. Smith (1996).

61. Specifically, FERC collects revenue for the US Treasury through fees on the industry, but it is actually funded through annual appropriations from Congress. The fees are equal to the appropriated budget. This arrangement allows Congress to retain oversight and budgetary approval while passing costs on to the users through fees.

monitoring of competitive behaviour. Likewise, the development of a formerly non-existent market in supply to end users calls for a careful scrutiny of anti-competitive practices.

In the past, competition authorities have not been particularly concerned with the ESI. Thus, it is important that enough resources be timely assigned to this new task. Also, since detailed understanding of the operation of the ESI is needed, close co-operation of competition authorities with electricity regulators is advisable whenever they are two different institutions.

There are two areas in which competition policy may have a key role in the development of competition in electricity markets: merger policy and subsidies. First, the stance taken by competition authorities towards mergers and acquisitions is critical in many countries in which the electricity market is initially highly concentrated. Entry and geographical expansion of market boundaries, which can also mitigate market power, occur only slowly in electricity markets. Additionally, merger and acquisition activity may seek to reaggregate functions of the ESI, such as generation and distribution, that reform has sought to disaggregate in order to promote competition. An active merger control policy may be the only effective remedy against market power in a number of situations.

Experience in the US and elsewhere shows that merger policies can be tailored and adjusted to address concerns about market power without generally blocking mergers themselves. Identifying appropriate remedial measures to mitigate market power requires a careful analysis of markets to identify the geographical areas in which market power may be exerted and the particular assets that confer market power. Standard antitrust analysis based on concentration measures is likely to underestimate the potential for the exercise of market power⁶².

62. See Borenstein, Bushnell and Knittel (1998).

Second, competition authorities have a key role in ensuring that subsidies do not distort competition in electricity markets. Subsidies have been common in monopolised electricity markets, including aid to other industries (coal), to specific generation technologies (nuclear and some renewables), and to some end user groups (energy intensive industries). The introduction of competition into electricity markets increases pressure to dismantle subsidies but does not necessarily eliminate them. Subsidies may be particularly damaging to competition in international electricity markets since differences among national policies may provide an unfair competitive advantage to some electricity companies.

Specific tools and expertise for the analysis of competition in electricity markets are being quickly developed, particularly in the US where antitrust legislation is most widely applied. While the basic concepts (e.g. market power) and remedies (e.g. divestitures and facilitation of entry) of antitrust analysis remain the same, market definition and the specific factors that are likely to facilitate the exercise of market power (or to make it more difficult) in the ESI require a refinement of the concepts⁶³.

First, the relevant geographical and product electricity market for antitrust analysis has to be defined with reference to demand and supply conditions that change over time. For instance, the same geographical area may constitute just one market in periods of low demand but may be split into two or more markets in periods of high demand if transmission constraints impede trade between zones. As a result, there may be different markets for different time periods. In addition, wholesale and retail transactions generally would not be in the same market because the opportunities of buyers of electricity to switch from one to the other are limited. And, for some purposes, long, medium, and short-term transactions also define different markets.

63. See Frankena and Owen (1994) and Binz and Frankena (1999) for a detailed analysis of antitrust in power markets.

Second, the assessment of market power in electricity markets has to take into account a number of specific factors including the way in which competition takes place (i.e. how prices are set given a particular vertical or horizontal structure) and the conditions of entry into the market. Antitrust analysis often relies on concentration indices, such as the Herfindalh-Hirschman Index, built from market shares to assess how likely it is that market power will result in uncompetitive prices. This approach is seen to be too broad to make an accurate assessment in the ESI. Increasingly, antitrust analysis of electricity markets relies on full structural models of the industry that include an explicit description of the vertical and horizontal structures and specific assumptions about the behaviour of firms. As regards entry conditions, antitrust analysis needs to take into account the relatively long (even if decreasing) time span from initial planning to operation of generation and transmission assets.

Developing a Framework for International Trade

International electricity trade is increasing in many regions of the world, including the EU and North America. In these regions the ESI is rapidly evolving from a set of national markets to become a much broader regional market. A similar process is taking place in federal countries such as the US and Australia, where more integrated national markets are growing out of previously separate state markets. The development of regional electricity markets brings some important benefits. In addition to the direct benefits of trade resulting from lower overall costs, regional competition may compensate for high concentration in domestic markets and encourage the competitiveness of national electricity firms.

However, lack of harmonisation among national regulations may result in barriers to trade. First, if some countries are more open than others within a common trade area, there may be reciprocity concerns that could make international electricity trade more difficult. Second, nationally set environmental standards (e.g. post-

Kyoto commitments to reduce CO₂ emissions) may not be effective once international electricity trade is engaged. Third, differences in taxation may also distort and discourage trade. A prominent illustration of how lack of harmonisation may result in market fragmentation is provided by the EU internal electricity market⁶⁴.

