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Chapter 3

Assessing the Long-Term Outlook for Business Models in Electricity Infrastructure and Services

by
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Rising electricity demands call for greater investment in electricity supply infrastructure. What are the long-term drivers of and prospects for business models in the construction and operation of electricity infrastructure and the provision of electricity services? This chapter describes electricity industry structure and patterns of ownership and the reasons for differences among countries and regions. It examines the challenges that governments face, including establishing and sustaining competitive markets in electricity supply, pricing network services efficiently, and ensuring security of supply.

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Summary

The adequacy and timeliness of investment in physical electricity infrastructure will remain closely linked to the long-term structural evolution of the industry, to sources of finance and to financing mechanisms. Several factors – including the pace of demand growth, government policies on market structure and ownership, technological change and growing cross-border trade – will strongly influence business models and prospects for investment. Policy and regulation, in turn, will have to continue to adapt in order to meet a number of challenges, including establishing and sustaining competitive markets in electricity supply, pricing network services efficiently and ensuring security of supply.

Liberalisation of the electricity industry – involving greater private sector involvement, the introduction of competition in generation and supply and new regulatory structures – will continue to have a profound impact on business models. Privatisation has largely run its course in most OECD countries, with the bulk of the industry now in private hands. But rapidly rising electricity demand in developing countries and emerging market economies, where the electricity industry is often owned by the state, will increase the pressure on governments to look to the private sector for at least part of the capital needed to expand infrastructure. Market and regulatory reforms will remain the primary driver of changing business models in OECD countries and may become increasingly important in many other parts of the world. Unbundling of vertically-integrated monopolies will impose new models in generation and supply.

How successful privatisation and market reforms, which are still being implemented in many countries, are judged to be will clearly have an enormous impact on future policy directions in all regions and, therefore, business models. In most cases, the implementation of reforms is far from complete and their effects on sector organisation and structure are not yet fully evident. Although experience so far suggests that competition in electricity generation and supply can in principle bring major benefits through gains in efficiency and lower prices, there are growing concerns about whether the new business and regulatory models that are emerging involve adequate incentives for investment in generating and network capacity as market players adapt to the new environment. Continuing difficulties in financing independent or merchant power plants in many parts of the world could hinder market entry,

the development of competition and new investment. There will undoubtedly be profitable opportunities for new power generation investments in the future, but an improvement in the financing climate will call for changes in corporate governance, better risk management strategies and more transparency in accounting practices.

New developments in technology – particularly in power generation – and costs of supply will also have a major impact on the structure of the electricity industry. Upheavals in international energy markets and surging fossil fuel prices, if they persist, would have major consequences for future choices of technology and fuels. Faster growth of small-scale renewables-based generation technologies, as well as other forms of distributed generation, such as small-scale fossil-based co-generation plants and fuel cells, could radically alter the structure of the electricity industry.

The development of interconnections between national or regional networks and the subsequent expansion of cross-border trade will be both a major driver and a consequence of structural change throughout the electricity supply industry. Rising electricity demand will expand opportunities for profitable investments in interconnectors in liberalised markets. But how much new capacity is actually built and used will depend to a large extent on the regulatory framework.

Utilities are adopting varying business strategies in response to the changing market and regulatory landscape and the associated shifts in business risk. In general, the industry is consolidating and converging with other sectors, mainly through mergers and acquisitions. These trends are likely to continue. Risk management and economies of scale and scope will continue to underpin the business rationale for vertical and horizontal integration, reversing to some extent the initial restructuring where market reforms have been introduced. However, competition authorities may take a tougher stance on future horizontal deals in generation and supply amid growing concerns about the impact of concentration on the effectiveness of competition on wholesale and retail markets.

Electricity utilities are likely to become more integrated with gas and other network sectors, because of potential synergies, economies of scale and the potential to hedge fuel-price risk. The traditional boundaries between the utility sector and upstream oil and gas will become increasingly blurred, as upstream companies move downstream to protect market share and downstream companies seek to secure fuel supply and storage assets. In the longer term, utilities may seek more global reach. Opportunities and incentives to invest in emerging markets and developing countries will depend on national policies and their implications for perceived risk and potential returns. Further unbundling of networks would yield new opportunities for private investors to buy relatively low-risk regulated assets.

Many non-OECD countries will continue to struggle to attract private domestic and foreign investment in their electricity industries because of poorly developed domestic financial markets and the higher cost of capital caused by higher risk. Private investment is expected to play a growing role in the medium term, but this will hinge on the economic, political, regulatory and legal environment. The multilateral lending institutions are likely to remain a major source of much-needed capital in many countries for as long as the number of active international investors in developing countries remains small and national and regional finance modest.

Policy makers and regulators will increasingly need to focus on incentives for investment in generating and network capacity. In principle, competitive electricity markets can provide incentives for timely and efficient investments, as long as the market is well designed and the regulatory framework is appropriate. There are growing concerns about the adequacy of generation and transmission investment in liberalised markets – notably in Europe, the United States and parts of Asia. Reserve margins are falling in several countries as a result of a downturn in investment in recent years. Given the economic, social and political importance of "keeping the lights on", establishing efficient mechanisms for remunerating reserve capacity and network investments, streamlining procedures for approving new power plants and transmission lines and ensuring that utilities meet minimum standards for transmission-system reliability will remain of critical importance.

1. Introduction

This chapter assesses the long-term drivers of and prospects for business models in the construction and operation of electricity infrastructure and the provision of electricity services. Modern economies are becoming increasingly dependent on grid-based electricity services. Investment in expanding and upgrading electricity supply infrastructure – including power generation plants and transmission and distribution networks – will, therefore, continue to be of crucial importance to economic development and growth.

In its broadest sense, the term "business model" refers to the way an industry or an enterprise goes about doing business. This chapter focuses on the aspects of the electricity industry that set it apart from other industries – namely, the way the industry is structured and patterns of ownership. How the organisation of the electricity supply industry evolves will affect whether the industry is willing and able to invest in a timely manner, as well as sources of finance and financing mechanisms. Several factors, including the pace of demand growth, government policies on market structure and ownership, technological change and growing cross-border trade, will strongly influence business models and incentives to invest. But policy and regulation, in turn, will have to continue to adapt in order to meet a number of challenges, including establishing and sustaining competitive markets in electricity supply, pricing network services efficiently and ensuring security of supply.

The next section summarises existing models of industry structure, operation and ownership, and the reasons for differences among countries and regions. The chapter then goes on to review the principal drivers of change in the structure of the industry and markets for electricity services. This is followed by an assessment of how the industry could evolve in the medium to long term and what this will mean for financing and investment. The final section considers the policy and regulatory challenges posed by possible future developments in industry structure and ownership.

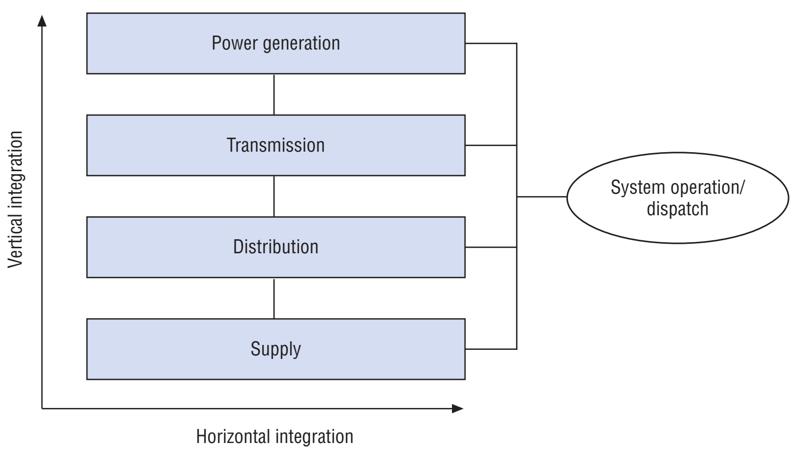
This chapter builds on the findings of Chapter 3 "Outlook for Global Investment in Electricity Infrastructure" (Morgan, 2006) in the OECD book *Infrastructure to 2030: Telecom, Land Transport, Water and Electricity*.

2. Current business models in electricity supply

2.1. Vertical and horizontal integration

There are many ways in which the electricity industry in its broadest sense – covering the construction, operation and maintenance of generating plants and networks that deliver electricity services to end-users – can be organised. The structure of the electricity supply industry is most obviously characterised by the degree of vertical and horizontal integration (Figure 3.1).

Figure 3.1. **Functional activities in electricity supply**



Vertical integration

Vertical integration describes the linkage between the main functional activities within the electricity supply chain – power generation, transmission, local distribution and supply.[1] An electricity industry or utility[2] is said to be fully vertically integrated if it is responsible for, owns or controls all four functions. At the other extreme, each function may be owned or controlled by different entities or companies. In practice, the actual structure of an electricity industry usually lies somewhere between these extremes. For example, a company may own and operate generation and transmission assets, but have no involvement in distribution.

Traditionally, the electricity supply industry in most countries has been characterised by a high degree of vertical integration because of the cost savings that could be realised from integrated planning of investment and capacity, especially in generation and transmission, and operational co-ordination. The highly capital-intensive nature of the industry, the large economies of scale in electricity supply, the importance of maintaining reliability and the natural monopoly[3] characteristics of the electricity industry were also seen as arguments in favour of vertical integration. Supply to final end-users was always the exclusive activity of distribution or transmission companies.

In the last two decades, however, several factors, including the emergence of new power-generation technologies with smaller efficient scales, the development of information and communications technology and growing support for market-based approaches to regulating network industries, have led governments to introduce market reforms aimed at encouraging competition in electricity generation and supply. These reforms, involving the unbundling of the network functions (transmission and distribution) from generation or supply in order to ensure non-discriminatory access by competing generators and suppliers to the network, have forced the break-up of the vertically integrated structure in some countries. In some cases, unbundling is structural, meaning that ownership is entirely separate. In other cases, unbundling may involve simply separation of the management or accounts of the network (sometimes by spinning off specific activities into subsidiary companies) within a vertically integrated firm (see Section 3).

Horizontal integration

Horizontal integration describes the degree of concentration within any one of the four main functions, such as the share of total generation controlled by individual generators. Historically, the electricity supply industry was characterised by a high degree of horizontal integration at all levels in most countries, at the national or, in large countries such as the United States, the regional level. Governments typically granted exclusive or monopoly rights to companies to take responsibility for planning, building and operating the generating plant or the network on the grounds that this was the most effective and efficient way to ensure that sufficient capacity was built and made available to meet national or regional demand.

The degree of horizontal integration in generation and supply has fallen in those countries that have successfully introduced market reforms. Indeed, horizontal *dis*integration is a necessary condition for competition to develop. In practice, policy makers or regulators may encourage investment by independent power producers or require incumbent generators with a large market share to divest assets to create multiple power wholesalers, especially where there is little opportunity or need to build new capacity. Reforms may also involve encouraging or obliging incumbent firms to reduce their share of retail supply, by breaking up and selling off their marketing functions piecemeal. In contrast, market reforms *per se* have not directly concerned the degree of horizontal integration in transmission and distribution, as these activities remain regulated as natural monopolies. In deregulated electricity markets, there is no centralised planning of generation capacity, though the authorities may continue to play a key role in identifying the need for new transmission and distribution capacity and encouraging private network operators to invest.

While horizontal integration is declining *within* many markets undergoing reform, many utilities are responding by acquiring or building assets or merging with other utilities in other markets overseas or by moving into other domestic or foreign network industries – such as natural gas, telecommunications and water. The past decade had seen the emergence of large multinational multiservice utilities, driven by economies of scale and scope (see Section 4). In some countries, notably Germany, municipal multiutilities were established long before the introduction of market reforms.

Co-operative arrangements

Regardless of the structure of an individual utility or of the electricity industry within a given country, co-operative arrangements often exist between networks both within countries (such as in the United States) or across national borders (for example, in Europe). These arrangements usually involve interconnected systems operating in synchronous mode. The system operator of each participating network is obliged to fulfil certain operating conditions, aimed at ensuring a minimum level of reliability across the entire interconnected system, and may be required to undertake certain actions in the event of an emergency. Co-operative arrangements can reduce both capital and operating costs, mainly by taking advantage of economies of scale, by establishing joint merit orders, by lowering the need for reserve capacity within a particular country or region and by reducing the overall system peak load.[4] They also make possible a larger market in power supply, increasing the potential for more effective competition between generators and marketers. Examples of co-operative arrangements include the North American power pools, some of which involve both US and Canadian utilities; the Union for the Transport of Electricity (UCTE) in western and central Europe; and Nordel, which groups the four Scandinavian countries (Denmark, Finland, Norway and Sweden).

The above discussion concerns the day-to-day operation and maintenance of the physical assets that comprise the electricity *supply* industry and related commercial activities. The electricity *services* industry, which provides maintenance and construction services to utilities, is normally structurally separate from the supply industry. In most cases, major maintenance and rehabilitation programmes are outsourced to specialist firms, because it is usually less costly than keeping such a capability in-house. Similarly, the design and construction of generating plants and network facilities are usually carried out by different entities. A contract to build a power plant usually involves start-up operations and training of the staff of the owner and eventual operator of the plant.

2.2. Ownership

Various models of ownership exist, ranging from wholly state-owned national utilities through municipality-owned local distribution companies and mixed private-public enterprises to private energy companies. In many countries, the electricity industry was developed initially by private companies, while the period of rapid expansion in the second half of the 20th century was carried out with a high degree of public ownership. This was especially the case in Europe and most developing countries, where the supply of electricity was, and often still is, regarded as a public service and of strategic importance in economic and social development. The United States and Japan, where electricity generation and transmission are still dominated by privately owned utilities, are the main exceptions. In contrast, the electricity services industry, which is becoming increasingly international, has always been dominated by private companies. A notable exception is France, where the state still holds a controlling stake in Areva, the world's largest nuclear services company.

Patterns of ownership have changed enormously in recent years, with a move back towards more private ownership in many parts of the world. In some cases, this has involved privatisation of state-owned utilities, through stock market flotations or private sales. In other cases, the electricity industry has been opened up to private investment solely in new power projects with public utilities retaining their central role in the industry.

