FOREWORD

Energy policy makers and policy analysts often talk about electric power technology in rather abstract terms. It is seen as responsive to economic forces, long-lived, often capital-intensive, adaptable to environmental requirements, critical to total energy use patterns. It does indeed have those characteristics, but at any given time real technology consists of a collection of equipment, techniques, and knowledge. Changes in technology can come quickly, but the changes do not have to be revolutionary to make a deep impact. It can be helpful to examine electric power technology in more concrete terms.

This book does just that. It explores the implications of electricity market competition for specific power generation and transmission technologies. Many governments throughout the OECD and the world are in the midst of substantial change in the regulation and structure of the electricity supply industry. They are introducing competition to their electricity-supply systems in search of greater economic efficiency. The goal of these changes is to reduce electricity prices to consumers by reducing the costs of inputs to electricity generation and supply. Technology plays a pivotal role in realising this goal.

The seas of technology forecasting are littered with shipwrecks. The trends and technologies identified in this report are therefore offered, modestly, not as predictions, but as suggestions of some of the likely focal points for continued technological development.

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This report is published under my responsibility as Executive Director of the IEA and does not necessarily reflect the views of the Member countries of the IEA.

Robert Priddle
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INTRODUCTION

The introduction of competition in electricity markets has important implications for the technologies used in the electric supply industry. Competition induces an intensified search for the technologies providing the cheapest electricity. Such technologies must meet all the relevant operational, geographical, environmental, and other constraints. This text reviews the technologies most likely to receive a developmental push from the introduction of competitive markets.

The list of such technologies includes some applicable within existing plants, as well as those that can be used in new power plants. In most OECD countries, mature electricity demand will limit the importance of new plants in the overall generation mix for many years. A crucial question is therefore how competition will cause technology in existing plants to change incrementally. A myriad of supporting technologies and improvements to existing plants will present themselves.

In this type of review it is difficult to avoid a simple survey of new technologies because it is never clear which ones will deliver what they promise. Nonetheless, this review concentrates on those technologies that will at least be favoured by competitive markets, even if they are not ultimately successful. The text does not analyse how technology choice will vary by individual market and by country. The detailed developments in technology will vary according to the economics, fuel supply, and regulation in each market. Electricity supply systems that were relatively efficient under monopoly supply arrangements may see only small changes in technology, or may continue along established paths of development.

Throughout the text, it is assumed for ease of discussion that there are no particular regulatory or administrative constraints on technology choices. Implicitly, this assumes that government policies are implemented using market-compatible instruments. This is an idealised picture that will never be fully attained. In some countries reform may only be partial. Especially during the period of transition to competition, there remain constraints linked to past regulatory and policy arrangements. Even in the long run, few markets will be completely “open.” In some countries, for example:

- utility coal consumption may remain subsidised
- generators may still be required in certain instances to use specific technologies, such as co-generation
- generators may be forbidden from using specific technologies, such as nuclear
- environmental constraints may be imposed via technological requirements

Electricity Market Competition

Electricity systems throughout the world have been based on monopoly production. Utilities have had exclusive rights to produce, transport, and sell electricity in defined service areas. Since the early 1990s, this traditional arrangement has given way to electricity supply based on competition among suppliers. The motivation for this shift in market organisation and regulation is to increase the efficiency of the electricity supply industry and to lower prices for electricity consumers. By 2000, over three-fourths of OECD Member countries will allow competition in at least a portion of their wholesale electricity markets.

The introduction of competition gives consumers the right to choose their supplier of electricity. This right may be given to only large customers, such as industrial and commercial companies, or to all customers, regardless of size. The latter is becoming increasingly common. Prices are no longer set by regulatory formulae relating to assets, fuel costs or other expenses. A marketplace is established in which buyers and sellers of electricity freely trade and set prices. The new market discipline strengthens the attention to cost-effectiveness in all areas of electricity supply, especially in generation.

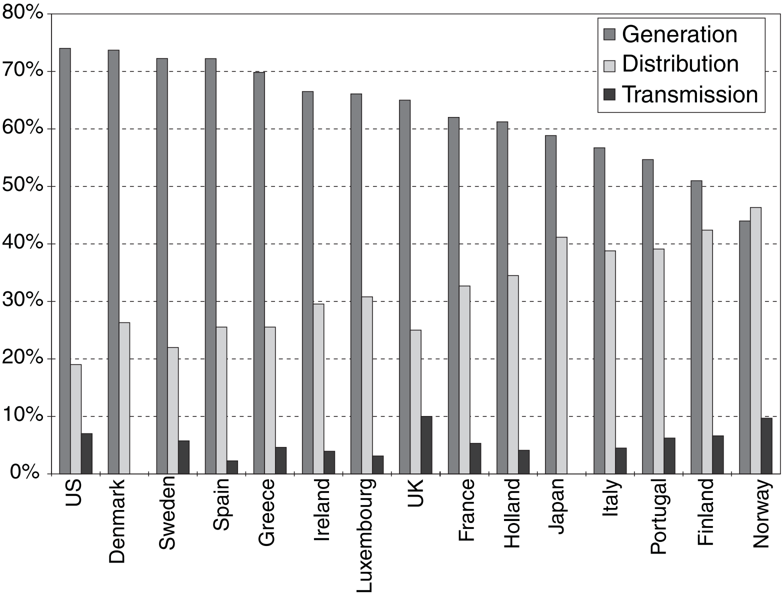
To enable the transport of electricity from producers to customers, the owners of transmission systems must provide access to their lines to others. If the owner of the transmission network is also a generator, there is a potential conflict of interest to favour its own power plants by setting unfair transmission prices or access conditions. Therefore, in order to make sure that all users of the electricity network have fair access to the system, the control of transmission networks is usually given to an independent system operator whose prices are regulated.

Other changes are accompanying the introduction of competition. Government institutions such as ministries responsible for electricity supply and regulators must adapt their organisations and functions. Energy and environmental policies must be made more market-compatible. Competition (anti-trust) authorities take on a greater role in supervising the sector.

An important and unpredictable factor is the entry into the power generation market of companies from other industrial and commercial sectors. For example, oil companies and refineries have shown an interest in the generation market. Finance and commodity companies are participating in the development of electricity financial markets. Such companies could introduce very different approaches to the power supply industry. Competitive principles that are well known in other sectors will soon find their application in power markets, bringing innovations that break the traditional mould of utility thinking.

The main cost components of electricity supply are generation, transmission, and distribution. Figure 1 shows the proportions of these components in OECD countries. In all countries, generation accounts for over half of total cost and in most countries it accounts for over 60%. Transmission typically accounts for 5% to 10%. Both generation and transmission are highly technical undertakings. They are likely to be the areas where the greatest changes in technology will be concentrated. This review considers only these two areas and does not examine technological changes in electricity distribution.

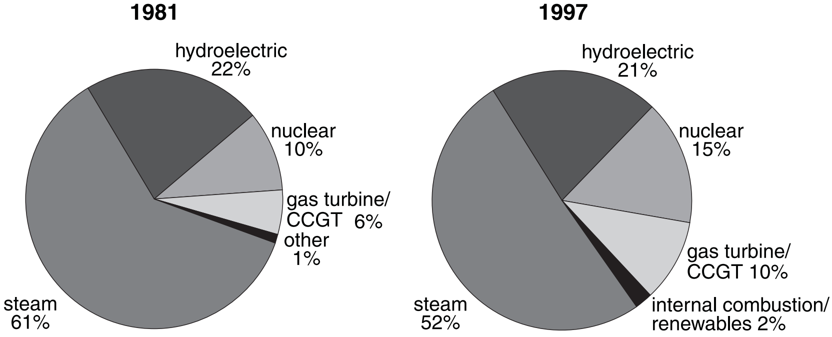
Figure 1
COST SHARES OF GENERATION, TRANSMISSION AND DISTRIBUTION IN OECD COUNTRIES



Source: IEA.

The analysis is not meant to suggest that competition is the only factor driving technological change. That is certainly not the case, as shown by continuous technological development in the electricity supply industry since its beginnings. For example, in the past two decades alone there has been a steady decline in the share of power plants using fossil-fuelled steam boilers in favour of plants using nuclear steam generation and gas turbines (Figure 2).

Figure 2
GENERATION TECHNOLOGY SHARES IN OECD POWER GENERATION, 1981 AND 1997



Source: IEA, *Electricity Information 1998.*

The issues affecting technology choice are common to many industries. In this review they are discussed under the following headings:

- better use of existing plants
- lower operations and maintenance costs
- reduced fuel costs
- new capacity
- environmental protection technology and renewables
- transmission

The introduction of competition also affects the means by which governments attain their energy policy objectives. The review begins by noting how changes in energy policy implementation can influence power plant technology.

END OF FREE COMPLIANCE WITH GOVERNMENT TECHNOLOGY WISHES

One of the first changes in electricity technology under competitive electricity markets is that utilities will not choose government-favoured technologies unless they are the most economic or unless they are compensated for the choice. Under monopoly regimes, the technological choices of utilities were sometimes strongly affected by government requirements or pressure favouring indigenous fuels, domestic manufacturers, environmental performance and the provision of jobs. Governments frequently encouraged coal-fired and nuclear plants to reduce dependence on imported oil, particularly in the aftermath of the oil price shocks of the 1970s. Combined heat and power, renewables and other technologies were given special attention and financial support. Utilities were often required to purchase electricity at preferential prices from facilities using favoured technologies. The 1978 Public Utilities Regulatory Policies Act in the United States was the model for many such laws in other OECD countries.

Government policies encouraged both state-owned and private utilities to use specific technologies. Only rarely were the extra costs associated with the selection of government-favoured technologies estimated or revealed to electricity consumers. Stranded costs have emerged as an issue in the liberalisation of electricity markets because utilities cannot continue to bear the cost of uneconomic technologies in newly competitive environments. For example, uneconomic contracts signed for renewable or co-generated power under the Public Utilities Regulatory Policies Act account for approximately one third of all stranded costs estimated for US utilities. In the Netherlands and Germany, generous provisions for purchases of electricity from co-generators and renewable energy plants imposed substantial costs on both utilities and consumers.