Extensive international co-operation to deal with these issues is needed. There are signs that it is increasing. The efforts made in the context of the EU Electricity Directive to set common rules, the “flexibility” mechanisms included in the Kyoto Protocol and the incipient analysis of trade of energy services in the context of the General Agreement on Trade and Services (GATS) are examples of increasing international co-operation.⁶⁵ However, more remains to be done.

A difficult issue that needs to be addressed in the development of international electricity markets is the management of transmission. In practice, the development of international electricity trade depends on market players having access to international interconnectors at a reasonable price. Pricing and allocating international transmission capacity raises similar issues to those raised by domestic transmission. First, pricing has to avoid the “pancaking effect” of transmitting power across various electricity systems, meaning the accumulation of two or more national transmission charges when this accumulation of charges is not justified by the cost of the transmission services provided. Second, pre-existing contracts and international agreements between utilities and system operators may conflict with an efficient allocation of transmission capacity. The development of the EU internal electricity market provides an example of these two problems⁶⁶ and of the need for common rules to overcome them.

64. See the *Second Harmonisation Report*, EU Commission (1999).

65. See WTO (1999).

66. See EU Commission (1998), *Comision Nacional de la Energia* (1999) and *European Transmission System Operators* (1999).

The Relationship with Natural Gas

Developments in the natural gas market also have to be taken into consideration as gas and electricity markets are increasingly interrelated. The opening of gas markets and the related changes in gas prices have a potentially large effect on the ESI. Gas prices have a short-term impact on the generation mix that is dispatched. In the long-term, investment decisions in generating capacity are also affected. The fuel inputs to the generation of electricity will result from the combined action of changes in both gas and electricity markets. In addition, gas companies are actual, or potential, competitors in the electricity market. A wider energy sector perspective is important in assessing the institutional and other changes that are taking place in the ESI.

A convergence of gas and electricity regulation is already apparent in a number of countries. For instance, the regulation of gas and electricity is assigned to the same regulatory agencies in many countries.

The Broader Policy Framework: Security of Supply

This book is primarily concerned with the introduction of competition to stimulate greater economic efficiency in the ESI. However, most governments consider they have a strategic obligation to ensure that the ESI is reliable in the short, as well as in the long-term; that environmental objectives are met; and often also that other objectives such as social or regional equity are met. How do these wider considerations fit into a reform process which is mainly driven by the objective of improving efficiency?

An important policy priority is to sustain security of supply in its three dimensions of short-term system reliability, long-term system reliability through adequate investment, and diversity and security of fuel inputs used for power generation. In the past,

governments have often promoted security of supply through direct intervention. Under competition, security has to be promoted with more market compatible tools.

■ **Short-term System Reliability**

There is a need to develop effective rules to facilitate co-ordination and to ensure the reliability of electricity systems under competition. Several objectives have to be considered in designing these rules, including economic efficiency, minimal commercial interference and reliability. There is no tailored set of rules for system operation under competition. Rules are now being developed and tested in many countries and it is not yet clear which approaches are more effective. From a policy perspective, the most important issue is to assign responsibilities clearly, including an explicit definition of the obligations of each agent and the financial consequences of failing to meet these obligations. Governments need to ensure that this happens.

■ **Long-term System Reliability**

In the new ESI, investment in generation is governed by market rules. In this context, prices signal the relative scarcity of generation capacity, and investment is driven by prices. This market process should result in adequate investment levels and, in particular, eliminate the incentives to overinvest that arise in a regulated environment. However, it is sometimes suggested that competition may have a negative impact on investment in generation assets. First, there is the argument that competition may be “too effective”, leading to unsustainably low prices that may, in turn, temporarily discourage investment and reduce security of supply. However, the real problem has often been the opposite: insufficient rivalry rather than cut-throat competition. Second, it has been argued that investment may follow a cyclical pattern if investors are myopic, but investors can be expected to take into consideration returns over the entire life of the investment. Third, there are concerns that under competition there may be a

shortage of investments in peak load capacity, because it will tend to be remunerated randomly and infrequently in a competitive market. This argument has already been explored (see Chapter 6 on capacity payments).

Even if such concerns were relevant, there are a number of elements in the ESI that may compensate for any temporary imbalances, thus suggesting that investment in generation capacity should not be an issue under competition. The development of Information Technology increasingly allows demand to be responsive to price changes without ultimately affecting reliability; and the shortening of lead and construction times for some generation technologies means that supply can react relatively quickly to maintain reliability.

To summarise, the level of investment in generating capacity should not be a concern in a competitive electricity market. However, the transition to effective competition could create some problems. First, there could be higher-than-normal regulatory risk that may delay or make it more costly to finance investments. Experience to date (see Chapter 3) indicates that regulatory risk is not merely an academic concern. Second, inadequate transmission pricing may distort generators' decisions. Third, insufficient demand participation may result in prices that do not provide the correct signals for investment.