Despite the increasing involvement of the private sector, the overwhelming majority of countries both in the OECD area and in the rest of the world still have at least some publicly owned electricity companies. Public ownership and a high degree of vertical and horizontal integration generally go hand in hand. State ownership and a highly integrated, centralised structure enable the authorities to retain direct control over the industry. Most countries that have introduced market reforms have also privatised at least some parts of the industry – except where the industry was largely privately owned already.

The structure of cross-ownership of electricity and other utilities, within and across national borders, can be complex in some countries, involving both public and private companies. Usually, subsidiary or sister companies operate at arm's length, for commercial reasons or because of regulatory requirements aimed at ensuring non-discriminatory access to networks and competition among generators and suppliers. Some utilities also hold stakes in electricity services companies.

2.3. Typologies

Today, there is a considerable diversity of industry structure and ownership across countries. This reflects primarily historical differences in the development of the electricity industry, the stage reached in the liberalisation process, the regulatory framework and the overall business and investment climate. Table 3.1 provides a snapshot of the typology of the electricity supply industry as it is

Table 3.1. **Industry structure and ownership in the world's 15 largest national electricity markets**

	Electricity consumption, 2003 (TWh)	Horizontal integration				Vertical integration (structural)	Ownership of infrastructure (predominant)
		Generation	Transmission	Distribution	Supply		
United States	3 475	Mixed	Low	Low	Mixed	Mixed	Private
China	1 483	High/moderate	High	Moderate	Moderate	High	Public
Japan	934	Moderate	Moderate	Moderate	High	High	Private
Russian Federation	632	High	High	High	High	High	Public
Germany	509	Moderate	Moderate	Low	High	Mixed	Mixed
Canada	504	Moderate	Moderate	Moderate	Mixed	High	Public
India	418	High	High	High	High	High	Public
France	408	High	High	High	High	High	Public
UK	337	Low	High	Low	Low	Moderate	Private
Brazil	329	Moderate	High	Low	Low	Moderate	Private
Korea	318	Moderate	High	High	Low	High	Public
Italy	291	Moderate	High	High	Moderate	High	Public
Spain	218	Moderate	High	Moderate	Moderate	Moderate	Private
Australia	190	Low	Moderate	Mixed	Low	Moderate	Private
Chinese Taipei	182	High	High	High	High	High	Public

Note: Mixed means that different utilities have different degrees of vertical and/or horizontal integration; *moderate* means that generation, transmission, distribution and supply are not fully integrated vertically or horizontally within each utility or country.
Source: IEA (2005a); Menecon Consulting analysis.

currently organised with respect to the degree of horizontal and vertical integration and the ownership of physical assets in the 15 largest countries world wide by domestic consumption. These countries account for just under three-quarters of total final electricity consumption world wide.

Among these countries, vertical integration is usually more pronounced than horizontal integration. In some countries, reforms have required or encouraged the break up of the horizontally integrated structure of power generation or supply, either through the divestment of assets or through new entrants, while allowing a degree of vertical integration to remain, at least for the time being. In several EU countries, for example, distribution and retail supply remain partially integrated, though this will change when full retail competition is introduced in July 2007. In other cases, it is down to the regionalisation of the industry within a given country. In China, for example, there exist several provincial utilities responsible for power generation, regional transmission, local distribution and marketing within clearly demarcated areas.

In general, transmission and distribution are more integrated horizontally than generation or supply because market reforms have generally not involved any requirement on the incumbent utilities to divest assets, as these activities are considered to be natural monopolies. In many countries, the authorities have organised transmission into a single monopoly company with responsibility for the entire country or state, in order to exploit economies of scale and facilitate network planning and operation. Distribution is usually less integrated than transmission, especially in big countries, as it is carried out in geographically distinct areas.

Market reforms are generally most advanced and the degree of vertical and horizontal integration lowest in OECD countries, though reforms have stalled or are progressing slowly in several of them. Today, the United Kingdom, where reforms were first introduced, has perhaps the most competitive market with a relatively low level of public ownership. In several EU countries, including France, Germany and Spain, contestability and the intensity of competition remain limited, and the industry remains largely in public hands. Korea today has one the most integrated electricity sectors in the OECD area, though the government is pressing ahead with plans to privatise state companies and promote competition.

Most non-OECD countries have taken steps in recent years to liberalise their electricity industries, but few of them have succeeded in establishing truly competitive markets even at the wholesale level. In China, the Russian Federation, India, Brazil and Chinese Taipei – the five largest non-OECD electricity-consuming countries – the industry is highly integrated and predominately publicly owned.

3. Principal drivers of change

3.1. Rising electricity demand and investment needs

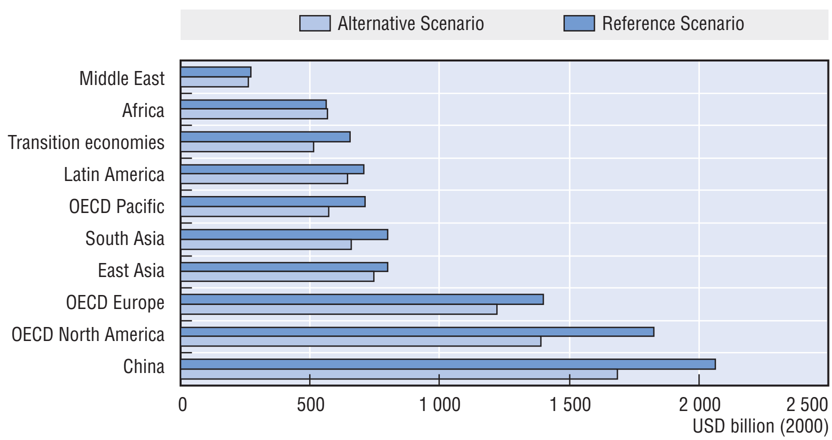
Business models in the electricity supply industry will be influenced by sector with rising electricity demand and investment needs in all major world regions. The International Energy Agency (IEA) projects that global electricity demand will grow at an average annual rate of 2.5% through to 2030 in a Reference Scenario, which assumes no new government policies are adopted. In this scenario, the world consumes twice as much electricity in 2030 as it does today. Developing countries and emerging market economies are expected to account for most of the increase in global demand. Their electricity consumption is projected to grow at about the same rate as their GDP, so that it more than triples by 2030. In the OECD area, the projected pace of demand growth is markedly slower, at 1.4% per year. Nonetheless, the 1.3 billion people in the OECD would still be consuming more electricity than the 6.5 billion people in the developing world a quarter century from now. Outside the OECD area, the Asian economies experience the highest growth in electricity demand. Increasing economic activity, partly linked to rising population, is the main factor behind higher demand in all regions. The Reference Scenario projections assume that the world economy grows on average by 3.2% through to 2030.

In an Alternative Scenario, which assumes that governments around the world adopt policies to curb energy demand for energy security and environmental reasons, electricity demand grows less rapidly. In 2030, electricity demand is 12% lower than in the Reference Scenario, an increase of 70% over 2003 compared with 94% in the Reference Scenario. The annual average rate of growth, at 2%, is 0.5 percentage points lower than in the Reference Scenario. Energy-efficiency measures for industrial processes, appliances and lighting are the main causes of these saving in all regions.

Factors other than government policies could lead to significantly faster or slower growth in electricity demand than projected in these scenarios.[5] For example, climate change could result in pronounced changes in demand for electricity for heating and cooling in the long term. This would have major implications for the amount and type of investment needed as well as policies for ensuring energy security (see Section 5.4). Similarly, faster economic growth – especially in developing regions – could boost electricity demand and infrastructure needs.

The rate of growth of demand will determine how much investment is needed in supply infrastructure. Projected demand growth in the Reference Scenario implies a need for total cumulative investment in electricity infrastructure world wide of USD 9.8 trillion in year-2000 dollars over 2003-30, equal to about USD 350 billion per year. Developing countries account for more than half of world electricity investment. China needs the largest increase, exceeding USD 2 trillion (Figure 3.2). New investment is also substantial in North America and Europe. More than half of global electricity investment is required in transmission and distribution networks. The share of transmission and distribution is generally highest in non-OECD countries, where there is the greatest need to extend and expand existing networks. In the Alternative Scenario, worldwide cumulative investment is about USD 1.5 trillion (in year-2000 dollars), or almost 16%, less than in the Reference Scenario. Although the average unit capital cost of power generation is 14% higher in the Alternative Policy Scenario than in the Reference Scenario (because of the greater use of more capital-intensive nuclear power, renewables and distributed generation), this effect is more than offset by slower demand growth, which reduces the need for new power plants and new network capacity.

Figure 3.2. **Cumulative electricity investment by region, 2003-30**



Source: IEA (2004).

There is no certainty that all of the investment needed will, in fact, be forthcoming – in either scenario. If actual investment falls short of that required or is delayed, some part of demand might go unmet, leading to temporary or persistent power shortages. The main uncertainties surrounding the adequacy of electricity investment world wide relate to the impact of liberalisation and market reforms, which will affect incentives to invest and access to capital. Any shortfalls in investment, especially where the industry is state owned, might lead to pressure to reorganise the sector, possibly involving opening it up to private capital. Environmental policies, notably affecting the siting of new power plants and transmission lines as well as airborne emissions, may also constrain investment. Investment opportunities and incentives will, in turn, affect the evolution of business models, regionally and globally.

3.2. Corporatisation and privatisation

The way in which state-owned electricity utilities are run and government policies on allowing private companies to invest in the sector will be of major importance to how business models evolve – especially in developing countries and emerging market economies. Corporatisation and privatisation have been widely adopted in the past two decades as ways of achieving more efficiency in electricity supply. Corporatisation involves the reorganisation of state-owned assets and the transfer of responsibility for operating them from a government ministry to a separate commercially oriented entity. This can be either a transitional step towards, or an alternative to, privatisation. Where privatisation is the objective, the assets are allocated to a joint stock company and the shares transferred to the treasury before they are sold. In either case, the aim is to introduce management and accounting structures and disciplines, and to improve operational efficiency. In practice, corporatisation and privatisation can have a dramatic impact on the way the industry operates.

Corporatisation

Corporatisation aims to separate the two roles of the state: as the owner and as the regulator. Where there is no such separation, there is a risk that the government will use its control of the industry to pursue social objectives for short-term political reasons, often in an *ad hoc* and non-transparent way. The most common example of this phenomenon is the direct imposition of price caps that results in operating losses that have to be financed out of the state budget. This creates conflicts between its responsibility to maintain a financially viable electricity industry and protect taxpayers' interest on the one hand, and its responsibility to protect consumers' interest in the short and long term on the other. In India, large subsidies to electricity consumers – notably farmers and households – have caused the state electricity boards to incur huge financial losses, which have undermined the boards' ability to invest, to meet growing demand for electricity and to maintain reliable supply.

Generally, publicly owned corporations have a statutory objective to be commercially successful businesses and to maximise the net worth of the assets. They normally have a management structure similar to that of a private company, with an independent board of directors elected by the representatives of the shareholders (municipal, state or central government). The board is responsible for service delivery and commercial performance. The corporation would typically agree with the shareholders on strategic goals by means of a planning agreement or agreed business plans. In this way, the corporation operates at arm's length from the public authorities.

In contrast to electricity boards controlled directly by a ministry, commercial functions are separated from any social obligations the government may impose, such as price discounts for poor households, which would then be funded separately. In practice, however, there remains considerable scope for governments to intervene in the day-to-day running of the electricity utility. For example, the government may decide to extract an exceptional unplanned dividend in response to short-term budgetary pressures, undermining the utility's ability to meet its investment and performance targets. Moreover, corporatisation does not by itself provide incentives for the utility to behave efficiently or competitively.

Privatisation

Privatisation policies are driven by two main forces. First, the perception exists that state ownership is a barrier to efforts to supply electricity efficiently and at the lowest possible cost to end-users – in large part because of political interference in the running of the business. Second, the highly capital-intensive nature of the industry places a heavy financing burden on the government, which may want to give priority to other sectors and types of spending in allocating scarce capital. Rising electricity demand in developing countries and emerging market economies will increase the pressure on governments to look to the private sector for at least part of the capital needed to expand infrastructure. In addition to relieving the financial obligation, privatisation may also yield a substantial one-off injection of cash into the state coffers. In most cases, privatisation has been accompanied by market reforms aimed at promoting competition in the construction of electricity infrastructure and provision of electricity supply services. This is likely to remain the case in the future.

There are various ways in which electricity companies can be privatised. The first issue to be addressed is whether to restructure the utility (or industry in the case of a fully integrated monopoly) before selling it, with a view to introducing market reforms aimed at creating the conditions for competition to develop (see below). Experience around the world has shown that restructuring is far easier prior to privatisation. The UK government decided to restructure the industry before privatising it in 1990 at the same time as introducing market reforms. In contrast, the French government did not undertake any major restructuring before selling off a tranche of shares in the state-owned utility, Électricité de France (EdF), in 2005.

In many cases, privatisation involves only the generation and distribution companies, with transmission-related activities (including dispatch and, in some cases, operation of the wholesale pool or spot market) kept under state ownership and control following corporatisation of the entire industry. For example, the recent restructuring of the Pakistan Water and Power Development Authority resulted in the creation of a structurally separate National

Transmission and Dispatch Company, a commercial enterprise that will remain in state ownership. In contrast, the three generation and eight distribution companies created at the same time are due to be privatised in the near future.

Other important issues include to whom the assets are to be sold and how, and the size of the stakes to be sold. Public flotations have been the most popular approach in most countries where sales have been large. This has often fitted with policies aimed at extending share ownership generally or, in the case of the former communist bloc countries, with the goal of redistributing wealth among the population. In many cases, a tranche of shares is reserved for institutional investors in order to ensure a degree of stability in ownership and effective oversight of management in the longer term. In the case of smaller companies, governments usually prefer to sell the assets directly to a single buyer – typically a well-established firm in the industry either domestically or internationally – to ensure that the privatised entity will be properly managed. Whatever the preferred approach to selling the assets, the government may decide to sell the state's entire stake, a majority of the shares or a minority – for practical or political reasons. Recent large electricity privatisations in France and Italy have involved minority stakes. In Italy, the decision to sell off an initial stake of about 30% in the national utility, ENEL, in 1999 was driven by practical considerations related to such a large flotation. Subsequent share offerings have reduced the state's stake to about 20%. In France, the government decided to limit the sale of shares in EdF to 10% in the face of strong opposition from the trade unions to the state losing its majority control of the company.