With the introduction of competitive electricity markets, utilities are no longer willing to choose technologies that do not provide the lowest electricity cost. Governments will continue to have, in specific instances, a legitimate interest in influencing technology choices made by utilities. If governments wish certain technologies to be used for policy reasons, they must make explicit and non-discriminatory arrangements for this, including explicitly accounting for the financial implications. This permits power plant developers to account for the financial effects of government support measures when making their technology choices. Most competitive electricity markets have introduced mechanisms for the support of specific technologies. Table 1 lists examples of technology-support features in several competitive markets.

Table 1
Technology Support Features
in Selected Competitive Electricity Markets

Country	**Favoured Technology**	**Means of Support**
Australia – New South Wales	renewables	absence of revenue caps on distributor purchases
Denmark	renewables, combined heat & power	parallel green electricity market obligation for new plant
Finland	renewables	investment subsidies, tax rebate
Germany	renewables	subsidies, electricity purchase obligations on distributors
Netherlands	green technologies	parallel green electricity market
Spain	renewables	“special regime” price supports
Sweden	renewables	investment subsidies, tax breaks
United Kingdom	non fossil fuels	levy on transmission (the Non-Fossil Fuel Obligation)
USA – California	renewables	non-bypassable transmission charge

Source: IEA.

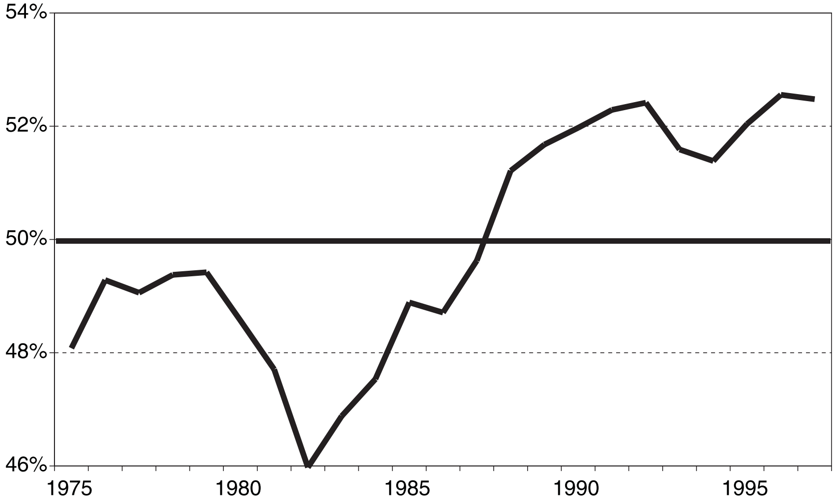
Most often, the money to pay for technologies preferred by governments comes either directly from the government, in the form of a subsidy, or from consumers, through a fee on electricity sales or transmission services. Because of the improved transparency of competitive electricity markets, technology choices are now likely to be based more strictly on cost effectiveness. Governments will therefore find it necessary to fully justify their policy choices if those choices impose large additional costs on taxpayers or consumers.

As shown in Table 1, electricity generation from renewables is explicitly supported in nearly all electricity markets where competition has been introduced. In the near term, the technologies most likely to benefit from this situation are wind power and biomass generation. These are currently the renewables technologies with lowest cost of generation in many regions.

BETTER USE OF EXISTING PLANTS

Utilities have not always had strong incentives to use power plants to their maximum potential. Utilities were typically allowed a fixed return on investments. Consequently, in some utilities, management focussed more attention on building new power plants than in improving the economic performance of existing plants. The average capacity utilisation rate of OECD power plants is only about 50% (Figure 3). Country averages range from about 40% to 60%. These utilisation rates are lower than in most other industries, where minimum average rates of 75% are typical. Although power plants cannot economically hold inventory (electricity) to meet swings in demand or

Figure 3
AVERAGE UTILISATION RATE OF OECD POWER GENERATION CAPACITY, 1975 TO 1997



Source: IEA, *Electricity Information 1998*.

input energy (specifically, low rainfall for hydroelectric plants), the range of power plant utilisation rates among OECD countries suggests that average utilisation rates can be improved.

In competitive markets, existing power plants carry a sizeable advantage because they are already in the market and may have substantially or completely retired their construction debt. Market entrants wishing to build new power plants face the hurdles of siting, gaining public permission, financing, building the plants, and connecting them to the grid, along with the associated financial risks. Therefore, owners of existing plants have every incentive to maximise the output of those plants and to operate them as long as possible. Technologies to help them do this involve:

- improvements in reliability and availability
- incremental capacity additions
- life extension and repowering
- smoothing demand peaks
- operational flexibility

Reliability and availability

A plant that is not running cannot sell electricity. Each instant a plant is out of operation due to equipment failure represents a large lost income. Even when a plant is not operating, keeping the plant available to meet unexpected demand has a substantial value. Reliability can help to differentiate generators in the electricity market. Therefore, power plant owners will place emphasis on improving plant reliability and availability.

Redundancy of important components is one method that can be used to improve reliability. Given the incentives for capital investment under monopoly supply systems, redundancy may have been over-used in some utilities in the past. Adding redundant components does not address the causes of component failures (unreliability), nor is it always possible in existing processes. The focus of reliability improvement in existing plants will probably be on analysing the causes of component failure and then taking steps to reduce minimise their effects or eliminate them. Historical operating data can be analysed to identify sources of unreliability and suggest technical means to reduce them.

Typical utility practice has been to inspect and overhaul equipment at fixed intervals of time, as specified by equipment suppliers or based on historical company experience. Such procedures focus on individual items of equipment, regardless of their importance to the system. Consequently, these approaches to maintaining reliability are sometimes too conservative and do not adequately take into account the actual condition of the equipment.

Reliability-centred maintenance is a method that establishes time intervals between maintenance based on equipment operating data rather than on pre-defined maintenance intervals. It is a means of balancing the cost of maintenance and the cost of unplanned outages. Reliability-centred maintenance shifts maintenance schedules, making some longer and some shorter. Cost savings are obtained by reducing unplanned outages and increasing system performance. The nuclear industry has applied the method, and it is likely to see wider application in electric utilities in general under competition.

Specialised sensor technology needed for detecting abnormal conditions, with or without maintenance software, takes on greater importance under competition. Sensors make reliability-centred maintenance possible by allowing monitoring of individual plant components and by indicating the conditions that precede failures. Examples are sensors to monitor flame conditions in boilers, heat-flux sensors to monitor heat-transfer rates on boiler tubes, and gas analysers to monitor the decomposition of transformer oil.

Specialised monitoring software can help detect imminent equipment problems. Three examples are acoustic monitoring of boiler tubes to detect imminent failure, coal chute monitoring to provide operators with early warnings about blockages in coal feed systems and turbine-vibration monitoring to warn operators about potentially destructive imbalances in rotating turbines. There are many other opportunities to improve component-specific monitoring and improve overall system reliability.

Simplifying designs can improve reliability in any system because simple systems have fewer parts to break. When power plants were originally engineered, designers sometimes added components due to a lack of operating experience or knowledge. In the light of operating experience, plant operators may be able to remove unnecessary components and thus improve reliability.

Availability is improved when plant operators make sure that maintenance periods are scheduled for periods when the plant is not needed or when the value of its electrical output is low. Specialised software can again help in achieving this goal. Improved working methods and better scheduling during plant outages are also means to improve availability. Nuclear plant operators have succeeded in dramatically reducing outage times in recent years.

An interesting idea for increasing nuclear plant availability, not yet in existence, is an on-line probabilistic safety assessment. This software would monitor the key variables affecting overall plant risk, so that plant operators could judge immediately whether the loss of a particular component warranted stopping plant operation the plant due to increased risk. Currently, plants must sometimes cease operation when given components are out of service due to procedures imposed by safety regulations, even though risk to the public might be unaffected by the component outages. A safety-assessment “meter” could in principle provide a better means of deciding whether a plant shutdown were required. The hardware and software for such a meter exist, but it may take the pressure of competition to see if the idea can advance and be acceptable to regulatory authorities.

Another possibility to improve availability in fossil-fuel plants is to enable plants that are used to meet variable load to operate at very low load levels. The ability to run at low loads increases the range over which a plant can sell its output. This is especially relevant for old boiler plants originally designed for baseload duty. However, almost all generation technologies have limits on how far downward low-load operation can be pushed. The limiting factor is usually safe operation of combustion systems at low levels. The plant must demonstrate that safe combustion is possible even at conditions of low air and fuel flow. Sensors measuring flows and temperatures must all be adapted to function properly at lower levels, and their outputs monitored by specialised software to keep plant operation within safe limits. On the economic side, the poor low-load performance of certain components such as turbines, pumps or fans may have to be improved. Introducing variable-speed drives or replacing a single component by multiple, parallel components can improve part-load performance. The plant must also have technologies that keep it within its pollution emissions limits at low load.

Incremental capacity additions

Some power plants could increase their maximum output at relatively low marginal cost. This is a formidable competitive advantage compared to building entirely new plants, since existing plants are already operating and have established positions in the market. Major power-plant components are designed with some excess margin of capacity to account for uncertainties in fuel composition and operating conditions. Consequently, improving the performance of only a single major piece of equipment (the one with the lowest operating performance margin) can sometimes increase plant capacity.

Steam turbine manufacturers have been upgrading the output of old steam turbines for many years. There have been many improvements in steam blading, metallurgy and design of steam flow paths since the 1960s and 1970s, when many steam boiler plants were built. These advances can be applied to existing turbines to increase their output. This upgrading service is increasingly competitive. The major manufacturers of steam turbines all have business units devoted to upgrade projects. Manufacturers now regularly bid on and win upgrades of equipment made by rivals.

