



POLICY ROUNDTABLES

Competition Policy in the Electricity Sector 2002

Introduction

The OECD Competition Committee debated competition policy in the electricity sector in October 2002. This document includes an executive summary and the documents from the meeting: an analytical note by Mr. Darryl Biggar for the OECD, written submissions from Australia, Austria, Belgium, Brazil, Canada, Denmark, the European Commission, France, Germany, Hungary, Ireland, Japan, Korea, Lithuania, the Netherlands, New Zealand, Norway, Poland, Switzerland, Chinese Taipei, the United States, as well as an aide-memoire of the discussion.

Overview

Electricity markets are prone to the exercise of market power due to a combination of factors including: inelastic demand, lack of extensive practical storage of electricity, transmission congestion, transmission loop flows and capacity constraints coupled with diversity in the marginal costs of different types of generators. The level of market power can vary rapidly in time according to changes in transmission congestion and fluctuating load levels.

Given the propensity of the electricity market to market power, horizontal structural separation (or divestiture) of the generation market is a key policy tool. Some structural separation has been carried out, but on a relatively limited scale. But congestion segments electricity markets and contributes to the exercise of generator market power. This effect can provide the incentive for building new generation capacity.

So a balance must be found between providing an incentive to build new generation capacity and the construction of adequate transmission capacity. As long as it is costly to add transmission capacity it is usually not efficient to construct a transmission network capable of handling all power flows without congestion.

Related Topics

Restructuring Public Utilities for Competition (2001)

Recommendation of the Council concerning structural separation in regulated industries (2001)

Competition Policy in the Electricity Sector (1996)

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COMPETITION ISSUES IN THE ELECTRICITY SECTOR

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FOREWORD

This document comprises proceedings in the original languages of a Roundtable on Competition issues in the electricity sector which was held by the Working Party n°2 of the Competition Committee in October 2002.

It is published under the responsibility of the Secretary General of the OECD to bring information on this topic to the attention of a wider audience.

This compilation is one of a series of publications entitled "Competition Policy Roundtables".

PRÉFACE

Ce document rassemble la documentation dans la langue d'origine dans laquelle elle a été soumise, relative à une table ronde sur la concurrence dans le secteur de l'électricité, qui s'est tenue en octobre 2002 dans le cadre du Groupe de Travail n°2 du Comité de la concurrence.

Il est publié sous la responsabilité du Secrétaire général de l'OCDE, afin de porter à la connaissance d'un large public les éléments d'information qui ont été réunis à cette occasion.

Cette compilation fait partie de la série intitulée "Les tables rondes sur la politique de la concurrence".

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EXECUTIVE SUMMARY

By the Secretariat

In the light of the written submissions, the background note and the oral discussion, the following points emerge:

Market Power and Generation

- (1) *Across the OECD countries, experience with electricity industry reform has highlighted that electricity markets are prone to the exercise of market power. This is due to a combination of factors including: inelastic demand, lack of extensive practical storage of electricity, transmission congestion, transmission loop flows and capacity constraints coupled with diversity in the marginal costs of different types of generators. In the presence of capacity constraints conventional measures of concentration such as the HHI may need to be supplemented with additional market power indicators. Since the level of market power can vary rapidly in time according to changes in transmission congestion and fluctuating load levels, analysis of the relevant market and market power may require constructing computer models of the electricity market.*

Although demand in nearly all OECD countries is sufficient to sustain a large number of competing electricity generation facilities, electricity markets are still prone to the exercise of market power. This market power arises from a combination of factors: (a) demand for electricity is almost entirely inelastic, so that withholding even small amounts of output can have a very substantial impact on price; (b) since electricity cannot easily be stored, consumption must be matched by production at all points in time; it is essential to distinguish a separate market for electricity delivered at different times of the day, month or year. (c) when the transmission network is congested, it is essential to distinguish a separate geographic market for electricity in different geographic locations.¹ Some generators may have significant market power in their local area. Other generators may have significant market power because their output is required to alleviate congestion on the transmission network. (d) since generators often differ in their marginal cost, at any given point in time, some generators in the market may be operating at or near their maximum output so that they are unable to respond to an increase in the market price. Even though there are many generators active in producing electricity at any one point in time, if most of those generators are capacity constrained the remaining generators can exercise significant market power.

Other factors may also contribute to enhance market power, such as the fact that the same set of generators meet repeatedly in the same market and may learn to communicate through pricing signals.² Market power can also be present in related markets such as the markets for ancillary services.

As in any market, the presence of market power is harmful for overall efficiency – it distorts short-term production and consumption decisions and, in the longer term induces inefficient investment decisions, such as decisions regarding the location or technology choice of new generation or major electricity consumers. It may also significantly enhance the variability of

electricity spot market prices, undermining the political sustainability of electricity market reforms.

When some generators are capacity constrained the HHI measure of market concentration (which is based on market shares of generators producing in the market at any point in time) will typically give a limited picture of market power, as some incumbent producers may be unable to expand output to offset a reduction in output by some other generator. In this context, the HHI measure should be supplemented by other indicators of market power. Since each segment of time constitutes a separate product market and since the relevant geographic market fluctuates on the basis of demand levels and associated transmission congestion patterns, analysis of the relevant market and market share is complex. “Often, in geographic product market analysis information about transmission congestion in geographic product market analysis is so complex that computer simulations of load flows and prices are the most practical method to access the relevant geographic markets”.³

- (2) *Faced with concerns over market power, policy-makers have taken a variety of different actions to mitigate market power, including improving transmission capacity, capping generators bids, and enhancing the responsiveness of demand to changes in electricity prices. These policies are discussed separately in this summary below. One of the most important responses to market power in the market for electricity generation is structural reform of the generation market. Although there has been attention to structural separation and divestiture in some countries there remains considerable scope for further reducing concentration in generation markets.*

Policy-makers have used a wide-range of tools to address market power in electricity generation markets. These tools can be grouped under the following headings: structural policies (including, especially, reducing the concentration of electricity producers), transmission pricing and investment policies (enhancing the geographic scope of the relevant market), demand-side policies (designed to enhance the elasticity of demand for electricity), policies regarding entry of new generation and policies governing the determination of prices and dispatch in electricity markets (such as caps on generators’ bids, and the use of real-time locational marginal prices). These policies are discussed further in this summary below.

Given the propensity of the electricity market to market power, horizontal structural separation (or divestiture) of the generation market is a key policy tool. Some structural separation has been carried out, but on a relatively limited scale. In New Zealand and the UK, the former state-owned integrated electricity utility was separated into three competing parts.⁴ In Ontario the government entered into a long-term “Market Power Mitigation Agreement” which seeks to progressively reduce the share of total capacity of the incumbent from 90% to under 35% within 10 years of market opening⁵. In Brazil, the privatisation process is accompanied by strict limits on the market share which can be purchased by any one entity. In the US, the state of California required the two largest privately owned utilities to divest half of their thermal generating capacity.

Nevertheless, there remains scope for substantial further horizontal divestiture. The European Commission recognises that “a significant degree of concentration persists in electricity generation in many [EU] Member States”⁶. Of 14 EU member countries (excluding Luxemburg), the capacity share of the three largest generating companies exceeds 50% in 12 countries, and 90% in 5 countries.⁷ As mentioned below, the Commission has often required structural reforms as a condition for approval of mergers. In the US “efforts to undertake broad deconcentration of electric power markets through divestitures have not been implemented.”⁸

Market power in generation could, in principle, be eroded through the creation of new generation capacity. Some countries have experienced a significant addition of new capacity (e.g., the UK), but the scope for new entry varies from one country to another. Where cheap coals supplies are tied up in long-term contracts or where all available hydro sites have been occupied, the scope for new low-cost entry may be limited. Much electricity generation also raises environmental concerns which can prolong and raise the cost of the approval process for a new generation facility. In many countries much of the newly added capacity has been in the form of gas-fired generation. Access to gas supplies is therefore a key factor in promoting new entry in electricity generation.

Transmission

- (3) *The electricity transmission network plays a key role at the heart of the electricity industry, transporting electricity, improving reliability of supply and promoting inter-regional and international trade. Key issues concerning transmission include how to prevent discrimination against third-party generation, how to efficiently price access to the transmission network and how to create incentives for timely and efficient investment in enhancing the transmission network. Of these issues, there is a discernible trend towards imposing stronger forms of separation in an attempt to prevent discrimination. There is also growing acceptance of the need to establish real-time geographically differentiated (nodal) prices reflecting moment-by-moment congestion on the transmission network.*

As long as it is costly to add transmission capacity it is usually⁹ not efficient to construct a transmission network capable of handling all power flows without congestion. But congestion segments electricity markets and contributes to the exercise of generator market power. This effect can be substantial. The Danish submission points out that congestion on the transmission lines connecting Denmark to the rest of the Nord Pool increases the price-cost mark-up (i.e., the Lerner index) in Denmark from 2-4% to around 40-43%, suggesting the exercise of significant market power.

One key issue facing policy-makers is how this congestion should be reflected in the prices charged to generators and end-users for access to the transmission network. In many cases, the price paid for access to the transmission network at a particular location depends only on time-averaged congestion or loss factors (at least within certain regions known as zones). Although this approach provides some locational signals to generators or consumers, it does not provide incentives in real-time for generators and consumers to adjust their supply and demand to reflect moment-by-moment changes in congestion on the transmission network.

It is increasingly being recognised that efficiency is better served by allowing the market to determine different real-time prices for electricity at different locations on the network. The US notes “Although a number of transmission pricing arrangements have been used in the US, there is increasing agreement that nodal, locational marginal pricing represents the best practice available”¹⁰ Although several electricity markets determine different prices for a number of different regions or “zones”, full nodal pricing is in operation in just a few transmission networks in the OECD. For example, in New Zealand an electricity spot price is established at each of 244 grid connection points around the country (for each of the 48 half-hour trading periods of the day). Theoretical arguments have been made that zonal pricing, by averaging prices faced by consumers reduces the responsiveness of demand to the prices at any one node, enhancing the market power of generators at that node. The determination of locational prices is usually carried out by an entity separate from the transmission operator to alleviate concerns that the

transmission operator would use its market power to extract more revenue from differences in the spot price for electricity across different locations.

Under locational pricing of transmission, transactions between a generator and a consumer located in different nodes (or different zones) are exposed to fluctuations in the price of transporting electricity between those nodes. This creates a demand for financial instruments which allow transacting parties to hedge some or all of that risk. Most regions that have adopted some form of nodal (or zonal) pricing have also introduced some kind of hedging instrument such as “financial transmission rights” (or FTRs). Although FTRs differ in their details, they usually allow the holder to a payment which depends on the price difference between two nodes or locations. Various forms of FTRs are in use, for example, in the region known as PJM in the North-East of the USA and between the zones of the NEM in Australia, and are being considered for adoption in New Zealand.

It has been suggested that the price of FTRs could be used as a signal for investment requirements in the transmission network. This possibility is discussed under the next heading below. Concerns have been raised that generators (especially generators in importing regions) could enhance their market power through the purchase of FTRs.¹¹

In many countries the owner of the transmission network also owns generation facilities. In this case there is a real danger that the transmission operator will discriminate against rival generators despite behavioural controls on such discrimination.¹² As the difficulty of using behavioural controls to prevent such discrimination has been recognised, there has been a move towards greater use of structural policies, including various forms of structural separation. In Europe, the accounting separation requirement in the earlier electricity directive is being replaced by a requirement for corporate (or “legal”) separation. In the US “FERC policy toward vertical integration between transmission and generation continues to evolve toward increased separation”. After FERC found that the behavioural rules in orders 888 and 889 were not fully effective, it encouraged the formation of “independent system operators” which place the control (but not the ownership) of the transmission network in the hands of an independent board. More recently, in order to discourage discrimination against competitors in transmission services more effectively, FERC has encouraged the formation of “regional transmission organisations” in all areas of the US.

- (4) *In the medium and long term the success of reforms in the electricity sector will depend on establishing incentives for timely and efficient new investment in transmission. Although nodal prices may provide some information regarding when and where to upgrade the transmission network, creating efficient incentives for investment in transmission remains a largely unresolved issue.*

A fundamental and still largely unresolved question is how to induce efficient and timely expansions and augmentations to the transmission network. Who should have responsibility for selecting augmentation projects, what incentives should be placed on that organisation and how should the projects be funded? If the entity responsible for planning network expansions does not own the transmission network, what are the incentives on that entity to ensure efficient levels of network construction? On the other hand, if the entity responsible for planning network expansions also owns and operates the network, does that entity have an incentive to expand the network in a way which maximises its revenue from operating the network by, for example, enhancing rather than reducing congestion? In New Zealand, for example, the for-profit transmission grid operator has chosen a very conservative expansion policy. As a result, rising

demand has not been met with commensurate transmission investment, leading to the emergence of a number of transmission constraints at peak times.¹³

Some commentators have argued that the information revealed in nodal prices (and reflected in the price of financial transmission rights or “FTRs”) should be used to guide new investment in transmission networks. A few countries (e.g., Australia and the US) allow private (or “merchant”) investment in transmission links to arbitrage the price differences revealed in nodal prices. Several theoretical difficulties have been raised against primary reliance on merchant transmission to expand the network (such as the difficult of internalising the effect of a new link on power flows on other parts of the network or the possible inadequacy of congestion revenues in the presence of increasing returns to scale). Nevertheless, there may be some scope for using the information in nodal prices to guide the decisions of a central planner of the transmission network, especially for projects which have a small effect on overall prices and flows on the network.

The problem of creating the right incentives for expanding the transmission network is even more difficult when responsibility for the transmission network is divided up amongst a number of separate network operators (as in the different states of Australia or across the different countries in Europe). In this case new issues arise such as: Who has responsibility for installing or upgrading interconnection links between regions? What if a contract between a generator and a consumer in two different regions requires augmentation of the electricity network in a third region? Resolving these issues requires a coordinated cross-network response to transmission investment, which may involve the creation of a supra-regional transmission coordination and planning institution.

The construction of new interconnectors creates both winners and losers. Losers have an incentive to oppose a proposed transmission augmentation. “Concerns have been voiced that any individual state would be reluctant to authorise siting of a transmission line or generator that is primarily likely to serve customers in another state. Indeed, states with low electricity costs have indicated that they are reluctant to lose the comparative economic development advantage they have from low-cost power”.¹⁴ In the case of Europe, the European Commission has been pushing for strengthening the transmission links between member states. “There is insufficient interconnection infrastructure between Member States and, where congestion exists, unsatisfactory methods for allocating scarce capacity”.¹⁵

Distribution networks raise similar issues to transmission. In many cases reform of distribution has involved changing its role from both a buyer and distributor of electricity (on behalf of local users) to simply a distributor of electricity, by giving consumers the right to directly choose their own supplier. In the EU this right will be extended to all electricity consumers by 2005. In the US, in which distribution is largely a state (as opposed to a federal) government responsibility, the degree of retail competition varies widely from state to state. At the time of the roundtable, states accounting for about half of the US population had implemented some form of retail competition.

Demand-Side Reform

- (5) *The electricity market is virtually unique in that relatively few end-users pay a price for electricity which depends directly on the wholesale spot price of electricity. As a result, demand is almost entirely inelastic. This significantly increases the impact of the exercise of market*

power. Many commentators have argued for urgent policy action to enhance the price-responsiveness of electricity demand.

Most electricity end-users pay a time-averaged price for electricity. They therefore are completely insulated (at least in the short term) from movements in the wholesale spot price of electricity. These consumers have no incentive to curtail their consumption on days when the price is exceptionally high due to higher-than-average load, transmission congestion, or generation outages. Even a small increase in the elasticity of demand could significantly lower the size of price spikes and the extent of market power enjoyed by generators.

Several commentators have argued for policy action to increase the responsiveness of electricity demand to the market price. The comments of the “Blue Ribbon Panel” advising the California Power Exchange are worth noting in full: “Demand side responsiveness to price is essential to the operation of a restructured market; the promotion of increased efficiency in the use of electricity in the long term, and a much more elastic response to short-term peak prices are clearly essential remedies. ... We cannot refrain ... from emphasising how essential it is, if consumers are to modify their purchasing habits in response to extreme fluctuations in price and by doing so to moderate those fluctuations that they either be offered inducements by their suppliers to permit their use of power to be curtailed or specific appliances to be ripped off for short periods of time by signals from the supplier and/or confront prices that vary with the correspondingly extreme fluctuations in wholesale prices, so that they can be induced to modify their consumption behaviour accordingly.”¹⁶ Confronting consumers with time-varying prices requires devices which measure the quantity of electricity consumed in each time period. Whether or not it is efficient to encourage the use of such devices for even the smallest consumers depends on their cost.

Although some variation in the spot price of electricity is essential for efficiency and inducing new investment (especially in so-called “energy only” markets), extremely high price spikes undermine the political sustainability of energy market reforms and may call into question the liberalisation process.¹⁷ In some cases political desire to insulate retail consumers from price hikes has complicated the reform process. For example, in California the combination of retail price controls and market-based wholesale prices caused the bankruptcy of a major incumbent utility when wholesale prices reached unforeseen levels. In Australia, the New South Wales government has sought to insulate consumers from wholesale price movements by establishing a fund designed to dampen retail price fluctuations.

Other Elements of Market Design

- (6) *Many other features of the design of the electricity market can affect the overall outcome, including the propensity for market power. For example, electricity markets in OECD countries differ in the number of time periods in a day, or in the period before dispatch in which bids cannot be changed. It is also common to regulate in some way the market price or the bids that can be submitted, for example, through bid caps.*

Most wholesale electricity markets are not comprised of a single spot market but a series of inter-related markets. In particular, there is usually some form of day-ahead market (which may determine an official or reference price) as well as a real-time or balancing market. In addition, there are often markets for ancillary services (such as the provision of reactive power, frequency support or operating reserves). Some regions also have a separate market for the provision of

capacity. As already mentioned, some generators may be able to exercise market power in these related markets.

Different regions also differ in the number of time periods in which a spot price is determined over the course of the day, how far in ahead bids must be submitted, and how often and how much bids can be changed before dispatch. In the wholesale electricity market in Ontario, for instance, participants submit offers or bids for each hour of the day one day ahead. Offers can be fully revised up to four hours ahead of dispatch and by at most 10% up to two hours before dispatch. In contrast, in Australia participants may change their bids with virtually no restrictions up until the moment of dispatch.

It is common to impose controls on the market price. For example, virtually all wholesale markets place a cap on the maximum possible wholesale price (usually known as the Value of Lost Load or VoLL). Some markets have other forms of price controls. In the US, for example, only generators which can pass the market power screen are allowed to set market-based rates. For the remaining generators (i.e., those which have market power) FERC has legislative authority to establish rates that are 'just and reasonable'.¹⁸ FERC's most recent proposals for a "Standard Market Design" (or SMD) include bid caps, overall safety-net bid caps and triggered area-wide bid caps. In addition, FERC's SMD proposals include penalties for withholding capacity and investigations of unscheduled withdrawals of capacity.

Experience with the markets in the UK and California highlighted how flawed market rules can facilitate market power. In the UK the capacity charge (under the previous market rules) increased the profitability of strategic withholding of capacity. In the case of California, "Analysis of the market rules affecting California during the period of high prices and reliability problems suggest that suppliers developed strategies specifically to take advantage of provisions in the market rules that facilitated the exercise of market power".¹⁹ "One of the widely accepted conclusions of [studies of the US experience] is that poor market rules can result in the exercise of market power."²⁰

As an aside, it is also important to note that long-term fixed-price contracts can play an important role in electricity markets by encouraging efficient sharing of risk, encouraging entry of new generators and mitigating market power. Generators which have a large proportion of their output sold in the form of long-term fixed price contracts have little incentive to exercise market power.

Institutional Arrangements

- (7) *As in other regulatory reforms, reform of the electricity sector has led to the establishment of new institutions such as new electricity regulatory authorities, new market operators and, in a few cases, a "market surveillance panel". The roles and responsibilities of these agencies often overlap with one-another and with the role and responsibilities of the national competition authority, often requiring explicit forms of co-operation. In some cases regulatory responsibilities have been given directly to the national competition authority.*

In virtually all OECD countries, the liberalisation of the electricity industry has been associated with the creation of a new independent electricity regulatory authority (in fact, the EC's acceleration directive explicitly requires the establishment of independent national regulators with certain specified minimum powers). In some cases the role of the electricity regulator has been given (in whole or in part) to the national competition authority. In the case of Australia, regulatory responsibility price regulation on the transmission network was given to the national

competition authority. In The Netherlands, the energy regulator (known as DTe) operates as a chamber of the Dutch competition authority.²¹ Several jurisdictions have also established a quasi-independent “Market Surveillance Panel” (or MSP) to investigate and report on market behaviour, including suspected abuse of market power.

In addition to the creation of a new regulatory authority, liberalisation of the electricity industry usually involves the creation of new institutions to perform the roles of market and/or system operator – that is accepting bids, calculating the efficient set of prices and determining the efficient dispatch of electricity and ancillary services in real time. These roles are usually separated from the control of a for-profit transmission network provider. In addition, some jurisdictions (such as the state of Victoria in Australia) have created a separate institution responsible for planning network expansion and augmentation. As mentioned earlier, the need for coordinated planning in interconnected networks (such as NordPool, across the states of Australia or the interconnections in the US) has led to pressure for supra-regional transmission coordination and planning institutions.

In the case of control of anticompetitive behaviour there is often overlap between the responsibilities of the regulator and the national competition authority (and the MSP where it exists). In the case of Canada, given the substantial overlap in the different roles, the agencies have developed a joint statement setting out the respective agencies’ jurisdictions and formalising modes of co-operation. In Brazil, where there are market share caps on the privatisation process, the market share caps are administered by the Brazilian competition agencies, under a collaborative agreement with the energy regulator.

Competition Enforcement

- (8) *As in other network industries, regulatory reform has been associated with a substantial increase in the number of competition enforcement cases including primarily abuse of dominance cases, on the one hand, and mergers on the other.*

Competition authorities have been active in opposing anti-competitive behaviour in the electricity industry, including both control of mergers and controls on abuse of a dominant position. In Japan, for example, the JFTC issued a warning to Hokkaido Electric Power Co. after it was found to be planning to charge an unreasonably high adjustment fee and cancellation penalty to its customers when they sought to switch their electricity supply contract to a new entrant. Similarly, the Swiss competition authority found that a refusal by a transmission network to carry power from a generator outside its franchise area was an abuse of dominant market power. In Germany, the competition authority has conducted preliminary investigations against 23 network operators on suspicion of abuse of a dominant position and has instituted formal proceedings against 12 of them.

In cases of mergers between generating companies, the European Commission has sought to enhance competition by requiring divestiture of generation capacity and the strengthening of interconnection capacity. For example, the EC required divestiture of 6000 MW of generation capacity and the breaking of the exclusive contract between Electricité de France (EdF) and Compagnie Nationale du Rhône as a condition of the acquisition of Energie Naden-Württemberg AG (EnBW) by EdF and Zweckverband Oberschwäbische Elektrizitätswerk. In another case EdF “committed to take all the necessary steps in order to gradually increase the commercial capacity on the interconnector at the French/Spanish border to about 4000 MW from an existing 1100 MW”.²²

Because natural gas is both a substitute for electricity and a primary input into the production of electricity, mergers between electricity generators and major gas suppliers have both a horizontal and a vertical dimension. The US provides an example of such a “convergence” merger which was opposed by the US authorities. Germany also provides an important illustration in the case of the merger of E.ON and Germany’s largest gas supplier Ruhrgas. In that case, the German competition authority blocked the merger but it was later granted a Ministerial authorisation (which is provided for in Germany’s competition law). Germany notes that “In this case greater weight was attached to the overall economic advantages resulting from the merger, i.e. it would ensure the supply of energy and strengthen Ruhrgas’ international competitiveness, than to the likely restraints of competition.”²³

Conclusion

- (9) *The experience of OECD countries in promoting competition in electricity have highlighted both the strengths and the difficulty of relying primarily on a market-based approach in the electricity industry, laying a solid foundation for further careful fine-tuning of the reforms in the future.*

Transforming the electricity industry from a vertically-integrated monolithic entity into an efficient, competitive, market-based structure is a substantial and complex regulatory undertaking. Although the electricity industry shares certain features with other network industries there are important differences which complicate the task of liberalisation. In particular, electricity reformers must face several challenges including the strong propensity of the industry to market power in the generation market, network effects in the transmission sector which complicate the task of pricing and creating investment incentives, and political and consumer resistance to exposing end-users to the extreme fluctuations in electricity prices seen in wholesale electricity markets. The collective experience of OECD countries provides an important set of lessons for on-going improvements to these reforms in the future.

NOTES

1. The Norwegian submission, page 15, emphasises the multiplicity of markets: “Because of capacity constraints in the network ... the structure of the power market can vary from one hour to the next, on a daily, weekly or seasonal basis during the 8760 hours of the year”.
2. The Australian submission, page 26, notes that, as time goes by, generators develop strategies to raise pool prices and these strategies spread to other generators.
3. US submission, page 4.
4. Although, in the case of the UK, since one of those parts was the nuclear power stations, it did not play a role in setting the market price.
5. But it can divest control of as much as 25% to any single third party, so overall market concentration may remain high. At the same time, a revenue cap applies to a large proportion of the incumbent’s remaining production.
6. EC submission, page 6.
7. These capacity share figures may not be an accurate reflection of market power for several reasons. In addition to the concern expressed earlier regarding capacity constraints, these figures may understate the scope for market power where there is cross-ownership between generators (e.g., Statkraft owns 44% of Sydkraft, Sweden’s second largest power producer) or may overstate the scope for market power by ignoring competition from imports.
8. In full, the US notes: “High concentration and constrained transmission persist in some areas. Although the U.S. antitrust laws were designed to protect competition and prevent monopolization, they were not designed to create or restore competition. Under U.S. antitrust laws, monopolies and market power are not *per se* illegal and neither is the unilateral exercise of market power. Hence, the burden of ensuring that market structure supports competition in electric power markets falls to FERC and to state utility commissions. Efforts to undertake broad deconcentration of electric power markets through divestitures have not been implemented. ... Absent structural remedies, efforts directly to curtail market power in U.S. wholesale electric power markets have focused on bid and price caps and assessment of capacity withholding.” US submission, page 11
9. This statement is true when there is effective competition between generators. When there is insufficient competition between generators it may be efficient to augment the transmission network to the point where congestion is eliminated if the cost of doing so is outweighed by the benefits of enhanced generator competition.
10. US submission, page 7. Canada, in its submission, observes that the uniform pricing requirement in Ontario stifles demand-based incentives for enhancing transmission into high-cost areas and notes that a review of the possibility of switching to locational prices will take place in May 2003.
11. “Although locational marginal pricing and the associated “financial transmission rights” (FTRs) help provide efficient investment incentives to suppliers and help transmission customers to hedge transmission pricing risk, they do not solve market power problems directly. Concern has been expressed that some

suppliers might monopolise FTRs and try to exercise market power through the market for FTRs". US submission.

12. This is discussed in detail in the OECD publication *Restructuring Public Utilities for Competition*, OECD 2001.
13. "At present, Transpower will invest in new transmission assets only if it can obtain satisfactory contracts to cover the cost of the new investment. This process is fraught with 'free rider' problems. ... Under proposed new arrangements, an independent Electricity Governance Board will be able to require Transpower to invest in new transmission assets and will be able to require beneficiaries to pay for the investment". New Zealand submission, page 6.
14. US submission, page 8.
15. EC submission, page 13.
16. Reflecting the lessons learnt from the previous market rules in the UK, the UK's New Electricity Trading Arrangements allow for demand side bidding in the market.
17. Canada notes the uncertainties introduced by political reaction to large movements in prices "In any electricity market, it can be expected that there will be periods of high prices and low prices reflecting the need for capacity or an excess of capacity. If the Ontario electricity market is to provide the right signals for efficient new generation to be developed, it will be important that efficient pricing signals not be unduly distorted by government intervention in the markets". Canada submission, page 11. Other policies such as the use of capacity markets and bid caps can also mitigate price spikes and price fluctuations.
18. In addition, in the US, retail prices are often de facto controlled by the residual price regulation on the "default supplier" (the supplier if a retail customer fails to choose an alternative supplier).
19. US submission, page 10.
20. US submission, page 10.
21. The DTe has also established "Market Surveillance Committee" which functions under the responsibility of the competition authority, whose job is to obtain empirical information and to provide analyses of the functioning of the Dutch electricity market.
22. EC submission, page 15.
23. Germany submission, page 7.

SYNTHÈSE

Par le Secrétariat

Au vu des contributions écrites, du document de référence et des débats, les conclusions suivantes s'imposent :

Pouvoir de marché et production

- (1) *Dans les pays de l'OCDE, l'expérience de la réforme de l'industrie électrique a montré que les marchés de l'électricité étaient exposés à l'exercice de pouvoir de marché. Une combinaison de facteurs y contribue : demande inélastique, impossibilité de stocker de grandes quantités d'électricité, congestion du réseau de transport, transits de bouclage et contraintes de capacité associés à la diversité des coûts marginaux des différents types de producteurs. Lorsque la capacité est limitée, les mesures classiques de la concentration, tels que l'indice HHI doivent être parfois complétées par des indicateurs supplémentaires du pouvoir de marché. Etant donné que ce pouvoir de marché peut varier rapidement en fonction de l'évolution de la congestion du réseau de transport et des fluctuations de la charge, l'analyse du marché pertinent et du pouvoir de marché peut exiger l'élaboration de modèles informatiques du marché de l'électricité.*

Bien que la demande suffise, dans la quasi-totalité des pays de l'OCDE, à assurer l'exploitation d'un grand nombre de moyens de production en concurrence, les marchés de l'électricité sont toujours exposés à l'exercice de pouvoir de marché. Ce pouvoir de marché découle d'une combinaison de facteurs : (a) la demande d'électricité est presque intégralement inélastique, de sorte qu'une réduction, même faible, de la production peut avoir un impact très significatif sur les prix ; (b) comme l'électricité ne peut pas être stockée facilement, la consommation doit être égale à la production à tout instant. Il est par conséquent essentiel de définir un marché de l'électricité livrée à chaque moment de la journée, du mois ou de l'année ; (c) lorsque le réseau de transport est encombré, il faut absolument établir une distinction entre les différents marchés géographiques¹. Certains producteurs peuvent détenir un pouvoir de marché important dans leur zone de desserte. D'autres producteurs peuvent également jouir d'un pouvoir de marché significatif parce que leur production est indispensable pour résorber les goulots d'étranglement du réseau de transport. (d) Comme le coût marginal varie souvent en fonction des producteurs, à tout instant t, certains producteurs sur le marché peuvent fonctionner au maximum de leur production ou près de ce maximum, et donc être incapables de réagir à une hausse du prix du marché. Même si les producteurs d'électricité sont nombreux à produire à un moment donné, le seul fait qu'ils fonctionnent aux limites de leurs capacités permet aux autres producteurs d'exercer un pouvoir de marché significatif.

D'autres facteurs peuvent également contribuer à augmenter le pouvoir de marché, dont le fait que les mêmes producteurs se rencontrent régulièrement sur un marché et apprennent à communiquer par l'intermédiaire des signaux de prix². Le pouvoir de marché peut également apparaître sur les marchés associés, tels que les marchés des services auxiliaires.

Comme dans tout marché, la présence d'un pouvoir de marché nuit à l'efficacité globale : elle fausse les décisions à court terme de production et de consommation et, à plus long terme, incite à des décisions d'investissement inefficaces concernant, par exemple, l'emplacement ou la

technologie de production choisis ou les gros consommateurs d'électricité. Ce pouvoir de marché peut également accentuer considérablement la variabilité des prix de l'électricité sur le marché spot, et ainsi saper la viabilité politique des réformes des marchés de l'électricité.

Si certains producteurs fonctionnent aux limites de leur capacité, l'indice HHI de la concentration du marché (qui repose sur la part de marché des producteurs présents sur ce marché à un instant t) donnera normalement une vision limitée du pouvoir de marché, dans la mesure où certains producteurs historiques peuvent se trouver dans l'incapacité de relever leur production en cas de défaillance d'autres producteurs. Dans ce cas, l'indice HHI doit être associé à d'autres indicateurs du pouvoir de marché. Etant donné que chaque intervalle de temps représente un marché séparé de produit et que le marché géographique pertinent varie en fonction de la demande et des schémas de congestion du réseau de transport correspondants, l'analyse du marché pertinent et des parts de marché se révèle extrêmement complexe. "Souvent, les informations concernant les congestions que donne l'analyse du marché géographique du produit sont si complexes qu'il est plus pratique, pour obtenir les marchés géographiques pertinents, de procéder à des simulations informatiques des transits et des prix³".

- (2) *Soucieux d'éviter les pouvoirs de marché, les décideurs ont adopté un éventail de mesures, consistant notamment à améliorer la capacité de transport, à plafonner les enchères des producteurs et à accentuer la réactivité de la demande aux variations des prix de l'électricité. Ces politiques feront l'objet d'un développement séparé. La réforme structurelle du marché de la production constitue l'une des principales solutions à l'exercice de pouvoirs de marché dans la production de l'électricité. Bien que l'on ait veillé dans certains pays à procéder à la séparation structurelle et à des cessions d'actifs, il est encore possible de réduire dans de fortes proportions la concentration sur les marchés de la production.*

Les décideurs ont eu recours à une diversité de moyens pour résorber les pouvoirs de marché dans la production de l'électricité, que l'on peut regrouper dans plusieurs catégories : politiques structurelles (dont la réduction de la concentration des producteurs d'électricité), politiques de tarification du transport et d'investissement dans le réseau (en élargissant le périmètre géographique du marché pertinent), politiques d'intervention sur la demande (conçues pour accentuer l'élasticité de la demande d'électricité), politiques jouant sur l'entrée de nouveaux moyens de production et politiques déterminant la fixation des prix et le dispatching sur les marchés de l'électricité (comme le plafonnement des enchères des producteurs et l'application de prix nodaux marginaux en temps réel). Ces politiques seront développées plus loin.

Etant donné la propension à l'exercice de pouvoir de marché que l'on observe dans le secteur électrique, la séparation structurelle horizontale (ou cession d'actifs) du marché de la production est un moyen d'action fondamental. Bien qu'à une échelle assez réduite, la séparation structurelle a eu lieu. En Nouvelle-Zélande et au Royaume-Uni, l'ancienne entreprise d'électricité publique verticalement intégrée a été séparée en trois pôles concurrents⁴. En Ontario, le gouvernement a passé un accord à long terme intitulé "Market Power Mitigation Agreement", une tentative pour réduire progressivement la part de la puissance totale détenue par l'opérateur historique, aujourd'hui de 90 %, à moins de 35 % dix ans après l'ouverture du marché⁵. Au Brésil, le processus de privatisation s'accompagne de restrictions strictes des parts de marché qui peuvent être achetées par une seule et même entité. Aux Etats-Unis, l'Etat de Californie a exigé des deux plus grandes entreprises privées de céder la moitié de leur capacité de production thermique.

Malgré tout, les possibilités d'opérer des cessions horizontales sont loin d'être épuisées. La Commission européenne reconnaît "que la concentration dans la production de l'électricité reste forte dans bien des Etats membres [de l'Union européenne]"⁶. Sur 14 pays Membres de l'Union

européenne (si l'on exclut le Luxembourg), les trois plus grandes compagnies d'électricité détiennent 50 % de la puissance installée dans 12 pays et 90 % dans 5 pays⁷. Comme nous l'avons vu précédemment, la Commission a souvent subordonné son accord pour des fusions à la mise en œuvre de réformes structurelles. Aux Etats-Unis, "rien n'a été entrepris pour opérer une déconcentration globale des marchés de l'électricité par des cessions d'actifs"⁸.

Le pouvoir de marché dans la production doit, en principe, s'atténuer lorsque l'on construit des moyens de production. Dans certains pays, beaucoup d'installations nouvelles ont été construites (par exemple, au Royaume-Uni), mais les possibilités d'entrée varient d'un pays à l'autre. Si la production des centrales au charbon, à bas prix, est bloquée par des contrats à long terme, ou si tous les sites hydrauliques disponibles ont été aménagés, les possibilités de voir des moyens de production peu chers apparaître sur le marché risquent d'être limitées. En outre, bon nombre de centrales peuvent soulever des problèmes environnementaux susceptibles de ralentir et de renchérir la procédure d'autorisation. Dans bien des pays, les centrales au gaz constituent le gros des nouveaux moyens de production. C'est pourquoi l'accès aux ressources gazières importe tellement si l'on veut favoriser les entrées dans la production électrique.

Transport

- (3) *Le réseau de transport est un élément vital de l'industrie électrique, assurant le transport de l'électricité, améliorant la fiabilité d'approvisionnement et favorisant les échanges entre régions et pays. Les principaux problèmes qui se posent dans ce domaine sont : comment éviter toute discrimination à l'encontre de la production de tiers, comment tarifier de manière efficiente l'accès au réseau de transport et comment créer des incitations à investir en temps utile et de manière rentable dans des améliorations du réseau de transport. On peut discerner une tendance à imposer des formes plus rigoureuses de séparation pour éviter la discrimination. On note également une prise de conscience de la nécessité d'établir une différenciation spatiale des prix (prix nodaux) en temps réel qui reflète de l'encombrement minute après minute du réseau de transport.*

Tant que la construction de lignes de transport coûte cher, il n'est généralement⁹ pas intéressant de construire un réseau de transport capable de laisser passer tous les transits sans subir de congestion. Toutefois, la congestion segmente les marchés de l'électricité et ainsi contribue à l'exercice de pouvoir de marché du producteur, un effet qui peut être significatif. La contribution danoise souligne que la congestion des lignes de transport entre le Danemark et le reste du Nord Pool fait passer la différence entre le prix et le coût (c'est-à-dire l'indice Lerner) de 2-4 % à près de 40-43 %, laissant donc entrevoir un pouvoir de marché non négligeable.

Parmi les décisions importantes à prendre, il faudra déterminer comment la congestion doit se traduire dans les prix demandés aux producteurs et aux consommateurs finals pour accéder au réseau de transport. Souvent, le prix d'accès au réseau de transport d'un point donné ne dépend que de facteurs de congestion ou de pertes dont on a calculé la moyenne dans le temps (du moins dans certaines régions appelées zones). Bien que cette méthode fournisse aux producteurs et aux consommateurs des signaux géographiques, elle ne les incite pas en temps réel à adapter leur offre et leur demande pour suivre minute par minute les fluctuations des congestions sur réseau de transport.

Il est de plus en plus admis que la meilleure manière de gagner en efficacité consiste à laisser le marché déterminer des prix en temps réel différents en divers emplacements du réseau. La contribution des Etats-Unis précise à cet égard : "Aux Etats-Unis où l'on a expérimenté plusieurs

modes de tarification du transport, il apparaît peu à peu que la tarification nodale, au prix marginal, est la meilleure pratique actuelle¹⁰. Bien que plusieurs marchés déterminent des prix variant suivant les régions ou les zones, la tarification nodale est appliquée sur un nombre restreint de réseaux de transport dans les pays de l'OCDE. En Nouvelle-Zélande, par exemple, le prix spot de l'électricité s'établit pour chacun des 244 nœuds du réseau (et pour chacune des 48 demi-heures d'enchères de la journée). Il a été avancé que, en théorie, la tarification zonale, qui écrête les prix payés par les consommateurs, atténue la réactivité de la demande au prix à chaque nœud concerné, accentuant le pouvoir de marché des producteurs en ce point. Le prix nodal ou zonal est normalement déterminé par un organisme distinct du gestionnaire du réseau de transport de façon à éviter que ce dernier n'use de son pouvoir de marché pour gonfler les recettes qu'il peut tirer des différences entre les prix spot de l'électricité pratiqués en différents emplacements.

Dans un système de tarification du transport spatialement différencié, les transactions entre un producteur et un consommateur situé en différents nœuds (ou dans différentes zones) sont soumises aux fluctuations des prix du transport de l'électricité entre ces nœuds. D'où l'intérêt d'instruments financiers permettant aux parties à la transaction de se protéger partiellement ou totalement contre le risque. La plupart des régions qui ont adopté une forme de tarification nodale (ou zonale) se sont également dotées d'instruments tels que "les droits financiers des transports" (DFT). Bien que variant dans le détail, ces DFT permettent à celui qui les détient d'obtenir une indemnité qui dépend de la différence de prix entre deux nœuds ou emplacements géographiques. Il en existe différentes formes, notamment dans la région connue sous le nom de PJM au nord-est des Etats-Unis et entre les zones du NEM en Australie. On envisage de les adopter en Nouvelle-Zélande.

Il a été suggéré que le prix de ces DFT pourrait être un indicateur de la nécessité d'investir dans le réseau de transport. Nous reviendrons sur cette possibilité au titre suivant. Certains redoutent, par ailleurs, que les producteurs (en particulier, ceux qui opèrent dans des régions qui importent) puissent renforcer leur pouvoir de marché en achetant ces DFT¹¹.

Nombreux sont les pays où le propriétaire du réseau de transport détient également des moyens de production. Il y a donc dans ce cas un risque réel que le gestionnaire du réseau de transport exerce une discrimination à l'encontre des producteurs concurrents malgré tous les mesures destinées à interdire un comportement discriminatoire¹². Devant la difficulté d'utiliser ce type de contrôle pour éviter toute discrimination, on s'est tourné vers les politiques structurelles, notamment diverses formes de séparation structurelle. En Europe, l'obligation de dissociation comptable qui figure dans la première directive sur l'électricité a été remplacée par une obligation de séparation juridique. Aux Etats-Unis, la politique de la FERC à l'égard de l'intégration verticale du transport de la production continue d'évoluer en faveur d'une séparation accrue". Lorsque la FERC s'est aperçue que les normes de comportement prévues dans les ordonnances 888 et 889 n'étaient pas pleinement respectées, elle a encouragé la création de "gestionnaires de réseau indépendants", ce qui revient à confier la gestion (et non la propriété) du réseau de transport à un organisme indépendant. Ensuite, pour mieux décourager la discrimination à l'égard de concurrents sur le marché des services de transport, la FERC a favorisé la création "d'organismes de transport régionaux" dans toutes les zones des Etats-Unis.

- (4) *A moyen et à long terme, le succès des réformes dans le secteur de l'électricité dépendra des incitations à investir en temps utile et de manière efficiente dans le réseau de transport. Si les prix nodaux sont capables de renseigner sur le moment et l'endroit où améliorer le réseau de transport, on n'a encore pas trouvé comment procurer des incitations efficaces à investir dans le transport.*

Reste une question fondamentale qui n'a en général pas trouvé de réponse : comment inciter à développer un réseau de transport de manière efficiente et en temps utile. A qui doit revenir la responsabilité de choisir les projets de développement, de quelles incitations doit bénéficier cet organisme et comment doit-on financer les projets ? Si le responsable de la planification du développement du réseau ne possède pas le réseau, qu'est-ce qui pourrait le pousser à entreprendre les travaux nécessaires ? Au contraire, si le responsable du développement du réseau possède et exploite ce réseau, sera-t-il incité à le développer de manière à tirer le maximum de recettes de son exploitation, par exemple en s'efforçant d'augmenter les congestions plutôt que de les réduire ? En Nouvelle-Zélande, le gestionnaire du réseau de transport, une entreprise à but lucratif, a opté pour une politique de développement très prudente, si bien que l'investissement dans le réseau de transport n'a pas suivi la croissance de la demande et qu'il existe des contraintes en période de pointe¹³.

Certains commentateurs ont fait valoir que l'information révélée par les prix nodaux (que reflète le prix des droits financiers de transport ou DFT) doit orienter l'investissement dans le réseau de transport. Quelques rares pays (Australie et Etats-Unis, par exemple) autorisent les investissements privés (ou "marchands") dans les lignes de transport qui tirent parti des différences de prix révélées par les prix nodaux. Mais la politique qui consiste à développer le réseau en tablant uniquement sur l'investissement privé se heurte à plusieurs objections théoriques (notamment la difficulté d'internaliser les effets d'une nouvelle ligne sur les transits de puissance dans d'autres parties du réseau ou l'éventuelle insuffisance des recettes liées à la congestion en présence de rendements d'échelle croissants. Néanmoins, le responsable de la planification centralisée d'un réseau de transport doit pouvoir utiliser dans une certaine mesure les informations données par les prix nodaux pour prendre ses décisions, en particulier concernant des projets ayant peu d'effet sur les prix globaux et les transits.

La difficulté de créer des incitations appropriées à développer le réseau de transport s'accroît encore lorsque plusieurs gestionnaires se partagent la responsabilité de ce réseau (ce qui est le cas des différents Etats d'Australie ou des pays européens). Se posent alors de nouvelles questions telles que : qui est responsable de l'installation ou de l'amélioration des liaisons d'interconnexion entre régions ? Que se passe-t-il si un contrat entre un producteur et un consommateur de deux régions différentes exige un renforcement du réseau dans une troisième région ? La réponse à ces questions passe par une attitude coordonnée des responsables des différents réseaux vis-à-vis de l'investissement, ce qui peut nécessiter la création d'un établissement suprarégional de coordination et de planification du transport.

La construction de nouvelles interconnexions fait des gagnants comme des perdants. Ces derniers ont donc intérêt à s'opposer à la proposition de renforcement du réseau. "Il a été avancé que certains Etats pourraient s'opposer à l'installation d'une ligne de transport ou d'un producteur susceptible de desservir essentiellement des clients d'un autre Etat. En fait, les Etats jouissant d'une électricité bon marché ont indiqué qu'ils ne souhaitent pas perdre l'avantage économique comparatif que leur procure cette électricité"¹⁴. En Europe, la Commission européenne a favorisé le renforcement des liaisons entre Etats membres. "Les infrastructures d'interconnexion entre Etats membres sont insuffisantes et, là où existent les congestions, les méthodes d'attribution de cette capacité limitée ne sont pas satisfaisantes"¹⁵.

Les réseaux de distribution posent des problèmes analogues à ceux rencontrés sur les réseaux de transport. La réforme de la distribution a souvent consisté à réduire cette activité, regroupant jadis l'achat et la distribution d'électricité (pour le compte de consommateurs locaux), à la simple distribution d'électricité, dans la mesure où le consommateur s'est vu accorder le droit de choisir directement son propre fournisseur. Dans les pays de l'Union européenne, tous les

consommateurs d'électricité jouiront de ce droit à compter de 2005. Aux Etats-Unis, où la distribution relève en grande partie des autorités de l'Etat (et non des autorités fédérales), le degré de concurrence sur le marché de détail varie considérablement d'un Etat à l'autre. A l'époque où a eu lieu la table ronde, les Etats qui avaient mis sur pied une forme de concurrence sur le marché de détail représentaient environ la moitié de la population des Etats-Unis.

Réforme du côté de la demande

- (5) *Le marché de l'électricité a ceci de remarquable que les consommateurs finals qui paient un prix de l'électricité dépendant directement du prix spot sur le marché de gros sont assez rares. La demande est par conséquent presque entièrement inélastique. Dans ces circonstances, les répercussions de l'exercice d'un pouvoir de marché sont considérablement accentuées. De nombreux observateurs préconisent des mesures d'urgence pour augmenter la réactivité au prix de la demande d'électricité*

La plupart des consommateurs finals paient pour leur électricité un prix qui correspond à une moyenne temporelle. De cette manière, ils sont complètement isolés (du moins à court terme) des fluctuations sur le marché spot de l'électricité, si bien qu'ils n'ont aucune incitation à consommer moins les jours où le prix est exceptionnellement élevé parce que la charge dépasse la moyenne, qu'il y a des congestions sur le réseau de transport ou que des moyens de production sont indisponibles. Une augmentation ne serait-ce que limitée de l'élasticité de la demande pourrait de sensiblement aplanir ces pointes de prix et réduire le pouvoir de marché dont jouissent les producteurs.

Plusieurs commentateurs préconisent une politique destinée à augmenter la réactivité de la demande d'électricité au prix du marché. Les commentaires du "Blue Ribbon Panel" en faveur d'une bourse de l'électricité californienne méritent d'être cités intégralement : "La réactivité de la demande au prix est un facteur primordial du fonctionnement d'un marché restructuré ; l'amélioration de l'efficacité de l'utilisation de l'électricité à long terme, de même qu'une réponse plus élastique aux pointes de prix à court terme sont de toute évidence des remèdes essentiels... Nous ne pouvons qu'insister sur le fait que, si les consommateurs doivent modifier leurs habitudes à cause de fluctuations extrêmes des prix et, ce faisant, amortir ces fluctuations, il est indispensable que leur fournisseur les incite sur un signal à s'effacer ou à déconnecter certaines installations pendant de courtes périodes et/ou qu'on leur fasse payer des prix correspondant aux fluctuations importantes des prix de gros, ce qui les conduira à modifier leur consommation en conséquence"¹⁶. Pour proposer aux clients des prix variant en fonction du temps, il faut posséder des dispositifs mesurant la quantité d'électricité consommée sur chaque intervalle de temps. Du coût de ces dispositifs dépend la rentabilité de leur application, même au plus petit consommateur.

Bien que l'efficacité et l'investissement exigent une certaine fluctuation du prix spot de l'électricité (en particulier sur les marchés purement énergétiques), la flambée des prix nuit à la viabilité politique des réformes du marché de l'énergie au point parfois de remettre en cause le processus de libéralisation¹⁷. La volonté politique de protéger des hausses de prix certains clients sur le marché de détail a, dans certains cas, compliqué le processus de réforme. En Californie par exemple, le fait que les prix de détail aient été contrôlés alors que les prix de gros étaient déterminés par le marché a provoqué la faillite d'un des principaux opérateurs en place lorsque les prix de gros ont atteint des niveaux imprévus. En Australie, le gouvernement de l'Etat de Nouvelle-Galles du Sud a créé un fonds destiné à amortir les fluctuations des prix de détail de façon à protéger des consommateurs des variations des prix de gros.

Autres éléments de la conception du marché

- (6) *Le résultat final, y compris la propension à l'exercice de pouvoir de marché, dépendent de bien d'autres aspects de la conception du marché de l'électricité. Par exemple, les marchés de l'électricité dans les pays de l'OCDE diffèrent par le nombre de guichets au cours de la journée, ou par la période pendant laquelle il est possible de revenir sur les enchères avant que l'électricité ne soit dispatchée. Il est également courant de réglementer le prix du marché ou les enchères en plafonnant par exemple ces dernières.*

Sur la plupart des marchés de l'électricité, on ne trouve pas seulement un marché spot mais une série de marchés interconnectés. Il existe en général un marché la veille pour le lendemain (où se détermine le prix officiel ou de référence) ainsi qu'un marché en temps réel ou mécanisme d'ajustement. A cela viennent s'ajouter souvent les marchés des services auxiliaires (fourniture de puissance réactive, réglage secondaire, ou réserve d'exploitation). Comme nous l'avons mentionné précédemment, certains producteurs peuvent être en mesure d'exercer un pouvoir de marché sur ces autres marchés.

Différentes régions peuvent également se distinguer par le nombre de périodes au cours de la journée où le prix spot est déterminé, par le délai accordé pour soumissionner ainsi que par le nombre d'enchères qui peuvent être modifiées avant le dispatching de l'électricité et la fréquence des changements autorisés. Sur le marché de gros de l'électricité d'Ontario, par exemple, les participants présentent des offres, ou enchères, pour chaque heure de la journée, la veille pour le lendemain. Elles peuvent être entièrement revues jusqu'à quatre heures avant le dispatching et dans une proportion de 10 % jusqu'à deux heures avant le dispatching. En revanche, en Australie, les participants peuvent modifier leurs offres sans aucune restriction jusqu'au moment même où l'électricité est dispatchée.

Il est courant de contrôler le prix du marché. Sur la quasi-totalité des marchés de gros, le prix de gros est plafonné (en général au coût de la défaillance). On trouve sur certains marchés d'autres formes de contrôle des prix. Aux Etats-Unis, par exemple, seuls les producteurs qui satisfont aux critères de pouvoir de marché sont autorisés à établir des tarifs fondés sur le marché. Pour ce qui est des autres (à savoir, ceux qui détiennent des pouvoirs de marché), la FERC est en droit d'établir des tarifs "justes et raisonnables"¹⁸. Les propositions les plus récentes de la FERC concernant la conception d'un marché standard prévoient le plafonnement des enchères, à savoir un plafonnement généralisé "de sécurité" et un plafonnement par zone des desserte déclenché au coup par coup. Elles prévoient par ailleurs des pénalités pour tout refus de capacité sur le marché ainsi qu'une procédure d'enquête sur les retraits de capacité imprévus.

L'expérience acquise sur les marchés du Royaume-Uni et de Californie est particulièrement instructive quant à la façon dont des règles du marché mal conçues peuvent faciliter l'exercice de pouvoir de marché. Au Royaume-Uni, le prix de l'offre de capacité (pratiqué dans les conditions antérieures) rendait plus intéressant financièrement le retrait stratégique de capacité. En Californie, "l'analyse de l'effet des règles du marché lorsque les prix sont élevés et qu'il y a des problèmes de fiabilité conduit à penser que les fournisseurs avaient mis au point des stratégies destinées à tirer parti des dispositions des règles du marché qui facilitaient l'exercice de pouvoir de marché"¹⁹. "Le fait que des règles du marché mal conçues puissent favoriser l'exercice de pouvoir de marché est l'une des conclusions des [études de l'expérience américaine] qui rallient le plus de suffrages"²⁰.

Accessoirement, on notera que les contrats à long terme à prix fixe peuvent avoir un effet significatif sur les marchés de l'électricité dans la mesure où ils encouragent un partage efficace

du risque, l'entrée des nouveaux producteurs tout en atténuant les pouvoirs de marché. En effet, les producteurs ayant vendu une forte proportion de leur production dans le cadre de contrats à long terme à prix fixe sont peu incités à exercer un pouvoir de marché.

Dispositions institutionnelles

- (7) *Comme toute autre réforme réglementaire, la réforme du secteur de l'électricité a provoqué la création de nouvelles institutions telles que les autorités de régulation, de nouveaux opérateurs et, dans certains cas, une commission de surveillance du marché. Souvent on observe des chevauchements entre les rôles et responsabilités respectifs de ces autorités et ceux de l'autorité de la concurrence. D'où la nécessité d'explicitier les modalités de coopération. Dans certains cas, les responsabilités en matière de réglementation ont été confiées directement à l'autorité nationale de la concurrence.*

Dans la quasi-totalité des pays de l'OCDE, l'ouverture de l'industrie électrique s'est accompagnée de la création d'une autorité de régulation indépendante (en fait, la directive d'accélération de la CE exige la création d'autorités de régulation indépendantes jouissant d'un minimum de prérogatives). Dans certains cas, la fonction d'autorité de régulation de l'électricité a été confiée (intégralement ou en partie) à l'autorité nationale de la concurrence. En Australie, la compétence réglementaire en matière de tarification du réseau de transport revient à l'autorité nationale de la concurrence. Aux Pays-Bas, l'autorité de régulation de l'énergie (connue sous le nom de DTe) est une instance de l'autorité de la concurrence néerlandaise²¹. Plusieurs pays ont également créé un comité quasi-indépendant de surveillance du marché avec pour mission d'étudier les comportements sur le marché, notamment les abus de pouvoir de marché, et d'établir des rapports.

Outre la création d'une autorité de régulation, l'ouverture de l'industrie électrique s'accompagne normalement de l'instauration de nouvelles institutions jouant le rôle d'opérateurs de marché et/ou de gestionnaires du réseau, à savoir des instances chargées d'enregistrer les offres, de calculer un éventail de prix efficient, d'établir le dispatching et les services auxiliaires en temps réel et de manière efficace. Normalement, on fait en sorte que ces fonctions échappent au contrôle d'un gestionnaire de réseau de transport à but lucratif. Certaines administrations ont également créé (dans l'Etat de Victoria, en Australie, par exemple) un établissement séparé chargé de planifier le développement du réseau. Comme nous l'avons mentionné précédemment, la nécessité d'une planification coordonnée des systèmes interconnectés (tels que le Nord Pool, ou les systèmes des différents Etats en Australie ou encore les interconnexions aux Etats-Unis) a conduit à envisager la création d'institutions supranationales chargées de la coordination et du planning du réseau de transport.

S'agissant des comportements anticoncurrentiels, les fonctions de l'autorité de régulation et de l'autorité nationale de la concurrence (voire du Comité de surveillance du marché lorsqu'il existe) font souvent doublon. Pour remédier à des chevauchements importants, les autorités du Canada ont conclu une entente définissant leurs domaines de compétences respectifs ainsi que les modalités de leur coopération. Au Brésil, où la privatisation est assortie d'un plafonnement des parts de marché, le contrôle de ces plafonds a été confié aux autorités de la concurrence dans le cadre d'un accord de collaboration avec l'autorité de régulation de l'énergie.

Application du droit de la concurrence

- (8) *Comme dans toute autre industrie de réseau, la réforme de la réglementation s'est traduite par une augmentation du nombre d'affaires de concurrence, concernant essentiellement des abus de position dominante, d'une part et les fusions, de l'autre.*

Les autorités de la concurrence ont pris des mesures pour faire échec aux comportements anticoncurrentiels dans l'industrie électrique, contrôles des fusions et des contrôles des abus de position dominante notamment. Au Japon, par exemple, le JFTC a délivré un avertissement à Hokkaido Electric Power Co. qui avait envisagé de facturer un coût d'ajustement et une pénalité exorbitants à ses clients qui envisageaient d'annuler leurs contrats pour se fournir auprès d'un concurrent. De même, l'autorité suisse de la concurrence a jugé que le refus par un réseau de transport d'acheminer l'électricité d'un producteur en-dehors de sa zone de desserte équivalait à un abus de position dominante. En Allemagne, l'autorité de la concurrence a mené des enquêtes préliminaires sur 23 opérateurs de réseau soupçonnés d'abus de position dominante et a lancé une procédure officielle contre 12 d'entre eux.

En cas de fusion entre producteurs, la Commission européenne exige la cession d'actifs de production et le renforcement de la capacité d'interconnexion, dans un souci de renforcer la concurrence. C'est ainsi qu'elle a exigé la cession de 6 000 MW de capacité de production et la rupture du contrat d'exclusivité entre Electricité de France et la Compagnie Nationale du Rhône comme condition de l'acquisition d'Energie Baden-Württemberg AG (EnBW) par EDF et Zweckverband Oberschwäbische Elektrizitätswerk. A une autre occasion, EDF "s'est engagée à prendre toutes les mesures nécessaires pour faire passer progressivement la capacité commerciale de l'interconnexion franco-espagnole de 1 100 MW à 4 000 MW environ"²².

Etant donné que le gaz naturel est à la fois une énergie de substitution de l'électricité et une énergie primaire pour la production d'électricité, les fusions entre producteurs d'électricité et les gros fournisseurs de gaz possèdent à la fois une dimension horizontale et une dimension verticale. Les autorités américaines ont empêché une fusion de ce type. La fusion de E.ON et du plus gros producteur de gaz, Ruhrgas, en Allemagne, en est une autre illustration. Dans ce cas, l'autorité de la concurrence allemande a interdit la fusion, qui a pourtant été autorisée ultérieurement par le ministère (dispositions prévues dans le droit de la concurrence allemand). La contribution de l'Allemagne conclut que "En l'occurrence, on a accordé plus de poids aux avantages économiques généraux de la fusion, qui devait garantir la fourniture d'énergie et renforcer la compétitivité internationale de Ruhrgas, qu'aux éventuelles entraves à la concurrence"²³.

Conclusion

- (9) *L'expérience des pays de l'OCDE en matière de concurrence sur le marché de l'électricité a mis en évidence tant les avantages que les difficultés d'une politique consistant à s'appuyer essentiellement sur le marché dans l'industrie électrique, et permet désormais de s'appuyer sur une base solide pour affiner les futures réformes.*

Faire passer l'industrie électrique d'un bloc monolithique verticalement intégré à une structure efficiente, concurrentielle, fondée sur le marché, représente une tâche réglementaire substantielle et complexe. Cette industrie, proche par certains aspects d'autres industries de réseaux, possède des caractéristiques importantes qui compliquent la libéralisation. En particulier, les responsables de la réforme se trouvent confrontés à plusieurs défis dont la forte tendance à l'exercice de pouvoir de marché dans la production, les effets de réseau dans le secteur du transport, qui

rendent si compliquées la tarification et la création d'incitations à investir, et la résistance des responsables politiques et des consommateurs à exposer le client final aux fortes fluctuations des prix de l'électricité sur les marchés de gros. L'expérience collective des pays de l'OCDE représente un riche corpus d'enseignements dont on ne manquera pas de s'inspirer pour améliorer les réformes.

NOTES

1. La contribution norvégienne (page 15) souligne la multiplicité des marchés : "Etant donné les contraintes de capacité sur le réseau... la structure du marché de l'électricité peut varier à chaque heure, journée, semaine, saison et cela pendant les 8 760 heures que dure une année".
2. Il apparaît dans la contribution australienne (page 26) qu'à mesure que le temps passe, les producteurs mettent au point des stratégies permettant de relever les prix du pool, stratégies qui se propagent aux autres producteurs.
3. Contribution des Etats-Unis, page 4.
4. Même si, dans le cas du Royaume-Uni, l'un de ces pôles, en possession des centrales nucléaires, n'avait aucune influence sur les prix du marché.
5. Comme cette entreprise peut céder au maximum 25 % de ses parts à un seul tiers, la concentration globale du marché risque de rester forte. Par ailleurs, une bonne proportion du reste de la production de l'opérateur historique est soumise à un plafonnement des recettes.
6. Contribution de la Commission européenne, page 6.
7. Ce pourcentage de la puissance détenue par les entreprises ne donne pas toutefois une image précise du pouvoir de marché, et cela pour plusieurs raisons. En dehors des considérations évoquées antérieurement concernant les contraintes de capacité, ces chiffres peuvent sous-estimer les possibilités d'exercer un pouvoir de marché, s'il existe des participations croisées entre producteurs (Statkraft, par exemple, détient 44 % de Sydkraft, le second producteur d'électricité suédois), ou, au contraire, les surestimer dans la mesure où ils ne tiennent pas compte de la concurrence des importations.
8. Pour être précis, il est dit dans la contribution des Etats-Unis : "De forts niveaux de concentration et des contraintes de transport persistent dans certaines zones. Bien que les lois antitrust américaines aient été conçues pour préserver la concurrence et empêcher les monopoles, elles n'ont pas été faites pour créer ni rétablir la concurrence. Aux termes du droit antitrust américain, les monopoles et le pouvoir de marché ne sont pas en soi illégaux, de même que l'exercice unilatéral d'un pouvoir de marché. Par conséquent, c'est à la FERC et aux commissions des services publics des Etats qu'il revient de s'assurer que la structure du marché est favorable à la concurrence sur les marchés de l'électricité. Rien n'a été fait en général pour déconcentrer les marchés de l'électricité à des cessions d'actifs... faute de remède structurel, les efforts visant directement à atténuer les pouvoirs de marché sur les marchés de gros de l'électricité aux Etats-Unis ont été centrés sur le plafonnement des enchères et des prix et sur l'évaluation du refus de capacité". Contribution des Etats-Unis, page 11.
9. Ce principe vaut s'il existe une concurrence efficace entre producteurs. Faute de concurrence suffisante entre producteurs, il peut être rentable de développer le réseau de transport tant que les points de congestion n'ont pas été éliminés, si le coût de cette amélioration est compensé par les avantages d'une concurrence accrue entre producteurs.

10. Contribution des Etats-Unis, page 7. Dans sa contribution, le Canada observe que l'obligation de pratiquer une tarification uniforme imposée en Ontario annule les incitations fondées sur la demande à renforcer le réseau de transport dans les zones à coûts élevés et que les possibilités de passer à une tarification nodale feront l'objet d'un examen au mois de mai 2003.
11. "Bien que la tarification marginale différenciée et les droits financiers de transport (DFT) soient des moyens efficaces d'inciter les fournisseurs à investir et permettent aux clients du réseau de transport de se prémunir contre le risque de prix, ils n'apportent pas directement de solution aux pouvoirs de marché. Il a été dit que certains fournisseurs pouvaient monopoliser les DFT en se servant du marché des DFT pour exercer un pouvoir de marché." Contribution des Etats-Unis.
12. Cet aspect est amplement développé dans la publication de l'OCDE intitulée *Concurrence et restructuration des services publics*, OCDE 2001.
13. "A l'heure actuelle, Transpower n'investira dans des actifs de transport que s'il est assuré d'obtenir des contrats satisfaisants couvrant le coût de cet investissement. Cette manière de procéder favorise les comportements opportunistes. ... Les nouvelles dispositions qui sont actuellement proposées permettront à un Electricity Governance Board indépendant d'exiger que Transpower investisse dans le réseau et d'imposer aux bénéficiaires de payer le prix de cet investissement". Contribution de la Nouvelle-Zélande, page 6.
14. Contribution des Etats-Unis, page 8.
15. Contribution de la Commission européenne, page 13.
16. Au vu des enseignements de l'application des précédentes règles de marché au Royaume-Uni, les New Electricity Trading Arrangements au Royaume-Uni permettent aux consommateurs de participer à l'ajustement.
17. La communication du Canada évoque les incertitudes liées à la réaction politique à de fortes fluctuations de prix. "Sur tout marché de l'électricité, on peut s'attendre à des périodes de prix élevés ou au contraire bas, dénotant par là une sous-ou une surcapacité. Si l'on veut que le marché de l'électricité en Ontario envoie des signaux de nature à stimuler la construction de nouveaux moyens de production dans des conditions satisfaisant le critère d'efficacité, il importe que ces signaux ne soient pas déformés par l'intervention des pouvoirs publics sur le marché." Contribution du Canada, page 11. Le recours au marché pour l'allocation de capacité et le plafonnement des enchères sont d'autres moyens d'amortir les variations des prix.
18. En outre, aux Etats-Unis, les prix de détail sont souvent contrôlés *de facto* par ce qui reste du système de régulation des prix applicable au fournisseur par défaut (fournisseur d'un client sur le marché de détail, lorsque ce dernier n'a pas choisi de fournisseur particulier).
19. Contribution des Etats-Unis, page 10.
20. Contribution des Etats-Unis, page 10.
21. La DTe a également créé un comité de surveillance du marché qui rend compte à l'autorité de la concurrence, dont la mission est d'obtenir des informations empiriques et d'analyser le fonctionnement du marché de l'électricité national.
22. Contribution de la Commission européenne, page 15.
23. Contribution de l'Allemagne, page 7.

BACKGROUND NOTE

By the Secretariat

Introduction

Over the last decade the majority of OECD countries have undertaken substantial reform of their electricity supply industry. One of the primary objectives of these reforms was the promotion of competition – particularly competition between electricity generators. Competition, it was hoped, would promote efficiency and innovation in this section of the industry, and lower prices for consumers.

While the benefits of electricity sector reform have been substantial, experience has shown that liberalised markets for electricity are prone to the exercise of market power. Across OECD countries many generators enjoy market power at least some of the time and, at least at certain times, some generators enjoy an effective monopoly.

In California, for example, market power rose to the point where 60% of the value of wholesale market transactions in the summer of 2000 could be attributed to market power. As a result, California consumers over-paid for electricity by around \$4.5 billion. Such market power also induces substantial production inefficiencies as higher-cost generation is substituted for lower-cost generation and inefficient higher-cost producers are induced to enter the market.

This paper seeks to understand why liberalised electricity markets are prone to the exercise of market power and what can be done about it. The key points of the paper are as follows:

- As is often pointed out, electricity generation markets have several fundamental features which facilitate market power, including the fact that electricity cannot be stored (implying that electricity markets must be distinguished by the time at which the electricity is delivered), that generators face capacity constraints (so that supply is inelastic at peak times), that demand for electricity is very inelastic (due to the fact that most end-users pay prices which are averaged over time) and the fact that the transmission network may experience congestion (separating electricity markets geographically).
- Although more sophisticated techniques have been used it is possible to gain some insights into market power in electricity markets using a simple Cournot model. Under a simple Cournot model market power depends only on market concentration and demand elasticity and is independent of the level of demand. But, when generating firms face capacity constraints as demand increases, some firms become constrained and therefore unable to discipline the market power of the remaining unconstrained firms. At times of peak times the few remaining unconstrained firms may be able to exercise significant market power.
- The conventional measure of concentration in an economic market is the Herfindahl-Hirschman index (“HHI”). Unfortunately, this measure is inaccurate in markets with capacity constraints. A market that appears quite competitive using conventional concentration measures may, in fact, be subject to significant market power. An alternative measure of concentration (called here the “adjusted HHI”) is presented which correctly reflects the degree of market power in a market where some firms face capacity constraints.