Privatisation and, to a lesser extent, corporatisation will remain controversial policies. Efforts to privatise electricity infrastructure – and other economic sectors – have often met with fierce political, social and institutional opposition. Most recently, there have been public protests in China, India, Indonesia, Korea, Thailand, Peru, Ecuador and Paraguay. Such opposition usually rests on arguments about economic nationalism and the strategic advantages of direct government control of the sector, fears of job losses associated with a more commercial approach to the business and concerns that prices may increase (Buresch, 2003). Underpricing of assets in past programmes and in other sectors or countries has contributed to public resistance to electricity privatisation.

Scepticism concerning the supposed benefits of privatisation is supported by research suggesting that public or private ownership makes little difference to efficiency of public utilities generally.[6] As a result of public opposition and doubts about the effectiveness of privatisation, governments have either abandoned plans or are proceeding more slowly and carefully with privatisation programmes, while placing more emphasis on explaining the long-term benefits of privatisation to the general public (Section 4). International financial institutions, including the World Bank, are now noticeably more cautious about supporting heavy reliance on private investment in the electricity sectors (World Bank, 2004). It seems likely that power companies in many developing countries will remain in public ownership for the foreseeable future.

3.3. Market and regulatory reform

Market and regulatory reforms will remain the primary driver of changing business models in OECD countries and in many other parts of the world. In most cases, the implementation of reforms is far from complete and their effects on sector organisation and structure are not yet fully evident. Although experience so far suggests that competition in electricity generation and supply can in principle bring major benefits through gains in efficiency and lower prices, there are growing concerns about whether the new business and regulatory models that are emerging involve adequate incentives for investment in generating and network capacity as market players adapt to the new environment.

The term "liberalisation" is normally used to describe a process involving the opening up of the electricity to both private investment and to competition between generators and possibly between suppliers too. Market reform, and the accompanying regulatory reform, normally refers only to the introduction of competition. In fact, the two elements are distinct: it is possible to privatise or allow private investment in the electricity sector without introducing competition and *vice versa*. Nonetheless, where market reforms have been introduced into a predominately state-owned industry, it has usually been preceded by privatisation. This was the case in Chile and the United Kingdom – the first countries to privatise their electricity industries, in the 1980s. A notable exception is New South Wales, where state-owned power generators were broken up and transformed into public corporations, and competition introduced at the wholesale (through participation in Australia's National Electricity Market) and retail levels.

Competition in various forms

Competition in the electricity sector can take different forms. At a minimum, it can involve a competitive tendering process for the long-term supply of wholesale electricity from independent power plants. The process may be organised by the authorities or by the incumbent utility that holds monopoly rights over transmission. This approach was adopted by the United States in 1978, with the adoption of the Public Utility Regulatory Policies Act (PURPA), which enabled utilities to choose between building their own capacity or contracting with independent producers under long-term contracts. Many other countries subsequently chose this route.

In most OECD countries – including the United States – and several non-OECD countries, reforms are being taken much further, with the extension of competition to real-time wholesale supply and, in some cases, also to retail supply under a system of open or third-party access to physical power networks. This has been achieved through the establishment of wholesale markets in electricity supply and related activities. Generators are free to sell power to wholesalers, retailers or directly to end-users. Generators, wholesale suppliers and retailers remunerate the transmission and distribution network operators for the actual use of their services, based on a pre-determined schedule of charges, in some cases adjusted *ex post* according to capacity constraints and actual grid losses. Independent regulators normally play a critical role in overseeing compliance with electricity laws, ensuring that the market operates efficiently and fairly, and in establishing cost-based network tariffs. With this approach, existing or new generators are free to decide when, where and how much capacity to build, subject to licensing procedures and conditions.

Process of market and regulatory reform

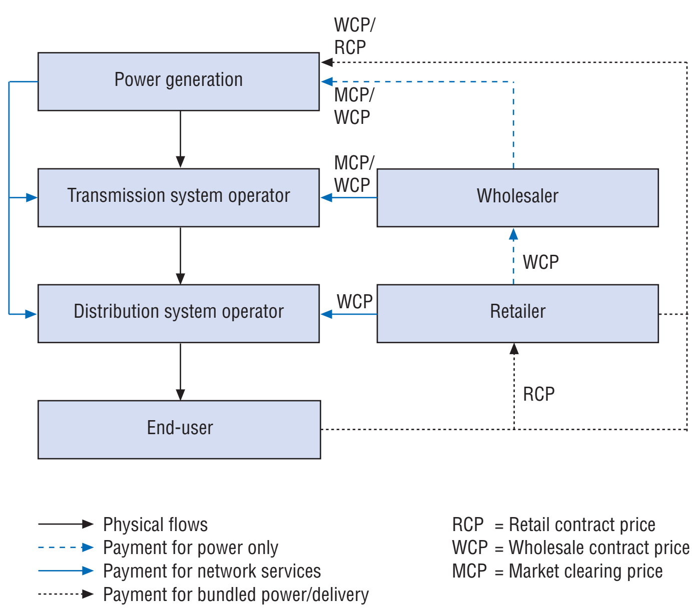
The process of market and regulatory reform involves several key components:

- The vertical separation of competitive segments (generation and supply) from the natural monopoly regulated segments (distribution, transmission and system operation), either through legal unbundling of the network entities or through unbundling of ownership. The latter is often considered to be a more effective way of ensuring that network operators do not discriminate in granting third parties access to the network. Unbundling effectively replaces the centralised decision-making system found in vertically integrated utilities with a decentralised system in which a number of players make commercial decisions within a markets framework.
- The reorganisation of transmission and network operations to create a geographically inclusive wholesale market and the establishment of a single system operator to manage the operation of the entire network, to schedule generation and dispatch power to meet actual load, and to maintain frequency, voltage and stability of the network. Where the network is not structurally (or legally) unbundled from generation and retailing, an independent system operator is typically established to handle dispatch so as to ensure non-discriminatory access.
- The setting up of a formal wholesale market in electricity and operating reserves to support the need for real-time balancing of supply and demand, to handle unplanned outages of transmission or generating facilities and to facilitate economically efficient trade among generators, wholesaler buyers and sellers, and retailers. The wholesale market determines a price for

power supplied for any given time period (and possibly delivery point, or node, on the transmission system) according to the marginal cost of supply to meet estimated load.

- Unbundling of retail tariffs for retail power supplies and network services to ensure non-discriminatory access by third parties to the network and a level playing field for competitors in supplying end-users. Retailers buy their power in wholesale markets, or own generating facilities to support their retail supply commitments, and deliver the power for a fee over the regulated distribution network. Where retail competition is restricted to large consumers, distribution companies remain responsible for supplying other customers by purchasing power in wholesale markets. In the case of full retail competition, no end-user has any direct contractual relationship with the network operators (Figure 3.3).
- The design and implementation of detailed regulatory rules and institutions to promote access to the transmission network by third parties, including mechanisms to allocate scarce transmission capacity and procedures for determining the use-of-network charges.

Figure 3.3. **Contractual relationships and physical electricity flows in a competitive market with full structural unbundling and retail competition**



Source: Menecon Consulting analysis.

Country experiences

England and Wales pioneered the introduction of wholesale competition in 1990, with the extension of retail competition to all consumers being completed in 1999 (Box 3.1). Norway followed in 1991 and was joined by the other Scandinavian countries – Sweden, Finland and Denmark – in Nordpool during the second half of the 1990s. In Australia, regional competitive markets were launched in 1994 and the National Electricity Market started in 1998. In North America, several markets in the north-east of the United States were formed in the late 1990s, the largest of which operates across Pennsylvania, New Jersey and Maryland (PJM). The Californian market opened in 1998, but was suspended following the catastrophic power shortages of 2001. Texas and the Canadian province of Alberta opened their markets in 2001.

Member countries of the European Union are opening up their markets to competition at varying speeds. Under a 2003 directive, they are legally required to introduce full retail competition from 1 July 2007. However, competition is actually developing only very slowly, as evidenced by the limited degree of switching by eligible customers to alternative suppliers and the continuing dominance of the traditional incumbent utilities (Box 3.2). Japan launched electricity market reform towards the end of the 1990s. The 2003 Electricity Utility Network Law sets out the time frame for the full roll-out of retail competition by 2007. End-users accounting for more than two-thirds of total electricity consumption are already eligible to choose their supplier. Faster development of competition in both Europe and Japan will hinge on more proactive measures by regulators and policy makers to reduce the dominance of the big generators in regional and national markets (see Section 5).

Experience in Great Britain, Australia, Scandinavia, the north-eastern United States and elsewhere suggests that the process of market and regulatory reform involves three distinct phases. The initial phase, which may take several years, involves political negotiations, the adoption of formal legislation, the creation of new regulatory institutions, the preparation and implementation of regulations and the design and establishment of technical and management systems. This is followed by a phase of market development, involving the fine-tuning of wholesale trading arrangements, the gradual opening up of retail markets and the emergence of a number of competing generators and suppliers. The final phase involves a maturing of the market and the regulatory framework. It is debatable whether any market has passed beyond the second phase. In reality, the full process of market reform culminating in the establishment of a robust and relatively stable market might last at least one to two decades, and perhaps as long as the economic lifetime of existing assets.

Monitoring, oversight and decision making by governments and regulators will continue to drive the development of the electricity sector. How market

Box 3.1. **Development of competition and restructuring in the British electricity market**

The English and Wales monopoly utility, the Central Electricity Generating Board, was corporatised, restructured and then privatised under the 1989 Electricity Act, creating three generating companies, one transmission company and 12 regional distributors. The Act also established a competitive trading system, known as the pool. It also granted the right to consumers above 1 MW access to the grid. Eligibility was gradually extended, covering all end-users from June 1999. In 1993, the largest generator, National Power, agreed to divest capacity in order to increase competition in the pool and avoid an anti-trust inquiry. In 1998, the National Power and PowerGen, the other main non-nuclear generator, agreed to divest more capacity in return for approval to buy shares in the regional distributors. These divestitures had the effect of partially re-integrating the industry vertically, while reducing the degree of horizontal integration. The entry during the 1990s of a number of new independent power producers that built gas-fired power stations further reduced the shares of the three big generators in total generating capacity, from 91% in 1990 to 37% in 2004.

Following a detailed review by the regulator of the functioning of the pool, the government decided to redesign the trading arrangements to prevent dominant generators from “gaming” the pool and to lower prices. In 2001, the pool was replaced by a fundamentally different system, called the New Electricity Trading Arrangements (NETA). NETA replaced the obligation on generators to dispatch power through the pool with a voluntary, decentralised, bilateral trading system. The only formal market under NETA is for balancing, operated by ELEXON (a subsidiary of National Grid Company), in which prices are set through an auction. A capacity payment mechanism that had been set up with the pool, which had proved prone to manipulation by the dominant generators, was scrapped.

It was hoped that informal over-the-counter markets for different market segments, corresponding to the length of time before actual dispatch, would develop. In practice, however, spot trading has remained illiquid. One day-head exchange, called APX, is currently in operation, but trading volumes are very small. This has raised concerns about price transparency and, therefore, pricing efficiency, as well as transaction costs. Day-ahead balancing prices are nonetheless publicly available from ELEXON. Prices fell significantly immediately after NETA came into effect, though the extent to which NETA was responsible is still a matter of debate. Questions remain about the efficiency of the balancing market in signalling scarcity of capacity. In April 2005, NETA became BETTA (British Electricity Trading and Transmission Arrangements), with the integration of Scotland.

The British electricity supply industry has recently continued to re-integrate vertically, with large generating companies acquiring retail-supply businesses. The main driver of this trend appears to be the need for generators to hedge against fuel-input and wholesale electricity price movements. They can achieve this by securing the retail market for their physical output, through the acquisition of a retailer – despite the high transaction costs and the inflexibility associated with such a strategy. To some extent, this may reflect the lack of cost-effective alternatives in the form of liquid financial contract markets.

Box 3.2. **Obstacles to the development of competition in the EU electricity market**

Electricity market reform is progressing at varying speeds across the European Union. An EC directive adopted in 1996 together with a second directive and regulation on cross-border trade adopted in 2003 set minimum requirements for market reform. By 1 July 2004, EU countries were required to open their electricity markets to retail competition for all non-household consumers, to establish at least legal unbundling of the transmission system and set up an independent regulator. The deadline for countries to complete full retail market opening is 1 July 2007. Some countries have gone further and quicker, but the majority of member states have missed, or are likely to miss, EC deadlines. In general, competition has developed very slowly, markets are illiquid, and prices have not come down as much as originally hoped – notwithstanding the general rise in fossil fuel prices on international markets.

The European Commission has identified several obstacles to the development of a truly competitive single market in electricity (EC, 2005a and 2005b):

- A lack of integration between national markets, reflected in the absence of price convergence across the EU and the low level of cross-border trade. This is generally due to the existence of barriers to entry, inadequate use of existing infrastructure and insufficient interconnection between many member states, resulting in congestion.
- A high degree of concentration of the industry in many countries, impeding the development of effective competition. Switching by end-users – especially small consumers – remains limited and the market share of new suppliers from other member states remains small in most member states.
- Unbundling rules are not yet fully effective in practice, partly as a result of the late implementation of the directives by some member states. In around half of the member states, ownership of the transmission network is structurally unbundled (Table 3.2). However, most have taken advantage of derogations, by exempting smaller distributors from both legal and functional unbundling and postponing legal unbundling for larger distributors until July 2007.