Adequate investment in transmission and distribution is also essential to sustain reliability. Investment can be open to any interested parties or, alternatively, responsibility for investment may lie with a single transmission company. In both cases, transmission prices play a key role in guiding investment decisions. Cost reflective ("nodal") prices can provide adequate signals for investment. However, transmission networks have some special characteristics that may result in investment distortions. There is a broad consensus that governments (or the appropriate regulated companies) should retain at least a residual role in investment in electricity transmission, including monitoring investment developments. This is in addition to the ongoing role of governments in providing an adequate regulatory framework for investment.

■ Diversity and Security of Fuel Inputs

It is not clear which fuel and technology choices will develop under competition. A competitive market provides incentives for investors to choose the least cost alternatives. For instance, given current conditions, fossil fuels such as gas often provide electricity at least cost. This, of course, may conflict with national policies that give preference to other fuels (e.g. nuclear promotion in some countries and closing of nuclear plants in others) or that would favour a different fuel mix (e.g. more domestic coal and less natural gas in electricity generation).

Governments can, to some extent, continue to implement fuel policies in a competitive market. For instance, governments can restrict fuel choices for new entrants or can establish subsidies for generation based on certain fuels. However, this approach may have a significant impact on market performance, as it distorts entry and investment decisions. Ultimately, regulations on entry are likely to conflict with the efficient operation of the market, and reduce the efficiency gains that were the primary objective of reform.

The Broader Policy Framework: the Environment

Protection of the environment is a growing policy priority. This objective includes a broad array of issues ranging from post Kyoto CO₂ emissions reduction targets, and other air and water pollution control, to nuclear safety and radioactive waste disposal. Monitoring and enforcement of established environmental standards remains a public policy issue in a competitive market. Indeed, once environmental standards are set, strict enforcement is important also from a competition policy perspective to ensure that no agent unfairly enjoys a cost advantage from non-compliance.

Policy makers face the challenge of designing least cost policies to pursue these objectives, that is, policies that reduce or eliminate environmental externalities (or promote social objectives) while minimising market distortions. In general, this means that environmental objectives have to be implemented with competitively neutral, non-discriminatory, mechanisms and that the use of other mechanisms must be minimised. A broad set of economic incentives to promote environmental objectives is available. Tools like tradable emission permits or emission taxes have the potential of improving environmental performance while minimising market distortions. Other market-friendly policy tools that have been used to pursue environmental goals are renewable portfolio standards, enhanced public research and development (R&D) budgets, and non-bypassable grid charges established to finance public benefits.

Environmental protection regulations already have a large impact on the ESI, and this impact is likely to increase in the future throughout OECD countries. Regulations include specific actions on both the demand and the supply side of the electricity market as well as general economic instruments that act simultaneously on both sides of the market and on other markets.

On the supply side, there are requirements on generating plants to reduce emissions of pollutants such as sulphur and carbon dioxide. These take the form of standards and quotas that may be assigned either to individual generation units or globally to the industry.

Support programmes aim to increase the use of environment-friendly technologies, particularly renewables, and to increase the efficiency of power generation, specially by promoting co-generation. These measures include investment subsidies, fiscal incentives, green pricing, guaranteed markets and/or subsidised prices, tradable green certificates markets (i.e., consumers have an obligation to buy “green certificates” from “green generators” in proportion to their electricity consumption), government-supported R&D, standards and obligations to adopt certain

technologies. Such programmes have already significantly increased the share of renewables and CHP in power generation.

On the demand side, policies include demand side management programmes, aimed at improving energy efficiency at the consumption point, government-supported R&D and consumer education programmes.

The difficulty with current approaches is that they do not optimise the economic efficiency of meeting environmental objectives in a liberalised ESI, as they have a very significant potential to distort market decisions. Hence, there is growing emphasis on so-called economic (or market compatible) instruments to achieve environmental objectives.

Economic instruments, including taxes and tradable quotas, are those that result in electricity producers receiving the same price regardless of its source, and all emitters (or any other targeted externality) paying the same price regardless of source. The first condition is necessary for an efficient allocation of electricity: since all electricity renders the same service regardless of its source, price should not depend on the source. The second condition is necessary for an efficient — least cost — allocation of abatement costs among polluters.

A tax on the externality — for instance, on each tonne of carbon dioxide discharged into the atmosphere — is designed to make polluters internalise the social cost of emissions. There are two main advantages of environmental taxation compared with other options. First, environmental taxes are efficient, that is, they can “price away” the externality while minimising distortions on other aspects of economic activity. Second, the cost to tax payers is known in advance, while the cost of regulatory measures is only known after they have been implemented. Assigning environmental taxes, however, requires governments to develop measurement and collection mechanisms, and so the implementation of an environmental tax is not costless. Environmental taxation is being considered in the EU and, individually, in some EU member

countries (e.g. UK and Denmark) as a tool to meet CO₂ reduction commitments. In practice, the EU approach may involve a tax levied on all energy, combined with a series of exemptions and refunds linked to the contribution to achieve emission reduction objectives.