Nuclear plants often are able to increase output because of the very conservative design margins chosen in many plants. Plants typically are able to accommodate increases in power from 2% to 15% with no loss in safety margins. Steam generators and turbines can be upgraded to increase power output. Since steam generators in many plants using pressurised water reactors must be replaced because of corrosion problems, they may be conveniently replaced by models of higher output. At the same time, the steam turbine can be increased in capacity, or just improved in efficiency. Moisture-separator reheaters are other components whose refurbishment or replacement can add capacity to existing nuclear plants. Considering the low marginal operating costs of well run nuclear plants, it is likely that competitive markets will focus special attention on increasing nuclear plant output.

The capacity of older hydroelectric power plants can be increased with refurbishment of the turbines or generators. Even improvements in hydraulic flow can result in increased output. Performance of “low-tech” civil engineering works can be improved using sophisticated computer analyses to minimise losses of hydraulic energy upstream of the turbines.

Life extension and repowering

Old plants destined for decommissioning under monopoly systems may now be targeted for life extension and repowering technologies. Every decision to continue operating a plant is based on an expected net present-value calculation which estimates potential profits in light of the ongoing costs of operation. At a certain point, when costs increase due to the age of components, changes in environmental regulations, or the need for major overhaul, the plant may be shut because it is expected to generate insufficient or no further profit. In competitive electricity markets, many such evaluations will shift in favour of life extension rather than retirement due to the removal of regulated rates of return on capital investment. The loss of other, less obvious incentives for investment in new plant, such as those arising from certain government employment or regional development policies, is also likely to favour life extension.

Life extension maintains the plant without major changes in components or systems. Frequently, plant environmental performance must be improved at the same time as its economic performance. There are no “universal” technologies for plant life extension. Rather, all plant systems are candidates for refurbishment and economic improvement in light of technological advances since their installation. In coal-fired boiler plants, new burners and combustion improvements are often important. Low-emission burners, staged combustion, and natural-gas afterburning can increase fuel combustion efficiency and reduce emissions of nitrogen oxides. Applying recent steam turbine technology (noted above) also is a means to improve plant efficiency. Steam turbine life can be extended by replacing old seals and bearings and by using wire-arc spray coating and shot peening to prolong the life of components. If a fossil steam plant requires a major boiler refurbishment, the boiler may simply be replaced with one of completely new design. This a type of plant “repowering”.

Repowering means the replacement of major plant systems with new technology. Using this method, a nearly new power plant can be obtained at substantial savings in cost due to the use of existing infrastructure and plant components. With an increase in plant efficiency, the marginal operating costs of the plant can decrease and thus make possible an increase its capacity factor.

So far, the most common type of plant repowering has been to replace boilers with combined-cycle steam-generation systems. This approach uses the existing steam turbine and other steam cycle equipment. Both fossil-fuelled and nuclear plants have been repowered in this way. Plant capacity is multiplied by three, since gas-turbine output is double that of the steam turbine, efficiency increases by roughly one third and emissions of gaseous pollutants decrease as well. The resulting plant can generate electricity at nearly the same cost as a new combined-cycle plant, but with lower total investment. Since repowering with gas turbines increases plant capacity, it may be considered as a type of incremental capacity addition as well.

There are other repowering options using gas turbines. These involve keeping the old boiler, but using the exhaust heat of the gas turbine either to preheat boiler combustion air or preheat boiler feedwater. In both cases, the power output of the plant can increase by up to 40% and its efficiency can increase by 10%. Neither has yet been widely used, but might be considered more frequently in competitive markets.

Replacing conventional pulverised solid fuel boilers with fluidised bed boilers is also a possibility. Large circulating fluidised bed boilers of over 200 MWe are commercially available. They can provide modern environmental performance in the same space as an existing boiler, with no separate sulphur control system. This repowering option is most feasible when low-cost coal or other inexpensive solid fuel supply is available to justify the heavy investment in a new boiler.

Smoothing demand peaks

Electricity demand is variable, and many power plants are operated only to meet this variable load. While this is convenient for users, it is costly in investment terms because many plants are used only to a fraction of their potential. Competitive systems are likely to reduce the ratio of peak load to steady demand by setting prices which reflect the high cost of meeting infrequent demand. Retail prices will begin to vary more like wholesale prices – hour by hour. Technologies for demand side load management and energy storage could also emerge to help improve the usage rate of existing plants and reduce the need for new generation capacity.

Demand side technology

Demand side technologies are those that reduce electrical consumption at the point of use. They require:

- control hardware and an electrical usage profile which can allow for consumption to be lowered when needed
- frequent electricity price information or, alternatively, an automatic control signal from the electricity supplier when prices reach a pre-determined level
- special metering that allows users to keep track of electricity consumption at different price levels

So-called "real-time pricing" systems allow large commercial and industrial customers to modify their electrical loads automatically in response to changes in electricity prices. Two-way communications between electricity users and suppliers and specialised control systems can automatically reduce loads and shift use of electrical equipment in response to real-time prices. Such systems are most useful for large-scale users of lighting, heating, and ventilation such as hotels, large office buildings, shopping centres, and business centres. Industrial facilities of all types can benefit from this type of system. Metering technologies are critical for the use of demand side controls, particularly for smaller loads where metering costs are high in relation to the total electricity bill.

Energy storage

Energy storage technologies could be boosted by persistent, significant differences in price between low-cost and high-cost periods. Although it is often said that "electricity cannot be stored", there are technologies which can store electricity in sufficient amounts to profit from price differences. Electricity storage systems may not be the very large systems usually envisioned by utilities in the past, but smaller systems suitable for large individual customers.

For example, small (2 kWh) flywheel power storage systems are already used as uninterruptible power supply systems (Audin, 1998). Chilled-water storage systems are also in use for commercial cooling loads. Refrigeration units draw electricity during off-peak hours to make chilled water, which is then used during periods of high electricity price. Storage systems using conventional lead-acid batteries are also well developed, but are expensive and costly to maintain.

Superconducting, magnetic energy storage systems have been studied for many years, but have appeared to be most suitable for large, grid-sized storage duty. As improved superconductors are developed, smaller units may become economically feasible. Their simplicity of conception (no mechanical conversion devices are required) is one of their key attractions. Regenerative fuel cells have been proposed recently as a technology suitable for large-scale electricity storage (National Power, 1999).

Operational flexibility

Even if demand peaks become less pronounced in competitive markets, plants will still be called upon to meet variable demand. Plants competing for variable electrical demand can gain an advantage by stepping in faster to meet unexpected electrical demand or quickly replace lost generation capacity elsewhere in the system. This may be a particular advantage in the early years of a competitive market, as plant managers adapt to the greater independence of individual operating units. Until the information in a competitive market flows as efficiently as it does within a single company or co-operative power pool, there will be a premium on being prepared for unexpected operation. Plant flexibility can also make it possible to profit from momentary fluctuations in fuel and electricity prices.

Steam boilers designed for constant-load service are poorly adapted technically to cycling service, though careful operating procedures can minimise the wear and tear from repeated thermal cycling. Techniques to reduce standby fuel consumption, and retrofits of auxiliary components specifically adapted to allow repeated cycling can be used to increase operational flexibility. In plants designed for constant-pressure operation of the steam turbine, sliding-pressure operation can be applied to improve plant efficiency.

Power plants using gas turbines and internal combustion engines have an advantage over steam boilers in providing operational flexibility because of their quick start-up times.

LOWER OPERATIONS AND MAINTENANCE COSTS

Operations and maintenance (O&M), excluding fuel cost, remains a major expense for every utility. O&M costs are driven largely by plant staffing, which can be reduced through better management, but also by new technology. Other variable O&M costs can also be reduced through new technology. If these measures are to be successful, of course, they must be engineered to maintain the reliability of supply.

Labour productivity

An early result in nearly all electricity markets where competition has been introduced has been a reduction in operating staff at power plants and throughout utility functions (Table 2). Staffing at power plants varies greatly by technology - from seven employees per 100 MWe in simple-cycle gas-turbine plants to 60 per 100 MWe in US nuclear plants. Therefore, at a utility level, shifting the plant mix towards natural-gas-fired plants improves labour productivity over time.

In existing plants, better staff management, such as better use of project teams or training workers for broader responsibilities, can improve labour productivity with little change to plant systems or operation. Deeper changes can come as plant components and systems are modified to simplify their operation and increase reliability. There are a host of component-level technologies, defying classification, which can contribute to reduce labour requirements for operations and maintenance. Improved process control (see below) can be an important contributor. Consolidation of control areas, implementing remote control, and providing remote fault diagnosis can all help to reduce plant staffing.

Table 2
Average Annual Decrease in Utility Employment
Due to Market Liberalisation

Country	Form of Liberalisation	Decrease (% of initial value)	Time Period
Victoria, Australia	privatisation, competition	10%	1989-96
Hungary	privatisation	4%	1995-97
New Zealand	corporatisation	10%	1987-92
United Kingdom			
National Power	privatisation, competition	13%	1990-95
PowerGen		10%	1990-95
British Energy		7%	1996-98
United States †	impending competition	3%	1990-96

Source: IEA, *Electricity Reform: Power Generation Costs and Investment*, 1999.
Note: † major investor-owned utilities.

Maintenance

The key technologies enabling power plants to reduce maintenance expenses are those related to improving reliability and reducing the risk of catastrophic failure. They will reduce the expected costs of a major breakdown by giving operators time to take corrective or preventive maintenance measures. Here the most important technologies are improved sensor technologies and software for reliability-centred maintenance (discussed above under “Reliability and availability”).

REDUCED FUEL COSTS

In some non-competitive systems, fuel costs were simply a “pass-through” to consumers. This provided very little incentive to minimise fuel costs aggressively. The Italian electricity regulator has cited this as a cause of high fuel costs in Italy. In competitive systems, the incentive for better use of fuel comes from the utility's diminished ability to pass fuel costs directly on to electricity consumers.