- Market power in electricity markets is not necessarily limited to peak times. Indeed it is possible for market power to arise only at off-peak times. For example, if a single, large low-cost generator competes with a fringe of higher-cost generators, market power will be present only at off-peak times. Market power that arises only at peak times may not be eroded through new entry. If new entrants have a higher cost than the existing base-load generation (for example, if the scope for new hydro or nuclear plants is exhausted) market power which is transient (but recurring), may not be eroded by new entry if there are even small fixed costs of generation.
- Market power may also arise from congestion on the transmission network. Transmission congestion can isolate generators geographically, enhancing market power. The effect of transmission constraints is analogous to the effect of capacity constraints on generators. When the transmission network is constrained, the traditional HHI measure of concentration is inaccurate and should be replaced with the adjusted HHI. The presence of “financial transmission rights” – the right to a share of the congestion rents created by transmission constraints – can enhance the market power of generators which benefit from congestion.
- As before, congestion on transmission networks is not necessarily limited to peak times. It can also arise at off-peak times. Electricity flows over transmission links depend on differences in prices across geographic areas. If demand is more variable in one area than another, flows over a transmission link may change direction between peak and off-peak periods and may be constrained only at off-peak times.
- In electricity networks with more than one path from generation to consumption, electricity flows overall all the possible paths, in amounts inversely proportional to the resistance of the path. An increase in generation at one point, even if matched by an increase in consumption at another point, can affect the flows of electricity (and the level of congestion) on all the other links on the network. It can be shown that even if there are no capacity constraints on the transmission links between generators and consumers, capacity constraints on other links can lead to a situation where a generator has significant market power.
- Many studies of market power and concentration have been carried out in wholesale electricity markets, especially in the UK and California. A substantial body of evidence has emerged that at least certain generators have exercised market power in the past. In California, although costs increased substantially between the summer of 1998 and the summer of 2000, market power increased even faster, increasing total payments to generators from \$1.7 billion in 1998 to over \$9 billion in 2000.
- Many different policies have been proposed for the control of market power in generation markets, including policies for increasing the geographic scope of markets, structural policies, price control policies and policies to increase the elasticity of demand. The geographic scope of markets can be increased by the construction of new transmission links, the enhancement of the capacity of existing links or enhancements in the way that access to transmission is priced. The right way to create incentives for transmission enhancement remains an important unresolved problem. It may not be possible to leave the upgrading of the transmission network to market forces – for example, a transmission link may be economically justified even when no electricity flows over the link at any time.
- Structural policies can mitigate market power by reducing concentration and market share of unconstrained generators. Particularly attention should be paid to deconcentration of plants that use the same fuel, as these tend to cluster in the merit order and therefore are each other's

closest competitors. Attention should also be paid to separation of generation and transmission, not only to eliminate incentives to discriminate in access to transmission but also to alleviate incentives to restrict transmission capacity to enhance generator market power.

- Many commentators have emphasised the importance of enhancing the elasticity of demand. In simple models of market power a doubling of the demand elasticity is equivalent to a doubling of the number of competitors operating in the market. Demand elasticity can be increased by increasing demand-side participation in electricity markets and by increasing use of time-of-use meters. In some liberalised electricity markets there was no opportunity for demand-side participation – demand was estimated as a simple fixed quantity, unresponsive to price. Electricity buyers should be able to submit bids into the power pool in order to signal their willingness to restrict demand in peak periods.
- Finally, where market power is persistent and cannot be mitigated through other policies, consideration should be given to price or quantity controls. Given the very substantial variation in demand and supply conditions from one moment to the next, control of generating prices is difficult but not necessarily impossible. Possible approaches include price caps on bid prices at peak periods or limitations on the variance of the bids for individual units.

The paper has three parts. The first part reviews some of the principles of measurement of market power in markets with capacity constraints and looks at the basic characteristics of electricity markets that facilitate market power. The second part looks more closely at how market power arises in electricity market and makes several observations about the conditions under which market power might arise, how it should be measured and its effects. The third part discusses the pros and cons of policies for mitigating market power.¹

Background: The Theory of Market Power and Features of Electricity Markets

Before looking more closely at electricity markets, it is useful to review some basic principles of the assessment and measurement of market power, especially in markets with capacity constraints.

Review of the Theory of Market Power

A firm is said to have market power when it can, by reducing its output or raising the minimum price at which it is willing to sell its output, increase its profit by raising the market price. A firm that cannot influence the market price is known as a price-taker. A price taker will continue to produce and sell its output as long as the market price exceeds the marginal cost of producing the last unit of output. In a market where all firms are price takers (i.e., a market without market power), the marginal cost of all the firms in the market will be equal to the market price.²

For this reason, the size of the gap between the market price and a firm's marginal cost can be used as an indicator to detect and measure market power. One common measure of the gap between price and marginal cost is the so-called "Lerner index". The Lerner index is simply the percentage mark-up over marginal cost included in the final price – that is, when the final price is P and the marginal cost is c , the Lerner index is:

$$\frac{P - c}{P}$$

It is straightforward to show (see Appendix B) that in a market in which firms compete in quantities, the size of the price-cost mark-up (the Lerner index) is given by a measure of concentration known as the Herfindahl-Hirschman index (“HHI”), divided by the elasticity of demand. That is,

$$\frac{P - c}{P} = \frac{HHI}{\varepsilon} \quad \dots(1)$$

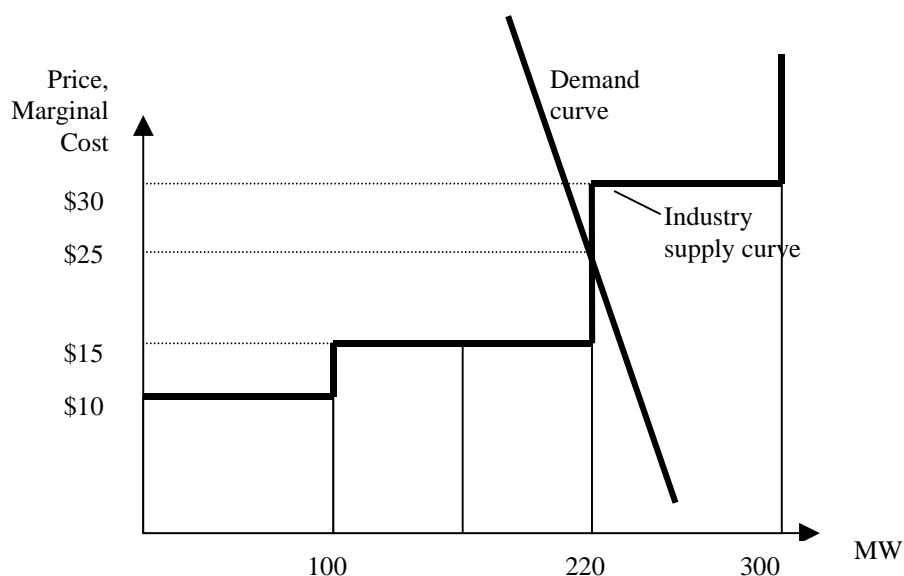
where HHI is the sum of the squares of the market shares of the individual firms competing in the market ($HHI = \sum_{i=1}^N s_i^2$ where s_i is the market share of the i th firm), ε is the elasticity of the demand curve at the equilibrium price and quantity and c is a weighted average of the marginal cost of each producer at the equilibrium quantity.³

Equation (1) highlights the importance of the elasticity of the demand curve in determining the effect of market power on the price. Other things equal, reducing the elasticity of demand by half has the same effect as a doubling of the concentration in the market (i.e., a halving of the number of competitors). Holding constant the degree of concentration in a market, market power will be much higher in markets with low elasticity of demand.

As we will see below, a key feature of electricity generation markets is the presence of capacity constraints on individual firms. For simplicity we will assume that each generation unit has a constant marginal cost for all levels of output below its capacity. In effect the marginal cost curve has the shape of a backwards “L”.

The market supply curve can be formed out of the marginal cost curves of the individual generation units by ranking generation units from the lowest marginal cost to the highest marginal cost (known as the “merit order”) and then adding up their marginal cost curves horizontally. This is illustrated in the following diagram.⁴

Figure 1 illustrates a situation in which there are four generation units, the first with a marginal cost of \$10 per MW and a capacity of 100 MW, the second and third with a marginal cost of \$15 per MW and a capacity of 60 MW and the fourth with a marginal cost of \$30 per MW and a capacity of 80 MW. This “merit order” determines the industry supply curve. In a perfectly competitive market the market price would be given by the intersection of the demand curve and the industry supply curve as illustrated in Figure 1.

Figure 1. Demand and Supply in a market with capacity constraints

It is possible to use the Lerner index to measure market power in markets with capacity constraints, subject to one important caveat. In a market where firms have capacity constraints, the market price may exceed the marginal cost of any individual firm without any exercise of market power when all the firms in the market are operating at capacity and no other firm with a marginal cost lower than the market price wishes to enter the market. This is illustrated in Figure 1. In that figure, the demand and supply curves intersect at a price of \$25 per MW which is above the marginal cost of all the firms operating in the market, without any market power.⁵

Importantly, as we will see below, the relationship between the Lerner index, the elasticity and the HHI no longer applies in markets with capacity constraints. As a result, the use of the HHI in these markets can give highly misleading results. The next section presents an alternative measure of concentration that accurately reflects market power in such markets.

Throughout this paper we will use the Cournot model of market power (that is, generating firms will be assumed to compete in quantities). The Cournot model is both simple to calculate and yields results which are intuitively sensible. It is useful to bear in mind, though, that a Cournot model might over or under-estimate the true level of market power. The Cournot model over-estimates market power by ignoring the potential for entry and under-estimates by ignoring the potential for collusive behaviour. In addition, in most wholesale electricity markets firms do not bid specific quantities but an entire supply function – that is, the amount they are willing to supply at each price. An equilibrium in supply-functions yields a lower estimate of market power than a Cournot equilibrium. In fact, it seems that a supply-function equilibrium yields Bertrand-like competition when there is plenty of excess capacity in the market and Cournot-like competition when excess capacity is limited. The pros and cons of Cournot versus a supply-function equilibrium are discussed in the attached box.

Supply Function Competition vs Cournot Competition

“Cournot competition does not fully describe the options available to firms in an electricity market. Generators are not forced to bid quantities in a spot market, but are, in fact, free to bid any supply curve, with a quantity bid corresponding to the special case of a vertical supply curve. However, an estimate of a static Cournot equilibrium of the electricity market would still provide a rough estimate of competitive behaviour if firms face little demand uncertainty. When there is no uncertainty, it turns out that of the many Nash equilibria that are possible, the one

produced by quantity bids (the Cournot strategy) is the most profitable. Thus, if there were no uncertainty and cost data were available, an estimate of the price-cost margin from the Cournot model could take the place of a structural index such as an HHI calculation.

In a market with uncertain demand, the situation is different. A producer will face many possible demand levels, even when it knows its competitor's production levels. Firms then engage in supply curve competition. This problem was analysed by Klemperer and Meyer (1989) for a general context. Under supply curve competition, it is profitable for firms to move away from the Cournot equilibrium towards a Nash equilibrium that is described in terms of upward sloping (but not vertical) supply curves. Thus suppliers are not bidding simple quantities as specified by the Cournot model. This outcome leads to price-cost margins that are smaller than those from Cournot competition. The introduction of demand uncertainty therefore mitigates the effects of market power.⁶

“The supply-function model ... has some weaknesses that may limit its usefulness when applied to certain electricity markets. In some markets, trades do not occur exclusively, or even primarily, through a supply-function bid process. Bilateral trading of specified quantities is common in many restructured markets around the world, as are futures markets and different forms of spot markets. ... The supply function approach also does not lend itself well to markets where there is a competitive fringe whose capacity may be limited due to either generation or transmission constraints. Overall the supply function approach approximates one important aspect of many restructured electricity markets more accurately than the Cournot approach, but it is not as flexible as the Cournot approach in incorporating other institutional aspects of these markets. Furthermore, the supply function approach produces multiple equilibria and the diversity of these equilibria grows as the uncertainty of demand is reduced. The Cournot equilibrium represents an upper bound on supply function equilibria and is generally easier to calculate, thus it may be a more appropriate screening measure of the potential for market power.”⁷

Features of Electricity Markets That Facilitate Market Power

As already noted, a firm is able to exercise market power when it can, by raising its price, or reducing its quantity, have some influence over the market price. In most markets, the ability of a firm to raise its price or reduce its output of some particular service at a given place and time is limited by:

- (a) the response of consumers who reduce their consumption of the service, switch their consumption to other times, to other places or to other services entirely;
- (b) the response of other firms already producing in the market who expand their own output in response to a increase in price or a reduction in the output of another firm;
- (c) the response of other firms who are not already producing in the market who enter the market in response to an increase in price or a reduction in output of an existing firm.

As we will see, the extent to which each of these constraints operates in the electricity market is limited, for the following reasons:

- First, it is costly to store electricity. “The technologies for storage – for instance, hydroelectric pump storage (pumping water uphill to store as potential energy) or batteries – are quite inefficient”⁸. Because electricity cannot be easily stored, there is a separate market for electricity delivered at each point in time. In the case of storable goods, the price tends to be evened out over time as entrepreneurs purchase the good when the price is low and sell it again when the price is high. Because electricity cannot be stored electricity markets tend to be more volatile than other energy markets, such as gasoline markets. As we will see, although there may be substantial competition between generators at certain times, at other times (especially at times of peak demand), competition may be significantly limited.

- Second, it is at times costly to transport electricity - specifically when the transmission network is congested. When the transmission network is congested, electricity generation markets are divided geographically, reducing the number of potential competitors and potentially enhancing market power. Furthermore the level of congestion depends both on the level of demand and on the strategic decisions of the generating firms themselves.
- Third, the elasticity of demand for electricity is very low. Very few consumers pay a price that varies in line with the market price in the electricity “pool” or “power exchange”. As a result, the drop in demand in response to a rise in the market price is negligible. “Almost no end-use consumers of electricity even have the technology to observe, let alone respond to, real-time prices. Demand is virtually completely inelastic in the short run”⁹. As mentioned above, inelastic demand greatly facilitates the exercise of market power by limiting the extent to which consumers reduce their demand in response to a price rise.
- Fourth, generators face clear constraints on the output they can produce. “Generating units have hard capacity constraints that imply marginal cost turns steeply upward at a certain output”¹⁰. If other firms in the market are capacity constrained they are unable to increase output in response to an increase in price –the market power of remaining unconstrained firms can be substantial.
- Fifth, electricity is a homogeneous good sold in repeated auction markets with a limited number of players who know the costs of the other players and can quickly learn to respond to one another’s behaviour, facilitating collusive practices.

Furthermore, there may be special features of the way that the electricity markets are organised that further facilitate market power, such as the markets for “capacity payments” or “reserve capacity”. These markets may themselves be prone to strategic manipulation by the firms in the market.¹¹

Borenstein and Bushnell summarise the characteristics of electricity markets as follows:

“In most markets, there are other constraints that keep a single firm with a fairly small percentage of production from driving up the price by a large amount. If the good is storable, the buyers, or marketers in the middle, can store product to defend against such vulnerability. If end-user consumers receive the price information before buying, their own hesitancy to pay extreme prices discourages the seller from asking such a price. If there is supply elasticity, one firm demanding a high price for its output will just shift market share to another supplier. Each of these attributes is much less prevalent in electricity markets than in most other industries. The result is that the ability of firms with even modest market shares to exercise market power is greater than in most markets”.¹²

Observations on Market Power in Electricity Generation Markets

Let’s turn now to look in more detail at how market power arises in electricity markets, its impact and how it should be measured. To keep the discussion as simple as possible, let’s start by considering an electricity market without any transmission component – in other words, all production and consumption is assumed to take place at the same location. This allows us to focus exclusively on the effects of capacity constraints on generators. Shortly we will re-introduce the transmission component to explore the effect of transmission constraints.

As mentioned earlier, the predictions of economic models regarding the level of market power that will arise in wholesale electricity markets depends on the nature of the strategic interaction of the

generating firms. However, it is possible to argue that, at least at peak times, some form of market power must be present whatever the form of competition between generators.

Suppose we have a market with capacity constraints on generation and inelastic demand for electricity, and suppose the level of demand is high enough so that if one generator ceased to produce electricity, the remaining generators in the market could not make up for the shortfall themselves. If demand is sufficiently inelastic, that one generator, no matter how small, could raise the market price significantly by reducing its output. Indeed, if demand is perfectly inelastic, that firm could charge any price it wants. Borenstein and Bushnell summarise this intuitive argument as follows:

“Think about the dreadful summer afternoon when the temperature and humidity are at peak levels and the grid needs virtually all resources in production in order to meet the tremendous demand for electricity to run air-conditioning units. If the grid has only a few percent margin of reserve capacity at that time and there is a producer supplying more than a few percent of the total output, then that producer is pivotal in meeting the demand. Put differently, that producer can ask for an extremely high price in order to deliver the power and consumers ... will pay it.”¹³

Note that this argument does not imply that we should expect the degree of market power to rise as the level of demand increases. Whether or not the level of market power increases at peak times depends on the nature of the competition between the generating firms. If these firms compete in quantities (i.e., play a Cournot game) then with any number of identical generators, and constant elasticity of demand, the market power is *constant* for any level of demand, even when almost all the capacity in the market has been exhausted.

This can be seen using equation (1). In a market with identical generators, all produce the same level of output. Therefore either all the generators are constrained or all are unconstrained. As long as these generators are unconstrained, the level of market power is given by equation (1). When all generators produce the same level of output the HHI is just the reciprocal of the number of firms so the market power is equal to $HHI / \varepsilon = 1/n\varepsilon$, independent of the level of demand.

In Appendix B we show that this result remains true even when firms are not identical – as long as the elasticity of demand is held constant and firms are not capacity constrained, an increase in demand has no impact on the price.

On the other hand, if the generators differ in size (and play a Cournot game) market power *increases* as demand increases. As demand increases, more and more of these generators are operating at their capacity, limiting their ability to discipline other market players. In the limit just one generator (the largest) will be left. This last unconstrained generator has an effective monopoly over the residual market demand. This is summarised by the US FTC as follows:

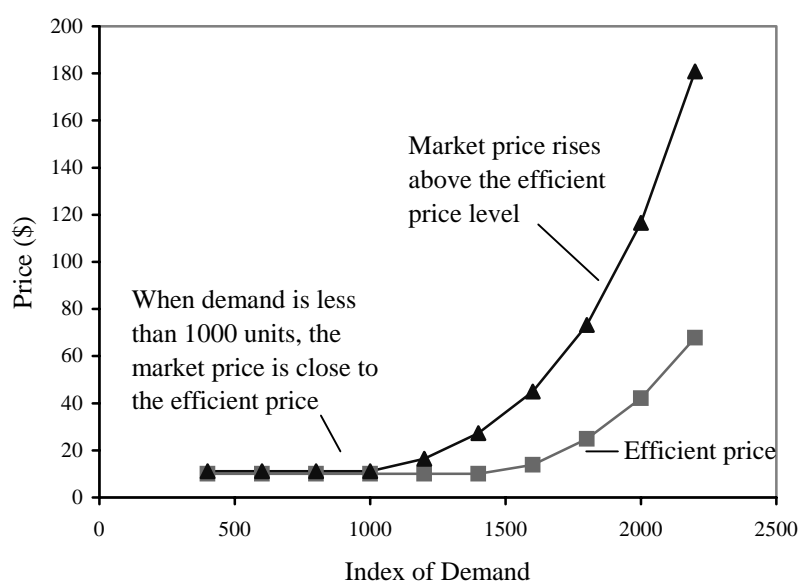
“How can participation of suppliers comprising only a small fraction of capacity affect the market price for electric power? The answer lies in the way in which power plants are dispatched. Power plants tend to have very flat cost functions until they reach their capacity. Thus, power plants tend to operate at maximum capacity if they can economically do so at the prevailing price. Otherwise they tend to be idled. Consequently, most of the power plants generating electricity, at any particular time period, have almost no ability to expand output and offset anti-competitive behaviour”.¹⁴

This is illustrated in the following diagram. The diagram illustrates a market with a constant-elasticity demand curve, with an elasticity of demand of 0.2. There are 51 generators, all with identical marginal cost of \$10 per MW. 50 of these generators are small, with a total capacity of 20 MW. The remaining generator is large, with a capacity of 500 MW. (We can imagine that this large generator is the

result of previous mergers of 25 small generators). These generators are assumed to compete in the quantities that they produce (that is, we will look for the conventional Cournot equilibrium).

Figure 2 illustrates the path of the market price as demand increases. For low levels of demand the smaller generators are not capacity constrained and the price remains close to the efficient market price of \$10/MW. When demand (at the price of \$10) rises above 1000 units, the smaller generators are capacity constrained; the larger generator has an effective monopoly over the residual demand. The generator does not expand output as fast as demand increases, leading to an increase in the market price. Note that when the demand at price \$10 rises above 1500 MW all the generators would be constrained in a perfectly competitive market. As a result, the efficient price (the price in a competitive market) rises above the marginal cost of \$10.

Figure 2. Market Power In Peak Periods In A Market With Generators of Different Sizes



In a market where some firms are operating at capacity, these firms can no longer increase output in response to an output reduction by some other firm. These firms are, in some sense no longer “in the market”. The remaining unconstrained firms are, in effect, competing in a separate market of their own, except that demand in this “separate” market is reduced by an amount equal to the output of all the capacity constrained firms (i.e, this is known as the “residual” demand).

Note that one implication is that in a market where some firms are capacity constrained the relevant market must be defined not only on the basis of the time and location at which the electricity is sold but also on the level of demand. The market may be highly competitive at certain levels of demand and very uncompetitive at other levels of demand.

We can summarise this result in the following observation:

Observation #1: When generating firms differ in their capacity an increase in demand may increase the number of firms operating at capacity and can lead to an increase in market power even though all firms have an identical marginal cost and elasticity of demand is held constant.

Market Power and Concentration Measures

We have already seen that the degree of market power in a market without capacity constraints can be related to concentration in that market according to the following expression.

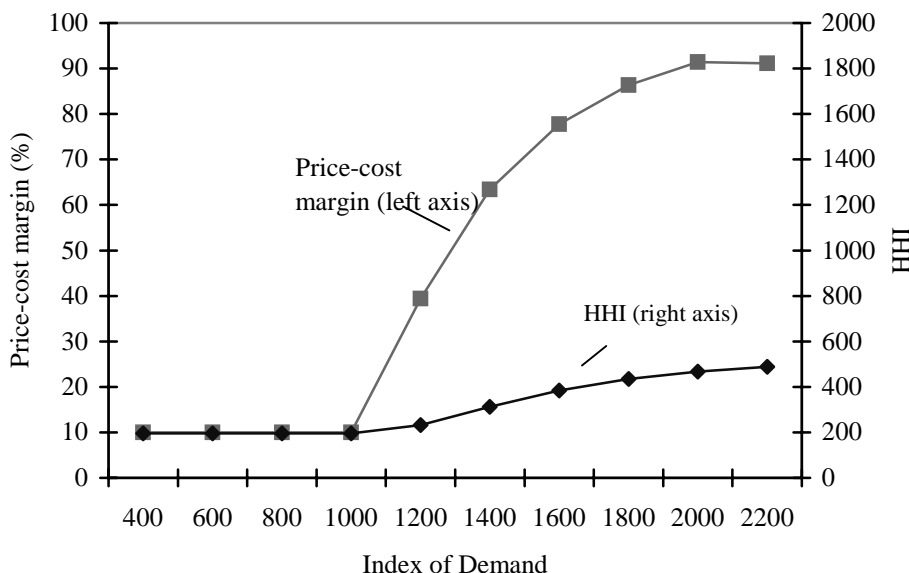
$$\frac{P - c}{P} = \frac{HHI}{\epsilon}$$

where HHI is the sum of the squares of the market shares of the individual firms competing in the market ($HHI = \sum_{i=1}^N s_i^2$ where s_i is the market share of the i th firm) and ϵ is the elasticity of the demand curve at the equilibrium price and quantity.

However, as we noted earlier, the use of HHI to assess market concentration in a market with capacity constraints can yield highly misleading results.

This is easily seen when we consider again the market illustrated in Figure 2 above. In that example there are 50 small firms and one large firm. As we can see in Figure 3, the market is not very concentrated – the HHI never rises above 500 – well below the (somewhat arbitrary) threshold of 1000 that the US Department of Justice uses to designate a competitive market. Yet, as can be seen in Figure 3, the margin between price and cost approaches 90% of the market price, implying relatively low levels of competition.

Figure 3. Concentration vs Price-cost margin



Other measures of concentration do not fare much better. For example, the market share of the largest firm never exceeds around 18%. The other 50 firms have only 1-2% of the market each. The market share attributed to the top 4 firms never exceeds 25%.

Suppose there were originally 75 identical small (20 MW) firms in this market. 25 of these firms propose to merge. With a post-merger concentration less than 500 on the HHI scale, or a CR4 less than 25%, a competition authority might have trouble blocking such a merger. Yet, as can clearly be seen in Figure 2, the merged firm can enjoy significant market power at periods of high market demand.

It is clear that the traditional HHI is a poor indicator of market power in a market with capacity constraints. Is there some alternative that is a better measure of market power in such markets?

In Appendix B we show that the relationship between the Lerner Index, the HHI and demand elasticity still holds, provided we adjust the formula for the HHI. Specifically, we find that in markets where some firms are capacity constrained,

$$\frac{P - c}{P} = \frac{HHI^{adj}}{\varepsilon}$$

where

$$HHI^{adj} = \sum_{i=1}^n s_i \left(s_i + \frac{\bar{s}}{n} \right) \quad \dots(2)$$

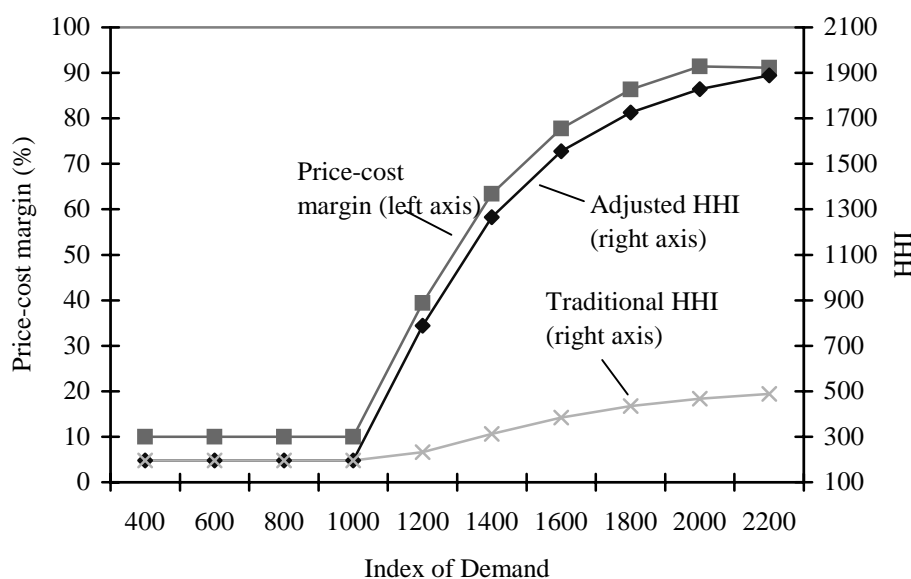
and where n is the number of unconstrained firms, s_i is the market share of an unconstrained firm ($i=1,..n$) and \bar{s} is the combined market share of all the constrained firms.

As an example of the calculation of this adjusted HHI, consider again the market illustrated in Figure 2 and Figure 3. When the demand has the level 1200, all 50 of the small firms produce at their maximum capacity of 20 units of output. The large firm produces 85.6 units of output. The large firm therefore has a market share of around 7.9% while the small firms each have a market share of 1.8%. The conventional HHI would therefore give a market concentration of: $7.9^2 + 50 \times 1.8^2 = 224$.

In contrast, since the combined constrained market share of the small firms is 92.2%, the adjusted HHI is $7.9 \times (7.9 + 92.2) = 790$ - around 3.5 times more concentrated than might be expected by the simple HHI.¹⁵

The difference in the HHI calculations can be clearly seen in Figure 4, which reproduces Figure 3 with the adjusted HHI instead of the conventional HHI. It is clear that the adjusted HHI does a much better job of reflecting the real level of market power in this market for different levels of demand than does the conventional HHI. (Note that in this graph the HHI scale has been offset slightly to separate these two lines which would otherwise be superimposed).

Figure 4. Price-cost margin vs Adjusted Concentration



Observation #2: *In a market where some firms are capacity constrained the traditional HHI measure of market concentration gives inaccurate results and should be replaced by the “adjusted HHI” as given in equation (2).*

Implications for Structural Policies

It is worthwhile exploring some of the consequences of this concept of “adjusted HHI”. To begin, note that whenever demand rises to the point where there is just one unconstrained firm remaining, the adjusted HHI of the market is then simply equal to the market share of that firm – the market shares of the other firms are irrelevant. This can be seen easily by looking at the formula for the adjusted HHI. If there is just one unconstrained firm, (firm 1 say) then the market share of this firm plus the unconstrained firms is, of course, equal to 100% - i.e., $s_1 + \bar{s} = 1$, so:

$$HHI^{adj} = \sum_{i=1}^n s_i (s_i + \frac{\bar{s}}{n}) = s_1 (s_1 + \bar{s}) = s_1$$

One conclusion that we can draw from this is that any attempt to lower market power at a time when there is just one unconstrained firm must involve a reduction in the market share of that firm – presumably through divestiture. *Simply increasing the number of firms in the market will not necessarily have any effect on the level of market power.*

Wolak and Patrick (1997) make a similar point: “Simply introducing more firms in the [England and Wales] market will most likely have little effect There are already many independent power producers serving the market, so that simply increasing the number of competitors is not the solution. Given the current number of firms in the market and the market rules, what is important to limiting market power is reducing the size of the largest firm relative to all the others”.¹⁶

In Appendix B we show that, for a fixed number of unconstrained firms, the adjusted HHI is minimised when all of the unconstrained firms have an identical market share. This market share must therefore be equal to the total share of the unconstrained firms divided by the number of unconstrained firms $\frac{1-\bar{s}}{n}$. The minimum value of the adjusted HHI is therefore:

$$HHI^{adj} \geq \frac{1-\bar{s}}{n}$$

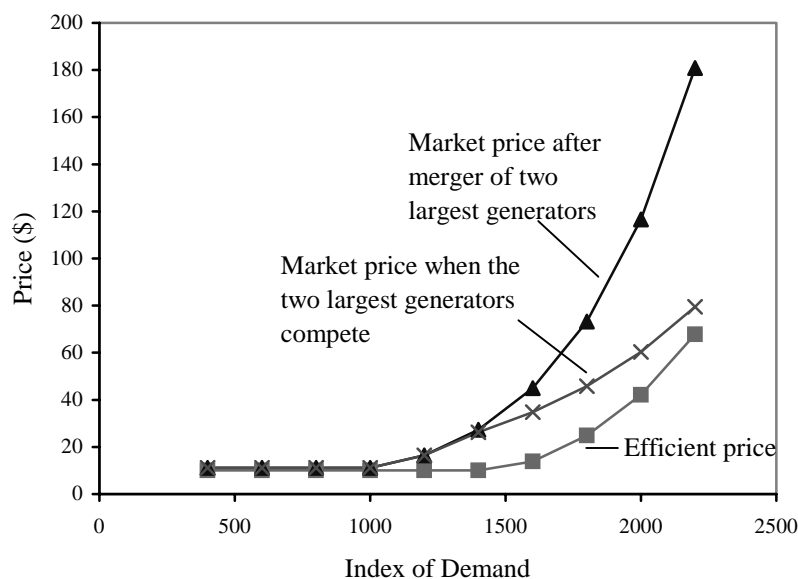
This expression suggests that in order to reduce market power, policy makers should focus on (a) increasing the number of unconstrained firms and (b) reducing the market share of the unconstrained firms (or, equivalently, increasing the share of the constrained firms).

What does this discussion imply for merger policy? One point we can make is that control of concentrations should focus on mergers for which the merged firm will be unconstrained after the merger (a merger of two firms which will remain constrained at a given level of demand has no impact on market power at that level of demand, although it may of course increase market power at other levels of demand).

Another point we can make is that control of concentrations should focus on mergers involving unconstrained firms with marginal generators which are relatively close in the merit order. The market power of an unconstrained generator is limited primarily by the ability of other unconstrained generators to increase their output in response to an increase in price – including those generators which have a marginal cost which is close to the market price but which have not yet been turned on.

In fact, as the next diagram shows, the merger of a generator with a the next-highest-cost generator in the merit order can have a substantial impact on price even when the market share of the of the higher cost generator is very small. Consider again the market described in Figure 2, except now we assume there is an additional generator, with a capacity of 200 MW and a marginal cost of \$25/MW which operates in the market. When the market price rises above \$25 this generator starts producing output. Figure 5 presents the level of prices for different levels of demand both before and after the merger of these two largest firms. The impact of this merger on the market price can be very substantial even when the market share of the highest-cost generator is small. For example, at a level of demand of 1600, a merger increases price from \$34.70/MW to \$45.00/MW (a 30% increase) even though the pre-merger market shares of the two unconstrained generators are only 14.2% and 5.6%.

Figure 5. Effect of a Merger Of Two Firms Which Are Adjacent in the Merit Order

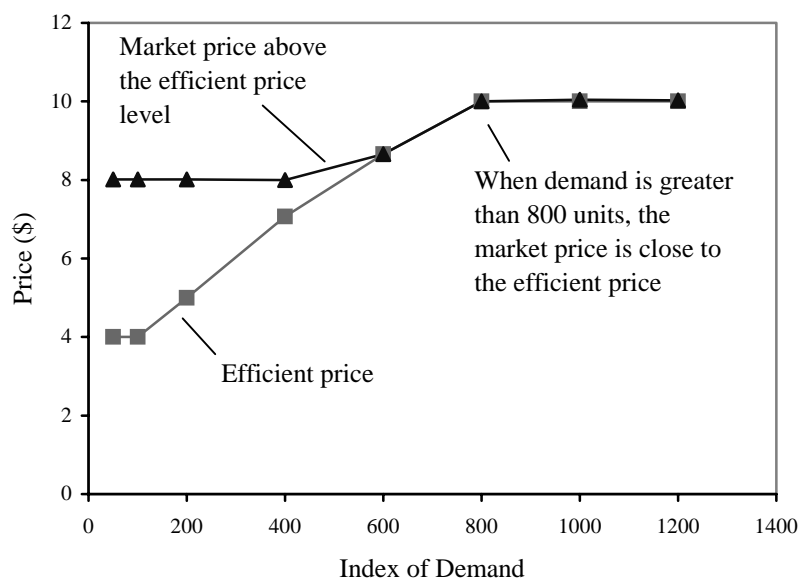


Observation #3: *Control of mergers of generators should focus on mergers for which the merged firm will be unconstrained after the merger and on mergers of firms where the marginal generators are close in the merit order. A merger of two unconstrained firms which are close in the merit order can have a significant effect on price even though both firms have a relatively low market share.*

Market Power at Off-Peak Times

So far in this discussion we have seen how the presence of capacity constraints increases market power relative to a situation with no capacity constraints. But, it is worthwhile emphasising that this does not imply that market power will always tend to increase at peak times. In fact, the reverse may be the case. An increase in demand may, for example, bring into service a very large number of higher cost generators, lowering, rather than increasing, market power.¹⁷

Figure 6 illustrates a market in which there is a single low-cost generator (with a marginal cost of \$4) and a capacity of 800 MW and a large number (50) of higher-cost generators (with marginal cost of \$10). The elasticity of demand is 2. As can be seen from the graph, for low levels of demand the low-cost generator has a monopoly – it exercises this monopoly by charging a market price of \$8. This remains the market price until the monopolist becomes capacity constrained, at which point the price rises to \$10, the other generators enter the market and the price-cost margin drops to close to zero.

Figure 6. Market Power At Off-Peak Periods

Observation #4: Market power is not necessarily limited to periods of peak demand. When generators have different costs, an increase in demand can lead to a reduction in market power (holding constant the elasticity of demand). In other words, market power can also arise at off-peak periods.

New Entry

In this discussion we have seen how the presence of capacity constraints can enhance market power for the remaining, unconstrained firms. Will entry erode this market power?

The scope for entry to erode market power in this market depends (as in any market) on the extent of economies of scale and the technology available to new entrants. If there are no economies of scale and new entrants can select any technology (and cost structure) that they wish, new entrants will choose the lowest cost technology. Such entry will have a tendency to lower the market price relative to marginal cost. Such entry will continue to the point where the (average) price is equal to the average cost of the marginal entrant.

In some cases, incumbent operators may be able to deter entry through the sale of long-term contracts for the electricity that they generate. As discussed later, when incumbent generators have pre-sold a substantial fraction of their output at a fixed price they are more inclined to compete aggressively on the spot market. The reason is that they no longer benefit from cutting their output and raising the market price on all the remaining units that they sell – since most of the remaining units are already sold at a fixed price. By choosing their level of forward contract cover, therefore, the incumbent generators may be able to lower the spot market price to the point where entry is deterred. This possibility is explored by Newbery (1998) who concludes:

“If the industry has enough total capacity (given the number of firms), the incumbents can sell enough contracts to drive the price down to the entry-detering level and will find it most profitable to coordinate on the highest-price, highest-contracted supply schedule that sustains this price. The resulting

equilibrium is one in which the level of contract cover and bidding strategies are both uniquely specified. The threat of entry will, in most cases, cause the incumbents to increase their contract cover, which will make their behaviour in the spot market more competitive and reduce the average pool price. They will also maximise the variability of spot prices, and Newbery (1995) provides evidence that the two price-setting incumbents in the English electricity market, once they grasped the reality of entry threats (or after they had allowed in sufficient competitors to satisfy the regulator's desire for more competition), rapidly co-ordinate their bidding strategy in a way consistent with the story presented here".¹⁸

Consider now the case where entrants can only enter with a higher-cost technology than the bulk of the existing generation. For example, it may be that the bulk of existing generation is relatively low-cost hydro-electric, but that the possibilities for further hydro-electric generation have been exhausted. New entry is possible, but only with, say, oil-fired generation.

The scope for new entry to erode market power that arises higher up in the merit order may be limited. The reason is that the "higher" a generator is in the merit order the higher demand needs to be before the generator is asked to produce. Some generators may only be required for a few periods a day or month. These generators must recover all their fixed and operating costs in a relative short period of operation. For these generators, even relatively small fixed costs are a much more important component of total costs than a generator which is operating almost all the time. In effect, economies of scale are much larger for "part-time" generators.

To see this, suppose, again, that we have a market with 50 identical generators with a capacity of 20 MW and a marginal cost of \$10/MW. Demand is assumed to have a constant elasticity of 0.2. When demand at the price of \$10 increases to 1200 MW, these 50 generators are capacity constrained – they produce 1000 MW of output and the price rises to \$24.88. Suppose that new entrants can enter this market with a technology which has a capacity of 20MW, a marginal cost of \$15 and a fixed cost of \$2. How much new entry can this market support?

If the level of demand of 1200 is sustained indefinitely, this market could sustain a relatively high level of new entry – in fact with a fixed cost of \$2, 19 firms could enter the market. The market price is pushed down to \$15.37 and each new entrant produces 5.32 MW of output.

But what if this high level of demand is sustained only a small fraction of the time? If this demand is sustained only 1% of the time say, this market can sustain only *one* new entrant. The market price is now \$19.58 – which is better than if no entry had occurred at all, but still substantially above the efficient price of \$15.10.

In effect, if only 1% of hours are peak, any fixed costs are magnified by 100 times. This may be sufficient to significantly limit the scope for new entry. Market power may persist for firms higher up in the merit order precisely for this reason.

Observation #5: Market power that arises only at certain times may not be eroded through new entry. The shorter the episodes of excess returns, the more important are even small fixed costs as a barrier to new entry.

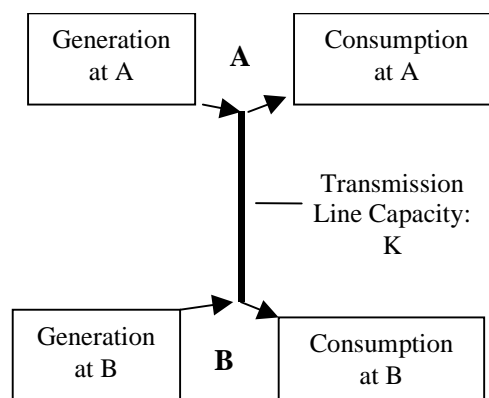
Market Power Due To Transmission Constraints

In the previous sections we saw how market power can arise in a simple electricity industry even without the possibility of transmission constraints. In this section we will see how capacity constraints on transmission networks can further divide markets and further enhance market power.

Electricity is transported over high-voltage transmission networks. Each transmission link between two points can carry a limited maximum quantity of electricity. For simplicity we will assume that the cost of carrying electricity over an uncongested link is zero (i.e., there are no line losses).

Consider, first, the simple transmission network illustrated in the following figure. There is a single transmission link between A and B. Both generation and consumption can take place at both A and B.

Figure 7. A Simple Two-Node Network

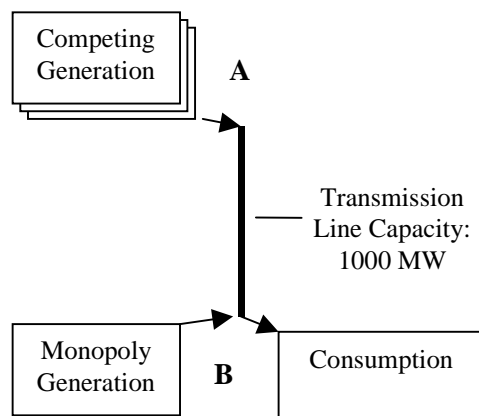


The direction of flow of electricity between A and B depends on the relative price of electricity at A and B. If there is lower demand at A and/or lower-cost generation at A, the intersection of supply and demand at A will tend to yield a lower price than the intersection of supply and demand at B so electricity will tend to flow from A to B. Of course, the quantity and direction of flow over the transmission line may change at any moment of the day in response to supply and demand changes at A and B. In particular, the direction of flow may differ between off-peak and peak times. This is discussed further below.

Transmission Congestion and Market Power at Peak Times

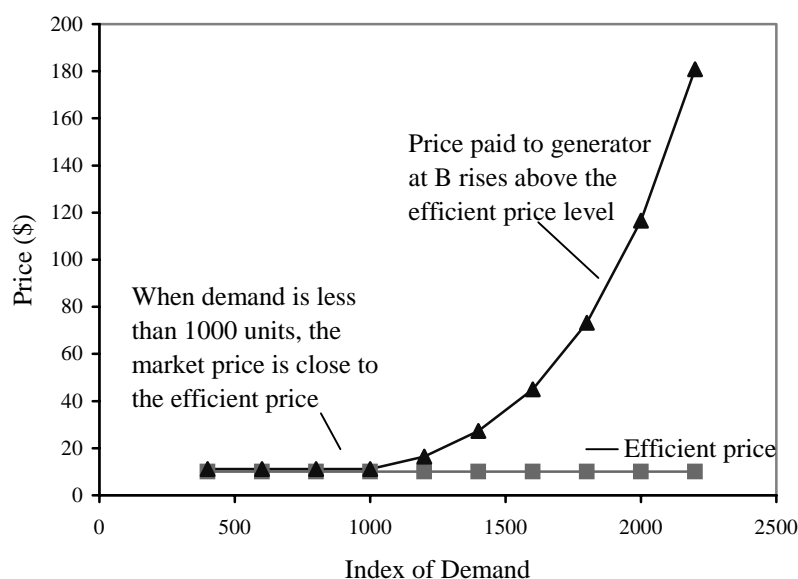
In the section above we saw how the presence of capacity constraints can enhance market power. Transmission network constraints can have exactly the same effect. For example, consider a market in which there are 50 generators located at point A and one generator at point B. Assume that none of these generators is capacity constrained, but the link between A and B has a maximum capacity of 1000 MW. All of the consumption occurs at point B. The demand curve is assumed to have constant elasticity, with an elasticity of 0.2. All the generators have a constant marginal cost of \$10.

Figure 8. A Simple Two-Node Network With Transmission Constraints



The effect of the constraint is illustrated in Figure 9. When demand increases to the point where the link between A and B is congested, any increase in consumption must be matched by an increase in output by the generator at B. As a result the generator at B has significant market power and is able to raise the price further as demand increases. In this example the transmission network constraint operates exactly in the same way as capacity constraints on the generators at A. As before, correct assessment of the market power of the generation market at B requires use of the adjusted HHI.

Figure 9. Transmission constraints at peak times in a simple 2-node network



The effect of the congestion is to allow the market price for electricity at A to differ from the market price at B. Although A and B are in the same electricity market when demand is low, as demand increases the geographic market at A and B separate. The generator at B needs to increase its output in order to satisfy the market demand. The generator at B is sometimes said to be “constrained on” or to be in a situation of “reliability must run”. Again we see that, in the presence of capacity constraints, market definition must take into account not only the time and location at which the electricity is sold but also the level of demand.

A market that is isolated at peak times due to transmission constraints is known as a “load pocket”. For example, when demand for electricity is high in San Diego, the capacity of transmission into the region can be exhausted, leading to a “load pocket” in which San Diego-based generation has significant local market power.

The effect of generator B’s market power depends on how access to the transmission network is priced. Under the so-called “nodal” pricing system prices for injecting or withdrawing electricity can differ from point to point on the network. “Prices vary in a way that reflects the marginal impact of supply on network operating constraints, which can differ by location. Power injected into the network in an area that relieves congestion will receive a higher price than power injected into an area that creates additional congestion. In general, power is more expensive in the areas in which import constraints are binding, although the complexities of power flows can sometimes lead to less intuitive outcomes.”¹⁹ Under a nodal pricing system, when the transmission link A-B becomes congested the price for injecting electricity at A rises above the price for injecting electricity at B, to the point where the generators at A are induced to produce no more than the capacity of the transmission link A-B. The level of output chosen by the generator at B affects both the prices paid by consumers and the price for congestion on the transmission link.

Under “zonal” pricing systems, prices for injecting or withdrawing electricity are constant over a small number of zones covering broad regions. Ideally these zones are chosen in such a way as to reflect regions within which there is sufficient transmission capacity so that intra-zone transmission congestion is rare. Since these prices do not reflect congestion on the transmission network the system operator must occasionally depart from dispatching according to the merit order and must, instead, direct a generator to produce, paying the generator the amount that it bid, rather than the market price for electricity in the zone. Since the amount the generator bid is higher than the system market price, this incurs a cost, which is typically recovered by being spread over all users.

In our example, if A and B are in the same zone, the price for injecting electricity at A and B is the same. Therefore some other mechanism must be used to limit the output at A and increase the output at B. For example, the system operator may require dispatch from B, regardless of the amount bid by the generator at B. The generators at A must be paid a lower amount than the generator at B in order to prevent them from expanding their output. The amount paid by the final consumers for electricity will be lower than the amount paid to the generator at B and higher than the amount paid to the generators at A – in effect the higher cost of the “constrained on” generator at B is spread over all the electricity purchased. Or, put another way, the rents created by the congested transmission network are returned to consumers in the electricity prices. Bushnell and Wolak (1999) write:

“In both kinds of markets, those with a large number of nodal prices and those with only a few zonal prices, strategically located generators can profit from network constraints by raising their offer prices. The existence of transmission constraints means that these generators face less potential competition than those located elsewhere in the network. In the absence of substitutes for the output of these units, the market must either raise the locational price of energy [in the case of zonal pricing] or make an above-market payment to the generator [in the case of nodal pricing]. Such generators are disproportionately able to affect prices, at least in their local areas. During the early years of operation of the England and Wales power pool, for example, strategically located generators learned to adjust their bids to take advantage of their constrained-on status, causing a year-to-year increase in constrained-on payments of over £70 million. Supply bids from these units appear to have been limited primarily by a fear of regulatory intervention”.²⁰

Observation #6: In a simple two-node electricity network with transmission constraints, market power can arise at peak times, even when generators are not capacity constrained. The resulting analysis is the same as if the generators in exporting regions faced generation capacity constraints. The market power of generators in markets into which imports are constrained is correctly reflected by the adjusted HHI.

In the previous section we noted that a merger of an unconstrained firm and a constrained firm might increase market power. Here, in this context, though, a merger of the unconstrained generator at B and an upstream generator at A *has no effect on market power* when the link is congested provided that the link between A and B remains congested after the merger. The reason is that, when the link is congested, any attempt to reduce the output of the generator at A is met by an increase in the output of the other generators, ensuring the link stays congested and eliminating the effect of the reduction of the output on the market price. As long as the flow of electricity through the link remains constant the firm has no incentive to reduce the output of the generator at B. A merger of a generator at A with the generator at B therefore has no overall effect on market power.

Financial Transmission Rights

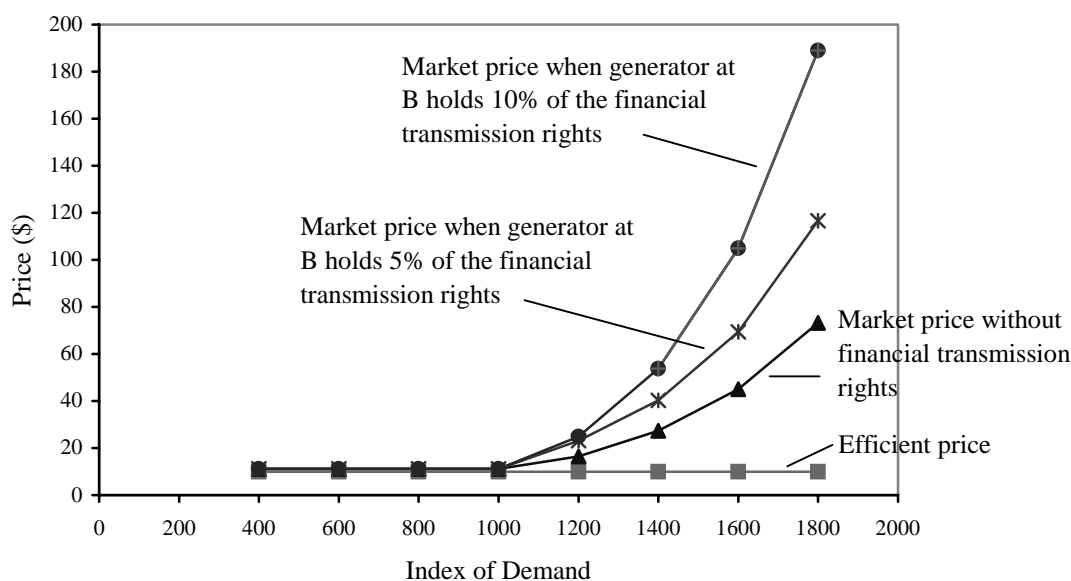
Under the system of nodal pricing, the transmission network is able to collect revenue for the transportation of electricity on congested links. This revenue is known as “congestion rents”. Sellers and buyers of electricity may wish to hedge against congestion charges. One way they can do this is to purchase an interest in the congestion rents – that is, to share in the rent that accrues to the transmission operator. The right to a share of the congestion rents is known as a “financial transmission right”. Does the presence of financial transmission rights affect the level of market power?

The answer is yes. If the generator at B is allowed to purchase a share of the financial transmission rights, it can be shown that its incentive to restrict output increases. In other words, the higher the share of the transmission rights held by the monopoly generator at B, the higher the market price will be. This is explained by Joskow and Tirole (2000) as follows:

“The larger the fraction of rights held by the generator [at B], the stronger its incentive to jack up the price [at B]. ... The [generator at B] now has two revenue streams: one stream of revenue from sales of energy and a second stream of revenues from the congestion rents that it is entitled to by virtue of holding financial rights. The more the [generator at B] internalises the congestion rent, the higher the congestion rent... it effectively reduces the elasticity of the residual demand curve and increases market power. ...

When [the generator at B holds all the financial transmission rights it] faces the total demand rather than the residual demand it faces when it holds no financial rights. That is, if the monopoly generator [at B] holds all the financial rights, it maximises its profit (... its net revenues from supplying energy plus its revenue from congestion rents) as if it had a monopoly over the entire demand function. In doing so, the [generator at B] sacrifices some profits it would otherwise earn from supplying electricity in order to increase the profits it receives in the form of “dividends” on the financial rights it owns a result of its ability to increase the price”.²¹

This is illustrated in Figure 10. The graph illustrates the market price for different levels of demand for the same market structure as in Figure 8, but with the generator at B holding a varying share of the financial transmission rights.

Figure 10. Effect of Financial Transmission Rights on Market Power

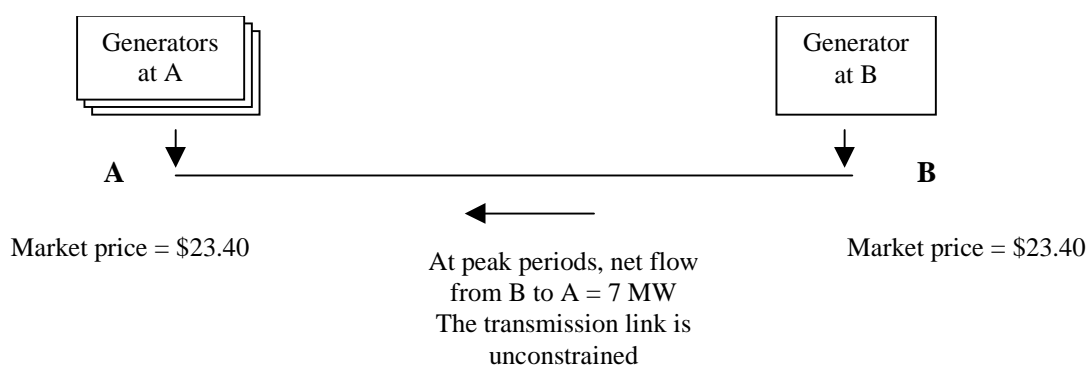
Observation #7: *When the transmission network sells rights to a share in the congestion rents, those generators which benefit from congestion have an incentive to purchase those rights and in doing so can enhance their market power.*

Transmission Congestion and Market Power at Off-Peak Times

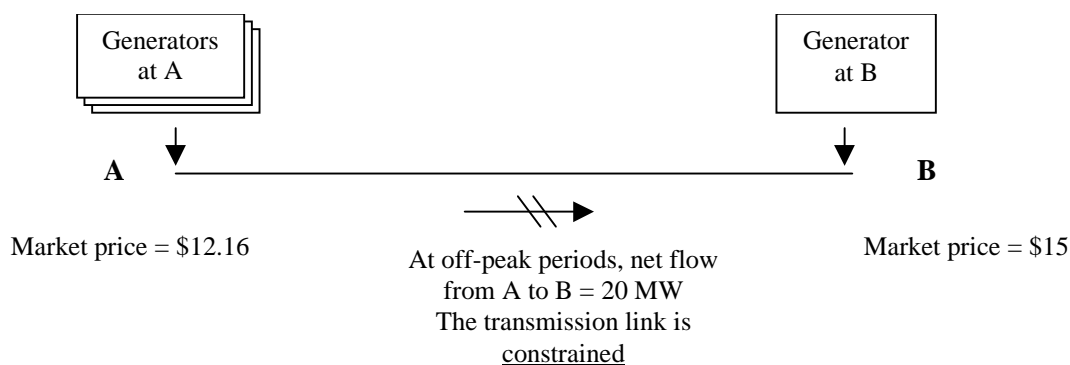
In the simple example that we have just discussed, the market power only arises at times of peak consumption. In a slightly more general model it is possible to show that transmission network congestion might arise only at *off-peak* times, even in a market in which all firms have identical marginal cost.

The possibility for network congestion only at off-peak times is clear at an intuitive level. The direction of electricity flow between A and B depends on the market price for electricity at A and B. At peak times, it is possible that production and consumption at each location would be balanced, with relatively little flows over the link connecting A and B. If, at off-peak times, demand drops at A more than B, generators at B would like to export to A. The quantity of these exports may exceed the capacity of the link between A and B.

For an explicit example, consider a market in which demand at A and B is linear, with a slope of 0.5. There are 50 generators at A and only 1 at B. All have a constant marginal cost of \$10. The link between A and B has a capacity of 20 MW. At peak times the level of demand at A is 1200 and the level of demand at B is 40. At peak times the link between A and B is not congested so the price in both markets is the same. This market price is \$23.40. At that price, the generator at B exports 7 MW of electricity to the market at A.



At off-peak times, demand at A reduces to a level of 200, while demand at B remains at 40. The price drops in both markets, but it drops by more at A. The generators at A attempt to offset this price reduction by exporting to B, but the link between A and B becomes congested. The market price at A is \$12.16 and the market price at B is \$15.



Observation #8: In a simple two-node electricity network with transmission constraints, market power may arise at off-peak times, even when all generators have the same marginal cost.

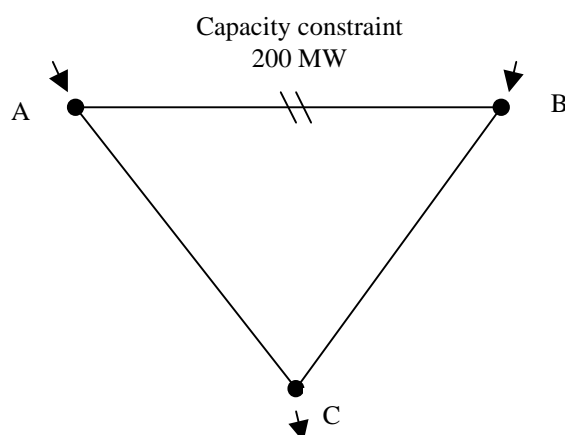
Transmission Congestion and Loop Flow

In the previous section we looked at the effects of congestion in the simplest possible transmission network consisting of a single link between two points. In slightly more complicated transmission networks a new possibility arises, called “loop flow”. In this section we will illustrate how, in the presence of loop flow, a generator can enjoy market power *even though there are no capacity constraints on the links between generators and consumers*.

Loop flow arises because electricity cannot be directed to take any one particular path. Instead electricity flows over a network following the path of least resistance. When there is more than one path between production and consumption, the electricity flows over all the possible paths in quantities that are inversely proportional to the resistance of the path.

This can be illustrated in a simple three-node network, as in Figure 11. Figure 11 presents a simple electricity network with three nodes and three links between these nodes. All the links have equal lengths. Generation occurs at A and B, while consumption occurs at point C. At point B there are a large number of competing generators while point A hosts a single generator. The links between A and C and B and C have no capacity constraints, while the link between A and B is constrained to, say, 200 MW.

Figure 11. A Simple Three-Node Network with a Constraint on the Link A-B



Power generated at A can reach its destination over two paths – a direct path A-C and an indirect path A-B-C. Since the indirect path is exactly twice as long it has exactly twice the resistance of the direct path, so the direct path carries twice the power of the indirect path. In other words, of all the power generated at A, one third travels via A-B-C and two-thirds travels A-C.

The same is true for the electricity generated at B, so the net flow over the link A-B is one third of the difference in the output of the generators at A and B. Since this link has a limited capacity, we can deduce that the difference in the output of the generators at A and B can never exceed three times the capacity constraint on the link A-B.

Figure 13 illustrates what happens in this industry when demand increases from low levels to increasingly high levels. At low levels of demand the difference in output of the generators at A and B is sufficiently small that the link A-B is not congested. However, an increase in demand elicits a much greater response from the generators at B than at A. At moderate levels of demand the link A-B becomes congested. At higher levels of output the output of A must increase by one unit for every one unit increase in the output at B. In effect the generator at A is “constrained on”. This generator is in a position analogous to the “load pocket” generator of Figure 9. The difference in this market is that the generators at B are not entirely prevented from expanding their output – merely that they can only expand output when generator A does so simultaneously. In effect, rather than facing the entire residual demand, the generator at A faces exactly one half the residual demand. Still, this places the generator at A in a position of significantly enhanced market power. As demand increases the market price at C increases rapidly. This is illustrated in Figure 13.

Even though the generator at A has some market power when there is a constraint on the link between A and B, this market power is significantly enhanced when there is constraint on the link between B and C as in Figure 12. In this case additional production at A does not relieve congestion on the link B-C, rather it worsens congestion. An increase in output by the generator at A can then simultaneously increase high-price sales at C and restrict the output of rival imports from B. The resulting prices for different levels of demand is illustrated in Figure 13.²²

Figure 12. A Simple Three-Node Network with a Constraint on the Link B-C

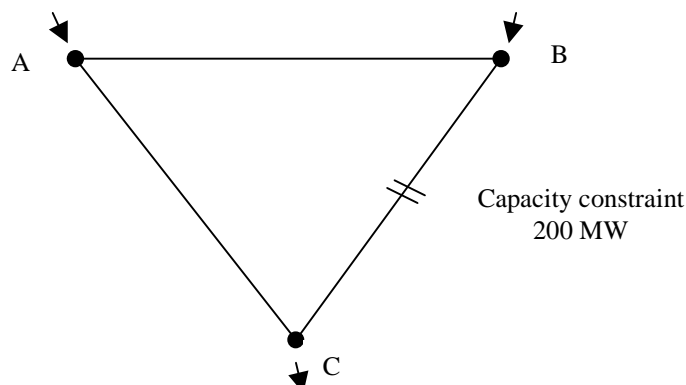
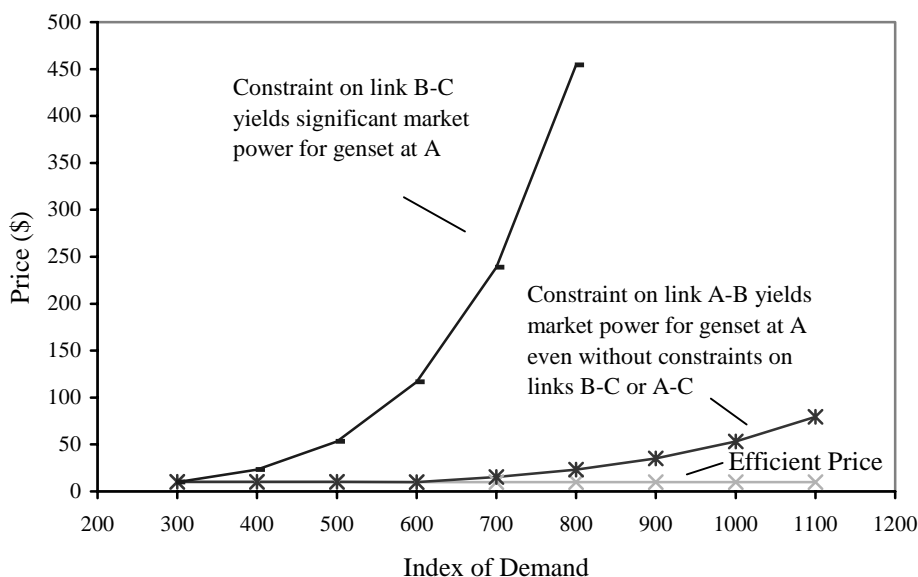


Figure 13. Market Power in a Three-Node Network



Observation #9: *In a simple 3-node network with transmission constraints, market power can arise even when there are no capacity constraints on the direct transmission links between generators and consumers.*

Market Power in Practice

A large number of studies of market power in wholesale generation markets have been carried out. Appendix A reproduces an excellent survey of studies of market power by the US Department of Energy.

Interesting studies of market power in the England and Wales market include Green (2002), Wolfram (1999, 1998), Wolak and Patrick (1997), Newbery (1995a) and Green and Newbery (1992).

There are numerous studies of market power in the California wholesale market including Borenstein (2002), Borenstein, Bushnell and Wolak (2002), Borenstein, Bushnell and Wolak (2001), Joskow and Kahn (2001), Hildebrandt (2001a, 2001b), Puller (2001), Sheffrin (2001), Wolak, Nordhaus and Shapiro (2000), Bushnell and Wolak (1999), Borenstein and Bushnell (1998) and Borenstein, Bushnell, Kahn and Stoft (1996).

Studies of market power the electricity market in Scandinavia (“Nordpool”) include Johnsen, Verma and Wolfram (1999), Andersson and Bergman (1995), Halseth (1999), and Hjalmarsson (2000)²³.

The two boxes on the following pages summarise some of the results of one or two these studies of the England and Wales power pool and the California power exchange.

Is Market Power in Electricity Markets Harmful?

Market power problems seem to be common in wholesale electricity markets, but is this market power genuinely harmful? After all, if demand is inelastic, the effect on demand from higher prices is virtually nil – in other words, one of the very features which makes market power a significant issue (demand inelastic) also ensures that the resulting market power has very little impact on welfare. If demand is inelastic, the deadweight loss from market power is zero. “Due to extreme short-run inelasticity of demand, market power in electricity markets has little effect on consumption quantity or short-run allocative efficiency”.²⁴

However, allocative efficiency is not the only component of overall welfare which is affected by market power. Market power can also give rise to productive inefficiency if the exercise of market power induces substitution of higher-cost for lower-cost generating units in the short-run, or if it induces entry of inefficient generation units in the medium and long-run. Borenstein, Bushnell and Wolak (2002), write:

“[T]he exercise of market power by one firm can lead to an inefficient reallocation of production among generating firms: a firm exercising market power will restrict its output so that its marginal cost is below price (and equal to its marginal revenue), while other firms that are price-taking will produce units of output for which their marginal cost is virtually equal to price. Thus, there will be inefficient production on a market-wide basis as more expensive, competitive production is substituted for less expensive production owned by firms with market power. This is the outcome Wolak and Patrick (1997) described in the UK market, where higher cost combined-cycle gas turbine generators owned by new entrants provide baseload power that could be supplied more cheaply by coal-fired plants that were being withheld by the two largest firms. ...

In addition, several recent analyses have demonstrated that the exercise of market power in an electricity network can greatly increase the level of congestion on the network.²⁵ This increased congestion impacts negatively both the efficiency and the reliability of the system. Market power can also lead firms to utilise their hydro-electric resources in ways that decrease overall economic efficiency.²⁶

Lastly, electricity prices influence long-term decision-making in a way that can seriously impact the economy and efficient investment. While it has been pointed out that high prices should spur new investment and entry in electricity production, these investments may not be efficient if motivated by high prices that are caused by market power, which may indicate a need not for new capacity, but for the efficient use of existing capacity. Artificially high prices also can lead some firms not to invest in productive enterprises that require significant use of electricity, or to inefficiently substitute to less electric-intensive production technologies”.²⁷

Market Power in the England and Wales Power Pool²⁸

From April 1990 until March 2001 all but a small fraction of the electricity consumed in England and Wales had to be sold through a day-ahead spot market with market-clearing prices set on a half-hourly basis. In 1990 the former integrated state-owned electricity company (the Central Electricity Generating Board) was separated into three large generation companies. Two of those companies, National Power and PowerGen took over all of the existing fossil fuel power stations. The nuclear power stations remained state-owned. These three companies compete with independent power producers, generators in Scotland and Electricité de France, which can supply electricity into the UK through an interconnector with France. However, the cost of these other operators and the presence of transmission constraints means that these other generators are very seldom in a position to affect the market price of electricity in the UK. Although there has been substantial entry, in 1996 the market price was set by National Power or PowerGen 84% of the time, and another 11% of the time, the transmission network's pumped storage facilities set the market price.

The price paid to generators under the previous market rules (which was known as the pool purchase price or PPP) was the price bid by the marginal generator (known as system marginal price or SMP) plus a term called the capacity charge (CC). (i.e., $PPP=SMP+CC$). The capacity charge was given by the formula $CC = LOLP \times (VOLL - SMP)$. LOLP was the loss of load probability and was an decreasing function of the expected amount of excess capacity available during each half-hour period. The more excess capacity there is available, the lower the LOLP. VOLL is the value of loss load which was a constant – set at £2000 in 1990 and increasing at the CPI thereafter. Wolak and Patrick (1997) emphasise that the capacity charge component provided strong incentives for generators to withhold capacity – not only does doing so increase the system marginal price, but also, by reducing the amount of spare capacity available, it also increases the capacity charge. The capacity charge was abolished when England and Wales adopted new market rules in March 2001.

The first paper to attempt to model market power in the E&W power pool was a paper by Green and Newbery (1992). This paper models the competition between PowerGen and National Power as a non-co-operative game where each generator chooses not its quantity (as in a Cournot game) but its entire supply function (i.e., the amount it will produce at each possible market price). Green and Newbery choose parameters for their model which are intended to reflect the situation in the E&W market. They conclude that there is substantial monopoly power in this market as it then existed:

“In the short run the strategies followed by National Power and PowerGen will have little effect on the level of entry, and in this period, they have very considerable market power, which they can exercise without collusion by offering a supply schedule that is considerably above marginal operating cost. They have additional methods of market manipulation that exploit the constraints on the grid's transmission capacity, since their market power in some of the regional sub-markets is considerably greater than in the country as a whole. ...

In the medium run, considerable entry is already planned and is a logical response to the likely market equilibrium, though our calculations suggest that the forecast level of capacity expansion is not justified on social cost-benefit grounds. ... [T]otal dead-weight loss is £262 million higher than if the industry had been divided up into five equal-sized firms, in our central case of the demand elasticity and our optimistic assumption that the incumbents act as a symmetric duopoly. Even though entry will cause the incumbents to set lower prices, considerable social loss is caused by the large and unnecessary induced investment in additional capacity.

Our analysis suggests that the scope for the exercise of market power has been seriously underestimated by the government, perhaps misled by the notion that Bertrand competition is necessarily very competitive, even in concentrated markets. The potential dead-weight losses are high, both on the demand side and on the cost side as a result of departures from the efficient merit order. ... Almost all these inefficiencies could have been avoided by subdividing the industry into five equal-sized rather than two unequal thermal generators. ... One is forced to conclude that a great opportunity to move to a competitive and unregulated supply industry was lost. Whether it is better to move to a US style of regulating the generators to keep prices low enough to deter unwanted entry or whether it is better to accept this extra cost in the hope of moving to a more competitive industry that does not require regulation remains an interesting and open question”.²⁹

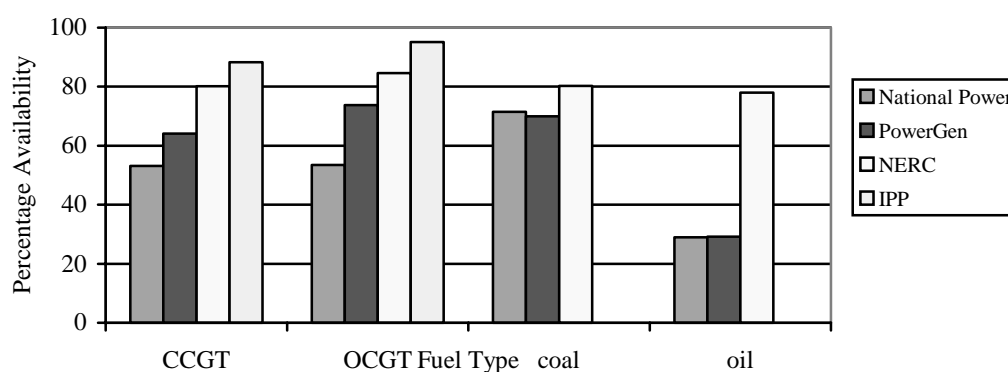
Writing a few years later, in 1997, Wolak and Patrick argued that although bidding above marginal cost was feasible, it could easily be detected and punished. A preferable strategy, therefore, was to withdraw infra-marginal capacity –

doing so not only raises the system marginal price but also the capacity charge.