In April 2006, the EC announced 48 legal challenges in one of the biggest court assaults ever initiated by Brussels. Most of the cases concern specific market practices, such as whether governments have implemented unbundling legislation adequately. Spain and Luxembourg already face action before the European Court of Justice over infringements in implementing unbundling rules. The EC has also launched an inquiry into electricity competition, focusing on the functioning of wholesale markets. The inquiry will consider the extent to which the lack of market integration and cross-border trade affects prices and barriers to market entry. Concerns about market concentration and dominant players are growing with the announcement of several large mergers and rising national protectionism surrounding corporate takeover attempts in France and Spain (see Section 4.1).

Table 3.2. **Status of electricity market reform in EU countries as of January 2005**

	Declared market opening (% of total)	Large eligible customers switch[1]	Small eligible customers switch[1]	Unbundling	
				Transmission	Distribution
Austria	100	22 (78)[2]	3	Legal	Legal
Belgium	c. 90	35	19[3]	Legal	Legal
Denmark	100	> 50	5	Ownership	Legal
Finland	100	> 50	Not known	Ownership	Accounting
France	70	22	Market not yet open	Legal	Management
Germany	100	35 (65)[2]	6 (25-50)[2]	Legal	Accounting
Greece	62	0	Market not yet open	Legal	None
Ireland	56	> 50	1	Legal	Management
Italy	79	c. 15	Market not yet open	Ownership	Legal
Luxembourg	57	10	Market not yet open	Legal	Management
Netherlands	100	30	35	Ownership	Legal
Portugal	100	9	1	Legal	Accounting
Spain	100	18	0 (18)[2]	Ownership	Legal
Sweden	100	> 50	Not known	Ownership	Legal
United Kingdom	100	> 50	> 50	Ownership	Legal
Estonia	10	0	Market not yet open	Legal	Legal
Latvia	76	0	Market not yet open	Legal	Accounting
Lithuania	Not known	17	Market not yet open	Ownership	Legal
Poland	52	10	Market not yet open	Legal	Accounting
Czech Republic	47	Not known	Market not yet open	Ownership	Accounting
Slovak Republic	66	10	4	Legal	Management
Hungary	67	24	Market not yet open	Ownership	Accounting
Slovenia	75	10	Market not yet open	Ownership	Accounting

1. Since market opening. The split between large and small customers is around 1 GWh/year.
2. Others that have renegotiated in parentheses.
3. Flanders only.

Source: EC (2005a and 2005b).

players anticipate policy and regulatory developments and respond to the risks they generate will have major implications for business models. A strong re-affirmation of political commitment to reform can create the necessary market response and avert actions that could undermine the long-term development of competition. But political interventions to address short-term issues – such as price caps to protect consumers from market volatility – can have a detrimental impact on investment, market stability and supply security (IEA, 2005a).

Measuring the success of reforms

How successful market reforms are judged to be will clearly have an enormous impact on future policy directions and, therefore, business models. It is misleading to take a snapshot of the industry at a particular stage of the reform process and use that as proof of success or failure. Nonetheless, evidence from a number of markets that have made good progress in implementing reforms suggests that they have had a significant positive impact on industry performance, when those reforms have been designed and implemented well. The performance improvements have stemmed from a combination of market, regulatory and organisational reforms, including privatisation or corporatisation of state-owned utilities and the introduction of competitive pressures (Joskow, 2003). These improvements have been manifested in a number of ways, including more efficient planning of generating and network capacity, construction of infrastructure and operation of those assets; reduced thermal and network losses; lower operating and maintenance costs through improvements in labour productivity; lower prices to end-users; and the extension of electricity service to households previously denied service. In some developing countries, investment has increased sharply, relieving shortages of capacity and boosting economic development.

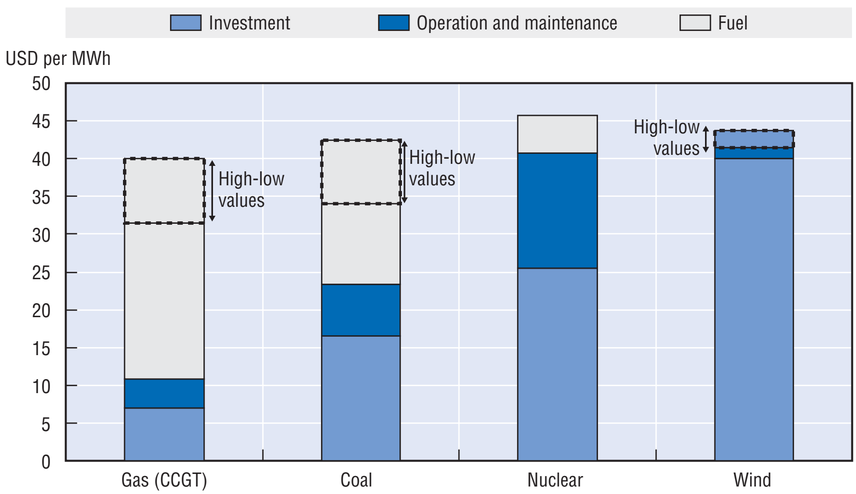
Reforms have also run into serious problems and led to disappointing results in some cases, making ongoing adjustments necessary. During the first two phases of market reform, problems with abuse of market power have frequently emerged, which have had to be addressed through changes to the design of trading systems and legal or regulatory action to reduce horizontal integration and market concentration. Efforts to mitigate market power with restrictions on bidding behaviour and price caps, rather than with structural remedies, have often caused more harm than good by discouraging investment in new generating capacity. The ability to finance independent, or merchant, power plants has emerged as a major obstacle to market entry (see next section). Many markets have also encountered a supply crisis – often resulting in blackouts or brownouts – which effectively serves as a test of the robustness of the new market structure. In some countries, especially those with relatively immature electricity sectors, reforms have been delayed or suspended. How governments deal with these issues will directly affect utilities' business strategies and the organisation of the sector. Section 5 considers the main challenges facing policy makers and regulators.

3.4. Technological and cost developments

Developments in technology – particularly in power generation – and costs of supply will continue to have a major impact on the structure of the electricity industry. Traditionally, power generation was dominated by very large centralised fossil fuel, nuclear and hydroelectric plants. The emergence of combined-cycle gas-turbine (CCGT) technology, using natural gas as the fuel input, has dramatically altered the structure of the industry in many parts of the world. Upheavals in international energy markets and surging fossil fuel prices could have major consequences for future choices of technology and fuels.

Decisions about new generating capacity are largely driven by financial evaluations of different technologies and fuels, taking into account market, technical and policy risks. In competitive markets, the smaller economic size and shorter construction times of CCGT plants – together with their lower overall production costs – made them the favoured option for new capacity in many parts of the world, at least until the recent surge in gas prices (Figure 3.4). CCGTs account for almost all the new fossil fuel fired capacity brought on line in North America and Europe in the last ten years.

Figure 3.4. **Indicative mid-term generating costs of new power plants**



Note: Assumes a natural gas price in the range of USD 3.00-4.50/Mbtu, a coal price of between USD 35 and USD 60/ton, and a discount rate of 7%.

Source: IEA (2004).

Higher gas prices since 2003, in absolute terms and relative to coal, and concerns about the long-term availability of gas in several major markets have curbed the interest in building more gas-fired capacity and boosted the competitiveness of coal-fired plant, nuclear power and renewables technologies. If prices were to remain at current levels, all three options would most likely see their shares in generation increase significantly. In most parts of the world, hydropower and wind power are the most competitive of various renewable technologies under development. But advances in biomass, solar thermal and photovoltaic power and other advanced technologies could boost their market prospects in the longer term. The latest Reference Scenario projections from the International Energy Agency show a marginal increase in the share of renewable technologies in power generation from around 18% at present to 19% in 2030 (IEA, 2004). The US Department of Energy projects the share to remain broadly constant through to 2025 (DOE/EIA, 2006). Both organisations project the share of non-hydro renewables to increase significantly: from about 2% to 6% in 2030, according to the IEA.

Distributed generation

The growth of small-scale renewables-based generation technologies, as well as other forms of distributed generation, such as small-scale fossil-based co-generation plants and fuel cells, could radically alter the structure of the electricity industry. Distributed generation represents a small share of the electricity market today, but the wide range of potential applications and favourable government policies for combined heat and power and for renewable energy technologies could boost their market share over the coming decades.

Policy makers in many countries are actively encouraging the development and deployment of distributed generation, because of the economic, environmental and energy-security benefits they can bring. On-site power production by fossil fuels generates waste heat that can be used by the customer, reducing overall primary energy needs. Distributed generation may also be better positioned to use inexpensive fuels that would otherwise go to waste, such as landfill gas. Distributed generation facilities located at an end-user's site or at a local distribution utility, and supplying power directly to the local distribution network, can also reduce the need to invest in long-distance high-tension transmission lines. Increased use of distributed generation technologies could avoid around USD 130 billion (in year-2000 dollars) of global investment in transmission networks between 2001 and 2030 – equal to 8% of total transmission investment (IEA, 2003). The reliability of electric power systems can be enhanced by distributed generation, as the system is less dependent on centralised facilities. The use of distributed generators at selected locations can also help distributors overcome local bottlenecks. However, distributed generation has some drawbacks, which may limit the extent to which it will penetrate the power generation market. Unit capital costs per kilowatt can be higher than for large plants, especially if any associated heat is not captured and used. For some types of technology, there is a need for reserve capacity to deal with the non-availability of distributed power because of operating variability, where power output is tied to heat demand, and natural intermittency (such as with wind power).

The widespread deployment of distributed generation would require profound changes in the way the electricity networks are organised, constructed and operated. Networks would operate in a much more decentralised manner. This could expand opportunities for small generators. More power would be generated and managed by the system operator at low voltages. In such a system, the high-voltage network would need to provide back-up for the local decentralised systems.

The opening up of the retail market to competition, allowing access by generators and end-users to the local network, and appropriate regulation may prove critical to the development of distributed generation. If market reforms are limited to wholesale liberalisation, the incentives for distributed generators would depend on the terms and conditions offered by the monopoly distribution company. Government policies may oblige the distributor to offer favourable terms, but this approach is unlikely to be economically efficient as the price signals would not reflect market conditions. For example, excess capacity in the Dutch market can at least partly be attributed to policies that encouraged the creation of decentralised generation regardless of need (IEA, 2002).

In some markets that have not been fully liberalised, only high-voltage consumers have the ability to choose suppliers. Smaller customers and independent producers are required to notify the incumbent vertically integrated utility of their intent to install distributed generation facilities. The utility may respond by offering to discount the regulated electricity price in order to discourage the installation of those facilities. Distribution companies that continue to own generating capacity to supply their customers directly will also have an incentive to discriminate against distributed generators. Separation of distribution from generation and retail removes this incentive to discriminate. Conversely, a restriction on distributors owning and operating small generating plants may result in some inefficiencies. In certain cases, for example, the operation of distributed generation at a transformer station to relieve distribution system congestion may be the most efficient solution.

3.5. Cross-border trade and network interconnections

The development of interconnections between national or regional networks and the subsequent expansion of cross-border trade will be both a major driver and a consequence of structural change throughout the electricity supply industry in many parts of the world. Rising electricity demand will expand opportunities for profitable investments in interconnectors in liberalised markets. But how much new capacity is actually built and used will depend to a large extent on the regulatory framework.

International trade can bring important mutual economic benefits by exploiting comparative advantages. This yields a more efficient allocation of overall investment in transmission and generation and the creation of a larger, more liquid wholesale electricity market. Cross-border transmission can be an economically efficient alternative to building new generation capacity in a home market, where lower-cost spare capacity exists in a neighbouring market. For many countries, cross-border trade will be an important means of realising benefits from market reform, especially for small countries with geographically close neighbours; cross-border trade may prove to be the easiest and quickest way to enhance competition by enhancing the size of the market. The

Pennsylvania-New Jersey-Maryland (PJM) Interconnection provides an example of how network integration paved the way for the development of a wholesale market (Box 3.3).

Box 3.3. **Wholesale market development in the PJM Interconnection**

PJM is a power pool that co-ordinates trade between the states of Pennsylvania, New Jersey, Maryland and Delaware. It was actually formed in 1927 but only started to transform itself into an independent organisation in 1993, primarily through the formation of the PJM Interconnection Association to administer the power pool. PJM became a fully independent body in 1997, when a bid-based wholesale spot market for power was launched. PJM was the first independent system operator in the United States to be approved by the Federal Energy Regulatory Commission (FERC) under Order 888, which restructured the wholesale electricity business. In 2002, PJM was officially recognised as a regional transmission operator.

The initial day-ahead spot market was based on a single market-clearing price for the entire region. High costs for congestion management and poor operational flexibility in the utilisation of the system, largely due to security restrictions, led to the introduction of locational (or nodal) marginal pricing (LMP) based on reported costs, in which market-clearing prices were calculated for each node in the system. In 1999, a capacity market was introduced involving daily, monthly and multimonthly auctions, as well as a new pricing system based on competitive bidding. In 2000, the day-ahead market was extended with the introduction of a real-time market and a market for spinning reserves. In 1999, PJM introduced an auction of allocated financial transmission rights, enabling market participants to hedge price risk across nodes. These were replaced in 2003 with a more sophisticated system of auction revenue rights.

The geographical coverage and trading volume of the PJM market has grown considerably since its inception. In 2002, Allegheny Power joined PJM, added more regions of Pennsylvania, large parts of West Virginia, parts of Virginia and small parts of Ohio. In the same year, American Electric Power, Commonwealth Edison (Com Ed), Illinois Power and National Grid agreed with PJM to develop an independent transmission company that would operate within a western part of the PJM system. Dominion also joined PJM, integrating a large share of the electricity system in Virginia and a small share in North Carolina into PJM's system and market operation. These moves were completed in 2004-05. The integration of Com Ed alone expanded PJM's market by 20%. Midwest ISO (MISO) and PJM have worked together since 2004, with the aim of developing an integrated wholesale market across 24 states and the province of Manitoba in Canada. MISO launched a LMP-based market in 2005. Today, PJM serves approximately 51 million people, dispatching 163 806 MW of generating capacity over 56 070 miles of transmission lines.