An alternative to taxation is to set pollution quotas limiting the amount of pollutants that can be generated. Pollution quotas have one key advantage over taxation. Unlike taxation, a quota implies that the amount of pollution that will be generated is known in advance. However, the cost imposed on the generators of pollution is not known at the time of setting the quota. Conversely taxation implies that the cost to taxpayers is known in advance but the amount of pollution that will be generated is uncertain.

A pollution quota, like a tax, requires governments to set up mechanisms to measure pollutants and to enforce the quota through penalties for non-compliance which, implicitly, will act as a ceiling for the actual unit cost of the quota. In addition, an efficient quota system requires the development of a trading mechanism among polluters. For instance, governments may establish the total amount of carbon dioxide emissions allowed in their country in a given year. Setting limits for each polluter within the country would require very detailed and disperse information which is not available to governments. An aggregate approach, such as forcing all polluters to cut their emissions of carbon dioxide by X %, would not be efficient because the cost of reducing emissions is lower for some industries and technologies and higher for others. To assign the pollution quota to the polluters efficiently, that pollution should be reduced by industries with the lowest abatement technologies. Governments (or any other single party) are not in a good position to assess differences in costs across industries and firms.

One approach to minimise the total cost of a pollution quota is to create a market for emissions. This amounts to establishing an aggregate emissions limit, distributing to individual sources a number of emission permits equal to this limit following some criteria, and allowing the permits to be traded. Emissions trading is

efficient because firms with lower emissions abatement costs may prefer to abate more and to sell their allowances to firms with higher emission abatement costs. The price of the emission permits conveys valuable information to traders on the cost of reducing emissions and, in this way, trade lowers the overall cost of compliance with the quota. Experience with this approach is still limited. It has been tested with some success under the US acid rain programme to limit sulphur dioxide emissions. Other programmes developed in the US covering a range of air pollutants and water effluents have been less successful. There is virtually no experience with tradable permits outside the US.

Tradable permits for carbon dioxide « equivalents », including carbon dioxide itself and five other greenhouse gases which are measured in terms of the former, have been proposed in the context of the Kyoto Protocol. At this stage, the implementation of tradable carbon permits bears two main difficulties. One is the allocation of the pollution quota within each country. If countries adopt different allocation systems, the same industries will bear different costs in different countries and this may affect international competitiveness. The second difficulty is that of finding a consistent set of national and international enforcement systems ensuring, for instance, a common penalty level. The performance of emissions trading mechanisms depends on a number of factors, including the size of transaction costs and the « liquidity » of the emission permits.

Technology support measures and, to a lesser extent, emission controls currently dominate the international scene for meeting environmental objectives. Economic instruments are not widely used. This picture may change if environmental policies in response to the threat of climate change become important. The Kyoto Protocol commits the Annex I countries, including IEA countries and Economies in Transition, to cut their greenhouse gas emissions by about 5% relative to their 1990 levels. Reduction targets have to be met from 2008 to 2012 and must cover five other greenhouse gases in addition to carbon dioxide. Specific

reduction targets vary from country to country, ranging from an 8% reduction for most countries to increases of up to 8% for other countries. The Protocol will enter into force 90 days after 55 countries, accounting for 55% of total carbon dioxide emissions of Annex I countries, have ratified it. When this could happen is subject to considerable uncertainty as ratification of the accord by some countries, notably the US, is still uncertain. Overall, while there is an expectation that greenhouse gas emission control policies will develop, there is considerable uncertainty as to which particular policies will be applied to achieve the emissions reduction goal⁶⁷.

From the point of view of competition and market performance, economic instruments have a number of advantages over other policy instruments. In particular, economic instruments address externalities without distorting competition or inducing inefficiencies, but they are not yet widely applied in practice. A number of factors, including political constraints, macroeconomic (e.g. fiscal policy) considerations, lack of international harmonisation, and concerns about the competitiveness of particular industries, have resulted in environmental policies that are largely based on other, less efficient instruments.

In principle, taxes and tradable quotas are equivalent in that both have the potential to resolve the externality without inducing distortions in other parts of the market. In practice, however, there are differences because the cost of reducing emissions is highly uncertain. Thus, the actual cost of a tradable quota may differ significantly from the expected cost. The actual cost of taxation, on the other hand, is less subject to variation. This provides an

67. The Protocol includes or allows a number of mechanisms aimed at minimising the costs of implementation by allowing flexibility in the timing, the place and the subjects of reduction targets. These mechanisms allow flexibility within Annex I countries by means of joint implementation, international trading of GHG and bubbling, i.e. joint commitments by several countries. These mechanisms also allow flexibility between Annex I countries and the rest of the world under the Clean Development Mechanism. In addition, the Protocol sets an overall target to be reached by the end of the agreement period (2008-2012) but does not constrain the path of emissions reductions over time.

argument to choose taxes over quotas as the preferred instruments of environmental policy⁶⁸.