“Bidding prices in excess of marginal cost for each genset is one way for these producers to obtain large values of the SMP and therefore large values of the PPP and PSP. However, because it is relatively straightforward to perform the marginal generation fuel cost calculations for each genset using its fuel costs and heat rates ... bidding substantially above the marginal cost for any genset would be relatively easy for the Director General of OFFER to detect. ... Generators would face severe credibility problems rationalising bids in excess of £100/MWh for anything but peak-load gensets. ... [G]iven the market rules, bidding prices substantially in excess of each genset’s marginal cost to obtain high prices is not likely to be as successful at achieving this goal as a strategy involving capacity withholding.

A more high-powered and more difficult to detect strategy for the two major generators is to bid each genset at close to its marginal cost and then declare capacity unavailable in different load periods throughout the day so that the forecasted value of total service load for the next day crosses the day-ahead aggregate industry supply curve in the rapidly increasing portion of aggregate bid function for as many load periods during the following day as is feasible given the physical constraints of bringing gensets on and off line. By declaring unavailable capacity from the flat (baseload) portion or upward sloping (intermediate load) portion of the bid function, a generator can control where its bid function becomes very steep. This strategy achieves a large value of SMP and, more important, a small expected reserve margin and accompanying large value of CC during these load periods.”

Amongst other evidence to support their claim, Wolak and Patrick show that the actual availability of generation facilities of National Power and PowerGen were substantially lower than North American standards and even lower than the availabilities of independent power producers in the UK.



NERC = availability figures from the North American Electric Reliability Council. IPP= average of availabilities of independent power producers in the UK (most of whom use CCGT)
CCGT = combined cycle gas turbine; OCGT - ordinary cycle gas turbine (1995)

In March 2001, the rules of the England and Wales power pool were changed. Instead of requiring all trades to occur in the spot market, bilateral trades were allowed between buyers and sellers. The capacity payment was abolished. 3.5 hours before each half-hour period buyers and sellers notify their contracted positions to the system operator and also submit bids for the balancing market. The system operator uses these bids to ensure an “energy balance” and a system balance (to relieve congestion and ensure the security and quality of supply in real-time).

Market Power In the California Electricity Market³⁰

Severin Borenstein, James Bushnell and Frank Wolak all have played key roles in the California electricity market. Borenstein is a member of the Governing Board of the California Power Exchange, Bushnell was a member of the Power Exchange’s Market Monitoring Committee during 1999-2000 and Wolak is chair of the California Independent System Operator’s Market Surveillance Committee. In a recent paper they summarise the results of their

measurement of market power in California's wholesale electricity market:

"California's restructured wholesale electricity market opened in 1998 and operated relatively smoothly for two years. Beginning in the summer of 2000, however, prices increased dramatically, more than tripling from their levels in the previous summer. While some observers said that this was simply the result of growing demand and inadequate supply, others argued that sellers exercised market power. ... [Our results show] that there were significant departures from competitive pricing and that these departures were most pronounced during the highest demand periods, which tend to occur during the summer. ... We find that 60% of the change in wholesale market expenditures, which rose from about \$2.1 billion in summer 1999 to over \$9 billion in summer 2000, can be attributed to market power. ...

We find that, due to rising input costs, even a perfectly competitive California electricity market would have seen wholesale electricity expenditures triple between the summers of 1998 and 2000. Market power, however, also played a very significant role. In summer 1998, 27% of total electricity expenditures could be attributed to market power, a figure that increased to 51% in summer 2000. The increased percentage margins due to market power combined with substantial production cost increases for marginal producers to create a drastic rise in absolute margins and, thus, push the market into a crisis later in the summer of 2000. ...

The California electricity generation market at first glance appears relatively unconcentrated. The former dominant firms, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) divested the bulk of their fossil-fuelled generation capacity in the first half of 1998 and most of the remainder in early 1999. Most of the capacity still owned by these utilities after the divestitures were covered by regulatory side agreements, which prescribed the price the seller was credited for production from these plants independent of the PX or ISO market prices. These divestitures left the generation assets in California more or less evenly distributed between seven firms. ...

[The results of the analysis] show that market power steadily increased with the demand faced by the non-utility instead suppliers ... During lower demand hours and months, as well as springtime months when significant hydro energy is available, no single firm can affect prices significantly. During higher demand hours, however, competitive source of energy begin to reach their capacity limits and the pool of potential competitors for additional supply dwindles. Because of the lack of significant storage capacity and the inelasticity of demand, firms can take advantage of the capacity limits of their competitors during these high demand hours. ... The combination of the concentration of ownership of generating assets and the level of demand did combine to create circumstance where one or more market participants recognised that their capacity was needed to meet the ISOs energy and ancillary services needs regardless of the actions of other market participants. Under these circumstances, firms find it in their unilateral interest to raise bid prices even though there is sufficient capacity available to meet the California ISO's total energy and ancillary services requirements. ...

Between the summers of 1998 and 2000, the wholesale market cost of power rose from \$1.7 billion to over \$9 billion. Efficient production costs more than tripled between these periods and with the marginal unit having higher costs, competitive rents for lower cost units also more than tripled. Oligopoly rents, however, increased by an order of magnitude, from about \$455 to about \$4.7 billion between these summers. Thus while a substantial portion of the increased market cost of power was due to rising input costs and reduced imports, these factors also increased the dollar magnitude of the market power that was exercised by suppliers. ... The underlying competitive structure of the market does not appear to have changed substantially between 1998 and 2000. Rather the higher demand and lower import levels in 2000 created more frequent opportunities for in-state fossil-fuel producers to collect large margins on increased costs, leading to the 10-fold increase in oligopoly rents to suppliers.

Production Costs and Rent Distribution (\$ millions) June-October

	1998	1999	2000
Total Actual Payments	1710	2097	9250
Total Competitive Payments	1255	1668	4520
Production Costs – Actual	767	1047	3016

Production Costs – Competitive	717	954	2433
Competitive Rents	538	714	2087
Oligopoly Rents	455	429	4730
Oligopoly Inefficiency – Instate	27	29	113
Oligopoly Inefficiency – Imports	22	64	470

An earlier paper by Borenstein, Bushnell and Knittel (1999) uses computer simulation of the California market and comes to similar results:

“We found ... that under the generation ownership that existed in 1997 there would be significant potential for market power in hours with high demands. ... At the higher demand levels, many producers reach their full output capacities. The disciplining effect of those producers on strategic behaviour by the remaining firms is therefore severely reduced. These remaining producers can profitably reduce their output, knowing that most of their capacity-constrained competitors will be unable to respond with increased production. Ironically, when such behaviour occurs, the concentration in the market appears to be reduced, since the strategic firms – the largest producers – are, in fact, withholding production, and therefore reducing their market share. We found many cases in which the price-cost margin increased as concentration declined. ...

[In our simulations] the Cournot price closely tracks the perfectly competitive price at low demand levels and then rises sharply beyond a certain threshold level, around 27,000 MW. Prices at this point begin to rise because an increasing number of competitive firms reach their maximum capacity. The two largest firms, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) then find it profitable to reduce their output and drive up prices. The resulting effect on concentration is that the market appears most concentrated at demand levels where these two firms are not trying to reduce output and, thus, mark-ups are low.”

Remedies for Market Power in Electricity Markets

Let's turn now to look at what can be done about market power in wholesale electricity generation markets. At a general level, the various policies for mitigating market power are well known from other markets, and include policies to:

- (a) increase competition from rival products – e.g., enhancing the ability of consumers to use rival forms of energy;
- (b) increase competition between time periods – e.g., to enhance the storability of electricity;
- (c) increase competition across geographic areas – in particular through the construction of transmission links or the alleviation of constraints on existing links;
- (d) increase the sensitivity of demand to price – e.g., through time-of-day metering or self-generation;
- (e) promote entry of new generators;
- (f) lower prices or increase quantities by direct regulatory controls;
- (g) separate electricity companies horizontally or vertically;

- (h) changes the rules governing the electricity market itself to reduce the incentive to withhold capacity or reduce reserves.

Of these policies, the authorities have relatively little control over the first two. The extent to which consumers are able to switch to other fuels, or the extent to which electricity can be stored, is largely a function of current levels of technology over which policy-makers have relatively little short-term influence. We will therefore put these policies to one side and focus on the remaining policies.

Policies to Enhance Competition across Geographic Areas

Competition between generators in different geographic areas can be enhanced through either (a) the construction of new transmission links; (b) the enhancement of capacity on existing congested links; (c) improvements in the degree of utilisation of existing infrastructure; or (d) through improving the efficiency of the pricing of access to the transmission network.

Let's look first at methods to improve the efficiency of transmission pricing. If the marginal price of transmission is above the marginal cost of transmission, generators will be artificially "separated" geographically. This is particularly likely to arise under the practice of "pancaking" transmission rates under which fees are paid to each transmission owner along the contract path. The total fees for the use of the transmission network are equal to the sum of the fees paid to each transmission owner along the route. The US Department of Energy finds in its simulations that pancaked fees "raise the cost of wheeling power across more than one utility system and effectively reduce the geographic scope of several regional markets".³¹ "Distance-based" transmission pricing may also lead to a marginal price for transmission above its marginal cost. The European Commission recognises that this may be a problem for cross-border flows of electricity within the EU:

"Currently there is little co-ordination between different transmission system operators or regulators to ensure that tariffs for cross border transactions are cost reflective. In most cases, cumulative transit charges are still levied in each Member state along a notional contract path. This process, known as 'pancaking' is not cost reflective; for example it does not reflect the actual physical flow of electricity, or recognise that some flows may actually alleviate congestion and reduce costs. Some Member States also impose specific import or export charges."³²

In some cases, congestion may be exacerbated by underutilisation of existing infrastructure. This might arise, for example, if a transmission link into a high-cost area was owned or controlled by generators based in that area, which stand to lose from the import competition. This is particularly a problem in the EU where incumbent electricity companies in many companies own or share control over cross-border transmission links. One solution to this problem is structural separation of these transmission links from generation in high-cost areas (discussed below). A series of guidelines for improving access to this infrastructure (short of structural separation) was agreed at the 6th meeting of the European Electricity Regulatory Forum. These guidelines require:

- "(i) Member States to ensure that capacity is allocated on a non-discriminatory basis;
- (ii) a high level of transparency regarding available capacity;
- (iii) capacity to be allocated according to market-based methods (auctioning, market-splitting, etc.)
- (iv) that any profits from auctions do not accrue to transmission system operators, and
- (v) the application of the 'use-it-or-lose-it' principle"³³

What processes should be put in place to ensure efficiency enhancement of the transmission network? This is a difficult and still largely unresolved question.

We may note that nodal pricing mechanisms enhance the incentives for private companies to voluntarily seek to upgrade the transmission network and improve the incentives on generators to make efficient location decisions – that is, to locate in regions which alleviate rather than exacerbate transmission constraints. Indeed, the US regulator, FERC, is currently considering allowing merchant transmission firms to enter and sell the financial transmission rights from their transmission investment. Even in the absence of a full nodal pricing mechanism, there may be opportunities for companies to enhance competition through the construction of transmission links which exploit price differences between regions or across national boundaries (as in the EU). Many authorities are seeking to encourage this kind of investment.

It is unclear, however, whether reliance on private incentives will lead to an efficient levels of investment.³⁴ Several points are worth noting:

- First, it is not clear that private entrepreneurs will have incentives to build a transmission link of sufficient capacity. If the only source of revenue for a transmission link is the congestion rents, the entrepreneur will have no incentive to eliminate those congestion rents entirely. Thus private entrepreneurs may mitigate, but could not be expected to eliminate transmission congestion.
- Second, private entrepreneurs may fail to build a transmission link at all, even where one is justified. A transmission link between two locations may be worth constructing even if there is no price difference between the two locations at any time of the day, even if the transmission link is never congested and even if no electricity ever flows over the link. A transmission link between two locations enhances the scope for competition between generators. Construction of a transmission link will therefore have a tendency to lower prices. The effect on prices may be sufficiently strong to justify the link even if, in equilibrium, no electricity actually flows over the link.³⁵
- Third, it is conceivable that, in some cases, there may be incentives for construction of a transmission link which is harmful for overall welfare - in particular, the construction of a transmission link between two points may enhance rather than reduce market power. This can clearly be seen in the discussion above in the case of the network illustrated in Figure 11. In that network, if there were no link between A and B, the generators at A and B would compete at point C. The construction of the link between A and B diverts some electricity from A and B via an indirect route to C. As the discussion associated with Figure 11 showed, if the link between A and B has a limited capacity, a situation can arise where the generator at B must produce if the capacity constraint on the link between A and B is not to be violated.³⁶

In part because of these observations, Joskow expresses doubts that transmission upgrades could be left entirely to market forces:

“Transmission investment decisions do not immediately strike me as being ideally suited to relying entirely on the invisible hand. Transmission investments are lumpy, characterised by economies of scale and can have physical impacts throughout the network. The combination of imperfectly defined network property rights, economies of scale and long-lived sunk costs for transmission investments, and imperfect competition in the supply of generating services can lead to either under-investment or over-investment in transmission at particular points on the network if we rely entirely on market forces. However, there is no reason why the primary initiative for transmission upgrades should not be left to private parties, especially if a reasonably good allocation of capacity rights, whether physical or financial, is created. The network operator could then determine whether proposed upgrades have adverse uncompensated effects on some users of the network, or whether there are inadequate private

market incentives for investment because of scale economies of free-riding problems. In those cases the network operator could identify investment projects that the transmission owners would be obligated to build and the associated costs could be recovered from all network users. This appears to be the direction in which public policy is now moving.”³⁷

The problem of creating the right incentives for efficient transmission network enhancement will be one of the most important regulatory issues to address in liberalised electricity industries in the future.

Structural Policies

As in other markets, competition between generators can be enhanced through various forms of horizontal and vertical separation. The discussion in the previous sections allows us to be more precise about which forms of separation should be targeted. Specifically, at any given level of market demand, the degree of market power depends on (amongst other things), (a) the market share of unconstrained generators, (b) the number of competitors and degree of competition between unconstrained generators and (c) the extent to which an increase in price induces new generators to enter the market.

Structural separation (or its opposite, the control of concentrations) should therefore focus on separating unconstrained generators, especially when the separated generators would themselves be unconstrained post-separation and especially when the unconstrained generators have a similar marginal cost, such as when they use a similar fuel source. Hilke notes that “To the extent that generators with the same fuel type cluster along specific portions of the supply curve, the structure of the ownership of generation from a particular fuel source may have significant market power implications during periods when generators using a specific fuel source are at the margin”.³⁸

Structural separation could also focus on the separation of generation and transmission. In many of the earlier examples the primary competition to generation in a geographic area was via transmission links. If we assume that facilities-based competition in transmission is difficult or impossible, the control by a generator over transmission may give it control over its primary rivals. We saw above how ownership of financial transmission rights can further enhance the market power of generators. Earlier we mentioned how the guidelines agreed at the European Electricity Regulatory Forum seek to promote non-discriminatory use of transmission lines in this circumstance. In many cases it will make sense to go further and separate generation from transmission. Hilke writes: “Independent, nondiscriminatory control of grid access and connection standards is a fundamental element of effective competition. Our experiences suggest that behavioural rules are not sufficient to promote nondiscriminatory grid access”.³⁹

Are there other structural policies we might consider, other than strict ownership separation? One alternative possibility is a form of club ownership. Suppose, for example, that a plant had many non-cooperating owners, each with a contractual right to a certain share of the output of the plant. Suppose also that these co-owners share in the costs of the firm and pay for the electricity produced at marginal cost, but do not otherwise share in the profits from the sale of the electricity produced. In this case these holders of capacity rights will compete downstream in the sale of the resulting electricity. This is a form of “club ownership” as discussed in OECD (2001). Hilke notes:

“Even if operation of generating plants is concentrated due to operating economies, ownership may be more dispersed without substantial inefficiency penalties. In the US, for example, there are a great many large power plants with multiple owners. Each of these owners independently determines the output and disposition from its proportion of the plant’s capacity. (The contracts for the operation of these facilities typically call for one owner to operate and maintain the facility)”.⁴⁰

Several countries have used the sale of “virtual capacity” in generation as a tool for enhancing or “kick starting” competition.⁴¹ The European Commission has imposed the divestiture of such “virtual capacity” as merger condition. For example, Electricité de France has undertaken to the European Commission to divest 6,000 MW of generation capacity (about 6% of total capacity) in France in order to obtain approval to acquire a further interest in the German electricity utility, EnBW:

“EDF will make the capacity available through two types of product:

- “Virtual Power Plants” representing rights to nominate electricity output for delivery on the following day on the high voltage grid at a pre-defined price. There will be peak and base-load capacity rights;
- “Power Purchase Agreements” representing a block of power based on the output from co-generation plants from which EDF has the obligation to purchase power at regulated tariffs under power purchase contracts. The contract will deliver its full output on base-load from November to March inclusive and may provide a lower base-load output in the summer months, depending on the level of gas prices.

By purchasing these products, generators, suppliers and traders will be able to acquire firm electricity without having to assume all of the engineering and operational risk of plant ownership. ... In total EDF will make available 1,000 MW of peak-load virtual power plant (VPP) capacity with an energy price of around 26 Euros/MWh and 4,000 MW of base-load VPP capacity with an energy price of around 8 Euros/MWh. In addition, EDF will make available capacity equivalent to 1,000 MW of co-generation plant.”⁴²

“Joint” or “club” ownership arrangements of this kind are, of course, also feasible for ensuring non-discriminatory access to congested transmission links.

Enhancing the Elasticity of Demand

Market power in generation markets may also be reduced through policies to increase the elasticity of demand. Given the political and legal obstacles to structural separation, even a small increase in elasticity may yield a stronger reduction in price than all of the feasible structural separation options combined. The elasticity of demand can be increased through policies which (a) facilitate demand-side participation in the “pool”; (b) enhance the use of time-of-day meters; (c) promote the use of interruptible contracts and (d) facilitate switching to other fuels.⁴³

In discussing the power pool in England and Wales, Wolak and Patrick advocate allowing buyers to participate in the price-setting process:

“Perhaps the most important lesson from the England and Wales experience is the necessity of building in the potential for demand-side responses by customers into the price determination process. ... [Under the previous trading arrangements] the expected demand which sets the system marginal price and capacity charge is perfectly price inelastic. This aspect of the rules ... makes it substantially easier for National Power and PowerGen to produce high values of system marginal price and capacity charge from the pool price determination process. The easiest way to build a significant price response into the expected demand determination process is to allow large scale demand-side bidding by regional electricity companies or other large customers”.⁴⁴

This recommendation to include buyers in the price determination process was implemented in the New Electricity Trading Arrangements (“NETA”) which came into effect in March 2001. Under NETA, buyers and sellers are able to make bilateral contracts independent of the market price. In addition,

buyers are able to submit bids into the balancing market. The system price is then the intersection of demand and supply. This allows buyers are able to signal their willingness to reduce consumption in the event that prices rise.

Even if large buyers (such as distribution companies) are able to participate in the power pool directly they will have little opportunity to reduce their demand at higher prices unless they can, in turn, induce their customers to reduce consumption when prices rise. This can be achieved either by interruptible contracts (which allow distribution companies to curtail supply in periods of exceptionally high prices) or real-time metering and billing of distribution customers. Interruptible contracts are common in the gas sector. There may be some scope for expanding their use in electricity, especially for customers who can switch to other fuels or self-generation.

As a tool for reducing demand in peak periods, interruptible contracts are a blunt instrument. It is far preferable to pass on the real price of electricity directly to end-user customers through the use of real-time metering and billing. Many electricity customers (especially the largest) are already subject to real-time metering. The need to expand such metering is one of the most common recommendations for mitigating market power in electricity markets. The “Blue Ribbon Panel” advising the California Power Exchange notes:

“Demand side responsiveness to price is essential to the operation of a restructured market; the promotion of increased efficiency in the use of electricity in the long term, and a much more elastic response to short-term peak prices are clearly essential remedies. ... We cannot refrain, however, from emphasising how essential it is, if consumers are to modify their purchasing habits in response to extreme fluctuations in price and by doing so to moderate those fluctuations that they either be offered inducements by their suppliers to permit their use of power to be curtailed or specific appliances to be ripped off for short periods of time by signals from the supplier and/or confront prices that vary with the correspondingly extreme fluctuations in wholesale prices, so that they can be induced to modify their consumption behaviour accordingly.

We are not in a position to offer a judgement of the cost effectiveness of the more sophisticated meters that would register consumption in units of time corresponding to the wide fluctuations in prices their distribution companies must pay. ... All we can say is that the behaviour of power markets in California in the last few months must inevitably have shifted the balance of relative costs and benefits powerfully in the direction of making that kind of metering economic and strongly recommends a reconsideration of the advisability of their widespread – indeed, to the extent possible, universal – installation, whether at the customer’s location or via ubiquitous, centrally controlled electronic metering”.⁴⁵

Even where time-of-use meters are not feasible, it may be feasible to promote interruptible contracts. An interruptible contract gives the electricity supplier the right to curtail supply in the event the market price exceeds some level.

Where time-of-use meters are feasible, the elasticity of demand can be further enhanced by facilitating switching to other fuels. The most likely possibility in many applications is self-generation. Hilke writes:

“Where on-site generation is attractive because of on-site uses for waste heat, firms (or even residential customers) that are normally the customers of the traditional power companies can become their competitors. To the extent that co-generation owners have accurate price information and the ability to sell into the market or shave their load during peak demand periods by self-producing electric power, demand facing traditional generators will become more elastic. If self-generation (or electric power storage technology) options become extensive enough and the entry of such facilities becomes quick

enough, demand facing traditional suppliers could become so elastic that it would eliminate many market power concerns (both in generation and transmission)⁴⁶

Controls on Prices or Quantities

A number of OECD countries have put in place policies designed to either lower prices or increase output (or declared capacity).

In regard to price controls, for example, caps have been imposed in the following circumstances:

- In Australia, a price cap was imposed on prices determined in the spot market in part as a transitional measure, to control market power and to prevent inexperienced participants from being exposed to unnecessarily high financial risks. The cap was set at \$A5000 until 31 March 2002 and \$A10,000 from 1 April 2002.⁴⁷
- In the England and Wales market, price caps were imposed on the pool prices in the fiscal years 1994/95 and 1995/96 as part of a voluntary agreement between National Power, PowerGen and OFFER after the Director-General for Electricity Regulation threatened to refer these two generators to the UK Monopolies and Mergers Commission.⁴⁸
- In California, so-called “reliability must run” generators are subject to special contractual arrangements which are intended to ensure that these generators were compensated on the basis of their actual costs rather than on their bid prices.⁴⁹

Another possibility is to limit the variance in the bids of individual units. Under competitive conditions the bid price of a generation plant would not vary according to demand conditions – the plant would always be bid at its marginal cost. If competitive conditions vary throughout the course of the week or month, the generator might be limited in the extent to which it can vary its bids. In this way, the extent to which the generator can increase its bids during periods with limited competition is restricted.

The basic difficulty in regulating the prices of generation is that generators compete in many different markets throughout the course of the day, with varying competition conditions. Generators can therefore be thought of as “multi-product” firms. One of the results of the theory of natural monopoly regulation is that multi-product firms should be regulated through a cap on an overall basket of prices. The generator can then be given flexibility to choose its prices throughout the day (or week) subject to the overall cap. In this way the generator will use its own information about market demand to set prices efficiently, while the cap can ensure that the generator does not earn excess returns.

Rather than focus on reducing prices, it may make sense to implement policies designed to increase output or, at least, declared capacity. In the UK policies designed to penalise capacity withdrawals date back to the very early days of reform in the UK. For example, in December 1991, after just 8 months of experience with the power pool the generation licence was revised to restrict the ability of generators to manipulate the pool purchase price by reducing capacity made available to the pool.

“The changes require generators to provide, for public viewing, reports containing the generator’s criteria for determining the availability of their capacity to the pool, closing generating stations and otherwise reducing generating capacity. Each year, generators must also file a detailed forecast of the availability of each generating unit for the coming year and, at year’s end, file a ‘reconciliation’ explaining any deviations from anticipated availability. This information is also publicly available”.⁵⁰

In the UK, the incentives to withdraw capacity were enhanced because of the effect it had on the “capacity charge”. As discussed below, the abolition of the capacity charge reduced the incentive to withdraw capacity. More recently, in 2001, a “Blue Ribbon Panel” advising the California Power Exchange recommended action to prevent capacity withdrawals in the California market:

“To the extent that large generators have engaged in strategic withholding of supplies in times of peak demand, with the effect of sharply increasing market-clearing prices, we concur in the suggestions ... that some agencies have the authority to investigate such incidents, to issue orders prohibiting such practices and to impose penalties”.⁵¹

One variation of this proposal is a “use-it-or-lose-it” requirement on generators which mandates generators to either divest or sell “virtual capacity rights” to unused capacity in its generators.

Yet another policy proposal is for the state to intervene to ensure that there is always sufficient capacity in reserve. “A number of state and federal policymakers have argued that the state should always market sure that capacity exceeds expected demand by at least 15 percent”. Although this approach may significantly reduce market power, other policies are likely to have higher net benefits. “It does not make sense to hold such capacity if the customer’s value of consuming the additional power when it is used is less than the full cost of making the power available. Real-time retail prices that reflect the cost imposed by additional consumption in each hour are the ideal mechanisms for making that trade-off”.⁵²

Changes To Market Rules

One of the lessons that clearly emerges from the experience of the England and Wales market is that the rules governing the operation of the market can have a substantial impact on ability and incentives of generators to act strategically. Wolak and Patrick write:

“Whether or not setting up an electricity market ... will deliver benefits to consumers in the form of lower electricity prices depends on the market structure and the details of the market rules governing its operation. Subtle differences in the rules of the market can dramatically enhance the ability of generators selling into the market to set prices substantially in excess of their marginal and average costs. ... [T]he rules governing the market can present opportunities for the large producers to exploit their market power and many of these modes of exercising market power are subtle, but high-powered in the sense that they can yield high rates of return. These strategies can be difficult to detect and even more difficult to correct.”⁵³

The factors that must be chosen in the design of a wholesale electricity market include: (a) whether participation in the market is compulsory or bilateral trades are allowed; (b) whether demand-side bids are allowed; (c) whether bids are simple prices and quantities or include other terms such as plant flexibility; (d) whether prices are calculated ex ante (on the basis of forecast demand and supply) or ex post (on the basis of actual demand and supply); (e) whether bidders are paid on the basis of their bid (pay-as-bid) or on the basis of the market-clearing price; (f) whether or not there are special payments for capacity availability; (g) and whether or not bids are firm or non-firm.⁵⁴ Some of these market-design factors have little impact on the exercise of market power. In particular, the change from single-price to a pay-as-bid system is not likely to reduce the exercise of market power.⁵⁵

Particular attention has been focused on how capacity payments can enhance market power by enhancing the incentives of dominant generators to withhold capacity:

“In the UK market, there are several factors that have made the strategy of withholding capacity an attractive way to raise the pool selling price. ... The availability declaration strategy has the advantage that the generators can disguise their intentions behind several veils. The Director General will have a

very difficult, if not impossible time telling plant unavailability due to actual breakdowns from those due to an unavailability declaration for strategic reasons".⁵⁶

In particular, Wolak and Patrick advocate abolishing the capacity charge component of the pool purchase price in the England and Wales market.

If the capacity charge were eliminated "these generators could no longer bid each genset into the market at close to its marginal cost and rely on high capacity charge's to compensate them for their fixed costs. Getting rid of the capacity charge would not eliminate the ability to withhold capacity to achieve higher system marginal prices, but it would eliminate the very profitable added benefit of this strategy that it triggers a high loss-of-load-probability and there a high capacity charge. Consequently, it does seem that serious consideration should be given to the elimination of the capacity charge from the England and Wales market".⁵⁷

In the UK, the capacity charge was abolished with the implementation of the New Electricity Trading Arrangements in March 2001.

Other Policies

Various other policies for mitigating market power have been proposed, including policies to promote entry, policies to promote the use of long-term contracts and policies that make use of public ownership as a tool to offset the incentive to maximise profits.

Entry can be promoted through policies which seek to reduce licensing requirements and which facilitate the processes for obtaining approval for the establishment of a new generation facility. Policies which promote long-term contracts may also facilitate entry by assisting smaller entrants to raise the necessary capital⁵⁸.

Long-term contracts may also be a tool to control market power. Borenstein explains:

"While forward prices won't systematically beat spot prices, there is a potential price-lowering effect in *both* forward and spot markets if, in aggregate, buyers purchase more power through long-term contracts. Locking in some sales in advance reduces the incentives of multiple firms to behave less competitively among themselves (Allaz and Vila, 1993) ...

The possibility of selling in advance makes it more difficult for firms to restrain competition. Once a firm has sold some output in advance, it has less incentive to restrict its output in the spot market in an attempt to push up prices in that market, since it does not receive the higher spot price on the output it has already sold through a forward contract. Thus, in anticipation of more aggressive competition in the spot market – because some firms have presold a significant quantity in the forward market – firms are likely to price more aggressively in the forward market".⁵⁹

Some evidence of this effect was seen in the England and Wales market. One of the innovations of the NETA policies was that it allowed and encouraged long-term bilateral contracting between generators and buyers. "Forward prices for electricity were lower for the period after NETA was expected to start and rose when NETA was delayed. – the market consensus was that wholesale prices would fall under NETA".

Market power might also be mitigated by including the presence of a non-profit-maximising firm in the market. The study by Schmalensee and Golub finds that "public enterprises, if they behave competitively, provide a strong check on the ability of profit-seeking private utilities to exercise market power. ... Proponents of deregulation must find a way to eliminate subsidies to publicly owned electric

utilities while retaining or strengthening their incentives to behave as price-takers in bulk power markets".⁶⁰

Conclusion

There is now a widespread consensus that electricity markets are prone to market power. "The spatial attributes of generation markets and changing network conditions virtually assure that generation markets will never be perfectly competitive under all system conditions".⁶¹

Because electricity cannot be stored electricity markets must be differentiated according to the time the electricity is delivered. When transmission networks are congested, electricity markets must be divided geographically. Even within these markets divided along time and geographic dimensions, a large proportion of the generators may be operating at capacity, preventing them from responding to an increase in price. Furthermore, the very low elasticity of demand for electricity implies that only a very small reduction in output is necessary to achieve a large impact on price.⁶²

Periodic episodes of very high prices are not necessarily evidence of market power. Since demand is both cyclical and difficult to forecast episodes of periodic high prices are inevitable even in a perfectly competitive electricity supply industry. Nevertheless market power can exacerbate price fluctuations. In addition, market power can lead to both allocative inefficiency (as consumers switch to other fuel sources) and productive inefficiency (as higher-cost generators substitute for lower-cost generators and as higher-cost generators are induced to enter the market). The resulting transfers from consumers to producers can be substantial. Around 60% of the total payments to California electricity producers in summer 2000 could be attributed to market power alone.

Market power in electricity markets can be controlled, through a variety of policy interventions. Given the susceptibility of electricity markets to market power all of the policies for reducing market power should be given serious consideration, including, for example, policies to promote real-time pricing, long-term contracting, further horizontal and vertical separation, reform of transmission pricing and well-targeted price controls.⁶³

The problems with market power (along with other issues) have lead to calls for a reassessment of the arguments for and against electricity liberalisation. So far, there does not seem to be consensus that market power problems are insurmountable or call for a reversal of the reforms of the past decade. Borenstein writes:

"The difficulties with the outcomes so far ... should not be interpreted as a failure of restructuring, but as part of the lurching process toward an electric power industry that is still likely to serve customers better than the approaches of the past".⁶⁴

APPENDIX A:

The following summary of empirical studies on market power is taken from a document of the US Department of Energy, produced in March 2000:

Concentration in Electric Generation Markets:

“Schmalensee and Golub (1984) calculate HHI values for electricity markets throughout the US for 170 generation markets serving nearly three-quarters of the US population, using alternative assumptions about the geographic scope of generation markets. They find a significant number of instances where market concentration as measured by the HHI is in the danger zone defined by the Horizontal Merger Guidelines. For example, under the assumption of low transmission capacity, between 35% and 60% of all generation markets have HHI values above 1800 across a range of alternative marginal cost and demand elasticity cases. The load-weighted mean HHI value ranges from 1590 to 2650, indicating substantial concentration. For the more favorable case of high transmission capacity, concentration is less severe, but up to 33 percent of markets still had HHI values above the threshold value of 1800 used in the merger guidelines to identify markets that are highly concentrated.

...

A recent study by Cardell, Hitt and Hogan (1997) suggests that electricity markets are still highly concentrated today. Using 1994 data and a narrower definition of the geographic scope of electricity markets, they calculate HHI values for 112 regions based on State boundaries and North American Electric Reliability Council (NERC) sub-regions. Although the analysis does not reflect the recent spate of mergers and divestitures, approximately 90 percent of these regions have HHI values above 2500.

The Impact of Market Power on Wholesale Electricity Prices in the UK and California

Analysts have been able to assess the impacts of market power based on actual data from the U.K. and California. These studies suggest that generators in these two markets may have earned substantial excess revenues due to market power. The U.K. experience has been the subject of many reviews, in part because that country was one of the first to implement competition in wholesale power markets. Since the creation of the U.K. power pool in 1990, the Office of Electricity Regulation (OFFER)⁶⁵ has investigated market power abuses on a number of occasions in response to unusually high pool prices. The U.K. market design provided generators with two types of compensation: capacity payments based on a day-ahead comparison of anticipated capacity requirements with available capacity, and energy payments based on system marginal prices. In early 1992, both system marginal prices and capacity payments rose dramatically. After investigating, OFFER determined that National Power and PowerGen, the two largest generating companies, which together accounted for 70 percent of total capacity in the pool, were bidding prices in excess of their marginal costs. In addition, PowerGen had declared a number of plants unavailable in order to raise the capacity payment. Once the capacity payment had been determined, PowerGen then declared the units available, making them eligible to receive the higher capacity payments. Although OFFER instituted a number of reforms after the episode, they seemed to have somewhat limited success in restraining market power.⁶⁶

Wolfram (1998 and 1999) examined strategic bidding behavior by National Power and PowerGen. Using data on fuel costs and heat rates, she estimated the marginal cost of electricity for the system and compared this cost with the pool's "system marginal price"⁶⁷ in order to determine the price-cost markup (the difference between a generator's marginal cost and its bid price). Wolfram estimates that from 1992 to 1994, system marginal prices ranged from 19 percent to 25 percent above estimated marginal costs.

Wolak and Patrick (1997) examine the issue of capacity withholding in the U.K. power pool. Because of the structure of the U.K. power pool, firms can benefit significantly by withholding generation. Prices paid to generators include a capacity payment determined each half-hour by the pool operator, based on the level of reserves available and the "value of lost load"⁶⁸. As reserve capacity falls, the capacity payment increases. By withholding capacity, firms receive both higher capacity payments and higher system marginal prices for their output, making this a very profitable strategy.

After analyzing the half-hourly market-clearing prices and quantities, and half-hourly bids and availability declarations from 1991 to 1995, the authors cite several pieces of evidence to demonstrate that National Power and PowerGen are strategically withholding capacity. First, they find that the percent of total capacity declared unavailable by National Power and PowerGen in 1995 during off-peak months is more than twice the average amount of capacity declared unavailable by all generators in off-peak months. In addition, they calculate average availability factors by fuel type for National Power and PowerGen and compare them to industry benchmarks based on NERC data for comparable units. For every fuel type, the availability factors for both National Power and PowerGen are below the industry benchmark. For example, average availability factors for combined-cycle gas turbines (CCGTs) are 53 percent and 64 percent for National Power and PowerGen, respectively, compared with an industry benchmark of 80 percent. By contrast, availability factors for independent power producers selling to the U.K. pool are all above the industry benchmark, ranging from 81 to 93 percent for CCGTs.

The California wholesale market is much newer than the U.K. market, having opened to competition in 1998. This market has an institutional structure different from that used in the U.K. —for example, there are no payments for capacity outside of those directly related to the provision of ancillary services. Despite the opportunity of California market designers to learn from the U.K. experience, early analyses provide some evidence that market power is being exercised. Borenstein, Bushnell and Wolak (1999) examine the California wholesale market for June-November 1998. They compute the aggregate marginal supply curve based on fuel costs, heat rates, and variable operating and maintenance (O&M) costs, using data from the California Energy Commission and other sources. Using the hourly generation levels from the Independent System Operator, they determine the competitive price for each hour. The competitive price is then compared to the hourly (unconstrained) price in the California Power Exchange (PX) to estimate the price-cost markup. For the entire 6-month period, total payments to generators were 29 percent, or \$494 million, above competitive levels. At certain times, prices were as much as 75 percent above competitive levels. The highest markups were found during July and August from noon to 6 p.m., when demand is high. Wolak recently extended the analysis to include the summer of 1999, resulting in a revised estimate of more than \$800 million in payments above competitive levels to generators during the summers of 1998 and 1999 taken together.

The studies discussed in this section generally report the price premium as a percentage of the wholesale market price of power. The wholesale price of power is only one component of the overall price paid by consumers for electricity service, which also includes the costs of transmission and distribution and other expenses. The same price impacts measured as a percentage of the total delivered price of electricity to end users would be significantly smaller, in many markets ranging from one-half to two-thirds of the generation-only percentage impact.

Other Evidence of Market Power in the UK and California

Empirical studies such as those by Wolfram (1998, 1999) and by Borenstein, Bushnell and Wolak (1999) measure the extent of market power by first estimating the marginal cost of generation and then comparing the estimates to prices. There are, however, a number of difficulties in attempting to estimate generation costs. Wolfram, for example, does not include variable O&M costs in her estimates, and thus may be understating actual generation costs. In California, generators do not explicitly submit bids for startup costs (as in other power pools) and must instead include these costs in their bid prices for energy (although the inclusion of startup costs would not fully account for the higher payments to California generators noted above). As such, a generator's bid may appear to be above marginal costs even though the bid price accurately reflects the generator's variable cost of production

Other evidence, however, suggests that firms are exercising market power —bidding behavior in the U.K., for example. While firms will have an incentive to bid higher prices into the pool in order to receive higher revenues, these incentives are countered by a need to ensure that the plant is dispatched. Economic theory predicts that, if generators are behaving strategically, price-cost markups will be higher for plants that are more likely to set the pool price, and when more of a generator's inframarginal capacity is available. Wolfram finds evidence of both of these outcomes in the U.K. power pool. In addition, she finds that the variation in bid prices for a given generating unit is greater than the variation in bid prices across generating units.

Other analysts have compared actual California PX prices to a 1997 Borenstein and Bushnell study examining the potential for market power in the California wholesale market. In two of the four months examined, the model overestimates prices assuming either competition or market power. In the other two months, however, the model accurately predicts competitive prices for about 80 per-cent of the hours, generally when loads are low. For approximately 10 percent of the hours during these two months, actual PX prices fall within the range of predicted prices assuming market power.

The entry of new competitors into the market is one important factor that can limit the ability to sustain prices above the competitive level for a significant time period, which defines market power. The possibility of rapid entry by new competitors can deter the exercise of market power by an incumbent firm that dominates its market, because the entry attracted by the above-normal profits associated with high prices can lead to overcapacity and subpar profits following entry.

Although there has been considerable entry into the U.K. market since privatization, it has not completely eliminated market power. Pool prices during 1993 and 1994 were, on average, just below a potential entrant's long-run average costs. In addition, National Power and PowerGen retired significant amounts of generation as new firms entered the market in the early 1990s, thus limiting the net increase in capacity within the pool. The most recent price spikes in 1999 suggest that National Power and PowerGen can still exercise market power despite new entry and their subsequent decreases in market share.⁶⁹

Market power problems have persisted in the U.K. despite substantial capacity additions by independent power producers (12,300 megawatts) and previously committed nuclear capacity (3,200 megawatts) between 1991 and 1997 that together represented additions equivalent to 25 percent of total capacity in the England-Wales Pool. Since conditions within the U.K. market were probably more favorable to the early entry of significant independent power producer capacity than those in many U.S. regional power markets, entry should probably not be viewed as the "cure all" for market power in the short to intermediate run.

Studies of Market Power in Other Regions

Borenstein, Bushnell and Knittel (1997) analyze the potential for market power in New Jersey. Because of transmission constraints both within and into the Pennsylvania-New Jersey-Maryland (PJM) power pool, New Jersey (“PJM-East”) may at times be a small, geographically distinct market, providing opportunities for generators to exercise market power. The analysis investigates the potential for the five major New Jersey utilities to raise prices by reducing their output, assuming that the surrounding markets (New York and “PJM-West”) are perfectly competitive and will sell into the New Jersey market when possible, given prices and transmission constraints. They find that market prices begin to exceed competitive levels when demand in New Jersey rises above 14,500 megawatts (peak demand for New Jersey is assumed to be 16,500 megawatts in 2000 for this analysis). At this level of demand, potential price increases due to market power range from just a few percentage points to a factor of 4.

Colorado is another region in which the potential for market power has been analyzed. Sweester (1998) notes that transmission constraints and the presence of a dominant firm may provide opportunities to exercise market power in eastern Colorado. He examines the mitigating effects of various policy options or market developments. For example, the participation of rural electric cooperatives and municipal power agencies in competitive markets reduces the projected price-cost markups by approximately 10 percent. If 1,000 megawatts of new, competitive generation is assumed to enter the market, price-cost markups fall dramatically. The greatest reduction in price-cost markups under a market power scenario results from requiring 50 percent divestiture by the dominant firm.

Several State public utility commissions have also undertaken market power studies as part of restructuring. In Michigan, for example, staff at the Public Service Commission calculated HHI values for the State and concluded that the Michigan market is “so highly concentrated and the advantages of incumbent utilities are so pervasive that proactive measures are imperative.” The Public Service Commission of Utah used simulation studies similar to the New Jersey and Colorado studies and found that the dominant firm would be able to exercise market power 45 to 60 percent of the time”.

APPENDIX B:

The Lerner Index and the HHI in a market without capacity constraints

Suppose we have a market with n firms producing an identical good, with costs $c_i(q_i)$ for $i=1, \dots, n$. The market demand curve is $P(Q)$ where $Q = q_1 + q_2 + \dots + q_n$. The profit of the i th firm is therefore:

$$\pi_i(q_i, q_{-i}) = P(Q)q_i - c_i(q_i) = P(q_i + \sum_{j \neq i} q_j)q_i - c_i(q_i)$$

Suppose that these firms compete in quantities. Let $(q_1^*, q_2^*, \dots, q_n^*)$ be the Cournot equilibrium. From the first order conditions we know that:

$$\frac{\partial \pi_i}{\partial q_i}(q_i, q_{-i}) = P'(Q)q_i + P(Q) - c'_i(q_i) = 0 \text{ for } i=1, \dots, n.$$

Which implies that:

$$\frac{P(Q) - c'_i(q_i)}{P(Q)} = -\frac{P'(Q)}{P(Q)}q_i = \frac{s_i}{\varepsilon} \text{ for } i=1, \dots, n.$$

Where $s_i = q_i / Q$ is the market share of the i th firm and ε is the elasticity of the demand curve when the total output is Q . If we multiply this expression by s_i and sum over all the firms we find that:

$$\frac{P - \bar{c}}{P} = \frac{HHI}{\varepsilon}$$

Where $\bar{c} = \sum_i s_i c'_i(q_i)$ is the weighted average of the marginal costs of the firms at the equilibrium level of output (weighted by the market shares of each firm) and $HHI = \sum_i s_i^2$ is the sum of the squares of the market shares of the firms in the market.

Suppose now that the firms have constant marginal cost. From the expression above we can derive that:

$$\frac{P - \tilde{c}}{P} = \frac{1}{n\varepsilon}$$

Where $\tilde{c} = \frac{1}{n} \sum_i c_i$ is the simple average of the marginal costs of the firms. This result has one immediate consequence – if the demand curve has constant elasticity the price-marginal cost mark-up is constant whatever the level of demand.

Capacity constraints and the adjusted HHI

Suppose now that the i th firm faces a capacity constraint of K_i . The problem of the firm is now to maximise $\pi_i(q_i, q_{-i})$ subject to $q_i \leq K_i$. Suppose that there are m firms which are not capacity constrained, labelled $1, 2, \dots, m$. For these firms, the first order conditions above hold. Let \bar{s} be the total market share of the constrained firms. Then $\sum_{i=1}^m s_i + \bar{s} = 1$. If we multiply the first order conditions by

$s_i + \frac{\bar{s}}{m}$ and sum over i , we find that:

$$\sum_{i=1}^m (s_i + \frac{\bar{s}}{m}) \frac{P(Q) - c'_i(q_i)}{P(Q)} = \frac{P(Q) - \hat{c}}{P(Q)} = \frac{HHI^{adj}}{\epsilon}$$

Where $\hat{c} = \sum_{i=1}^m (s_i + \frac{\bar{s}}{m}) c'_i(q_i)$ and $HHI^{adj} = \sum_{i=1}^m s_i (s_i + \frac{\bar{s}}{m})$.

The Minimum value of the adjusted HHI

For a given number of unconstrained firms, we can find the minimum value of the adjusted HHI by choosing s_1, s_2, \dots, s_m to minimise HHI^{adj} subject to $\sum_{i=1}^m s_i + \bar{s} = 1$. It is straightforward to show that

s_1, s_2, \dots, s_m must be identical, hence, $s_i = \frac{1 - \bar{s}}{m}$. Substituting this into HHI^{adj} we find that:

$$HHI^{adj} \geq \sum_{i=1}^m \left(\frac{1 - \bar{s}}{m} \right) \left(\frac{1 - \bar{s}}{m} + \frac{\bar{s}}{m} \right) = \frac{1 - \bar{s}}{m}$$

NOTES

1. Throughout this paper “market power” will refer primarily to unilateral, horizontal market power (as opposed to collusive, co-operative or vertical market power).
2. For consistency with the rest of the paper we should add that when a firm is constrained the market price may be above the unconstrained marginal cost.
3. This is shown in Appendix B. The mark-up of price over average marginal cost can be declining even as the mark-up of price over the lowest marginal cost is increasing.
4. Here we are ignoring the possibility of transmission losses or congestion. As we will see later, when transmission lines are constrained, it may be necessary to call on higher-cost generators to maintain system integrity.
5. See Borenstein (1999): “In the absence of market power by any seller in the market, price may still exceed the marginal production costs of all facilities producing output in the market at that time”, page 3. In a market with capacity constraints, therefore, demonstrating the presence of market power requires *both* a showing that the market price is higher than the marginal cost of all the firms in the market (i.e., that the Lerner index is positive) *and* that at least one firm is operating below its capacity.
6. Borenstein, Bushnell, Kahn and Stoft (1996), page 18.
7. Borenstein, Bushnell and Knittel (1999), page 5.
8. Borenstein and Bushnell (2000), page 48-49.
9. Borenstein and Bushnell (2000), page 49. In the England and Wales market: “The vast majority of a [regional electricity supply company’s] customers purchase electricity at rates fixed and independent of within-year variations in the pool price. All residential customers pay fixed prices that may vary in a mutually agreed-upon manner on a daily or weekly basis, independent of fluctuations in the pool price, for the entire fiscal year. The most common form of this pricing plan has one fixed price per kWh for all consumption during daylight hours and another fixed price per kWh for consumption during nighttime hours. Almost all commercial and industrial users purchase power through similar annually negotiated fixed price contracts which also vary on a daily or weekly basis, independent of movements in the pool price. Consequently, within-day, day-to-day, or even month-to-month movements in the pool price have no impact on the prices that all but a small fraction of customers pay because the price patterns they face do not change for the entire fiscal year. Only a very small fraction of E&W total system load, approximately 5%, is purchased by final consumers according to the variations in the half-hourly spot market price”. In any case, under the former trading system in England & Wales, there was no mechanism by which buyers could communicate their willingness to reduce demand in response to higher prices. Wolak and Patrick (1997), page 8-9.
10. Borenstein and Bushnell (2000), page 49. Strictly speaking the key issue is not that generators are capacity constrained but that the marginal cost curve increases sharply near the maximum capacity so that generators are most of the time operating at capacity.

11. See, for example, Cramton and Lien (2000).
12. Borenstein and Bushnell (2000), page 49-50.
13. Borenstein and Bushnell (2000), page 49-50. Furthermore, this argument can easily be extended to show that the market power can arise not only at times of peak demand but at any time when the industry supply curve is inelastic (such as when an increase in output requires bringing on line a high-cost facility). In fact, any time when the supply curve is inelastic, it is argued, even a small firm may find it profitable to reduce output a little – the costs of the reduction in output are more than offset by the rise in the market price on the remaining units sold.
14. US FTC, *In the Matter of PacifiCorp; The Energy Group PLC; Peabody Holding Company, Inc.; and Peabody Western Coal Company*, Analysis of Proposed Consent Order to Aid Public Comment, available at <http://www.ftc.gov/os/1998/9802/>
15. On the other hand, the adjusted HHI is a more accurate measure than simply ignoring the market share of the constrained firms on the basis that they are not “in the market”. This approach is discussed, for example, by Werden (1996) who writes: “Under present market institutions, capacity committed to serve native load perhaps should be treated as off the market; ... Thus, shares of excess capacity provide much better indicators of the likelihood of a significant exercise of market power than do shares of total capacity”. page 19.
16. Wolak and Patrick (1997), page 47.
17. The reduction in market power does not imply a reduction in the market price, but merely a reduction in the mark-up of the market price over the efficient cost level.
18. Newbery (1998), page 744.
19. Bushnell and Wolak (1999), page 4-5.
20. Bushnell and Wolak (1999), page 4-5. Joskow (1997) notes that “[S]ome generators have strategic locations on the grid and, from time to time, “must run for reliability”. Naturally, when the generators know that they will be called to run by the network operator to maintain network reliability (almost) regardless of what they bid, they submit high bids. Certain generating stations at strategic locations on the grid in England and Wales charged prices six times higher than those of otherwise comparable generators before the regulator imposed a price ceiling on them”. Joskow (1997), page 134.
21. Joskow and Tirole (2000), page 458.
22. See, for example, Hogan (1997).
23. Hjalmarsson (2000) notes “To my knowledge, this is the first study of power markets that is not able to reject the hypothesis of perfect competition”.
24. Borenstein, Bushnell and Wolak (2002), page 5.
25. See Cardell, Hitt and Hogan (1997), Bushnell (1999), Borenstein, Bushnell and Stoft (2000), Joskow and Tirole (2000).
26. See Bushnell (2002).
27. Borenstein, Bushnell and Wolak (2002), page 5-6.

28. The information in this box is taken from Wolak and Patrick (1997) and Green and Newbery (1992). See also Wolak (1997).
29. Green and Newbery (1992), page 952.
30. The information in this box is taken from Borenstein, Bushnell and Knittel (1999). Other studies which have concluded there is significant market power in California's wholesale electricity market include Borenstein, Bushnell and Wolak (2001), Wolak, Nordhaus and Shapiro (2000), Puller (2001), Joskow and Kahn (2001), Hildebrandt (2001) and Sheffrin (2001)
31. US Department of Energy (2000), page 13.
32. European Commission (2001), page 30.
33. European Commission (2001), page 18-29.
34. The US Department of Energy (2000) raises the possibility that generators could be required to upgrade transmission under their control to mitigate their market power in load pockets where they operate.
35. Hogan (1998) writes: "It is entirely possible to construct examples of valuable transmission links that have no net power flow, making them appear worthless for many definitions of link-based rights". page 11.
36. Third, the construction of a transmission link or the enhancement of capacity on existing link will not always lower market prices. The alleviation of a transmission constraint between A and B will not necessarily lower prices at both A and B. In fact, the opposite is likely to be nearer the case. A transmission link between A and B is, in effect, a means for arbitraging the prices of A and B. The fact that there is a flow of electricity from A to B signifies that (at least in the absence of the flow) the market price for electricity is higher at B than at A. A transmission link therefore has a tendency to *raise* prices at A (and lower prices at B). As mentioned above, however, the competition-enhancing effect has a tendency to lower prices at both A and B. It is not possible to say in the abstract which effect will dominate.
37. Joskow (1997), page 132.
38. Hilke (2001).
39. Hilke (2001).
40. Hilke (2001).
41. See for example Ireland, <http://www.cer.ie/cer01101.pdf>, Oregon and Alberta.
42. See <http://www.edf.fr/htm/en/enchere/enchere/Highleveloverview>
43. See, for example, Fraser (2001).
44. Wolak and Patrick (1997), page 51.
45. Kahn et al (2001), page 16-17. "Though real-time pricing has not been widely used in the US, the technology is well established. Most large commercial and industrial customers in California have real-time meters already, and communication of the day-ahead or imbalance market price to those customers can easily take place through the Internet. In the near future it may not be practical or necessary to include residential customers in a real-time pricing program, but as the cost of real-time meters declines, including residential customers can be straightforward. It is critical to understand that the *variation* in prices can be separated from the *average level* of prices. For any given level of flat retail price that is contemplated, the

same system-wide average price level can be attained each month with real-time retail pricing. Doing it with real-time pricing will reduce the cost of procuring the power and reduce the need to build more power plants, ultimately allowing lower retail prices”. Borenstein (2002), page 205-206.

46. Hilke (2001). Hilke also sounds a note of caution: “One concern here is that demand elasticity is likely to vary over time ... For example, peak demand that stems from extremely cold weather may be less elastic than peak demand that stems from a vibrant economy. It is risky to assume that increased demand elasticity from demand-side participation will persist in all market circumstances”.
47. National Electricity Code section 3.9.4 and section 3.9.5.
48. Wolak and Patrick (1997), page 14.
49. This is described further in Bushnell and Wolak (1999), page 12-13. In the US, the authority to allow rates to be determined by market-based processes can be withdrawn by FERC if it considers that the outcomes are undesirable.
50. Wolak and Patrick (1997), page 13-14.
51. Kahn et al (2001), page 13.
52. Borenstein (2002), page 203.
53. Wolak and Patrick (1997), page 48-49.
54. IEA (2000) has a good summary of the pros and cons of different approaches to market design.
55. See Kahn et al (2001).
56. Wolak and Patrick (1997), page 48-49.
57. Wolak and Patrick (1997), page 50.
58. See Kahn et al (2001), page 15.
59. Borenstein (2002), page 202.
60. Schmalensee and Golub (1984), page 26.
61. Joskow (1997).
62. “A significant contributor to the world-wide momentum towards competitive restructuring of electricity markets has been the perception that the generation sector of this industry no longer constitutes a natural monopoly. While competition for the generation of electricity may indeed be robust over large regions, the limits of transmission capabilities in most electric systems combined with the lack of means to economically store electricity often limit the scope of competition to relatively small geographic areas. Within these smaller areas, individual generation units can possess significant market power. This market power is exacerbated by the fact that the real-time demand for wholesale electricity is extremely price-inelastic”. Bushnell and Wolak (1999), page 3.
63. “The movement toward restructuring of electricity markets was born from a history of well-supported dissatisfaction with outcomes under cost-of-service regulation. Nonetheless, electricity markets have proven to be more difficult to restructure than many other markets ... due to the unusual combination of extremely inelastic supply and extremely inelastic demand. Real-time retail pricing and long-term

contracting can help to control the soaring wholesale prices recently seen in California and can buy time to address other important structural problems that need to be solved to create a stable, well-functioning electricity market. These problems include creating a workable structure for retail competition, determining the most efficient way to set locational prices and transmission charges, implementing a coherent framework for investing in new transmission capacity and optimising the procurement of reserve capacity. ” Borenstein (2002), page 210.

64. Borenstein (2002), page 210.
65. In 1999, OFFER and the Office of Gas Supply were combined to create the Office of Gas and Electricity Market, Ofgem.
66. OFFER eventually instituted price caps on system marginal prices, required National Power and PowerGen to divest a portion of their generation assets, and required generators to file annual plans regarding scheduled plant outages.
67. Pool prices in the UK include three distinct elements: the system marginal price, which equals the bid of the last generator scheduled for dispatch, a capacity payment designed to compensate generators for supplying capacity; and an uplift charge to adjust for differences in forecasted and actual demand and to cover the costs of additional services provided by generators (e.g., voltage support). Increased costs due to higher capacity payments are not reflected in this analysis, because only the system marginal price is examined.
68. The value of lost load is the estimated amount that end-use customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service.
69. Pool prices in the UK in July 1999 were about 80 percent higher than in the same period in 1998 despite relatively little increase in demand or fuel prices compared to the previous year. Ofgem determined that these price increases were due primarily to higher bid prices for coal-fired units owned by National Power and PowerGen.

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NOTE DE RÉFÉRENCE

Par le Secrétariat

Introduction

Ces dix dernières années, la plupart des pays de l'OCDE ont mis en train une vaste réforme du secteur de la fourniture d'électricité. L'un des principaux objectifs des différentes réformes engagées était d'introduire la concurrence – notamment entre les producteurs d'électricité. La concurrence devait, espérait-on, permettre l'efficacité et l'innovation dans ce secteur et favoriser une baisse des prix pour les consommateurs.

Malgré les effets positifs non négligeables de la réforme du secteur électrique, on a constaté à l'usage qu'un pouvoir de marché avait tendance à s'exercer sur les marchés de l'électricité libéralisés. Dans les pays de l'OCDE, de nombreux producteurs détiennent un pouvoir de marché, du moins une partie du temps, tandis que d'autres exercent un monopole effectif, du moins par moments.

En Californie, par exemple, le pouvoir de marché a progressé à tel point qu'on lui impute 60 pour cent de la valeur des échanges effectués sur le marché de gros pendant l'été 2000. En conséquence, les consommateurs californiens ont payé l'électricité environ 4.5 milliards de dollars en trop. Le pouvoir de marché entraîne par ailleurs des inefficacités productives considérables, dans la mesure où une production à faible coût est remplacée par une production à coût élevé et que des producteurs dont le fonctionnement coûte cher sont encouragés à entrer sur le marché.

Dans le présent document, nous examinons les raisons qui font que les marchés de l'électricité libéralisés sont enclins à exercer un pouvoir de marché et les mesures qui pourraient être prises à cet égard. Les principaux points abordés sont les suivants :

- On fait souvent observer que les marchés de l'électricité présentent plusieurs caractéristiques de base qui facilitent l'exercice d'un pouvoir de marché, notamment que l'électricité ne peut être stockée (ce qui signifie que les marchés de l'électricité doivent être définis en fonction du moment où intervient la livraison), que les producteurs font face à des contraintes de capacité (de sorte que l'offre est inélastique en période de pointe), que la demande d'électricité est très peu élastique (étant donné que la plupart des consommateurs finals paient des prix correspondant à une moyenne dans le temps) et que le réseau de transport peut être congestionné (ce qui a pour effet de séparer les marchés de l'électricité sur le plan géographique).
- On a déjà pu se faire une idée du pouvoir de marché qui s'exerce sur les marchés de l'électricité en utilisant des formalisations poussées, mais on peut également avoir recours à un modèle de Cournot simple. Dans un modèle de Cournot simple, le pouvoir de marché est fonction de la concentration du marché et de l'élasticité de la demande uniquement, et non du niveau de la demande. Toutefois, lorsque les entreprises de production font face à des contraintes de capacité liées à l'augmentation de la demande, certaines d'entre elles deviennent soumises à des contraintes et ne peuvent par conséquent pas discipliner le pouvoir de marché des entreprises sans contraintes. Pendant les périodes de pointe, les quelques

entreprises sans contraintes qui restent sont susceptibles d'exercer un pouvoir de marché significatif.

- La mesure conventionnelle de la concentration sur un marché économique est l'indice de Herfindahl-Hirschman. Cette mesure n'est malheureusement pas précise sur les marchés où existent des contraintes de capacité. Un marché en apparence très concurrentiel lorsqu'on se fonde sur des mesures conventionnelles de la concentration peut, de fait, être exposé à un pouvoir de marché significatif. Le présent document introduit une autre mesure de la concentration appelée « indice de Herfindahl-Hirschman ajusté », qui reflète correctement le degré de pouvoir de marché exercé sur un marché où certaines entreprises font face à des contraintes de capacité.
- L'exercice d'un pouvoir de marché, sur les marchés de l'électricité, n'est pas nécessairement limité aux périodes de pointe. De fait, il est possible que le pouvoir de marché se manifeste seulement *en période creuse*. Par exemple, si un gros producteur à faible coût rivalise seul avec un petit nombre de producteurs à coût élevé, le pouvoir de marché sera observé seulement en période creuse. Le pouvoir de marché qui se manifeste seulement en période de pointe n'est pas nécessairement affaibli par l'arrivée de nouveaux concurrents. Si l'électricité produite par ces derniers coûte plus cher que l'électricité produite en base (par exemple, si les possibilités de nouvelles centrales hydroélectriques ou nucléaires sont épuisées), le pouvoir de marché qui est momentané (mais récurrent) n'est pas nécessairement entamé par un nouvel entrant, si faibles que soient ses charges fixes.
- Le pouvoir de marché peut aussi découler de la congestion du réseau de transport. La congestion tend à isoler les producteurs sur le plan géographique, ce qui accentue le pouvoir de marché. Les contraintes de réseau de transport exercent sur les producteurs des effets analogues à ceux des contraintes de capacité. En présence de contraintes de transport, l'indice de Herfindahl-Hirschman classique ne fournit pas une mesure précise de la concentration et doit être remplacé par l'indice de Herfindahl-Hirschman ajusté. Les « droits financiers de transport » – le droit à une part des rentes de congestion engendrées par les contraintes de transport – peuvent renforcer le pouvoir de marché des producteurs qui tirent profit de la congestion.
- Comme par le passé, la congestion des réseaux de transport n'est pas nécessairement limitée aux périodes de pointe. Elle peut également se produire en période creuse. Les transits d'électricité sur les liaisons de transport sont fonction des écarts de prix entre des zones géographiques. Si la demande varie davantage dans une zone que dans une autre, les transits d'électricité sur une liaison de transport peuvent changer de direction entre les périodes de pointe et les périodes creuses et n'être contraints que pendant les périodes creuses.
- Dans les réseaux électriques comportant plus d'un chemin entre le point de production et le point de consommation, l'électricité circule sur toutes les liaisons possibles en quantité inversement proportionnelle à la résistance de la liaison. L'augmentation de la production à un point, même si elle s'accompagne d'une augmentation de la consommation à un autre point, peut affecter les transits d'électricité (et le degré de congestion) sur toutes les autres liaisons du réseau. On peut établir que même en l'absence de contraintes de capacité sur les liaisons de transport entre les producteurs et les consommateurs, des contraintes de capacité existant sur d'autres liaisons peuvent conférer à un producteur un fort pouvoir de marché.
- De nombreuses études ont été réalisées sur le pouvoir de marché et la concentration sur les marchés de gros de l'électricité, en particulier au Royaume-Uni et en Californie. Il existe de

bonnes raisons de croire que certains producteurs ont exercé un pouvoir de marché par le passé. En Californie, même si les coûts ont considérablement augmenté pendant la période comprise entre l'été 1998 et l'été 2000, le pouvoir de marché s'est accru plus rapidement encore, le total des paiements versés aux producteurs étant passé de 1.7 milliard de dollars en 1998 à plus de 9 milliards en 2000.

- De nombreuses politiques différentes ont été proposées pour contrôler le pouvoir de marché observé sur les marchés de la production d'électricité. Il s'agit notamment de politiques visant à élargir l'étendue géographique des marchés, de politiques structurelles, de politiques de contrôle des prix et de politiques ayant pour but d'accroître l'élasticité de la demande. L'étendue géographique des marchés peut être élargie par la construction de nouvelles liaisons de transport, l'augmentation de la capacité des liaisons existantes ou l'amélioration des modes de tarification de l'accès au réseau de transport. Il reste à traiter l'important problème posé par la recherche de moyens adaptés pour stimuler la modernisation du réseau de transport. Il n'est peut-être pas possible d'en laisser l'initiative aux forces du marché – compte tenu du fait, par exemple, qu'une liaison de transport peut être économiquement justifiée même s'il n'y circule jamais d'électricité.
- Les politiques structurelles peuvent atténuer le pouvoir de marché en réduisant la concentration et la part de marché de producteurs sans contraintes. Il faudrait en particulier examiner attentivement la déconcentration des centrales qui utilisent le même combustible, étant donné qu'elles ont tendance à se regrouper dans le classement par ordre de coûts croissants et, par conséquent, à se concurrencer de près. Il faudrait également se pencher sur l'opportunité de séparer la production du transport, pour supprimer les mécanismes qui favorisent la discrimination en matière d'accès au transport et réduire ceux qui encouragent les producteurs à pratiquer le retrait de capacité dans le but d'accroître leur pouvoir de marché.
- De nombreux observateurs ont souligné l'importance qu'il y a à accroître l'élasticité de la demande. Dans les modèles simples de pouvoir de marché, le doublement de l'élasticité de la demande équivaut au doublement du nombre de concurrents actifs sur un marché. L'élasticité de la demande peut être accrue par une plus grande participation des consommateurs sur les marchés de l'électricité et l'utilisation plus répandue des compteurs horo-saisonniers. Sur certains marchés de l'électricité libéralisés, la participation des acheteurs n'était pas envisageable – la demande était évaluée en tant que quantité fixe simple, insensible au prix. Les acheteurs d'électricité devraient avoir la possibilité de faire des offres sur le pool de l'électricité de façon à signaler leur intention de restreindre leur demande en période de pointe.
- Enfin, lorsque le pouvoir de marché persiste sans qu'on ne parvienne à l'affaiblir par d'autres politiques, il faut étudier la possibilité d'instituer des mesures de contrôle du prix ou de la quantité. Comme les conditions de l'offre et de la demande fluctuent beaucoup à tout instant, le contrôle du prix de la production d'électricité est ardu, bien qu'il ne soit pas nécessairement irréalisable. Parmi les approches possibles, citons la mise en place d'une tarification de type « price cap » applicable aux prix demandés pendant les périodes de pointe, ou l'imposition de limites d'écart entre les prix demandés par les différents groupes.

Le présent document comporte trois parties. La première partie passe en revue certains des principes de mesure du pouvoir de marché sur les marchés souffrant de contraintes de capacité et examine les principales caractéristiques des marchés de l'électricité qui favorisent le pouvoir de marché. La deuxième partie s'intéresse davantage à la façon dont le pouvoir de marché s'exerce sur le marché de

l'électricité et formule plusieurs observations sur les conditions dans lesquelles il est susceptible de se manifester, sur la façon dont il convient de le mesurer, de même que sur ses effets. La troisième partie examine les avantages et les inconvénients des politiques visant à modérer le pouvoir de marché.¹

Généralités : la théorie du pouvoir de marché et les caractéristiques des marchés de l'électricité

Avant de s'intéresser aux marchés de l'électricité, il convient de passer en revue certains principes de base qui régissent l'évaluation et la mesure du pouvoir de marché, notamment sur les marchés qui présentent des contraintes de capacité.