Most of the states covered by the PJM market have decided to introduce retail access for all consumers. The first state was New Jersey, in 1999, followed by Pennsylvania, the District of Columbia, Delaware, Ohio, Maryland and Illinois between 2000 and 2004.

Source: PJM website *www.pjm.com*.

Opportunities for expanding cross-border trade in a given market will depend on the availability of transmission capacity. In liberalised markets, efficient prices on both sides of a congested transmission line signal the need to invest in new generation or transmission capacity. The pricing of access to interconnector capacity can reflect congestion, providing an incentive for the transmission system owner to expand capacity. In practice, however, the congestion rent earned by the owner of that capacity (or the rights to use it) might undermine incentives to build new capacity. This disincentive would be exacerbated if the interconnector owner is a dominant vertically integrated utility with a clear interest in limiting the development of competition in its home market. For this reason, the way the industry is structured and the way cross-border transmission access and charges are regulated are of critical importance to investment in interconnectors and cross-border trade.

In practice, approaches to handling these issues vary. The business model that has been adopted in the PJM and Australian markets involves the separation of transmission operation from ownership, as an alternative to full structural unbundling. This approach ensures that all congestion can be priced, that transmission needs are transparent and access is non-discriminatory. In these markets, there are two possible ways in which investments in transmission capacity can be remunerated within the current regulatory framework. The first involves a competitive or merchant approach, whereby the return on investment depends entirely on the difference in market prices between the two connected markets. In effect, the interconnector owner buys power at the end of the line where prices are lowest and sells into the market at the other end. The investor may be able to extract rent if a large enough price differential can be maintained for long enough, but runs the risk of losing money if this is not the case. The second approach involves pre-determined regulated tariffs to finance the extensions. In the PJM and Australia, most investment still relies mainly on financing through regulated tariffs. This approach is likely to remain predominant in these and other markets where opportunities for expanding interconnector capacity emerge in the medium term.

The European market

The model used in Europe keeps transmission ownership and system operation together in a monopoly arrangement. This approach allows for co-ordinated planning of transmission lines to fulfil both reliability and trading requirements, but may not lead to economically efficient investment in interconnector capacity. The incumbent monopolies have an incentive to maximise congestion rents and limit capacity expansion. Fear of distorted incentives is one of the main drivers behind the European Union's efforts to promote investments in new transmission lines relieving serious congestion points. Cross-border flows of electricity between western European countries in 2004 stood at around 10.7% of total consumption – an increase of only around two percentage points over 2000 (EC, 2005). The construction of priority electricity infrastructure is supported under the TEN-Energy programme, which the EC plans to reinforce.

The EC is also studying interconnector pricing approaches with a view to increasing incentives for enhancing investment. Barely half of the 34 country-to-country interconnections between the 24 member countries of the association of European Transmission System Operators (ETSO) are allocated according to market-based principles. ETSO and the association of European Power Exchanges have proposed a pricing approach that integrates trade of power with that of transmission capacity involving an implicit auction of transmission capacity – the approach known as market coupling used in the Nordic, Australian and various US markets (ETSO/EuroPex, 2004). Power exchanges in the Netherlands (APX) and France (Powernext) have agreed with the Belgian system operator (ELIA) to establish an exchange based on market coupling between all three exchanges. The proposal uses a methodology that partially takes into account loop flows. The proposal focuses on cross-border trade between jurisdictions but does not address the need for congestion management within countries and control areas. Statnett, the Norwegian system operator, and TenneT, the Dutch operator, are building an interconnector, the capacity of which will be allocated using market coupling.

The Nordic market

Transmission system operators in the Nordic market collaborate on interconnector capacity operation, planning and investment through Nordel. Substantial progress has been made in harmonising the operation of the national systems, adopting measures to improve reliability and developing pricing approaches to allocate scarce capacity efficiently. The capacities of the six Nordic cross-border interconnectors are allocated according to market-coupling principles. In 2004, the national system operators agreed to give priority to considering five major projects costing a total of EUR 1 billion to alleviate congestion on these lines. Four of these projects have so far been given the green light. The investment decisions are being taken on the basis of the net economic benefits to the entire Nordic market, rather than to local markets. The investments will be financed by grid users through tariffs.

Increased cross-border trade will also create opportunities for integrating the management of reserve capacity and markets for ancillary services, enhancing system reliability and security. In Australia, for example, the national Electricity Market Management Company (NEMMCO) was able to cut minimum reserve levels by more than half through sharing of reserves and by exploiting differences in load profiles among regions. Trade in ancillary services across jurisdictions has also reduced the aggregate need for reserves in the PJM. Summer peak demand increased by 30% as a result of expansion in the coverage of the market, but the demand for spinning reserves increased by only 20% – a clear illustration of the value of system co-ordination. National systems in Europe have long co-ordinated the use of reserves and other ancillary services, largely through agreements within UCTE and Nordel. But the only case of trading of reserves across borders was in 2003, when Eltra, the western Danish transmission system operator (TSO), bought operational reserves in Norway in agreement with the Norwegian TSO, Statnett. This led to a reduction in the need for reserves

3.6. Managing increased business risk

Changes in the risks of doing business in different regions and activities will play a major role in driving the evolution of industry structure and business practices in the electricity supply industry. Liberalisation radically alters the allocation of business risk, leading to the development of new ways of managing that risk. Prior to liberalisation, investment in the power sector carried relatively low risk. Utilities were guaranteed the ability to recover reasonable costs incurred in providing service to their customers. As a result, they had no need to hedge against unforeseen increases in the prices of their fuel inputs and the costs of other factors of production. For state-owned utilities, access to debt capital was easy. Even for independent power producers, the use of a long-term contract, which allowed market risk to be passed on to the single buyer, made it possible to finance investment at a low risk premium. Regardless of ownership, business risk – as well as any costs of excess capacity, inappropriate technology and inefficient operations – was largely borne by consumers.

Market reform and restructuring make risks more transparent and allocate risks more closely to the decision makers themselves. The nature of risk changes in different ways for generators, transmission and distribution companies, suppliers/retailers and end-users. The development of wholesale markets exposes generators to price risk, as their output is sold at unregulated prices, either into a real-time market or under bilateral contracts with suppliers. Price risk grows with increased volatility of both fuel input prices (especially natural gas) and electricity prices. For example, in the late 1990s, during a boom in construction, finance was relatively easy to find for independent or merchant power plants in US markets. Increased price risk, together with other events (notably California's electricity crisis, the bankruptcy of Enron and lower spark spreads in the early part of the current decade), has led to a sharp increase in the cost of capital for new plants in the United States and, consequently, a slump in investment.

In the United States and elsewhere, generators, merchant interconnectors, suppliers and large end-users are being forced to seek out ways of hedging price and other market risks. In principle, business risks can be effectively managed through contracts. Market participants can agree on quantities, timing, prices and other terms and conditions in a way that meets each participant's need for certainty. Such contracts can take the form of a bilateral deal between a generator and a supplier or end-user, or a futures contract traded on a formal exchange. The more liquid electricity markets become and the greater the degree of competition that develops, the greater the scope for introducing sophisticated risk management tools. Most competitive wholesale markets involve arrangements for day-ahead and real-time trading, but trading in long-term contracts remains limited in many markets (Table 3.3). In the United States, NYMEX began offering electricity derivatives in March 1996, and the Chicago Board of Trade and the Minneapolis Grain Exchange have also offered electricity derivatives. NYMEX had the most success, at one point listing six different futures contracts. Trading in electricity futures and options contracts peaked in the second half of 1998. However, by the end of 2000, most activity had ceased. NYMEX has since relaunched a monthly PJM contract, but trading remains relatively thin. In Great Britain, liquidity on the APX power exchange, launched in 2000, is even smaller.

Table 3.3. **Share of spot and futures trade in total electricity consumption in selected markets, 2004**

	England and Wales (%)	Australia (NEM) (%)	PJM (%)	Nordic market (Nord Pool) (%)	Germany (European Energy Exchange) (%)
Real time	5	100	35	3	n.a.
Day ahead	n.a.	n.a.	26	43	11
Further ahead (exchange)	n.a.	13[1]	24[3]	151[5]	29
Further ahead (over the counter)	n.a.	125[2]	58[4]	309[6]	34[7]

1. d-cyphas trade.
2. Australian Financial Market Association.
3. NYMEX.
4. ICE.
5. Nord Pool.
6. Nord Pool Clearing.
7. EEX Clearing.

Source: D-cypha trade; AFMA, FERC, Nord Pool and EEX websites.

Geopolitical risks will also influence where utilities will seek to invest, their long-term sources of fuel inputs to power generation, their choice of technology and their business strategies. Generators in many parts of the world will become increasingly dependent on imported oil and gas to meet their fuel needs. A growing share of those import needs will most likely be met by a small group of countries with large reserves, primarily Middle East members of OPEC and the Russian Federation (IEA, 2005d; DOE/EIA, 2006). In addition, more of the oil and gas traded internationally will pass through critical maritime chokepoints, such as the Straits of Hormuz in the Persian Gulf and the Straits of Malacca in South-east Asia, heightening the risk of a disruption through piracy, terrorist attacks, accidents or military conflict. Recent events in the Middle East, the Russian Federation, and Latin America, civil unrest in Nigeria and surging prices have drawn attention to the growing threat of supply disruptions.

Hedging risks

Organisational hedges are now emerging as an increasingly popular way of dealing with the investment and operational risk associated with price volatility and unpredictability and threats to the security of fuel supply for generators. Increasing risk resulting from the intensification of competition, made possible by vertical disintegration, leads to pressure on utilities to re-establish the original vertical structure through mergers and acquisitions, especially where it is difficult to replicate it through contractual arrangements. Other strategies include integration upstream, typically though the acquisition of natural gas or coal production assets, which provides a hedge against rising fuel input prices and the threat of a major supply disruption. Expansion into market overseas or into other network industries, such as gas distribution and supply, can reduce risk through diversification. Large consumers may also hedge their risks by developing their own power plants, with the potential to sell surplus to other consumers.

Transmission and distribution utilities are not faced with the same level of risk insofar as they remain regulated as natural monopolies. In this case, business risk will remain generally low, reflected in the relatively low rate of return on assets that network owners will be allowed to earn. Risk will remain lowest when all costs are allowed to be recovered regardless of whether they are judged to be reasonable or not. Risk is greater with incentive regulation, an approach pioneered in the United Kingdom. The regulated utility is allowed to earn an above target rate of return if it is able to provide service at a below target cost, allowing for inflation. But it is exposed to the risk of making a lower return if it is not able to keep costs down to at least the level deemed to be achievable by the regulatory authorities. In some countries, regulators have introduced measures aimed at increasing incentives to improve efficiency in investment and operation of networks. In Europe, the United States and Australia, several interconnectors between national or regional networks have been allowed to operate on an unregulated or merchant basis, on the grounds that they are effectively competing with spare generating capacity. This regulatory framework provides opportunities for network owners to earn higher returns, but at the cost of higher market risk.

4. Prospects for business models

4.1. Consolidation, concentration and globalisation

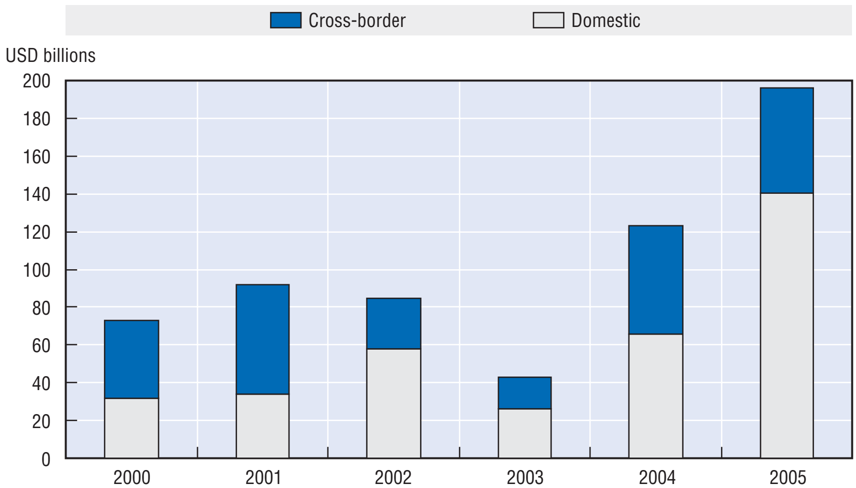
Utilities are adopting varying business strategies in response to the changing market and regulatory landscape and the associated shifts in business risk. Overall, there is a clear trend towards consolidation and convergence in the industry, achieved mainly through mergers and acquisitions (M&A), at the national level and, increasingly, regionally and internationally, too. M&A is the preferred mechanism for improving the prospects of stable cash flows as a source of finance for large, capital-intensive investments, as the cost of capital is typically lower than equity financing. Electricity utilities are likely to become more global in their activities and integrated with gas and other network sectors because of the potential synergies and economies of scale. In markets that are already liberalised, there may be a tendency for concentration to increase once again for similar reasons. However, competition authorities may take a tougher stance on future horizontal deals in generation and supply amid growing concerns about the impact of concentration on the effectiveness of competition on wholesale and retail markets.

The last few years have seen a boom in electricity M&A activity throughout the world. After falling back in 2002 and 2003, the total value of electricity sector deals world wide (including downstream gas) surged to a record high of USD 196 billion in 2005 – an increase of more than half over the previous year and more than twice the level of 2001 (Figure 3.5). This spending is almost equal to all the capital invested world wide in oil and gas exploration and production.

Domestic deals have dominated recent M&A activity, accounting for 71% of the value of all deals world wide in 2005, up from 54% in 2004 (PwC, 2006). In fact, the true scale of home market activity was probably even higher; a significant share of the other deals classified as cross-border were either moves by European companies to grow further in foreign markets where they were already present (such as E.ON's PowerGen subsidiary acquiring additional assets in the United Kingdom), to build scale in adjacent countries within a relatively contiguous home market (for example, Vattenfall's acquisition in Denmark) or were the public offerings of three big European privatisations. M&A activity in 2005 was strong on all continents, but Europe overtook North America for the total value of deals. European firms accounted for 58% of all targets and 44% of all bidders world wide. Three deals in Spain, Italy and France accounted for almost half of the value of the ten largest deals globally (Table 3.4).