Reducing fuel costs does not mean the blind search for higher fuel efficiency, a purely technical measure, but is the result of combining technical improvements with commercial measures, such as improved contracting strategies and partnerships with fuel suppliers. The most relevant areas of technology are efficiency improvements of all types, process control systems, and those enabling fuel flexibility.

Plant efficiency and process control

Steam turbine and steam cycle technologies are the focus of many efforts to improve the performance of existing power plants. Turbine efficiency increases of 1% to 10% are commonly attainable, leading to plant efficiency gains of several percentage points. Many vendors have developed specialised programs to repair, modernise and increase the efficiency of existing steam turbines, while also reducing maintenance costs (Giovando, 1998). Older gas turbines can also benefit from upgrades to process control systems (Valenti, 1999).

Upgraded or new process control systems for old plants can greatly improve fuel efficiency. Digital control systems are well suited to feed constantly monitored control variables into a computer program that evaluates plant efficiency or fuel performance frequently, or even constantly. If fuel efficiency drops, the plant operator or control system can take corrective action. Such real-time efficiency evaluators are nearly standard in new plants and increasingly retrofitted in old plants. Competition will hasten their spread among existing plants.

Such systems can focus on subsystems, including the boiler, steam cycle, turbine system, pollution control systems, or auxiliary systems. Boiler systems can, for example, monitor the cleanliness of boiler tubes to make sure that insulating ash layers do not build up for too long, or that internal deposits do not reduce the boiler's effectiveness. Similarly, condensers can be monitored to detect fouling of their heat transfer surfaces.

Fuel flexibility

Competition will favour options that allow a plant to use a wider variety or grade of fuels, especially low-cost ones. The ability to switch quickly as a result of momentary market changes can enable a plant to reduce fuel costs or to profit by selling unused quantities of contractually available fuel. For existing plants not designed for multi-fuel firing, there are usually limits in combustion and heat-transfer systems which do not allow a great range of fuels to be regularly used without increased operating (non-fuel) costs. However, if there are large annual variations in relative fuel prices between two or more fuels, it may be worthwhile to invest in plant systems to enable them to handle the multiple grades or types of fuels. Quite a number of plants that are (or at least were) multi-fuel capable have been used on a single fuel for many years. A total of 380 GWe capacity of plants in the IEA is capable of using multiple fuels (Table 3). Competition will test whether the current minimal use of multi-fuel firing is a matter of fuel prices or operating inertia.

Table 3
Multi-Fuel Electric Capacity in IEA Regions, 1997 GWe

	Europe	North America	Pacific	Total
solids/gas	8	37	2	47
liquids/solids	45	14	5	63
liquids/gas	45	162	22	229
liquids/solids/gas	18	24	1	43
Total	117	237	29	383

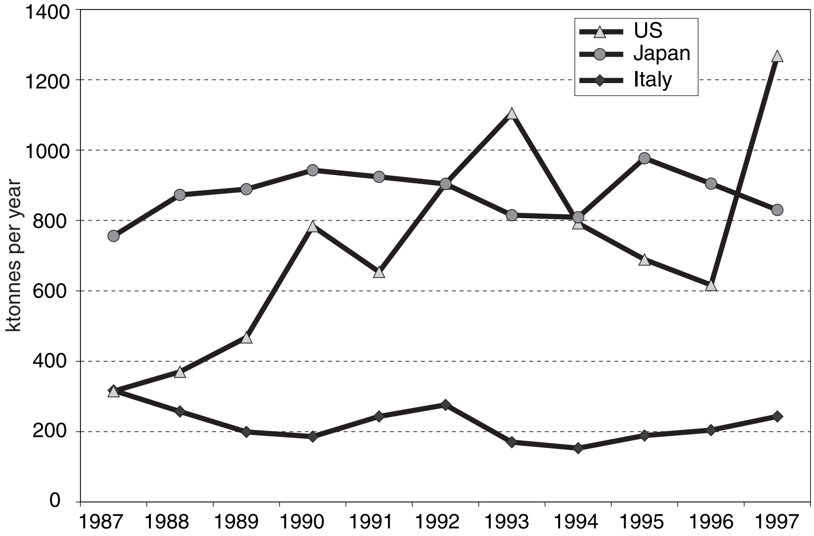
Source: IEA, *Electricity Information 1998.*

Existing power plants can often use fuel of lower quality and cost, but obtaining clear cost savings depends on careful management of equipment, operation, and maintenance for the plant as a whole. Fuel-management software can help to evaluate prices for different fuel supplies and relate them to the economics of the power plant. This is not just a financial assessment, but relates to the technical effects of the different fuel choices on plant operation. Such global evaluations, including technical implications, are important. They can ensure that use of lower cost fuels does not result in higher net costs due to unforeseen plant problems or reduced performance. For example, using a lower quality coal in a power plant boiler may decrease fuel cost, but lead to a lower boiler output or increased maintenance expenses. A careful balance must be made for each plant (Carpenter, 1998).

Plants will increasingly seek out low-cost fuels that can be consumed along with the main fuel without disturbing plant operation. Shredded tires, waste oils, pelletised municipal wastes, waste wood, and many other low-cost feedstocks have been added to power plant fuel streams. Petroleum coke has been a rapidly growing fuel in US coal-fired power plants for this reason (Figure 4).

Figure 4

USE OF PETROLEUM COKE FOR POWER GENERATION IN THE UNITED STATES, JAPAN AND ITALY



Source: IEA.

Emulsified heavy oils could be of commercial interest in some cases where the heavy oil is not used locally for power production, and must be transported over some distance to reach power plants. This could be the case for refiners seeking to dispose of residuals but who do not wish to develop a power project themselves (CE, 1998). It is also the case for Orimulsion, the emulsified natural bitumen marketed by Bitor SA, a subsidiary of the Venezuelan state oil company. Emulsified heavy oils can be handled as heavy fuel oil, and thus can be suitable either in existing oil-fired boilers or new plants.

Solid-fuel upgrading technologies can allow plants to use cheaper fuel while maintaining the quality of plant input fuel. These may not be economically viable for individual power plants, but they could be cost-effective in regional markets where the heavy investment costs can be recovered over large fuel quantities. Coal cleaning, drying and sulphur reduction are possible. Blending of feedstocks of different qualities can lower total fuel costs, and can be attractive if the blender has easy access to international coal markets. Advanced sensors capable of analysing coal characteristics on line are important to upgrading and blending processes.

NEW CAPACITY

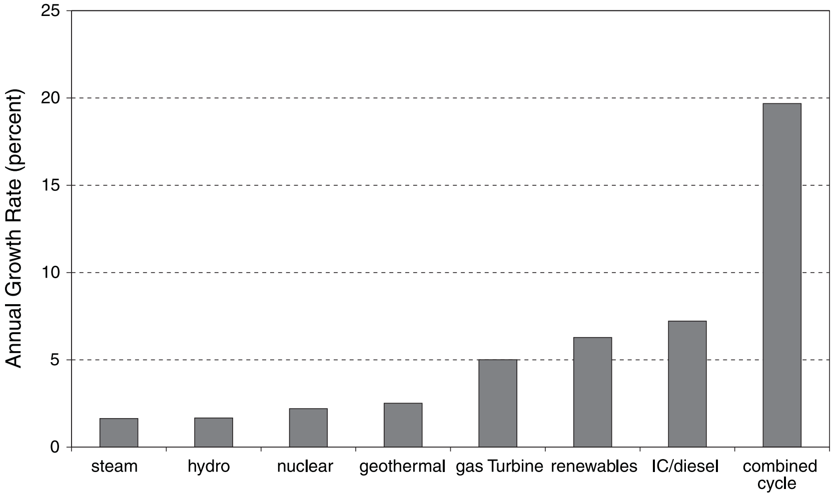
The loss of automatic returns on capital invested in generating plant in competitive markets will compel investors to make a more careful balance of capital versus other costs in decisions on new plants. The tendency to over-engineer or over-size plants will be reduced in competitive markets. Expensive high-efficiency plants must justify the extra capital expense with lower total generation costs. Similarly, under-engineered or shoestring plants will not succeed if they demonstrate low reliability or high operations and maintenance costs. The example of some poorly designed plants built for independent power producers already bears this out.

Today, the mix of capital and fuel costs points to the dominance of gas-fired combined-cycle power plants for new capacity in regions where pipeline natural gas is available. However, conventional steam technology will still have a place in competitive markets. Plants able to provide a hedge against increases in fuel price, those able to use low-value fuels, technologies suited to the requirements of co-generators and other distributed generators, and those able to be put in place quickly are all well positioned for competitive electricity markets.

Gas turbines dominate technology development

Since 1990, one third of new net capacity in the OECD has been provided by gas turbines or combined-cycle gas turbines (CCGTs) fired on natural gas. Combined-cycle gas turbines have had the highest average annual growth rate for capacity additions of any technology – 20% (Figure 5). Gas turbines (also called "simple-cycle gas turbines" or "combustion turbines") are most economic when used for meeting variable load, while CCGTs are suitable for high utilisation rates. The strength of gas turbines has been their low expected generation costs, given today's prices for pipeline natural gas.

Figure 5
ANNUAL GROWTH RATE OF OECD POWER GENERATION TECHNOLOGIES, 1990 TO 1997



Source: IEA, *Electricity Information 1998.*
Note: IC is internal combustion.

Turbines have developed along two main lines:

- aeroderivative turbines characterised by smaller unit capacity, low weight and high simple-cycle efficiency
- heavy-duty turbines optimised for stationary power generation and better suited to combined-cycle operation

Gas-turbine technology developed rapidly in the 1980s as a result of concentrated programs of military jet engine development and the end of policies restricting natural gas use for power generation. Competition between gas turbine manufacturers has sustained further technical development. The distinctions between aeroderivative engines and heavy-duty engines are lessening over time, as key advances are incorporated in both. There are many promising and realistic avenues for improving the economic performance of gas-turbine power plants.