Examen de la théorie du pouvoir de marché

Une entreprise est réputée détenir un pouvoir de marché lorsqu'elle peut, en réduisant sa production ou en augmentant le prix minimum auquel elle est disposée à la vendre, accroître ses bénéfices en faisant monter le prix du marché. L'entreprise qui ne peut pas influencer le prix du marché est preneuse de prix. Une entreprise preneuse de prix continue de produire et de vendre sa production tant que le prix du marché dépasse le coût marginal de production de la dernière unité de production. Sur un marché où tous les producteurs sont des preneurs de prix (autrement dit, où ne s'exerce aucun pouvoir de marché), le coût marginal de toutes les entreprises présentes sur le marché est égal au prix du marché.²

C'est pourquoi l'ampleur de l'écart entre le prix du marché et le coût marginal assumé par une entreprise peut constituer un indicateur permettant de détecter et de mesurer le pouvoir de marché. L'« indice de Lerner » est une mesure courante de l'écart entre le prix et le coût marginal. Il exprime simplement la marge en pourcentage comprise dans le prix final par rapport au coût marginal – autrement dit, en supposant un prix final P et un coût marginal c , l'indice de Lerner s'établit comme suit :

$$\frac{P - c}{P}$$

On peut aisément montrer (voir annexe B) que sur un marché où les entreprises rivalisent en quantité, la taille de la marge prix-coût (l'indice de Lerner) est obtenue par une mesure de la concentration appelée indice de Herfindahl-Hirschman, divisée par l'élasticité de la demande. Autrement dit :

$$\frac{P - c}{P} = \frac{IHH}{\varepsilon} \quad \dots(1)$$

où IHH est la somme des carrés des parts de marché des différentes entreprises qui rivalisent sur le marché ($IHH = \sum_{i=1}^N s_i^2$ où s_i est la part de marché de la i ème entreprise), ε l'élasticité de la courbe de la demande au prix et à la quantité d'équilibre et c une moyenne pondérée du coût marginal de chaque producteur à la quantité d'équilibre.³

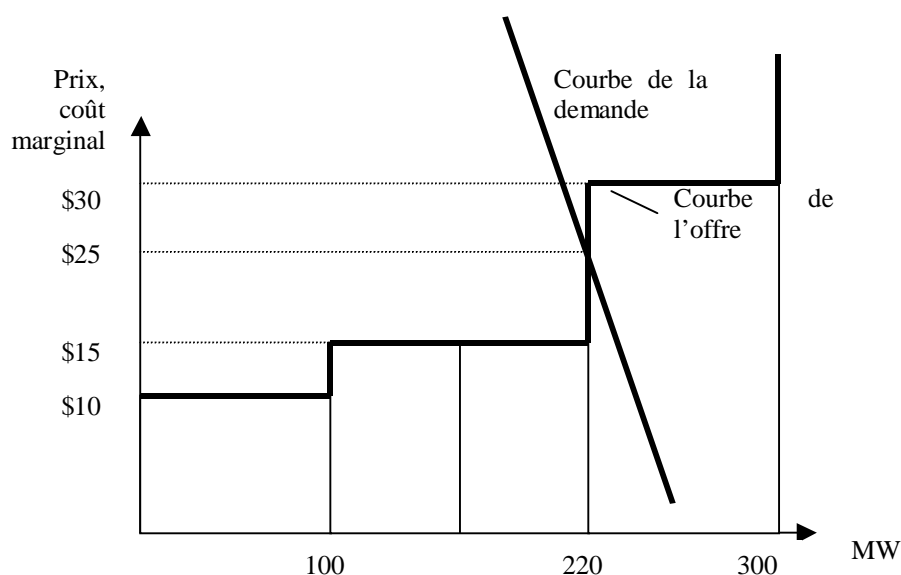
L'équation (1) met en évidence l'importance de l'élasticité de la courbe de la demande pour la détermination de l'effet du pouvoir de marché sur le prix. Toutes choses égales par ailleurs, une réduction de moitié de l'élasticité de la demande a le même effet que le doublement de la concentration sur le marché (c'est-à-dire la réduction de moitié du nombre de concurrents). En supposant un degré constant de concentration sur un marché, le pouvoir de marché est beaucoup plus grand sur les marchés où l'élasticité de la demande est faible.

On verra plus loin qu'une des caractéristiques principales des marchés de production d'électricité est que les différentes entreprises sont soumises à des contraintes de capacité. Par souci de simplicité, supposons que chaque groupe assume un coût marginal constant pour tous les niveaux de production en dessous de sa capacité. De fait, la courbe de coût marginal a la forme d'un « L » inversé.

La courbe de l'offre sur le marché peut être formée à partir des courbes de coût marginal des différents groupes classés par ordre de coûts marginaux croissants et l'addition horizontale subséquente des courbes de coût marginal. Ce calcul est illustré dans le diagramme ci-après.⁴

La figure 1 illustre une situation dans laquelle sont présents quatre groupes, le premier ayant un coût marginal de 10 dollars le MW et une capacité de 100 MW, le deuxième et le troisième un coût marginal de 15 dollars le MW et une capacité de 60 MW, et le quatrième un coût marginal de 30 dollars le MW et une capacité de 80 MW. Cet « ordre de coûts marginaux croissants » détermine la courbe de l'offre du secteur. Dans un marché parfaitement concurrentiel, le prix du marché se situerait à l'intersection de la courbe de la demande et de la courbe de l'offre, comme l'illustre la figure 1.

Figure 1 : Demande et offre sur un marché ayant des contraintes de capacité



On peut avoir recours à l'indice de Lerner pour mesurer le pouvoir de marché sur les marchés ayant des contraintes de capacité, à une importante réserve près. Sur un marché où les entreprises ont des contraintes de capacité, le prix du marché peut dépasser le coût marginal de n'importe quelle entreprise donnée sans que l'on observe pour autant un pouvoir de marché, lorsque toutes les entreprises présentes sur le marché fonctionnent à pleine capacité et qu'aucune autre entreprise dont le coût marginal est inférieur au prix du marché n'entend accéder au marché. Cette situation est illustrée à la figure 1. Dans cette figure, l'intersection de la courbe de la demande et de la courbe de l'offre se situe à 25 dollars le MW, montant supérieur au coût marginal assumé par toutes les entreprises actives sur le marché, sans que cela n'entraîne de pouvoir de marché.⁵

Fait important, comme on le verra ci-après, la relation entre l'indice de Lerner, l'élasticité et l'indice de Herfindahl-Hirschman ne s'applique plus sur des marchés présentant des contraintes de capacité. Par conséquent, l'utilisation de l'indice de Herfindahl-Hirschman pour ces marchés peut donner des résultats très trompeurs. La section suivante propose une autre façon de mesurer la concentration qui reflète avec précision le pouvoir de marché qui s'exerce sur ce type de marchés.

Nous utilisons dans le présent document le modèle de pouvoir de marché de Cournot (autrement dit, nous supposons que les entreprises se concurrencent en quantité). Le modèle de Cournot nécessite un calcul simple et donne des résultats justifiés intuitivement. Il convient cependant de ne pas perdre de vue que le modèle de Cournot peut surévaluer ou sous-évaluer le degré réel de pouvoir de marché. La surévaluation du pouvoir de marché s'explique par le fait que le modèle de Cournot ne tient pas compte des possibilités d'entrée, et sa sous-évaluation, par celui qu'il fait abstraction d'un éventuel comportement collusoire. En outre, sur la plupart des marchés de gros de l'électricité, les entreprises ne font pas des enchères sur des quantités spécifiques mais sur une fonction d'offre complète – c'est-à-dire sur la quantité qu'elles sont disposées à fournir pour chaque prix. Un équilibre des fonctions d'offre aboutit à une évaluation du pouvoir de marché inférieure à celle d'un équilibre de Cournot. De fait, il semble qu'un équilibre de la fonction d'offre aboutisse à une concurrence au sens de Bertrand lorsqu'il y a une importante capacité excédentaire sur le marché, et à une concurrence à la Cournot lorsque la capacité excédentaire est limitée. L'encadré qui suit examine les avantages et les inconvénients d'un équilibre à la Cournot et d'un équilibre de la fonction d'offre.

Concurrence selon la fonction d'offre et concurrence à la Cournot

« La concurrence à la Cournot ne rend pas entièrement compte des options qui s'offrent aux entreprises sur un marché de l'électricité. Les producteurs ne sont pas obligés de faire des enchères sur les quantités sur un marché spot mais sont, en fait, libres de faire des enchères sur n'importe quelle courbe d'offre, les enchères sur les quantités correspondant au cas particulier d'une courbe d'offre verticale. Cependant, l'évaluation de l'équilibre statique de Cournot sur le marché de l'électricité ne donne qu'une indication approximative du comportement concurrentiel si les entreprises font face à une faible incertitude de la demande. En l'absence d'incertitude, on observe que parmi les nombreux équilibres de Nash possibles, celui produit par les enchères sur les quantités (stratégie de Cournot) est le plus rentable. Par conséquent, en l'absence d'incertitude et si l'on dispose d'information sur les coûts, l'évaluation de la marge prix-coût selon le modèle de Cournot pourrait remplacer un indice structurel comme celui de Herfindahl-Hirschman.

Il en va autrement sur un marché où la demande est incertaine. Un producteur y est confronté à de nombreux niveaux possibles de demande, même lorsqu'il connaît les niveaux de production de son concurrent. Les entreprises s'engagent alors dans une concurrence axée sur la courbe de l'offre. Ce problème a été analysé par Klemperer et Meyer (1989) dans un contexte général. Dans le cas d'une concurrence axée sur la courbe de l'offre, il est rentable pour les entreprises de s'éloigner de l'équilibre de Cournot pour aller vers un équilibre de Nash, qui se définit en terme de courbes d'offre ascendantes (mais non verticales). Les fournisseurs ne font pas des enchères sur des quantités simples comme le spécifie le modèle de Cournot. On aboutit alors à des marges prix-coût inférieures à celles que l'on obtient dans une concurrence à la Cournot. L'introduction de l'incertitude de la demande atténue par conséquent les effets du pouvoir de marché.⁶

« Le modèle de la fonction d'offre (...) présente certaines faiblesses qui pourraient limiter son utilité lorsqu'il est appliqué à certains marchés de l'électricité. Sur certains marchés, les échanges ne s'effectuent pas exclusivement ni même principalement par le biais d'un processus d'enchères portant sur la fonction d'offre. L'échange bilatéral de quantités spécifiées est répandu dans de nombreux marchés restructurés à l'échelle mondiale, comme les marchés à terme et différentes formes de marchés spot. (...) L'approche selon la fonction d'offre ne convient pas non plus aux marchés sur lesquels la capacité d'une frange concurrentielle peut être limitée par des contraintes de production ou de transport. Globalement, l'approche selon la fonction d'offre réalise une meilleure approximation d'un aspect important de nombreux marchés de l'électricité que l'approche de Cournot mais n'est pas aussi souple que cette dernière pour ce qui est d'incorporer d'autres aspects institutionnels de ces marchés. L'approche selon la fonction d'offre produit enfin des équilibres multiples dont la diversité augmente lorsque diminue l'incertitude de la demande. L'équilibre de Cournot représente une borne supérieure des équilibres selon la fonction d'offre, est en général plus facile à calculer, et constitue peut-être, à cet égard, le meilleur moyen de mesurer l'existence potentielle d'un pouvoir de marché. »⁷

Caractéristiques des marchés de l'électricité qui facilitent l'exercice d'un pouvoir de marché

On a vu qu'une entreprise est à même d'exercer un pouvoir de marché lorsqu'elle peut, en augmentant son prix ou en diminuant la quantité de son produit, influencer le prix du marché. Sur la plupart des marchés, la capacité qu'a une entreprise d'augmenter son prix ou de diminuer sa production d'un service particulier à un lieu et à un moment donné est limitée par :

- (a) la réaction des consommateurs, qui peuvent réduire leur consommation du service en question ou modifier les moments et les lieux de consommation, ou consommer d'autres services ;
- (b) la réaction d'autres entreprises déjà présentes sur le marché, qui peuvent accroître leur propre production à la suite de l'augmentation du prix ou de la réduction de la production d'une autre entreprise ;
- (c) la réaction d'autres entreprises qui ne produisent pas encore sur le marché et qui y entrent à la suite d'une augmentation du prix ou d'une diminution de la production d'une entreprise existante.

Chacune des contraintes énumérées ci-dessus a un effet limité sur le marché de l'électricité pour les raisons suivantes :

- Premièrement, le stockage de l'électricité coûte cher. « Les techniques de stockage – par exemple, par pompage d'eau en amont afin de constituer des réserves d'énergie hydroélectrique ou sur des batteries – sont très peu efficaces »⁸. Etant donné que l'électricité ne peut être stockée facilement, il existe un marché distinct pour chaque moment de livraison. Le prix des marchandises qui peuvent être stockées a tendance à s'uniformiser avec le temps étant donné que les entrepreneurs les achètent lorsque le prix est bas et les revendent lorsque le prix est élevé. Comme l'électricité ne peut être stockée, les marchés de l'électricité ont tendance à être plus instables que d'autres marchés de ressources énergétiques, par exemple ceux de l'essence. Nous verrons que même s'il existe une vive concurrence entre les producteurs à certains moments, la concurrence est parfois considérablement limitée (notamment pendant les périodes de forte consommation).
- Deuxièmement, le transport de l'électricité coûte cher par moments – en particulier lorsque le réseau de transport est congestionné. Dans ce cas, les marchés de la production sont séparés géographiquement, ce qui réduit le nombre de concurrents potentiels et peut accroître le pouvoir de marché. En outre, le degré de congestion est à la fois fonction du niveau de la demande et des décisions stratégiques prises par les entreprises de production elles-mêmes.
- Troisièmement, l'élasticité de la demande d'électricité est très faible. Très peu de consommateurs paient un prix correspondant aux variations du prix du marché du « pool » ou de la « bourse » de l'électricité. Par conséquent, la chute de la demande qui résulte d'une augmentation du prix du marché est négligeable. « La plupart des consommateurs finals d'électricité ne disposent pour ainsi dire d'aucun moyen technique d'observer les prix en temps réel et encore moins d'y réagir. La demande est pratiquement inélastique à court terme »⁹ On a vu que l'inélasticité de la demande facilite beaucoup l'exercice d'un pouvoir de marché en limitant la réduction de la demande des consommateurs à la suite d'une hausse de prix.

- Quatrièmement, les producteurs font face à des contraintes de production évidentes. « Les groupes ont de fortes contraintes de capacité qui font augmenter considérablement le coût marginal au-delà d'un certain seuil de production ». ¹⁰ Si les autres entreprises présentes sur le marché souffrent de contraintes de capacité, elles sont incapables d'augmenter leur production à la suite d'une hausse de prix – le pouvoir de marché des entreprises restantes qui n'ont pas de contraintes peut donc être substantiel.
- Cinquièmement, l'électricité est un bien homogène vendu dans le cadre d'enchères répétées sur des marchés comportant un nombre limité d'acteurs qui connaissent les coûts assumés par leurs partenaires et peuvent apprendre rapidement à réagir au comportement des autres, ce qui facilite les pratiques collusives.

En outre, il se peut que des caractéristiques particulières du mode d'organisation des marchés de l'électricité contribuent à faciliter davantage le pouvoir de marché, comme c'est le cas, par exemple, des marchés où se négocient des primes de capacité ou une capacité de production de réserve. Ces marchés peuvent eux-mêmes se prêter aux manipulations stratégiques des entreprises qui y sont présentes. ¹¹

Borenstein et Bushnell résumant comme suit les caractéristiques des marchés de l'électricité :

« Sur la plupart des marchés, il existe d'autres contraintes qui empêchent une entreprise donnée représentant un assez faible pourcentage de la production de procéder à des hausses de prix substantielles. Si le produit peut être stocké, les acheteurs, ou les intermédiaires qui le commercialisent, peuvent le stocker pour être moins vulnérables aux hausses de prix. Si les consommateurs finals reçoivent des informations sur les prix avant d'acheter, leur hésitation à payer des prix excessifs dissuade le vendeur de pratiquer de tels prix. Si l'offre est élastique, l'entreprise qui demande un prix élevé pour sa production provoque simplement un déplacement de part de marché vers un autre fournisseur. Chacune de ces caractéristiques est beaucoup moins présente sur les marchés du secteur électrique que sur ceux de la plupart des autres secteurs. Les entreprises qui détiennent des parts de marché, si modestes soient-elles, sont par conséquent davantage en mesure d'exercer un pouvoir de marché dans ce secteur que dans la plupart des autres secteurs ». ¹²

Observations sur le pouvoir de marché sur les marchés de la production d'électricité

Examinons de façon plus détaillée comment le pouvoir de marché naît sur les marchés de l'électricité, son impact ainsi que la façon dont il doit être mesuré. Pour simplifier, prenons le cas d'un marché de l'électricité en faisant abstraction de la composante transport – et supposons que la totalité de la production et de la consommation interviennent au même endroit. Nous pourrions de la sorte nous attacher exclusivement aux effets des contraintes de capacité sur les producteurs. Nous réintroduirons ensuite la composante transport afin d'étudier l'effet des contraintes de transport.

Nous avons vu que les prédictions des modèles économiques en ce qui a trait au degré de pouvoir de marché qui se manifeste sur les marchés de gros de l'électricité sont liées à la nature de l'interaction stratégique qui existe entre les entreprises productrices. On peut toutefois faire valoir que, du moins en période de pointe, une certaine forme de pouvoir de marché doit exister, quel que soit le type de concurrence que se livrent les producteurs.

Prenons l'exemple d'un marché sur lequel la production est soumise à des contraintes de capacité, où la demande d'électricité n'est pas élastique, et où le niveau de la demande est suffisamment élevé pour faire en sorte que si un producteur cesse de produire, les autres producteurs ne peuvent compenser eux-mêmes la production manquante. Si l'inélasticité de la demande est suffisante, un producteur, si petite que soit sa taille, pourrait hausser significativement le prix du marché en réduisant sa

production. De fait, si la demande est parfaitement inélastique, cette entreprise pourrait facturer le prix de son choix. Borenstein et Bushnell résumant cet argument intuitif comme suit :

« Imaginez un pénible après-midi d'été où la température et l'humidité ont atteint des niveaux record et où presque toutes les centrales du réseau doivent tourner afin de répondre à la demande extraordinaire d'électricité nécessaire pour faire fonctionner les appareils de climatisation. Si le réseau n'a qu'un faible pourcentage de marge de capacité de production de réserve et qu'un producteur fournit plus qu'un faible pourcentage de la production totale, ce producteur joue un rôle essentiel dans la satisfaction de la demande. Autrement dit, il peut demander un prix très élevé pour livrer l'électricité... et les consommateurs paieront ce prix. »¹³

Cela n'implique pas pour autant que le degré de pouvoir de marché augmente avec la demande. L'augmentation du degré de pouvoir de marché, en période de pointe, dépend de la nature de la concurrence entre les entreprises. Si elles se concurrencent en quantité (c'est-à-dire à la Cournot), quel que soit le nombre de producteurs identiques, et en supposant une élasticité constante de la demande, le pouvoir de marché est *constant*, peu importe le niveau de la demande, même lorsque la quasi-totalité de la capacité du marché est épuisée.

C'est ce que démontre l'équation (1). Sur un marché comportant des producteurs de taille identique, le niveau de production est le même pour tous les producteurs. Tous ces producteurs sont donc soit soumis à des contraintes, soit exempts de contraintes. Tant que dure l'absence de contraintes, le degré de pouvoir de marché est obtenu à l'aide de l'équation (1). Lorsque tous les producteurs atteignent le même niveau de production, l'indice de Herfindahl-Hirschman (IHH) est la réciproque exacte du nombre d'entreprises, de sorte que le pouvoir de marché est égal à $IHH / \varepsilon = 1/n\varepsilon$, peu importe le niveau de la demande.

L'annexe B montre que ce résultat est vrai même lorsque les entreprises ne sont pas de taille identique – tant que l'élasticité de la demande demeure constante et que les entreprises n'ont pas de contrainte de capacité, l'augmentation de la demande est sans effet sur le prix.

Par ailleurs, si les producteurs ne sont pas de même taille (et se concurrencent à la Cournot), le pouvoir de marché *augmente* avec la demande. Plus la demande augmente, plus le nombre de producteurs qui fonctionnent à pleine capacité croît, et moins ceux-ci sont en mesure de discipliner les autres acteurs du marché. Au point limite, il ne restera qu'un seul producteur (le plus gros). Ce dernier producteur sans contrainte détient un monopole effectif sur la demande résiduelle sur le marché. Le FTC des Etats-Unis résume ce cas de figure :

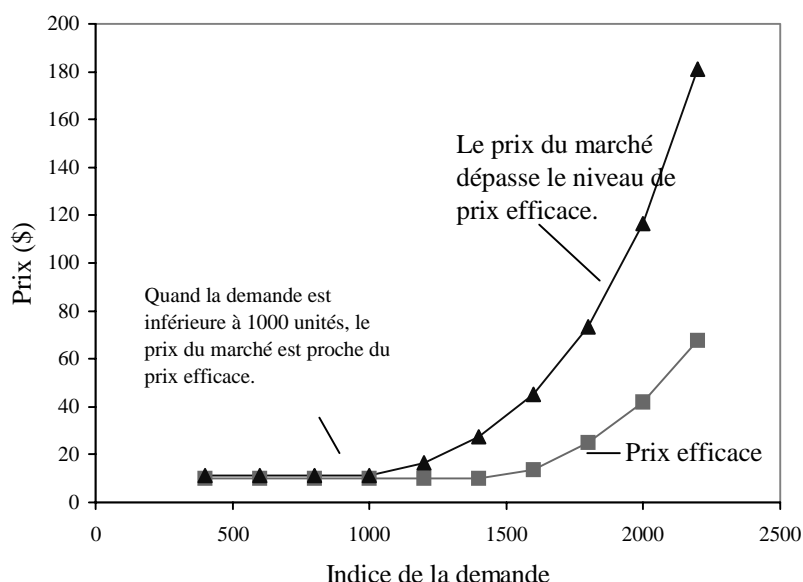
« Comment la participation de fournisseurs qui ne représentent qu'une petite fraction de la capacité peut-elle affecter le prix du marché de l'électricité ? Cela tient à la manière dont s'effectue le dispatching des centrales électriques. Les centrales électriques ont en général des fonctions de coûts très uniformes jusqu'à ce qu'elles atteignent leur pleine capacité. Elles fonctionnent par conséquent au maximum de leur capacité si elles sont économiquement en mesure de le faire au prix courant. Sinon, elles tournent au ralenti. Par conséquent, la plupart des centrales électriques qui produisent de l'électricité, pendant une période donnée, ne sont pour ainsi dire pas en mesure d'accroître leur production et de contrebalancer un comportement anticoncurrentiel ».¹⁴

C'est ce qu'illustre le diagramme suivant : il s'agit d'un marché dont la courbe de la demande a une élasticité constante égale à 0.2. On compte 51 producteurs ayant tous un coût marginal identique de 10 dollars le MW. Sur ce nombre, 50 sont de petits producteurs ayant une capacité totale de 20 MW. Le cinquante et unième producteur est un gros producteur et a une capacité de production de 500 MW. (Supposons que ce producteur est né de fusions antérieures effectuées par 25 petits producteurs). Ces

producteurs sont réputés se concurrencer en quantité produite (autrement dit, on recherchera l'équilibre classique de Cournot.)

La figure 2 illustre le profil d'évolution du prix du marché à mesure que la demande augmente. Lorsque les niveaux de la demande sont bas, les petits producteurs n'ont pas de contraintes de capacité et le prix reste voisin du prix du marché efficace, soit 10 dollars le MW. Lorsque la demande (en supposant que le prix soit de 10 dollars le MW) dépasse les 1000 unités, les petits producteurs ont une contrainte de capacité et le gros producteur détient un monopole effectif sur la demande résiduelle. Ce producteur n'accroît pas sa production aussi rapidement que la demande augmente, ce qui conduit à une hausse du prix du marché. Notons que sur un marché parfaitement concurrentiel, une demande supérieure à 1500 MW, lorsque le prix est de 10 dollars le MW, entraînerait des contraintes pour tous les producteurs. Par conséquent, le prix efficace (le prix en vigueur sur un marché concurrentiel) dépasse le coût marginal de 10 dollars.

Figure 2 : Pouvoir de marché en période de pointe sur un marché comportant des producteurs de tailles différentes



Lorsque, sur un marché, certaines entreprises fonctionnent à pleine capacité, elles ne peuvent plus augmenter leur production lorsqu'une autre entreprise diminue la sienne. Dans une certaine mesure, ces entreprises se retrouvent « hors marché ». Les autres entreprises présentes sur ce marché qui fonctionnent sans contraintes sont, de fait, en concurrence sur un marché séparé, à cette différence que la demande, sur ce marché « séparé », est réduite d'une quantité égale à la production de toutes les entreprises ayant des contraintes de capacité (c'est ce que l'on appelle la demande « résiduelle. »)

Notons que cela signifie entre autres que lorsque certaines entreprises ont des contraintes de capacité, le marché doit être défini non seulement en fonction du moment et du lieu où l'électricité est vendue, mais aussi du niveau de la demande. Le marché peut être très concurrentiel à certains niveaux de demande et très peu à d'autres.

Cette réflexion peut se résumer ainsi :

Observation n° 1 : *Lorsque des entreprises de production d'électricité n'ont pas la même capacité, un accroissement de la demande peut entraîner une augmentation du nombre d'entreprises qui fonctionnent à pleine capacité et intensifier le pouvoir de marché, même si toutes les entreprises assument le même coût marginal et que l'élasticité de la demande demeure constante.*

Mesures du pouvoir de marché et de la concentration

On a vu que sur un marché sans contraintes de capacité, le degré de pouvoir de marché peut être relié à la concentration qui existe sur ce marché selon l'équation suivante.

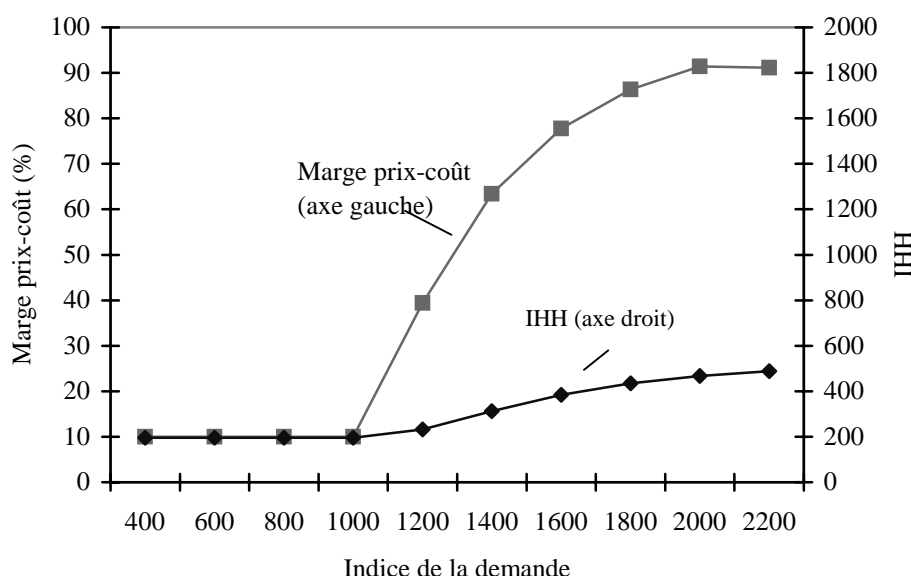
$$\frac{P - c}{P} = \frac{IHH}{\varepsilon}$$

où IHH est la somme des carrés des parts de marché des différentes entreprises qui sont en concurrence sur le marché ($IHH = \sum_{i=1}^N s_i^2$ où s_i la part de marché de la i ème entreprise) et ε l'élasticité de la courbe de la demande au prix et à la quantité d'équilibre.

Cependant, comme on l'a déjà noté, le recours à l'indice de Herfindahl-Hirschman pour évaluer la concentration sur un marché ayant des contraintes de capacité peut aboutir à des résultats très trompeurs.

On peut aisément le constater en reprenant l'exemple du marché illustré à la figure 2 ci-dessus. Dans cet exemple, il y a 50 petites entreprises et une grande. Comme le montre la figure 3, le marché n'est pas très concentré – l'indice de Herfindahl-Hirschman ne dépasse jamais 500 – et se situe largement en dessous du seuil (quelque peu arbitraire) de 1000 fixé par le *Department of Justice* des Etats-Unis pour qu'un marché soit considéré comme concurrentiel. Cependant, comme le montre la figure 3, la marge prix-coût approche les 90 pour cent du prix du marché, ce qui suppose des niveaux de concurrence relativement bas.

Figure 3 : Concentration et marge prix-coût



Les autres mesures de la concentration ne donnent pas de résultats beaucoup plus probants. Ainsi, la part de marché de la plus grande entreprise ne dépasse jamais les 18 pour cent. Les 50 autres entreprises ne détiennent que 1 à 2 pour cent du marché chacune. La part de marché attribuée aux quatre premières entreprises ne dépasse jamais 25 pour cent.

Supposons que ce marché comportait à l'origine 75 petites entreprises identiques (20 MW). Sur ce nombre, 25 envisagent fusionner. Etant donné que la concentration, après la fusion, serait inférieure à 500 sur l'échelle établie pour l'indice de Herfindahl-Hirschman, ou, en d'autres termes, que le ratio de concentration des quatre plus grandes entreprises serait inférieur à 25 pour cent, l'autorité de la concurrence concernée pourrait difficilement empêcher cette fusion. Mais, comme l'indique la figure 2, l'entreprise née de la fusion peut détenir un pouvoir de marché significatif pendant les périodes de pointe.

Il est évident que l'indice de Herfindahl-Hirschman classique est un indicateur médiocre du pouvoir de marché sur un marché présentant des contraintes de capacité. Existe-t-il une meilleure méthode de mesure du pouvoir de marché sur ces marchés ?

L'annexe B montre que la relation entre l'indice de Lerner, l'indice de Herfindahl-Hirschman et l'élasticité de la demande est toujours valable à la condition d'ajuster la formule de l'indice de Herfindahl-Hirschman. Plus précisément, on constate que sur les marchés où certaines entreprises ont des contraintes de capacité,

$$\frac{P - c}{P} = \frac{IHH^{adj}}{\varepsilon}$$

où

$$IHH^{adj} = \sum_{i=1}^n s_i \left(s_i + \frac{\bar{s}}{n} \right) \quad \dots(2)$$

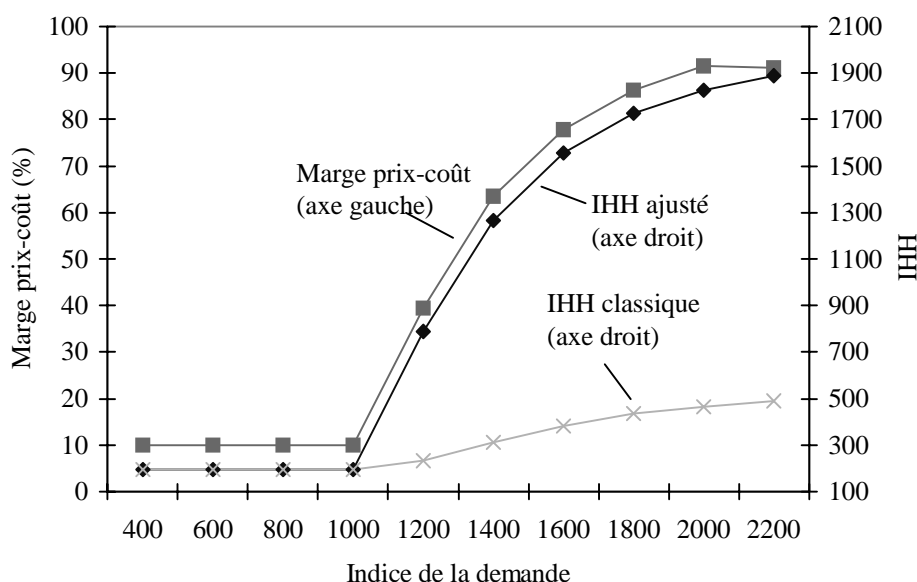
et où n représente le nombre d'entreprises sans contraintes, s_i la part de marché d'une entreprise sans contraintes ($i=1,..n$) et \bar{s} la part de marché combinée de toutes les entreprises soumises à des contraintes.

Pour donner un exemple du calcul de l'indice de Herfindahl-Hirschman ajusté, prenons le marché déjà illustré aux figures 2 et 3. Lorsque la demande atteint un niveau égal à 1200 unités, les 50 petites entreprises produisent au maximum de leur capacité de 20 unités de production. La plus grande entreprise produit 85.6 unités de production. Elle détient par conséquent une part de marché d'environ 7.9 pour cent, alors que les petites entreprises détiennent chacune une part de marché de 1.8 pour cent. L'indice de Herfindahl-Hirschman classique aboutirait par conséquent à la concentration du marché suivante : $7.9^2 + 50 \times 1.8^2 = 224$.

Par comparaison, étant donné que la part de marché combinée des petites entreprises ayant des contraintes de capacité est de 92.2 pour cent, l'indice de Herfindahl-Hirschman ajusté se calcule comme suit : $7.9 \times (7.9 + 92.2) = 790$ - soit une concentration environ 3.5 fois plus élevée que celle obtenue à l'aide de l'indice de Herfindahl-Hirschman classique.¹⁵

Les différentes façons de calculer l'indice de Herfindahl-Hirschman apparaissent clairement à la figure 4, qui reprend l'exemple de la figure 3 avec l'indice de Herfindahl-Hirschman ajusté plutôt qu'avec l'indice de Herfindahl-Hirschman classique. Il ne fait pas de doute que l'indice de Herfindahl-Hirschman ajusté reflète mieux le degré véritable du pouvoir de marché sur ce marché pour différents niveaux de demande que ne le fait l'indice de Herfindahl-Hirschman classique. (Il convient de noter que dans ce graphique, l'échelle de l'indice de Herfindahl-Hirschman a été légèrement décalée pour dissocier les deux lignes qui autrement se seraient superposées).

Figure 4 : Marge prix-coût et mesure de la concentration selon l'indice ajusté



Observation n°2 : Sur un marché où certaines entreprises ont des contraintes de capacité, la mesure de la concentration au moyen de l'indice de Herfindahl-Hirschman classique donne des résultats imprécis et il faudrait plutôt recourir à l' « indice de Herfindahl-Hirschman ajusté » illustré dans l'équation (2).

Incidences sur les politiques structurelles

Il est intéressant d'examiner certaines des conséquences du recours au concept de l'« indice de Herfindahl-Hirschman ajusté ». D'abord, il faut noter que chaque fois que la demande atteint un point où il ne subsiste qu'une seule entreprise sans contraintes, l'indice de Herfindahl-Hirschman ajusté de la concentration du marché est alors simplement égal à la part de marché de cette entreprise – les parts de marché détenues par les autres entreprises ne sont pas pertinentes. C'est ce que l'on constate aisément en examinant la formule de calcul de l'indice de Herfindahl-Hirschman ajusté. S'il n'y a qu'une seule entreprise sans contraintes, (l'entreprise 1, par exemple) sa part de marché et celle des autres entreprises totalisent évidemment 100 pour cent - soit $s_1 + \bar{s} = 1$, de sorte que :

$$IHH^{adj} = \sum_{i=1}^n s_i (s_i + \frac{\bar{s}}{n}) = s_1 (s_1 + \bar{s}) = s_1$$

Nous pouvons notamment en conclure que toute tentative de réduire le pouvoir de marché lorsqu'il n'y a qu'une seule entreprise sans contraintes passe obligatoirement par la réduction de la part de marché de cette entreprise – en recourant sans doute à la cession d'actifs. *L'augmentation du nombre d'entreprises sur le marché ne suffira pas nécessairement à contrer le pouvoir de marché.*

Wolak et Patrick (1997) font ressortir le même argument : « L'entrée de nouvelles entreprises sur le marché [de l'Angleterre et du Pays de Galles] n'aura sans doute à elle seule qu'une influence limitée... De nombreux producteurs d'électricité indépendants desservent déjà le marché, de sorte qu'on ne saurait se contenter d'augmenter le nombre de concurrents. Compte tenu du nombre actuel d'entreprises sur le marché et des règles de marché, il importe, pour limiter le pouvoir de marché, de réduire la taille des plus grandes entreprises comparativement à l'ensemble des autres entreprises. »¹⁶

L'annexe B montre que pour un nombre fixe d'entreprises sans contraintes, l'indice de Herfindahl-Hirschman ajusté est réduit au minimum lorsque toutes les entreprises sans contraintes ont une part de marché identique. Cette part de marché doit par conséquent être égale à la part totale des entreprises sans contraintes divisée par le nombre d'entreprises sans contraintes $\frac{1-\bar{s}}{n}$. La valeur minimum de l'indice de Herfindahl-Hirschman ajusté est par conséquent :

$$IHH^{adj} \geq \frac{1-\bar{s}}{n}$$

Cette expression conduit à penser que pour réduire le pouvoir de marché, les responsables de l'élaboration des politiques devraient porter leur attention sur (a) l'augmentation du nombre d'entreprises sans contraintes et (b) la réduction de la part de marché des entreprises sans contraintes (ou, ce qui revient au même, l'accroissement de la part de marché des entreprises ayant des contraintes).

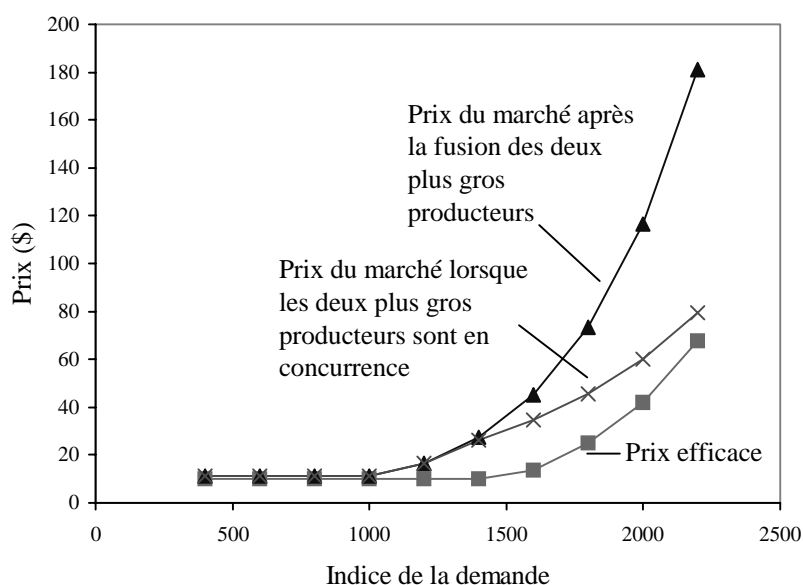
Qu'implique cette analyse pour la politique en matière de fusions ? Soulignons notamment que le contrôle des concentrations devrait être axé sur les fusions aboutissant à la création d'une entreprise sans contraintes (la fusion de deux entreprises qui continueront d'avoir des contraintes à un niveau donné de demande n'a pas d'impact sur le pouvoir de marché à ce niveau de demande, même si elle peut évidemment accroître le pouvoir de marché à d'autres niveaux de demande.)

Notons également que le contrôle de la concentration devrait porter sur les fusions d'entreprises sans contraintes réalisées par des producteurs marginaux qui sont relativement proches dans l'ordonnement selon l'ordre de coûts croissants. Le pouvoir de marché d'un producteur sans contraintes

est limité principalement par l'aptitude des autres producteurs sans contraintes à accroître leur production à la suite d'une hausse de prix – notamment les producteurs qui assument un coût marginal voisin du prix du marché mais qui n'ont pas encore été appelés.

De fait, comme l'illustre le diagramme ci-dessous, la fusion d'un producteur avec le producteur qui le précède immédiatement dans le classement par ordre de coûts croissants peut avoir un impact considérable sur le prix, même lorsque la part de marché du producteur dont le coût est le plus élevé est très petite. Reprenons l'exemple du marché décrit à la figure 2, en supposant cette fois qu'un producteur additionnel ayant une capacité de 200 MW et un coût marginal de 25 dollars le MW est actif sur le marché. Lorsque le prix du marché dépasse 25 dollars, ce producteur commence à produire. La figure 5 présente le niveau des prix pour différents niveaux de demande avant et après la fusion des deux plus grandes entreprises considérées. L'impact de cette fusion sur le prix du marché peut être très considérable, même lorsque l'entreprise dont le fonctionnement coûte le plus cher détient une petite part de marché. Par exemple, lorsque le niveau de demande est égal à 1600, une fusion fait monter le prix, qui passe de 34.70 à 45 dollars le MW (soit une augmentation de 30 pour cent), même si les parts de marché détenues avant la fusion par les deux producteurs sans contraintes ne sont que de 14.2 et 5.6 pour cent.

Figure 5 : Effet de la fusion de deux entreprises qui sont voisines dans le classement selon l'ordre de coûts croissants



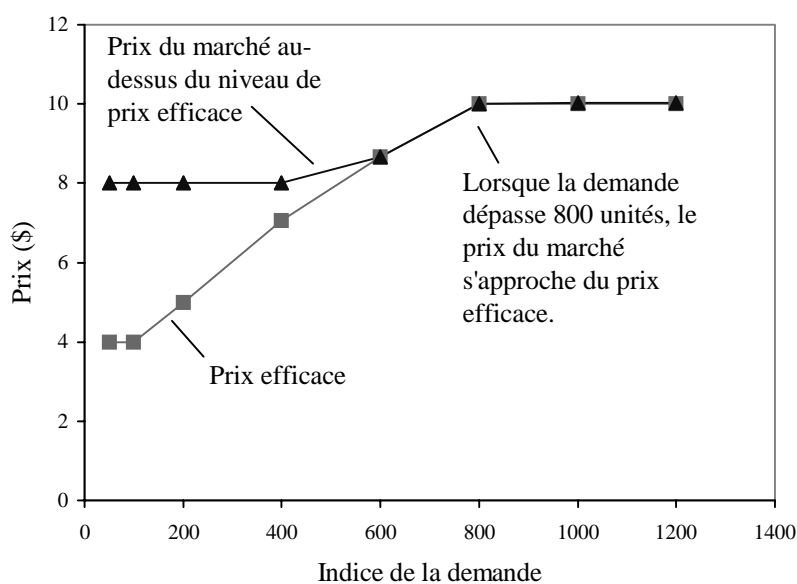
Observation n°3 : Le contrôle des fusions de producteurs devrait s'exercer sur les fusions qui débouchent sur la création d'entreprises sans contraintes et sur les fusions d'entreprises dont les producteurs marginaux sont voisins dans le classement selon l'ordre de coûts croissants. La fusion de deux entreprises sans contraintes qui sont proches dans le classement selon l'ordre de coûts croissants peut avoir un effet significatif sur le prix même lorsque les deux entreprises en question ont une part de marché relativement faible.

Le pouvoir de marché en périodes creuses

Nous avons vu comment la présence de contraintes de capacité augmente le pouvoir de marché comparativement à une situation où il n'existe pas de contraintes de capacité. Soulignons toutefois que pour autant, le pouvoir de marché n'a pas toujours tendance à augmenter en période de pointe. De fait, c'est plutôt le contraire qui peut se produire. Une augmentation de la demande peut, par exemple, occasionner le démarrage d'un très grand nombre de producteurs à coût élevé, ce qui a pour effet de réduire et non d'augmenter le pouvoir de marché.¹⁷

La figure 6 illustre un marché dont les acteurs sont un producteur à faible coût (coût marginal de 4 dollars) et qui possède une petite capacité de 800 MW, et un grand nombre (50) de producteurs à coût élevé (coût marginal de 10 dollars). L'élasticité de la demande est égale à 2. Comme l'indique le graphique, lorsque les niveaux de la demande sont bas, le producteur à moindre coût détient un monopole – qu'il exerce en facturant un prix du marché de 8 dollars. Ce montant demeure le prix du marché jusqu'à ce que le monopoleur ait des contraintes de capacité, et c'est alors que le prix augmente à 10 dollars, que les autres producteurs accèdent au marché et que la marge prix-coût chute à près de zéro.

Figure 6 : Le pouvoir de marché en périodes creuses



Observation n°4: *Le pouvoir de marché ne s'exerce pas nécessairement pendant les périodes de pointe uniquement. Lorsque les producteurs assument des coûts différents, une augmentation de la demande peut entraîner une réduction du pouvoir de marché (à élasticité de la demande constante). Autrement dit, le pouvoir de marché peut aussi se manifester pendant les périodes creuses.*

Nouvelles entrées

Nous avons examiné comment les contraintes de capacité peuvent accroître le pouvoir de marché des entreprises restantes qui ne sont pas soumises à des contraintes de capacité. Voyons maintenant si l'entrée de nouvelles entreprises peut contribuer à réduire ce pouvoir de marché.

La capacité de nouveaux entrants à réduire le pouvoir de marché sur le marché considéré (comme sur n'importe quel marché) est fonction de l'ampleur des économies d'échelle qu'ils réalisent et de la technologie à laquelle ils ont accès. S'il n'y a pas d'économies d'échelle et que les nouveaux entrants peuvent choisir la technologie (et la structure de coûts), ils optent pour la moins chère. Ces nouvelles entrées ont tendance à faire baisser le prix du marché par rapport au coût marginal et se poursuivent jusqu'à ce que le prix (moyen) soit égal au coût moyen de l'entrant marginal.

Dans certains cas, les opérateurs historiques parviennent à dissuader des concurrents potentiels d'entrer sur le marché en vendant leur production par le biais de contrats à long terme. Nous verrons ci-après que lorsque les producteurs historiques ont vendu à l'avance, à un prix fixe, une fraction importante de leur production, ils sont davantage portés à concurrencer de manière agressive sur le marché spot. Cela s'explique par le fait qu'ils ne profitent plus de la possibilité de réduire leur production et d'augmenter le prix du marché de la totalité des unités restantes qu'ils vendent – puisque la plupart d'entre elles sont déjà vendues à prix fixe. En choisissant leur niveau de couverture à terme, les producteurs historiques arrivent donc parfois à faire baisser le prix spot et à repousser ainsi les entrants potentiels. Newbery (1998) étudie cette possibilité et conclut :

« Si le secteur a la capacité totale voulue (compte tenu du nombre d'entreprises), les opérateurs historiques peuvent conclure suffisamment de contrats pour faire baisser le prix à un niveau dissuasif pour de nouveaux entrants potentiels et estiment très rentable de convenir d'un programme de fourniture au prix contractuel le plus élevé possible pour maintenir le prix à ce niveau. On obtient alors un équilibre où le niveau de couverture contractuelle, de même que les stratégies d'enchères, sont déterminés de manière univoque. La plupart du temps, la menace d'une nouvelle entrée incite les opérateurs historiques à augmenter leur couverture contractuelle. Ce faisant, ils deviennent plus compétitifs sur le marché spot et font baisser le prix moyen du pool. Ils font également en sorte d'optimiser la variabilité des prix spot. Newbery (1995) a montré que lorsque les deux opérateurs historiques qui fixent les prix sur le marché britannique de l'électricité constatent que de nouveaux concurrents risquent d'entrer sur le marché (ou lorsqu'ils ont permis l'entrée d'un nombre suffisant de concurrents pour satisfaire l'exigence de concurrence accrue de l'autorité de la concurrence), ils coordonnent rapidement leur stratégie d'enchères de la manière décrite ici. »¹⁸

Prenons maintenant le cas où le seul moyen dont disposeraient de nouveaux entrants potentiels pour accéder au marché serait le recours à une technologie qui coûte plus cher que celle qui est utilisée pour le gros de la production existante. Cette production se composerait pour l'essentiel d'énergie hydroélectrique coûtant relativement peu cher à produire, mais les possibilités de production d'énergie hydroélectrique additionnelle seraient épuisées. De nouvelles entrées seraient alors envisageables, mais seulement, par exemple, dans le secteur de la production d'électricité à partir du pétrole.

Il est sans doute peu probable que de nouveaux concurrents affaiblissent le pouvoir de marché exercé par des producteurs haut placés dans le classement selon l'ordre de coûts croissants. En effet, plus un producteur est « haut placé », plus la demande doit être forte pour qu'il lui soit demandé de produire de l'électricité. Certains producteurs ne sont parfois sollicités que pour quelques périodes par jour ou par mois. Ces producteurs doivent récupérer la totalité de leurs charges fixes et de leurs frais d'exploitation sur une période de fonctionnement relativement courte. Pour ces producteurs, des charges fixes, si petites soient-elles, constituent une composante beaucoup plus importante du prix de revient total que pour un producteur qui est presque toujours en activité. Dans la pratique, les producteurs « à temps partiel » réalisent des économies d'échelle beaucoup plus importantes.

Pour illustrer cette situation, supposons comme précédemment un marché comportant 50 producteurs identiques ayant une capacité de 20 MW et un coût marginal de 10 dollars le MW. La demande est à élasticité constante et est égale à 0.2. Lorsque le prix est de 10 dollars et que la demande augmente à 1200 MW, ces 50 producteurs font face à une contrainte de capacité – ils produisent 1000 MW

et le prix passe à 24.88 dollars. Supposons que de nouveaux concurrents peuvent accéder à ce marché et utilisent une technologie correspondant à une capacité de 20MW, en assumant un coût marginal de 15 dollars et des charges fixes de 2 dollars. Combien de nouveaux entrants ce marché peut-il accueillir ?

Si le niveau de la demande se maintient indéfiniment à 1200, ce marché peut supporter un niveau relativement élevé de nouveaux entrants – de fait, il pourrait accueillir 19 entreprises ayant des charges fixes de 2 dollars. Le prix du marché serait abaissé à 15.37 dollars et chaque nouvel entrant produirait 5.32 MW d'électricité.

Qu'advierait-il cependant si ce niveau élevé de demande ne se maintenait que pendant une courte période ? Si cette période ne correspondait qu'à un pour cent du temps, par exemple, ce marché ne pourrait accueillir qu'un seul nouveau concurrent. Le prix du marché s'établirait à 19.58 dollars – prix préférable à celui qui serait pratiqué s'il n'y avait eu aucun nouvel entrant, mais qui dépasse largement le prix efficace, qui est de 15.10 dollars.

De fait, si les périodes de pointe ne représentent qu'un pour cent du temps seulement, les charges fixes sont multipliées par 100. Cela peut suffire pour restreindre considérablement la possibilité d'une nouvelle entrée. C'est précisément pour cette raison que les entreprises haut placées dans le classement selon l'ordre de coûts croissants peuvent conserver leur pouvoir de marché.

Observation n°5: Le pouvoir de marché qui ne se manifeste que par intermittence n'est pas nécessairement affaibli par de nouvelles entrées. Plus les épisodes de rendement excédentaire sont brefs, plus les charges fixes, si basses soient-elles, font obstacle aux nouvelles entrées.

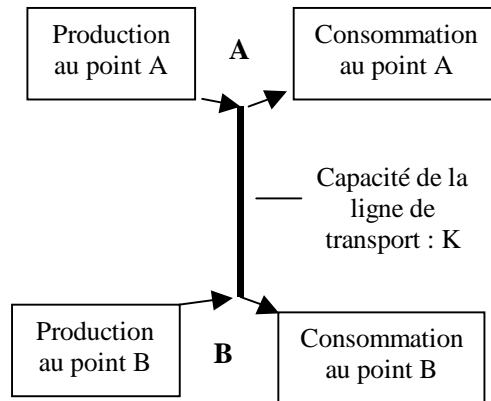
Pouvoir de marché attribuable aux contraintes de transport

Nous avons vu dans les sections précédentes comment le pouvoir de marché peut s'exercer dans un secteur de l'électricité simple, même lorsque des contraintes de transport sont improbables. Voyons maintenant comment les contraintes de capacité qui affectent les réseaux de transport peuvent séparer davantage les marchés et accentuer le pouvoir de marché.

L'électricité est transportée sur des réseaux de transport à haute tension. Chaque liaison de transport entre deux points peut transporter une quantité maximum limitée d'électricité. Pour simplifier, supposons que le coût d'acheminement de l'électricité sur une liaison non congestionnée est nul (c'est-à-dire qu'il n'y a pas de pertes de transport).

Prenons d'abord le réseau simple illustré à la figure ci-après. Il existe une seule liaison de transport entre les points A et B. La production et la consommation peuvent intervenir aux deux points.

Figure 7 : Réseau simple à deux noeuds

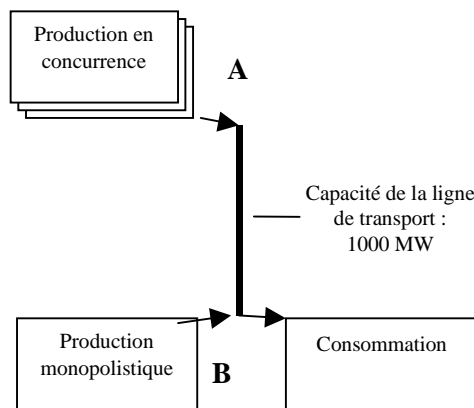


La direction du transit d'électricité entre les points A et B est fonction du prix relatif de l'électricité aux points A et B. Si la demande et/ou le coût de production sont moindres au point A, le fait que l'offre et la demande se coupent au point A aura tendance à produire un prix plus bas que si elles se coupaient au point B, de sorte que l'électricité sera portée à circuler de A vers B. Bien évidemment, la quantité et la direction du transit peuvent changer à tout moment au cours d'une journée à la suite de fluctuations de l'offre et de la demande aux points A et B. En particulier, la direction du transit peut être différente en période de pointe et en période creuse. Ce point sera approfondi ci-après.

Congestion du réseau de transport et pouvoir de marché en période de pointe

Dans la section précédente, nous avons vu que des contraintes de capacité peuvent accentuer le pouvoir de marché. Les contraintes de réseau de transport peuvent avoir exactement le même effet. Prenons par exemple un marché composé de 50 producteurs au point A et d'un producteur au point B. Supposons qu'aucun de ces producteurs n'a de contraintes de capacité, mais que la liaison entre le point A et le point B a une capacité maximum de 1000 MW. La totalité de la consommation intervient au point B. Supposons que la courbe de la demande a une élasticité constante égale à 0.2. Tous les producteurs assument un coût marginal constant de 10 dollars.

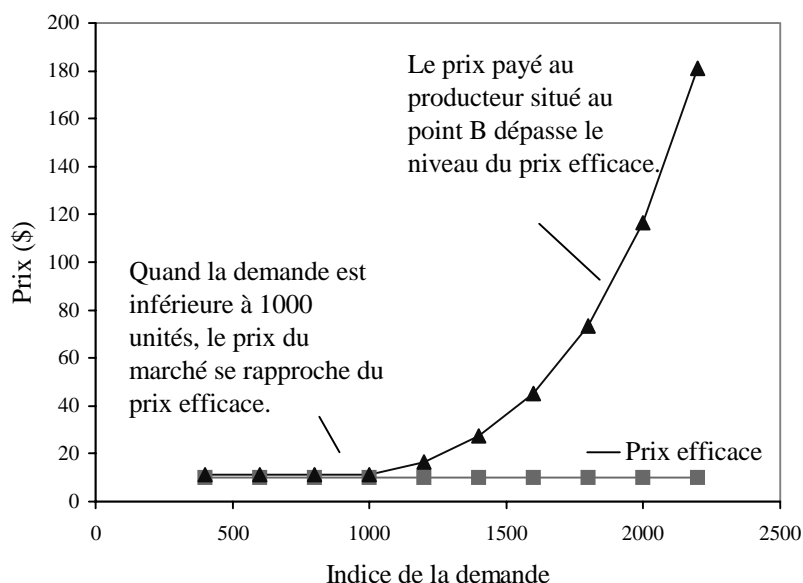
Figure 8 : Réseau simple à deux nœuds ayant des contraintes de transport



L'effet de la contrainte est illustré à la figure 9. Lorsque la demande s'accroît de telle sorte que la liaison entre A et B est congestionnée, toute hausse de la consommation doit s'accompagner d'une hausse de la production du producteur situé au point B. Ce producteur détiendra un pouvoir de marché significatif

et pourra augmenter le prix à mesure que la demande s'accroît. Dans cet exemple, la contrainte de transport fonctionne exactement de la même façon que les contraintes de capacité sur les producteurs situés au point A. L'évaluation précise du pouvoir de marché qui existe sur le marché de la production au point B nécessite dans ce cas également l'utilisation de l'indice de Herfindahl-Hirschman ajusté.

Figure 9 : Contraintes de transport en période de pointe sur un réseau simple à deux nœuds



La congestion fait en sorte que le prix du marché au point A diffère de celui pratiqué au point B. Le point A et le point B sont sur le même marché électrique quand la demande est faible, mais se séparent géographiquement lorsque la demande s'accroît. Le producteur situé au point B doit augmenter sa production afin de répondre à la demande. Le producteur situé au point B est parfois réputé être « une centrale contrainte à tourner » ou se trouver dans une situation où il doit « tourner pour assurer la fiabilité du réseau ». Dans ce cas également on constate qu'en présence de contraintes de capacité, il faut prendre en compte, pour définir le marché, non seulement le moment et du lieu où l'électricité est vendue, mais aussi le niveau de la demande.

Un marché qui est isolé en périodes de pointe en raison de contraintes de transport est appelé une zone de saturation. Ainsi, lorsque la demande d'électricité est forte à San Diego, la capacité de transport vers cette région peut être épuisée, ce qui crée une « zone de saturation », et les producteurs de San Diego détiennent un pouvoir de marché local significatif.

L'effet du pouvoir de marché du producteur situé au point B est fonction du mode de tarification de l'accès au réseau de transport. Selon la tarification nodale, les prix d'injection ou de soutirage de l'électricité peuvent différer d'un point à l'autre du réseau. « La variation des prix reflète l'impact marginal de la fourniture sur les contraintes de fonctionnement du réseau, qui peuvent différer selon les endroits. L'électricité injectée dans le réseau d'une région donnée qui a pour effet d'atténuer la congestion est payée plus cher que celle qui accentue la congestion. En général, l'électricité coûte plus cher dans les régions où existent des contraintes d'importation, même si les mécanismes complexes qui caractérisent les transits d'électricité aboutissent parfois à des résultats moins évidents. »¹⁹ Suivant la tarification nodale, lorsque la liaison de transport A-B devient congestionnée, l'injection d'électricité coûte plus cher au point A qu'au

point B, de sorte que les producteurs situés au point A sont portés à ne pas produire une quantité d'électricité supérieure à la capacité de la liaison de transport entre les points A et B. Le niveau de production choisi par le producteur situé au point B affecte à la fois les prix payés par les consommateurs et le prix attribuable à la congestion sur la liaison.

Dans les réseaux appliquant la tarification par zone, les prix d'injection ou de soutirage d'électricité sont constants dans quelques zones couvrant de vastes régions. Dans l'idéal, ces zones sont sélectionnées de manière à correspondre à des régions possédant une capacité de transport suffisante et dont le réseau est peu exposé aux congestions. Etant donné que selon la tarification nodale, les prix ne reflètent pas la congestion du réseau de transport, le gestionnaire du réseau de transport doit parfois s'abstenir d'effectuer le dispatching selon l'ordre des coûts croissants et doit plutôt appeler un producteur et payer le montant qu'il demande plutôt que le prix du marché en vigueur dans la zone concernée. Comme le montant demandé par le producteur est supérieur au prix du marché du système, cette intervention entraîne un coût qui est habituellement récupéré en étant répercuté sur l'ensemble des utilisateurs.

Dans l'exemple qui précède, si les points A et B sont situés dans la même zone, le prix de l'injection d'électricité est le même aux points A et B. Par conséquent, un autre mécanisme doit être mis en œuvre pour limiter la production au point A et l'accroître au point B. Par exemple, le gestionnaire du réseau de transport peut demander que le dispatching soit fait depuis le point B, sans égard au prix demandé par le producteur situé au point B. Il faut que les producteurs situés au point A perçoivent un montant inférieur à celui payé au producteur situé au point B et soient ainsi dissuadés d'accroître leur production. Le prix payé par les consommateurs finals sera inférieur au montant versé au producteur situé au point B et supérieur à celui versé aux producteurs situés au point A – de fait, le surcoût payé au producteur « contraint à tourner » situé au point B est fondu dans l'ensemble des achats d'électricité. En d'autres termes, les rentes issues de la congestion du réseau de transport sont répercutées sur les consommateurs par le biais des prix de l'électricité. Selon Bushnell et Wolak (1999) :

« Sur les deux types de marchés, à savoir ceux où l'on retrouve de nombreux prix nodaux et ceux où il n'existe que quelques prix à l'intérieur d'une zone, les producteurs situés stratégiquement peuvent tirer profit des contraintes de réseau en demandant des prix plus élevés. Grâce aux contraintes de transport, ces producteurs font face à une concurrence potentielle moindre que ceux qui sont situés ailleurs sur le réseau. En l'absence de substituts à la production de ces groupes, le marché doit ou bien augmenter localement le prix de l'énergie [dans le mode de tarification par zone], ou bien payer au producteur un prix supérieur au prix du marché [dans le mode de tarification nodale]. Ces producteurs peuvent influencer les prix de façon disproportionnée, du moins dans leurs régions. Pendant les premières années d'existence du pool de l'électricité de l'Angleterre et du Pays de Galles, par exemple, des producteurs situés dans des régions stratégiques ont appris à ajuster leurs offres de manière à tirer parti de leur statut de producteurs contraints à tourner, ce qui a entraîné, d'une année à l'autre, une augmentation de plus de 70 millions de livres des paiements versés à ces producteurs. Les offres de fourniture faites par ces groupes ont semble-t-il été limitées essentiellement par la crainte d'une intervention des autorités de la réglementation ».²⁰

Observation n° 6 : Dans un réseau électrique simple à deux nœuds affecté par des contraintes de transport, le pouvoir de marché peut se manifester en période de pointe même lorsque les producteurs n'ont pas de contraintes de capacité. L'analyse qui s'applique à cette situation est la même que si les producteurs situés dans les régions exportatrices étaient soumis à des contraintes de capacité de production. L'indice de Herfindahl-Hirschman ajusté rend compte avec précision du pouvoir de marché exercé par des producteurs présents sur les marchés où existent des contraintes d'importation.

Dans la section précédente, nous avons noté que la fusion d'une entreprise sans contraintes et d'une entreprise ayant des contraintes est susceptible d'accroître le pouvoir de marché. Dans le cas présent, cependant, la fusion d'un producteur sans contraintes situé au point B et d'un producteur situé en amont au

point A n'a pas d'effet sur le pouvoir de marché lorsque la liaison est congestionnée, pour autant que la congestion de la liaison A-B subsiste après la fusion. En effet, lorsque cette liaison est congestionnée, il est possible dans tous les cas de réduire la production du producteur situé au point A en augmentant celle des autres producteurs, ce qui assure que la liaison demeure congestionnée et élimine l'effet de la baisse de production sur le prix du marché. Tant que le transit de l'électricité sur la liaison demeure constant, l'entreprise n'a pas intérêt à réduire la production du producteur situé au point B. La fusion d'un producteur situé au point A avec le producteur situé au point B n'a donc pas d'effet global sur le pouvoir de marché.

Droits financiers de transport

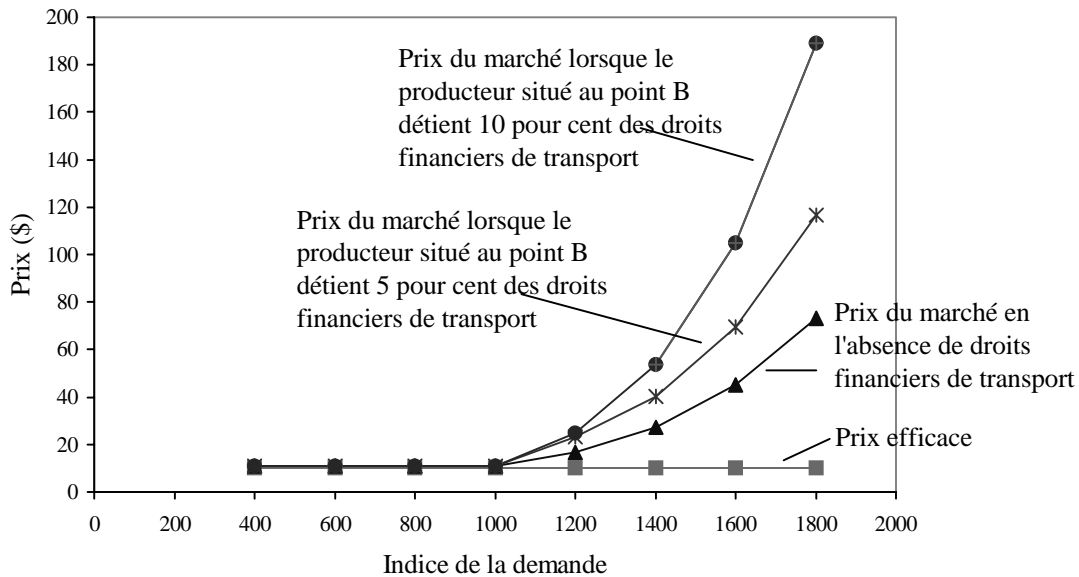
Selon le mode de tarification nodale, le réseau de transport peut percevoir des recettes au titre du transport d'électricité sur des liaisons congestionnées. Ces recettes sont appelées « rentes de congestion ». Les vendeurs et les acheteurs d'électricité souhaitent parfois se couvrir contre les frais inhérents à la congestion, notamment en acquérant une participation dans les rentes de congestion – c'est-à-dire en partageant la rente qui revient au gestionnaire du réseau de transport. Le droit à une part des rentes de congestion est appelé « droit financier de transport ». L'existence de droits financiers de transport affecte-t-elle le degré de pouvoir de marché ?

La réponse est affirmative. Si le producteur situé au point B est autorisé à acquérir une part des droits financiers de transport, il se peut que cela l'incite davantage à restreindre sa production. Autrement dit, plus la part de droits financiers de transport détenue par le producteur monopoleur situé au point B est grande, plus le prix du marché est élevé. Joskow et Tirole (2000) expliquent ce phénomène :

« Plus la part des droits détenus par le producteur [situé au point B] est grande, plus il est incité à augmenter le prix [au point B]. (...) Le [producteur situé au point B] dispose alors de deux sources de revenus : les ventes d'énergie et les rentes de congestion que lui rapportent ses droits financiers de transport. Plus le [producteur situé au point B] internalise la rente de congestion, plus celle-ci est élevée, ce qui (réduit sensiblement l'élasticité de la courbe de la demande résiduelle et accroît le pouvoir de marché. (...)

Lorsque [le producteur situé au point B détient tous les droits financiers de transport, il] fait face à la demande totale alors que lorsqu'il n'en détient pas, il fait face à la demande résiduelle. Autrement dit, si le producteur monopoleur [situé au point B] détient tous les droits financiers de transport, il optimise ses bénéfices (les recettes nettes qu'il tire de la fourniture d'énergie, auxquelles s'ajoutent les rentes de congestion) comme s'il détenait un monopole sur la totalité de la fonction de demande. Ce faisant, le [producteur situé au point B] sacrifie certains des bénéfices qu'il tirerait autrement de la fourniture d'électricité dans le but d'accroître ceux qu'il tire sous forme de « dividendes » au titre des droits financiers de transport qu'ils possède, en raison de sa capacité de faire monter le prix ». ²¹

Le graphique de la figure 10 illustre le prix du marché applicable à différents niveaux de demande pour la même structure de marché qu'à la figure 8, sauf que le producteur situé au point B détient une part variable des droits financiers de transport.

Figure 10 : Effet des droits financiers de transport sur le pouvoir de marché

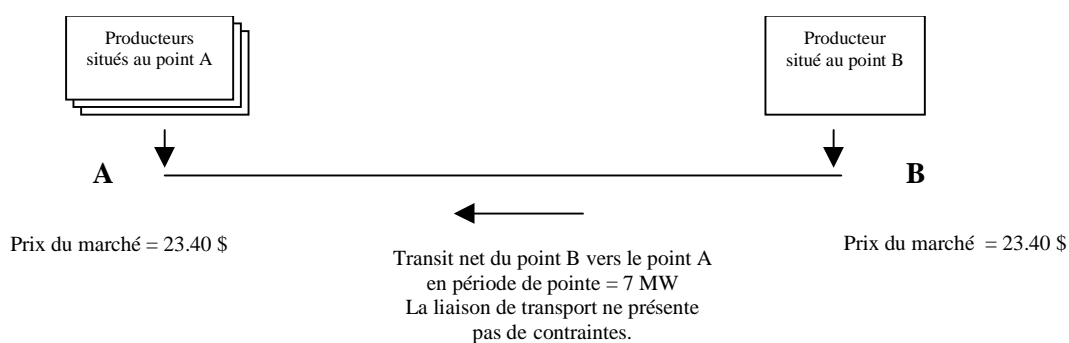
Observation n° 7 : Lorsque le réseau de transport vend des droits à une part des rentes de congestion, les producteurs qui tirent profit de la congestion sont incités acquérir ces droits et peuvent ainsi accroître leur pouvoir de marché.

Congestion du réseau de transport et pouvoir de marché en périodes creuses

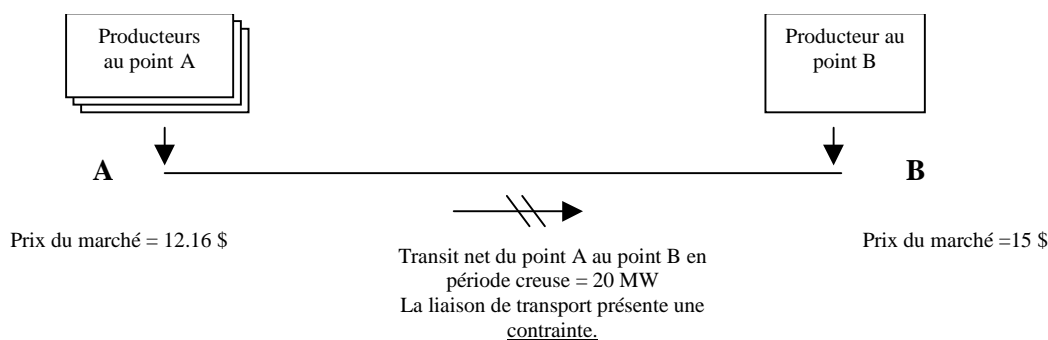
Dans l'exemple simple que nous venons d'examiner, le pouvoir de marché n'intervient que pendant les périodes de pointe. Dans un modèle un peu plus général, on peut montrer que la congestion du réseau de transport peut survenir *en périodes creuses* seulement, même sur un marché où toutes les entreprises assument un coût marginal identique.

La possibilité qu'une congestion du réseau survienne uniquement en périodes creuses est par intuition manifeste. La direction du transit d'électricité entre le point A et le point B est fonction du prix du marché pratiqué au point A et au point B. En période de pointe, il se peut que la production et la consommation à chaque point soient équilibrées, et qu'il y ait relativement peu de transits sur la liaison A-B. Si, pendant les périodes creuses, la demande chute davantage au point A qu'au point B, les producteurs situés au point B voudront exporter vers le point A. La quantité des exportations alors effectuées peut excéder la capacité de la liaison qui relie le point A au point B.