The impact of other policy instruments on competition and market performance differs. Some policy instruments, such as adequately targeted R&D subsidies, are competitively neutral and therefore need not conflict with the introduction of competition into electricity markets. Other instruments, to different degrees, distort the market by creating separated markets for green and non-green electricity, subsidising some competitors, or forcing (possibly non-cost effective) technological choices.

A fundamental issue in assessing the potential impact of these “non economic” instruments is whether they are cost effective in meeting their goals. Consider, for instance, technology support policies aimed to increase the share of renewables in power generation. A number of alternative measures can achieve the goal that X% of all energy be produced from renewable energy sources. Possible measures include a guaranteed price for green energy, a reserved market for green energy (i.e., some X% of all energy has to be purchased from green generators) and a tradable green certificates market. The important issue is the cost effectiveness of these alternatives.

Market-based approaches can be expected to perform better than those based on administrative intervention because they allow market players to search for the most cost-effective alternative. In addition, larger and more flexible markets can be expected to perform better than more restricted markets. Thus, a green certificates market can be expected to be more cost effective than the other two options. In particular, market-based approaches have a significant potential when environmental policies commit substantial resources and the underlying market is large and potentially efficient. On the other hand, setting a guaranteed price has lower start-up costs, and may be an easier and more

68. Koops (1999).

straightforward option when the underlying market is small. This suggests that, while administrative approaches have dominated the first steps of environmental policy, market-based approaches will be needed if environmental policies are escalated.

The Broader Policy Framework: Social and Regional Objectives

To varying degrees, countries have also pursued social and/or regional objectives in connection with the ESI and these objectives may continue to be important. Governments may, however, need to review and clarify what social and regional objectives they want to pursue. Policy priorities of the past may no longer be important. For instance, uniform electricity tariffs may no longer be justified if broad geographical cohesion ceases to be an important policy goal because it is already achieved. Social objectives, including universal service, support to disadvantaged consumers or equalisation of tariffs can, in principle, be promoted in a market context provided they are made explicit and they are financed in ways that do not distort competition. Achieving these objectives, nonetheless, generally entails distorting electricity prices and therefore there is a limit to what electricity markets can contribute to social objectives without suffering significant loss of economic performance. In the long run, general policies, rather than sectoral electricity policies are more efficient in achieving social objectives.

In defining social objectives, policy makers should keep in mind that competition itself brings some significant social benefits. For instance, low prices are an important step forward in achieving universal service; and more product and price differentiation have the potential of allowing a better match between special consumer groups and the service they need.

CONCLUSIONS AND OUTLOOK

Consumer Choice is the Key to Reform

A fundamental pillar of effective reform in the ESI is consumer choice, that is to say, giving all consumers the ability to choose their electricity supplier. Consumer choice disciplines market players, because dissatisfied consumers can switch supplier, and it encourages innovation. As in any other market, consumer choice in the ESI is fundamental to achieving both static and dynamic efficiency, and it is difficult to envisage real competition without it. There are virtually no examples of markets in which competition does not depend on consumer choice.

Competition in wholesale markets has resulted in significant improvements in the productivity and internal efficiency of electricity companies but translating these benefits to consumers has proven to be a crucial challenge for electricity market reform. Experience has shown that consumers benefit from reform only if the other elements of the supply chain transmit the benefits of competition. This means that there is an increasing emphasis on the regulation of transmission and distribution to ensure non-discriminatory access conditions and cost-oriented tariffs, and that competition in end-user supply is increasingly seen as a means of translating to consumers efficiency gains obtained upstream in the supply chain.

Challenges

A major challenge which early reformers have had to tackle is that lifting barriers to entry and changing the rules is not enough: competition requires a sufficient number of competitors. If supply is concentrated in a few firms, competition generally fails to develop and prices may remain persistently above their competitive levels. In the electricity sector, concentration has often

resulted in prices that are too high⁶⁹. The UK experience, for instance, showed that the performance of a duopoly was not satisfactory and that further measures were needed to reduce concentration after privatisation⁷⁰.

High concentration is a common feature of the ESI. In the past, power supply has tended to be concentrated in a small number of firms. Because of the lack of competition, seller concentration was not considered a problem. Liberalisation policies, aimed at market entry and prices may not be enough, at least in the short-term, to establish effective competition. Restructuring policies may also be needed to correct inappropriate market structures. These policies have been developed in most liberalising countries either at the time of liberalisation or later, when market performance has indicated the need for a less concentrated structure.