Efficiency has been improved steadily by increasing combustion temperatures. Designers have developed new combustion techniques, better cooling technologies and materials able to withstand the higher temperatures. Simple-cycle efficiency ranges from 30% to nearly 40% (using lower heating value) for high-performance aeroderivative units. Many manufacturers are expecting efficiencies of over 40% in units currently under development (Burr, 1998). Units with high efficiency require the use of natural gas or distillate oils to avoid fouling the turbine, but lower-efficiency units can use heavier petroleum oils, at the cost of increased maintenance.

For peaking and mid-range duty, simple-cycle gas turbines are very attractive. Capital costs range from 300 to 600 $/kWe, maintenance can be inexpensive, and few operating staff are required. The short construction times and low capital cost of simple-cycle gas turbines make them well suited for peaking applications. For higher-efficiency units, gas turbines can still be attractive up to 4400 hours per year (50% utilisation rate). There is a wide range of gas turbine sizes available, from so-called “micro-turbines” of less than 100 kWe capacity, to heavy-duty industrial turbines of over 200 MWe.

For operation at intermediate and baseload utilisation, combined cycles are more economic. The exhaust heat of the gas turbine is captured to raise steam and drive a steam turbine. Combined-cycle efficiencies are typically 50% today, and 55% for plants using large, heavy-duty turbines. Gas turbine models under development are approaching 60%. CCGT plants have the highest efficiency of any fossil power plant today.

The recent OECD study on costs of generation confirms the strong economics of gas-fired combined cycles for baseload power generation in many countries of the world (Paffenbarger and Bertel, 1998). Of the 18 countries providing estimates for two or more baseload options, gas-fired combined-cycles were the cheapest option in eleven countries at a 10% discount rate. Considering only those cases where there is an estimated difference in the cost of electricity of 10% or more between competing options, nine out of 10 countries show CCGTs to be the most economic option at 10% discount rate. The average capital cost of CCGTs reported in the study is half that of coal-fired plants and just one third that of nuclear plants (Table 4). Time needed to construct combined cycle plants is also substantially less than other baseload options.

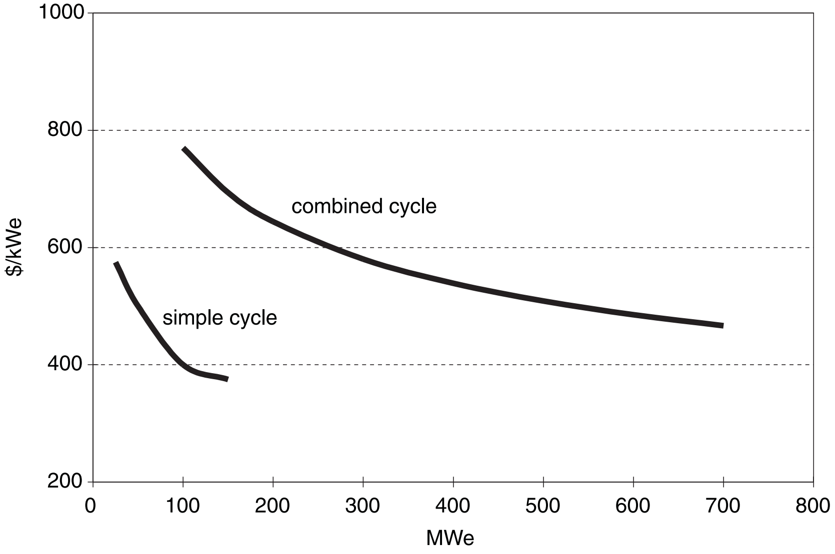
Table 4
Average Values of Plant Size, Capital Cost, and Construction Expenditure Schedule Length, OECD Generating Cost Study

Plant Type	Plant Size (MWe)	Capital Cost (US$/kWe)	Schedule Length (years)
combined-cycle gas turbine	530	700	4.4
coal-fired	750	1350	5.6
nuclear	1240	1900	6.6

Source: OECD, 1998.
Note: Averages are rounded and reflect OECD plants only. Capital cost is without interest, contingency or major refurbishment.

There are classic economies of scale in turbine efficiency and cost, with the large units generally having higher efficiencies and costing less per unit capacity (Figure 6). The small size of gas turbines allows major plant sections to be standardised and pre-fabricated. Standard plant designs that can be adapted at minimal cost to most sites are widely available. They reduce the time to engineer plants and reduce total plant cost (MPS, 1997).

Figure 6
INSTALLED CAPITAL COST OF GAS TURBINE POWER PLANTS



Sources: Garrity and Stoll, 1994; IEA.
Notes: Actual costs depend on many plant-specific factors. Figures are indicative only.

There are numerous improvements to combined cycles under development or already in commercial operation, including:

- humid air turbines (HAT)
- cascaded humidified-air turbines (CHAT)
- direct injection of steam into the gas turbine (STIG)
- heat recovery using endothermal reforming plus steam injection (CHRISTIG)
- heat recovery using an ammonia-water working fluid (Kalina Cycle)

Improvements in gas-turbine cycles are not limited to systems running on natural gas or even fossil fuels. Gasification can convert fossil fuels, biomass, and other feedstocks into combustible gas suitable for use in gas turbines. There have been many modern coal gasification demonstration plants since Coolwater was built in the early 1980s. All the major gas turbine manufacturers are aware of the potential importance of coal gasification and biomass gasification. If some manufacturers have not specifically adapted turbine hardware, all have a strategy for optimising their turbines for use with fuel gas other than natural gas. General Electric is carrying out a project called Biomass Integrated Gasification – Gas Turbine to verify the suitability of their LM2500 for use with fuel gas derived from the gasification of biomass (GE, 1997). ABB and Westinghouse are participating in biomass gasification programmes sponsored by the US Department of Energy.

There have been reliability problems in some of the latest heavy-duty industrial turbines, although these now seem to have been overcome. Breakdowns of systems in operation have made the actual economics look less attractive than some projections. These problems highlight the dangers facing the rapid adoption of new technologies. While they may temper enthusiasm for incorporating the latest advances and encourage plant developers to make adequate allowances for possible failures, they do not call into question the basic attractiveness of gas-turbine technology.

In summary, gas-turbine based power plants are today already highly competitive in many markets around the world. They come in a wide range of sizes suited to low and high growth rates in electricity markets, as well as industrial autoproducers. Continuing and real improvements in gas turbine and combined-cycle plants are likely to improve their economics further in the next decade. Competitive electricity markets are expected to rely heavily on gas turbines.

Still a place for conventional steam power plants, but nuclear struggles

Gas-turbine power plants are attractive in many markets, but there remain opportunities for conventional steam power plants. Coal-fired steam boiler plants can be competitive for baseload generation where low-cost coal is available. Oil-fired boilers remain competitive in isolated or small systems, or in areas without access to other fuels. Steam boilers fired on natural gas are likely to be built only rarely because simple-cycle gas turbines fired on natural gas are more efficient, are less expensive and quicker to build, and cost less to operate.

In the past decade, prices of conventional steam power plants have dropped substantially (in real terms) due to competition among equipment manufacturers and pressure from independent power producers. Steam power plants have reached a plateau of technological development that make further substantial changes in their economic competitiveness appear unlikely in the near future. The main trade-off of enhanced steam technologies is one of lower fuel costs against higher capital cost. Supercritical boilers with multiple reheats provide high efficiency, and have been used in coal-fired power plants in countries with high fuel cost or low cost of capital. Subcritical boilers have been prevalent in countries with cheaper coal (Couch, 1997). The best economic performance in coal-fired plants has been obtained in unit sizes of 500 MWe or higher because of economies of scale. A substantial challenge is to obtain good economic performance in smaller unit sizes suited to the low demand growth typical of OECD countries.

Nuclear technology is mature, and where fossil-fuel costs are high, it holds a potential advantage. However, today it is generally judged to be non-competitive in most countries. Except in France, Japan, and Korea, there has been no recent experience on which to base confidence in economic assessments of new nuclear plants. The main hurdles for such plants are high capital cost, uncertain costs for waste disposal and dismantling and, importantly, a political environment generally hostile to nuclear plant development.

There are advanced, pre-approved designs available for nuclear plants, including the System 80+, the Advanced Boiling Water Reactor, the European Pressurised Water Reactor, the AP600, and others. However, some experts consider these designs to be dated because they do not place adequate emphasis on cost-effectiveness. The European reactor design effort builds on successful French designs and relies heavily on standardisation and economies of scale to reach its economic performance targets. At 1500 MWe, the European Pressurised Water Reactor is enormous. It may be difficult to fit in utility grids in the OECD unless it replaces retiring coal or nuclear installations. The Advanced Boiling Water Reactor and System 80+ are also large plants. In contrast, the AP600 design attacks high nuclear costs through a systematic attempt to simplify systems and seek safety through simplification rather than through the use of engineered systems. A recent South African effort to revive the modular high-temperature gas-cooled reactor is interesting and goes in the same direction of design simplification and the avoidance of engineered safety systems. The design leap to innovative, smaller nuclear plants may be too great for utilities in competitive markets to try, even if the economics appear attractive and political conditions allow it.

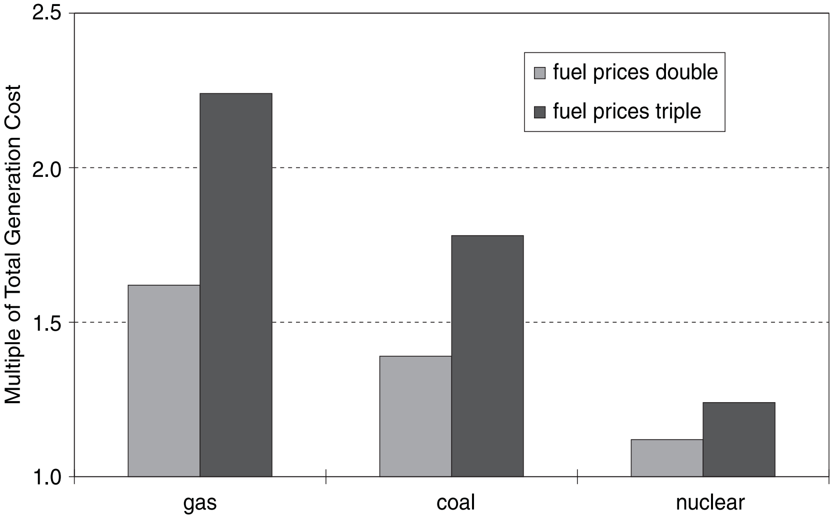
One strength of nuclear power is its insensitivity to increases in fossil fuel prices. Another is its absence of gaseous emissions. Either feature could make nuclear power an unexpected entrant in competitive markets if there are substantial changes in fuel prices or environmental policies.