Prenons un exemple explicite, soit un marché sur lequel la demande au point A et au point B est linéaire avec une pente égale à 0.5. On compte 50 producteurs situés au point A et un seulement au point B. Tous les producteurs assument un coût marginal constant de 10 dollars. La liaison entre le point A et le point B a une capacité de 20 MW. Pendant les périodes de pointe, le niveau de la demande est de 1200 au point A et de 40 au point B, et la liaison A-B n'est pas congestionnée, de sorte que le prix pratiqué sur les deux marchés est le même, soit 23.40 dollars. Le producteur situé au point B exporte à ce prix 7 MW d'électricité vers le marché du point A.



Pendant les périodes creuses, le niveau de la demande au point A baisse à 200, tandis que la demande au point B se maintient à 40. Le prix chute sur les deux marchés, mais davantage au point A. Les producteurs situés au point A tentent de compenser la baisse de prix en exportant de l'électricité vers le point B, mais la liaison A-B devient congestionnée. Le prix du marché est de 12.16 dollars au point A et de 15 dollars au point B.



Observation n°8 : Dans un réseau électrique simple à deux nœuds présentant des contraintes de transport, le pouvoir de marché peut se manifester en période creuse même lorsque le coût marginal est le même pour tous les producteurs.

Congestion du réseau de transport et transits de bouclage

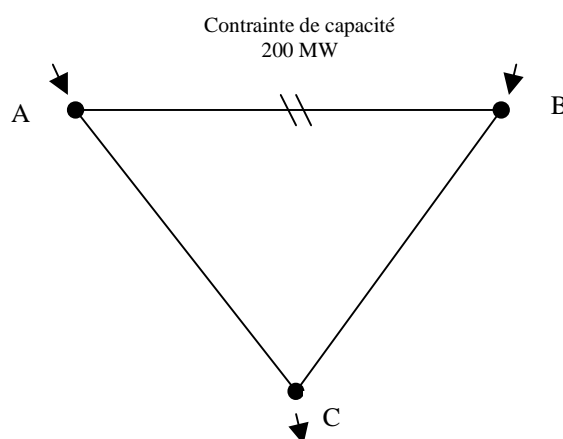
Nous avons examiné dans la section qui précède les effets de la congestion sur le réseau de transport d'électricité le plus simple qui soit, composé d'une liaison unique entre deux points. Dans les réseaux de transport légèrement plus complexes, une autre possibilité existe, celle du « transit de bouclage ». Nous montrerons dans la présente section comment, en présence d'un transit de bouclage, un producteur peut détenir un pouvoir de marché même s'il n'existe pas de contraintes de capacité sur les liaisons entre les producteurs et les consommateurs.

Le transit de bouclage est dû au fait que l'électricité ne peut pas être acheminée par un chemin particulier. Elle circule plutôt sur un réseau en suivant la liaison qui offre le moins de résistance. Lorsqu'il y a plus d'une liaison entre le point de production et le point de consommation, l'électricité emprunte toutes les liaisons possibles en quantités inversement proportionnelles à leur résistance.

Cette situation peut être illustrée à l'aide d'un réseau simple à trois nœuds, comme celui de la figure 11. La figure 11 présente un réseau électrique simple à trois nœuds reliés par trois liaisons d'égal

longueur. La production est réalisée aux points A et B, alors que la consommation intervient au point C. On compte un grand nombre de producteurs en concurrence au point B et un seul au point A. La liaison entre A et C et entre B et C ne présente pas de contraintes de capacité alors que la liaison entre A et B en comporte une de 200 MW.

Figure 11 : Réseau simple à trois nœuds présentant une contrainte de capacité sur la liaison A-B



L'électricité produite au point A peut atteindre sa destination de deux manières – en empruntant une liaison directe, A-C, ou une liaison indirecte, A-B-C. Comme la liaison indirecte est exactement deux fois plus longue, elle offre exactement deux fois la résistance de la liaison directe, de sorte que la liaison directe transporte deux fois plus d'électricité que la liaison indirecte. En d'autres termes, sur la totalité de l'électricité produite au point A, le tiers circule par A-B-C et les deux tiers par A-C.

Il en va de même pour l'électricité produite au point B, et le transit net qui circule du point A au point B correspond au tiers de la différence entre la quantité d'électricité produite par les producteurs situés au point A et celle produite par les producteurs situés au point B. Comme cette liaison a une capacité limitée, nous pouvons déduire que la différence entre la quantité d'électricité produite par les producteurs situés au point A et celle produite par les producteurs situés au point B ne peut jamais excéder le triple de la contrainte de capacité présente sur la liaison A-B.

La figure 13 illustre ce qui se produit dans le secteur électrique lorsque la demande augmente, passant de niveaux bas à des niveaux de plus en plus élevés. Lorsque les niveaux de la demande sont bas, la différence entre la production des producteurs situés au point A et celle des producteurs situés au point B est suffisamment faible pour que la liaison A-B ne soit pas congestionnée. Toutefois, les producteurs situés au point B réagissent plus fortement à une augmentation de la demande que ceux qui sont situés au point A. Lorsque les niveaux de la demande sont moyens, la liaison A-B devient congestionnée. Lorsque les niveaux de production sont élevés, la production au point A doit augmenter d'une unité par unité de production additionnelle réalisée au point B. De fait, le producteur situé au point A est « contraint à tourner ». Ce producteur se trouve dans une situation analogue à celle du producteur considéré comme étant en zone de saturation (figure 9). La différence, sur ce marché, tient au fait que les producteurs situés au point B ne sont pas complètement empêchés d'accroître leur production – mais ils n'ont la possibilité de le faire que lorsque le producteur situé au point A le fait simultanément. En réalité, le producteur situé au point A ne fait pas face à la totalité de la demande résiduelle, mais à la moitié de cette demande exactement. Cela le place néanmoins dans une situation de pouvoir de marché significativement accru. Lorsque la demande augmente, le prix du marché au point C augmente rapidement, comme l'illustre la figure 13.

Même si le producteur situé au point A détient un pouvoir de marché lorsqu'il y a une contrainte de capacité sur la liaison A-B, ce pouvoir de marché s'accroît de façon significative lorsqu'il existe une contrainte de capacité sur la liaison B-C, comme l'illustre la figure 12. Dans ce cas, la production additionnelle réalisée au point A n'élimine pas la congestion qui existe sur la liaison B-C, mais, au contraire, l'accroît. Le producteur situé au point A peut alors, en augmentant sa production simultanément, faire monter les ventes à prix élevé au point C et restreindre la production d'importations rivales provenant du point B. Les prix qui en résultent pour différents niveaux de demande sont illustrés à la figure 13.²²

Figure 12 : Réseau simple à trois nœuds présentant une contrainte de capacité sur la liaison B-C

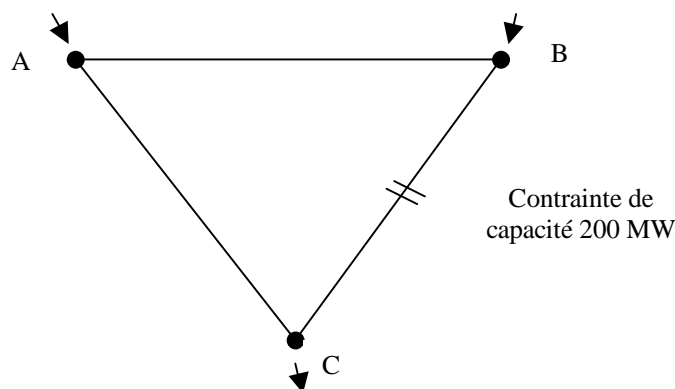
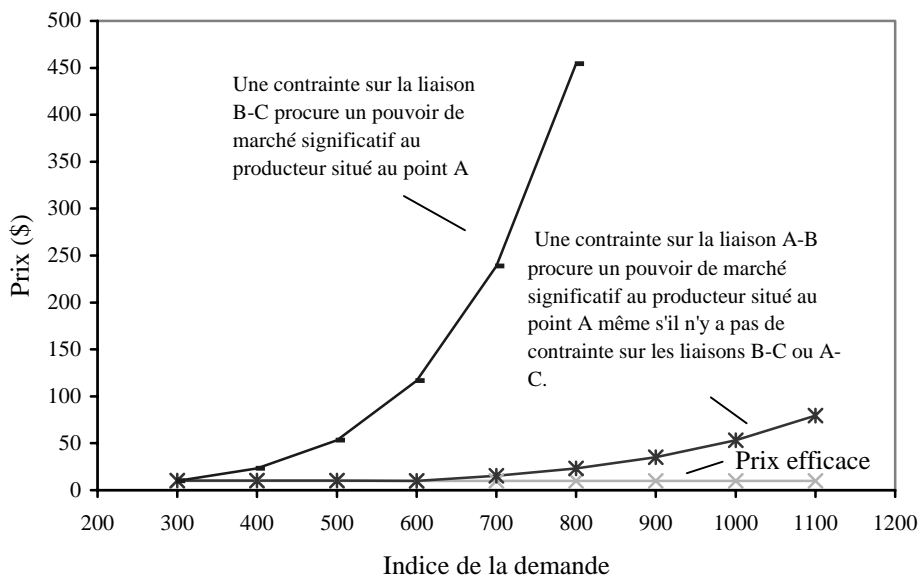


Figure 13 : Pouvoir de marché sur un réseau à trois nœuds



Observation n° 9 : Dans un réseau simple à trois nœuds ayant des contraintes de transport, le pouvoir de marché peut se manifester même lorsqu'il n'y a pas de contraintes de capacité sur les liaisons de transport directes entre les producteurs et les consommateurs.

Le pouvoir de marché dans la pratique

De nombreuses études ont été réalisées sur le pouvoir de marché sur les marchés de gros de l'électricité. On trouvera à l'annexe A un excellent survol de ces études effectué par le *Department of Energy* des Etats-Unis.

Les auteurs suivants ont réalisé des études intéressantes sur le pouvoir de marché en Angleterre et au Pays de Galles : Green (2002), Wolfram (1999, 1998), Wolak et Patrick (1997), Newbery (1995a) et Green et Newbery (1992).

Parmi les nombreuses études sur le pouvoir de marché observé sur le marché de gros de la Californie, citons celles menées par Borenstein (2002), Borenstein, Bushnell et Wolak (2002), Borenstein, Bushnell et Wolak (2001), Joskow et Kahn (2001), Hildebrandt (2001a, 2001b), Puller (2001), Sheffrin (2001), Wolak, Nordhaus et Shapiro (2000), Bushnell et Wolak (1999), Borenstein et Bushnell (1998) et Borenstein, Bushnell, Kahn et Stoft (1996).

Des études portant sur le pouvoir de marché sur le marché de l'électricité dans les pays scandinaves (« NordPool »), ont été effectuées par Johnsen, Verma et Wolfram (1999), Andersson et Bergman (1995), Halseth (1999) et Hjalmarsson (2000)²³.

Les deux encadrés qui suivent résument certains des résultats d'études portant sur le pool de l'électricité de l'Angleterre et du Pays de Galles et la bourse de l'électricité de la Californie.

Le pouvoir de marché sur les marchés de l'électricité est-il préjudiciable ?

Les problèmes liés au pouvoir de marché semblent répandus sur les marchés de gros de l'électricité mais ce pouvoir de marché est-il vraiment nuisible ? Après tout, lorsque la demande est inélastique, des prix plus élevés n'ont à peu près pas d'effet sur la demande – autrement dit, l'un des aspects qui font du pouvoir de marché un problème important (l'inélasticité de la demande) assure également que le pouvoir de marché qui s'ensuit a un impact limité sur le bien-être. Si la demande est inélastique, la perte sèche imputable au pouvoir de marché est nulle. « En raison de l'extrême inélasticité à court terme de la demande, le pouvoir de marché observé sur les marchés de l'électricité a très peu d'effet sur la quantité consommée ou sur l'efficacité allocative à court terme ».²⁴

L'efficacité allocative n'est cependant pas la seule composante du bien-être général affectée par le pouvoir de marché. Le pouvoir de marché peut aussi mener à une inefficacité productive s'il entraîne à court terme le remplacement de centrales à faible coût par des centrales à coût élevé, ou, à moyen et à long terme, l'entrée de centrales inefficaces. Borenstein, Bushnell et Wolak (2002) soulignent :

« [L]'exercice d'un pouvoir de marché par une entreprise peut donner lieu à une réaffectation inefficace de la production entre les entreprises productrices : une entreprise qui exerce un pouvoir de marché limite sa production de manière à ce que son coût marginal soit en dessous du prix (et égal à son revenu marginal), alors que les autres entreprises qui sont preneuses de prix produisent des unités pour lesquelles elles assument un coût marginal presque égal au prix. Il y a par conséquent une production inefficace à l'échelle du marché, puisqu'une production qui coûte plus cher et qui est plus concurrentielle remplace une production à moindre coût réalisée par des entreprises qui détiennent un pouvoir de marché. Cela correspond à l'évolution du marché britannique telle que décrite par Wolak et Patrick (1997) : des centrales appartenant à de nouveaux entrants, qui fonctionnaient avec des turbines à gaz à cycles combinés, fournissaient à coût élevé de l'électricité en base qu'auraient pu produire à moindre coût des centrales au charbon dont les deux plus grandes entreprises restreignaient la production.

Plusieurs analyses effectuées récemment ont également démontré que l'exercice d'un pouvoir de marché sur un réseau d'électricité peut accroître considérablement le degré de congestion.²⁵ L'accroissement de la congestion a un effet négatif sur l'efficacité et la fiabilité du système. Le pouvoir de marché peut aussi inciter les entreprises à utiliser leurs ressources hydroélectriques de manière à diminuer l'efficacité économique générale.²⁶

Enfin, l'influence des prix de l'électricité sur la prise de décision à long terme peut avoir une incidence considérable sur l'économie et l'efficacité des investissements. Même si, comme on l'a fait remarquer, des prix élevés sont susceptibles de stimuler les nouveaux investissements et l'accès à la production d'électricité, les investissements en question ne seront pas efficaces s'ils sont motivés par des prix élevés qui résultent de l'exercice d'un pouvoir de marché, et qui traduisent peut-être un besoin non pas de capacité accrue mais d'utilisation efficace de la capacité existante. Les prix artificiellement élevés peuvent aussi conduire les entreprises à ne pas investir dans des activités productives qui nécessitent une forte utilisation d'électricité, ou à avoir recours à des techniques de production à moins forte intensité d'électricité mais inefficaces »²⁷

Le pouvoir de marché sur le pool de l'électricité de l'Angleterre et du Pays de Galles²⁸

Pendant la période comprise entre avril 1990 et mars 2001, la quasi-totalité de l'électricité consommée en Angleterre et au Pays de Galles devait être vendue la veille pour le lendemain sur un marché spot aux prix d'équilibre du marché établis pour chaque demi-heure. En 1990, l'ancienne société d'électricité d'Etat intégrée (le *Central Electricity Generating Board*) a été séparée en trois grandes sociétés de production. Deux d'entre elles, National Power et PowerGen, ont pris en charge toutes les centrales existantes de production d'électricité à partir de combustible fossile et l'Etat a conservé la propriété des centrales nucléaires. Ces trois sociétés concurrencent avec des producteurs d'électricité indépendants, des producteurs situés en Ecosse et Electricité de France, qui peut fournir de l'électricité au Royaume-Uni par l'intermédiaire d'un interconnecteur avec la France. Cependant, le coût assumé par ces trois autres opérateurs et l'existence de contraintes de transport font qu'ils sont très rarement en mesure d'influencer le prix du marché de l'électricité au Royaume-Uni. En 1996, malgré les nombreuses entrées, le prix du marché était fixé par National Power ou PowerGen et par les installations de stockage par pompage du réseau de transport dans 84 et 11 pour cent des cas respectivement.

Le prix payé aux producteurs en vertu des anciennes règles qui prévalaient sur le marché, c'est-à-dire le prix payé par le pool (*Pool Purchase Price* ou PPP) était le prix proposé par le producteur marginal, ou prix marginal du système (*System Marginal Price* ou SMP) auquel s'ajoutait une prime de capacité (*Capacity Charge* ou CC). (Autrement dit : $PPP = SMP + CC$). La prime de capacité se calculait au moyen de la formule suivante : $CC = LOLP \times (VOLL - SMP)$. La LOLP (*Loss of Load Probability*) représentait la probabilité de perte de charge et était une fonction décroissante du montant prévu de capacité excédentaire disponible pour chaque tranche semi-horaire. Plus la capacité excédentaire était élevée, plus la probabilité de perte de charge était faible. La valeur de la perte de charge (*Value of Loss Load* ou VOLL) était une constante fixée à 2000 livres en 1990 et a suivi l'augmentation de l'IPC par la suite. Wolak et Patrick (1997) soulignent que la prime de capacité encourageait fortement les producteurs à restreindre leur capacité déclarée – ce qui, en plus d'augmenter le prix marginal du système, contribuait, en réduisant la capacité de réserve disponible, à augmenter les primes de capacité. Les primes de capacité ont été supprimées en mars 2001, lorsque l'Angleterre et le Pays de Galles ont adopté les nouvelles règles du marché de l'électricité.

La première tentative de modélisation du pouvoir de marché sur le pool de l'électricité de l'Angleterre et du Pays de Galles a été faite par Green et Newbery (1992). D'après ce modèle, la concurrence entre PowerGen et National Power est un jeu non coopératif dans lequel chaque producteur choisit non pas la quantité (comme dans une concurrence à la Cournot) mais la totalité de sa fonction d'offre (c'est-à-dire la quantité qu'il produira selon chaque prix du marché possible). Green et Newbery retiennent pour leur modèle des paramètres censés refléter la situation sur le marché de l'Angleterre et le Pays de Galles. Ils concluent que comme par le passé, il existe un pouvoir monopolistique important sur ce marché:

« A court terme, les stratégies mises en œuvre par National Power et PowerGen auront peu d'effet sur le niveau des entrées, et elles détiennent un pouvoir de marché très significatif, qu'elles peuvent exercer sans collusion en présentant un plan de fourniture situé nettement au-dessus des coûts marginaux d'exploitation. Elles ont recours à

d'autres méthodes de manipulation du marché qui consistent à exploiter les contraintes de capacité de transport sur le réseau, étant donné que leur pouvoir de marché sur certains marchés secondaires régionaux est de beaucoup supérieur à celui qu'ils exercent sur l'ensemble du pays.

A moyen terme, on prévoit déjà de très nombreuses entrées et cela est une réaction logique à l'équilibre probable du marché, bien que, selon nos calculs, le niveau prévu d'expansion de la capacité n'est pas justifié en termes de coûts et d'avantages sociaux. (...) [L]a perte sèche totale dépasse de 262 millions de livres celle qui aurait été enregistrée si le secteur avait été séparé en cinq entreprises de taille égale, d'après notre schéma médian et dans l'hypothèse optimiste selon laquelle les opérateurs historiques agissent comme un duopole symétrique. Même si les nouvelles entrées obligeront les opérateurs historiques à fixer des prix plus bas, les investissements importants et inutiles dans une capacité additionnelle entraînent une perte sociale très importante.

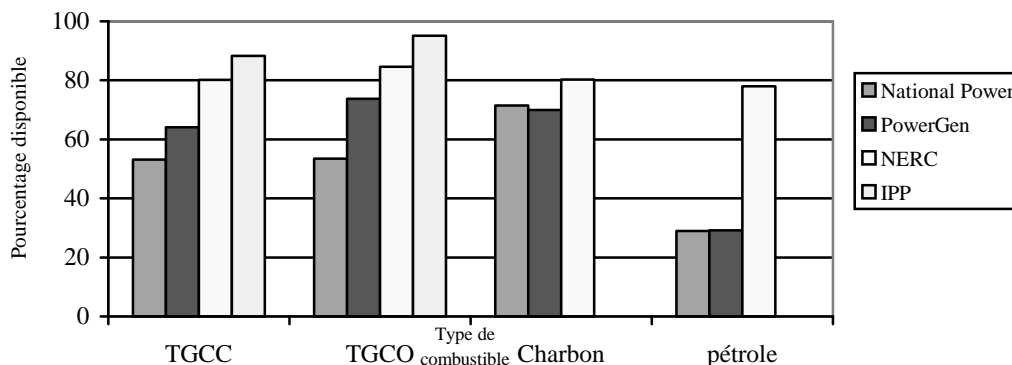
D'après notre analyse, l'ampleur du pouvoir de marché a été grandement sous-estimée par les pouvoirs publics, qui ont peut-être été induits en erreur par la notion selon laquelle la concurrence à la Bertrand est nécessairement très vive, même sur les marchés concentrés. Les pertes sèches potentielles sont élevées aussi bien du côté de la demande qu'en ce qui a trait aux coûts en raison des écarts par rapport au classement efficace selon l'ordre de coûts croissants. (...) La quasi-totalité de ces inefficacités auraient pu être évitées si le secteur avait été séparé en cinq producteurs de taille égale plutôt qu'en deux producteurs d'énergie thermique de taille inégale. (...) Force est de constater que l'on a laissé passer une excellente occasion d'effectuer une transition vers une industrie concurrentielle et non réglementée. La question de savoir s'il est préférable d'adopter un système de réglementation des producteurs à l'américaine afin de maintenir les prix à un niveau suffisamment bas pour dissuader les entrées indésirables ou d'accepter ces coûts supplémentaires dans l'espoir de favoriser l'émergence d'un secteur plus concurrentiel qui peut se passer de réglementation demeure intéressante et ouverte ».²⁹

Quelques années plus tard, en 1997, Wolak et Patrick ont soutenu que même s'il est possible de demander des prix supérieurs au coût marginal, cette pratique pouvait être facilement détectable et punie. Les producteurs estimaient par conséquent préférable d'adopter une stratégie consistant à retirer la capacité infra-marginale – ce qui fait monter à la fois le prix marginal du système et les primes de capacité.

« En demandant des prix supérieurs au coût marginal de chaque centrale, ces producteurs font en sorte que le prix marginal du système et, partant, le prix payé par le pool et le prix final payé par le consommateur, soient élevés. Cependant, comme il est relativement facile de calculer le coût marginal de production de chaque centrale en se fondant sur ses coûts de combustible et ses coûts thermiques (...) le directeur général de l'OFFER pourrait facilement détecter les centrales qui demandent des prix considérablement supérieurs au coût marginal. (...) Les producteurs pourraient difficilement justifier des offres supérieures à 100 livres le /MWh autrement que pour les charges de pointe. (...) [C]ompte tenu des règles de marché, demander des prix très nettement supérieurs au coût marginal de chaque centrale dans le but d'obtenir des prix élevés ne permettrait vraisemblablement pas d'atteindre cet objectif autant qu'une stratégie de retrait de capacité.

Il existe une autre stratégie plus efficace et difficilement détectable, dans le cadre de laquelle les deux principaux producteurs demandent pour chaque centrale un prix proche du coût marginal et déclarent une capacité indisponible à différentes périodes de charge de la journée, de sorte que la valeur anticipée de la charge de service totale pour le lendemain coupe la courbe de l'offre agrégée de l'industrie établie pour le lendemain dans la portion rapidement croissante de la fonction d'offre agrégée pendant autant de périodes de charge que possible le lendemain, compte tenu des contraintes physiques de démarrage et d'arrêt des installations. En déclarant indisponible la capacité de la portion uniforme (charge de base) ou de la portion en pente ascendante (en semi-base) de sa fonction d'offre, un producteur peut contrôler le moment où celle-ci devient très accentuée. Cette stratégie aboutit à un prix marginal élevé et, ce qui est plus important, à une faible marge de capacité de réserve anticipée et à des primes de capacité élevées pendant ces périodes de charge. »

Wolak et Patrick ajoutent que la disponibilité réelle des installations de production de National Power et PowerGen a été considérablement moins élevée au regard des normes nord-américaines et qu'elle a même été inférieure à celle des producteurs d'électricité indépendants du Royaume-Uni.



NERC = chiffres concernant la disponibilité du *North American Electric Reliability Council*. IPP (*independent power producers*) = moyenne des disponibilités des producteurs indépendants du Royaume-Uni (la plupart utilisent des turbines à gaz à cycle ordinaire.)

TGCC = turbines à gaz à cycles combinés. TGCO – turbines à gaz à cycle ordinaire (1995)

Depuis mars 2001, les règles du pool de l'électricité de l'Angleterre et du Pays de Galles ont été modifiées. Il n'est plus exigé que tous les échanges se déroulent sur le marché spot, et les acheteurs et les vendeurs sont autorisés à conclure des contrats bilatéraux. Les primes de capacité ont été supprimées. Trois heures et demie avant chaque période d'une demi-heure, les acheteurs et les vendeurs notifient leur situation contractuelle au gestionnaire du réseau et font des offres pour le marché d'ajustement. Le gestionnaire du réseau a recours à ces enchères pour assurer l'« équilibre énergétique » et l'équilibre du réseau (afin de supprimer la congestion et de veiller à la sécurité et à la qualité de la fourniture en temps réel).

Le pouvoir de marché sur le marché de l'électricité de la Californie³⁰

Severin Borenstein, James Bushnell et Frank Wolak ont tous tenu un rôle crucial sur le marché de l'électricité de la Californie. Le premier est membre du conseil d'administration de la bourse de l'électricité, le *California Power Exchange*, le deuxième a été membre du comité de surveillance de la bourse de l'électricité en 1999-2000 et le troisième est président du comité de surveillance du marché du gestionnaire indépendant du réseau de la Californie (*Independent System Operator*, ou *ISO*). Dans un document publié récemment, ils résument leur évaluation du pouvoir de marché observé sur le marché de gros de l'électricité de la Californie:

« Le marché de gros de l'électricité restructuré de la Californie date de 1998 et a relativement bien fonctionné pendant deux ans. Mais depuis l'été 2000, les prix ont connu une hausse spectaculaire et atteint plus du triple des niveaux de l'été précédent. Certains observateurs y voient simplement les effets de l'accroissement de la demande et d'une offre inadéquate, mais d'autres estiment que les vendeurs exerçaient un pouvoir de marché. (...) [D'après les résultats de notre étude], on s'est largement éloigné de la tarification concurrentielle, et ce de façon plus marquée durant les périodes de forte consommation, qui surviennent généralement en été. (...) Nous estimons que les dépenses sur le marché de gros, qui sont passées de quelque 2.1 milliards de dollars à plus de 9 milliards de dollars entre l'été 1999 et l'été 2000, sont imputables à hauteur de 60 pour cent au pouvoir de marché. (...)

Nous estimons qu'en raison de l'augmentation des coûts de production, même si le marché de l'électricité de la Californie avait été parfaitement concurrentiel, les dépenses d'électricité de gros auraient triplé pendant la période comprise entre l'été 1998 et l'été 2000. Le pouvoir de marché a cependant joué lui aussi un rôle très significatif. Ainsi, on peut lui imputer 27 pour cent des dépenses totales d'électricité de l'été 1998, et 51 pour cent de celles de l'été 2000. Les marges en pourcentage accrues dues au pouvoir de marché, associées à des augmentations substantielles des coûts de production des producteurs marginaux, ont entraîné une augmentation spectaculaire en marges absolues et ont par conséquent précipité le marché dans la crise à la fin de l'été 2000. (...)

Le marché de la production d'électricité de la Californie semble à première vue relativement peu concentré. Les anciennes entreprises dominantes, Pacific Gas & Electric (PG&E) et Southern California Edison (SCE) ont cédé le gros de leur capacité de production d'électricité à partir de combustible fossile pendant la première moitié de 1998 et la quasi-totalité de la capacité restante au début de 1999. La plus grande part de la capacité que possédaient toujours ces sociétés après les cessions a été couverte par des accords réglementaires parallèles qui prévoyaient que le prix perçu par le vendeur pour la production de ces centrales ne serait pas fondé sur les prix du marché de la bourse de l'électricité ou du gestionnaire indépendant du réseau. Ces cessions ont donné lieu à la répartition plus ou moins égale, entre sept entreprises, des actifs de la production d'électricité de la Californie.

[L'analyse] montre que le pouvoir de marché a, de façon régulière, augmenté parallèlement à la demande à laquelle ont fait face les autres fournisseurs hors service public. (...) Pendant les heures et les mois où la demande est peu élevée, de même qu'au printemps, lorsque la quantité d'énergie hydroélectrique disponible est importante, aucune entreprise ne peut à elle seule affecter les prix de manière significative. Aux heures de forte demande, cependant, les sources d'énergie concurrentielles commencent à atteindre leurs limites de capacité et le pool de concurrents potentiels pour la fourniture additionnelle diminue. L'absence d'importante capacité de stockage et l'inélasticité de la demande permettent alors aux entreprises de profiter des limites de capacité de leurs concurrents. (...) La concentration des propriétaires des centrales, associée au niveau élevé de la demande, ont attiré l'attention d'un ou plusieurs acteurs sur le fait que leur capacité était nécessaire pour combler les besoins d'énergie et de services auxiliaires du gestionnaire du réseau, indépendamment des interventions des autres acteurs du marché. Dans ce genre de situation, les entreprises estiment qu'il est dans leur intérêt d'augmenter les prix de leurs offres, même si elles détiennent la capacité suffisante pour combler la totalité des besoins d'énergie et de services auxiliaires du gestionnaire indépendant du réseau de la Californie. ...

Pendant la période comprise entre l'été 1998 et l'été 2000, le coût de l'électricité sur le marché de gros a augmenté, passant de 1.7 milliard à plus de 9 milliards de dollars. Les coûts de production efficaces ont plus que triplé pendant cette même période, et compte tenu de l'augmentation de l'unité marginale, les rentes induites par la concurrence portant sur des coûts unitaires plus bas ont elles aussi plus que triplé. Les rentes d'oligopole, en revanche, ont pris une ampleur démesurée, passant d'environ 455 dollars à environ 4.7 milliards pendant la même période. Par conséquent, alors qu'une portion substantielle du coût marchand accru de l'électricité était due à l'augmentation des coûts de la

matière première et à la diminution des importations, ces facteurs ont également augmenté l'ampleur, exprimée en dollars, du pouvoir de marché exercé par les fournisseurs. ... La structure concurrentielle sous-jacente du marché ne semble pas avoir changé considérablement entre 1998 et 2000. En 2000, l'accroissement de la demande et les moindres niveaux d'importation ont plutôt créé des occasions plus fréquentes pour les producteurs de combustible fossile en place d'obtenir de fortes marges sur les coûts accrus, ce qui a multiplié par 10 les rentes de monopole des fournisseurs.

Coûts de production et répartition des rentes (en millions de dollars) de juin à octobre

	1998	1999	2000
Total - paiements effectifs	1710	2097	9250
Total - paiements en situation de concurrence	1255	1668	4520
Coûts de production effectifs	767	1047	3016
Coûts de production – situation de concurrence	717	954	2433
Rentes – situation de concurrence	538	714	2087
Rentes – situation d'oligopole	455	429	4730
Inefficacité oligopolistique – producteurs en place	27	29	113
Inefficacité oligopolistique – importations	22	64	470

Une analyse précédente réalisée par Borenstein, Bushnell et Knittel (1999) à l'aide d'une simulation sur ordinateur du marché de la Californie débouche sur des résultats similaires:

« Nous avons constaté (...) que selon la configuration de la participation dans la production qui existait en 1997, il y aurait eu une forte possibilité d'exercice de pouvoir de marché aux heures de forte demande. (...) Aux niveaux de demande les plus élevés, de nombreux producteurs atteignent leurs capacités de production maximum. L'effet disciplinaire de ces producteurs sur le comportement stratégique des autres entreprises est par conséquent très réduit. Celles-ci peuvent avoir intérêt à réduire leur production, sachant que la plupart de leurs concurrents ayant des contraintes de capacité ne seront pas en mesure de réagir en augmentant la leur. Paradoxalement, ce comportement s'accompagne d'une réduction de la concentration sur le marché, puisque de fait, les entreprises ayant une importance stratégique – les plus gros producteurs – restreignent leur production et réduisent par conséquent leur part de marché. Dans de nombreux cas, nous avons constaté que la marge prix-coût augmentait lorsque la concentration diminuait.

[Dans nos simulations] le prix selon la concurrence à la Cournot suit de très près le prix parfaitement concurrentiel lorsque les niveaux de la demande sont faibles, et augmente brusquement au-delà d'un certain seuil, situé autour de 27 000 MW. Lorsque ce seuil est franchi, les prix se mettent à augmenter parce qu'une frange concurrentielle croissante atteint sa capacité maximale. Les deux plus grosses entreprises, Pacific Gas & Electric (PG&E) et Southern California Edison (SCE), estiment alors avantageux de réduire la production et d'augmenter les prix. Il en résulte, du point de vue de la concentration, que le marché est plus concentré lorsque la demande se situe à des niveaux où ces deux entreprises n'essaient pas de réduire leur production et, par conséquent, que les marges prix-coût sont peu élevées. »

Comment faire cesser le pouvoir de marché sur les marchés de l'électricité

Voyons maintenant comment on peut faire cesser le pouvoir de marché sur les marchés de gros de l'électricité. Sur un plan général, les différents moyens d'action mis en œuvre sur d'autres marchés pour affaiblir le pouvoir de marché sont bien connus et comprennent notamment des politiques visant à :

- (a) accroître la concurrence de produits rivaux – par exemple, faciliter l'utilisation de formes rivales d'énergie par les consommateurs ;
- (b) accroître la concurrence pendant les intervalles entre les différentes périodes de consommation – par exemple, pour améliorer la stockabilité de l'électricité ;
- (c) intensifier la concurrence entre les zones géographiques – notamment en construisant des liaisons de transport ou en allégeant les contraintes sur les liaisons existantes ;
- (d) renforcer la sensibilité de la demande au prix – par exemple, au moyen de compteurs horaires ou de l'autoproduction ;
- (e) encourager l'entrée de nouveaux producteurs ;
- (f) baisser les prix ou augmenter les quantités par des contrôles réglementaires directs ;
- (g) séparer les sociétés d'électricité horizontalement ou verticalement ;
- (h) modifier les règles régissant le marché de l'électricité lui-même afin que les producteurs soient moins encouragés à restreindre leur capacité ou à réduire leurs réserves.

Les autorités exercent relativement peu de contrôle sur les deux premiers types de politiques. La possibilité qu'ont les consommateurs de se tourner vers d'autres combustibles et la stockabilité de l'électricité sont largement tributaires des niveaux courants de technologie, sur lesquels les responsables de l'élaboration des politiques ont assez peu d'influence à court terme. L'examen qui suit fait donc abstraction de ces politiques et s'attache principalement aux autres politiques qui ont été énumérées.

Politiques destinées à accroître la concurrence entre les zones géographiques

La concurrence entre les producteurs de différentes zones géographiques peut être rehaussée par (a) la construction de nouvelles liaisons de transport ; (b) l'amélioration de la capacité sur les liaisons congestionnées existantes ; (c) l'utilisation accrue des infrastructures existantes ; ou (d) la tarification plus efficace de l'accès aux réseaux de transport.

Examinons d'abord les méthodes qui permettent d'améliorer l'efficacité de la tarification du transport. Si le prix marginal de transport est supérieur à son coût marginal, les producteurs sont « séparés » artificiellement sur le plan géographique. Cela est particulièrement susceptible de se produire en cas de superposition (« *pancaking* ») des tarifs de transport en vertu de laquelle des frais sont payés à chaque propriétaire de liaison de transport le long du chemin. Le total des frais payés en contrepartie de l'utilisation du réseau de transport est égal à la somme des frais payés à chaque propriétaire de liaison de transport sur le chemin. Le *Department of Energy* des Etats-Unis constate dans ses simulations que la tarification superposée « augmente le coût de transit de l'énergie sur plusieurs réseaux et réduit effectivement l'étendue géographique de plusieurs marchés régionaux ». ³¹ La tarification du transport « en fonction de la distance » peut aussi faire en sorte que le prix marginal du transport soit supérieur à son coût marginal. La Commission européenne reconnaît que cela peut poser un problème pour les transits transfrontaliers d'électricité dans l'Union européenne:

« Actuellement, il y a peu de coordination entre les différents gestionnaires de réseau ou les autorités de réglementation pour s'assurer que les frais des échanges transfrontaliers reflètent les coûts. Dans la plupart des cas, les frais de transit cumulés sont toujours prélevés dans l'Etat de chaque membre suivant un chemin contractuel notionnel. Ce processus, appelé « *superposition* », ne reflète pas les coûts ; il ne

tient pas compte, par exemple, du transit physique réel de l'électricité, ni du fait que certains transits peuvent de fait alléger la congestion et réduire les coûts. Certains Etats membres imposent également des droits spécifiques à l'importation ou à l'exportation. »³²

La congestion est parfois accentuée par la sous-utilisation des infrastructures existantes. C'est ce qui pourrait être le cas, par exemple, d'une liaison de transport située dans une zone où les coûts sont élevés et appartenant en totalité ou en partie à des producteurs situés dans cette zone susceptibles de souffrir de la concurrence de l'importation. Ce problème se pose notamment dans l'UE, où les opérateurs historiques de nombreuses entreprises possèdent ou partagent le contrôle de liaisons de transport transfrontalières. On pourrait y remédier en séparant structurellement ces liaisons de transport de la production réalisée dans les zones où les coûts sont élevés (voir ci-dessous). Une série de lignes directrices visant l'amélioration de l'accès à ces infrastructures (exclusion faite du recours à la séparation structurelle) a été adoptée à l'occasion de la 6^e réunion du Forum européen de réglementation de l'électricité. Ces lignes directrices sont les suivantes :

- « (i) Les Etats membres font en sorte que la capacité soit attribuée sur une base non discriminatoire ;
- (ii) il y a un niveau élevé de transparence en ce qui concerne la capacité disponible ;
- (iii) la capacité est attribuée en suivant des méthodes fondées sur le marché (enchères, séparation du marché, etc.)
- (iv) les bénéfices des enchères ne reviennent pas aux gestionnaires des réseaux de transport, et
- (v) le principe en vertu duquel « ce qui n'est pas utilisé est perdu » s'applique.³³

Quels processus faudrait-il mettre en place pour assurer l'amélioration efficace du réseau de transport ? Il est difficile de répondre à cette question, qui est de manière générale toujours sans réponse.

On notera que les mécanismes de tarification nodale incitent davantage les sociétés privées à prendre d'elles-mêmes l'initiative d'améliorer le réseau de transport et les producteurs à prendre des décisions rationnelles en matière d'emplacement – c'est-à-dire à s'implanter dans des régions choisies de manière à diminuer les contraintes de transport et non à les aggraver. De fait le FERC, l'autorité de réglementation américaine, envisage actuellement de permettre aux entreprises de transport négociantes de percevoir et de vendre des droits financiers de transport au titre de leur investissement dans le transport. Même en l'absence d'un mécanisme complet de tarification nodale, les entreprises pourraient être en mesure de renforcer la concurrence en construisant des liaisons qui exploitent les différences de prix entre des régions ou des frontières nationales (comme dans l'UE). De nombreuses autorités cherchent à encourager ce type d'investissement.

On ignore toutefois le fait de s'en remettre aux motivations privées conduira à des niveaux d'investissement efficaces.³⁴ Plusieurs points méritent d'être soulevés à cet égard :

- Premièrement, on ignore si les entrepreneurs privés seront encouragés à construire une liaison de transport ayant une capacité suffisante. Si les rentes de congestion sont l'unique source de revenu d'une liaison de transport, l'entrepreneur ne sera pas incité à les éliminer entièrement. Il est par conséquent vraisemblable que les entrepreneurs privés atténueront la congestion, mais ne l'élimineront pas.
- Deuxièmement, il se peut que les entrepreneurs privés ne construisent aucune liaison de transport, même lorsque cela est justifié. Il est parfois utile de construire une liaison entre deux points, même s'il n'y a pas de différence de prix entre ces deux points à toute heure du jour, si la liaison n'est jamais congestionnée et s'il n'y circule jamais d'électricité. La présence d'une liaison entre deux points renforce la concurrence entre les producteurs. La

construction d'une liaison de transport a par conséquent tendance à faire baisser les prix. L'effet sur les prix peut être suffisant pour justifier la liaison même si, à l'équilibre, l'électricité n'y circule jamais.³⁵

- Troisièmement, on peut supposer que dans certains cas, il soit justifié de construire une liaison de transport préjudiciable au bien-être général – et, notamment, que la construction d'une liaison de transport entre deux points puisse accentuer le pouvoir de marché au lieu de le réduire. Le réseau illustré à la figure 11 ci-dessus est à cet égard un excellent exemple. Dans ce réseau, s'il n'y avait pas de liaison entre le point A et le point B, les producteurs situés aux points A et B se concurrenceraient au point C. La construction de la liaison entre le point A et le point B détourne une partie de l'électricité produite aux points A et B sur un chemin indirect vers le point C. Comme l'a montré l'examen de la figure 11, si la liaison entre les points A et B a une capacité limitée, il se pourrait que le producteur situé au point B doive produire si la contrainte de capacité qui existe sur la liaison A-B ne peut être enfreinte.³⁶

En se fondant pour une part sur ces observations, Joskow doute de l'opportunité de laisser les améliorations du réseau de transport à l'entière discrétion des forces du marché :

« Il ne me semble pas d'emblée opportun de s'en remettre entièrement au libre jeu de l'économie en ce qui a trait aux décisions d'investissements dans les réseaux de transport. Ces investissements sont morcelés, caractérisés par des économies d'échelle et peuvent avoir des impacts physiques sur tout le réseau. Si l'on se fie uniquement aux forces du marché, il se peut que la définition imprécise des droits fonciers sur le réseau, les économies d'échelle et les coûts irrécupérables de longue date, de même que la concurrence imparfaite en matière de fourniture de services de production, mènent soit au sous-investissement, soit au surinvestissement dans le transport sur certains points du réseau. Par ailleurs, rien n'empêche que l'initiative des améliorations du réseau soit principalement laissée aux entreprises privées, surtout si cela va de pair avec une attribution raisonnablement bonne des droits de capacité, qu'ils soient physiques ou financiers. Le gestionnaire du réseau de transport pourrait alors déterminer si les améliorations proposées ont des effets néfastes non compensés pour certains des utilisateurs du réseau, et si l'investissement privé est motivé par des économies d'échelle ou des perspectives de bénéfice sans contrepartie. Dans ces cas, le gestionnaire du réseau pourrait désigner les projets d'investissement que les propriétaires des installations de transport seraient tenus de mettre en oeuvre et les coûts annexes pourraient être récupérés auprès de tous les utilisateurs du réseau. Il semble que ce soit dans cette direction que s'oriente la politique menée par les pouvoirs publics ».³⁷

La création d'incitations adaptées pour favoriser l'amélioration efficace des réseaux de transport sera l'un des problèmes de réglementation les plus importants qui devront être abordés à l'avenir dans les secteurs libéralisés de l'électricité.

Politiques structurelles

Comme sur d'autres marchés, la concurrence entre les producteurs peut être améliorée par l'intermédiaire de différentes formes de séparation horizontale et verticale. L'examen mené dans les sections précédentes permet de préciser les formes de séparation qui devraient être visées. Spécifiquement, quel que soit le niveau de la demande sur le marché, le degré de pouvoir de marché est fonction (entre autres) (a) de la part de marché des producteurs non contraints, (b) du nombre de concurrents et du degré de concurrence que se livrent les producteurs non contraints et (c) de la capacité qu'a une hausse de prix de favoriser l'arrivée de nouveaux producteurs.

La séparation structurelle (ou son contraire, le contrôle des concentrations) devrait par conséquent s'appliquer aux producteurs non contraints, en particulier lorsque ces producteurs seraient eux-mêmes non contraints après la séparation, et qu'ils assument un coût marginal comparable, par exemple lorsqu'ils utilisent un combustible similaire. Hilke fait observer : « Dans la mesure où les producteurs qui utilisent le même type de combustible sont concentrés sur des portions spécifiques de la courbe de la demande, la structure de la participation dans les moyens de production d'un combustible particulier peut influencer considérablement sur le pouvoir de marché pendant les périodes où les producteurs qui utilisent un combustible particulier se situent à la marge ». ³⁸

La séparation structurelle pourrait également concerner la dissociation de la production et du transport. Dans bon nombre des exemples précédemment cités, la concurrence sur la production dans une zone géographique s'exerçait principalement par le biais des liaisons de transport. En supposant que la concurrence fondée sur les installations de transport soit difficile ou impossible, le fait qu'un producteur exerce le contrôle sur le transport pourrait lui permettre d'exercer un contrôle sur ses principaux rivaux. On a vu précédemment que la détention de droits financiers de transport peut faire augmenter le pouvoir de marché des producteurs, et que les lignes directrices établies d'un commun accord lors du Forum européen de réglementation de l'électricité cherchent à promouvoir l'utilisation non discriminatoire des lignes de transport en pareil cas. Il sera souvent indiqué d'aller jusqu'à séparer la production du transport. Selon Hilke : « Le contrôle indépendant et non discriminatoire de l'accès au réseau et des critères de raccordement constitue un élément fondamental de la concurrence efficace. On a constaté à l'usage que les règles de comportement ne suffisent pas à encourager l'accès non discriminatoire au réseau. » ³⁹

On peut se demander s'il faudrait envisager d'autres politiques structurelles que la séparation rigoureuse de la participation, par exemple la copropriété. Supposons, par exemple, qu'une centrale compte de nombreux propriétaires qui ne sont pas des co-exploitants et que chacun d'eux a un droit contractuel à une certaine part de la production de la centrale. Supposons que ces copropriétaires partagent les coûts de l'entreprise et paient l'électricité produite au coût marginal, mais ne participent pas d'une autre façon aux profits de la vente de l'électricité produite. Dans ce cas, ces détenteurs de droits de capacité se concurrenceront en aval de la vente de l'électricité produite. Il s'agit là d'une forme de copropriété du type évoqué dans le document de l'OCDE (2001). Hilke constate :

« Même si l'exploitation de centrales de production est concentrée en raison d'économies d'exploitation, la participation peut être plus dispersée sans pour autant entraîner d'inefficiences majeures. Aux Etats-Unis, par exemple, de nombreuses centrales électriques appartiennent à plusieurs propriétaires. Chaque propriétaire détermine de façon indépendante la production et l'utilisation de sa part de la capacité de la centrale. (Les contrats d'exploitation de ces installations confient généralement à un des propriétaires le mandat d'exploitation et d'entretien de la centrale.) » ⁴⁰

Plusieurs pays ont eu recours à la vente de « capacité virtuelle » de production pour renforcer la concurrence ou l'introduire. ⁴¹ La Commission européenne a imposé la cession de cette « capacité virtuelle » comme condition aux fusions. Par exemple, Electricité de France s'est engagée auprès de la Commission européenne à céder 6 000 MW de sa capacité de production (environ 6 pour cent de la capacité totale) en France afin d'obtenir l'autorisation d'acquérir une plus grande participation dans la société allemande de services d'électricité EnBW :

« EDF mettra cette capacité à la disposition des enchérisseurs sous la forme de deux types de produits :

- « produits sur centrales virtuelles » (VPP) qui donnent le droit d'appeler pour le lendemain, à un prix pré-déterminé, de l'électricité livrée sur le réseau à haute tension. Des produits de base et de pointe seront offerts.

- « Produits Power Purchase Agreements » (PPA) qui représentent un bloc d'énergie calé sur les profils de charge des unités de cogénération bénéficiant d'une obligation d'achat d'EDF. Ces produits incluent un bloc d'énergie de base du 1er novembre au 31 mars, et pour le reste de l'année, un bloc d'énergie de base pouvant éventuellement être, en fonction des prix du gaz, d'un niveau inférieur au bloc d'hiver.

En achetant ces produits, les producteurs, fournisseurs et traders ont la possibilité d'acquérir de l'électricité ferme sans supporter l'ensemble des risques opérationnels et techniques inhérents à la propriété physique de centrales. ... EDF mettra globalement en vente 1 000 MW de capacité virtuelle de pointe avec un prix de l'énergie d'environ 26 euros/MWh et 4 000 MW de capacité virtuelle de base avec un prix de l'énergie d'environ 8 euros/MWh. EDF mettra d'autre part en vente une capacité équivalente à 1 000 MW de produits PPA. »⁴²

Il va de soi que des accords de copropriété de ce type peuvent également être envisagés pour assurer l'accès non discriminatoire à des liaisons de transport congestionnées.

Accroître l'élasticité de la demande

Le pouvoir de marché qui se manifeste sur les marchés de la production de l'électricité peut aussi être réduit au moyen de politiques visant à accroître l'élasticité de la demande. En raison des obstacles politiques et juridiques à la séparation structurelle, une augmentation de l'élasticité, si modeste soit-elle, peut entraîner une plus forte réduction de prix que toutes les mesures de séparation structurelle conjuguées. L'élasticité de la demande peut être accrue par le biais de politiques qui (a) facilitent la participation des acheteurs dans le « pool » ; (b) améliorent l'utilisation des compteurs horaires ; (c) incitent à conclure des contrats prévoyant des réductions de puissance (contrats « interruptibles ») (d) facilitent l'utilisation d'autres combustibles.⁴³

Dans leur examen du pool de l'électricité de l'Angleterre et du Pays de Galles, Wolak et Patrick préconisent d'autoriser les acheteurs à prendre part au processus de fixation des prix :

« L'enseignement le plus important à tirer de l'expérience de l'Angleterre et du Pays de Galles est peut-être la nécessité d'intégrer le potentiel de réactions du côté de la demande au processus de détermination des prix. (...) [Dans le cadre des précédents accords commerciaux] la demande anticipée, qui permet de fixer le prix marginal du système et les primes de capacité, est parfaitement inélastique au prix. Cet aspect des règles (...) fait qu'il est beaucoup plus facile pour National Power et PowerGen de tirer parti du processus de détermination des prix du pool pour faire en sorte que le prix marginal du système et les primes de capacité atteignent des valeurs élevées. Le meilleur moyen d'intégrer une réaction significative aux prix dans le processus de détermination de la demande anticipée est de permettre aux sociétés d'électricité régionales ou à d'autres gros clients de faire des offres à grande échelle ».⁴⁴

La recommandation de faire participer les acheteurs au processus de détermination des prix a été mise en œuvre dans les *New Electricity Trading Arrangements* (« NETA »), qui sont entrés en vigueur en mars 2001. En vertu des NETA, les acheteurs et les vendeurs peuvent conclure des contrats bilatéraux indépendamment du prix du marché. Les acheteurs peuvent en outre faire des offres sur le marché d'ajustement. Le prix du système est alors à l'intersection de la demande et de l'offre. Les acheteurs peuvent ainsi signaler leur intention de réduire leur consommation en cas de montée des prix.

Même si de gros acheteurs (par exemple, les sociétés de distribution) peuvent participer directement au pool de l'électricité, ils n'auront pas tellement la possibilité de réduire leur demande en cas d'augmentation des prix, sauf s'ils peuvent eux-mêmes inciter leurs clients à réduire leur consommation.

Ils peuvent à cette fin soit conclure des contrats interruptibles (qui permettent aux compagnies de distribution de réduire l'offre pendant les périodes où les prix sont exceptionnellement élevés), soit utiliser des compteurs qui mesurent et facturent la consommation en temps réel des clients des sociétés de distribution. Les contrats interruptibles sont répandus dans le secteur du gaz. Il serait peut-être possible de les utiliser davantage dans le secteur de l'électricité, en particulier pour les clients qui peuvent se tourner vers d'autres combustibles ou vers l'autoproduction.

Les contrats interruptibles sont un moyen peu différencié de diminuer la demande pendant les périodes de pointe. Il est de loin préférable de répercuter le prix réel de l'électricité directement sur les utilisateurs finals par le biais de compteurs qui permettent la mesure et la facturation de la consommation en temps réel. De nombreux clients du secteur électrique (notamment les gros clients) sont déjà assujettis à la mesure de la consommation en temps réel. Le recours accru à cette méthode est l'un des moyens les plus souvent recommandés pour réduire le pouvoir de marché sur les marchés de l'électricité. Le « *Blue Ribbon Panel* », qui conseille le California Power Exchange constate :

« La capacité d'ajustement de la demande au prix est essentielle au fonctionnement d'un marché restructuré ; l'incitation à utiliser l'électricité de manière plus efficace à long terme et une réaction beaucoup plus élastique aux prix pendant les périodes de pointe à court terme sont des solutions qui s'imposent d'elles-mêmes. (...) Nous ne pouvons cependant qu'insister sur le fait qu'il est essentiel, pour que les consommateurs modifient leurs habitudes de consommation à la suite des fluctuations extrêmes des prix et, ce faisant, contribuent à atténuer ces fluctuations, que leurs fournisseurs les encouragent à aller dans ce sens en leur permettant de réduire leur consommation d'énergie ou d'interrompre l'utilisation de certains appareils pendant de courtes périodes sur avis du fournisseur et/ou à comparer les variations de prix avec les fluctuations extrêmes correspondantes des prix de gros, et modifier leur consommation en conséquence.

Nous ne pouvons pas nous prononcer sur la rentabilité des compteurs très perfectionnés qui enregistreraient la consommation en unités de temps correspondant aux grandes fluctuations des prix que les sociétés de distribution doivent payer. (...) Nous nous bornerons à dire est que le comportement des marchés de l'électricité de la Californie, ces derniers mois, a de toute évidence largement modifié l'équilibre des coûts et des avantages relatifs dans un sens qui tend à donner une justification économique à ce type de compteurs. Ce comportement exige un réexamen du bien-fondé de leur installation à grande échelle – que ce soit chez l'abonné ou au moyen d'un système de comptage électronique à contrôle centralisé ubiquiste. »⁴⁵

Même lorsque l'utilisation de compteurs horo-saisonniers n'est pas pratiquement envisageable, il est parfois possible de favoriser les contrats interruptibles. Ces contrats permettent aux fournisseurs d'électricité de réduire l'offre lorsque le prix du marché dépasse un certain seuil.

Lorsqu'il est possible d'utiliser des compteurs horo-saisonniers, l'élasticité de la demande peut être améliorée davantage en facilitant le recours à d'autres combustibles. Dans de nombreuses applications, l'autoproduction est la solution la plus susceptible de se présenter. Hilke constate :

« Lorsque la production sur place présente de l'intérêt parce qu'il est possible d'utiliser sur place la chaleur résiduelle, les entreprises (ou même les particuliers) qui sont normalement les clients des sociétés d'électricité traditionnelles peuvent devenir leurs concurrents. Dans la mesure où les propriétaires d'installation de production combinée détiennent des informations précises sur les prix et peuvent vendre sur le marché ou écarter leur charge durant les périodes de pointe en ayant recours à l'autoproduction d'énergie électrique, la demande à laquelle font face les producteurs traditionnels devient plus élastique. Si les possibilités d'autoproduction (ou de la technologie du stockage de l'électricité) se développent suffisamment et que ces installations font assez rapidement leur entrée sur le marché, la demande à laquelle font face les fournisseurs traditionnels pourrait devenir élastique au

point d'éliminer les problèmes de pouvoir de marché (aussi bien du point de vue de la production que du transport). »⁴⁶

Contrôles des prix ou des quantités

De nombreux pays de l'OCDE ont mis en place des politiques visant soit à faire baisser les prix, soit à accroître la production (ou la capacité déclarée).

S'agissant des contrôles exercés sur les prix, par exemple, des plafonds ont été mis en place dans les cas suivants :

- En Australie, un plafond a été imposé sur les prix déterminés sur le marché spot et constitue en partie une mesure de transition destinée à contrôler le pouvoir de marché et à veiller à ce que des participants inexpérimentés ne soient pas exposés à des risques financiers inutilement élevés. Le plafond a été fixé à 5 000 dollars australiens jusqu'au 31 mars 2002 et à 10 000 dollars australiens à compter du 1er avril 2002.⁴⁷
- Sur le marché de l'Angleterre et du Pays de Galles, des plafonds ont été imposés sur les prix du pool pendant les exercices financiers 1994-1995 et 1995-1996 dans le cadre d'un accord amiable entre National Power, PowerGen et l'OFFER après que le directeur général de l'autorité de réglementation de l'électricité eut menacé de renvoyer ces deux producteurs devant la commission des monopoles et des fusions du Royaume-Uni.⁴⁸
- En Californie, les producteurs qui fonctionnent pour assurer la fiabilité du réseau sont assujettis à des accords contractuels spéciaux pour assurer qu'ils ont été rémunérés en fonction de leurs coûts réels plutôt que des prix de leurs offres.⁴⁹

On pourrait également envisager de limiter l'écart entre les offres faites par chaque centrale. Dans des conditions concurrentielles, le prix demandé par une centrale ne varierait pas en fonction des conditions de la demande – le prix demandé correspondrait toujours au coût marginal. En cas de changement des conditions de la concurrence au cours de la semaine ou du mois, le producteur serait tenu de limiter l'écart entre ses offres. Cela permettrait de restreindre l'ampleur de l'augmentation des offres faites par un producteur pendant les périodes où la concurrence est limitée.

La principale difficulté que pose la réglementation des prix de la production est que les producteurs rivalisent sur de nombreux marchés différents pendant une journée, selon des conditions de concurrence variables. On peut donc considérer les producteurs comme des entreprises « multiproduits ». La théorie de la régulation des monopoles naturels veut entre autres que les entreprises multiproduits soient réglementées au moyen d'un plafond sur un panier global de prix. Le producteur a alors la latitude voulue pour choisir ses prix pendant une journée (ou une semaine) sans dépasser le plafond global. Le producteur utilise ainsi l'information dont il dispose sur la demande pour fixer les prix de manière efficiente, et le plafond garantit qu'il n'a pas des revenus excessifs.

Plutôt que de s'attacher à réduire les prix, il y aurait peut-être lieu de mettre en oeuvre des politiques qui viseraient à accroître la production ou, du moins, la capacité déclarée. Au Royaume-Uni, les politiques élaborées pour pénaliser les retraits de capacité remontent au tout début de la réforme engagée dans le pays. C'est ainsi qu'en décembre 1991, 8 mois seulement après la création du pool de l'électricité, la licence de production a été modifiée afin d'empêcher davantage les producteurs de manipuler le prix d'achat du pool en réduisant la capacité disponible.

« En vertu de ces modifications, les producteurs présentent pour consultation publique des rapports indiquant les critères sur lesquels ils se fondent pour déterminer la capacité disponible pour le pool, fermer des centrales et réduire par d'autres moyens leur capacité de production. Chaque année, les producteurs doivent également établir une prévision détaillée de la capacité disponible de chaque centrale pour l'année suivante et, à la fin de l'année, présenter un état de rapprochement expliquant les écarts éventuels par rapport à la capacité anticipée. Cette information est elle aussi librement accessible. »⁵⁰

Au Royaume-Uni, les retraits de capacité ont présenté un intérêt accru en raison de l'effet de cette pratique sur la « prime de capacité ». Comme on le verra ci-après, la suppression de la prime de capacité a ôté de leur intérêt aux retraits de capacité. Plus récemment, en 2001, le « *Blue Ribbon Panel* » consulté par la bourse de l'électricité de la Californie recommandait l'adoption de mesures pour empêcher les retraits de capacité sur le marché de la Californie :

« Dans la mesure où les gros producteurs ont adopté une stratégie de retrait de capacité pendant les périodes de pointe, ce qui a eu pour effet de faire monter abruptement les prix d'équilibre à moyen terme du marché, nous appuyons les propositions (...) visant à habiliter une agence à enquêter sur ce type d'incidents, ordonner l'interdiction de ces pratiques et imposer des pénalités ». ⁵¹

Une solution légèrement différente consisterait à exiger que les producteurs utilisent la capacité sous peine de la perdre, et cèdent ou vendent des « droits virtuels » de capacité inutilisée.

Une autre politique proposée concerne l'intervention de l'Etat pour veiller à ce qu'il y ait toujours une capacité suffisante en réserve. « Un certain nombre d'Etats et de responsables de l'élaboration des politiques au niveau fédéral ont affirmé que l'Etat devrait toujours s'assurer que la capacité excède la demande prévue d'au moins 15 pour cent. » Bien que cette approche soit susceptible de réduire considérablement le pouvoir de marché, d'autres politiques seraient peut-être plus efficaces. « Il n'est pas utile de conserver cette capacité si la valeur de l'électricité supplémentaire éventuellement consommée par le client est inférieure au coût total de mise à disposition de l'électricité. La communication des prix de détail en temps réel reflétant le coût horaire de la consommation additionnelle est le mécanisme le mieux indiqué pour réaliser cet arbitrage ». ⁵²

Modifications des règles du marché

L'un des enseignements qui se dégagent clairement de l'évolution du marché de l'Angleterre et du pays de Galles est que les règles qui régissent le fonctionnement du marché peuvent avoir un impact substantiel sur la capacité qu'ont les producteurs d'agir en fonction d'une stratégie et sur les mécanismes qui les incitent à le faire. Wolak et Patrick observent :

« La question de savoir si l'établissement d'un marché de l'électricité (...) engendrera ou non des avantages pour les consommateurs sous forme de baisse des prix de l'électricité est fonction de la structure du marché et des détails des règles qui en régissent le fonctionnement. Des différences subtiles dans les règles de marché peuvent accroître considérablement l'aptitude des producteurs qui vendent de l'électricité à fixer des prix considérablement supérieurs à leur coût marginal et à leur coût moyen. (...) [L]es règles de marché permettent parfois aux gros producteurs d'exploiter leur pouvoir de marché et ils ont recours pour ce faire à de nombreux moyens subtils, mais aussi très efficaces dans la mesure où ils sont très rentables. Ces stratégies peuvent être difficiles à détecter et encore plus à corriger. » ⁵³

La conception d'un marché de gros de l'électricité exige que l'on détermine : (a) si la participation sera obligatoire ou si des échanges bilatéraux seront autorisés ; (b) si les offres du côté de la demande seront autorisées ; (c) si les offres porteront simplement sur les prix et les quantités ou sur d'autres conditions comme la souplesse de la centrale ; (d) si les prix seront calculés *ex ante* (en fonction

de la demande et de l'offre anticipées) ou *ex post* (en fonction de la demande et de l'offre réelles) ; (e) si les soumissionnaires seront payés en fonction de leurs offres (enchères à la hollandaise) ou en fonction du prix à l'équilibre du marché ; (f) si des primes spéciales de disponibilité seront versées ; (g) et si les enchères seront fermes ou non.⁵⁴ Certains de ces éléments influent peu sur l'exercice d'un pouvoir de marché. En particulier, le passage d'un système à prix unique à un système d'enchères à la hollandaise n'est pas susceptible de réduire l'exercice d'un pouvoir de marché.⁵⁵

On s'est penché attentivement sur la façon dont les primes de capacité peuvent accroître le pouvoir de marché en incitant davantage les producteurs dominants à pratiquer des retraits de capacité :

« Sur le marché du Royaume-Uni, plusieurs facteurs ont fait de la stratégie de retrait de capacité un moyen intéressant de faire augmenter le prix final payé par le consommateur. ... La déclaration de disponibilité en fonction d'une stratégie a l'avantage de fournir aux producteurs différents moyens de dissimuler leurs intentions. Il sera très difficile, voire impossible, pour le directeur général, de faire la différence entre l'indisponibilité due à de véritables interruptions et celle qui relève d'une déclaration stratégique. »⁵⁶

En particulier, Wolak et Patrick préconisent la suppression de la composante prime de capacité du prix payé par le pool sur le marché de l'Angleterre et du Pays de Galles.

La suppression de la prime de capacité empêcherait « ces producteurs de faire des offres pour chaque centrale à un prix proche de son coût marginal et de miser sur la prime de capacité élevée pour compenser leur charge fixe. Il serait toujours possible de restreindre la capacité pour que les prix marginaux du système soient élevés, mais cela éliminerait l'avantage supplémentaire très rentable de cette stratégie, tenant au fait qu'elle suscite une probabilité de perte de charge très élevée et, partant, une prime de capacité très substantielle. Il faudrait donc envisager sérieusement la suppression de la prime de capacité sur le marché de l'Angleterre et du Pays de Galles. ».⁵⁷

La prime de capacité a été supprimée au Royaume-Uni lors de la mise en œuvre des nouveaux accords relatifs aux contrats de vente de l'électricité (NETA), en mars 2001.

Autres politiques

Différentes autres politiques destinées à atténuer le pouvoir de marché ont été proposées. Elles consisteraient notamment à encourager l'entrée de nouveaux concurrents sur le marché ainsi que la passation de contrats à long terme, et auraient recours à la participation publique pour contrebalancer les mécanismes incitant à optimiser les profits.

L'entrée de nouveaux concurrents sur le marché peut être favorisée par le biais de politiques qui cherchent à simplifier les critères d'attribution de licences et facilitent les processus d'obtention des autorisations pour l'établissement de nouvelles centrales. Les politiques qui favorisent les contrats à long terme peuvent également faciliter les nouvelles entrées en aidant les petites entreprises à se procurer les capitaux nécessaires⁵⁸.

Les contrats à long terme constituent aussi un moyen de contrôler le pouvoir de marché. Borenstein explique :

« Bien que les prix à terme ne dépasseront pas systématiquement les prix spot, il se peut que les prix baissent sur ces *deux* types de marchés si, dans l'ensemble, les acheteurs achètent plus d'électricité par le biais de contrats à long terme. Le fait qu'une partie des ventes soit bloquée à l'avance diminue pour de nombreuses entreprises l'intérêt qu'il y a à se comporter de manière moins concurrentielle. (Allaz et Vila, 1993)

La possibilité de conclure des ventes à l'avance fait que les entreprises peuvent plus difficilement limiter la concurrence. Lorsqu'une entreprise a vendu une partie de sa production à l'avance, elle est moins motivée à restreindre sa production sur le marché spot dans le but de faire monter les prix sur ce marché, puisqu'elle ne recevra pas le prix le plus élevé sur ce marché pour la production qu'elle a déjà vendue par le biais d'un contrat à terme. Par conséquent, en prévision d'une concurrence plus agressive sur le marché spot – du fait que certaines entreprises ont vendu à l'avance une quantité significative sur le marché à terme – les entreprises sont susceptibles de pratiquer des prix plus agressifs sur le marché à terme ».⁵⁹

Il y a lieu de penser que cet argument est fondé si l'on se fie à ce qui a été constaté sur le marché de l'Angleterre et du Pays de Galles. L'une des motivations des politiques mises en œuvre dans le cadre des NETA était que ces accords autorisaient et encourageaient les contrats bilatéraux à long terme entre les producteurs et les acheteurs. « Les prix à terme de l'électricité étaient plus bas pendant la période qui a suivi l'annonce de la conclusion des NETA et ont augmenté lorsque leur entrée en vigueur a été différée – les acteurs du marché s'accordaient à reconnaître que les NETA provoqueraient une chute des prix de gros. »

Le pouvoir de marché pourrait également être atténué par la présence d'une entreprise qui ne cherche pas à maximiser ses profits sur le marché. Dans leur étude, Schmalensee et Golub constatent que « les entreprises publiques, si elles se comportent de manière concurrentielle, permettent de bien contrôler la capacité des sociétés privées de services publics à but lucratif à exercer un pouvoir de marché. ... Les tenants de la déréglementation doivent trouver un moyen d'éliminer les subventions aux sociétés d'électricité appartenant à l'Etat, tout en maintenant ou en renforçant les mécanismes qui les encouragent à agir en preneuses de prix sur les marchés du réseau de grand transport..⁶⁰

Conclusion

On s'accorde généralement à reconnaître que les marchés de l'électricité sont exposés au pouvoir de marché. « Les caractéristiques géographiques des marchés de la production et les conditions changeantes des réseaux permettent presque d'affirmer que les marchés de la production ne seront jamais parfaitement concurrentiels, quelle que soit la situation. »⁶¹

Comme l'électricité ne peut pas être stockée, les marchés de l'électricité doivent être différenciés en fonction du moment où elle est livrée. Lorsque les réseaux de transport sont congestionnés, les marchés de l'électricité doivent être séparés géographiquement. Même sur ces marchés séparés selon des critères temporels et géographiques, une forte proportion de producteurs peut fonctionner à plein rendement, ce qui les empêche de réagir à une augmentation du prix. En outre, la très faible élasticité de la demande d'électricité implique qu'une infime réduction de la production suffit pour influencer fortement le prix.⁶²

L'observation d'épisodes pendant lesquels les prix sont très élevés n'apporte pas nécessairement la preuve de l'exercice d'un pouvoir de marché. Comme la demande est à la fois cyclique et difficilement prévisible, les épisodes de prix élevés sont inévitables, même dans un secteur où l'offre d'électricité est parfaitement concurrentielle. Il n'en reste pas moins que le pouvoir de marché peut accentuer les fluctuations de prix. En outre, le pouvoir de marché peut engendrer à la fois une inefficience allocative (étant donné que les consommateurs changent de sources de combustible) et une inefficience productive (étant donné que des producteurs à coût élevé remplacent des producteurs à faible coût et que des producteurs à coût élevé sont incités à entrer sur le marché). Les transferts qui en résultent des consommateurs vers les producteurs peuvent être substantiels. Environ 60 pour cent du total des paiements versés aux producteurs d'électricité de la Californie au cours de l'été 2000 sont imputables au pouvoir de marché seulement.