However, it is also important to note that “workable” rather than “perfect” competition is the goal. Workable competition may emerge even if suppliers are not “atomised”. Most experts agree that four or five comparable power generating firms, under the appropriate circumstances, may yield a satisfactory market performance or, at least, one that improves upon the initial situation. If this view is correct, relatively limited restructuring policies may suffice to obtain workable competitive markets. An adequate market structure in other parts of the supply chain is also essential to develop workable competition. In particular, effective consumer choice requires the development of a critical mass of retail suppliers (who may not be generators).

Another challenge is to develop techniques and approaches to meet objectives for the ESI, including efficiency, security of supply, environmental protection and social goals, in a market compatible way. Development of regulation compatible with undistorted

69. This was not totally clear until the first competitive pool started operation in the UK. It is possible that intense price competition may develop even if the number of competitors is low (“price wars” among duopolistic air carriers, for instance, are not uncommon).

70. A survey of studies on market power in electricity markets can be found in Kahn (1998).

market performance is a key challenge for most regulatory systems as the required know-how and procedures involved in developing market-oriented regulation are radically different from those needed without competition. In a competitive environment, economic factors tend to outweigh technical factors in defining feasible regulations; regulators have to be independent from the regulated entities, and regulatory procedures have to be explicit and transparent. All these elements force some important changes in the management of regulation, typically leading to a reinforcement of the resources devoted to regulation and, more important, to more independent and transparent regulatory institutions. One particular challenge is to develop effective regulatory approaches to transmission systems, which present difficult characteristics and which remain an essential input to electricity supply.

Security of supply, and environmental and social objectives have to be pursued with suitable instruments that include taxes to price externalities, non-discriminatory subsidies for the development of long-term R&D projects, market mechanisms (tradeable emission permits), performance standards and some general obligations (obligations on suppliers to contract with renewable fuel power producers). Command and control mechanisms are not the best approach in this new context. Also, social objectives whenever pursued have to explicitly and transparently regulated; for instance, obligations to supply and codes of practice for some categories of captive end users such as the elderly and disabled.

This has proved to be a difficult task. Transition and broader economic policy issues often slow the reform of the regulatory framework. As an example, the taxation of CO₂ emissions raises issues about the differential impact on energy-intensive industries, the competitiveness of national economies and the overall design of fiscal policy. As a result, taxation of emissions is still rare in the international arena.

The environmental challenge is perhaps the biggest. The last thirty years have seen rapidly growing concern about the environmental

effects of energy production, including acid rain, nuclear waste disposal and, more recently, the issue of climate change. Environmental protection is consequently a top priority for governments.

Further Change Can be Expected

Electricity market reform is a moving target. Many studies on the subject written only a few years ago are already outdated. One key development is the market itself. The ESI is rapidly expanding its boundaries. Generation is increasingly integrated with gas and oil companies. Vertical integration allows generators to hedge risks related to the availability of fuel. Simultaneously, integration reduces risks for gas and oil companies by securing a relatively stable demand for their products. Two factors work in combination to increase vertical integration. First, gas-fired generation is growing around the world. Second, the liberalisation of generation facilitates vertical integration by removing regulatory barriers to entry into generation.

At the same time, distribution and end user supply activities in network industries, such as gas, electricity and some areas of telecommunications or water, are likely to become more integrated across industries. The reason is that there are economies of scope in end user activities and, to a more limited extent, in the distribution of services. Again, the opening to competition facilitates this trend.

The geographical boundaries of the ESI, once coincident with national or state boundaries, are also changing. Increasingly, electricity systems are becoming integrated within regional markets. Liberalisation is also opening the way for significant direct investment by foreign companies in national markets. Countries in which electricity companies are owned by foreign companies or investors include the US, UK, Australia, New Zealand and many non-OECD countries.

The implication for policy of this expanding industry boundary is that regulation will have to be managed more and more at a multi-

sectoral and multinational level. This evolution towards greater dependence on general regulation, competition law, and common rules for international trade is a process that has already occurred in many other industries opened to competition.

Technology is also changing. The emergence of “e-commerce” will have an important impact on transactions and market behaviour in the ESI. Internet-based electronic commerce provides opportunities for companies to develop by expanding services, providing new choices, streamlining processes and reducing costs. These new processes are also creating new business models that will continue to change the shape of the ESI and related industries.

Another, even more important, technological development on the horizon is the widespread adoption of non-centralised (self-) dispatch. Autoproduction and distributed generation are rapidly growing in many countries due to the development of efficient small-scale generation. Environmentally, these developments are very positive to the extent that they make use of renewable sources of energy.

Distributed generation and autoproduction are both substitutes for electricity transportation services. This has the effect of weakening the effectiveness of natural monopoly regulation of the network. If electricity is generated closer to where it is consumed, relatively fewer transmission and distribution services will be needed, with large potential implications for network regulation. For instance, if transportation services are not used by all consumers, the effectiveness of transportation charges as a means of financing stranded and fixed costs will be reduced. In due course, if new generation technologies become a profitable substitute for transportation, transportation will cease to be a natural monopoly. Such a development would have a crucial impact on the future economics, market structure and regulation of the ESI.