The value of cross-border deals has grown less rapidly than domestic deals in recent years. Nonetheless, cross-border M&A spending – mostly within the main regions – in 2005 equalled the record of over USD 55 billion reached in 2001. Cross-border spending is becoming increasingly concentrated in markets geographically near to the home country.[7]

Figure 3.5. **Value of electricity and downstream gas and acquisitions mergers world wide**



Source: PwC (2006).

Table 3.4. **Top ten electricity mergers and acquisitions world wide, 2005**

No.	Value of transaction (USD billions)	Target name	Target nation	Acquirer name	Acquirer nation
1	28.3	Endesa SA	Spain	Gas natural SDG	Spain
2	14.3	Cinergy Corp	US	Duke Energy Corp	US
3	13.9	Electrabel SA/NV (49.9%)	Belgium	Suez	France
4	11.2	Constellation Energy Group	US	FPL Group	US
5	10.3	Italenergia Bis	Italy	AEM/EdF	Italy
6	9.4	Pacificorp	US	Midamerican (Berkshire Hathaway)	US
7	8.3	Texas Genco LLC	US	NRG Energy	US
8	7.2	Électricité de France (10.4%)	France	Market purchase	International
9	5.6	Gaz de France (20.5%)	France	Market purchase	International
10	4.9	Enel (9.3%)	Italy	Market purchase	International

Note: Includes gas.
Source: PwC (2006).

Infrastructure fund investors are playing an increasingly important role in electricity sector M&A as they build global portfolios of assets, for the most part comprising network assets. These funds are starting to account for a significant share of total electricity industry assets, especially in Europe and North America. In 2004, GC Power Acquisition LLC, a US fund, bought Texas Genco Holdings for USD 2.9 billion – the largest acquisition of US power plants by a non-utility company since deregulation began.

With competition limiting the opportunities for businesses to grow organically, utilities are increasingly looking to M&A opportunities to deliver growth, both horizontally and vertically up the electricity supply chain. The bulk of the mergers and acquisitions world wide in recent years have been motivated by horizontal integration, even if they have generally involved vertically integrated utilities merging with or acquiring the same. More than half of all domestic and cross-border deals over the period 2002-04 involved firms operating predominantly in the same functional segment of the supply chain (PwC, 2004). New entrants, including fund investors, account for a growing share of M&A activity – close to a third in 2004. Convergence between electricity and gas utilities represented 15%. Vertical integration accounted for less than 10% of all deals world wide in 2005, down from about 20% in 2004. The impetus for vertical integration is coming largely from the supply end of the chain; many retail companies have adopted aggressive strategies to increase their assets in generation and fuel-supply sources. In Australia, for example, Origin Energy, a retailer, has moved into power generation to hedge against rising wholesale prices.

High wholesale electricity, natural gas and carbon prices have contributed to the surge in M&A activity, by pushing up generation asset values and reinforcing the need for utilities to hedge against price risk. The surge in international gas prices has reduced interest in building or acquiring CCGT plants and increased the attractiveness of other generating technologies, including nuclear power, clean coal and renewables. Growing worries about the security of oil and gas supply are also strengthening the drive to diversify and acquire assets, particularly in Europe. So far, the European competition authorities have not stood in the way of major deals, but there are signs that the competition authorities may take a tougher stance in the future because of concerns about the impact of concentration in national markets and in the European market generally on competition and pricing (Box 3.4).

Considerable room remains for further consolidation in the electricity sector at national, regional and global levels. Risk management and economies of scale and scope will continue to underpin the business rationale for vertical and horizontal integration, as well as convergence with gas and other activities. The traditional boundaries between the utility sector and upstream oil and gas will become increasingly blurred, as upstream companies move downstream to protect market share and downstream companies seeking to secure fuel supply and storage assets. The unbundling of network assets will continue to generate opportunities for infrastructure and pension funds and for other investors to buy network assets that yield steady returns with relatively low risk. Investor appetite remains strong for now, fuelling M&A activity. The attitude of competition authorities will play a key role in determining the extent of future megadeals in the power sector. In the longer term, utilities may seek more

Box 3.4. **Consolidation in the European electricity industry**

In continental Europe, "The Seven Brothers" – EdF, E.ON, RWE, Vattenfall, Endesa, Electrabel and Enel – have emerged as the dominant electricity utilities. Consolidation will increase further if the recently proposed merger of France's Gaz de France and Suez and E.ON's acquisition of Endesa go ahead. The E.ON bid is a record in terms of overall deal size and the amount of cash involved. The run-up to full retail market opening in 2007 may give momentum to consolidation. At the same time, the number of genuine newcomers to the European market has been declining recently. Only a very limited share of new electricity generation projects has been commissioned by non-incumbents in recent years.

Growing vertical integration between generation and supply activities has raised concerns about its impact on liquidity on wholesale markets. In addition, convergence of gas and electricity utilities may reduce incentives for competitors to build new gas-fired plants. The French government's role in promoting the GdF/Suez merger and the Spanish government's attempt to block the E.ON/Endes deal have raised concerns about national protectionism. The European Commission is monitoring these developments carefully and is investigating the concentration and consolidation of the industry in more detail as part of the inquiry into wholesale electricity pricing launched in June 2005. Following recent changes anti-monopoly rules and a revision to the Merger Regulation, the EC is adopting a more proactive approach to enforcing competition rules in the liberalised utility sectors (EC, 2004).

global reach. Renewed interest of the largest western utilities in investing in emerging markets and developing countries will depend on national policies and their implications for perceived risk and potential returns (see below).

In Europe, worries about security of gas supply from the Russian Federation and the need for a major increase in investment in gas infrastructure could drive further convergence between the gas and electricity sectors across Europe and the transition economies. Further consolidation and regionalisation are likely in other parts of the world too. In the United States, federal and state regulation will continue to play a key role in the pace and pattern of deals. The recent repeal of the 1935 Public Utilities Holding Companies Act (PUHCA), which limited the ownership of electricity utilities, will help to accelerate consolidation and the emergence of large regional players. The US market remains highly fragmented and regionalised, offering considerable scope for consolidation.

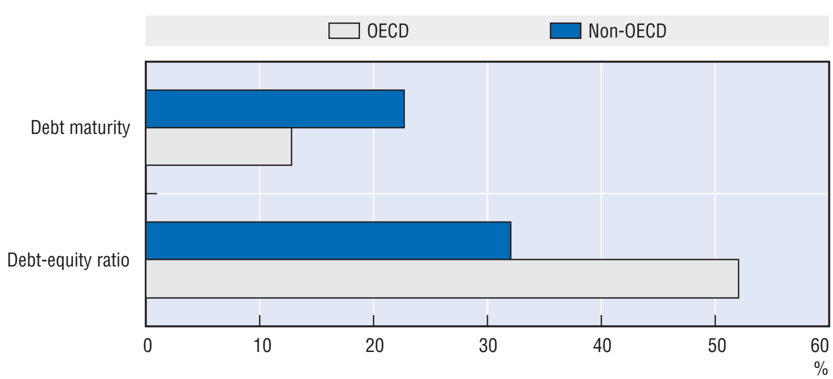
Similarly, regional consolidation in the more mature markets of Asia Pacific, spurred by the gradual implementation of market and regulatory reforms, will most likely continue. Geopolitical risks to the security of oil and gas supplies, notably from the Middle East, may accentuate this tendency. Some Asian companies – mainly private, but some nationally owned – have started expanding or are seeking to expand internationally, and others are considering doing so. In some cases they have taken over companies sold by western multinationals. Investment by Asian electricity utilities in Australia, for example, is now comparable to total private electricity investment by OECD-based utilities in Asia (Hall, Corral and Thomas, 2004).

4.2. Ownership and financing

Electricity sector ownership and financing issues differ greatly between the rich, industrialised countries on the one hand and emerging market and developing countries on the other. Privatisation has largely run its course in most OECD countries. Generally, a majority of generation assets are now in private hands. In some countries, state ownership is now limited to transmission and distribution. France and Korea are the main exceptions. Neither country plans to sell off a majority of its stake in generation in the foreseeable future.

There is little doubt that enough capital will potentially be available for required electricity investments in most OECD countries. But there are concerns about whether adequate incentives exist to ensure that all the investment will be made in a timely way and in the right areas. At present, electricity utilities finance new projects largely through a mixture of equity (internally generated cash or equity issued as public shares) and debt (through borrowing from banks or bonds). The current debt-equity structure of OECD utilities varies considerably. For example, Japan relies heavily on debt, while US utilities rely more on equity. On average, debt accounts for a little over half of electricity companies' shareholder capital structure (Figure 3.6). Some highly leveraged companies,

Figure 3.6. **Capital structure of electricity companies by region, 1992-2001**



Note: The debt-equity ratio is debt as a share of the sum of shareholders' total debt and equity. Debt maturity is short-term debt as a share of total debt.

Source: IEA (2003).

such as in Japan and France, have reduced their debt in anticipation of the emergence of competition. In other cases, increased investment has been funded largely through borrowing, for example in the United States.

It remains to be seen how market reforms and the development of competitive electricity markets will affect the debt-equity structure of OECD-based utilities in the future, and in particular whether the share of equity will increase towards the higher levels typical in the oil industry. Electricity utilities will most likely remain relatively highly leveraged, *i.e.* they will keep their high debt-to-equity ratios. The growing involvement of infrastructure funds and other financial investors could push these ratios even higher. Returns on investment could fall as competition develops, which could drive up borrowing up especially for the most leveraged firms and for power-generation companies.

The environment for financing new independent, or merchant, power projects, has changed dramatically in the last few years. It has become extremely difficult to obtain debt financing for merchant plants, partly as a result of financial looses incurred by companies in Europe, the United States and other regions in the late 1990s and early part of the current decade. A combination of other events, including the collapse of Enron, the retreat of US firms from overseas markets (notably the United Kingdom) and the Californian power crisis, have added to the reluctance on the part of banks and other lenders to provide finance. The credit ratings of most power-generation companies have fallen in recent years; investment-grade ratings are now extremely difficult to achieve for new projects. Investors are looking for stable market rules and longer term contractual commitments before they will commit capital. The absence of liquid forward markets and corresponding supply contracts of more than a few years duration, such as in Great Britain, increases the risk of merchant plant investments. There will undoubtedly be profitable opportunities for new power-generation investments in the future, but an improvement in the financing climate will call for changes in corporate governance, better risk management strategies and more transparency in accounting practices.

Transmission and distribution will remain a relatively low-risk business, with returns remaining protected to a large degree by regulators. The cost of their capital will depend partly on how the regulatory framework evolves and, in the case of state-owned firms, the ability and readiness of the government to finance investment themselves. Pension fund and life assurance companies will remain obvious investors in these businesses, as the long-term licences and franchises allow long-term liability to be financed in a predictable way. This is especially true under rate-of-return regulation, whereby the risk is almost entirely transferred to customers, and equity risk is minimal. Under incentive regulation, equity risk is greater, rendering network investments less attractive to long-term institutional investors.

The prospects for further privatisation and opening of state monopolies to private capital in non-OECD countries are very uncertain. Most countries that have tried to privatise their electricity companies in the past few years have suffered serious delays, largely due to strong public resistance. In several cases, privatisation has been held up by a lack of credible buyers. At the same time, investment in independent power projects has plunged in response to deteriorating local business conditions and disillusionment with past investments (see Morgan, 2006). Yet the budgetary pressures on governments to seek greater private involvement in the electricity sector will not go away. Investment in electricity infrastructure in developing countries has traditionally been the responsibility of governments. Public utilities in several large developing countries are unprofitable – often because of underpricing of power for social reasons – and so are not able to finance new projects themselves. Governments will need to find an acceptable balance between private and public ownership that ensures adequate funding for development of electricity infrastructure and energy security (see Section 5.4).

As a result of political and practical difficulties with privatisation and often disappointing results, policy is undergoing a fundamental reassessment in many non-OECD countries. The World Bank and other multilateral lending institutions are also reviewing their policies in the light of the failure of privatisation and market reform policies to deliver the necessary investment, as well as sharply reduced private capital flows in many developing countries. They nonetheless remain committed to the same principles of power sector restructuring, including privatisation where possible. Accordingly, future policies are unlikely to remain based solely on the standard approach adopted in the industrialised world, involving the sale of assets to private investors, unbundling and independent regulation. Instead, the onus of policy may shift towards seeking ways of securing international financing through bonds and loans while retaining a central role for the public sector where straightforward privatisation is problematic.

The multilateral lending institutions are likely to remain a major source of much-needed capital in many non-OECD countries for as long as the number of active international investors in developing countries remains small and national and regional finance modest. The utilities' ability to borrow is much lower than in OECD countries, reflected in low debt/equity rations and reliance on short-term debt. There are signs that domestic and regional investors are becoming more prominent in the electricity sectors, especially in Asia (Estache and Goicoechea, 2004). Maintaining the momentum of the growth in financing from this source will hinge on policies that improve the investment climate. For now, private participation in the electricity sector remains relatively low across developing countries, especially in transmission and distribution. The Middle East and South Asia have been least successful or interested in attracting private capital.

In many cases, financing will remain difficult, especially in Africa, the transition economies and South Asia, because of poorly developed domestic financial markets and the higher cost of capital caused by higher risk. Private investment is expected to play a growing role in the medium term, but the success of efforts to attract private capital will depend critically on the economic, political, regulatory and legal environment in each country.

5. Policy and regulatory challenges

5.1. *Role of government*

Government has a critically important role to play in the provision of electricity services, regardless of the business model. It is responsible for ensuring that electricity is produced and supplied efficiently, that market failures – such as the failure of the market to place an appropriate value on public goods – are properly addressed and that the electricity sector develops in such a way that social, economic and environmental goals are met. Governments intervene through legislative and regulatory processes, and may directly involve themselves in the running of the industry through state ownership.