Insurance against fuel price increases

Power generation using gas turbines fired on natural gas is very competitive at today's prices for natural gas. However, total generation costs in CCGT plants are more sensitive to increases in fuel prices than they are in other generation technologies. Fuel costs account for 60% to 75% of total generation cost, whereas in plants powered by renewables, nuclear or coal the share of fuel in total cost ranges from zero to 40%. Consequently, equal increases in the prices of different fuels for electricity generation would have a more serious impact on the economics of CCGTs than they would have on other technologies (Figure 7). The rapid development of natural gas-fired power generation could strain gas production and transmission systems and lead to gas price increases. The rapid growth in gas-fired power generation might lead utilities to seek hedges against fuel price increases.

Figure 7

EFFECT OF FUEL PRICE INCREASES ON COST OF ELECTRICITY



Source: IEA.

Note: Estimates based upon data from OECD generating cost study. Base cost of electricity is at 10% discount rate.

To hedge against short-term price increases, gas turbines can be fitted with multi-fuel burners allowing the combustion of clean liquid fuels. But to insure against long-term price increases, an alternate, low-cost fuel is the only real hedge for an existing plant. Gasification of coal or heavy oils could be one such hedge. Although the performance of a CCGT designed for natural gas may not be optimum when fired on a synthetic natural gas, that solution could preserve the plant investment. A practical near-term insurance policy against long-term natural gas price increases could be to leave the room available on the plant site for the later addition of a gasification facility. This approach has already been taken, and it may be given more attention if natural gas price increases appear likely.

Low-value fuels

Generators will increasingly search out low-cost fuels from the "energy junkyard" outside dominant energy markets. Such fuels include refinery residuals, emulsified heavy oils, poor quality coals, coal-mine tailings, coal-washery wastes, automobile tires, and biomass wastes. New power plants designed to use low-cost fuels enjoy an advantage in low marginal cost and have some protection against fluctuations in the prices of the major fossil fuels. The disadvantage is that the use of inexpensive fuels in new power plants almost invariably requires sophisticated technology to meet environmental protection regulations.

Fluidised bed combustion and gasification are the two dominant technologies that can use low-cost fuels for power production. Fluidised bed boilers burn fuels in a fine bed of solid material (ash or sand) in which a sorbent is added to capture sulphur compounds in solid form. These boilers produce steam for use in a conventional steam cycle. There has been a substantial effort to develop high-temperature particulate filters and gas cleanup systems that would allow fluidised bed combustors to be used in tandem with gas turbines, but such systems are not likely to be commercially viable for some time.

Gasification is the only commercially available technology that can transform low-value fuels to a gas that can be used in modern combustion turbines. Furthermore, it can simultaneously provide a feedstock for other processes such as methanol synthesis or hydrogen production. Coal gasification providing fuel gas for combined-cycle power production (GCC) has benefited from two decades of subsidised development. Many large coal gasification plants for utility power production have been built and, for the most part, operated successfully. A key feature for the future of gasification is its ability to reach high levels of environmental performance (low sulphur and particulate emissions; inert solid wastes) with only minimal increases in cost.

Although coal GCC plants have been under development since the 1970s, the cost of the electricity they produce is usually estimated to be more expensive than from conventional pulverised coal plants. However, a low-cost fuel can reduce total production costs sufficiently to enable GCC plants to compete with both coal and natural gas-fired plants. For this reason, GCC power production using refinery residuals is an area of significant activity today. As of mid-1999, the SFA Pacific world-wide gasification database counted under active development 10 projects using petroleum feedstocks (Childress, 1999). Table 5 lists a number of current gasification projects using refinery residuals. Electricité de France estimates there is 130 GWe of potential from refinery residues around the world (UE, 1998). Gasification of refinery residuals and other low-cost fuels is likely to grow in importance in competitive electricity markets.

The shift in petroleum product demand from heavier to lighter products contributes to this trend. Increasing demand for low-sulphur products in transportation is the main cause of this shift. To meet the changing demand mix, refiners have made investments in refinery capacity to upgrade or convert heavy residues to light products. The fraction of residues converted varies by market according to the overall product demand mix, but as residual oil accounts for less and less of total demand, conversion processes have become increasingly expensive. Gasification provides an opportunity to refiners to find an outlet for residues and, at the same time, to enter competitive power markets.

Table 5
Selected Gasification Projects using Refinery Residuals

Project	Country	Fuel	MWe	Year	Application (in addition to power)
El Dorado	USA	petcoke	40	1996	hazardous waste disposal
Pernis	Netherlands	vacuum distillate	127	1997	hydrogen production
Puertollano	Spain	coal + coke	300	1997	
Priolo Gargallo	Italy	visbreaker tar	500	1999	co-generation
Falconara	Italy	visbreaker tar	240	1999	co-generation
Sarlux	Italy	residues	550	1999	co-generation, hydrogen
Delaware City	USA	petcoke	160	2001	
Muskiz	Spain	residues	900	2003	
Gonfreville	France	residues	365	2003	co-generation, hydrogen
Negishi	Japan	residual oil	430	2003	

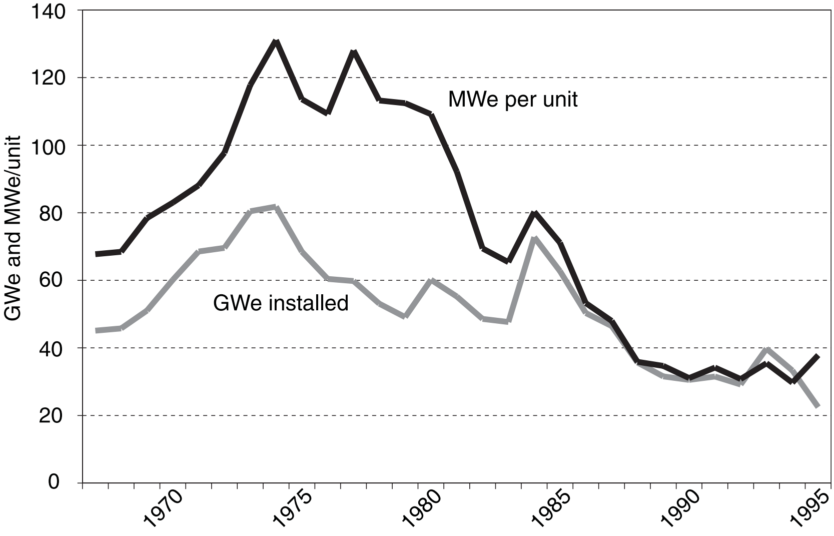
Source: IEA.

Size of new capacity

One traditional approach to reducing cost of electricity has been to pursue economies of scale in power plant construction. Conventional boilers and nuclear reactors commonly reached unit sizes of over 1000 MWe in the 1970s and 1980s. Economies of scale can still be achieved, but OECD electricity markets, with few exceptions, are not growing fast enough to accommodate large plants as easily as they did in the past. Large plants can take many years to reach full utilisation. Since the mid 1970s, both the total annual capacity additions and the average unit sizes of OECD power plants have been dropping (Figure 8).

Figure 8

ELECTRICITY CAPACITY ADDITIONS AND AVERAGE UNIT SIZE IN OECD COUNTRIES, 1967 TO 1995



Source: IEA, using the UDI power plant database.

Competitive markets will favour plant sizes better matched to expected load growth. Plant sizes will remain closer to the equivalent annual load growth of just a few years rather than 10 or 15 years. This provides a better match with financial risks. It also reduces the reserve margin needed to guard against the loss of large units. This will tend to minimise total investment costs within a given market.

Gas-turbine power plants are favoured by this expected tendency, because their economies of scale are obtained at lower unit capacities: hundreds of megawatts rather than thousands (see Figure 6). Competitive markets will put pressure on manufacturers to seek the same economic performance in smaller total plant sizes.

Distributed generation

Many observers predict an increasing share of distributed generation in competitive electricity markets. Distributed generation is generation that is produced in units close in size and location to specific loads. This approach is not likely to be used to replace central station plants, but it could respond to particular needs within competitive markets. Possible growth applications for distributed generation are:

- industrial co-generation
- support for network operation (provision of ancillary services)
- insurance against power outages (standby power)
- avoidance of high electricity prices during periods of peak demand
- overcoming power transmission bottlenecks
- applications requiring high power quality

The real potential for distributed generation is difficult to assess, but any growth will be based on the ability of small generating units to beat central station economies of scale, plus transmission costs. The key variables are per-unit capital costs and non-fuel operating costs, because efficiencies can approach those of larger generating units. A suitably priced fuel, not too closely tied to electricity generation, must also be available. For example, the ability of a distributed generator to avoid peak electricity prices depends on the availability of fuel during that period. A small generator might not be able to negotiate a suitable fuel price applicable when large power stations are consuming large quantities of the same fuel for peak production. Distributed generating units must also have acceptable environmental performance.

A number of technologies are in a position to compete with central-station generation. Industrial co-generation is probably the largest potential area of growth for distributed power generation. Gas turbines, small CCGTs, and industrial combustion engines have already proven their merit in industrial co-generation applications. Turbine and engine manufacturers have been intensifying their efforts to produce small, economic generation packages for distributed generation (Bray, 1999; Makanski, 1999). Natural gas or clean distillate petroleum fuels are generally the energy sources for these because they do not require expensive emissions control equipment.