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GLOSSARY⁷¹

Access Charge: A charge levied on a power supplied, or its customer, for access to a utility's transmission or distribution system. It is a charge for the right to send electricity over another's wires.

Ancillary Services: Services that are required for the security and stability of the transmission system, such as reactive power, hot standby and frequency control.

Base Load: The minimum load over a given time period (e.g. a day or a year).

Bilateral Contract: A direct contract between a power producer and user or broker outside of a centralised power pool or POOLCO.

Broker: An entity acting as an agent for others in negotiating contracts, purchases, or sales of electrical energy or services without owning any transmission or generation facilities. Brokers do not own the power transacted.

Bulk Power Market: Purchases and sales of electricity among electricity companies. Often this term is used interchangeably with wholesale power market.

Capacity Payment: A payment to generators proportional to the generating capacity they make available.

Captive Customer: Those customers who do not have an option to go to another supplier to buy electricity.

CHP: Combined Heat and Power, or Cogeneration.

Cogeneration: A process of producing simultaneously electric and thermal (heat) energy from one fuel source.

71. Many of the definitions in this glossary have been taken from other sources including the glossaries elaborated by NARUC, Offer, California ISO, Entergy, Edison Electric Institute, US DOE and Australia's Parliamentary Library.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines.

Congestion: See transmission congestion.

Contract for Differences: A financial contract that enables customers to purchase power at a fixed price.

Contract Path: The most direct physical transmission tie between two interconnected entities. In some electricity transactions, the transfer of power is presumed to take place across the “contract path”.

Corporatisation: Subjecting government business enterprises to the principles of corporate law, often accompanied by a range of other initiatives, such as providing greater management autonomy and clear commercial objectives.

Cost of Service Regulation: A form of regulation where the profit of a regulated company is determined by its actual costs regardless of performance. Tariffs are set to allow the firm to recover its costs, including the cost of capital.

Countertrade: See Redispatching.

Demand-Side Management: See DSM.

Deregulation: The elimination of regulation from a previously regulated industry or sector of an industry.

Direct Access: The ability of a customer to purchase electricity directly from the wholesale market rather than through a local distribution utility. Customers with direct access are also said to be “eligible”.

Distributed Generation: This refers to generation units located near a consumption point so that power can be delivered without making use of the transmission grid.

Distribution: The process of transferring electricity from the transmission grid to final users.

Distribution Company (Disco): The regulated electric company that constructs and maintains the distribution wires connecting the transmission grid to the final customer.

Divestiture: Removing one function from others by selling (spinning-off), or in some other way changing the ownership, of the assets related to that function. For instance, spinning-off generation assets so they are no longer owned by the shareholders who own the transmission and distribution assets.

DSM (Demand-Side Management): Planning, implementation, and evaluation of utility-sponsored programmes to influence the amount or timing of customers' energy use.

Economic Efficiency: A term that refers to the optimal production and consumption of goods and services. This generally occurs when prices of products and services reflect their marginal costs.

Economies of Scale: An industry (or technology) exhibits economies of scale if marginal cost decreases with output.

Eligible Customer: Those customers who have the option to go to another supplier to buy electricity.

Embedded Cost: See sunk Cost.

End User Supply: See retail supply.

Excess Capacity: Volume or capacity over and above that which is needed to meet peak (planned or expected) demand.

Forwards: A "forward" is a commodity bought and sold for delivery at some specific time in the future. It is differentiated from a futures contract in that a forward contract is a customised, non-exchange traded, and non-regulated hedging mechanism.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Futures Market: An arrangement through a standardised contract for the delivery of a commodity at a future time and at a

price specified at the time of purchase. The price is based on an auction or market basis.

Generation: The process of converting primary energy (e.g. coal, gas, oil, stored water, wind and solar) into electricity.

Generation Company (Genco): An entity that operates and maintains generating plants.

Generation Dispatch and Control: Aggregating and dispatching (sending off to some location) generation from various generating facilities, providing backup and reliability services.

Grid: A network for the transmission of electricity throughout the state or country typically consisting of several interconnected lines. Also, the high voltage transmission network.

Incentive Regulation: A form of regulation where the profit of a regulated company is determined by its actual performance relative to some pre-established standards of performance for service quality and cost effectiveness.

Independent System Operator (ISO): A neutral operator responsible for maintaining instantaneous balance of the grid system. The ISO performs his function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

Interconnector: High voltage transmission lines linking states or countries.

Load: The amount of electricity being used or demanded at one time by a circuit or system.

Load Profiling: The study of the consumption habits of consumers to estimate the amount of power they use at various times of the day and for which they are billed. Load profiling is an alternative to precise metering.