In a liberalised market, the government's role is fundamentally changed. Policy objectives, including industry structure and market design, must be expressed in legislation and implemented through regulation. In practice, the legal framework ranges from relatively light legislation, such as in New Zealand, to a more detailed legislative framework, such as in the United Kingdom. The roles of different players and the approach to liberalisation also differ considerably from country to country, reflecting *inter alia* differences in legal and political traditions, industry structure and the stage reached in the reform process. In particular, differences exist in the division of jurisdictional powers between government, the courts, the general competition authorities, the national regulatory authorities and, in federal countries, state regulators. Experience so far with liberalised markets suggests that relatively detailed rules are needed to prevent market abuse and regulatory uncertainty.

In most cases, an independent regulatory body is given responsibility for enforcing regulatory rules and requirements, including issuing and enforcing licences, setting tariffs for network services (and for supply to captive customers) and monitoring market behaviour. However, their sectoral scope, responsibilities, powers and degree of independence from government differ greatly from country to country. Transmission system operators and other market participant may also play an important role in establishing and adapting market rules. Effective regulation requires good information about the costs, service quality and comparative performance of the network companies, as well as qualified staff to regulate effectively the prices charged by distribution and transmission companies and the terms and conditions of access to these networks by wholesalers and retailers. Adequately resourced regulatory institutions are an essential condition of successful electricity market reform. Inadequate regulatory institutions have undermined the effectiveness of reforms in many countries, especially in the developing world.

There is no single best-practice approach to regulation. Regulatory structures and procedures need to be tailored to meet the particular circumstances of each jurisdiction. By its very nature, liberalisation results in markets that are in a continuous state of flux. Actual experience of operating competitive markets provides the impetus for modifications to trading arrangements and further reform of the regulatory framework, aimed at making the market work better – especially where problems of market manipulation and lack of transparency emerge. Changes in the physical electricity system brought about by network expansion and increased interconnection of previously independent networks or technological developments may also call for regulatory change.

Regulatory arrangements and structures must, therefore be *flexible* if they are to be able to adapt to the evolving competitive landscape. The need for a responsive regulatory system may clash with the benefits to investors of stable and predictable rules. Minimising regulatory uncertainty helps to encourage timely and adequate investment. Some regulatory uncertainty is unavoidable, as the regulatory framework needs to adapt to changing circumstances and deal with problems as they arise. Nonetheless, policy makers and regulators can take action to minimise uncertainty for investors, including improving access to market information, refraining from *ad hoc* interventions in the way markets operate (such as price-capping) and establishing transparent procedures for licensing. The procedures for regulating network pricing also need to be clear, transparent and predictable. Close interaction between system and market operators, generators and suppliers can help to reduce uncertainty and unpredictability.

Addressing environmental effects

The environmental effects of electricity generation are not automatically addressed by financial incentives in competitive markets. Pollution and global warming caused by rising concentrations of greenhouse gases in the atmosphere are prime examples of market failure; the market fails to put a financial value or penalty on the cost of emissions generated by power generators or other users of fossil fuels. Air quality and the weather are, in economists' parlance, public goods, from which everyone benefits. Damage done to the environment is known as an external cost or externality. Governments therefore have a responsibility to correct these failures, to discourage activities that emit noxious or greenhouse gases and to make sure that each polluter pays for the harm he causes to public goods. Placing a value of the pollution caused or emitted is effectively a way of internalising these environmental externalities. Policies motivated by environmental and climate change concerns are already having, and will continue to have, major effects on the functioning of competitive electricity markets.

Addressing environmental effects in the power sector is a highly complex issue. Some environmental policies may cause market distortions and inefficiencies, particularly where cross-border trade is possible. Subsidies for particular technologies, or non-transparent barriers that impede the development of others, may not lead to the optimal fuel mix or choice of technology in the long term given the unpredictability of technological development and imperfect information. The challenge here is to establish a legal and market framework that ensures that environmental objectives are met flexibly and at least cost. One such approach is to cap and trade emission allowances. The United States was one of the first countries to introduce such a system for sulphur dioxide emissions from power plants and large industrial facilities under the 1990 Clean Air Act Amendments. In January 2005, the European Union launched an Emission Trading Scheme for carbon dioxide – the largest multicountry, multisector greenhouse-gas emission trading scheme in the world.

5.2. Promoting effective competition in generation and supply

The intensity of competition in wholesale and retail electricity supply is a key measure of the success of market reform. A critical challenge for policy makers and regulators is, therefore, to establish a framework that allows for genuine contestability and, where necessary, measures to actively stimulate the development of effective competition. The benefits of competition come from the incentives for higher efficiency and more innovation through price signals that reflect the true cost and value of producing, transporting and consuming electricity. The number and types of participants in the market and how wholesale markets are designed and regulated are of vital importance. A high level of concentration and opportunities for dominant generators to earn monopoly profits remain serious problems in several markets, especially where the transition to competition is at an early stage.

For competition to flourish there must be a multitude of buyers and sellers in the market for wholesale and retail supply along the load curve.[8] If a single generator dominates one particular type of capacity, such as mid-load, it will be able to force up wholesale prices along that part of the load curve to the level of the next lowest cost generator, making abnormally high profits. In addition, the wholesale market must ensure that prices are driven by actual short-run marginal generation costs and that power plants are always dispatched in cost or merit order. Liquid bilateral forward wholesale markets for physical and financial contracts for electricity supply are also needed to ensure efficient pricing.

Governments and regulators can seek to enhance competition *ex ante* in various ways, including mandatory or negotiated restructuring and asset divestments – either before or after the market has been liberalised. In Great Britain, for example, the two largest generators created out of the old monopoly utility in 1989 later agreed with the regulator to divest assets to reduce their market shares and enhance competition in the wholesale pool as a condition for allowing them to acquire stakes in distribution companies. A second-best solution to mitigate the market power of dominant firms is to cap the prices they are able to charge through regulated forward contracts, but this is unlikely to result in an optimal outcome and can undermine incentives to build new capacity. This was a primary cause of the shortfall in capacity that contributed to the electricity crisis in California in 2001.

An *alternative approach* to the forced sale of physical assets is to require the dominant generators to sell the rights to their capacity to other generators or new entrant to the market under long-term contracts. In Europe, where France, Belgium, the Netherlands and Denmark have adopted this technique, these contracts are called virtual power plants (VPPs). Similar rights are also traded on financial markets in the form of options contracts. The buyer of VPP capacity, usually in an auction, gains the right to draw electricity from a plant or set of plants at a pre-determined price. The auction price corresponds to the option premium (the price the buyer of the options contract pays for the right to buy or sell power at a specified price in the future), while the pre-determined power price corresponds to the strike price in the options contract. The VPP auctions in Europe have all been used as part of an agreement in connection with a merger or acquisition. Experience suggests that this approach has helped to reduce the market power of the large generators and enhance competition.

The *ex ante* implementation of competition rules in connection with mergers and acquisitions provides another opportunity for the regulatory and competition authorities to strengthen the competitiveness of electricity supply. The authorities can make approval of a merger conditional on the utilities concerned divesting assets so as to reduce market concentration in the wholesale and/or retail market. This approach has been used on several occasions by the European Commission and national authorities. For example, the European Commission and the German Cartel Office imposed such conditions in approving mergers that led to the creation of the two German utilities, E.ON and RWE.

Ex post regulation of competition plays an important role in deterring and preventing anti-competitive behaviour and practices. In almost all countries, it is illegal to exercise or abuse market power. In practice, however, it is often hard to prove such behaviour, partly because of the complexity of the market and difficulties in measuring normal profit. The willingness of the competition and regulatory authorities to investigate and deal with allegations of market abuse may be compromised where the incumbent utility is regarded as national champions or is publicly owned. Market monitoring is an important element in detecting abuse of dominant position. Both PJM in the United States and Nord Pool in Scandinavia have independent market monitoring units with responsibility for monitoring and analysing market trade to detect breach of rules that support market manipulation. Nordic transmission system operators and regulators co-operate to model market power on a continuous basis.

In the long term, new entrants to the generation sector are vital to creating a *truly competitive wholesale market*. The incumbent dominant generators have an incentive to withhold capacity from the market and delay investment in new capacity as a way of forcing up prices. Easing the access for new entrants can be a particularly effective way of enhancing competition in countries where electricity demand is growing quickly. This requires regulators to introduce smooth, clear, rapid and transparent procedures for approving the construction of new power plants. Another way of achieving the same result is to extend markets across countries and regions, thereby importing competition. This can be particularly effective in small markets where the scope for a large number of players is restricted by the economies of scale in generation. The FERC has adopted this approach through the formation of Regional Transmission Organisations across the United States. Market integration to enhance competition has been critical to the development of the National Electricity Market in Australia. The European Commission also sees market integration through cross-border interconnections as the main path to a competitive single European electricity market.

The *design of wholesale trading arrangements and systems* is a vital factor in ensuring effective competition. There is no consensus on the most appropriate design of the wholesale market among market participants and experts. A central issue concerns whether the market should be built around a voluntary or mandatory pool for real-time and day-ahead supply or around bilateral contracts. Mandatory single-price pools encourage transparency and liquidity, but may be prone to gaming, where there is a small number of generators. Other issues concern the role of locational pricing of power and ancillary services in enhancing competition and achieving efficient pricing and the allocation of scarce transmission capacity (see below). Theoretical benefits have to be balanced against the costs and difficulties of implementing trading arrangements in practice. Because the physical characteristics of national or regional electricity systems differ, there is no single prescriptive model that can be applied to all markets. Nonetheless, experience with market design in Great Britain, North America, the Nordic market, Australia, Chile and elsewhere suggest that certain features are likely to contribute to the smooth functioning of wholesale markets, where practical. These include:

- Voluntary spot markets for day-ahead and real-time balancing for electricity supply and reserve capacity combined with bilateral contracts.
- Locational pricing of power to reflect the marginal cost of congestion and transmission losses at each location
- The integration of spot wholesale markets for energy with trade in transmission capacity to ensure that scarce capacity is priced and allocated according to its value to different users.
- Allowing the possibility of demand responses to spot-price signals.

Up to now, the potential contribution of *demand responses* in setting prices has not been fully exploited in any liberalised market. By enabling end-users – typically large industrial consumers – to adjust their load according to short-term changes in spot prices, the need for peak capacity and the threat of price spikes at times of peak load can be reduced. In this way, the potential for market abuse by dominant generators can be restricted. Demand response also enhances system security, as load is usually highest at nodes on the network where congestion is most frequent and network security most vulnerable. The United States and Great Britain have gone furthest in trying to incorporate demand-response programmes into wholesale and retail markets, but considerable potential remains to expand their coverage and effectiveness.

Transparency is critical to well-functioning competitive electricity markets. All the necessary information to enable market participants and the regulatory and competition authorities to analyse and understand market conditions must be made easily available. Market participants will only collect and publish fundamental market data and statistics if they are required to do so. Therefore, the authorities must devise a clear set of rules and requirements governing the disclosure of information. Access to basic market prices is most important. In the PJM, British, Nordic and Australian markets, day-ahead and/or real-time balancing prices are made public through the market operators' websites. In the Australian and Nordic markets, all spot market-sensitive information, such as unplanned outages, plant re-connections and changes in schedules for planned outages, must be disclosed immediately.

Competition in retail markets in many cases remains largely limited to large industrial and commercial customers – even where contestability has been extended to all customer categories (as in the British, Nordic, PJM and Australian markets). Extending competition to small residential consumers is an ongoing challenge. The principal barrier is the relatively high cost of implementing retail switching programmes, mainly because of the need to monitor closely actual consumption. This requires the installation of meters that can be read remotely on a daily basis or a system that uses calculated load profiles based on monthly, quarterly or annual meter readings. Replacing meters is very expensive. In both cases, the operating costs are high. Technological advances and cost reductions may pave the way for more widespread residential switching in the long term.

5.3. *Regulating networks*

Regulation of transmission and distribution networks is of central importance to the operation and the overall efficiency of the entire electricity supply industry. Network-related costs typically account for between 30% and 40% of the average cost of delivering electricity to end-users and as much as half of the cost of supplying residential customers. Even in liberalised markets, networks are generally regulated as natural monopolies. Charges for network services to third parties or, in the case of an unbundled monopoly industry, the costs of running the network that are passed through to final customers are controlled by the regulatory authorities to prevent the network owner from overcharging and earning monopoly rents. The challenge for regulators is to establish procedures and rules for allocating capacity rights and setting tariffs that reflect true costs so as to encourage efficient operation of the network and investment in new capacity as and when required. Non-transparent management of congested interconnections is a major barrier to trade and competition. In liberalised markets, how networks are regulated shapes the development of wholesale and retail competition as well as interregional and cross-border trade. It also affects how generating capacity is used and investment in new capacity.

Traditionally, network regulation was based on some form of *cost-plus approach*, which involved network owners passing through to customers all costs considered reasonable and approved by the regulator as well as a profit margin. This form of regulation, which is still widely used in many liberalised markets, guarantees a return on investment and, therefore, the long-term financial stability of the network owner. But it provides little incentive for efficient operation or investment. In some liberalised markets, incentive regulation, typically built around price or revenue caps, has been introduced to encourage network owners to improve the efficiency of their operations. Great Britain was the first to introduce such an approach, which allowed average network tariffs to increase with consumer price inflation but required continuous efficiency improvements of a pre-determined percentage amount each year over the price-review period (known as CPI-X). In the event that the regulated firm is able to cut costs by more than X% per year, it would be able to make a larger return on capital than that allowed in setting the initial tariff.

Although this form of incentive regulation has proved successful in lower operating costs, it has not provided sufficient incentives for efficient maintenance and investment. There is now increased focus on quality. Great Britain, Norway and Sweden have recently reformed their regulations to incorporate service quality and reliability, involving a reduction in the revenues to the utility if performance falls short of fixed benchmarks. The Spanish regulator recently introduced a system in which network companies must compensate electricity consumers for poor service quality.