Fuel cells running on natural gas may improve the chances of distributed generation markets in coming years. Their small physical size, simplicity of operation, modularity and environmental acceptability are well suited to distributed generation. However, they are not yet cost-competitive except in specialised situations such as military uses. Some developers hope to improve the economics of fuel cells by commercialising small units suited to domestic use. Mass production could help to lower costs for this market. A very attractive technical concept is that of a fuel cell/gas-turbine combined cycle. It would use a high-temperature, solid oxide fuel cell in combination with a gas turbine and natural gas reforming heat recovery to obtain plant efficiencies of over 70% (MPS, 1998).

There are likely to be opportunities for renewable energy technologies in distributed generation. Remote sites with limited or no access to a central transmission network can sometimes take advantage of renewable energy sources because of the high cost of fossil fuel transport or of extending transmission lines. Power plants fuelled on biomass already have the largest share of non-hydroelectric renewable generation in OECD countries, typically in industrial co-generation facilities, and small generators will seek additional opportunities to take advantage of electricity sales outside of their industrial facilities. Low-cost biomass fuels such as bagasse, straw, nut shells, cotton ginning wastes and other agricultural wastes may find higher value outlets in newly liberalised electricity markets than in existing disposal routes.

Speed of delivering new capacity

Providing capacity quickly may be more important in competitive markets for several reasons:

- uncertainty generated by the transition to competitive markets can delay decisions about new capacity
- rapid capacity additions are offered as a special service for large customers
- capacity is added due to the delay or absence of grid extension
- capacity is added to defer grid upgrades
- temporary capacity is added as a bridge to larger capacity additions

If there is a shortage of electricity supply for any reason, new capacity that is placed in service most quickly will be able to reap the advantage of higher electricity prices in the short term.

Technologies adaptable to pre-packaging, modularity or rapid construction will have an edge in such situations. Although the cost of electricity is important, speed of provision is the primary consideration here. Suitable technologies are generally the same as those for distributed generation:

- gas turbines
- internal combustion engines
- plants fuelled on natural gas or clean petroleum fuels

Steam boiler plants are less suitable because of their greater bulk, higher capital cost and lower efficiency.

Barge-mounted power plants are already well established commercially. They have been used largely outside the OECD area to meet rapid demand growth and to facilitate financing[1]. Barges with combined-cycle power plants of 100 to 200 MWe have been built. Both diesel plants and gas turbines are amenable to such packaging. Plants fuelled on petroleum products will be valuable because they do not depend on the availability of natural gas.

It is possible that the use of temporary rental capacity could grow. Rental capacity already exists for temporary needs such as construction, environmental cleanup projects, and minerals prospecting. The Caterpillar company has a 600 MWe rental fleet in the United States. In June 1999 the General Electric company created a new subsidiary to rent temporary generation capacity and other electrical equipment.

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[1] If the original electricity purchaser is unable to pay, the barge can be moved elsewhere to earn revenue and pay off its debt.

ENVIRONMENTAL PROTECTION TECHNOLOGY AND RENEWABLES

Environmental protection technology

Changes in environmental regulation are taking place in parallel with the introduction of competitive electricity markets and will have a profound effect on technology choices. Environmental protection systems are a significant factor in electricity generating cost, accounting for 10% to 40% in fossil fuelled plants and even higher fractions in nuclear plants (OECD, 1998: Annex 6). In competitive electricity markets, environmental protection technologies cannot be chosen without regard for their impact on plant costs.

Increasingly, environmental regulations require existing plants to reduce their emissions. The revision of the Large Combustion Plant Directive in the European Union could require the addition of scrubbers to some fossil plants. Phase II of the revised US Clean Air Act requires old plants to reduce emissions. The existing fleet of sulphur control systems in OECD countries dates largely from the 1980s. There have been many improvements in scrubbers over the last 20 years and these new technologies will face tougher economic scrutiny under competitive markets than in the past. Smaller systems that can fit on existing sites and systems consuming less power will have an advantage. If retroactive limits on sulphur emissions are less than 65%, simple furnace sorbent injection systems may be adequate. Spray dryer systems can also be effective to meet moderate sulphur removal requirements. However, these simpler systems are likely to face a limited future. High-efficiency scrubbers with lower installation and operating costs will be important to the future of coal and oil-fired systems. Finding the most cost-effective systems for meeting retrofit requirement will be vital to enable existing plants to continue operating.

In new plants, the generation technology chosen will depend critically on total generation costs including pollution control. Natural-gas-fired plants have an advantage because no sulphur or particulate control systems are required, nor are systems for the control of nitrogen oxides in many jurisdictions. For coal-fired plants, when emissions control limits require sulphur removal to exceed 95 to 98%, coal gasification combined-cycle plants become increasingly competitive compared to conventional pulverised coal plants with scrubbers. Control costs for GCC plants are less sensitive to airborne emissions limits because the small stream of fuelgas is cleaned before combustion.

At present, many environmental performance laws are tailored to specific technologies. Under pressure from competing generators to remove technology bias, governments may revise environmental regulations to become more technology-neutral. This will reduce the tendency to accord specific technologies a statutory preference, as is the case under regulatory practices known as "best available control technology" or "best available technology not entailing excessive cost." Environmental limits will increasingly be the same for all generators, and the trend toward market-based approaches to environmental regulation will be boosted.

The biggest wildcard in the evolution of environmental regulation is control of emissions of carbon dioxide to respond to concerns about climate change. Power generation would be strongly affected by limits on carbon dioxide production. Technologies able to generate electricity with lower or zero emissions of carbon dioxide could receive an economic benefit whose size depends on the severity of the limits.

Advocates of coal technology see high-efficiency coal-fired power generation as a means to meet restrictions on carbon dioxide, and this technological path does contribute incrementally to real reductions in carbon dioxide emissions. Though none are apparent today, cost-effective technologies to capture and sequestrate carbon dioxide from power plants could preserve coal's future in the face of carbon dioxide restrictions. GCC is the generation technology most likely to allow carbon sequestration to compete with the use of less carbon-intensive fuels (Simbeck, 1998). However, a change in fuel mix towards less carbon-intensive fuels is likely to be the most economic means of reducing carbon dioxide emissions. Carbon-free generation technologies such as nuclear power and renewables could become much more competitive compared to fossil-based sources.

Renewables

Competitive electricity markets pose a unique challenge to renewable energy technology. Today renewables are rarely the cheapest technologies to produce electricity, yet there is a tremendous public and government interest in them for their apparent environmental advantages. The challenge is to leverage this existing support, often expressed in clear financial terms, to improve the economic performance of renewable energy technology and to ultimately make it competitive with conventional technologies.

It seems likely that competition will help to speed innovations in renewable energy technology because of a heightened awareness by generators of the potential competitive advantages obtainable from renewable energy projects. The stereotypical monopoly utility might view renewable energy projects primarily as a “public relations” asset, since returns on such projects are no different than on any other project. Profit would be based on a regulatory formula tied to invested capital and operating expenses (net of public support, if any), as for any other project. Renewable energy projects might be seen as inconvenient, since they are generally small and require different skills to maintain and operate than those called for in conventional power plants. Hence, the monopoly utility might not pursue renewable projects with much enthusiasm. In contrast, competitive markets give new opportunities to those most interested in promoting renewable energy and they also make traditional utilities more aware of the financial potential of renewable energy projects. Developers specialising in renewables will be keenly aware of the financial and market opportunities offered by support policies. Small developers would also manage the small projects with proportionally greater attention than might do very large generating companies, in which small power projects are almost invisible compared to huge baseload fossil or nuclear plants.

Competition reinforces the importance of differentiating products apart from price. Some consumers see electricity from renewable energy plants as a product worth a premium price, and this provides a potential source of revenue unavailable to other competitors. So-called “green pricing” programmes will test the size of this potential advantage.

Many governments have recognised the advantages of making environmental protection policies compatible with competitive markets. Market-based methods of supporting renewable energy projects are often introduced in parallel with electricity market reform. These methods include “green certificates” and “green electricity markets” that operate in parallel with the ordinary market. In the first, a market for green certificates is created by regulation, and qualifying plants are allowed to sell these certificates. In the second, electricity consumers are required to purchase a certain fraction of their electricity from the green electricity market, on which renewable or other qualifying power plants compete on the basis of price. Both approaches provide greater incentives for renewable energy projects to improve economic performance than under systems in which utilities were required to purchase the output of any renewable project of specified technology, regardless of price, availability, or other commercial constraints.

It is difficult to identify which renewable energy technologies will gain the most from competitive markets. Wind power has shown the most rapid growth in recent years in many countries, in part because it is already among the most economic of renewable energy technologies. Wind turbine sizes have been increasing in parallel with decreasing operating costs, and various improvements to generators, airfoils, and electronic controls have helped to decrease costs. The rapid growth in capacity has decreased per-unit manufacturing costs as well. Entirely new technologies beyond horizontal-axis wind turbines are also under development, such as diffuser-augmented wind turbines and the wind-amplified rotor platform system.

As noted earlier, biomass projects, particularly in industrial co-generation, may be able to take advantage of the change to competitive markets. Large farming operations have a new opportunity to generate revenue from animal wastes using anaerobic digestion to produce methane. The economics of power production are helped by increasingly stringent limitations on pollution from animal wastes. Technology using municipal waste as the energy source may be able to leverage increasing pressures on landfill space in parallel with greater opportunities for selling electricity. Waste incineration and landfill gas combustion are the leading contestants. Small hydroelectric plants could be helped because there are many existing sites where low-head hydropower was used in industrial or small electric plants in the late 1800s and early 1900s. Small run-of-river hydroelectric plants can be refitted at such sites.