Le pouvoir de marché qui se manifeste sur les marchés de l'électricité peut être contrôlé par différentes politiques. Etant donné que les marchés de l'électricité sont exposés au pouvoir de marché, il faudrait étudier attentivement toutes les politiques visant à entamer le pouvoir de marché, notamment celles qui encouragent la tarification en temps réel, la passation de contrats à long terme, la séparation horizontale et verticale, la réforme de la tarification du transport et les contrôles bien ciblés des prix.⁶³

Les problèmes posés par le pouvoir de marché (ainsi que d'autres problèmes) ont nécessité une réévaluation des arguments concernant les avantages et les inconvénients de la libéralisation de l'électricité. Jusqu'à présent, rien ne semble indiquer que les problèmes de pouvoir de marché soient insurmontables ou nécessitent une réorientation des réformes engagées pendant la dernière décennie. Borenstein explique :

« Les difficultés rencontrées jusqu'ici (...) ne doivent pas être interprétées comme un échec de la restructuration, mais comme participant du processus ardu au bout duquel le secteur de l'électricité sera à même de servir les clients encore mieux que par le passé ».⁶⁴

ANNEXE A:

On trouvera ci-après un tour d'horizon des études qui ont été faites sur le pouvoir de marché tiré d'un document réalisé en mars 2001 par le *Department of Energy* des Etats-Unis :

Concentration sur les marchés de la production d'électricité :

« Schmalensee et Golub (1984) calculent les valeurs IHH de 170 marchés de production d'électricité desservant près des trois quarts de la population des Etats-Unis, à l'aide de différentes hypothèses d'étendue géographique des marchés de la production. Les auteurs font état d'un nombre significatif de cas où la concentration mesurée au moyen d'un IHH atteint le seuil critique défini dans les principes directeurs relatifs aux fusions horizontales. Par exemple, en supposant une faible capacité de transport, entre 35 et 60 pour cent de l'ensemble des marchés de production ont des valeurs IHH supérieures à 1800 dans un éventail de cas de coût marginal et d'élasticité de la demande. La valeur IHH moyenne pondérée s'établit entre 1590 et 2650, ce qui indique une concentration importante. Dans le cas plus favorable où la capacité de transport est forte, la concentration est moins élevée, mais jusqu'à 33 pour cent des marchés conservaient des valeurs IHH supérieures au seuil de 1800 établi dans les principes directeurs relatifs aux fusions pour l'identification des marchés très concentrés. (...)

Dans une étude récente, Cardell, Hitt et Hogan (1997) avancent que les marchés de l'électricité restent aujourd'hui encore fortement concentrés. A l'aide de données datant de 1994 et d'une définition plus étroite de l'étendue géographique des marchés de l'électricité, ils calculent les valeurs IHH de 112 régions en fonction des frontières des Etats et des sous-régions délimitées par le *North American Electric Reliability Council* (NERC). Même si l'analyse ne reflète pas la poussée récente de fusions et de cessions, environ 90 pour cent de ces régions affichent des valeurs IHH supérieures à 2500.

L'impact du pouvoir de marché sur les prix de l'électricité de gros au Royaume-Uni et en Californie

Des analystes ont été en mesure d'évaluer les incidences du pouvoir de marché en fonction de données réelles provenant du Royaume-Uni et de la Californie. D'après leurs études, les producteurs, sur ces deux marchés, ont pu percevoir des revenus excédentaires considérables grâce au pouvoir de marché. L'expérience du Royaume-Uni a fait l'objet de nombreuses études, en partie parce que ce pays a été l'un des premiers à introduire la concurrence sur les marchés de gros de l'électricité. Depuis la création du pool de l'électricité du Royaume-Uni, en 1990, l'*Office of Electricity Regulation* (OFFER)⁶⁵ a mené des enquêtes sur les abus de pouvoir de marché à plusieurs occasions après avoir constaté que les prix du pool étaient inhabituellement élevés. Lors de la conception du marché du Royaume-Uni, il a été prévu deux types de rémunération pour les producteurs : les primes de capacité, qui sont fonction de la comparaison pour le lendemain des besoins de capacité anticipés et de la capacité disponible, et les paiements liés à la fourniture d'énergie, lesquels sont fondés sur les prix marginaux du système. Au début de 1992, les prix marginaux du système et les primes de capacité ont considérablement augmenté. Après avoir mené une enquête, l'OFFER a établi que National Power et PowerGen, les deux plus gros producteurs, qui représentaient ensemble 70 pour cent de la capacité totale du pool, demandaient des prix qui excédaient leurs coûts marginaux. En outre, PowerGen avait déclaré qu'un certain nombre de centrales étaient

indisponibles afin de faire augmenter les primes de capacité. Une fois que la prime de capacité avait été déterminée, PowerGen déclarait les centrales en question disponibles, ce qui les habillait à recevoir les primes de capacité les plus élevées. Même si l'OFFER a institué un certain nombre de réformes par la suite, il semble avoir plus ou moins réussi à affaiblir le pouvoir de marché.⁶⁶

Wolfram (1998 et 1999) a examiné le comportement stratégique de National Power et PowerGen dans le cadre d'enchères. A l'aide de données sur les coûts du combustible et les coûts thermiques, elle a évalué le coût marginal de l'électricité et l'a comparé ensuite avec le « prix marginal du système »⁶⁷ afin de déterminer la marge prix-coût (la différence entre le coût marginal d'un producteur et le prix qu'il demande). Selon son évaluation, de 1992 à 1994, les prix marginaux ont dépassé 19 à 25 pour cent les coûts marginaux estimés.

Wolak et Patrick (1997) examinent le problème du retrait de capacité sur le pool de l'électricité du Royaume-Uni. La structure de ce pool permet aux entreprises de tirer grandement profit de cette pratique. Les prix payés aux producteurs comprennent une prime de capacité déterminée toutes les demi-heures par le gestionnaire du pool en fonction du niveau des réserves disponibles et de la « perte de charge »⁶⁸. Lorsque la capacité de production de réserve chute, les primes de capacité augmentent. Les entreprises qui pratiquent le retrait de capacité perçoivent des primes de capacité et des prix marginaux du système plus élevés pour leur production, et cette stratégie est très rentable.

Après avoir analysé les prix et les quantités à l'équilibre de l'offre et de la demande aux demi-heures, et les enchères et les déclarations de disponibilité aux demi-heures pendant la période comprise entre 1991 et 1995, les auteurs citent plusieurs éléments qui démontrent que National Power et PowerGen mènent une stratégie de retrait de capacité. Premièrement, ils constatent que le pourcentage de capacité totale déclarée indisponible par National Power et PowerGen pendant les mois creux de 1995 correspond à plus du double de la quantité moyenne déclarée indisponible par tous les producteurs pendant les mois creux. En outre, ils calculent les facteurs de disponibilité moyens par type de combustible pour National Power et PowerGen et les comparent avec les critères établis pour le secteur d'après les données du NERC pour des groupes comparables. Pour chaque type de combustible, les facteurs de disponibilité, aussi bien pour ce qui concerne National Power que PowerGen, sont inférieurs au repère établi pour le secteur. Ainsi, les facteurs de disponibilité moyens pour les turbines à gaz à cycles combinés sont respectivement de 53 et 64 pour cent pour National Power et PowerGen, comparativement à un repère de 80 pour cent pour le secteur. A l'inverse, les facteurs de disponibilité pour les producteurs d'électricité indépendants qui vendent au pool du Royaume-Uni sont tous supérieurs au repère du secteur, puisqu'ils s'établissent entre 81 et 93 pour cent pour les turbines à gaz à cycles combinés.

Le marché de gros de la Californie, beaucoup plus récent que celui du Royaume-Uni, est ouvert à la concurrence depuis 1998. Ce marché a une structure institutionnelle différente de celle du Royaume-Uni — par exemple, il n'y a pas de primes de capacité autres que celles qui sont directement liés à la prestation de services auxiliaires. Même si les concepteurs du marché de la Californie auraient pu tirer les enseignements de l'expérience britannique, les premières analyses font soupçonner qu'un pouvoir de marché s'exerce sur ce marché. Borenstein, Bushnell et Wolak (1999) s'intéressent au marché de gros de l'électricité pendant la période comprise entre juin et novembre 1998. Ils calculent la courbe de l'offre marginale agrégée en se fondant sur les coûts du combustible, les coûts thermiques et les coûts variables de fonctionnement et d'entretien, à l'aide de données fournies par la *California Energy Commission* et d'autres sources. A l'aide des niveaux de production horaire communiqués par le gestionnaire du réseau de transport, ils déterminent le prix concurrentiel horaire. Ce prix est ensuite comparé au prix horaire (plan non contraint) pratiqué sur la bourse de l'électricité de la Californie pour évaluer la marge prix-coût. Pour la totalité de la période de six mois, les paiements totaux aux producteurs ont dépassé de 29 pour cent, soit 94 million de dollars, et même, à certaines périodes, de 75 pour cent, les niveaux concurrentiels. Les marges les plus élevées ont été enregistrées en juillet et août entre midi et 18 h, lorsque la demande est

élevée. Wolak a récemment étendu l'analyse de manière à inclure l'été 1999, et révisé l'évaluation, de sorte que les montants versés aux producteurs auraient dépassé de plus de 800 millions de dollars les niveaux concurrentiels pendant les étés 1998 et 1999 combinés.

Les études mentionnées dans la présente section rendent compte du surprix en tant que pourcentage du prix du marché de gros de l'électricité. Le prix de gros de l'électricité n'est qu'une des composantes du prix global payé par les consommateurs de services d'électricité, qui comprend également les coûts de transport et de distribution et d'autres frais. Les mêmes impacts sur les prix, mesurés en pourcentage du prix total à la livraison de l'électricité aux utilisateurs finals, seraient beaucoup moindres, et se situeraient dans de nombreux marchés entre la moitié et les deux tiers de l'impact en pourcentage en ce qui concerne la production seulement.

Autres preuves du pouvoir de marché au Royaume-Uni et en Californie

Des études fondées sur des observations comme celles menées par Wolfram (1998, 1999) et par Borenstein, Bushnell et Wolak (1999) mesurent l'ampleur du pouvoir de marché en évaluant d'abord le coût marginal de production et en le comparant ensuite aux estimations obtenues avec les prix. La tentative d'estimation des coûts de production pose toutefois un certain nombre de difficultés. Wolfram, par exemple, n'inclut pas les coûts variables de fonctionnement et d'entretien dans ses estimations, et, de ce fait sous-estime peut-être les coûts de production réels. En Californie, les producteurs n'incluent pas explicitement les coûts de démarrage dans leurs offres (comme le font d'autres pools d'électricité) et doivent plutôt les inclure dans leurs offres d'énergie (même si l'inclusion des coûts de démarrage ne rendrait pas entièrement compte des paiements plus élevés déjà mentionnés versés aux producteurs de Californie). A ce titre, l'offre faite par un producteur peut sembler supérieure aux coûts marginaux même si le prix demandé reflète précisément le coût variable de production assumé par ce producteur.

D'autres éléments, cependant, font penser que les entreprises exercent un pouvoir de marché —le comportement en matière d'enchères au Royaume-Uni, par exemple. Même si les entreprises ont intérêt à faire des enchères plus élevées sur le pool afin d'augmenter leurs recettes, elles doivent faire en sorte que la centrale soit appelée. Selon la théorie économique, si les producteurs se comportent en suivant une stratégie, les marges prix-coûts sont plus élevées pour les centrales qui sont les plus susceptibles de fixer le prix du pool et dont la capacité disponible est supérieure à la capacité inframarginale. Wolfram constate que ces deux phénomènes ont pu être observés sur le pool du Royaume-Uni. Elle montre en outre que la variation des prix des offres faites par un groupe donné est supérieure à la variation des offres faites par l'ensemble des groupes.

D'autres analystes ont comparé les prix réels du pool de la bourse de l'électricité de la Californie avec ceux établis dans une étude réalisée en 1997 par Borenstein et Bushnell sur l'existence possible d'un pouvoir de marché sur le marché de gros de Californie. Pour deux des quatre mois étudiés, le modèle surestime les prix faisant supposer l'existence d'une situation de concurrence ou de pouvoir de marché. Pour les deux autres mois, cependant, le modèle prédit de manière exacte les prix concurrentiels pour environ 80 pour cent des heures, en général lorsque les charges sont basses. Pour environ 10 pour cent des heures pendant ces deux mois, les prix réels de la bourse de Californie se situent dans l'éventail des prix qui, selon les prédictions, font soupçonner l'existence d'un pouvoir de marché.

L'arrivée de nouveaux concurrents sur le marché peut restreindre considérablement l'aptitude à maintenir les prix au-dessus du niveau concurrentiel pendant une période significative, comportement qui correspond à la définition de l'exercice d'un pouvoir de marché. La possibilité d'une entrée rapide de nouveaux concurrents peut dissuader un opérateur historique qui domine le marché d'exercer un pouvoir de marché,

étant donné que l'entrée motivée par la perspective de profits supérieurs à la normale et de prix élevés peut mener à une surcapacité et diminuer les bénéfices après l'entrée.

Même si l'on a enregistré de nombreuses entrées sur le marché britannique depuis la privatisation, le pouvoir de marché n'y a pas été entièrement éliminé. En 1993 et 1994, les prix du pool se sont situés en moyenne immédiatement en dessous des coûts moyens à long terme d'un nouvel entrant potentiel. En outre, National Power et PowerGen ont pratiqué des retraits significatifs de capacité lors de l'arrivée de nouvelles entreprises au début des années 90, ce qui a limité l'augmentation nette de capacité au sein du pool. Les montées des prix les plus récentes, survenues en 1999, donnent à penser que National Power et PowerGen peuvent toujours exercer un pouvoir de marché malgré les nouvelles entrées et la baisse subséquente de leur part de marché.⁶⁹

Les problèmes liés au pouvoir de marché ont persisté au Royaume-Uni malgré les ajouts considérables de capacité qui sont le fait de producteurs d'électricité indépendants (12 300 mégawatts) et l'ajout, entre 1991 et 1997, de capacité nucléaire, conformément à un engagement pris antérieurement (3 200 mégawatts). Ensemble, ces ajouts ont représenté l'équivalent de 25 pour cent de la capacité totale du pool de l'Angleterre et du Pays de Galles. Comme les conditions qui prévalaient sur le marché britannique étaient probablement plus propices à l'ajout rapide d'une importante capacité fournie par des producteurs d'électricité indépendants que sur de nombreux marchés régionaux de l'électricité aux Etats-Unis, l'entrée de nouveaux concurrents ne devrait probablement pas être considérée comme la panacée au pouvoir de marché à court et à moyen terme.

Etudes du pouvoir de marché dans d'autres régions

Borenstein, Bushnell et Knittel (1997) examinent la possibilité qu'un pouvoir de marché s'exerce dans le New Jersey. En raison des contraintes de transport qui existent à destination et en provenance du pool de l'électricité Pennsylvanie-New Jersey-Maryland (PJM), le New Jersey (« PJM-East ») peut parfois être un marché restreint, distinct sur le plan géographique, qui se prête à l'exercice d'un pouvoir de marché. L'analyse examine la possibilité qu'ont les cinq principales entreprises de service public du New Jersey d'augmenter les prix en réduisant leur production, en supposant que les marchés voisins (New York et « PJM-West ») sont parfaitement concurrentiels et vendront de l'électricité sur le marché du New Jersey lorsque cela sera possible, compte tenu des prix et des contraintes de transport. Ils constatent que les prix du marché commencent à dépasser les niveaux concurrentiels lorsque la demande excède 14 500 mégawatts au New Jersey (ils situent la demande de pointe à 16 500 mégawatts en 2000 pour les besoins de cette analyse). Lorsque la demande atteint ce niveau, les augmentations potentielles de prix dues au pouvoir de marché vont de quelques points à un facteur de 4.

On a également étudié la possibilité qu'un pouvoir de marché s'exerce dans le Colorado. Sweester (1998) note que les contraintes de transport et la présence d'une entreprise dominante peuvent favoriser l'exercice d'un pouvoir de marché dans l'est du Colorado. Il examine comment différentes possibilités d'action ou d'évolutions du marché pourraient réduire ce pouvoir de marché. Par exemple, la présence de coopératives d'électricité rurales et d'agences d'électricité municipales sur les marchés concurrentiels réduit les marges prix-coûts prévues d'environ 10 pour cent. En supposant l'entrée sur le marché de 1 000 mégawatts de production nouvelle et concurrentielle, les marges prix-coûts chutent de façon spectaculaire. La plus forte diminution des marges prix-coût, dans une hypothèse de pouvoir de marché, est obtenue en exigeant de l'entreprise dominante qu'elle cède 50 pour cent de ses actifs.

Plusieurs commissions de services publics des différents états ont également entrepris des études sur le pouvoir de marché dans le cadre d'une restructuration. Dans le Michigan, par exemple, la commission des services publics a calculé des valeurs d'IHH pour cet Etat et conclu que le marché du Michigan est

« tellement concentré et que les avantages des services publics en place sont tellement généralisés que la prise de mesures s'impose. » La commission des services publics de l'Utah a réalisé des études de simulation similaires à celles qui ont été faites dans le New Jersey et le Colorado et constaté que l'entreprise dominante serait en mesure d'exercer un pouvoir de marché de 45 à 60 pour cent du temps.

ANNEXE B :

L'indice de Lerner et l'IHH sur un marché sans contraintes de capacité

Supposons un marché comportant n entreprises qui produisent un produit identique, assumant des coûts de $c_i(q_i)$ pour $i=1, \dots, n$. La courbe de la demande sur le marché est $P(Q)$, où $Q = q_1 + q_2 + \dots + q_n$. Le bénéfice de la i ième entreprise est donc :

$$\pi_i(q_i, q_{-i}) = P(Q)q_i - c_i(q_i) = P(q_i + \sum_{j \neq i} q_j)q_i - c_i(q_i)$$

Supposons que ces entreprises se font une concurrence en quantité, l'équilibre de Cournot étant $(q_1^*, q_2^*, \dots, q_n^*)$. D'après les conditions de premier ordre, nous savons que :

$$\frac{\partial \pi_i}{\partial q_i}(q_i, q_{-i}) = P'(Q)q_i + P(Q) - c'_i(q_i) = 0 \text{ car } i=1, \dots, n.$$

Ce qui implique que :

$$\frac{P(Q) - c'_i(q_i)}{P(Q)} = -\frac{P'(Q)}{P(Q)}q_i = \frac{s_i}{\varepsilon} \text{ car } i=1, \dots, n.$$

Où $s_i = q_i / Q$ est la part de marché de la i ième entreprise et ε est l'élasticité de la courbe de la demande lorsque la production totale est Q . Si nous multiplions cette expression par s_i et additionnons la production de toutes les entreprises, nous constatons que :

$$\frac{P - \bar{c}}{P} = \frac{IHH}{\varepsilon}$$

Où $\bar{c} = \sum_i s_i c'_i(q_i)$ est la moyenne pondérée des coûts marginaux des entreprises au niveau d'équilibre de la production (pondéré par les parts de marché de chaque entreprise) et $IHH = \sum_i s_i^2$ est la somme des carrés des parts de marchés des entreprises présentes sur le marché.

Supposons maintenant que les entreprises assument un coût marginal constant. L'expression ci-dessus permet de déduire que :

$$\frac{P - \tilde{c}}{P} = \frac{1}{n\varepsilon}$$

Où $\tilde{c} = \frac{1}{n} \sum_i c_i$ est la simple moyenne des coûts marginaux assumés par les entreprises. Ce résultat a pour conséquence immédiate que si la courbe de la demande a une élasticité constante, la marge prix-coût marginal est constante, quel que soit le niveau de la demande.

Contraintes de capacité et IHH ajusté

Supposons maintenant que la i ème entreprise fait face à une contrainte de capacité de K_i . Le problème de l'entreprise est maintenant de maximiser $\pi_i(q_i, q_{-i})$ à la condition que $q_i \leq K_i$. Soit m entreprises exemptes de contraintes de capacité désignées $1, 2, \dots, m$. Pour ces entreprises, les conditions de premier ordre ci-dessus sont maintenues. Supposons que la part de marché totale des entreprises contraintes soit \bar{s} .

Supposons ensuite que $\sum_{i=1}^m s_i + \bar{s} = 1$. Si nous multiplions les conditions de premier ordre par $s_i + \frac{\bar{s}}{m}$ et faisons le total, nous obtenons :

$$\sum_{i=1}^m (s_i + \frac{\bar{s}}{m}) \frac{P(Q) - c'_i(q_i)}{P(Q)} = \frac{P(Q) - \hat{c}}{P(Q)} = \frac{IHH^{adj}}{\varepsilon}$$

Où $\hat{c} = \sum_{i=1}^m (s_i + \frac{\bar{s}}{m}) c'_i(q_i)$ et $IHH^{adj} = \sum_{i=1}^m s_i (s_i + \frac{\bar{s}}{m})$.

Valeur minimum de l'IHH ajusté

Pour un nombre donné d'entreprises sans contraintes, nous pouvons trouver la valeur minimum de l'IHH en choisissant s_1, s_2, \dots, s_m pour réduire au minimum IHH^{adj} , pour autant que $\sum_{i=1}^m s_i + \bar{s} = 1$. On peut alors

aisément démontrer que s_1, s_2, \dots, s_m doivent être identiques et, par conséquent, que $s_i = \frac{1 - \bar{s}}{m}$. En intégrant ce résultat à l'expression IHH^{adj} , nous obtenons

$$IHH^{adj} \geq \sum_{i=1}^m \left(\frac{1 - \bar{s}}{m} \right) \left(\frac{1 - \bar{s}}{m} + \frac{\bar{s}}{m} \right) = \frac{1 - \bar{s}}{m}$$

NOTES

1. Dans le présent document, « pouvoir de marché » désigne principalement le pouvoir de marché unilatéral et horizontal (par opposition au pouvoir de marché collusoire, concerté ou vertical).
2. Par souci d'uniformité, ajoutons que lorsqu'une entreprise subit des contraintes, il se peut que le prix du marché soit supérieur au coût marginal assumé par les entreprises non contraintes.
3. Voir à l'annexe B. La marge prix-coût marginal moyen peut diminuer, même si la marge prix-coût marginal le plus bas augmente.
4. Nous ne tenons pas compte ici des pertes de transport ou de la congestion éventuelles. On verra plus loin que lorsque les lignes de transport subissent des contraintes, il est parfois nécessaire de faire appel à des producteurs à coût élevé afin de maintenir l'intégrité du système.
5. Voir Borenstein (1999) p. 3 : « En l'absence de pouvoir de marché exercé par un vendeur sur le marché, le prix peut quand même excéder les coûts marginaux de production de toutes les installations de production présentes sur le marché à ce moment. ». Par conséquent, sur un marché présentant des contraintes de capacité, il faut, pour démontrer la présence d'un pouvoir de marché, *à la fois* une indication que le prix du marché est plus élevé que le coût marginal de toutes les entreprises présentes sur le marché (c'est-à-dire que l'indice de Lerner est positif) *et* qu'au moins une entreprise fonctionne sans utiliser toute sa capacité.
6. Borenstein, Bushnell, Kahn et Stoft (1996), p. 18.
7. Borenstein, Bushnell et Knittel (1999), p. 5.
8. Borenstein et Bushnell (2000), p. 48-49.
9. Borenstein et Bushnell (2000), p. 49. En ce qui a trait au marché de l'Angleterre et du Pays de Galles, Wolack et Patrick (1997), p. 8-9, observent : « La grande majorité des clients [d'une société régionale de fourniture d'électricité] achètent l'électricité à des tarifs fixes et non liés aux variations du prix du pool au cours d'une année. Tous les particuliers paient des prix fixes pouvant varier selon des modalités convenues d'un commun accord sur une base quotidienne ou hebdomadaire, indépendamment des fluctuations du prix du pool, pendant la totalité de l'exercice budgétaire. Sous sa forme la plus courante, ce mode de tarification prévoit un prix fixe par kWh pour la consommation totale pendant les périodes diurnes et un autre prix fixe par kWh pour la consommation pendant les périodes nocturnes. Presque tous les utilisateurs commerciaux et industriels achètent l'électricité par le biais de contrats similaires à prix fixes négociés annuellement, selon lesquels les prix varient également sur une base quotidienne ou hebdomadaire, indépendamment des variations du prix du pool. Par conséquent, les variations du prix du pool au cours d'une journée, d'une journée à l'autre ou même d'un mois à l'autre n'ont d'incidence que sur les prix payés par une petite partie de la clientèle, étant donné que les structures des prix ne sont pas modifiées pour la totalité de l'exercice budgétaire. Seule une infime partie de la charge totale du réseau de l'Angleterre et du Pays de Galles, soit environ 5 pour cent, est achetée par des consommateurs finals en fonction des variations du prix semi-horaire sur le marché spot ». De toute façon, dans le cadre de l'ancien système de négociation de l'Angleterre et du Pays de Galles, il n'existait pas de mécanismes qui

permettaient aux acheteurs de signaler leur intention de réduire leur demande à la suite d'une hausse des prix.

10. Borenstein et Bushnell (2000), p. 49. A strictement parler, le problème de fond n'est pas que les producteurs sont confrontés à des contraintes de capacité, mais que la courbe de coût marginal augmente fortement lorsque la capacité maximum est presque atteinte, de sorte que les producteurs fonctionnent la plupart du temps à pleine capacité.
11. Voir, par exemple, Cramton et Lien (2000).
12. Borenstein et Bushnell (2000), p. 49-50.
13. Borenstein et Bushnell (2000), p. 49-50. Cet argument peut être facilement extrapolé pour montrer que le pouvoir de marché peut exister non seulement en période de pointe mais aussi à tout instant lorsque la courbe de l'offre du secteur est inélastique (par exemple lorsqu'une augmentation de la production nécessite l'appel d'une installation dont le fonctionnement coûte cher). De fait, lorsque la courbe de l'offre est inélastique, on estime que même une petite entreprise peut trouver rentable de réduire un peu sa production – les coûts de cette réduction sont plus que contrebalancés par la hausse du prix du marché des unités restantes vendues.
14. US FTC, *In the Matter of PacifiCorp ; The Energy Group PLC; Peabody Holding Company, Inc. ; Peabody Western Coal Company, Analysis of Proposed Consent Order to Aid Public Comment* (<http://www.ftc.gov/os/1998/9802/>).
15. D'autre part, l'indice d'Herfindahl-Hirschman ajusté est une mesure plus précise que celle qui consisterait simplement à ne pas tenir compte de la part de marché des entreprises soumises à des contraintes au motif qu'elles sont « hors marché ». Cette approche est examinée, par exemple, par Werden (1996), p. 19 : « Selon les règles actuelles des institutions du marché, la capacité destinée à la charge locale devrait peut-être être considérée comme « hors marché » ; ... En effet, les parts de la capacité excédentaire sont de bien meilleurs indicateurs d'un éventuel pouvoir de marché significatif que les parts de la capacité totale. »
16. Wolak et Patrick (1997), p. 47.
17. La réduction du pouvoir de marché n'entraîne pas de baisse du prix du marché mais plutôt une diminution de la marge du prix du marché par rapport au niveau de coût efficace.
18. Newbery (1998), p. 744.
19. Bushnell et Wolak (1999), p. 4-5.
20. Bushnell et Wolak (1999), p. 4-5. Joskow (1997) constate : « [C]ertains producteurs possèdent des centrales situées stratégiquement sur le réseau et sont de temps à autre « appelés pour assurer la fiabilité du réseau. » Naturellement, lorsque les producteurs savent que le gestionnaire du réseau leur demandera de tourner pour maintenir la fiabilité du réseau (presque) indépendamment du prix demandé, ils font des offres élevées. Certaines centrales situées stratégiquement sur le réseau de l'Angleterre et du Pays de Galles ont facturé des prix six fois plus élevés que des producteurs comparables avant que l'autorité de la réglementation ne leur impose un prix plafond ». Joskow (1997), p. 134.
21. Joskow et Tirole (2000), p. 458.
22. Voir, par exemple, Hogan (1997).
23. Hjalmarsson (2000) observe : « C'est, que je sache, la première étude sur les marchés de l'électricité qui ne peut rejeter l'hypothèse de la concurrence parfaite ».

24. Borenstein, Bushnell et Wolak (2002), p. 5.
25. Voir Cardell, Hitt et Hogan (1997), Bushnell (1999), Borenstein, Bushnell et Stoff (2000), Joskow et Tirole (2000).
26. Voir Bushnell (2002).
27. Borenstein, Bushnell et Wolak (2002), p. 5-6.
28. L'information contenue dans cet encadré est tirée de Wolak et Patrick (1997) et de Green et Newbery (1992). Voir aussi Wolak (1997).
29. Green et Newbery (1992), p. 952.
30. Les informations fournies dans cet encadré proviennent de Borenstein, Bushnell et Knittel (1999). Parmi les autres études ayant conclu à l'existence d'un pouvoir de marché significatif sur le marché de gros de l'électricité en Californie, citons celles de Borenstein, Bushnell et Wolak (2001), Wolak, Nordhaus et Shapiro (2000), Puller (2001), Joskow et Kahn (2001), Hildebrandt (2001) et Sheffrin (2001).
31. *Department of Energy*, Etats-Unis (2000), p. 13.
32. Commission européenne (2001), p. 30.
33. Commission européenne (2001), p. 18-29.
34. Aux Etats-Unis, le *Department of Energy* (2000) évoque la possibilité que les producteurs soient tenus d'améliorer le transport placé sous leur contrôle afin d'affaiblir leur pouvoir de marché dans les zones de saturation où ils exercent leurs activités.
35. Hogan (1998) observe : « Il est tout à fait possible d'élaborer des exemples de liaisons de transport valables n'ayant pas de transit net d'électricité, et qui apparaissent inutiles au regard de nombreuses définitions des droits établis en fonction des liaisons ». p. 11.
36. Troisièmement, la construction d'une liaison de transport ou l'amélioration de la capacité d'une liaison existante ne fait pas toujours baisser les prix du marché. L'allègement d'une contrainte de transport entre les points A et B ne fait pas nécessairement baisser les prix aux points A et B. A vrai dire, c'est l'opposé qui est quasiment le plus susceptible de se produire. Une liaison de transport entre les points A et B est, de fait, une sorte de mise en équilibre des prix en vigueur aux points A et B. L'existence d'un transit d'électricité du point A vers le point B signifie que (tout au moins en l'absence de transit) le prix du marché est plus élevé au point B qu'au point A. Une liaison de transport a par conséquent tendance à faire *augmenter* les prix au point A (et à les faire *diminuer* au point B). On a vu en revanche que l'effet d'accroissement de la concurrence a tendance à faire baisser les prix à la fois au point A et au point B. Il n'est pas possible de dire dans l'abstrait lequel des deux effets l'emportera.
37. Joskow (1997), p 132.
38. Hilke (2001).
39. Hilke (2001).
40. Hilke (2001).
41. Voir par exemple l'Irlande, <http://www.cer.ie/cer01101.pdf>, l'Oregon et l'Alberta.

42. Voir <http://www.edf.fr/hm/en/enchere/enchere/Survolproduit>
43. Voir par exemple Fraser (2001).
44. Wolak et Patrick (1997), p. 51.
45. Kahn *et al* (2001), p. 16-17. « Bien que la facturation en temps réel ne soit pas répandue aux Etats-Unis, la technologie y est bien établie. La plupart des gros clients commerciaux et industriels de la Californie sont déjà dotés de compteurs en temps réel et la communication du prix du marché du lendemain ou en temps réel à ces clients peut facilement se faire par Internet. Il se peut qu'il ne soit pas pratique ou nécessaire dans un avenir proche d'inclure les particuliers dans le programme de tarification en temps réel, mais la diminution du coût des compteurs en temps réel facilitera cette inclusion. Il importe de comprendre que la *variation* des prix peut être dissociée du *niveau moyen* des prix. Pour tout niveau de prix de détail uniforme considéré, le même niveau de prix moyen à l'échelle du réseau peut être obtenu chaque mois avec la tarification de détail en temps réel. La tarification en temps réel réduira le coût de passation des marchés d'électricité rendra moins nécessaire la construction de centrales électriques, et favorisera la baisse des prix de détail ». Borenstein (2002), p. 205-206.
46. Hilke (2001). Hilke se montre également prudent: « L'élasticité de la demande risque de varier dans le temps (...) Par exemple, la demande record qui est due à un froid très intense peut être moins élastique que celle qui relève du dynamisme de l'économie. Il est risqué de supposer qu'une plus forte élasticité de la demande attribuable à la participation du côté de la demande persistera en toutes circonstances ».
47. *National Electricity Code*, articles 3.9.4 et 3.9.5.
48. Wolak et Patrick (1997), page 14.
49. Cet aspect est approfondi par Bushnell et Wolak (1999), p. 12-13. Aux Etats-Unis, le FERC peut retirer l'autorisation de déterminer les tarifs au moyen de processus fondés sur le marché s'il estime que cela entraîne des résultats peu souhaitables.
50. Wolak et Patrick (1997), p. 13-14.
51. Kahn *et al* (2001), p. 13.
52. Borenstein (2002), p. 203.
53. Wolak et Patrick (1997), p. 48-49.
54. On trouvera dans IEA (2000) un résumé utile des avantages et des inconvénients des différentes approches de la conception de marché.
55. Voir Kahn *et al* (2001).
56. Wolak et Patrick (1997), p. 48-49.
57. Wolak et Patrick (1997), p. 50.
58. Voir Kahn *et al* (2001), p. 15.
59. Borenstein (2002), p. 202.
60. Schmalensee et Golub (1984), p. 26.

61. Joskow (1997).
62. « Un élément qui a contribué de façon significative au mouvement observé à l'échelle internationale vers la restructuration de la concurrence sur les marchés de l'électricité est que la composante production de ce secteur n'est plus considérée comme un monopole naturel. Alors que la concurrence portant sur la production de l'électricité peut effectivement être vive dans de grandes régions, les limites des capacités de transport dans la plupart des réseaux d'électricité, associées au manque de moyens de stockage économique de l'électricité, restreignent souvent la concurrence dans des régions géographiques relativement petites. Dans ces petites régions, les groupes peuvent détenir un pouvoir de marché significatif. Ce pouvoir de marché est accentué par le fait que la demande en temps réel d'électricité de gros se caractérise par une très grande inélasticité-prix ». Bushnell et Wolak (1999), p. 3.
63. « Le mouvement vers la restructuration des marchés de l'électricité est issu d'une nette insatisfaction à l'égard des résultats de la réglementation du coût des services. Cela dit, les marchés de l'électricité se sont révélés plus difficiles à restructurer que de nombreux autres marchés (...) en raison de la présence inhabituelle d'une très forte inélasticité de l'offre comme de la demande. La tarification de détail en temps réel et la passation de contrats à long terme peuvent contribuer à contrôler des prix de gros en hausse comme ceux observés récemment en Californie et à ménager du temps pour traiter d'autres problèmes structurels importants qui doivent être résolus pour instaurer un marché de l'électricité stable et fonctionnel. Ces problèmes concernent notamment la création d'une structure adaptée à la concurrence sur le marché de détail, la détermination de la meilleure façon de fixer localement les prix et les frais de transport, la mise en œuvre d'un cadre cohérent d'investissement dans de nouvelles capacités de transport et l'optimisation de l'approvisionnement en capacité de réserve ». Borenstein (2002), p. 210.
64. Borenstein (2002), p. 210.
65. En 1999, l'OFFER et l'*Office of Gas Supply* ont fusionné en vue de la création de l'*Office of Gas and Electricity Market* (OFGEM).
66. L'OFFER a fini par imposer un plafond sur les prix marginaux, exigé que National Power et PowerGen cèdent une partie de leurs actifs de production et demandé aux producteurs de présenter des plans annuels relativement aux interruptions temporaires anticipées des centrales.
67. Les prix du pool de l'électricité du Royaume-Uni comprennent trois éléments distincts : le prix marginal du système, qui correspond au prix de l'offre du dernier producteur figurant sur le plan de dispatching, une prime de capacité, qui rémunère les producteurs pour la fourniture de capacité et une prime d'ajustement au titre des écarts entre la demande anticipée et la demande réelle et des coûts des services auxiliaires fournis par les producteurs (par exemple, participation au réglage de la tension). Les augmentations des coûts attribuables à l'augmentation des primes de capacité ne sont pas prise en compte dans cette analyse, qui se borne à l'examen du prix marginal du système.
68. La valeur de la perte de charge est l'évaluation du montant que les consommateurs finals qui reçoivent de l'électricité en vertu de contrats fermes seraient disposés à payer pour éviter une interruption de leur service d'électricité.
69. En juillet 1999, les prix du pool de l'électricité au Royaume-Uni étaient d'environ 80 pour cent supérieurs aux prix en vigueur pendant la même période en 1998, malgré une augmentation relativement faible de la demande ou des prix du combustible comparativement à l'année précédente. L'OFGEM a établi que ces hausses de prix étaient principalement attribuables à l'augmentation des prix demandés par les centrales alimentées au charbon appartenant à National Power et PowerGen.

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QUESTIONNAIRE SUBMITTED BY THE SECRETARIAT

These questions are designed to understand the features of your regulatory regime in electricity which affect the incentives and ability of firms to exercise market power or to expand generation or transmission capacity.

As always, countries with a federal structure may have many different regulatory regimes within their borders. Countries in this situation are invited to respond by discussing the main developments at the federal level and highlighting some of the more interesting state or region-level developments where these are relevant.

Overview of Regulation

Although it is not necessary to describe the entire regulatory regime governing electricity, understanding your responses to the questions below will be greatly facilitated if you describe the basic features of your electricity sector, particularly developments since the last WP2 roundtable on electricity in 1996. There are more detailed questions on many of these issues in the next section below.

- (1) Please summarise the basic structure of the electricity sector in your country including recent and imminent developments. You may like to specify: the total generation capacity, the different primary fuel sources, the primary sources of imports (or destinations for exports), any constraints on the expansion of generation or transmission and any environmental policies affecting electricity. Is there an established market or pool in wholesale electricity? What are the basic features of this market? Are parts of the transmission network congested at certain times? Who are the key players in the generation market? Are these firms integrated into transmission or distribution? What is the market share of the largest players at different levels of demand? Finally, what is the nature of the regulatory authority? Does the regulatory authority have powers to intervene to collect information and set prices? If so, which prices? under what circumstances?

In the case of EU countries (for which regulatory reform has primarily been a matter of implementing the relevant EC Directives) we invite you to focus on the approaches you have chosen to comply with the Directives or where you have gone further than the minimum required by the Commission.

Factors Affecting Market Power

Many features of liberalised electricity markets affect the exercise of market power and the potential for periodic episodes of very high prices. We invite you to discuss these factors.

- (2) *Market Structure:* Who are the main players in the generation market? What fuel sources do they use? What is their capacity and cost structure? At different levels of demand which firms tend to set the market price? How important are imports from other regions? Do the imports set the market price? Are the imports capacity constrained? Is the market concentrated at certain times of the day or a certain levels of demand? How do you measure concentration in these markets?

Is the industry vertically-integrated? Is there integration between generation and transmission? If so, how does the regulatory authority prevent discrimination against non-integrated generators?

Has the regulator (or some other body) imposed a divestiture or separation requirement? (For example, a requirement to divest a certain proportion of generation capacity) If so, what divestiture or separation was required? What was the resulting effect?

- (3) *Congestion and Pricing of the Transmission Network:* Which components of the transmission network are sometimes congested? Under what conditions are these components congested? What are the consequences of this congestion – in particular, does the congestion facilitate market power? If so, for which generators?

How do you price access to the transmission network (for example, do you use “nodal” or “zonal” prices)? Does how you price access to the transmission network affect the level of market power? Are there market instruments which allow the market players to hedge against movements in the prices for access to the transmission network (for example, so-called “financial transmission rights”)? Do these instruments affect the incentives to exercise market power?

What are the incentives faced by generators when choosing where to locate? Do generators have incentives to make efficient location decisions? Where has most new generation capacity been constructed?

Are there special rules governing import/export transmission lines? Are these lines congested for all or some part of the time? How is access to these transmission links rationed at peak times? Do you auction the capacity of these links?

Which firm or firms have the ability to upgrade the transmission network to relieve congestion (through the construction of new links or through the enhancement of existing links)? For example, is this the sole responsibility of the transmission network operator, or can independent firms construct new pipelines? What are the incentives on these firms to upgrade the transmission network in this way?

- (4) *Market Rules:* Please describe the key features of the electricity “exchange” or “pool” (where there is more than one market, explain the differences between them – which market determines the “spot” price of electricity). In particular you may like to specify:

- whether or not participation in the spot market is compulsory (or can sellers sign bilateral contracts directly with buyers)? (In most cases participation is voluntary)
- whether or not buyers are able to submit bids directly into the market mechanism? (In most cases buyers also participate by bidding into the market)
- what is the nature of the bids – are they simple price-quantity pairs (how many such pairs can each generating firm submit?) or do firms bid other terms such as the rate at which they can ramp up production?
- is the spot price determined *ex ante* on the basis of forecast demand and supply or *ex post* on the basis of actual demand and supply?

- is there some mechanism designed to enhance investment in and availability of generation capacity? (In most cases there is no such mechanism – the market price itself provides the incentive for new investment)

Do the rules governing the operation of the electricity market affect the incentive for firms to act strategically? Are there other ways in which the market rules might influence market power?

- (5) *Bilateral, Long-Term and Forward Contracts:* Does the regulatory regime allow or promote the use of long-term or forward contracts for the sale and purchase of electricity? Are certain firms required or obliged to take out long-term contracts? Does the presence of such contracts affect the level of market power?
- (6) *Price or Quantity Controls:* Are wholesale electricity prices set through a market mechanism or through regulation? If they are set through a market mechanism, do there remain some controls on the prices that firms can charge (such as a ceiling on the amount the firm can bid, or a requirement that all bids be based on marginal cost)? If so, which firms and under what circumstances? (For example, are there caps on the prices of firms which are “constrained on” or “reliability must run”)

Are there special rules governing when firms are allowed to withdraw capacity from the market? For example, are there special provisions governing availability of generation capacity? Is a firm penalised when capacity ceases to be available which it declared to be available?

- (7) *Entry:* Are there special rules which encourage (or discourage) new entry into generation? For example, is there a requirement to maintain a certain level of excess generation capacity? Has there been significant new entry in recent years? Which fuel sources have the new entrants chosen, and why? Will the new entry be sufficient to offset any market power?
- (8) *Competition Law Enforcement:* Which mergers have you considered in this sector (either between generators or between electricity and gas producers)? Was the merger approved? What conditions were placed on the merger?

Have you investigated allegations of collusive behaviour in this sector? What was the outcome of that investigation?

Have you investigated abuse of dominance in this sector? What was the allegation? What was the outcome?

QUESTIONNAIRE SOUMIS PAR LE SECRÉTARIAT

Les questions que vous trouverez ici doivent nous permettre de comprendre quelles sont les caractéristiques de la réglementation de votre secteur électrique qui influent sur les incitations et la capacité des entreprises à exercer un pouvoir de marché ou à développer leur capacité de production ou de transport.

Comme toujours, les pays à régime fédéral se caractérisent par une multiplicité de réglementations. Ces pays sont invités à exposer les principales évolutions au niveau fédéral, en s'arrêtant éventuellement sur les développements les plus intéressants survenus dans un Etat ou une région.

Description de la réglementation

Nous ne vous demandons pas de décrire intégralement le régime réglementaire de l'électricité dans votre pays mais il nous sera plus facile de comprendre vos réponses aux questions ci-dessous si vous décrivez les principaux éléments du secteur électrique, notamment les évolutions depuis la dernière table ronde sur l'électricité organisée par le Groupe de travail n° 2 en 1996. Ces questions seront détaillées à la section suivante.

- (1) Veuillez résumer la structure fondamentale du secteur électrique dans votre pays, ainsi que ses évolutions récentes ou imminentes. Il sera peut-être nécessaire de préciser : la puissance installée totale, les différentes sources d'énergie primaire, les principales sources d'importation (ou destinations des exportations), toute contrainte au développement de la production ou du transport ainsi que les politiques environnementales susceptibles de se répercuter sur le secteur électrique. Existe-t-il un marché de gros ou pool de l'électricité et quelles en sont les principales caractéristiques ? Existe-t-il des goulots d'étranglement sur le réseau de transport à certaines périodes ? Quelles sont les principales entreprises intervenant sur le marché de la production ? Ces entreprises intègrent-elles également le transport ou la distribution ? Quelle est la part de marché des plus gros intervenants suivant les différents niveaux de la demande ? Enfin, en quoi consiste l'autorité de régulation : a-t-elle compétence pour recueillir des informations et fixer les prix ? Si oui, quels prix, et dans quelles circonstances ?

Dans le cas des pays de l'Union européenne (où la réforme de la réglementation consiste pour l'essentiel à appliquer les Directives pertinentes de la CE), nous vous invitons à vous concentrer sur les démarches choisies pour mettre en œuvre ces directives ou ouvrir le marché davantage que le minimum requis par la Commission.

Facteurs déterminant le pouvoir de marché

L'exercice de pouvoir de marché et la possibilité d'envolées temporaires des prix dépendent de nombreux aspects des marchés ouverts de l'électricité. Nous vous invitons à décrire ces facteurs.

- (2) *Structure du marché* : Quels sont les principaux intervenants sur le marché de la production ? Quelles sources d'énergie utilisent-ils ? Quelle est la nature de leur parc et leur structure de coûts ? Suivant les différents niveaux de la demande, quelles sont les entreprises qui déterminent le prix de marché ? Quelle est l'importance des importations en provenance d'autres régions ? Ces importations

déterminent-elles le prix de marché ? Y a-t-il des limitations à la capacité d'importations ? Le marché est-il concentré à certaines périodes de la journée ou suivant les niveaux de la demande ? Comment mesure-t-on la concentration sur ces marchés ?

L'industrie est-elle verticalement intégrée ? La production et le transport sont-elles intégrés ? Dans l'affirmative, comment l'autorité de régulation évite-t-elle la discrimination à l'encontre des producteurs non intégrés ?

L'autorité de régulation (ou toute autre instance) a-t-elle imposé la cession d'actifs ou la séparation ? (Par exemple a-t-elle imposé de céder une certaine proportion de la capacité de production ?). Dans l'affirmative, quel type de cession ou de séparation a été exigé ? Quel en a été le résultat ?

- (3) *Congestion et tarification de l'utilisation du réseau de transport* : Quels sont les tronçons du réseau de transport qui sont sujets à congestion ? Dans quelles conditions ces congestions ont-elles lieu ? Quelles en sont les conséquences – et en particulier ces congestions facilitent-elles le pouvoir de marché ? Dans l'affirmative, pour quels producteurs ?

Comment est tarifé l'accès au réseau de transport (par exemple, appliquez-vous des prix nodaux ou zonaux) ? Le mode de tarification adopté a-t-il des répercussions sur l'importance des pouvoirs de marché ? Existe-t-il des instruments par lesquels les intervenants sur le marché peuvent se protéger contre des fluctuations des prix d'utilisation du réseau de transport (par exemple, existe-t-il des droits financiers de transport ?). Ces instruments ont-ils un effet sur les incitations à exercer un pouvoir de marché ?

Qu'est-ce qui incite un producteur à choisir une situation géographique plutôt qu'une autre ? Est-il incité à prendre des décisions de localisation efficaces ? Où ont été construites la plupart des installations de production récentes ?

Existe-t-il des règles spécifiques aux liaisons de transport international ? Y-a-t-il parfois des goulots d'étranglement sur ces liaisons ? Comment régularise-t-on le transport sur ces lignes aux heures de pointe ? La capacité sur ces liaisons fait-elle l'objet d'enchères ?

Quelles sont les entreprises en mesure d'améliorer le réseau de transport pour atténuer les congestions (de construire de nouvelles liaisons ou d'améliorer les liaisons existantes) ? Par exemple, cette tâche incombe-t-elle au seul gestionnaire du réseau de transport, ou les entreprises indépendantes peuvent-elles construire de nouvelles lignes ? En quoi ces entreprises sont-elles incitées à améliorer le réseau de transport ?

- (4) *Règles du marché* : Décrivez les principales caractéristiques du marché de l'électricité ou du pool (s'il existe plusieurs marchés, expliquez ce qui les différencie : quel est le marché qui détermine le prix spot). Vous serez éventuellement amené à préciser :

- si la participation au marché spot est obligatoire (ou si les vendeurs peuvent signer des contrats bilatéraux directement avec les acheteurs) ? (Le plus souvent cette participation est facultative)
- si les acheteurs ont la possibilité de soumissionner directement ? (Dans la plupart des cas les acheteurs participent également aux enchères sur le marché)
- quelle est la nature des enchères : s'agit-il simplement de quantités données à un prix donné (dans ce cas combien un producteur peut-il en présenter ?) ou les entreprises peuvent-elles soumettre aux enchères la vitesse de montée en charge d'un moyen de production ?

- le prix spot est-il déterminé *ex ante* en fonction des prévisions de l'offre et de la demande ou *ex post* en fonction de l'offre et de la demande réelles ?
- existe-t-il un mécanisme conçu pour favoriser l'investissement dans les moyens de production et la disponibilité de ces moyens ? (Dans la plupart des cas, il n'en existe pas – le prix de marché est l'élément qui incite à investir)

Les règles régissant le fonctionnement du marché de l'électricité peuvent-elles inciter ou décourager les comportements stratégiques ? Existe-t-il d'autres moyens par lesquels ces règles pourraient influencer sur le pouvoir de marché ?

- (5) *Contrats bilatéraux, à long terme et à terme* : La réglementation permet-elle ou favorise-t-elle les contrats d'achat ou de vente d'électricité à long terme ou les opérations à terme ? Certaines entreprises sont-elles dans l'obligation en fait ou en droit de souscrire des contrats à long terme ? L'existence de ces contrats se répercute-t-elle sur le niveau de pouvoir de marché ?
- (6) *Contrôles des prix ou des quantités* : Les prix de gros de l'électricité sont-ils établis par un mécanisme de marché ou de manière réglementaire ? Si les mécanismes du marché déterminent les prix, reste-t-il une forme de contrôle des prix que les entreprises peuvent facturer (par exemple, plafonnement de la quantité que l'entreprise peut soumissionner ou obligation de fonder toutes les enchères sur le prix marginal) ? Dans l'affirmative, quelles entreprises sont concernées et dans quelles circonstances ? (Par exemple, les prix des entreprises qui doivent assurer la production des groupes imposés sont-ils plafonnés)

Existe-t-il des règles spécifiques concernant le retrait de moyens de production du marché ? Par exemple a-t-on pris des dispositions spéciales pour garantir la disponibilité des moyens de production ? Une entreprise est-elle sanctionnée si elle est incapable de produire alors qu'elle s'était engagée à le faire ?

- (7) *Entrée* : Existe-t-il des règles spéciales favorisant (ou décourageant) l'entrée de producteurs sur le marché ? Par exemple est-il obligatoire de conserver une surcapacité donnée ? A-t-on assisté a des entrées significatives sur le marché ces dernières années ? Quelles sources d'énergie les nouveaux entrants ont-ils choisi d'exploiter et pourquoi ? Ces entrées permettront-elles de compenser les pouvoirs de marché s'il y en a ?
- (8) *Application du droit de la concurrence* : Quels types de fusion ont-ils été envisagés dans ce secteur (entre producteurs d'électricité ou entre producteurs d'électricité et de gaz) ? Ces fusions ont-elles été approuvées et à quelles conditions ?

Avez-vous instruit des affaires de collusion dans ce secteur ? Quels ont été les résultats de ces instructions ?

Avez-vous instruit des affaires d'abus de position dominante dans ce secteur ? Quelles étaient les pratiques alléguées ? Quel a été le résultat ?

AUSTRALIA

1. Introduction

The Australian electricity supply industry has undergone radical transformation since the last WP2 roundtable on electricity in 1996. The National Electricity Market (NEM) was established in 1998 across the eastern and south-eastern states, providing the foundations for the development of competition in generation and retail supply activities and for the integration of the previously separated state markets. The reform program, has succeeded in creating strong competition, especially in some states, and has brought significant price reductions and other benefits to consumers.

Despite these significant achievements, the reform process is not complete. The introduction of full retail contestability and improved demand side participation are necessary to achieve a more fully functioning market. In some areas of the NEM, stronger interconnection is essential to enhance competition. This issue is highlighting perceived deficiencies in the NEM's transmission network planning and pricing arrangements.

Against this background, the Council of Australian Governments (COAG) is currently conducting a review of most aspects of future energy market directions and priorities.

2. Market regulation

2.1. *National Electricity Market*

The NEM commenced on 13 December 1998 and is a market for the supply and purchase of electricity, combined with an open access regime for the use of transmission and distribution networks in the participating jurisdictions of the Australian Capital Territory, New South Wales, Queensland, South Australia and Victoria.¹ It comprises five interconnected regions. Tasmania will join the NEM after the interconnector with Victoria is completed.

The NEM arrangements are defined in the National Electricity Code (Code), which includes rules and procedures for the operation of the wholesale electricity market and the access regime for electricity networks. The Code has been endorsed by the participating jurisdictions that enacted co-operative legislation, the National Electricity Law, to implement the regulatory arrangements that support the effective operation of the Code.

As electricity cannot be stored and because it is not possible to distinguish which generator produced the electricity consumed by a particular customer, all electricity output from generators is centrally pooled and scheduled to meet demand.

The two basic concepts of the NEM pool are the centrally co-ordinated dispatch process and the spot market. In the centrally co-ordinated dispatch process, electricity supply and demand requirements are continually balanced by scheduling generators to produce sufficient electricity to meet customer demand. Generators compete by providing dispatch offers (prices for different levels of generation) to the National Electricity Market Management Company (NEMMCO). Market customers (retailers and end use customers who are wholesale market participants) may submit dispatch bids, specifying quantities of

electricity demanded. NEMMCO dispatches the scheduled generation and demand with the objective of minimising the cost of electricity demand based on the offer and bid process.

The spot market is the market where generators are paid for the electricity they sell to the pool, and retailers and wholesale end-use customers pay for the electricity consumption. A spot price for wholesale electricity is calculated for each half-hour period during the day and is the clearing price to match supply and demand. NEMMCO calculates the spot price using the price offers and bids submitted by market participants. In general, all electricity must be traded through the spot market.

Generators and retailers also trade in financial instruments, such as hedge contracts, outside the pool to hedge the fluctuations in spot prices, which may vary every half-hour in response to electricity supply and demand. These hedge contracts do not affect the operation of the power system in balancing supply and demand in the pool directly, and are not regulated under the Code.

2.2. Regulation

Historically the electricity supply industry (ESI) in each of the Australian States and Territories has been owned and operated by State or Territory governments. The ESIs have been vertically integrated, basically operating as State based systems. Legislative powers in these industries rested in the hands of state regulators.

During much of the 1990s, the electricity industry underwent major structural and regulatory reforms. The reforms introduced in most States and Territories involved the separation of formerly integrated utilities into independent bodies with responsibility for generation, transmission, distribution and retail. The reforms have also tended to involve the separation of regulatory and commercial functions of the electricity authorities (generation and retail becoming part of the competitive market while transmission and distribution are regulated). This vertical separation has facilitated the introduction of competition into generation and retail sectors, and provided access to the natural monopoly elements of transmission and distribution systems on a non-discriminatory basis.

In order for such an approach to be adopted each State and Territory agreed to hand over some regulatory roles to independent regulators. In particular, the Australian Competition and Consumer Commission (ACCC), the National Electricity Code Administrator (NECA) and NEMMCO have significant regulatory roles in the NEM. The ACCC is becoming responsible for transmission network pricing regulation, NECA performs a number of market administrative roles, while NEMMCO manages the day to day operation of the electricity market. The roles of the various regulators are outlined below.

2.2.1. Australian Competition and Consumer Commission

The ACCC is responsible for administering and enforcing the *Trade Practices Act 1974* (TPA) that applies to all sectors of the economy, including the ESI. In part the TPA deals with access to essential facilities of national significance (Part IIIA) and with restrictive trade practices (Part IV). This provides the ACCC with many of its roles in the ESI. However, further roles in the ESI, most notably transmission pricing arrangements, are outlined in the Code.

The specific roles of the ACCC in the ESI are:

- Network regulation – approval of access arrangements to the network, determining the annual revenue requirement for each transmission network service provider operating in the NEM, approval of transmission network service provider capital expenditure, developing the details

of regulatory policy, setting service standards for transmission network performance, developing ring fencing guidelines, arbitration of disputes over regulated interconnector proposals, and developing accounting and reporting guidelines.

- Approval of market rules – Evaluation and authorisation of changes to the National Electricity Code that governs the operation of the market, including the future structure of network charges, market design and retail competition.
- Ongoing market supervision – Investigation of market arrangements and behaviour that may contravene anti-trust laws and evaluation of electricity industry mergers.

2.2.2. *National Electricity Code Administrator*

NECA's role is to supervise and enforce the National Electricity Code and administer the Code's development. NECA's functions are to

- monitor and examine the Code for its performance;
- to institute changes to the Code, as required, and forward these proposed changes to the ACCC;
- monitor and report on the compliance to the Code by all participants in the NEM; and
- to enforce the Code, fine participants for non-compliance, and pass on serious matters onto the National Electricity Tribunal.

2.2.3. *National Electricity Market Management Company*

NEMMCO is responsible for the day to day management of the NEM. The functions of NEMMCO are to:

- operate and administer the NEM in accordance with the Code's market rules;
- maintain the power system security;
- coordinate the power system network connections; and
- register Code participants.

2.2.4. *State Regulators*

The states and state regulators retain important roles in the ESI. A list of the state regulators is outlined in Table 1. The functions of the state regulators in the ESI largely concern distribution and retail activities. The regulation of distribution includes setting price controls for distribution and approval of distribution tariffs and setting standards for distribution and other related services, and monitoring compliance. The regulation of retailing includes approval of "safety net" retail tariffs for smaller customers, setting standards for retail services and monitoring compliance, and developing a scheme of retailer of last resort. The state regulators also have responsibilities for monitoring market conduct of

retailers and distributors, monitoring safety and environmental standards, developing information programs to customers, introducing competition in other supply-related services, such as metering, and issuing licences for all electricity companies operating in the state.

Table 1 – State Electricity Regulators

State	Regulatory agency
New South Wales	Independent Pricing and Regulatory Tribunal
Victoria	Essential Services Commission
Queensland	Queensland Competition Authority
South Australia	South Australian Independent Industry Regulator
Australian Capital Territory	Independent Competition and Regulatory Commission
Tasmania	Office of the Tasmanian Electricity Regulator

As electricity is regulated by a variety of agencies at the Commonwealth and State/Territory levels, the institutional framework of the Australian ESI is often perceived as complex. Concerns have been raised that there is the potential for overlap in regulatory responsibilities, which could impose additional costs and risks for market participants. It is therefore important to ensure that there is effective co-operation and communication by regulators. To this end, the ACCC, in conjunction with other state based regulators, established the Utility Regulators' Forum — a committee of regulatory agencies — to promote information sharing and consistent approaches to the development of regulation. Industry and user representatives are able to attend and address the Forum.

Nonetheless, given that there are at least ten different regulatory agencies with a role in the operation of the Australian ESI, there is a widespread view among market participants that there is some potential to streamline the governance arrangements in the NEM. This is an issue identified by the International Energy Agency (IEA) in its latest study of the Australian ESI.² It is also a matter that the COAG Energy Market Review is currently considering.

3. Market power

3.1. Market Structure and Market Power

The existence and ability to exercise market power is fundamentally linked to market structure. The market structure of each of the NEM jurisdictions, as well as Tasmania, is outlined in Appendix 1. This indicates that each of the NEM regions is characterised by a small number of very large generators with the exception of Victoria. While some generators comprise a single large power station (mainly the case in Victoria and South Australia), many generators control large portfolios of power plants (New South Wales and Queensland). The limited number of players in the market for generation means that there is limited competition in generation within regional boundaries. Despite the fact that the NEM has been designed as a national interconnected market where generators in all States compete with each other, in reality, on occasions, circumstances can arise that force the national market to operate as separate State markets in which competition is much more limited.

Since the summer of 2000-01 there has been criticism of market outcomes and allegations that some market participants have taken advantage of their position in the market to influence price outcomes. In order to obtain definitive analysis on the issue and to determine whether such behaviour had in fact breached the competitive conduct provisions of the TPA, the ACCC engaged two consultants to review generator bidding and rebidding behaviour in the NEM.

3.2. *Market Power Consultancies*

The ACCC engaged Intelligent Energy Systems (IES) and Bardak Ventures Pty Ltd (Bardak) to undertake a review of generator bidding and rebidding behaviour. The terms of reference stipulated that both consultants choose and analyse a set of incidents where the spot price for electricity had reached extreme levels. The consultants were asked to determine the factors affecting such price outcomes, analyse any rebidding activity and patterns of behaviour leading up to those trading intervals, and quantify the impact of the resulting price spike on average prices in the NEM.

Through their analysis, both Bardak and IES established that, at times, some generators in the NEM exhibit market power and, through bidding and rebidding, exercised this market power to increase prices in the NEM. IES claimed that generators currently have only limited opportunities to exert market power, with these opportunities becoming less frequent over the last year. Alternatively, Bardak found that several features inherent in the design of the NEM allowed generators to exercise market power with the resultant effect of higher than normal pool prices.

The IES report determined that extreme prices occur following an initiating event such as tightening of supply and demand within a region or group of regions, an outage of a generator or interconnector, or exceptionally high load forecasts. The report also found that where an initiating event was present, bidding and rebidding tended to greatly amplify extremes in price outcomes. Contrary to IES, Bardak claimed that in high price outcomes, an initiating event was only present some of the time. It argued that generators often withhold capacity through their bidding and rebidding behaviour in order to create artificial price spikes. IES conceded that a small number of large portfolio generators attempted to affect prices through their bidding and rebidding behaviour, however, it believed that such attempts only resulted in moderate price increases.

Both IES and Bardak agreed that the bids of generators that had reduced their volume of contract cover were generally much higher than other bids. Bardak calculated that the average pool price was effectively 13 per cent lower when the 20 highest dispatch prices of 2000 were eliminated.³

IES concluded that bidding and rebidding contributed to between \$3-\$11/MWh, or 9-26 per cent, of the annual average pool price. However, IES believed that the increase in prices was justifiable, as it encouraged much needed investment in the relevant regions without being prompted by high prices resulting from blackouts.

A more detailed summary of both reports is included in Appendix 4. The reports themselves are available on the ACCC's website.⁴

3.3. *Recent generation investment in the NEM*

One of the ways in which generator market power issues may be addressed in the NEM is through the construction of new generation capacity. Significant excess generation capacity existed in a number of Australian states at the beginning of 1990s. However, recent large demand growth has meant that new generation investment has become necessary in most NEM jurisdictions.⁵

Table 2 indicates generation capacity that has been commissioned since NEM commencement. The majority of generation capacity has been commissioned in Queensland. Until recently, Queensland experienced the tightest overall supply/demand balance because of the high growth rate in the region and the large distances between generation and many load centres.

South Australia and Victoria are both subject to summer peaks, driven by the residential air conditioning load, and the supply position has been relatively tight for periods of several days at a time over the last few years. The generation plants that have been commissioned in both states recently are largely peaking plants.

New South Wales, which is currently a winter peaking market, has substantial excess capacity although this is expected to change when it moves to summer peaking, which is forecast to occur by 2005/06.

Table 2 – Generators commissioned since NEM commencement

Region	Name	Location	Fuel Type	Year	Size (MW)
NSW	Liddell*	North Coast	Coal	2002	60
	Bayswater*	North Coast	Coal	2002	160
	Redbank	North Coast	Steam/Coal	2001	120
Victoria	Loy Yang Power*	La Trobe Valley	Coal	2002	236
	Hazelwood*	La Trobe Valley	Coal	2002	90
	Valley Power	La Trobe Valley	Gas Turbine	2002	300
	Somerton	South Central	Gas Turbine	2002	150
Queensland	Townsville	North	Combined Cycle Gas Turbine	2002	150
	Callide C	Central	Coal	2001	420
	Swanbank E	South East	Combined Cycle Gas Turbine	2001	380
	Tarong	South East	Combined Cycle Gas Turbine	2001	450
	Millmerran	South West	Coal	2001	862
	Callide	Central	Steam/Coal	2001	420
	Oakey	South East	Gas Turbine/Jet Fuel	2000	282
	Yabulu	North	Gas Turbine/Jet Fuel	1999	150
	Roma	South West	Natural Gas	1999	76
South Australia	Quarantine	Adelaide	Gas Turbine	2002	95
	Hallet	Adelaide	Gas Turbine	2002	180
	Torrens Island	Adelaide	Natural Gas	2001	100
	Ladbroke Grove	Mt Gambier	Natural Gas	2000	80
	Pelican Point	Adelaide	Combined Cycle Gas Turbine/Gas/Steam	2000	478

Sources: Electricity Supply Association of Australia: *Electricity Australia 2001* NEMMCO: 2002
Statement of Opportunities

*-Denotes upgrade to existing powerstation

3.4. *Bidding / rebidding rules*

NECA has proposed addressing some of the market power problems in the electricity industry by introducing rules that target generator-bidding behaviour in the spot market for electricity.

With respect to rebidding, NECA proposed that generators' bids and rebids be made in 'good faith' and represent their genuine intentions at the time that they are made. NECA also proposed a reverse onus of proof be implemented for those aspects of generators' bidding and rebidding strategies that may prejudice the efficient, competitive or reliable operation of the market.

The ACCC is assessing NECA's proposals at the moment. It has already released a draft determination on NECA's proposals and invited further submissions from interested parties.

The ACCC has argued that market power in the NEM stems largely from the market's structure and factors such as barriers to demand side participation and barriers to trade within the NEM. Structural reform would clearly be the most effective way of addressing market power issues. Altering market-bidding rules is clearly a second best solution to any problem.

4. Congestion and pricing of the transmission network

4.1. *Transmission Network Structure*

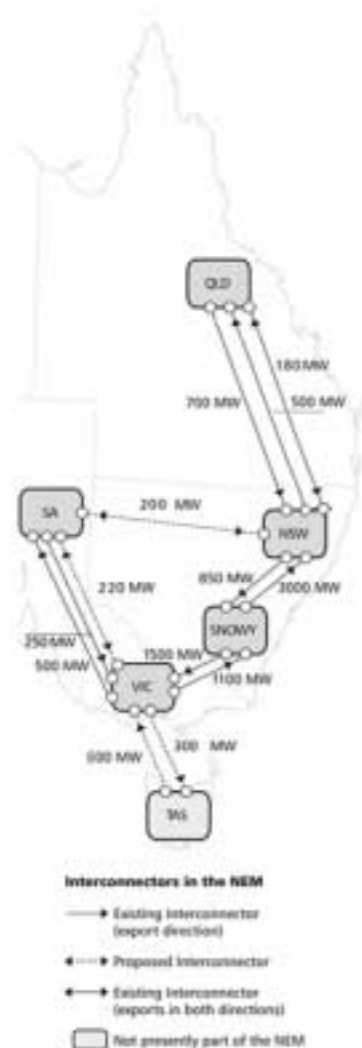
The NEM is a zonal market currently comprising five interconnected electrical regions. These regions basically follow State boundaries. The Australian Capital Territory is, however, incorporated in New South Wales and the Snowy is also a region. Each region contains a regional reference node, which may be a major load centre such as a city, or a major generation centre, such as the power plants in the Snowy region.

The construction of the Snowy scheme, which commenced in 1949, included an interconnector between the transmission systems of New South Wales and Victoria so that the two states could share the electricity generated from their mutual water resource.⁶ Over time, the Snowy has become an important provider of peak power for New South Wales (particularly in winter) and Victoria (particularly in summer). Because of the relatively high cost of local sources of coal and gas, South Australia was the first state to see the value in linking with another system. An interconnector joined existing transmission lines to Mount Gambier in South Australia and Portland in Victoria. This has enabled South Australia to import power from the surplus that has traditionally been available in Victoria.

More recently, two interconnectors, QNI (700MW capacity from Queensland to New South Wales and 500MW from New South Wales to Queensland) and Directlink (DC link, 180MW capacity) have linked Queensland with the other NEM regions. Links between South Australia and New South Wales and between Victoria and Tasmania have been proposed, while construction of the Murraylink interconnector between Victoria and South Australia has recently been completed.

Chart 1 highlights the interconnector flows between the NEM regions, as well as the proposed interconnectors.

Chart 1. Interconnection capacities in the NEM and regions



The regional reference node is where the Regional Reference Price (RRP), or regional spot price is set. The RRP is based on the bids and takes into account the constraints of interconnector capacities between the regions and energy transmission and distribution losses.

Because the RRP is determined by a range of factors including supply and demand, the physical limitations of transporting electricity and transmission and distribution loss factors there may be significant differences in the RRP of the trading regions. Transfers between regions are determined to provide an optimal dispatch of the NEM generation subject to a number of constraints, including technical limitations on the network within and between regions. The utilisation of the interconnectors will vary depending on a number of factors, including:

- seasonal variations within the NEM;
- new generating units entering the NEM;
- change in technical limits of interconnectors;

- generator bidding behaviour; and
- augmentations to the transmission network.

The difference between the price of energy generated in one region and the price of that energy once it has been transmitted to another is called the Inter-Regional Settlement Residue (IRSR).

IRSRs arises in the NEM because the amount required to be paid by market customers to NEMMCO in respect of spot market transactions will generally differ from the amount required to be paid by NEMMCO to generators for those transactions. By making the settlement residue available to the market place, the risks of trading between regions can be better managed.

The settlement residue auctions (SRA) are intended to improve the efficiency of the NEM by promoting inter-regional trade. Only registered generators, market customers and traders are able to participate in the SRA. Since the proceeds of the settlement residue auctions are deducted from a transmission network service provider's revenue cap, which is set by the ACCC, they are not permitted to participate in the auction.

4.2. *Inter-regional constraints*

As highlighted in Chart 1, the NEM is connected by a series of interconnectors linking all states. Every year NEMMCO identifies the number of hours for which the inter-regional constraints (congestion occurring across the interconnectors) have bound in each calendar year.