The incorporation of *locational pricing* is an increasingly important focus and highly controversial aspect of network regulation. In principle, efficient network pricing requires that tariffs reflect the actual costs associated with inputs and off-takes of power at specific locations or nodes in the grid. In practice, however, shifting patterns of generation and load result in constant changes in costs, making it hard to match them with tariffs. Furthermore, resistance in electricity networks creates losses, which add to transportation costs.[9] This has important implications for the pricing of the power itself and economically efficient dispatch. At the margin, dispatch of the generator with the lowest marginal cost might, at another location on the network, trigger higher losses that more than outweigh its competitive advantage over the next generator in the merit order. In this case, it would be more efficient for the entire system to dispatch the higher-cost generator, a practice known as out-of-merit-order dispatch. Dispatch of the generator with the lowest marginal cost may also lead to congestion somewhere else in the network, blocking access for other relatively cheap generators. Efficient pricing requires that these considerations are taken into account.

Nodal pricing principles seek to price use of the network at different nodes taking into account transmission capacity and grid losses. Typically, each transformer station in the transmission grid is designated a node. All flows and constraints between nodes, including loop flows, are priced (using computer models) and those prices are made public, signalling congestion and the need for investment in additional capacity. In the trading arrangements used in the PJM market, transmission congestion is priced and managed simultaneously with the settlement of bids and offers for power. Transmission capacity is thus priced implicitly in the spot prices. However, there are drawbacks with this approach: trading is fragmented into separate nodal markets, reducing liquidity, increasing the risk that one or more players may exert market power and raising transaction costs. In some cases, technical factors can prevent nodal pricing from always being applied.[10] An alternative approach, which has been adopted for pricing interconnector capacity in Europe, is to make the auction of transmission capacity explicit. In 1999, the German and Danish transmission system operators set up an auction of capacity for the Danish-German interconnector. Other countries have since established similar auctions along several other European borders, including the Netherlands-Germany and England-France borders. The European Commission has ruled that implicit and explicit auctions comply with EC directives and the 2003 regulation on cross-border power trade.

Zonal pricing, an alternative to nodal pricing, sets uniform prices for use of capacity for groups of nodes that correspond to the main congestion points in the grid. The aim is to simplify pricing, maintain liquidity and facilitate transparency. This approach is used in the Nordic market (see Chapter 1, Box 1.17), as well as in Australia. In both cases, networks are more radial and less intermeshed, with few loop flows. Each Australian state in the National Electricity Market together with the hydropower capacity in the Snowy Mountains region constitutes a zone. The system operator calculates network losses for each zone on the basis of loss factors, assessed annually, for specific nodes. Losses are taken into account in determining the dispatch schedule.

In Great Britain, BETTA introduced uniform balancing charges across the entire British system with the integration of Scotland in 2005. As a result, there are no locational pricing signals. A shortfall in physical transmission capacity between Scotland and the rest of the network has resulted in a sharp increase in constraint management charges, which the system operator recovers from all network users regardless of their location.

Regulation of *regional and cross-border interconnectors* may be treated differently to meshed networks. One approach is to simply let it compete with generation on equal terms without any price controls. Such merchant interconnectors would be financed purely by congestion rents. Several merchant interconnectors, built prior to liberalisation, currently operate in Europe, North America and Australia. In theory, greater reliance on competitive merchant lines would support more effective use of price signals to strengthen incentives for efficient transmission network performance and to promote cross-border trade. But this approach may undermine economies of scale and raise costs if several lines were built by competing utilities. Merchant lines might also be built without regard to reliability requirements (Joskow and Tirole, 2005). As a result, it is unlikely that policy makers will be able to rely primarily on a merchant model to drive interconnector investment. The objective is to develop regulatory mechanisms that provide opportunities for merchant investors to develop projects when they are the most efficient options. Experience in Europe suggests that strong incentives or active intervention in the form of publicly backed investments are needed to bring forth investment in interconnectors, because of the inherent self-interest of incumbent utilities in limiting cross-border exchanges in order to protect their dominant positions in their home markets.

The amount *of transmission capacity* that is made available for trade is a critical factor when incorporating the locational aspects into efficient electricity pricing. System operators typically restrict the transmission capacity available for trade below the actual physical thermal capacity of the line for reasons of security. Capacity held in reserve may be used in the event of an emergency. The methods used for analysing system security needs have changed little since liberalisation. In many cases, these methods are extremely conservative, are not based on probabilities of critical events occurring and rarely exploit the information on costs and prices revealed by the market (IEA, 2005c). There is considerable scope for better aligning such practices with the competitive market framework to maximise available transmission capacity. This, in turn, would allow for more trade and lower prices.

5.4. *Ensuring energy security*

Ensuring the security of electricity supply hinges on *timely investment* in generating and network capacity (and related infrastructure to supply fuel to power stations) and adequate systems for maintaining reliable uninterrupted operation of transmission and distribution networks. Threats to the reliability of supply could increase substantially in many parts of the world as a result of unexpectedly rapid increases in demand, which may squeeze reserve capacity and increase congestion in transmission systems. Underinvestment in transmission and distribution networks may compromise system reliability. Climate change might also lead to more frequent natural disasters, such as hurricanes, storms and flooding. Transmission and distribution systems would be most at risk from such events. Major changes in climate patterns would, therefore, make electricity supply less reliable unless electricity infrastructure is made physically more robust or additional back-up facilities are put in place to handle emergencies. Geopolitical factors may also affect the supply of natural gas, oil and other fuel inputs to power generation, with knock-on effects for electricity supply security. Increased risk of a disruption in fuel supplies increases the need for reserve capacity, fuel-switching capability or flexible demand responses.

At any given moment, the adequacy of generation and network capacity to meet all demand at all times depends on whether enough investment is forthcoming at the right location and in a timely manner. A lack of capacity forces system operators to impose blackouts and brownouts. System security depends, to some degree, on available network capacity and, therefore, the amount of investment. But it also depends on operating tools and co-operative arrangements that allow the system operators' to effectively monitor and flexibly control flows in real-time and to respond to emergencies. Many power outages, such as the major blackouts in North America and Europe in 2003, are caused by the sudden failure of the transmission system.

The costs of power outages or poor-quality electricity service can be extremely high. The economic cost of the disruption in electricity supply in the north-east United States and eastern Canada in August 2003 has been estimated at between USD 4 billion and USD 10 billion for the United States and close to CAD 1 billion in Canada (IEA, 2005c). For all of 2003, the total cost of all power disruptions throughout the United States is estimated at USD 52 billion for the information and communication industries and USD 100 billion, or 1% of GDP, for the economy as a whole (EPRI, 2003a).

In principle, competitive electricity markets can provide incentives for timely and efficient investments, as long as the market is well-designed and the regulatory framework is appropriate. There are growing concerns about the adequacy of generation and transmission investment in liberalised markets – notably in Europe, the United States and parts of Asia. Reserve-capacity margins – the difference between peak demand and available generating capacity – are falling in several countries as a result of a downturn in investment in recent years. In most cases, market reforms were introduced at a time of overcapacity, so the initial focus was on reducing operating costs. The focus is now shifting to the adequacy of incentives to invest in new capacity – particularly peaking – and streamlining regulatory procedures for authorising new investment in generating plant and high-tension transmission lines.

There are increasing doubts about whether markets for power only can provide sufficient incentives and whether prices need to be uplifted by formal capacity payments. Theory suggests that energy-only markets with spot prices that are allowed to fully reflect scarcity rents at peak will generate sufficient income to generators to allow the full recovery of their initial investment in capacity (Roques *et al.*, 2005). But, in practice, the perceived increase in investment risk, which has raised hurdles rates, may be skewing investment away from capital-intensive base-load and peaking plant. In poor developing countries, financing much-needed investment in infrastructure to meet rising demand and maintain reliability will be a major challenge in view of the limited availability of public funds, limited access to capital markets and the difficulties in attracting private capital.

Given the economic, social and political importance of "keeping the lights on", policy makers and regulators are considering *alternative mechanisms for remunerating reserve capacity*. These include capacity payments, determined by a formula for calculating the value of lost load (VOLL), and capacity obligations. The electricity pool established in 1990 in England and Wales incorporated a fixed VOLL-based capacity payment (increased each year in line with inflation). How much of the VOLL that was actually paid to generators for each half-hour settlement period was determined by the probability of a shortage occurring, computed according to available capacity and the assessed load for each period. Problems with gaming led to the payment scheme being phased out with the introduction of the New Electricity Trading Arrangements in 2001. Capacity payments are still used in Spain but the amount is fixed each year for all hours regardless of the actual supply and demand. Capacity obligations require retail companies to contract for an amount of generation capacity that meets a fixed percentage of contracted load plus a reserve. PJM, New England and New York have adopted this approach, together with a cap-and-trade system in which capacity can be traded using a competitive market mechanism.

In a draft proposal for an EC directive concerning security of electricity supply, the European Commission has proposed that member states can use either a one-price-only market or capacity obligations to maintain balance between electricity supply and demand. But if this leads to different arrangements in neighbouring states, investment would be distorted because of free-riding across borders and pricing differences. This is a major issue in the north-eastern United States, where different approaches to remunerating capacity have emerged.

Private investment in networks depends largely on the incentives provided by the regulatory framework. Many countries have adopted regulatory approaches to network-tariff setting that incorporate strong incentives to cut operating costs. This has led to concerns about whether reliability is being compromised – particularly following a series of large-scale blackouts in 2003 and 2004 in a number of OECD countries, notably in North America, Italy, southern Sweden, and eastern Denmark. Often, the costs of establishing effective communication and monitoring systems, training staff and managing vegetation[11] are far outweighed by the economic benefits of fewer outages (IEA, 2005c). In several countries, network regulation is being adjusted to provide direct incentives for maintaining reliability, including through investment. The regulated rate of return remains a critical factor in ensuring the adequacy of investment.

Obtaining permission to build electricity supply infrastructure is a vital factor in securing supply. Non-transparent and bureaucratic *approval procedures* – whether to use a particular technology, to build a power plant at a particular site or to build a transmission line along a particular route – remain a major barrier to investment in most markets (IEA, 2005b). The so-called "not-in-my-backyard" (NIMBY) syndrome was a major cause of the power shortages that emerged in California in 2001 and that persist today. In some European countries, the long lead times in obtaining approval to build new transmission lines in the face of public opposition is the most serious obstacle to expanding supply capacity.

Increased cross-border trade can bring major benefits, as described in Section 3.4, but they must be carefully managed by system operators in such as way as to prevent them undermining system security. One lesson learned from the recent blackouts in North America and Europe was the importance of co-ordination and co-operation between system operators, including the full implementation of bilateral agreements. Such agreements were subsequently made legally binding in the United States. Another lesson concerned the importance of monitoring compliance with reliability standards. For example, a failure to trim trees adjacent to power cables played an important role in the failure of the transmission system in Italy and north-east America in 2003. Although liberalisation does not *per se* affect these issues, it is clear that it has fundamentally changed the way transmission systems are used and managed and that regulation of the industry has to adapt to these changes. There is a growing consensus among policy makers on the need for better monitoring of the impact of market developments and changes in industry structure on energy security. Governments may need to intervene in electricity markets to respond to a looming capacity crunch and to ensure that system operators take appropriate steps, including co-operation with neighbouring operators, to ensure system reliability (IEA, 2005b). For example, in July 2006, the US National Electricity Reliability Council – a self-regulatory industry body – took on new powers under the 2005 Energy Policy Act to develop and enforce mandatory reliability standards, including the imposition of fines on utilities that fail to meet those standards.

Notes

1. Generation, transmission and distribution are physical activities, while supply – wholesale trading among generators and marketers and retailing to end-users – is a transactional function. Other functional activities include system operation/dispatch, which covers all levels of the physical supply chain, and risk management.
2. The term utility is used throughout this chapter to refer to any company or entity involved in one or more of the four main functional activities that comprise the electricity supply industry.
3. The supply of any commodity or service is defined as a natural monopoly if the economies of scale are such that the overall cost of supply is lower if there is a single supplier. Grid-based energy transportation and delivery, including electricity, natural gas and district heat, which require more or less permanent connections with customer premises, are widely recognised as natural monopolies.
4. Differences in load patterns across an interconnected system result in a lower overall peak load compared with the sum of the peak loads of the individual sub-systems.
5. The drivers of and prospects for electricity demand and investment are described in detail in Morgan (2006).
6. On balance, research has shown that private electricity utilities tend to be more efficient than public ones and that efficiency improvements are usually faster, though this may depend on efficient markets being established. See, for example, Pollitt (1995 and 1997) and IMF (2004).
7. The 1990s saw a number of European and US companies expand aggressively into foreign markets on different continents. Électricité de France (EdF), Spain's Endesa and Iberdrola (Spain) and Portugal's EdP acquired assets mainly in Latin America. The other large European companies, such as E.ON, RWE, Vattenfall and ENEL, have not invested to any significant extent outside Europe. EdF is now looking to sell its assets outside Europe. A number of US companies acquired assets in the United Kingdom during the 1990s, but have since largely divested them.
8. The ranking of load or demand in each hour or other period of the year, with peak load at the top and base load at the bottom.
9. Electricity follows along the path of least resistance ignoring any path that may have been envisaged in a contract. On any given line, resistance and losses increase with load. As these relationships are neither linear nor constant, determining the cost of transportation is extremely complex – especially with

highly meshed networks where different flow paths, or loop flows, are possible. Where loop flows exist, it is not possible to define the available transmission capacity at a point in time without the existence of complete information about the use of the overall network.

10. In the PJM, for example, it is sometimes necessary to dispatch capacity out-of-merit order dispatch for reliability reasons, usually to deal with heavy congestion in certain parts of the network. This results in additional costs, which are spread evenly across all users.

11. Trees touching transmission cables are a leading cause of system failures.

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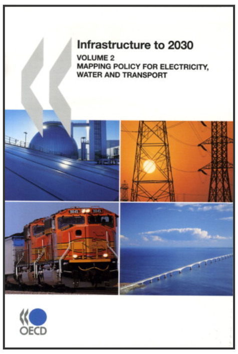

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