TRANSMISSION

Electric utilities have not had a strong need to determine the true costs of transmission. The allocation of investment and operating costs to factors according to geographical distribution of generation or demand at any moment were theoretical questions with little practical consequence for the vertically integrated utility. In competitive environments, however, system operators will at least wish to better understand the cost structure of their single business. Depending on the regulations for allocating transmission costs to generators and consumers, they will be under pressure to go beyond this and reduce them.

Grid operators will face more complicated operating conditions as markets demand power to flow in different patterns. The grid will be asked to cope with larger power transfers over greater distances. Transmission system operators will have to control the greater power flows while maintaining voltage levels and ensuring system stability. Electricity transmission constraints will appear in existing grids due to the new, unplanned patterns of operation brought about by competition. Yet building new transmission lines to remove these constraints can rarely be done quickly because of the acute difficulty of obtaining rights of way.

Control components

Improved technologies to control and monitor power flow are essential under competition because of the increased complexity of directing power to where it is needed. Existing control components of transmission systems are mostly electromechanical. Their speed is limited by the mechanical speed of their component parts. New types of transmission controls use solid-state electronics that can respond very quickly – faster than individual voltage cycles on 50 or 60 Hertz systems. They can react almost instantaneously to counteract transmission disturbances, improve system stability and provide faster protection against fault conditions. Such electronic controls are better at maintaining smooth voltage and, unlike electromechanical devices, can direct power flow by rapidly compensating for loads. Key components are static condensers, static compensators, gate thyristors, and the control software that makes their use possible.

The use of such components can allow greater loads on existing transmission lines and reduce the need for new lines. They can help reduce power losses. Solid-state electronic control devices are likely to grow in importance in competitive electricity markets.

The US Electric Power Research Institute has developed a number of such components under its Flexible AC Transmission System (FACTS) program. The Electric Power Research Institute and Westinghouse dedicated the first "Unified Power Flow Controller" station in June 1998. It is capable of simultaneously controlling the three basic transmission system parameters (voltage, line impedance, and phase angle) in order to control power flow on different lines. Major electrical equipment manufacturers are also developing solid-state electronic control hardware.

Power transmission

Technologies relating to the high-voltage cables and towers that enable capacity upgrades on existing rights of way are also likely to become important. Although these components are simple, there is still room to reduce costs with new technologies.

In new transmission lines, covered (insulated) conductors on high-voltage lines could reduce the size of required right of way, lessen tower height and bulk and reduce line failures when cables accidentally touch (Leskinen et al, 1998). Although covered conductors are double the price of standard bare wires, overall transmission costs may be lower in urban areas. A 110 kV test line 6 km long has been operating in Finland since 1996. Critical transmission constraints over short distances might be eliminated through upgrades with covered conductors.

Transmission-line towers made of plastic composites could help to reduce costs. Although the material costs more than traditional steel towers, they are cheaper to transport and easier to assemble on site (Brown, 1999). Because the tower structure is insulating, cables may be strung closer together and a narrower path may be used. Existing rights of way such as along railroad lines can be wide enough to accommodate high-capacity lines.

Technologies to reduce the cost of underground high-voltage power transmission could also help meet the need for increased transmission capacity in urban areas and environmentally sensitive areas. Superconducting cables, though in a relatively early stage of development, have the potential to triple the current-carrying capacity of existing underground lines. Techniques to reduce installation costs of conventional underground transmission lines could do more to contribute real transmission capacity within the next decade.

Remote monitoring and control can reduce staff operating costs for transmission systems. Substations can be linked to a central operations facility by satellite communications.

The cost of responding to line outages can be reduced by improved techniques for locating faults. Traditional methods of locating line problems involve sending out crews to search along miles of power lines for a break, tracking telephone calls about service interruptions, or examining where meter readings overlap. These methods are labour-intensive and slow. Software analyses of system characteristics, combined with remote sensors, can speed the process of pinpointing problems and reduce costs (Valenti, 1997).

Direct-current power transmission could be boosted by competition in selected competitive markets. Where large bodies of water separate regional markets, direct-current power lines can provide a suitable link. The cost of end stations needed to convert alternating current to direct current and back again has limited the use of direct-current links. The cost of direct-current links will decrease as solid-state power electronics decrease the cost of the end stations. Opportunities to tie newly competitive markets together might hasten the development of direct-current power transfer.

Ancillary services

Most systems where competition has been introduced have assigned the operation of the transmission system to a separate, independent system operator. Ancillary services for maintaining network stability that were formerly provided by a single company possessing both generation and transmission facilities must now be managed by the system operator. These services are voltage support, frequency support, and spinning reserve. The separation of ancillary services from an integrated company may increase the costs of providing them in the short term, but it may also provide opportunities to seek out more cost-effective technologies to provide them.

Spinning reserve remains a generating function since it is just the provision of generating capacity for unforeseen, short-term shortfalls. However, transmission system operators may more aggressively pursue energy storage technologies to meet brief capacity drops until slower moving, and presumably less expensive, generating plants can be brought on line. Power electronics may provide new means of maintaining voltage and frequency without the need for bringing generating capacity on line.

Telecommunications

Owners of transmission and distribution systems have a significant opportunity for additional revenue from the provision of telecommunications services using their existing electricity networks. The simplest means is to allow telecommunications lines to be placed in the network rights of way, either buried or hung on existing towers. However, an intriguing possibility is to use the existing infrastructure of power distribution cables to transport telecommunications signals. The first patent on using power lines for communication signals dates to 1899, so the idea is not new. Advances in technology and the arrival of competition could help to advance the idea (Nunn, 1998).

Two factors suggest that competition will hasten the development of power line communications:

- In competitive systems the control, if not the ownership, of the transmission systems is separated from other electricity supply functions. This separation gives a higher financial profile to incremental revenue associated with telecommunications
- The need for more sophisticated control of the transmission network provides its own motivation for developing the communications system along the network. Technologies used to communicate with transmission equipment, sensors and customer meters could be adapted or expanded to accommodate full-scale telecommunications systems

Power networks are not ideal for data communication because their topology changes as switches open and close, they have many fuses and circuit breakers, and their many transformers isolate different voltage levels from data transfer. Power line communications systems must be designed to overcome these and other obstacles.

Providing Internet access is an attractive potential market for power line telecommunications because it is growing rapidly and demanded everywhere. The Nor.Web company (UK) is currently developing systems to provide Internet access over local distribution areas.

SUMMARY AND CONCLUSIONS

The introduction of competition in electricity market is an established trend in OECD countries and many others. Competition will be a major factor in changing electric power technology. Competitive electricity markets are already transferring risk from consumers to electricity plant owners, who must now evaluate the cost-effectiveness of their technology choices more carefully than in the past.

All areas of electricity technology will be open to scrutiny. Power generation will be a focus of attention because it accounts for over 60% of total electricity cost in most countries. Generation is also the part of electricity supply that, in all market reform programmes, is opened to competition. Transmission systems are typically separated from their vertically integrated owners. This separation concentrates the attention of regulators and transmission system owners on the financial performance of transmission.

Existing power plants have a big advantage in markets that are opened to competition, because they are already in the market. They may have low debt loads and capital expenses. In contrast, companies wishing to develop *new* power plants face many difficulties: finding a location, obtaining all the necessary public permissions and building the plants. The financial risks for even a small power plant can be large. Therefore, owners of existing plants have every advantage to make the best possible use of technologies that improve plant reliability and availability, allow them to increase capacity, lengthen plant lifetime, and increase plant operating flexibility. Technologies to refurbish and improve maintenance in existing plants will be sought. Demand side technologies and energy storage can help improve the capacity utilisation rate of existing plants.

New plants will rely heavily on gas turbines in areas with access to pipeline natural gas. Gas turbines have had the highest growth rate of any generation technology in the past decade thanks to their favourable economics, flexibility, modularity and speed of construction. These characteristics will reinforce the role of gas turbines in competitive markets. Still, there remain ample opportunities for conventional steam technology, especially where low-cost coal is available. Nuclear technology faces a difficult near-term future in new plants, apart from the difficult issue of public acceptability. Substantial changes in fossil fuel prices or environmental policies could change the outlook for new nuclear and other technologies.

There is a danger that over-enthusiasm for gas turbine plants fired on natural gas could create bottlenecks in gas supply, increase gas prices, or weaken security of supply. Generators in competitive markets will, therefore, seek options that provide a hedge against natural gas price increases, such as multi-fuel firing. Generators will also increasingly search out technologies that can use low-cost fuels such as refinery residuals, emulsified heavy oils and coal wastes. In both existing and new plants, improving process control technology will help to minimise fuel costs.

The capacity of new plants will be matched better to the rate of electricity demand growth. Technologies that can be pre-packaged and brought into service quickly will be valued. Many observers predict that distributed generation will be strongly favoured, as it could respond well to particular requirements of competitive markets. It remains to be seen whether distributed technologies such as small gas turbines, internal combustion engines or fuel cells can compete with central station generation and its associated transmission.

Environmental protection technology accounts for a significant fraction of generation cost. Finding the most cost-effective environmental protection systems to be retrofitted could be particularly important as environmental laws become stricter. Measures to limit carbon dioxide emissions would have far-reaching effects on generation technology, favouring high-efficiency fossil-fuelled plants, nuclear, and renewables.

Most transmission systems will remain regulated as monopolies, but will nonetheless be under pressure to make technology improvements. Improved control components will be applied to handle the increased complexity of operation under competitive systems. Solid-state controls and power conditioning equipment are likely to grow in importance. Transmission- system owners will need improved telecommunications with all parts of their networks; they may also seek to provide telecommunications services using existing network infrastructure. Improved conductors, transmission-line towers and underground transmission technologies could help alleviate bottlenecks and reduce the cost of new lines. The separation of ancillary services from the generation function will provide opportunities to seek out better technologies for these services.

The changing requirements of competitive markets provide many opportunities for new technologies to be developed. Old technologies may find new uses or renewed standing. Some of the forces behind these technological changes have been identified in this text. However, as in any competitive market, time will show which technologies wane and which succeed in rising to the challenges of competitive electricity markets.

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