Locational Market Clearing Price: The price at which supply equals demand at a specified location. All demand which is

prepared to pay at least this price at the specified location has been satisfied. All supply which is prepared to operate at or below this price in the specified location has been purchased.

Losses: Electric energy transformed into heat and therefore lost during transportation.

Marginal Cost: The cost of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

Market Power: A company's use of its position in a market to raise prices above competitive levels.

Merger: The union of two or more commercial interests or corporations.

Merit Order: Ranking in order of which generation plant should be used, based on ascending order of price together with amount of energy that will be generated.

Monopoly: The only seller with control over market sales.

Natural Monopoly: A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries which exhibit decreasing average long-run costs due to size (economies of scale).

Nodal Pricing: Locational pricing of energy and transmission services (See Locational Market Clearing Price).

Oligopoly: A few sellers who exert market control over prices.

Options: A contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (e.g., a commodity or commodity futures contract), at a fixed price, within a specified period of time. Options may be standardised, exchange-traded, and government regulated, or over-the-counter customised and non-regulated.

Pancaking: Charging two or more access charges to electricity transactions that make use of two or more transmission systems. Pancaking discourages intersystem trade and does not generally reflect transmission costs.

Peak Load (or Peak Demand): The electric load that corresponds to a maximum level of electric demand in a specified time period.

Performance-Based Regulation (PBR): See Incentive Regulation.

Pool: A short-term market for electricity where sellers bid into the pool the advance prices of quantities of electricity, and generators are dispatched to meet the demand. A pool comprises the functions of a power exchange and a system operator. These functions can be performed by a single entity or, alternatively, can be unbundled.

Poolco: An entity that operates a pool.

Postage Stamp Tariff: In transmission, a price for transmission services that does not depend on location. Paying the tariff gives the right to inject energy at any node of the grid and take it at any other node.

Power Exchange (PX): An independent entity responsible for conducting an auction for generators seeking to sell energy and for loads which are not otherwise being served by bilateral contracts. The Power Exchange is generally responsible for scheduling generation, determining market clearing prices, and for settlement and billing.

Price Cap: A price determined by the regulator that cannot be exceeded by the regulated company. It serves to implement incentive regulation.

Rate of Return Regulation: See Cost of Service Regulation.

Redispatching: Management of transmission congestion directly by the system operator. This consists of requiring some generating

units located in the zone where demand exceeds supply to increase output while reducing the output of some generators in the zone where supply exceeds demand.

Reliability: Electricity system reliability has two components, adequacy and security. Adequacy is the ability of the system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

Renewable Resources: These are energy resources that are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies.

Retail Competition: A system under which more than one electricity provider can sell to retail customers, and retail customers can buy from more than one provider.

Retail Market: A market in which electricity and other energy services are sold to the end-user.

Retail Supply: The business of purchasing electricity at bulk supply points and selling it to retail customers.

“Split the Market” Approach: Managing transmission congestion by means of locational or nodal pricing.

Spot Market: A market for the immediate delivery of a commodity. Short-term electricity markets are sometimes (incorrectly) denominated “spot electricity markets” even if delivery does not take place immediately.

Stranded Assets: Unamortised ESI assets that will not generate enough revenue in a deregulated market to allow for full cost recovery.

Sunk Cost: A cost that has already been incurred, and therefore cannot be avoided or changed by any strategy going forward.

System (Electricity): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management or operating supervision.

System Operation: The process of maintaining instantaneous balance of an electricity system.

Tariff: A regulated price and any additional regulated service conditions linked to it.

Third Party Access: Right to equal (non-discriminatory) access to transmission services.

Time-of-Use (TOU) Rates: The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak, and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Transco: An independent transmission company that is engaged solely in the bulk transmission of electricity, owns transmission assets and manages system operation. It can be for-profit or not.

Transmission: The process of transporting electric energy in bulk from a source of supply to other parts of the system or to other systems.

Transmission Congestion: The condition when market participants seek to dispatch in a pattern which would result in

power flows that cannot be physically accommodated by the system. Although a system will not normally be operated in an overloaded condition, it may, nevertheless, be described as congested based on requested/desired schedules.

Transmission Congestion Contract (TCC): A financial instrument that provides a hedge against congestion price differences between zones or nodes of the grid.

Transmission System Operator (TSO): See System Operator.

Unbundling: Disaggregating a service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

Utility: A regulated company that is the monopoly supplier of some service. Today this term is also applied to companies that operate in former utility industries.

Vertical Integration: An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service. In the electricity industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system, and distribution lines to provide all aspects of electricity service.

Wheeling: Transmission of electricity by an entity that does not own, or directly use, the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially to mean transmission.

Wholesale Competition: A system whereby a distributor of power would have the option to buy his power from a variety of

power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

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