Table 3 – Occurrence of Inter-Regional Constraints in the 1999, 2000 and 2001 Calendar Years

Year	Type of constraint	NSW to Snowy	Snowy to NSW	Snowy to Vic	Vic to Snowy ^{1,2}	Vic to SA ^{1,3}	SA to Vic	NSW to Qld ⁴	Qld to NSW ^{4,5}
1999		0.5hr 0.0%	6.3hr 0.1%	8.5hr 0.1%	505.0hr 5.8%	5053.0hr 57.7%	0.1hr 0.0%	N/A	N/A
2000	Normal ⁷	0.4hr 0.0%	0.0hr 0.0%	67.3hr 0.8%	259.6hr 3.0%	2208.3hr 25.1%	6.7hr 0.1%	N/A	N/A
	Prior Outage	6.5hr 0.1%	0.0hr 0.0%	53.9hr 0.6%	181.4hr 2.1%	18.1hr 0.2%	0.0hr 0.0%	N/A	N/A
2001	Normal	2.4hr 0.0%	0.0hr 0.0%	36.3hr 0.4%	559.6hr 6.4%	671.6hr 7.6%	67.3hr 0.8%	67.3hr 0.8%	172.5hr 2.0%
	Prior Outage	1.0hr 0.0%	0.0hr 0.0%	27.3hr 0.4%	18.5hr 0.2%	127.1hr 1.4%	2.8hr 0.0%	1244.7hr 14.2%	911.8hr 10.4%

Source: NEMMCO, *Statement of Opportunities*, p 9-18 available at

<http://www.nemmco.com.au/publications/soo/soo4.htm>

Notes

1. Transient stability constraints on energy leaving Victoria constrain both the Victoria to Snowy and Victoria to South Australia interconnectors. In 2001, these 'joint' constraints bound for 358.4 hours for normal conditions and 16.7 hours during prior outages. For the 2001 calendar year the 358.4 hours of constraints have been reported against both interconnectors ie. Victoria to Snowy and Victoria to South Australia..

2. Constraints on the Victoria to Snowy interconnector due to thermal limits on the 500/330kV transformer at South Morang in Melbourne have been reported as a Victorian intra-regional constraint 2001 and as an interconnector constraint in 1999 and 2000.
3. Prior outage information on transfers from Victoria to South Australia include limitations due to lightning activity north of South East Substation, and limitations on the 132kV subtransmission system between the South East South Australia generation centre and Adelaide.
4. Binding constraint information on transfers between New South Wales and Queensland on QNI only, and jointly on QNI and DirectLink are reported here. Prior outage information for transfers between New South Wales and Queensland include QNI commissioning and frequency control requirements.
5. Constraints on DirectLink flow from Queensland to New South Wales only have been reported as intra-regional constraints in Queensland.

As is evident in Table 3 the transfer capability between New South Wales and Snowy had very few periods of constraint. The transfer from Snowy to New South Wales did not bind for any dispatch intervals during the 2001 calendar year, either as a result of system normal or a prior outage condition. The constraint from Snowy to New South Wales is limited by thermal considerations in the network.

In the other direction, from New South Wales to Snowy, the interconnector bound for 2.4 hours during the 2001 calendar year for system normal conditions and only slightly higher when the prior outage conditions are taken into account. The constraint from New South Wales to Snowy is limited by either thermal or transient stability considerations in the network.

The Snowy to Victoria interconnector was constrained for less than 1 per cent of the time or 36.3 hours in the 2001 calendar year and just over 56 hours when taking into account the prior outage conditions. This indicates a decrease in comparison to the 2000 calendar year, which could be attributed to the mild conditions experienced in Victoria over the 2001/02 summer. In general, this constraint is due to the voltage collapse limit in Victoria or a thermal limit elsewhere in Victoria. The Victoria to Snowy interconnector bound for approximately 560 hours or 6.4 per cent of the time for system normal conditions in the 2001 calendar year. This represents a significant increase in the number of constraint hours when compared to the 2000 calendar year.

The Victoria to South Australia interconnector was constrained for approximately 672 hours in the 2001 calendar year. This is a significant decrease in constraint hours when compared to the 2000 calendar year. This decrease could be attributed to the mild conditions experienced in Victoria and South Australia over the 2001/02 summer.

The Victoria to South Australia interconnector may be constrained for significant periods due to system security considerations and other operational requirements, including:

- the rating of the 500/275 kV transformers at Heywood (normally 500 MW);
- risk management during periods of storm activity near the 275 kV lines north of South East Substation (normally 250 MW); and
- thermal limitations on the 132 kV system with South Australia north of South East Substation (varies depending on commitment of generation at Snuggery and Ladbrooke Grove in South Australia).

NEMMCO believes that the last two of these should arguably be classified as intra-regional constraints. This will be considered further by NEMMCO in its regional boundary review process. The

South Australia to Victoria constraint is usually less limiting and constrained for approximately 67 hours in the 2001 calendar year. This transfer limit was increased to 300 MW in early 2002.

The Queensland to NSW interconnector only commenced operation in February 2001 and for this reason there are no comparative statistics. Details of the intra-regional constraints may be found in Appendix 2.

4.3. *Network planning and investment*

The constraints between regions can be minimised by signalling, through higher prices, for an increase in generation and transmission network investment. The NEM comprises two types of network investment, regulated and unregulated.

The relevant transmission network planning body in each region of the NEM undertakes regulated transmission investment. In most regions of the NEM the network owner is also the network planner. However, Victoria has a unique arrangement with a separation of the roles and functions of the network owner from the network planner. This is designed to eliminate the incentive for the regulated entity to “gold plate” its network through inefficient planning and investment. Regulated investments in the NEM will only receive a return if they pass the criteria set out in the regulatory test. A transmission and distribution network augmentation satisfies the regulatory test if:

- in the event the augmentation is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the augmentation minimises the net present value of the cost of meeting those standards; or
- in all other cases – the augmentation maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios.

Unregulated investments, or market network services, rely on trading in the wholesale market to derive their revenue and, unlike regulated interconnectors, they may also enter into financial contracts. A market network service provider (MNSP) has the ability to earn revenues in the following ways:

- as an electricity merchant - buying electricity in the low price region and selling it in the high price region;
- underwriting the investment by selling the rights to the revenue generated by trading electricity across the interconnector. Purchasers of such rights include electricity retailers, traders and generators; or
- selling a physical trading product, that is the right to bid the capacity into the market; or
- entering into contracts with NEMMCO for provision of ancillary services or reserve trader services.

There are however, no restrictions on unregulated augmentations within a region. However, because of the method used to calculate prices in the NEM, these types of augmentations are rare.

4.4. Regulated transmission charges

As was noted previously, regulated TNSPs recover some of their revenue via the IRSRs. They recover the remainder of their revenue based on the network pricing methodology outlined in the Code. The Code defines the transmission services on which networks can levy charges:

4.4.1. Entry services - provided to generators at a single connection point

A generator's connection service charges may be specifically allocated in a contract and if not, a generator's entry service charges are recovered by:

- allocating amongst all the generators at a particular connection point, the revenue needed to cover the entry assets at that connection point (plus an equitable amount for assets that jointly provide entry and exit services); and
- recovering this revenue through a fixed annual charge.

4.4.2. Exit services - provided to transmission network customers at a single connection

A customer's connection service charges may be specifically allocated in a contract and if not, a customer's exit service charges are recovered by:

- allocating amongst all the customers at a particular connection point, the revenue needed to cover the exit assets at that connection point (plus an equitable amount for assets which jointly provide exit and entry services); and
- recovering this revenue through a fixed annual charge.

4.4.3. Transmission use of system (TUOS) services - provided to either generators or customers

- Revenue arising through IRSRs and SRA (unless otherwise allocated under chapter 9 of the Code) is subtracted from the amounts to be recovered through TUOS charges.
- Fifty per cent of the remaining TUOS service costs are allocated to customer connection points using the CRNP method or modified CRNP method.
 - The variable price is determined at the discretion of the TNSP but must reflect the investment conditions in the network and may include any combination of demand, energy and fixed charges.
 - The charge may relate to either the actual (metered) use or an agreed use.
 - The demand-based charge is to be calculated on a customer's maximum demand as averaged over a metered half-hour period.
- In a connection agreement, generators may consent to pay some of the TUOS costs.

- Any remaining anticipated revenue shortfall is allocated to customer connection points on a postage stamp basis and recovered from customers through a variable common service charge (the annual rate is the common service cost divided by the network energy delivered).

4.4.4. *Common services provided to customers*

All of the revenue needed to provide such services is recovered from customers on a postage stamp basis. The revenue is recovered through a variable common service charge (the annual rate is the common service cost divided by the network energy delivered).

4.4.5. *Generator access services*

This is the risk premium for generators with connection agreements that include firm access compensation arrangements where the revenue is recovered from each generator in accordance with the connection agreement.

As is evident in the network pricing methodology used in the NEM generators are not charged according to the true utilisation cost they impose on the network. This is particularly true during peak periods because intra-regional losses are calculated using a static loss factor that will not necessarily reflect the conditions prevailing at critical times. As a result, for many generators the loss factors they see will be too low, most of the time, although some participants may be more exposed than others may. However, the NECA is currently conducting a review to address these and other issues. Its review is looking at:

- Developing an effective methodology for implementing the ‘beneficiary pays’ principle for new network investments;
- Attempting to facilitate ‘firm access’ to the transmission network, including introducing a regime of transmission property rights; and
- Whether efficiency gains in the operation of the market can be achieved by closer integration of transmission network pricing into the energy market.

NECA is expected to release its review in late 2002⁸.

5. Market rules

5.1. *The Spot Market*

The NEM is a mandatory auction market for generators with capacity of 30MW or more and wholesale market customers (retailers and end use customers who are wholesale market participants).

Generators provide dispatch offers consisting of simple price-quantity pairs specifying the amount of energy they are prepared to supply at a certain price. Up to ten such pairs can be submitted per day. Bids must be priced at between -\$1000/MWh to \$10,000/MWh. In principle, bids are firm and can only be altered under certain conditions. These generator bids are used to construct a merit order of generation dispatch. Market customers (retailers and end use customers who are wholesale market participants) may submit dispatch bids, specifying quantities of electricity demanded.

Energy offers are stacked in order of rising price until consumer demand is met. The spot price is the clearing price to match supply with demand. The scheduling of generators, however, can be constrained by the capacity of interconnectors between the regions. When this occurs, higher priced generators within the region will be called on to meet this demand. This is a major reason for the variations in electricity spot prices between regions.

Generation is scheduled according to this merit order and regional prices are calculated *ex post* for each five-minute period from actual supply and demand. Generators are paid the spot price, which is calculated for each half hour as the average of the six prices in that half hour.

A maximum spot price of \$10,000/MWh is set under the Code. This price cap is the maximum level at which generators can bid in the market. It is also the price automatically triggered when NEMMCO directs NSPs to interrupt customer supply in order to regain balance in the system. In this situation, the spot price is referred to as the Value of Lost Load (VoLL).

The NEM is an energy only market, with the price cap providing the incentive for new investment in generation capacity. There are no capacity payments or any other capacity mechanisms in the market.

5.2. *Bilateral, Long-Term and Forward Contracts*

Generators and retailers in the NEM trade in financial instruments, such as hedge contracts, outside the pool to hedge the fluctuations in spot prices. These hedge contracts do not affect the operation of the power system in balancing supply and demand in the pool directly, and are not regulated under the National Electricity Code.

It is estimated that approximately 75 per cent of capacity is tied up in long-term contracts. However, as many contracts are negotiated directly between the generators and retailers, very little is known on these contracts.

The Sydney Futures Exchange (SFE) has traded electricity futures contracts, but the market has been relatively illiquid. However, on 3 September 2002, SFE and d-cypha Limited⁹ listed new Australian Electricity Futures products on the Sydney Futures Exchange. The new products provide market participants with a wider range of more flexible trading options. The eight new futures products are based

on both baseload and peak-period energy bought and sold over a calendar quarter in New South Wales, Victoria, South Australia and Queensland. The products are available up to 15 quarters out.¹⁰

NEMMCO, does not provide a short-term forward market or an inter-regional hedging market. The only inter-regional risk management product offered by NEMMCO is the SRA. Inter-regional settlement residues arises when there is a constraint on one of the interconnectors between the different NEM regions. Whenever an interconnect is constrained, there is price separation in the two adjoining regions, as the price in each will be set by the highest marginal generator required to be dispatched to meet the physical electricity supply needs of that region.

Power flowing over the interconnector will be sold at the exporting region's (lower) price and purchased at the constrained importing region's (higher) price, creating a settlements residue equal to the difference between the two prices times the amount of power flowing over the constrained interconnect. Such price differences can pose a significant financial risk to NEM participants undertaking inter-regional trades. The successful bidders in the Settlements Residue Auction can use the residues to hedge such price risks. While the residues do not provide a perfect hedge, they do help facilitate inter-regional trade.

Only registered generators, market customers and traders are able to participate in SRAs. Transmission Network Service Providers are not permitted to participate.

At the state level, most jurisdictions, until recently, had vesting contracts between generators and retail companies in place, to protect retailers from variable pool prices in the initial stages of the markets. These mandatory contracts generally allowed the retailers to pay for energy at a fixed price at energy levels sufficient to cover their franchise load.

With full retail contestability being introduced in most jurisdictions, the vesting contracts have generally expired or are in the process of expiring. However, it appears likely that retail tariff safety net arrangements will remain in place in most jurisdictions. As such, some states have put alternative hedging arrangements between generators and retailers in place, the Electricity Tariff Equalisation Fund (ETEF) in New South Wales being one such example.¹¹

5.3. *Price or Quantity Controls*

The wholesale price of electricity is set through the NEM spot market. Generators offer to supply the market with different amounts of energy at particular prices. From all offers submitted, NEMMCO selects the generators required to produce power and at what times throughout the day based on the most cost-efficient supply solution to meet specific demand. The spot price is the clearing price to match supply with demand. While the spot price is set through this market mechanism, a maximum spot price of \$10,000/MWh is set under the Code. This price cap is the maximum level at which generators can bid in the market.

Generators can change their bids or submit re-bids according to a set of bidding rules. Generators and others must submit bids for a 24 hour period to NEMMCO by 12:30pm each day for the following trading day. Bids can be made in up to ten price bands from -\$1000/MWh to the price cap of \$10,000/MWh. Prices of bids must remain firm but generators are able to rebid the amount of capacity offered in any of the price bands subject to the bidding rules contained under clause 3.8.22 of the Code. Rebids are accepted up until approximately five minutes prior to dispatch.

The rebidding rules require participants to submit a brief, verifiable and specific reason to NEMMCO at the time of the rebid, and provide any other substantiating information as required by

NEMMCO. NEMMCO must publish the timing and reason for a rebid. However, the rebidding rules do not specify the type of reason that is considered appropriate, simply that a reason is supplied.

NECA produces a weekly market analysis of the market's performance, specifically price, demand and forecast difference arising during the week. For each trading interval, it compares the spot price to that week's average price, and the average for the last quarter. In its analysis, NECA highlights any significantly high prices arising during any trading intervals - they define a high price as one that is at least three times the average weekly price.

5.4. Market Entry

In an energy only market such as the NEM, the market price cap, VoLL, provides the incentive for investment in peak generation. There is no requirement to maintain a certain level of excess generation capacity. Prices are allowed to clear at the level which remunerates peak investments. Generators receive revenue only when they generate and customers pay in accordance with their half hourly demand.

In April 2002, the level of the price cap in the market increased from \$5,000/MWh to \$10,000/MWh. It was argued that an increase in the price cap was necessary to provide sufficient signals for new investment in peaking generation. NECA claimed that investments that ensure reliability during system peaks may only earn revenue from an energy only market such as the NEM for a few hours per year.¹² Therefore, NECA argued that without an increase in the price cap, there could be no assurance that investment in peaking capacity needed to ensure historical levels of reliability of supply would eventuate.

6. Conclusion

Clearly the Australian electricity supply industry has undergone radical transformation since the last WP2 roundtable on electricity in 1996. The reform program, has thus far succeeded in creating strong competition, especially in some states, and has brought significant price reductions and other benefits to consumers. However, despite these significant achievements, clearly as highlighted in this paper the reform process is not complete. In particular it seems that the introduction of full retail contestability and improved demand side participation are necessary to achieve a more fully functioning market. In addition in some areas of the NEM, stronger interconnection is essential to enhance competition. This issue is highlighting perceived deficiencies in the NEM's transmission network planning and pricing arrangements. COAG is currently conducting a review covering most aspects of future energy market directions and priorities, and it is expected that the review will address these market deficiencies.

APPENDIX 1

Market structure

Electricity Production and Fuel Mix

The market structure of each of the NEM jurisdictions and Tasmania is outlined in Attachment 1.¹³ It also indicates the generation capacity and fuel mix of generation.

Generation capacity across the NEM is approaching 40,000MW. Table 4 indicates the generation capacity in each of the NEM jurisdictions. New South Wales, Queensland and Victoria have the largest generation capacity. New South Wales and Victoria, the two most populous states in Australia, have also traditionally relied on capacity from the Snowy scheme¹⁴ to meet energy demand.

Table 4 – Generation Capacity in the NEM

	Generation Capacity (MW)	(As a % of NEM capacity)
New South Wales	12,436	30.4%
Victoria	8,441	20.6%
Queensland	10,264	25.1%
South Australia	3,483	8.5%
Tasmania	2,507	6.1%
Snowy	3,756	9.2%

Table 5 indicates NEM electricity generation capacity by fuel type. The continuing dominance of coal as a fuel source is due to its relative abundance and low cost. There are large deposits of coal relatively close to major population centres in New South Wales and Victoria. Power stations were built near coal deposits and supplied major load centres including large energy-intensive developments such as aluminium smelters. In Queensland and South Australia, coal deposits were located a long way away from major load centres. They were, however, still the lowest cost fuel options for these states. This drove the generation investment program in Queensland and, initially, in South Australia.

Table 5 – NEM Generation Capacity by Fuel Type

	Generation Capacity (MW)	(As a % of NEM capacity)
Coal	27,242	66.6%
Hydro	7,529	18.4%
Gas	5,504	13.5%
Other	612	1.5%

In South Australia, the discovery of natural gas in the Cooper Basin in 1963 made gas viable as a fuel for electricity generation. All subsequent generation in South Australia has been gas-fired, with the result that gas accounts for approximately 75 per cent of total South Australian capacity. South Australia is the only state where gas is the dominant fuel for generation. There is also gas plant in Victoria (1517MW) and Queensland (1085MW).

In Tasmania, almost all generation is hydro, while the Snowy is also a hydro scheme.

Structural reform

The extent of structural reform of the ESI has differed between jurisdictions but has generally involved the identification and separation of the more contestable segments of the industry (i.e. generation, retail) from the natural monopoly elements of the industry (i.e. transmission and distribution). In some jurisdictions structural reforms have also increased competition by splitting the various activities of the industry into separate competing companies (e.g. generation). In addition, a number of the generation and distribution companies have been privatised. These structural changes have often been accompanied by changes in the regulatory arrangements.

NEM Jurisdictions

Description of elements of the reform process undertaken in the NEM jurisdictions is outlined below.

Victoria

Historically, the State Electricity Commission of Victoria was responsible for most of the electricity generation, transmission and distribution networks in Victoria. Victoria was the first state in Australia to embark on a widespread electricity reform program. A review of the industry structure in 1993 resulted in the State owned generation, transmission and distribution businesses being split into six independent generating companies (Loy Yang A, Loy Yang B, Yallourn Energy, Hazelwood Power, Southern Hydro and Ecogen), five distribution businesses (United Energy, Solaris, Citipower, Powercor and Eastern Energy) and a transmission company (Powernet).

Starting in 1995, Victoria privatised all of these electricity assets. Subsequently, a number of the assets have been resold while in some instances distribution / retail businesses have been separated and elements on-sold. There has been some consolidation of interests at the distribution / retail level.

The Essential Services Commission (ESC) provides regulatory oversight of the ESI in Victoria.

New South Wales

In March 1996, the state-owned generation body, Pacific Power, had its generation portfolio split into three competing State-owned generators – Macquarie Generation; Delta Electricity and Pacific Power. All the transmission and distribution assets of Pacific Power were transferred to other entities. TransGrid is the Transmission Network Service Provider. At the distribution and retail levels, 25 electricity county councils were consolidated to form six distributors – Energy Australia, Integral Energy, Australian Inland Energy, North Power, Advance Energy, and Great Southern Energy. The latter three rural distributors subsequently merged to form Country Energy.

An independent regulator, the Independent Pricing and Regulatory Tribunal (IPART) provide regulatory oversight.

Queensland

In July 1997, the State owned generation body, AUSTA Electric, had its generation portfolio split into three competing State-owned generators –Stanwell; Tarong Energy and CS Energy. Further, the seven

regional electricity boards were corporatised and three retail corporations - Energex, Ergon Energy and Omega Energy- were created, based on aggregated distribution territories.

In March 1998, Ergon and Omega merged to enable them to compete more effectively with Energex and interstate retailers. In 1998, the six regional distribution corporations were merged to form Ergon Distribution.

The Queensland Competition Authority (QCA) has been established as an independent regulator.

South Australia

In South Australia, electricity generation, transmission and distribution were traditionally the responsibilities of the state owned Electricity Trust of South Australia (ETSA). With the advent of deregulation, the state government formed ETSA Corporation. The corporation was disaggregated between 1996 and 1998 into three separate generators, a transmission company, a distribution company and a retailer. All have subsequently been leased to private interests.

The South Australian Independent Industry Regulator (SAIIR) has been established as an independent ESI regulator.

Australian Capital Territory

In 1988, the functions of the power and water utilities were merged into a single government owned corporation, ACT Electricity and Water (ACTEW). ACTEW was corporatised in 1995.

In October 2000, ActewAGL was established as the first utility joint venture in Australia between a major private sector group and a government owned enterprise. It provides electricity, natural gas, water and sewerage services in the Australian Capital Territory.

Ownership of ActewAGL is shared equally between AGL and the ACTEW Corporation. ActewAGL is organised as two partnerships, one distribution and one retail.

The ACT has established an independent regulator, the Independent Competition and Regulatory Commission (ICARC) to oversee water and electricity tariffs.

Other States / Territories

There are three states / territories not connected to the NEM.

Tasmania

In July 1998, the Hydroelectric Corporation (HEC) was restructured to form separate generation, transmission (Transend Networks) and distribution / retail businesses (Aurora Energy).

Tasmania will join the NEM if the proposed Basslink interconnector, which will link Tasmania with Victoria, proceeds.

New regulatory arrangements have been put in place in Tasmania. The responsibility for the investigation of the pricing policies for Aurora, Transend and the HEC was transferred to an independent regulator, the Office of the Tasmanian Electricity Regulator in July 1998.

Western Australia

In Western Australia, the corporatised entity Western Power was formed in January 1995, when the former State Energy Commission of Western Australia was broken up into separate electricity and gas businesses - Western Power and Alinta Gas.

This corporatisation did not follow the structure followed in the other jurisdictions. It did not involve a vertical break up into separate generation, transmission and distribution/retail companies, or a horizontal break up of the generation and distribution/retail sectors. In Western Australia, Western Power retains responsibility for generation, transmission and distribution/retail.

Commencing in 1997, in order to promote competition between suppliers, access to Western Power's electricity transmission and distribution networks was progressively phased in. Under this regime, Western Power's largest customers are able to negotiate directly with the electricity supplier of their choice, subject to their existing contracts. However, new entrant generators have encountered significant difficulty in acquiring these customers.

A taskforce has been set up to conduct a review the structure of the Western Australian ESI.¹⁵ The review is to deliver recommendations to the Western Australian Government on:

- the design of a Western Australian electricity market;
- the extent and phasing of the division of Western Power into separate public enterprises;
- a Western Australian electricity Code; and
- arrangements for full retail contestability.

The taskforce's report is due later in 2002.

Northern Territory

In the Northern Territory, the ESI is characterised by a small and geographically dispersed load with minimal grid development. The Power and Water Authority primarily supplies electricity.

APPENDIX 2

Intra-regional constraints

Information on intra-regional constraints (congestion occurring within a region) can be found in NEMMCO's regional boundaries review, which was released in February 2002. Its report provides a summary of where the intra-regional constraints occur in the NEM.¹⁶

Table 6 – Intra-regional constraints in the NEM Victorian network constraints

Network connection	Hours of constraint
Latrobe Valley – Melbourne	Small
Northern Victoria – Melbourne	Small
Melbourne – Portland	Small
Portland – Eastern SA*	> 50 hours
Northern Victoria – Snowy*	> 50 hours

* indicates inter-regional network connections where higher constraint durations rate highly against the principles.

Snowy network constraints

Network connection	Hours of constraint
Snowy – Canberra*	Small
Snowy – Victoria*	> 50 hours
Snowy – Riverina*	Small

* indicates inter-regional network connections where higher constraint durations rate highly against the principles.

South Australian network constraints

Network connection	Hours of constraint
Adelaide – Northern SA	Small
Adelaide – Eastern SA	> 50 hours
Eastern SA – Portland*	>> 50 hours

* indicates inter-regional network connections where higher constraint durations rate highly against the principles.

NSW network constraints

Network connection	Hours of constraint
Sydney – Canberra	22 hours
Sydney – Western NSW	Small
Sydney – Hunter Valley	Small
Sydney – Central Coast	16 hours
Central Coast – Newcastle	Small
Newcastle – Hunter Valley. ¹⁷	Small
Hunter Valley – Northern NSW	Small
Hunter Valley – Western	Small
Western NSW – Marulan	Small
Northern NSW – Millmerran*	N/A – QNI commissioning
Canberra – Snowy*	Small
Snowy – Riverina*	Small

* indicates inter-regional network connections where higher constraint durations rate highly against the principles.

Queensland network constraints

Network connection	Hours of constraint
Tarong – Brisbane	> 50 hours
Central Queensland – Tarong	Small
Central Queensland – Brisbane	> 50 hours
Tarong – Millmerran	Small
Central Queensland – North Queensland	> 50 hours
Millmerran – North NSW*	N/A – QNI commissioning

* indicates inter-regional network connections where higher constraint durations rate highly against the principles.

APPENDIX 3

Competition law enforcement

The ACCC has considered a number of merger proposals in the electricity industry in the past four years. Victoria and South Australia are the only two Australian States to have fully privatised electricity sectors.

At the time that the Victorian government separated the functions of the previous state owned SECV the ACCC did not consider that the sale of these assets raised major competition issues, as cross ownership restrictions prohibited multiple acquisitions, and State-owned businesses were prohibited from bidding.

The South Australian electricity supply industry was privatised in 1999-2000 when 99 year leases over the assets held by three generation businesses, the single distribution network and the transmission network were sold. The retail business was also privatised. Owners of Victorian generators were the major bidders for the generation assets.

Since the initial sale of the Victorian and South Australian electricity assets, there have been a number of secondary sales. This has resulted in aggregation at the retail level, but not in generation. However, two US-based entities are both currently in the process of divesting their Australian generation interests.

To date, the major gas producers in south-eastern Australia have not acquired generation assets.

Table 7 summarises the relevant merger proposals considered by the ACCC.

ACCC Merger assessments

Date	Target assets	Acquirer	Outcome
1999	Ecogen Energy Privatisation of 966MW intermediate and peaking gas-fired plant in Victoria.	AES TransPower	<p>AES was a new entrant, and as such, did not raise issues. However, AES proposed to enter into associated long-term arrangements with TXU, which owned one of the incumbent retail and distribution businesses.</p> <p>The ACCC did not oppose AES's bid, or the associated contractual arrangements on the basis that other retailers would be able to secure suitable hedging products from the other five generation businesses.</p>
2000	Synergen Privatisation of 359 MW gas peaking plant in South Australia	International Power	<p>International Power had acquired one of the four coal-fired plants in Victoria, and was developing 487MW of CCGT capacity in South Australia.</p> <p>The ACCC did not oppose the acquisition as it was deemed that the Synergen plant was likely to complement that under construction. Furthermore, the addition of Synergen to International Power's portfolio of assets in South Australia and Victoria did not substantially change the structure of the generation sectors in those States.</p>
2000	Optima Energy Privatisation of 1280 MW gas-fired intermediate and peaking plant in South Australia.	TXU Australia	<p>TXU did not own any generation assets prior to this acquisition, although it had a long-term contract with the AES Ecogen plant in Victoria.</p> <p>The ACCC took the view that notwithstanding the relationship between AES and TXU, the acquisition did not significantly raise concentration levels in the Victorian and South Australian generation sectors so as to raise substantial competition concerns.</p>
2000	Flinders Power Privatisation of 940 MW baseload and peaking plant ¹⁸ in South Australia.	NRG	<p>NRG owned a 25% interest in Loy Yang Power, which is the largest of the Victorian coal-fired plants. Other bidders also held generation assets in Victoria.</p> <p>The ACCC did not oppose any bidders, for reasons similar to those outlined above in relation to the sale of Optima.</p>

Date	Target assets	Acquirer	Outcome
2000	Yallourn Energy Sale of 1450MW coal fired plant in Victoria.	China Light & Power	<p>China Light and Power was a new entrant.</p> <p>AES received clearance from the ACCC to acquire Yallourn Energy. This proposal was not opposed due to the relatively small increase in aggregation of generation assets and because of the existence of AES's contractual position with TXU.</p> <p>Another generator with assets in Victoria and South Australia also raised substantial competition issues. However, these issues were not fully considered by the ACCC as that party was not short-listed.</p>
2002	Flinders Power Sale of 940 MW plant in South Australia.	To be determined	<p>The ACCC has provided clearance to a number of parties with generation assets in Victoria to acquire Flinders Power. Assessment was similar to that originally undertaken in 2000.</p> <p>The ACCC opposed bids that raised significant competition concerns arising from vertical integration.</p>

APPENDIX 4

Summary of market power consultancy reports by bardak ventures and intelligent energy systems

Bardak Ventures Pty Ltd

Bardak Ventures Pty Ltd (Bardak) claimed that in the early period of the NEM, capacity was being physically withheld in South Australia and Queensland. Units were not being started up, and the capacity physically being offered to NEMMCO was generally sculpted to make sure that a tight balance was maintained between supply and demand.

By mid 2000, Bardak suggests that the practice of bidding large proportions of capacity in each Region at exceptionally high prices – typically \$4,000/MWh or above became prevalent, initially in NSW and then in the other States. This is what Bardak understands NECA to mean when they use the term “sleeper bids”.

Bardak contends that these types of bidding and rebidding practices now occur frequently in the NEM. Any underestimation of the demand by NEMMCO increases the probability of a fortuitous price spike occurring. Bardak considers this to be a direct form of economic withholding of capacity.

In early 2000 a new and more aggressive form of economic withholding began in Victoria. After first reducing the volume of capacity offered to the contract market, Loy Yang began to rebid large quantities of capacity from their normal price levels (less than \$20/MWh) to over \$4,000/MWh almost every day during the peak periods during the summer.

When the flow on the Snowy-Victoria interconnection exceeded approximately 1000MW, this rebidding was sufficient to constrain the line, separating the pool price in Victoria and South Australia from that of NSW, and leading to periods of very high prices as blocks of capacity which had been bid at high price levels in Victoria and South Australia were called upon to be loaded.

In early 2001 it was only Loy Yang which was rebidding capacity in the manner outlined above. However, later in the summer Loy Yang altered its approach, bidding blocks of capacity above \$4,000/MWh in the day-before offers and moving smaller blocks down to normal levels as the day progressed.

While Bardak does not draw any conclusions as to the reasons why Loy Yang altered its bidding pattern, it does speculate that the purpose of the strategy was to alert other generators that Loy Yang perceived an opportunity to generate high pool prices. Accordingly, rebidding by Hazelwood Power in Victoria, Macquarie Generation in NSW and NRG-Flinders in South Australia did have the affect of raising the pool price at various times.

Later in 2001, Bardak claims that several new players including AES, Yallourn Energy and Eraring Energy also joined Loy Yang, Hazelwood, Macquarie and NRG-Flinders in bidding and rebidding that resulted in price spikes.

Bardak states that this shows that as time goes on new techniques and strategies are developed and designed to raise pool prices and are adopted by more and more generators.

Conclusions

Bardak reached the following conclusions:

1. While physical withholding continues to take place in South Australia, Queensland and New South Wales, economic withholding of capacity has become the most common form of capacity withholding to create artificial price spikes unrelated to market dynamics or underlying cost structures.
2. A number of generators engage in this type of behaviour - including Loy Yang Power, Hazelwood Power and Yallourn Energy in Victoria; Macquarie Generation and Eraring Energy in New South Wales; each of the Queensland generators; NRG-Flinders, Optima Energy and Synergen in South Australia – the most aggressive being Loy Yang Power, Macquarie Generation and more recently Eraring Energy.
3. Bardak concludes that while in some high priced incidents examined, there is an initiating event, such as a loss of generator, interconnection limitations or exceptionally high load forecasts, the major factor contributing to the price spike is the bidding and rebidding practices of the generators.
4. The timing of rebids varies, sometimes capacity is rebid to higher cost bands very close to dispatch, allowing very little time for any competitive response. At other times, the initial bidding appears to serve the purpose of alerting other generators that one has seen an opportunity to raise the pool price – for example on the following day.
5. Given the number of rebids (NECA have reported an average of 800/day), their magnitude and their timing, there is little opportunity for a competitive response, by either another generator inclined to seek to counter the effect that the rebidding generator was seeking or a demand side response.
6. Bardak concluded that generator bidding and rebidding practices have a material effect on the average annual pool price. Using the year 2000 as an example, eliminating the 20 high priced events identified in the review reduced the NEM average annual pool price by \$912 million dollars or \$5.7/MWh, a reduction of 13 per cent.
7. While Bardak acknowledges that the generators behaviour always remains within the authorised rules of the NEC, the design of the NEM contains several features which, while intended to achieve other purposes in the main, greatly facilitate the exercise of market power. Where generators decide to make use of their market power the resultant effect is often higher pool prices than would normally be expected.

Intelligent Energy Systems

The conclusions drawn by Intelligent Energy Systems (IES) during its analysis of 29 high priced episodes, where spot prices reached \$1000/MWh in a trading interval were as follows:

1. Bidding and rebidding of generators to achieve extreme price levels has been the predominant cause of extreme prices in the NEM to date.
2. Generally, bidding and rebidding operates in two modes – “normal” and “extreme”. The extreme bidding is almost always triggered by a tightening of supply and demand within a

region or a group of regions due to either high loads, or to an outage or de-rating of a generator or inter-connector. The bidding and rebidding tends to greatly amplify the price outcomes from these conditions. However, the windows of opportunity for such behaviour are relatively narrow and have narrowed further in the past nine months, with new generation and inter-connection commissioned.

3. Bids that trigger high prices are often set early in the day by one or more generators. However, the trend of rising prices appears to encourage some other generators also to lock in that outcome by rebidding close to dispatch time with increased bids. As a counter to this, peaking plant tend to increase output greatly, thereby reducing the extent and duration of the market impact. This desirable and expected behaviour removes dispatch from the high-bidding generators and no doubt discourages them from bidding in this way except when supply and demand are in close balance.
4. Generators that have persistently used this tactic have sometimes lost 50 per cent or more of their dispatch, strongly suggesting that they were less than 50 per cent contracted at the time.
5. Persistent examples of this behaviour have been:
 - South Australian generators when the Victoria/SA link is de-rated due to lightning, a not infrequent occurrence;
 - Victorian and South Australian generators over the 2000-2001 summer, and especially in January and February 2001.
6. IES quantified the price impact of such behaviour in each region and each year since the start of the NEM. IES concluded that bidding and rebidding behaviour contributed about \$3-\$11/MWh to the annual pool price in recent times, depending on the region. This represents between 9 per cent and 26 per cent of the average energy price. While the impact has led to above new entrant prices in Queensland and South Australia for a time, there has since been new entry in those regions and the price effect has been lessening. IES consider that the price increment is consistent with that required to justify new reliability plant (gas turbines) in those regions where such plant is considered necessary.
7. While the analysis in IES's report clearly supports the view that generators can and do exert market power through limited windows of opportunity, the outcome has been a pattern of prices that is not inconsistent with what is required to maintain system reliability through the market.

NOTES

1. The material in this section draws primarily on NEMMCO, *2000-2001 Annual Report* and Salomon Smith Barney *The Australian Electricity Industry – June 1998*.
2. The IEA noted that “options to streamline and simplify regulatory policies and to improve co-ordination among regulatory bodies” need to be identified. International Energy Agency, *Energy Policies of IEA Countries – Australia 2001 Review*, OECD/IEA, Paris, 2001, p12.
3. This calculation may not represent the real price impact to end users as it does not take into account the volume of contracts. If contracted volume was at 90 per cent, only one tenth of the 13 per cent price rise would be retained by generators. However, price spikes and their frequency may influence forward contract prices.
4. At http://www.accc.gov.au/electric/authorisations/matters_under/rebidding/gen_nem.html.
5. The discussion on the supply and demand trends in the following paragraphs draws from NECA’s *The performance of the national electricity market*. This is available from NECA’s website at: <http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1086>
6. Some of the discussion on the development of interconnectors in the NEM draws from NECA’s *The performance of the national electricity market*. This is available from NECA’s website at: <http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1086>
7. Normal refers to a situation where the system is operating at full availability, while prior outage refers to a situation where elements of the system were out of service. (eg generator was off line)
8. <http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1044>
9. d-sypha is a subsidiary of Transpower Limited, the owner and operator of the New Zealand national electricity grid.
10. Further information on the new electricity futures product’s is available on the SFE’s website at <http://www.sfe.com.au/index.asp?dispage=/site/html/trading/products/intro.asp>
11. ETEF manages a retailer’s risk of purchasing wholesale electricity to meet its obligations to deliver regulated tariffs to small customers. Further information on the operation of ETEF is available at http://www.treasury.nsw.gov.au/pubs/trp00_4/etef.htm
12. A risk of between 3 and 7 hours of involuntary load shedding (that is net of voluntary demand side response) in the face of extreme demand conditions (10 per cent probability of exceedance) is a common international standard. NECA claims that reliability in Australia has often been better than this.
13. Generation capacity figures in Attachment 1, as well as in the following tables, are taken from NEMMCO’s *List of Generators and Scheduled Loads*. This is available from NEMMCO’s website at <http://www.nemmco.com.au/operating/participation/888.htm>. Some of the following discussion relies on

NECA's *The performance of the national electricity market*. This is available from NECA's website at: <http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1086>

14. The Snowy is a separate region in the NEM. The generation capacity in the Snowy is traded by Snowy Hydro Ltd., a self-supporting corporation jointly owned by the Commonwealth (13%), NSW (58%) and Victorian (29%) governments.
15. Further information on the Western Australian Electricity Reform Taskforce is available at <http://www.ertf.energy.wa.gov.au>
16. NEMMCO; *Regional Boundaries Review Volume II – Assessment*; February 2002. <http://www.nemmco.com.au/178-0029>
17. Flinders Power owns the Northern and Playford coal-fired power stations, as well as holding a long-term power purchase agreement with a 180 MW gas-fired station.

AUSTRIA

The Austrian parliament decided in 2000 to introduce a new legislation for the electricity market to become effective as of 1 October 2001 in order to liberalise the Austrian electricity market by 100 %.

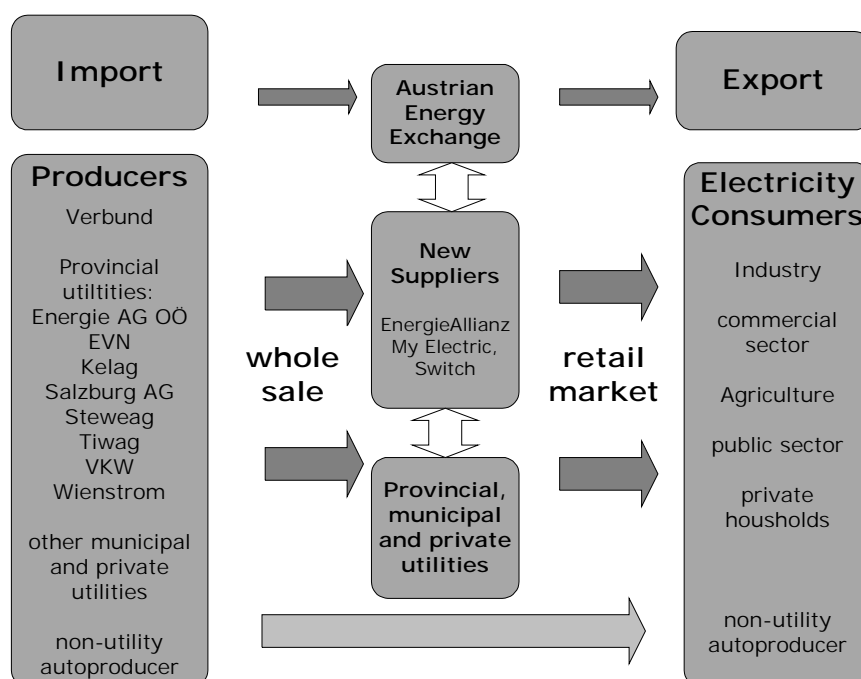
Liberalisation of the Austrian electricity market was accompanied by a reorganisation of the industry's regulatory authority whereas the Electricity-Control Ltd. (E-Control) and the Electricity-Control Commission were founded. The regulatory authorities began to work in March 2001. Their major objective has been to guide and overlook the market transition, to monitor the competition and to keep a close eye on network access and especially on network charges. Distributions fees are believed to be one of the highest in the EU and diverge strongly within the country making supply competition difficult. E-Control's first move was to cut back excessive tariffs and create price transparency.

The Structure of the Austrian Electricity Sector

Austria's electricity market has nearly 4 million customers (approximately 3 mill. households, 150,000 farms, 19,000 industrial and public sector customers and 730,000 other commercial customers). In 2000 the annual electricity consumption of customers served by public utilities amounted to 50.7 TWh and is projected to rise to 63.0 TWh by 2015 and 67.5 TWh by 2020¹. About 85 % of the electricity consumed in Austria is provided by public utilities, the remaining 15 % come from non-utility autoproducers. The annual consumption per inhabitant by 2000 came to 6,240 kWh. Electricity consumption is divided as follows: 35.5 % industry, 23.5 % households, 13.5 % commercial sector, 16.5 % public sector (incl. public transport) and 11 % losses, internal demand and pumped storage. Changes in annual power demand are mainly determined by weather conditions and economic growth.

Electricity generation is based on the so-called hydrothermal system producing 52,8 TWh in 2000 (excl. non-utility autoproducers). The most important energy resource is hydropower. On average over the last ten years about 70 % of the power was generated in hydro power plants. Thermal-power generation and power imports are used to balance the seasonal variations of demand (peak demand in winter) and water supply (minimum hydro power supply in winter). The most important fossil fuel is natural gas. The physical power imports usually come from Hungary, the Czech Republic and Germany. During the summer under normal weather conditions excess hydropower is generated and exported to Italy, Slovenia and Switzerland. In 2000 the net-exports (=exports minus imports) amounted to 2.69 % of domestic power consumption.

Figure 1: The Electricity Market in Austria



The Austrian electricity sector has traditionally consisted of vertically integrated and government-owned monopoly utilities whereas Verbund generates the vast majority of electricity which accounts for almost 50 %, followed by the provincial utilities with around 27 %, and other utilities and autoproducers. The Verbund is primarily running hydro power plants and operating the high voltage transmission network. Besides the nine provincial and four municipal utilities of the provincial capitals (Stadtwerke) there are another 150 small private utilities serving local customers (especially in the provinces of Styria and Upper Austria). The dominant distributors within the Austrian electricity supply industry are still the provincial utilities Wienstrom and EVN located in the eastern region of Austria. In general the Austrian electricity industry is still dominated by fully vertically integrated companies operating more or less on each level of the value chain.

The characteristic structure of the electricity industry – i.e. one strong utility mainly engaged in generation and transmission and several provincial and municipal utilities having their strength in distribution and supply – has both, political and historical reasons. In the course of post-war reconstruction, the parliament enacted a law concerning the nationalisation of the Austrian electricity companies (2nd Nationalisation Act) that requires either the state or the provinces to own a majority in each Austrian electricity company. The Austrian electricity industry has also been characterised by a division into regional markets where customers had no possibility of changing their local supplier. Pricing arrangements have not always been cost related and cross-subsidisation has occurred between different customer segments as well as between different public services offered by the provinces (e.g. public transport, district heating).

In August 2002 the parliament decided a new law regulating the promotion and maintenance of renewable energy as well as combined heat and power on a national wide basis. The Minister of economic affairs is responsible for setting minimum prices and tariffs in order to increase the share of renewable

energy up to 4 % of total consumption and the share of small-scale hydropower production up to 9 % of total consumption. By introducing a national wide solution also the transparency is improved.

Market structure

With the so-called EIWOG 2000 not only the market was fully liberalised by the 1 October 2001 but also regulatory authorities in the electricity sector have been set up for the regulation and monitoring the difficult development from a monopoly market to a fully liberalised electricity market with the primary objective to create a proper framework for an efficient supply of electricity. This framework should enable customers' choice, create market-based prices and foster long-term investment decisions. Beside the new regulatory bodies the Federal Ministry of Economic Affairs and Labour and the provincial governments have still certain regulatory competences. The Austrian government has opted for a system of regulated network access so that the network tariffs are published and fixed by the regulatory authorities.

By liberalising the market the value added chain was divided into monopolistic and competitive areas of operation. Whereas the distribution and transmission network remains due to the high fixed costs still a natural monopoly generation and the supply side have been opened to competition.

Besides strengthening the competition while taking into consideration the industry's public service obligations such as security of supply and environmental policy the Energie-Control Commission is also responsible for setting the price of the usage of the distribution and transmission. In 2003 a benchmark system will be implemented in order to set up incentives for distribution and transmission companies and to narrow the price differences between the network areas. Total reductions of nearly € 70 mill. have already been realised by the procedures for resetting system access charges.

The role of an effective unbundling in structuring competition in a fair and non-discriminatory way is well known. The EIWOG 2000 demands at least an organisational separation as well as a separation of the accounting of the distribution and transmission areas from the other business areas. E-Control will therefore create clear guidelines for separating generation, electricity trading, transmission, distribution and other activities and will also monitor compliance therewith.

Latest Developments

A characteristic element of the Austrian electricity sector is that public utilities hold complex cross-shareholdings in other utilities. That narrows management's room to manoeuvre because minority shareholders have substantial blocking rights under Austrian corporate law. The cross-shareholdings are mainly used not as defence against takeovers but instead as a mean to obstruct initiatives within the respective organisation.

Approximately four years ago there was the first attempt to found the so-called "Austrian Electricity Solution". Beside the state owned Verbund provincial utilities were supposed to merge or at least to cooperate in the area of the supply to industrial customers. Different perceptions of the management boards and of political leaders were at that time responsible for the failure of an overall Austrian electricity company.

Given the failed introduction of a nationwide solution, in 1999 Wienstrom und EVN started a supply cooperation to serve eligible customers. In the end of 2001 the cooperation was broadened (Wienenergie, EVN, Linz AG, and BEGAS/BEWAG; Energie AG joined the then established cooperation a couple of months later) and given the name "EnergieAllianz". This strategic alliance has successfully strengthened its dominant position in the consumer market in the Eastern control area. EnergieAllianz

launched a subsidiary company, which should compete against their existing brands, effectively discounting their regular deliveries to a no-frills service. In fact, this subsidiary did not really work the markets of its parent companies but went especially to other regions in Austria. EnergieAllianz also introduced a new-branded tariff program (*optima*) for small business and residential customers.

In 2001 Verbund and the German electricity enterprise E.ON started negotiations about merging their hydro power plants. Both companies were supposed to bring their hydro power plants into the newly created company (EHP - European Hydro Power). The EU commission and the German and the Austrian anti-trust authorities had already consented to the creation of EHP but finally the merger was not carried out because of other political interests.

Under this political pressure Verbund and the representatives of the major provincial utilities, especially the companies that are already working together in the EnergieAllianz, started again to negotiate about a new “Austrian Electricity Solution”. This time the negotiations succeeded and two companies will be created by merging parts of the parent companies. One of these companies will be a trading house, which will also coordinate the use of the common power plants. The other will supply electricity to industrial customers with an annual consumption of more than 4 GWh. The cooperation will probably be notified to the European Commission at the beginning of October 2002.

A cooperation like this would have a severe impact on the retail market. The companies involved are controlling the majority of the generation capacity and are the major suppliers of electricity in Austria. It can be expected that they will be successful in preventing foreign companies from getting into the supply market and that would harm long-term domestic supply competition. In general, the planned merger will create a new dominant undertaking in the Austrian electricity market. Further the parents companies are holding stakes of potential competitors.

Nevertheless, there is also a business rationale behind the planned merger. Verbund is the biggest generator in Austria (2001: 23,222 GWh), running mainly hydro power plants (low marginal costs of generation) but is not serving the supply market. On the other hand the provincial electricity companies are serving the supply market but do not have substantial generation capacities (they mainly have thermal power stations which produce at high marginal costs of generation) and have to rely on Verbund for a large percentage of their wholesale needs.

Through the “Austrian Electricity Solution”, the strategy of the provincial companies is to gain access to electricity generated by the hydro power plants of Verbund on a long-term basis and at the same time to prevent Verbund of gaining access to the supply market. IU is planned to buy exclusively the electricity produced by Verbund at wholesale price plus a “bonus” (1.1 €/MWh). In contrast, Verbund is trying to gain access to the market of final customers without being too much influenced by the interests of the provincial utilities. Beside the interests of the involved companies there is another driving force for the merger. In general the main purpose of the M&A activity and the creation of alliances in Austria is to increase the size in order to achieve the economies of scale needed to survive in the increasingly competitive European generation and supply markets.

In addition to cooperation between regional and/or national companies, municipal and provincial utilities also started to join forces (e.g. TIWAG and IKB, Stadtwerke Salzburg and SAFE, EStAG and Grazer Stadtwerke) in order to create synergy effects and thereby to increase their competitiveness. The creation of Salzburg AG has been the first successful merger of a former provincial and a former municipal utility. The main goal of the merger was to cut costs and to provide more comprehensive service packages to customers (e.g. multi utility).

As customers' switching is still modest, the sole possibility of foreign companies is to buy up existing utilities. However, one has to consider that due to the described situation above the majority in each Austrian electricity company has to be owned by either the state or the provinces. Unless this law is modified it is impossible to completely take over an Austrian electricity company at the moment. The mutual cross-shareholdings of the (public) utilities makes it even more difficult to buy shares of these utilities.

For many years partnerships between the Vorarlberger Illwerke and EnBW (Energie Baden-Württemberg) as well as the Tyrolian electricity company Tiwag and E.On have existed which is mainly due to the embedding of the Western control areas into the German control block. Beside the cooperation with German enterprises it can be expected that both Tiwag and VKW will remain independent at least for the medium term. Salzburg AG is seeking a foreign partner for its gas business at the moment.

The first foreign company (EdF) started to invest in 1998 and bought shares in the Styrian energy group EStAG. RWE acquired 49 % of Carinthia's Kärnten Energieholding, which controls the Kelag utility. The only company which is working in the Austrian market on its own is the German EnBW.

New suppliers

Although the first step of the market opening was taken in 1999 most of the new suppliers started their business with the full opening of the market in October 2001. Beside smaller companies like oekostrom AG and Alpen Adria Energie AG, which specialised in energy from renewables also incumbents launched new brands in order to attract residential and commercial customers.

Salzburg AG started a cooperation with Verbund (*My Electric*). Raiffeisen Ware Wasserkraft (RWA), a cooperation of Verbund and the farmers' supply federation promises hydropower to their customers. EnergieAllianz launched *switch* that will compete against their existing brands, effectively discounting their regular deliveries to a no-frills service. EnergieAllianz also introduced a new-branded tariff program (*optima*) for small business and residential customers. Under a simplified tariff structure the two biggest electricity companies in Styria pushed their *Select* brand to major industrial customers.

What can also be seen in Austria is - beside EnBW – the absence of foreign competitors. No foreign electricity company is serving residential customers. Foreign companies are concentrating their business on industrial customers, which are more attractive compared to small-scale business and domestic customers. It is far more expensive to gain market share in the residential customer market where cost-intensive marketing efforts are required than gaining industrial and commercial customers. Following its modest success in Germany, EnBW has decided not to introduce the widely known brand "Yello" in Austria. Although Kelag and ESTAG are not strong and big enough on their own to compete with the EnergieAllianz maybe RWE as well as EdF are able to stimulate the competition on the basis of their stakes in Kelag respectively Steweag. EdF might also increase its stake in EVN through EnBW and in ESTAG in the medium term.

Final Consumer

Prior to the liberalisation of Austria's electricity market the customers had no alternatives to their local supplier. So firstly, they had to gain experience as market participants in the rather complex field of the electric power market.

The new legislation (EIWOG 2000) comprises detailed instructions how suppliers have to specify their bills. In addition to legal requirements E-Control installed an electronic tariff calculator in the form of

an Internet application where users receive more comprehensive information than would be possible with conventional price comparisons (www.e-control.at).

Like in other European electricity markets, which liberalised fully, the switching rates are moderate in the beginning of the liberalisation among small-scale customers. Within the last year approx. 2 % - 50,000 customers – of residential customer and 11 % of the small business scale customers changed their supplier. A survey by OGM on behalf of E-Control shows that more than 8 % of residential customers are willing to change their supplier. In Sweden more than 20 % of residential and small industrial customers changed their supplier since the full opening of the market in 1996.

Congestion and Pricing of the Transmission Network

Totally, there are about 150 grid operators in Austria. But the ten largest operators – nine provincial utilities and APG – own 98.5 % of the transmission systems (380-kV, 220-kV, 110-kV-lines). APG owns some 92 % of the 380-kV- and 220-kV-lines, while about 80 % of the 100-kV-lines belong to the provincial utilities.

Permanent congestion occurs on the transmission line to Italy. Within the national borders the north south connection is often congested - mainly in winter due to generation of thermal power in the north, and a lack of generation in the south. In summer the appearance of congestion depends on the support of generation in the south due to congestion management measures.

Transmission Network operators are responsible for congestion management by law, but up to now no guidelines are defined for how to deal with congestion and congestion costs. In general generators currently do not get any refund of costs if they have to cut down or increase their generation due to congestion. Network operators have to make individual applications for getting accepted congestion costs.

Transmission prices are fixed and therefore not volatile, but prices differ within different areas (up to 15 areas depending on the voltage level). The pricing system gives no locational signals for new generation. Therefore generators have no incentive for efficient location decisions. Each generator with a capacity exceeding 1 MW pays a fee depending on the capacity for ancillary services but independent of its location.

Austria has signed the ETSO CBT agreement 2002 and therefore accepts the specified rules for cross-border trading.

Lines to the Czech Republic, Hungary and Slovenia are temporarily congested, depending on season and load flows pattern. On the interconnection lines capacity at peak time is rationed “pro rata”, an auction system is planned for the future.

Presently only the TSO has the ability to upgrade the transmission network. Electricity laws and grid code set the general conditions and technical requirements for building new transmission capacity.

Concerning entry there are no special rules, which encourage new entry into generation. Since the opening of the market there has been no new player entering the generation market.

Wholesale electricity markets

The unbundling in the electricity industry and the freedom of customers' choice has created a new market – the wholesale electricity market. The participants in this market are the generators, suppliers, traders, brokers and large-scale industrial customers.

In Austria electricity is traded in both, regulated (exchange) and unregulated (OTC) markets. There is no mandatory pool. The vast majority of the power produced by the generators are not traded, but directly passed on to the company owned energy marketing and supply units. Spot markets are rather used to optimise the integrated companies' energy portfolio.

The Energy Exchange Austria (EXAA) in Graz went alive on 21 March 2002 and operates a spot market with 24 single hour products for delivery next day (day-ahead). The electricity industry and the regional government mainly own the venture. The market process and the product specifications are very similar to those of the LPX (now EEX) in Leipzig, Germany. EXAA does not operate any futures market at the moment, but at least plans to do so sometime in the future.

Trading volumes has not been really catching up; the exchange has some 1 % market share (approx. 0.5 TWh/y). Austrian market prices strongly correlate with German and Swiss (Central European) wholesale prices, since there are no serious transmission constraints between these countries. As German trading volumes in absolute terms are by far larger than Austrian exchange traded volumes we would at present certainly consider EEX as the Central European spot benchmark. OTC markets basically follow the exchanges and are regularly assessed by price reporters, such as Platts.

In terms of wholesale trading Austria is largely integrated into the Central European electricity market. Austrian generators and traders on their own have not in general enough market power to influence prevailing market prices. Those prices are set by market forces and are not regulated by Austrian authorities. Indications – if any – for gaming and abuse of market power come rather from very large (German) market participants.

Bilateral, Long-Term and Forward Contracts

Forward markets – just like OTC spot markets - are not regulated. Market participants are free to enter into long term, forward contracts. There are no separate Austrian forward quotations, German OTC numbers are widely accepted as benchmarks.

There are also no financial futures contracts organised by EXAA. Market participants looking for hedging their exposures are free to do so on the EEX in Germany.

Competition Law Enforcement

In 2002 the Austrian competition law was reformed substantially. Since then, E-Control is allowed to take up different competition law matters (e.g. the examination of cartels or vertical agreements in the energy sector). In other cases, like the examination of mergers, E-Control is dependent on the cooperation of the independent Federal Competition Authority (*Bundswettbewerbsbehörde*) and the "Public Prosecutor in Cartel Matters" (*Bundeskartellanwalt*). In reality, the two newly established authorities usually rely on the expertise of the regulatory authority to clarify whether to take up a merger case. In addition, the regulatory authority has the possibility to deliver opinions to the Cartel Court. Beside the general competition law, E-Control is responsible for supervising the energy markets, especially in order to prevent discriminatory treatment through the incumbents.

Conclusion

Often the deregulation of markets leads to expectations that greater efficiency and lower prices are achieved automatically. However most of these expectations are not based on market considerations and the conditions necessary for competition to function effectively. When evaluating the achievements and effects of the liberalisation of the electricity market this has to be considered.

One major aim of the deregulation and liberalisation of the electricity market in Austria was to foster competition on the market to the benefit of all customers. After one year of full market liberalisation a first evaluation can be made. When measuring the success of liberalisation beside changes in prices also the behaviour of the electricity companies as well as of the end customers have to be considered.

Prices for electricity (up to 10 % for residential customers, up to 50 % for industrial customers) and the use of transmission network (up to 17 % depending on the network area) have decreased essentially over the last year, although taxes and other levies (e.g. renewable energy charges, charge for CHP) compensated partly the liberalisation gains. It also has to be considered that electricity companies reduced their energy price before full liberalisation started. Therefore not only the last year has to be taken into account when evaluating the liberalisation effects on energy prices.

In order to orientate the pricing of networks more with real costs E-Control will implement a benchmark system next year. This will also help to stimulate competition by an increasing transparency of network charges and decreasing network tariffs.

It is difficult to predict how prices and competition in different customer segments will develop in the near future in particular when a market has been a regulated monopoly for a very long time. Above all due to the fact that Austria is in a common price area with the German and Swiss wholesale market and only one foreign supplier – EnBW – has still a subsidiary in Austria which shows that either the Austrian market is not attractive at the moment as a whole or the electricity price is too low in order to enter the Austrian electricity market successfully. Further one cannot predict how the concentration of the Austrian electricity market will effect the competition in the electricity market and in the final electricity prices.

A comprehensive evaluation of the first year with a full liberalised electricity market will be finished within the next weeks and will be published as a working paper on the homepage of E-Control (www.e-control.at).

NOTES

1. Projection made by the Austrian Institute of Economic Research

BELGIQUE

Ce document répond au questionnaire de l'OCDE WP2 Roundtable on Competition Issues in the Electricity Sector.

Remarque: les réponses ne sont pas toujours dans l'ordre du questionnaire étant donné qu'elles proviennent d'un document rédigé pour la Commission des CE par la CREG (organe régulateur). Néanmoins les renseignements demandés y figurent.

Schéma de correspondance entre les réponses faites au questionnaire DGTREN et au questionnaire OCDE

1. Overview of Regulation

- A. informations générales : basic structure of the electricity sector in Belgium, implementation of the Directive, particular developments in Belgium
- F. structure du marché : the total generation capacity, the different primary fuel sources, who are the key players in the generation market
- I. questions environnementales : environmental policies affecting electricity
- C. marchés de gros et équilibrage : is there an established market or pool in wholesale electricity
- D. autorité de regulation : what is the nature of the regulatory authority, does the regulatory authority have powers to intervene to collect information and set prices ?

2. Market Structure

- F. structure du marché : who are the key players in the generation market
- H. questions transfrontalières : how important are imports from other regions
- A. informations générales : is there an integration between generation and transmission
- D. autorité de regulation : is there an integration between generation and transmission

3. Congestion and Pricing of the Transmission Network

- H. questions transfrontalières : are there special rules governing import/export transmission lines, are these lines congested, do you auction the capacity of these links, which firm(s) have the ability to upgrade the transmission network to relieve congestion
- B. accès au réseau : how do you price access to the transmission network

4. Market Rules

C. marchés de gros et équilibrage

5. Bilateral, Long-Term and Forward Contracts

C. marchés de gros et équilibrage

6. Price or Quantity Controls

b. accès au réseau : are wholesale electricity prices set through a market mechanism or through regulation

7. Entry

c. marchés de gros et équilibrage : are there special rules which encourage new entry into generation

f. structure du marché

i. questions environnementales

A. Informations générales

Cette partie est destinée à collecter des informations générales sur la structure du marché de l'électricité et le cadre réglementaire actuellement applicable au secteur.

1. *Quelle est la consommation annuelle d'électricité en TWh? Quelle est la consommation de pointe en GW?*

La consommation nette en 2001 s'élevait à 79.818,7 GWh (chiffre provisoire arrêté en juillet 2002)

La pointe de consommation de l'année 2001 a été de 12.953 MW (mercredi 17 janvier, 17h45-18h)

2. *Ouverture du marché: quel est le calendrier actuel en termes de seuils d'éligibilité, de nombre de clients éligibles (au cours des premières étapes) et de consommateurs éligibles en pourcentage de la consommation totale (approximativement)?*

Au niveau fédéral (transport), les clients finals consommant plus de 20 GWh par an (par site de consommation et autoproduction comprise) sont éligibles depuis le 31 décembre 2000 et les clients finals consommant plus de 10 GWh par an seront éligibles à partir du 31 décembre 2002 (voir article 16 de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité ; ci-après : loi électricité, telle que mise en œuvre par l'arrêté royal du 11 octobre 2000 déclarant éligibles d'autres catégories de clients finals). L'ensemble des clients raccordés au réseau de transport seront éligibles au plus tard le 31 décembre 2006.

Au niveau régional (transport local et distribution), la situation se présente comme suit :

- en région flamande, sont éligibles depuis janvier 2002, les clients finals consommant plus de 1 GWh par an; à partir de janvier 2003, seront éligibles les clients finals ayant une

puissance de raccordement supérieur à 56 kVA; en juillet 2003, l'ensemble de la clientèle sera éligible;

- en région wallonne et dans la région de Bruxelles-Capitale, sont éligibles les clients finals consommant plus de 20 GWh par an; à partir de janvier 2003, les clients consommant plus de 10 GWh par an seront éligibles; à partir de janvier 2005, l'ensemble de la clientèle haute tension sera éligible; dans la région de Bruxelles-Capitale, tous les clients basse tension seront éligibles en janvier 2007; en région wallonne, la date d'éligibilité de la clientèle basse tension doit encore être déterminée par le Gouvernement .

Les clients consommant plus de 20 GWh par an représentent environ 42 % de la consommation totale du pays. De plus amples informations concernant la situation des clients éligibles en 2001 figurent au point F. 11.

3. *Quelles sont les procédures applicables aux nouvelles installations de production, aux appels d'offres et aux autorisations (licences)?*

L'établissement de nouvelles installations de production d'électricité est soumis tantôt à l'octroi préalable d'une autorisation individuelle délivrée par le ministre sur proposition de la CREG (article 4 de la loi électricité) tantôt à l'octroi d'une concession domaniale également délivrée par le ministre sur proposition de la CREG (article 6). La procédure d'octroi de la concession est prévue lorsqu'il s'agit d'installation de production d'électricité à partir de l'eau, des courants ou des vents dans les espaces marins sur lesquels la Belgique peut exercer sa juridiction conformément au droit maritime international.

La procédure d'octroi de l'autorisation prévue à l'article 4 de la loi électricité est décrite à l'arrêté royal du 11 octobre 2000 relatif à l'octroi des autorisations individuelles couvrant l'établissement d'installations de production d'électricité (Moniteur belge, 1^{er} novembre 2000). La procédure d'octroi de la concession prévue à l'article 6 de la loi électricité est décrite à l'arrêté royal du 20 décembre 2000 relatif aux conditions et à la procédure d'octroi des concessions domaniales pour la construction et l'exploitation d'installations de production d'électricité à partir de l'eau, des courants ou des vents, dans les espaces marins sur lesquels la Belgique peut exercer sa juridiction conformément au droit international de la mer (Moniteur belge, 30 décembre 2000). En dépit de sa qualification qui évoque une relation contractuelle entre l'autorité et le demandeur, la « concession domaniale » qui est organisée en droit belge constitue une autorisation unilatérale.

4. *Quelles sont les principales entreprises de production? Quelles est leur structure de propriété?*

Les principales entreprises de production sont : ELECTRABEL, producteur privé (société anonyme), et SPE, producteur public (société anonyme).

5. *Comment l'accès au réseau est-il organisé: ATR réglementé ou négocié?*

Depuis le début, la Belgique a soumis l'accès des tiers au réseau à des conditions d'accès fixées à l'avance par voie réglementaire (voir articles 11 et 12 de la loi électricité). La règle applicable est donc celle d'un ATR réglementé. Cependant, les conditions commerciales d'accès au réseau de transport sont négociées pour les contrats portant sur des « transits d'électricité entre grands réseaux » et, le cas échéant, à titre de dérogation facultative, pour les contrats portant sur le transport de grands volumes d'électricité qui répondent aux critères

fixés par le Roi (article 15, §3, de la loi électricité). Le Roi n'a pas fait usage, à ce jour, de cette habilitation.

6. Combien de réseaux de transport existe-t-il? Quels en sont les propriétaires? Le propriétaire de réseau est-il le même que le gestionnaire de réseau?

Il existe un seul réseau de transport d'électricité. Actuellement, c'est la société ELIA ASSET, filiale de ELIA SYSTEM OPERATOR (ESO), qui est propriétaire du réseau de transport. La société ESO est candidate à la désignation du gestionnaire du réseau de transport.

7. Quelles sont les règles en matière de séparation des réseaux de transport (comptabilité, gestion, juridique ou propriété)? Les comptes séparés sont-ils publiés? Qui y a accès?

Le gestionnaire du réseau de transport doit être une société distincte qui s'occupe exclusivement de l'exploitation, de l'entretien et du développement du réseau de transport. Il ne peut s'engager dans des activités de production ou de vente d'électricité autres que les ventes nécessitées par son activité de coordination en tant que gestionnaire du réseau. Il ne peut détenir, directement ou indirectement, des droits associés dans des distributeurs, producteurs ou intermédiaires (article 9, §1^{er}, de la loi électricité).

La loi du 17 juillet 1975 relative à la comptabilité et aux comptes annuels des entreprises et ses arrêtés d'exécution, ainsi que les articles 64 à 66, 77 (à l'exception de son sixième alinéa), 80, 80bis et 177bis des lois coordonnées sur les sociétés commerciales sont applicables au gestionnaire du réseau de transport et aux gestionnaires des réseaux de distribution, producteurs, distributeurs et intermédiaires qui sont des sociétés ou organismes de droit belge. Les comptes annuels de ces entreprises indiquent, dans leur annexe, toutes opérations significatives effectuées avec des entreprises liées ou associées au cours de l'exercice en cause (article 22, §1^{er}, de la loi électricité).

Les entreprises susvisées tiennent, dans leur comptabilité interne, des comptes séparés pour leurs activités de production, de transport et de distribution et, le cas échéant, pour l'ensemble de leurs activités en dehors du secteur de l'électricité, de la même façon que si ces activités étaient exercées par des entreprises juridiquement distinctes (article 22, §2, alinéa 1^{er}, de la loi électricité).

La CREG a la possibilité de prescrire aux entreprises visées plus haut de lui transmettre périodiquement des informations chiffrées ou descriptives concernant leurs comptes séparés. La CREG a également la possibilité d'autoriser les entreprises évoquées plus haut à ne pas publier des données de comptabilité analytique dont l'entreprise concernée démontre que la divulgation est susceptible de porter préjudice à sa position concurrentielle (article 22, §3, de la loi électricité).

Les comptes des entreprises susvisées sont soumises en matière de publication aux règles prévues par les articles 80, 80bis et 177bis précités: dépôt des comptes à la Banque nationale de Belgique, mention du dépôt aux annexes du Moniteur belge et délivrance, à ceux qui en font la demande, de copies des documents déposés.

8. Combien de réseaux de distribution locaux existe-t-il et combien de clients sont desservis par chacun d'eux? Quelle est la structure de propriété?

Actuellement, il existe 33 réseaux de distribution locaux. En annexe figure la liste de ces réseaux de distribution et le nombre de clients desservis par chacun d'eux.

La structure des entreprises de distribution était jusqu'à présent la suivante:

- régie: propriété communale;
- intercommunale pure: société coopérative à responsabilité limitée avec comme associés uniquement des partenaires publics (communes, provinces);
- intercommunale mixte: société coopérative à responsabilité limitée avec pour associés des partenaires publics (communes) et un partenaire privé (Electrabel).

Conformément aux nouvelles dispositions décrétales transposant la directive 96/92/CE en matière de transport local et de distribution (décrets du 17 juillet 2000 et du 12 avril 2001 ainsi qu'ordonnance du 19 juillet 2001), la gestion d'un réseau de distribution ne peut plus être assurée que par une entité indépendante vis-à-vis des producteurs, fournisseurs et intermédiaires. Les gestionnaires des réseaux de distribution ont pour mission essentielle d'assurer l'exploitation, l'entretien et le développement du réseau. Ils ne peuvent se livrer à aucune activité de fourniture en faveur des clients éligibles. Ils peuvent prendre la forme d'une intercommunale ou celle d'une société, les règles en la matière diffèrent selon les régions.

B. Accès au réseau

Cette partie porte sur les tarifs d'accès aux réseaux de transport et de distribution.

1. Veuillez fournir les documents les plus récents sur les tarifs de transport et/ou l'adresse internet où ils sont publiés.

Après la désignation du gestionnaire du réseau de transport, les tarifs d'accès au réseau de transport seront soumis à l'approbation du régulateur. Aujourd'hui, en l'absence de gestionnaire du réseau de transport désigné, l'accès au réseau est de type accès de tiers négocié et l'opérateur du réseau (Elia) a publié sur le site internet www.elia.be un barème provisoire, c'est-à-dire des prix indicatifs, pour cet accès au réseau de transport.

2. Veuillez fournir des exemples de tarif de transport (en €/MWh) pour les clients types (voir annexe).

Le barème provisoire proposé par l'opérateur du réseau ELIA comprend une formule de souscription de puissance sur base annuelle et sur base mensuelle. Ces deux formes de souscription peuvent être combinées permettant ainsi au client d'adapter sa souscription totale de puissance aux besoins de son processus industriel au cours du temps. Dès lors que cette information temporelle n'est pas communiquée dans l'exemple type pour un grand client industriel, un prix moyen ne peut être valablement déterminé. Les autres clients types repris à l'annexe ne font pas partie du type de clientèle raccordée au réseau de transport belge.

3. Quand le régime tarifaire a-t-il été modifié en dernier lieu? Quand la prochaine modification aura-t-elle lieu?

En ce qui concerne les accès aux réseaux de transport et de distribution, le régime tarifaire est en cours d'élaboration. Les textes réglementaires actuellement disponibles à ce sujet sont :

- la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité, notamment l'article 12 relatif aux tarifs de raccordement au réseau de transport, d'utilisation de celui-ci, et aux tarifs des services auxiliaires fournis par le gestionnaire du réseau ;
- l'arrêté royal du 4 avril 2001 relatif à la structure tarifaire générale et aux principes de base et procédures en matière de tarifs et de comptabilité du gestionnaire de réseau national de transport d'électricité;
- l'arrêté royal du 11 juillet 2002 relatif à la structure tarifaire générale et aux principes de base et procédures en matière de tarifs de raccordement aux réseaux de distribution et d'utilisation de ceux-ci, de services auxiliaires fournis par les gestionnaires de ces réseaux et en matière de comptabilité des gestionnaires des réseaux de distribution d'électricité.

4. *Comment les problèmes de congestion sont-ils abordés à l'intérieur du réseau national? Existe-t-il des tarifs spéciaux en cas de congestion?*

Les mesures prises en matière de gestion des congestions à l'intérieur du réseau national (mesures préventives et mesures curatives) consistent essentiellement en :

- des modifications de la topologie d'exploitation du réseau ; et
- du redispatching du plan de production à l'intérieur du pays. Cette dernière mesure constitue l'un des services achetés par le gestionnaire du réseau auprès des acteurs de marché.

Les coûts ainsi à charge du gestionnaire du réseau sont répercutés actuellement dans la composante du barème qui est proportionnelle à l'énergie. La future structure tarifaire prévoit un « prix pour levée des congestions ». Ce prix s'appliquera à l'énergie prélevée et est une des composantes du « prix pour services système ».

5. *Veillez fournir les documents les plus récents sur les tarifs de distribution et/ou l'adresse internet où ils sont publiés.*

En ce qui concerne les réseaux 70 kV, 36 kV et 30 kV gérés par l'opérateur du réseau Elia, des prix indicatifs d'accès à ces réseaux sont publiés sur le site internet www.elia.be. Ces barèmes provisoires ont été établis dans l'attente de l'approbation par le régulateur des tarifs proposés par les gestionnaires des réseaux de distribution.

6. *Veillez fournir des exemples de tarif de distribution (en €/MWh) pour les clients types (voir annexe). S'il existe un grand nombre d'entreprises, il convient de collecter les données pour les grandes villes et de fournir une moyenne estimée.*

Les clients types repris à l'annexe ne font pas partie du type de clientèle raccordée au réseau de distribution géré par l'opérateur du réseau Elia. En effet, ce réseau se limite aux réseaux 70 kV, 36 kV et 30 kV et aux transformations vers la Moyenne Tension. Les clients types repris à l'annexe sont des clients des gestionnaires de réseaux de distribution ayant en charge les réseaux dont la tension d'exploitation est inférieure à 20 kV et dont les tarifs de raccordement et d'utilisation doivent encore être approuvés par le régulateur.

7. *Comment les redevances de transport et de distribution interagissent-elles? Sont-elles cumulatives ou les redevances de distribution locales sont-elles déjà incluses dans le prix payé aux réseaux de transport?*

En ce qui concerne les réseaux gérés par l'opérateur du réseau Elia, les prix indicatifs relatifs aux prélèvements en 70 kV, 36 kV ou 30 kV contiennent la composante « transport ». En d'autres termes, ces prix indicatifs couvrent également l'utilisation des réseaux 380 kV, 220 kV et 150 kV, ainsi que des transformations 220/70, 150/70, etc...

8. *Une partie de la redevance de distribution ou de transport constitue-t-elle un prélèvement contribuant à l'aide à la production à partir de sources d'énergie renouvelables ou à la PCCE, compensation pour coûts échoués, aux mesures en matière de sécurité d'approvisionnement, etc.? Si oui, dans quelle proportion?*

Le barème provisoire pour accès au réseau Elia reprend des prix indicatifs pour utilisation de ce réseau. A ces prix, s'ajoute une surcharge (augmentée d'un complément), relative au financement des frais de fonctionnement de la Commission de Régulation de l'Electricité et du Gaz. L'existence de cette surcharge a été prévue dans l'Arrêté Royal du 18 janvier 2001, modifié par l'Arrêté Royal du 14 mars 2002. Pour l'année 2001, le montant de la surcharge et de son complément s'élevait à environ 4% du prix pour services système.

D'autre part, diverses dispositions légales, décrétales ou réglementaires prévoient l'instauration de redevances et surcharges à appliquer aux tarifs d'utilisation des réseaux de transport et de distribution, tarifs qui seront soumis à l'approbation du régulateur.

Parmi les éléments qui pourraient donner lieu à de nouvelles redevances ou surcharges, citons (liste non exhaustive) :

- une redevance sur les tarifs d'utilisation du réseau de transport local, destinée à alimenter le « Fonds Energie » en Région Wallonne. Ce fonds est destiné au financement de la politique de promotion des sources d'énergie renouvelables et d'utilisation rationnelle de l'énergie ainsi que les obligations relatives à la protection de l'environnement ;
- une redevance sur les tarifs d'utilisation du réseau de transport local, destinée à alimenter le « Fonds Social » en Région Wallonne. Ce fonds est destiné au financement de la politique sociale adoptée dans le domaine de l'énergie ;
- l'accomplissement gratuit pour l'utilisateur du réseau de toutes les tâches liées à la distribution d'énergie écologique, en Région Flamande ;
- la fourniture gratuite d'une quantité d'électricité à la clientèle résidentielle, en Région Flamande ;
- la répartition des excédents d'autoproduction, en Région de Bruxelles-Capitale.

9. *Quels sont les tarifs et conditions pour les producteurs intégrés et les autoproducteurs, c'est-à-dire ceux qui sont raccordés uniquement au réseau de distribution? Le cas échéant, quelles incitations existe-t-il pour ces types de producteurs?*

Diverses dispositions légales, décrétales ou réglementaires prévoient des dispositions spécifiques à certains types d'unités de production, afin de promouvoir l'utilisation de ces moyens de production. Parmi ces éléments, citons (liste non exhaustive) :

- l'application, aux tarifs d'utilisation des réseaux 380 kV à 20 kV, de réductions pour les unités d'autoproduction et les unités de production utilisant des sources d'énergie renouvelables de prédictibilité limitée ;
- l'introduction d'une plage de tolérance relative à l'équilibre, pour les unités de production utilisant des sources d'énergie renouvelables et les unités de cogénération ;
- l'accomplissement gratuit pour l'utilisateur du réseau de toutes les tâches liées à la distribution d'énergie écologique, en Région Flamande ;
- des dispositions spécifiques en vue de la promotion de l'électricité verte, en Région Wallonne.

C. Marchés de gros et équilibrage

Dans cette partie, il s'agit de donner une description de la structure du marché de gros de l'électricité dans l'État membre concerné, ainsi que du marché d'équilibrage. Les pouvoirs dont disposent les organismes de régulation pour intervenir sur ces marchés présentent également un intérêt.

1. Dans la liste suivante, veuillez indiquer comment l'électricité est achetée et vendue sur le marché de gros.

- Le producteur vend directement l'électricité au fournisseur affilié, sans contrat? Non.
- Contrats bilatéraux entre fournisseurs/producteurs (différentes périodes) ? Situation belge
- Bourse de l'électricité avec contrats bilatéraux normalisés ? Non.
- Système de pool/acheteur unique avec contrats pour les différences de marché ("Contracts for Differences") ? Non

Dans quelles proportions ces différentes formes de commerce de l'électricité ont-elles lieu?

Quelle est la durée d'un contrat bilatéral normal? Durée variable mais généralement à long terme

S'il existe un pool, est-il obligatoire ou facultatif? Il n'existe pas de pool en Belgique.

2. Comment l'équilibrage est-il organisé? Les coûts d'équilibrage sont-ils répercutés sur tous les utilisateurs ou existe-t-il des redevances d'équilibrage pour ceux qui sont en déséquilibre?

L'opérateur du réseau ELIA surveille, maintient et, le cas échéant, rétablit à tout moment l'équilibre entre l'offre et la demande de la puissance électrique dans la zone de réglage, entre autres suite à d'éventuels déséquilibres individuels provoqués par les différents responsables d'accès conformément aux règles de l'UCPTE. L'opérateur du réseau Elia réalise ex-post le

bilan énergétique de chaque responsable d'accès par période de 15 minutes. Pour chaque quart d'heure, l'opérateur du réseau ELIA affiche un tarif pour l'énergie de compensation qu'elle fournit ainsi qu'un tarif pour l'énergie excédentaire qu'elle absorbe. Ce tarif s'applique à chaque responsable d'accès; il est fonction de l'amplitude du déséquilibre, de sa récurrence, de la saison, de la période du jour et des prix pratiqués au même moment sur les bourses du marché de l'électricité. A une échéance plus courte que 15 minutes, l'opérateur du réseau ELIA maintient l'équilibre de sa zone de réglage en achetant des services auxiliaires tels que prévu dans l'arrêté royal précité du 4 avril 2001. Les coûts associés à ces achats sont répercutés dans le barème provisoire proportionnel à l'énergie prélevée. L'organisation de la compensation des déséquilibres est décrite par l'arrêté royal du 27 juin 2001 établissant un règlement technique pour la gestion du réseau de transport et l'accès à celui-ci, et plus particulièrement par ses articles 157, 158, 159 et 160. Cet arrêté royal, dont notamment lesdits articles, sera modifié prochainement.

Les redevances d'équilibrage sont-elles fixées dans un cadre de marché ou par le GRT/régulateur?

L'arrêté royal du 27 juin 2001 établissant un règlement technique pour la gestion du réseau de transport de l'électricité et l'accès à celui-ci prévoit que le gestionnaire de réseau met en place la compensation des déséquilibres quart-horaire selon des procédures reposant sur les règles du marché (art. 232).

Le projet d'arrêté royal modificatif prévoit que le gestionnaire du réseau doit acquérir la réserve nécessaire à la compensation des déséquilibres quart-horaire sur un marché des réserves (art. 159), auquel les producteurs dont la puissance pour l'accès au réseau est supérieure à 75 MW participent en remettant une offre de prix. Cet article 159 prévoit également que les règles de fonctionnement de ce marché doivent être approuvées par le régulateur.

S'il n'existe pas de marché d'équilibrage, à qui le GRT achète-t-il le courant d'équilibrage et comment les tarifs d'équilibrage sont-ils fixés?

Actuellement, ce marché des réserves n'existe pas encore. L'opérateur du réseau ELIA acquiert cette réserve auprès des producteurs. Les prix du déséquilibre sont fixés par ELIA. Ces prix sont publiés chaque jour pour le jour précédent et sont basés sur les prix observés sur les bourses d'Amsterdam et de Paris.

Quelle est la période d'équilibrage et de règlement (par exemple, 1 heure, 1/2 heure)?

L'article 157 du règlement technique prévoit que le réglage secondaire se fait sur base quart-horaire.

Quels mécanismes existe-t-il pour veiller à ce que le marché de gros et le marché d'équilibrage ne soient pas manipulés?

L'arrêté royal précité du 27 juin 2001 ne prévoit pas de mécanisme particulier. Les barèmes fixés actuellement par l'opérateur de réseau ELIA pour un déséquilibre négatif (injection inférieure au prélèvement) ou positif (le processus inverse) sont liés à l'évolution des prix sur les bourses d'électricité des Pays-Bas (APX) et de la France (Powernext).

Le projet d'arrêté royal modificatif prévoit que le gestionnaire du réseau devra publier chaque jour au moins les prix des déséquilibres de la veille. Ledit projet oblige également les unités

de production de plus de 75 MW à remettre une offre de prix pour la fourniture de l'énergie d'équilibrage. Cette mesure permettra d'élargir les moyens appelables par le gestionnaire du réseau pour effectuer l'équilibrage de la zone de réglage.

3. *De quels pouvoirs l'autorité de régulation dispose-t-elle pour intervenir sur le marché d'équilibrage (ou le marché de gros en général), par exemple pour fixer des prix plafonds?*

Le régulateur dispose du pouvoir d'approbation des tarifs proposés par le gestionnaire du réseau de transport, en ce compris le tarif pour la compensation des déséquilibres.

A long terme, si le régulateur constate que les demandes d'autorisation de nouvelles installations de production d'électricité sont insuffisantes par rapport aux moyens de production préconisés par le programme indicatif, elle peut, avec l'accord du ministre, publier un avis dans ce sens dans la presse nationale et internationale. (Art. 5 de la loi électricité)

D. Autorité de régulation

Cette partie concerne le statut, les responsabilités et les ressources de l'autorité de régulation du secteur de l'électricité.

1. *Qui approuve les tarifs ou la méthode de calcul des tarifs: l'autorité de régulation ou le ministère?*

Les tarifs de raccordement aux réseaux de transport et de distribution sont approuvés par le régulateur fédéral, la CREG, sur proposition des gestionnaires des réseaux concernés.

2. *Qui règle les litiges concernant l'accès aux réseaux?*

Au niveau fédéral:

Les litiges concernant l'accès au réseau de transport d'électricité sont de la compétence du service de conciliation et d'arbitrage, prévu par l'article 28 de la loi électricité. Le règlement qui doit mettre en œuvre cette disposition est soumis actuellement pour avis au Conseil d'Etat.

Les différends relatifs à l'accès au réseau de transport, autres que ceux portant sur des droits et obligations contractuels, peuvent être soumis à la Chambres de litiges, prévue par l'article 29 de la loi électricité. Les règles de procédure de cette juridiction administrative sont déterminées par un arrêté royal du 16 novembre 2001.

Ces deux organes sont institués auprès de la CREG.

Au niveau régional

Les décrets du 17 juillet 2000 et du 12 avril 2001 et l'ordonnance du 19 juillet 2001 prévoient la création, auprès des régulateurs fédéraux, des organes suivants:

- régions flamande et wallonne: service de conciliation et d'arbitrage ainsi que chambre d'appel;
- région de Bruxelles-Capitale: service de médiation et chambre de recours.

3. *Qui désigne l'autorité de régulation et le conseil d'administration?*

Au niveau fédéral

La CREG est composée de deux organes : le comité de direction et le conseil général.

Le comité de direction, qui assure la gestion opérationnelle de la commission et accomplit les actes nécessaires ou utiles à l'exécution des missions de la CREG, est composé d'un président et de cinq autres membres nommés par arrêté royal délibéré en Conseil des ministres (article 24 de la loi électricité).

Le conseil général, est composé de membres nommés par le ministre fédéral de l'énergie. Il comprend notamment de représentants du Gouvernement fédéral, des Gouvernements de région, des syndicats, des organisations patronales, des producteurs, des transporteurs, des distributeurs et des consommateurs. Le conseil général a notamment pour mission de superviser le comité de direction et de définir les orientations en matière de mise en œuvre de la loi électricité.

Au niveau régional

- région wallonne: la CwaPE (Commission wallonne de régulation pour l'énergie) est composée d'un président et de trois administrateurs nommés par le Gouvernement wallon;
- région flamande: la VREG (Vlaamse Reguleringsinstantie voor de Elektriciteits- en Gasmarkt) est dirigée par un président et trois administrateurs nommés par le Gouvernement flamand;
- région de Bruxelles-Capitale: les missions de régulation sont exercées, d'une part, par le Gouvernement et, d'autre part, par le service de régulation de l'IBGE, qui fait partie de l'Administration.

4. *Quel est le degré d'indépendance de l'autorité de régulation? Les ministres peuvent-ils donner des instructions à l'autorité de régulation (politique générale ou cas par cas)?*

Au niveau fédéral

La CREG est un organisme autonome ayant la personnalité juridique (article 23 de la loi électricité). Sa qualité d'organisme autonome la soustrait au pouvoir hiérarchique des ministres.

Au niveau régional

- région flamande: la VREG est un organisme d'intérêt public et dispose de la personnalité juridique;
- région wallonne: la CwaPE est un organisme autonome doté de la personnalité juridique;
- région de Bruxelles-Capitale: le service de régulation fait partie intégrante de l'Administration régionale.

5. *Qui contrôle le travail de l'autorité de régulation – ministère, parlement?*

Au niveau fédéral

Le contrôle de la CREG s'opère en premier lieu de façon interne : son conseil général a pour mission d'évaluer la manière dont le comité de direction exécute ses tâches et de formuler des avis et recommandations à ce sujet au ministre et au comité de direction (article 24, §3, 2°, de la loi électricité). Par ailleurs, la CREG soumet chaque année au ministre qui a l'énergie dans ses attributions un rapport sur l'exécution de ses missions et l'évolution du marché de l'électricité (article 23, §3, de la loi électricité). Ce rapport est communiqué également aux Chambres législatives fédérales et aux gouvernements de région.

Au niveau régional

- région flamande: la VREG est sous la tutelle du Gouvernement flamand. Cette tutelle est exercée par un commissaire du gouvernement, lequel peut introduire un recours contre toute décision du régulateur. Faute d'annulation par le Gouvernement dans un délai de 20 jours, la décision devient définitive. Le régulateur fait annuellement un rapport sur ses activités au Gouvernement flamand et au Parlement flamand.
- région wallonne: la CwaPE est soumise au contrôle du Gouvernement wallon, par l'intermédiaire de deux commissaires du gouvernement. Ils peuvent introduire un recours contre une décision du régulateur. Ce recours est suspensif. A défaut d'annulation par le Gouvernement dans les 15 jours, la décision est définitive. La CwaPE établit un rapport annuel qu'elle transmet au Gouvernement et au Parlement wallons.
- région de Bruxelles-Capitale: vu que la réalisation des missions de régulation relève directement (action du Gouvernement) et indirectement (action du service de régulation) de la responsabilité du ministre régional de l'énergie, le contrôle du travail de l'autorité de régulation est effectué par le Conseil régional bruxellois.

6. *En dehors de la régulation des réseaux, quels sont les autres principaux domaines d'action et responsabilités de l'autorité de régulation?*

Indépendamment des activités liées directement ou indirectement à la "régulation des réseaux", les principales missions des autorités de régulation sont les suivantes:

- exercer un contrôle sur l'exécution des obligations de service public imposées aux producteurs, fournisseurs ou gestionnaires de réseaux;
- délivrer les autorisations de fourniture (régulateurs régionaux) ou soumettre une proposition d'autorisation de fourniture au ministre pour décision (CREG);
- organiser un service de conciliation et d'arbitrage;
- gérer et contrôler un mécanisme de certificats verts;
- approuver les tarifs de transport et de distribution (CREG);
- contrôler les comptes des entreprises du secteur de l'électricité;

- élaborer le programme indicatif des moyens de production d'électricité et contrôler le plan de développement du réseau de transport (CREG).

7. *Les entreprises peuvent-elles former un recours contre les décisions de l'autorité de régulation devant un tribunal ou un autre organisme? Que se passe-t-il entre-temps: la décision est-elle maintenue ou suspendue?*

Les décisions des régulateurs sont, à certaines conditions, susceptibles d'être contestées devant les juridictions judiciaires ou devant le Conseil d'Etat selon les critères de répartition internes entre ces deux types de juridiction (la question essentielle étant de savoir si le recours pour objet principal ou non un droit subjectif). Dans les deux cas, le recours n'est pas en lui-même suspensif.

8. *Quelle est la procédure de fixation des tarifs d'accès?*

Sont-ils basés sur une proposition du GRT/GRD ou sur une évaluation détaillée des coûts par l'autorité de régulation?

Les tarifs d'accès au réseau de transport et de distribution sont basés sur des propositions tarifaires émanant respectivement du GRT et des GRD. Ces propositions sont soumises à l'approbation de la CREG. Les tarifs doivent être orientés en fonction des coûts et ils comprennent une marge bénéficiaire équitable pour la rémunération des capitaux investis dans le réseau de transport ou dans les réseaux de distribution (article 12 de la loi électricité).

Les procédures afférentes à la fixation des tarifs d'accès aux réseaux sont déterminées par les arrêtés royaux du 4 avril 2001 (transport) et du 11 juillet 2002 (distribution).

L'introduction du budget comportant la proposition tarifaire se fait à l'aide du modèle de rapport. Sur proposition de la commission, le ministre définit le modèle de rapport et les lignes directrices suivant lesquelles le modèle de rapport et ses annexes doivent être complétées et interprétées.

Pendant combien de temps le revenu est-il plafonné?

Le revenu n'est pas plafonné.

Existe-t-il des objectifs et/ou des incitations en vue de réduire les coûts?

La loi électricité exige que les tarifs comprennent une marge bénéficiaire équitable pour la rémunération des capitaux investis dans le réseau en vue d'assurer le développement optimal de celui-ci à long terme (article 12, §2, 3°, de la loi électricité). La CREG a adopté des lignes directrices relatives à la politique tarifaire et à la marge bénéficiaire équitable en particulier à l'égard du gestionnaire du réseau national de transport d'électricité dans lesquelles elle donne son interprétation du concept de « marge bénéficiaire équitable ».

Le chapitre 7 des arrêtés royaux précités traite de la maîtrise des coûts.

Lorsque notamment l'application des tarifs a généré, durant l'exercice précédent, un boni ou un mali, celui-ci sera imputé pour moitié sur les tarifs de l'année suivante et pour moitié au gestionnaire de réseau. Si la CREG constate que ces boni ou mali résultent d'éléments exceptionnels ayant affectés durant une part importante de l'année et sur une grande part du

réseau de transport, tel que catastrophes naturelles ou conflits armés, elle peut décider d'une clef de répartition différente pour tout ou partie de ce boni ou mali.

Quelles informations l'autorité de régulation collecte-t-elle? Quels sont les droits dont dispose l'autorité de régulation pour demander des informations?

Pour rappel, le processus de désignation des gestionnaires de réseaux est en cours actuellement.

La CREG dispose du pouvoir de requérir les gestionnaires de réseaux toutes informations nécessaires à l'exercice de ses missions (article 26 de la loi électricité).

Les arrêtés royaux précités en leur chapitre 5 reprennent les rapports et informations que les gestionnaires de réseaux doivent fournir à la CREG en vue du contrôle des tarifs par la commission. Chaque gestionnaire de réseaux est tenu de remettre tous les éléments justificatifs nécessaires à la disposition de la CREG pour l'appréciation de la proposition tarifaire accompagnée du budget pour l'exercice suivant. Pour les GRD, ces éléments justificatifs sont définis en concertation avec les régulateurs régionaux.

Pour le GRT, l'art. 14, § 1^{er}, de l'arrêté précité du 4 avril 2001 requiert les informations suivantes :

1. en ce qui concerne les principes appliqués par le gestionnaire du réseau lors de la rédaction de son budget comportant la proposition tarifaire :
 - a) l'évolution escomptée du produit national brut;
 - b) l'évolution escomptée des kWh injectés et prélevés;
 - c) le taux d'inflation escompté;
 - d) les adaptations salariales, globalement et par catégorie;
 - e) les mutations de personnel escomptées, à savoir les recrutements et les licenciements;
 - f) les taux d'intérêt escomptés;
 - g) le coût du capital pondéré moyen pour la période à venir;
 - h) le taux d'impôt effectif;
 - i) les autres données macroéconomiques susceptibles de pouvoir influencer le résultat en termes d'output et de tarifs;
2. en ce qui concerne les investissements prévus :
 - a) la liste des investissements prévus pour l'exercice suivant
 - comprenant une différenciation entre les investissements de renouvellement des immobilisations corporelles et les investissements d'extension;

- comprenant une différenciation entre les investissements liés à l'acquisition de la propriété de composants du réseau de transport d'une part et les investissements liés à l'acquisition de la jouissance de composants du réseau de transport appartenant à des tiers et pour l'utilisation desquels le gestionnaire du réseau paiera une rémunération d'autre part;
 - mentionnant la valeur d'acquisition et l'amortissement annuel ou la redevance d'utilisation qui devra être payée;
- b) pour tous les investissements supérieurs à 2 478 935 EUR, y compris les nouvelles parties d'infrastructure devant être mises en service et qui ne figurent pas au bilan, une analyse financière d'investissement et de rendement comportant au moins les données suivantes :
- la description du projet;
 - les objectifs du projet;
 - le détail des principaux postes de coûts du projet;
 - un aperçu des fournisseurs et des entrepreneurs (et sous-traitants) qui collaborent à la réalisation du projet;
 - l'évolution dans le temps du projet, mentionnant la durée totale du projet lorsque le projet couvre une durée supérieure à un an;
 - l'impact sur les amortissements;
 - les améliorations visées au niveau de l'efficacité, notamment l'efficacité énergétique;
 - les effets sur l'environnement;
 - une analyse financière, à savoir un plan de cash-flow, y compris des besoins de financement pendant la durée de vie du projet et une analyse de rentabilité du projet;
3. en matière d'effectif du personnel :
- a) un plan du personnel détaillé comprenant un organigramme pour l'exercice suivant;
 - b) un aperçu du nombre de membres du personnel en équivalents temps plein par centre de coût, y compris les recrutements et licenciements envisagés;
 - c) un plan détaillé des formations prévues;
4. une analyse des points forts et des faiblesses, de même que des opportunités et des menaces par rapport aux différentes activités du gestionnaire du réseau impliquant au moins les domaines d'activités suivants
- la technologie;

- le personnel;
 - l'organisation administrative;
 - les relations avec la clientèle;
 - l'environnement;
 - la politique d'achat;
 - l'entretien;
 - l'exploitation;
 - l'utilisation du réseau;
 - les goulets d'étranglement au niveau de la capacité;
 - les risques de démarrage;
 - les flux de transit;
 - le déroulement des contrats à long terme;
 - la recherche et le développement;
5. un bilan prévisionnel selon le schéma normalisé des comptes annuels pour les trois premières années d'exploitation;
6. un aperçu des actions et des investissements visant spécifiquement une amélioration de l'efficacité et/ou des économies de coût, avec une analyse et un calcul des économies de coût escomptées;
7. les différentes formules de souscription pour lesquelles les utilisateurs du réseau peuvent opter, avec une différenciation des utilisateurs du réseau selon les différentes formules de souscription et une autre différenciation de chaque type d'utilisateur selon les différents groupes de clients;
8. une explication circonstanciée des différents types de charges et produits suivants:
- charges exceptionnelles;
 - produits exceptionnels;
 - charges pour la recherche et le développement;
 - charges des enquêtes réalisées par des tiers;
 - charges des investissements en matériel informatique.

Le chapitre 6 des arrêtés précités précise les obligations comptables de chaque gestionnaire de réseau.

Comment les informations sont-elles contrôlées?

Les informations seront contrôlées sur base des pièces comptables, financières, économiques et techniques. En outre la CREG évaluera le caractère raisonnable de ces coûts en les comparant, entre autres, aux coûts correspondants d'entreprises similaires.

9. Quels sont le budget et le nombre d'employés de l'autorité de régulation?

CREG: le budget pour 2002 s'élève à 8,25 millions d'euros et le nombre actuel d'employés est de 35.

CwaPE: le budget pour 2002 est fixé à 3,2 millions d'euros et le nombre d'employés est pour l'instant de 14.

Service bruxellois de régulation: le budget pour 2002 s'élève à 300.000 euros et le nombre d'employés est actuellement de 2.

VREG: information non disponible pour l'instant.

10. Comment les ressources financières sont-elles collectées: prélèvements sur l'électricité ou taxes? Qui approuve le budget?

CREG: les frais de fonctionnement sont couverts par une surcharge sur les tarifs (arrêté royal du 18 janvier 2001 établissant un système provisoire de financement) et le budget est approuvé par arrêté royal délibéré en Conseil des Ministres.

CWaPE: les dépenses de la CwaPE sont financées par un fonds budgétaire; il est prévu que ce fonds soit alimenté par une redevance prélevée par le GRD chargé d'alimenter un client final;

VREG: cette autorité de régulation dispose d'une dotation qui est inscrite annuellement au budget de la Communauté flamande;

Service bruxellois de médiation: ce service est financé par deux allocations budgétaires figurant au budget général de la Région de Bruxelles-Capitale.

E. Séparation des GRT et GRD

Cette partie concerne la séparation entre les réseaux d'électricité et les autres structures d'une entreprise verticalement intégrée.

Conformément aux dispositions légales et décrétales précitées, le GRT et les GRD, lorsqu'ils auront été désignés officiellement, auront une structure juridique indépendante et seront soumis au contrôle de leur régulateur respectif. De plus amples informations à ce sujet figurent au point A, 7 et 8. Les questions ci-dessous sont donc sans objet pour la Belgique.

1. Les comptes sont-ils publiés et contrôlés séparément? S'ils ne sont pas publiés, qui y a accès?
2. Quelles sont les règles existantes pour la répartition des coûts partagés entre différentes fonctions (par exemple, charges du siège, centres d'appel)?

3. Quelles procédures existe-t-il pour le traitement des données commercialement sensibles utilisées par le GRT (par exemple, les données des compteurs)?
4. Existe-t-il des arrangements juridiques/commerciaux entre différentes fonctions pour les transactions à l'intérieur de l'entreprise? Comment ces transactions sont-elles enregistrées?
5. Le respect de la séparation fait-elle l'objet de contrôles? Quelles sont les tâches des personnes chargées d'évaluer la conformité?
6. À qui l'équipe d'évaluation de la conformité fait-elle rapport?
7. L'évaluation de la conformité est-elle effectuée au sein de l'entreprise ou par des consultants externes?
8. Les lignes hiérarchiques au sein de la branche "réseau" sont-elles totalement séparées?
9. Qui est le supérieur direct du directeur général de la branche "réseau"?
10. Les décisions du conseil d'administration de la branche "réseau" peuvent-elles être annulées? Les directeurs d'autres branches (fourniture au détail/production) sont-ils présents lors des discussions sur les questions de réseau?
11. La branche "réseau" est-elle une personne morale distincte?
12. La branche "réseau" se trouve-t-elle dans un bâtiment distinct? Quelles sont les procédures de sécurité en place?
13. Existe-t-il des systèmes TI séparés pour la branche "réseau"? Existe-t-il des contrôles de l'accès à certaines parties du système pour différents employés? Y a-t-il des listes téléphoniques et des sites web séparés pour différentes fonctions?

F. Structure du marché

Dans cette partie sont demandées des informations sur la structure des segments concurrentiels du marché de l'électricité, à savoir la production et la fourniture au détail, ainsi que des informations sur les clients qui changent de fournisseur. On retrouvera ici certaines questions de l'enquête Eurostat "Indicateurs de concurrence sur les marchés de l'électricité".

NB: les réponses ci-dessous sont établies sur la base des informations actuellement disponibles.

1. Veuillez indiquer

- le nombre d'entreprises productrices qui, ensemble, représentent au moins 95 % de la production nationale nette d'électricité: 2
- le nombre d'entreprises productrices qui détiennent une part d'au moins 5 % dans la production nationale nette d'électricité: 2.

2. *Veillez indiquer la part i) de la production et ii) de la capacité installée de chaque entreprise détenant une part d'au moins 5 % (calcul des parts basé sur la production nette).*

Année 2000	Part dans la production	Part dans la capacité installée
Electrabel	91,1 %	87,5 %
SPE	6,5 %	8,4 %

3. *Veillez fournir une analyse de la capacité installée par type de combustible.*

Année 2000	Capacité nette installée (MW)
Thermique conventionnel	8.427,9
Nucléaire	5.713,0
Hydraulique	1.404,3
Eolien	9,9
Geothermique	
Solaire	
Autres	117,3
TOTAL	15.672,4

4. *Veillez indiquer le total de la nouvelle capacité raccordée (en MW) au cours de la dernière année pour laquelle des données sont disponibles.*

Capacité raccordée en 2001: 440 MW

5. *Veillez indiquer la capacité déclassée (en MW) au cours de la dernière année pour laquelle des données sont disponibles.*

Capacité déclassée en 2001: 70 MW

6. *Sur la base des autorisations accordées, veuillez fournir une estimation (en MW) de la quantité de production nouvelle indépendante qui sera raccordée au réseau dans les cinq prochaines années.*

Sur la base des autorisations délivrées jusqu'à présent, la situation est la suivante:

- production classique: 388 MW (Electrabel)
- éoliennes dans les espaces marins: 100 MW (Electrabel)

Les installations de production terrestres disposant d'une puissance inférieure à 25 MW ne doivent pas disposer d'une autorisation sur la base de la loi électricité. Sur la base de nos informations, divers projets d'installations de cogénération et d'éoliennes sont en projet ou en cours de construction, à l'initiative d'Electrabel mais également de producteurs indépendants.

De plus amples informations à ce sujet figurent au point I, 1 et 2.

7. *Quelles autres mesures sont actuellement prises pour accroître la concurrence sur le marché de gros (par exemple, mise aux enchères de capacités, revente)?*

Il n'y a pas de mesure actuellement en ce sens.

8. *Veillez indiquer*

le nombre de fournisseurs de détail titulaires d'une licence ou enregistrés;

le nombre de ces fournisseurs qui sont indépendants des entreprises de distribution (c'est-à-dire détaillants purs ou affiliés aux producteurs ou à des entreprises étrangères);

le nombre de fournisseurs de détail qui détiennent une part d'au moins 5 % dans la consommation.

- Région flamande: 10 fournisseurs disposent d'une autorisation de fourniture;
- Région wallonne: 6 autorisations de fourniture provisoires ont été délivrées;
- Région de Bruxelles-Capitale : aucune autorisation n'a été délivrée (réglementation en préparation);
- Fédéral: l'exercice d'activités de fourniture sur le réseau de transport ne requiert pas pour l'instant d'autorisation; un projet de réglementation imposant la délivrance d'autorisations aux intermédiaires est soumis actuellement pour avis au Conseil d'Etat.

9. *Veillez indiquer la part de la consommation servie par chaque fournisseur de détail ayant une part de marché d'au moins 5 %.*

Année 2000	Part de marché
fournisseur A	39,8 %
fournisseur B	6,4 %
fournisseur C	6,3 %

10. *Où les nouveaux fournisseurs achètent-ils de l'électricité (par exemple, importations, production propre, achat auprès des producteurs existants sur le marché de gros)?*

Leurs achats proviennent d'importations, d'achats auprès des producteurs existants et de leur propre production.

11. *Veillez fournir une estimation, pour la période 1998-2001, du nombre cumulé de clients éligibles qui ont changé au moins une fois de fournisseur (par fourchette de consommation annuelle).*

En 2001, seuls les clients consommant plus de 20 GWh étaient éligibles.

Année 2001	Plus de 20 GWh
Nombre de clients éligibles	230
Nombre de clients ayant changé de fournisseur	20
Nombre de renégociations du tarif avec le fournisseur en place	210
Consommation des clients éligibles (GWh)	32.300 GWh
% de la consommation ayant donné lieu à un changement de fournisseur	7 %

12. *Quelle est la procédure appliquée pour changer de fournisseur? Faut-il remplir certaines conditions ou y a-t-il des frais?*

Au niveau du réseau de transport, le changement de fournisseur peut s'effectuer lorsque le contrat conclu entre le consommateur et son fournisseur actuel arrive à son terme. Lorsqu'un client captif raccordé au réseau de distribution devient éligible, il lui est loisible de conclure un contrat avec le fournisseur de son choix.

13. *Existe-t-il des pénalisations pour les clients qui retournent à leur fournisseur de détail précédent?*

Ce point fait l'objet d'une négociation purement commerciale.

14. *Les fournisseurs de détail peuvent-ils offrir un prix différent à un client déterminé ou doivent-ils offrir le même prix à tous les clients ayant des caractéristiques comparables?*

A la différence des prix applicables à la clientèle captive, lesquels sont soumis à un régime de prix maxima, les prix pour les clients éligibles sont libres.

G. Sécurité d'approvisionnement/service universel

Cette partie concerne les instruments utilisés pour remplir les obligations de service public dans le cadre d'un marché concurrentiel, ainsi que des informations sur les résultats obtenus.

1. *Veillez fournir des informations détaillées sur toutes les obligations imposées aux entreprises d'électricité en ce qui concerne:*

la sécurité d'approvisionnement;

les prix (par exemple, péréquation tarifaire régionale/nationale, non-discrimination);

les objectifs environnementaux.

Veillez fournir une estimation du coût des obligations et, le cas échéant, indiquer la méthode de compensation en faveur des entreprises soumises aux obligations. Comment cette compensation est-elle déterminée?

Au niveau fédéral

Des obligations de service public peuvent être imposées aux producteurs, intermédiaires et au GRT notamment en matière de régularité et de qualité des fournitures d'électricité ainsi qu'en matière d'approvisionnement des clients captifs. Un fonds, à gérer par la CREG, prendra en charge le coût réel net de ces obligations de service public, dans la mesure où celles-ci représentent une charge inéquitable pour ces entreprises. Le financement de ce fonds peut être assuré par une surcharge sur le tarif de transport ou par des prélèvements sur l'ensemble, ou des catégories objectivement définies, de consommateurs d'énergie ou d'opérateurs sur le marché (article 21 de la loi électricité).

La réglementation destinée à mettre en œuvre ces mesures est en cours d'adoption.

En matière de prix, il est à noter que la fourniture d'électricité aux clients captifs est soumise actuellement à un régime de prix maxima. La loi électricité prévoit la possibilité d'étendre un tel régime aux clients éligibles (article 20 de la loi électricité).

Les structures tarifaires en matière de raccordement et d'utilisation du réseau de transport sont uniformes sur l'ensemble du territoire, sans différenciation par zone géographique. Les mêmes principes régissent les tarifs applicables aux réseaux de distribution.

Au niveau régional

Des obligations de service public peuvent être imposées aux GRD et aux fournisseurs en ce qui concerne notamment:

- la sécurité, la régularité et la qualité des fournitures;
- les mesures d'ordre social (fourniture ininterrompue d'une quantité minimale en cas de non-paiement, application d'un tarif social,...);
- les mesures environnementales (programme et normes en matière d'utilisation rationnelle de l'énergie, promotion de la production d'électricité à partir de sources d'énergie renouvelables ou de cogénération de qualité par le biais notamment d'un mécanisme de certificats verts,...).

Les modalités de financement de ces obligations de service public diffèrent selon les régions.

En régions flamande et wallonne, leur financement est effectué par le biais de fonds budgétaires alimentés par:

- des redevances attribuées aux fonds par les décrets,
- des moyens attribués aux fonds en vertu de dispositions légales, réglementaires ou conventionnelles en vue de financer les obligations de service public,
- une redevance prélevée par le GRD chargé d'alimenter un client final raccordé au réseau de distribution (uniquement en région wallonne).

Dans la région de Bruxelles-Capitale, le coût des missions de service public prises en charge par le GRD est couvert par le produit d'un droit perçu auprès des fournisseurs.

2. ***Quelle est la situation actuelle en matière de capacités de réserve (selon les définitions de l'UCTE)?***

L'opérateur du réseau ELIA ne dispose actuellement d'aucun moyen de production. Pour l'année 2002, l'opérateur du réseau ELIA a contractualisé la gestion des réserves auprès d'un producteur (CPTE), qui dispose d'un parc de moyens de production dans la zone de réglage suffisant pour satisfaire à un cahier de charges qui est établi sur base des règles UCTE. La quantité opérationnelle de la réserve dépend de la disponibilité des moyens de production dans le parc, notamment des révisions réglementaires qui sont à planifier par le producteur pour que les réserves soient assurées.

3. ***Quelle est la capacité actuelle d'importation d'électricité (flux physiques)?***

En 2001, l'importation nette de la zone était de 9106 GWh, contre 4325 GWh en 2000 et 852 GWh en 1999. La demande d'énergie en 2001 était de 83318 GWh.

L'importation nette est notifiée moyennant des programmes d'échange pour import et export aux frontières franco-belge et belgo-hollandaise.

La capacité d'importation nette de la zone belge dépend de la quote-part des transits notifiés par les acteurs de marché, à l'intérieure des capacités mises à disposition par l'opérateur du réseau.

4. ***Quelle est l'augmentation annuelle prévue de la demande d'électricité?***

L'évolution de la demande d'électricité dépend fortement des décisions prises par les autorités en matière de politique environnementale. Dans le cadre du projet de programme indicatif des moyens de production d'électricité soumis actuellement pour approbation au ministre fédéral de l'énergie, diverses variantes ont été retenues. Compte tenu de la nature et surtout de l'ampleur des contraintes environnementales susceptibles d'être prises en considération, les prévisions en matière d'évolution de la demande oscille entre une croissance de 1,9% par an entre 2002 et 2011 et une réduction de 1,5% par an durant la même période.

5. ***Comme est assuré le suivi de la situation en matière de sécurité d'approvisionnement? Quelle serait la séquence des mesures prises si les autorités estimaient qu'une pénurie est imminente?***

- Suivi: élaboration d'un programme indicatif décennal des moyens de production d'électricité, analysant l'adéquation entre l'offre et la demande d'électricité; il est mis à jour tous les 3 ans (art.3 de la loi électricité);
- Pénurie: publication d'un avis dans la presse nationale et internationale précisant que les demandes d'autorisations pour la construction de nouvelles installations de production d'électricité sont insuffisantes par rapport aux moyens de production préconisés dans le programme indicatif (art.5 de la loi électricité);
- Pénurie imminente: en cas d'impossibilité de mettre en place un ou plusieurs services auxiliaires (réserves primaire, secondaire et tertiaire,...), le GRT peut imposer aux producteurs et à d'autres utilisateurs la mise à disposition d'un ou plusieurs de ces services à un prix raisonnable. Il détermine la quantité d'un ou de plusieurs de ces services qu'un

ou plusieurs producteurs doivent fournir en fonction de leurs moyens de production existants. Le GRT en informe la CREG et le Ministre fédéral de l'énergie.

- Si l'impossibilité de mettre en place ces services persiste, le ministre fédéral de l'énergie:
 - impose à certaines catégories de producteurs des conditions de prix et de fourniture de tout ou partie de ces services et/ou
 - établit des règles transparentes et non discriminatoires visant à assurer au GRD une disponibilité permanente de ses services (art.234 du règlement technique et art.4 du projet d'arrêté royal relatif aux obligations de service public).
- De plus, sur base de l'article 32 de la loi électricité, en cas de crise soudaine sur le marché de l'énergie, le Roi peut, par arrêté délibéré en Conseil des ministres, après avis de la CREG, prendre les mesures de sauvegarde nécessaires, y compris des dérogations temporaires aux dispositions de la loi électricité.

6. *Quelles sont les incitations ou obligations pour les producteurs/fournisseurs/consommateurs en vue de pouvoir faire face aux pointes de la demande?*

De manière à réduire les pointes de la demande, des dispositions tarifaires spécifiques ont été instaurées :

- tarifs bi- ou tri-horaire pour les clientèles basse et haute tension
- contrats avec des contraintes de prélèvement (fournitures interruptibles, modulables et auto-éffaçables) pour les consommateurs plus importants (puissance supérieure à 4 MW).

7. *Quel est le pourcentage de la population raccordé au réseau national de distribution d'électricité? Quels sont les arrangements pour les ménages non raccordés?*

A l'exception de quelques cas très marginaux, l'entièreté de la population est raccordée au réseau de distribution.

8. *Existe-t-il un fournisseur de remplacement qui assure l'approvisionnement si aucune autre entreprise ne veut le faire ou en cas de faillite d'un fournisseur?*

Un fournisseur par défaut est désigné par les GRD aux fins d'alimenter les clients devenus éligibles lorsque ceux-ci n'ont pas choisi un autre fournisseur.

9. *Les prix varient-ils d'une région à l'autre? Si oui, dans quelle mesure? En cas de péréquation tarifaire nationale, comment fonctionne-t-elle?*

Les prix applicables aux clients captifs raccordés au réseau de distribution sont péréqués. Il s'agit d'un système de prix maxima imposés par un arrêté ministériel du 12 décembre 2001.

10. *Pour quelle proportion de la population la facture pour 2 000 kWh dépasserait-elle 5 % du revenu net?*

Cette information n'est pas disponible.

11. *Quelles mesures existe-t-il pour éviter que les personnes à faible revenu soient privées d'électricité?*

Des dispositions réglementaires garantissent en faveur des personnes à faible revenu la fourniture ininterrompue d'une quantité minimale d'électricité en cas de non-paiement (limiteur de puissance...).

12. *S'il existe un système de paiement anticipé, qui prend en charge le surcoût? Quel est le montant approximatif par ménage?*

Il existe un système généralisé de versements forfaitaires intermédiaires (mensuels, bimensuels ou trimestriels) qui a pour objectif de répartir le coût des fournitures sur l'ensemble de l'année. Les versements intermédiaires sont établis sur la base des données figurant dans la facture de régularisation de l'année précédente (consommation enregistrée, tarif appliqué,...)et indexées en fonction de l'évolution prévisible des prix. Ce système n'entraîne pas de surcoût.

13. *Combien y a-t-il eu de coupures d'électricité pour défaut de paiement au cours de la dernière année pour laquelle des données sont disponibles?*

Les informations disponibles en matière de coupures concernent l'année 2000 et portent sur les fournitures d'électricité mais aussi sur celles de gaz:

- nombre de clients domestiques (électricité et/ou gaz): 4.665.784
- nombre de coupures: 20.191
- nombre de remises en service(dans les 30 jours et plus): 10.057
- clients suspendus ayant déménagé ou disparu: 5.146
- nombre effectif de coupures: 4.988 soit environ 0,1% de la totalité des clients

14. *Quelle est la situation des gestionnaires de réseau de transport et de distribution en matière d'interruptions et de continuité de l'approvisionnement?*

Au niveau des réseaux de distribution, des dispositions décrétales et réglementaires garantissent pour des motifs sociaux la continuité de l'approvisionnement de la clientèle.

Dans la Région de Bruxelles-Capitale, aucune suspension des fournitures ne peut intervenir sans l'autorisation du juge compétent.

Dans les régions flamande et wallonne, la suspension des fournitures par le distributeur nécessite l'intervention d'une commission locale d'avis de coupure; celle-ci se prononcera sur l'opportunité ou non d'y procéder, après avoir entendu le client et le distributeur.

15. *Des objectifs ont-ils été fixés? Quelles sont les sanctions prévues: amende, lettre d'avertissement, classification des gestionnaires de réseau?*

Le non-respect des dispositions légales, décrétales et réglementaires relatives à l'organisation du marché de l'électricité peut entraîner pour le GRT et les GRD des sanctions pénales et/ou

administratives. En cas de manquement grave du GRT ou du GRD à ses obligations, celui-ci peut être révoqué.

16. *Quels contrôles existe-t-il en matière de maintenance et de renouvellement des réseaux?*

Le GRT et les GRD sont tenus d'établir un plan de développement de leur réseau en concertation avec leur régulateur. Ce plan d'une durée de 7 ou 5 ans doit faire l'objet d'une approbation par les autorités. Il contient une estimation détaillée des besoins en capacité de transport ou de distribution et énonce le programme d'investissements que le gestionnaire s'engage à exécuter en vue de rencontrer ses besoins.

Si le régulateur constate que les investissements prévus dans le plan ne permettent pas au GRT ou au GRD de rencontrer les besoins de manière efficace, le ministre de l'énergie peut lui enjoindre d'adapter le plan en vue de remédier à cette situation dans un délai raisonnable.

17. *Existe-t-il des conditions et normes minimales pour les fournisseurs au détail? Si oui, lesquelles?*

Les critères d'octroi pour la délivrance d'autorisations aux fournisseurs sont les suivantes:

- honorabilité et expérience professionnelle
- capacités techniques et financières
- structure de gestion et organisation administrative et comptable appropriées
- autonomie gestionnelle et juridique vis-à-vis du GRT et des GRD.

18. *Comment sont-elles appliquées (par exemple, amende, lettre d'avertissement, classification des fournisseurs)?*

Des sanctions pénales et /ou administratives sont imposées en cas de non-respect des obligations imposées par les dispositions légales, décrétales et réglementaires en la matière. En outre, l'autorisation peut être suspendue ou retirée lorsque le fournisseur ne respecte pas les obligations ou les critères établis en vertu des dispositions précitées.

H. Questions transfrontalières

Cette partie porte sur les procédures applicables aux flux transfrontaliers d'électricité, en particulier la tarification et la répartition des capacités limitées.

1. *Existe-t-il des redevances à l'exportation, à l'importation ou au transit? Quel en est le montant en €/MWh?*

Depuis le 1^{er} mars 2002, l'opérateur du réseau Elia a transposé l'accord entre les membres de l'association des gestionnaires de réseau ETSO dans ses tarifs : les acteurs réalisant en leur nom un export net (hors transit) sont redevables du tarif fixé à 1 €/MWh. Avant le 1^{er} mars 2002, les transits d'énergie étaient également redevables d'un droit de 1 €/MWh transité.

2. *Est-il prévu de supprimer ces redevances? Le pays participera-t-il mécanisme ETSO ou à son successeur?*

L'opérateur du réseau Elia participe au mécanisme ETSO actuel et probablement à son successeur.

3. *Veillez décrire les lignes d'interconnexion avec d'autres pays: courant alternatif ou courant direct. Quelle est la capacité existante? Comment la capacité disponible est-elle estimée?*

Le réseau Elia est interconnecté avec les réseaux français (RTE) ; des Pays-Bas (TenneT) et Luxembourgeois (Sotel réseau) par des lignes à courant alternatif capables de grand transport d'énergie à 380 kV et 220 kV.

La capacité d'échange entre deux zones est fonction des contraintes dans les réseaux respectifs. Exemple : la répartition des flux physiques liés aux échanges sur les éléments individuels de réseau doit respecter le flux maximum admissible sur l'élément (dans l'état sain et dans l'état perturbé N-1).

La congestion physique constituant la contrainte peut se trouver aussi bien à l'intérieur du réseau que sur un élément de réseau à la frontière (cas le plus fréquent).

Les valeurs indicatives de la capacité "NTC" selon la définition ETSO sont publiées deux fois par an par ETSO. Elles dépendent entre autres de

- la puissance installée des éléments de réseau;
- des transits non-notifiés, résultants d'échanges entre zones tierces sans l'approbation de la zone qui est traversée par les flux physiques.

Les capacités disponibles pour allocation au marché aux échéances diverses (ATC) dépendent des mêmes facteurs précités, ainsi que de facteurs supplémentaires :

- les conditions opérationnelles quant à la disponibilité du réseau, le parc de production mis en oeuvre, et la répartition de la charge (mise à jour de la NTC);
- les capacités allouées au préalable.

A titre d'information, et en précisant que d'autres contraintes techniques doivent également être respectées, les flux maximums admissibles sur les lignes aux frontières belges sont communiqués ci-après. Le réseau belge est connecté aux réseaux voisins via des lignes à la frontière, dont les capacités thermiques nominales sont données pour les diverses saisons (en termes de flux physiques en MVA).

capacité des lignes de transport d'électricité installées entre la Belgique et les Pays-Bas				
période d'été (16/5 - 15/9)	1650 MVA	Zandvliet-Borsele 380 kV (1)	1650 MVA	Zandvliet-Geertruidenberg 380 kV
entre saison (16/9 - 15/11 en 16/3 - 15/5)	1750 MVA		1750 MVA	Meerhout-Maasbracht 380 kV
période d'hiver (16/11 - 15/3)	1850 MVA		1850 MVA	Gramme-Maasbracht 380 kV
capacité des lignes de transport d'électricité installées entre la Belgique et la France				
période d'été (16/5 - 15/9)	1350 MVA	Avelin-Avelgem 380 kV	400 MVA	Chooz-Jamiolle 220 kV (2)
entre saison (16/9 - 15/11 en 16/3 - 15/5)	1430 MVA		424 MVA	Lonny-Achène 380 kV
période d'hiver (16/11 - 15/3)	1500 MVA		448 MVA	Moulaine-Aubange 220 kV

(1) En pratique limitée à 450 MVA par un transformateur placé en série à Borsele (NL).
 (2) En pratique limitée à 290 MVA par un transformateur placé en série à Jamiolle (B).

4. Quelle capacité est réservée, le cas échéant? Pour qui et pendant combien de temps?

Une partie de la capacité est réservée aux contrats conclus avant l'entrée en vigueur de la directive 96/92/CE. La capacité effectivement réservée dépend des nominations journalières dès lors que les méthodes mises en œuvre sur les deux frontières mettent en œuvre un principe de « use-it or lose-it ».

5. Si la demande de capacité dépasse la capacité disponible, comment la capacité est-elle répartie?

La méthode d'allocation de la capacité disponible diffère selon la frontière.

Frontière Elia-TenneT

La capacité disponible sur base annuelle, mensuelle ou journalière (24 heures) est allouée dans chaque sens sur base d'une mise aux enchères explicite, organisée par le TSO Auction Office

aux Pays-Bas. La méthode est décrite dans le document « Auction Regulation 2002 » disponible sur le site www.TSO-Auction.org.

Frontière Elia-RTE (sens France-Belgique)

La méthode d'allocation provisoire, commune à RTE et Elia à partir du 1er juillet 2002 répond au critère « premier demandeur, premier servi », les capacités demandées étant cependant limitées par acteur à 4 demandes de 25 MW maximum afin d'offrir la possibilité d'entrer dans le marché à un maximum d'acteurs.

La capacité disponible est allouée sur base mensuelle et journalière (par heure). La méthode est décrite dans le document « Modalités d'accès à l'interconnexion France-Belgique applicables entre le 1er juillet 2002 et le 31 décembre 2002 » consultable sur les sites internet d'ELIA ou d'RTE.

6. *Qui est propriétaire de chaque interconnexion? Comment son coût est-il couvert: par les tarifs de transport généraux ou par une redevance d'utilisation spéciale?*

Chaque opérateur de réseau est propriétaire des installations d'interconnexion situées sur son territoire. Le coût associé à ces installations est couvert en partie par le mécanisme ETSO, en partie par les tarifs de transport généraux.

7. *En cas de ventes aux enchères explicites:*

Les ventes aux enchères explicites concernent actuellement les capacités relatives à la frontière Belgique-Pays-Bas.

Quels sont les principaux produits (par exemple, capacité annuelle, mensuelle, journalière, intrajournalière)?

Les produits vendus sont :

- capacité annuelle
- capacité mensuelle
- capacité journalière (par heure)

Comment les proportions sont-elles déterminées?

La priorité est accordée aux allocations pour les périodes les plus longues, dans la limite de la capacité disponible et en réservant une capacité minimale de 100 MW à l'allocation journalière pour l'ensemble des frontières d'accès aux Pays-Bas (imposition du régulateur des Pays-Bas).

Y a-t-il un prix plancher? Si oui, quel en est le montant?

La méthode d'allocation prévoit un prix nul si la capacité disponible est supérieure à la capacité demandée.

Quel était le prix moyen de chaque produit en 2001?

Prix annuel 2001 :	Elia-Tennet :	26 324 €/MW.an
	Tennet-Elia :	105 €/MW.an
Prix mensuel moyen 2001 :	Elia-Tennet :	1031 €/MW.mois
	Tennet-Elia :	21 €/MW.mois
Prix horaire moyen en journalier :	Elia-Tennet :	0,09 €/MWh
	Tennet-Elia :	0,04 €/MWh

Quel était le revenu total produit par ces ventes? À combien s'élevait le surplus?

Revenu total 2001 : information confidentielle.

Comment le surplus a-t-il été utilisé? Quelle est la procédure prévue à cet effet?

Les revenus 2001 ont été utilisés pour compenser les pertes de transport et les frais encourus par Elia pour garantir la capacité mise à disposition.

8. *Quels étaient les flux physiques annuels à l'entrée et à la sortie en 2000 et 2001?*

Les flux physiques aux frontières Belgique-Pays-Bas et Belgique-France sont variables sur la période 2000 et 2001. En règle générale, les flux physiques suivent la direction Sud-Nord et varient entre 500 et 2500 MW à la frontière France Belgique et entre -300 et 2000 MW à la frontière Belgique Pays-Bas.

9. *À quelle nouvelle capacité d'interconnexion peut-on s'attendre au cours des prochaines années? Quel est le cadre réglementaire actuel pour les nouvelles interconnexions?*

Une étude commune RTE-Elia du renforcement de la capacité d'importation de la France vers la Belgique est en cours. Les conclusions sont attendues pour le 1er octobre 2002. Cette étude et un plan d'action seront soumis à l'approbation des régulateurs français et belge. Aucun renforcement de la capacité à la frontière Belgique Pays-Bas n'est actuellement à l'étude.

I. Questions environnementales

La dernière partie concerne les objectifs environnementaux de la politique énergétique.

1 et 2 Veuillez fournir des informations sur :

- la capacité (MW) mise hors service en 1998-2001 et le type de combustible;
- la capacité (MW) ajoutée en 1998-2001 et le type de combustible.

Quelle est l'évolution probable aux cours des 10 prochaines années? Quelle capacité sera mise hors service? De quel type s'agit-il? Quel sera l'effet de la directive concernant les grandes installations de combustion?

Capacités mises hors service:

- arrêt des unités de Péronnes (111MW), Schelle 31 (136MW), Schelle 32 (90MW) et du turbojet de Langerbrugge (90MW) en 2000;
- arrêt définitif de l'unité Rodenhuize 1 (129 MW) et de l'unité de cogénération de Verviers (23,5 MW) en 2001.

Nouvelles capacités et repowering

En 2001, le parc de production des entreprises électriques a évolué comme suit :

- mise en service industriel de l'unité TGV de Vilvoorde I (385 MW), le 25 avril; remise en service après conservation de l'unité de Rodenhuize 2 (129 MW);
- à la centrale de Tihange, lors de la révision pour rechargement de l'unité 2, les générateurs de vapeur ont été remplacés. De ce fait, la puissance utile a pu être relevée de 960 MW à 985 MW. Un second palier jusqu'à 1.008 MW nets a pu être atteint après obtention des autorisations le 12 janvier 2002.

Par ailleurs, plusieurs unités de cogénération de puissance réduite ont été mises en service en 2001, dont la plupart ont été construites par les intercommunales de distribution ou en collaboration avec celles-ci.(voir tableau à l'annexe 2)

Dans le domaine de la production à partir de sources d'énergie renouvelables, de nouvelles installations ont été développées:

- d'une part dans des éoliennes : en 2001, quelques dizaines de nouvelles éoliennes ont été construites, notamment à Bruges, Eeklo, Herdersbrug, Kapelle-op-den-Bos, Schelle, Zeebrugge (voir tableau à l'annexe 2);
- d'autre part dans la production à partir de la biomasse:, à Ruien, après des essais concluants de co-combustion de poussière de bois, une unité de gazéification des déchets de bois pur sera installée et couplée à une chaudière classique, et aux Awirs, la co-combustion de noyaux d'olives est à présent en phase de régime sur l'unité n°4 .

En 2002, il est prévu que :

- la puissance nette de l'unité de Monceau sera rétablie à sa valeur nominale (111 MW) après réparation de la roue moyenne pression de la turbine;
- la turbine à vapeur de 30 MW installée sur le site de Totalfina à Anvers ("Fina 6") sera mise en service;
- le turbojet de Zelzate sera remis en service dans le cadre d'un contrat de secours à SIDMAR.

Pour les années ultérieures, les discussions et travaux préparatoires à la construction des unités de cogénération en partenariat avec BASF à Anvers (385 MW) et avec Aceralia (Usinor-

Cockerill-Sambre) à Seraing (144 MW) se sont poursuivis en 2001. Les dates de mise en service prévues sont fin 2003 pour Aceralia et fin 2004 pour BASF.

3 et 4 Quelles incitations existe-t-il pour la production à partir de sources renouvelables et la PCCE? À combien s'élève l'aide disponible?

Quels sont les problèmes qui subsistent dans le domaine de la PCCE et des sources d'énergie renouvelables (équilibre, tarifs pour les producteurs intégrés, etc.)? Quelles sont les solutions envisagées?

Régime conventionnel

Dès 1995, le Comité de Contrôle de l'Electricité et du Gaz a instauré une aide extra-tarifaire de 1 BEF/kWh à l'électricité produite à partir de sources d'énergie renouvelables. En 1998, le Comité a porté cette aide à 2 BEF/kWh pour les installations de production d'électricité à base d'énergie hydraulique ou d'éoliennes. Ce mécanisme d'aides extra-tarifaires n'est plus applicable aux nouvelles demandes émanant de producteurs concernés. Les bénéficiaires existants de ces aides peuvent y renoncer à tout moment et opter pour le mécanisme des certificats verts; cette décision est irréversible. Ils peuvent également décider de conserver le bénéfice de l'aide extra-tarifaire pendant la période garantie (10ans après le mois de la 1^{ère} injection dans le réseau).

Régime légal

En vue de promouvoir le développement d'installations de production d'électricité à partir de sources d'énergie renouvelables, de nouveaux systèmes de "certificats verts" ou de "certificats d'électricité écologique" ont été créés dans chacune des régions ainsi que par le fédéral pour la production à partir d'éoliennes dans les espaces marins.

Textes de base:

Région flamande:	décret du 17 juillet 2000, art; 21 à 25 Arrêté du 28 septembre 2001
Région wallonne:	décret du 12 avril 2001, art.37 à 42
Région de Bruxelles-Capitale:	ordonnance du 19 juillet 2001, art.28
Fédéral:	loi électricité: art. 6 et 7 Arrêté royal du 16 juillet 2002

Particularités:

– En Région wallonne:

Outre un système de certificats verts, il y est créé une aide à la production d'électricité verte. Un montant sera octroyé à chaque kWh produit à partir d'installations de production d'électricité verte situées en Région wallonne. Ce régime d'aides n'est pas cumulable avec celui des certificats verts. Toutefois un régime d'aide à la production complémentaire au système des certificats verts est élaboré en faveur des producteurs d'électricité verte produite en région wallonne à partir de techniques prometteuses mais émergentes.

- au fédéral:

Des certificats verts seront attribués aux concessionnaires disposant d'installations produisant de l'électricité à partir des vents situées dans les espaces marins.

De plus, en vue d'assurer l'écoulement sur la marché d'un volume minimal d'électricité verte, il est établi un système de prix minima de rachat. Le GRT a l'obligation d'acheter au producteur d'électricité verte qui en fait la demande, les certificats verts octroyés en vertu des dispositions légales, décrétales et réglementaires précitées, à un prix minimal fixé selon la technologie de production, à:

- énergie éolienne off-shore: 90 EUR/MWh
- énergie éolienne on-shore: 50 EUR/MWh
- énergie hydraulique: 50 EUR/MWh
- énergie solaire: 150 EUR/MWh
- autres sources d'énergie renouvelables(dont biomasse): 20 EUR/MWh

Le solde net qui résulte de la différence entre le prix d'achat du certificat vert par le GRT et le prix de vente de celui-ci sur le marché est financé au moyen d'une surcharge sur le tarif de transport.

5. Veuillez fournir des informations détaillées sur les nouvelles taxes appliquées ou prévues depuis 1998.

Depuis 2001, une surcharge a été instaurée pour couvrir les frais de fonctionnement de la CREG (arrêté royal du 18 janvier 2001, modifié par l'arrêté du 14 mars 2002). Appliquée à l'énergie électrique consommée par la clientèle ultime, cette surcharge s'est élevée pour l'année 2001 à 0,000125EUR/kWh et s'établira pour l'année 2002 à 0,0002492 EUR/kWh.

6. Quelle est l'évolution des émissions provenant de la production d'électricité (SO₂, NO_x, CO₂, particules) pendant la période 1998-2001?

	1998	1999	2000	2001
Emissions de CO ₂ (en kilotonnes/an)	23.676	20.841	21.222	20.990
Emissions de SO ₂ (en tonnes/an)	61.235	33.417	34.505	30.593
Emissions de NO _x (en tonnes/an)	46.834	32.537	39.169	32.367

Les indicateurs environnementaux ci-dessus concernent les émissions émises par les centrales électriques de la CPTE (Electrabel et SPE)
(source : rapport environnemental 1999 et 2001, Electrabel)

J. Application de la loi sur la concurrence

1. Concentrations:

Six cas de concentrations ont été notifiés au Conseil de la concurrence, dans lesquels on trouve ECS (Electrabel Customer Solution) filiale de Electrabel SA, avec six intercommunales mixtes:

- Interlux
- Idec
- Sedilec
- Simogel
- Interrosane 2
- Imea

En date du 3/10/02, les deux premières ont été approuvées avec des conditions, dont l'une vise à assurer la transparence de l'information du client devenant éligible et l'autre visant à éviter que le client devenu éligible et ayant déjà signé un contrat de fourniture ne soit pas captif pour une trop longue durée.

Les autres dossiers sont encore pendants.

Préalablement à ces dossiers, il y avait déjà eu une précédente notification entre six intercommunales pures et les sociétés Publilum Centrica et Luminus en vue de créer une joint venture (Luminus) pour la fourniture des clients de ces intercommunales. La concentration a été acceptée sans condition le 10/09/01.

2. Ententes: il n'y a eu aucune instruction dans ce domaine.
3. Abus de position dominante: les autorités de concurrence n'ont encore instruit aucun cas dans ce domaine.

BRAZIL

I. Introduction

The Brazilian government regulates the energy sector with the objective to promote competition, in order to allow consumers to obtain energy with low prices and investors to receive a just return on their assets. In this sense, the Brazilian electricity industry has been divided in generation, transmission, distribution and retailing to obtain the best results. Generation and retailing are being regulated at a minimum level and becoming competitive activities, ran by the entrepreneurs at their own risk. Transmission and distribution, considered as natural monopolies, remain as regulated activities. The Federal companies, as well as some state companies, are being separated in transmission utilities and generation companies before privatisation.

This paper intends to describe and analyse the recent changes in the electricity sector in Brazil. The paper is divided as follows: section II presents an overview of the Brazilian electricity sector; section III describes the main characteristics of the electric market in the country; section IV analyses the division of the electric sector and the main rules in the field of competition adopted in Brazil; section V describes how prices are set in the sector, including the first large bid of energy and the measures adopted to avoid anticompetitive practices and section VI presents a brief conclusion.

II. Overview

The Brazilian electricity sector, as in other countries, was formed by vertically integrated companies. The production and long distance transmission activities were concentrated in federal and state companies¹ and the distribution was concentrated in state companies.

The Brazilian electricity regulatory model started to be restructured in 1995, when the Law 9,074 was approved by the Congress, defining the regulation model and introducing the first steps towards competition and the government started privatising its distribution companies².

In December 1996, the Law 9,427 created the Brazilian Electricity Regulatory Agency – ANEEL, established under a special administrative regime with financial and administrative autonomy³. ANEEL started its activities on December 2 1997, with five Directors, indicated by the President of the Republic and confirmed by the Senate for a fixed mandate. It was created with the mission of provide favourable conditions for the development of the electricity market, based on balanced relationship among its agents for the benefit of society.

An important step in terms of competition was taken in May 1998 by the Law 9,648, which established the Wholesale Energy Market – MAE, created the Independent System Operator – ONS, instituted free purchasing of power for the distribution companies, and created a new agent, the retailer⁴.

In June 2000, the National Energy Policy Council – CNPE was created with the duties and responsibilities to proposing national policies of energy, including the rational use of the nation's energy resources, guidelines for covering the use of natural gas, alcohol, coal, nuclear power and imports and exports of energy, among others.

From June 2001 to February 2002, the country has faced a supply crisis. The crisis occurred as a result of scarce rains and of delays in investments in plants and transmission lines. The administrative structure within the government is also starting to manage the new model in a totally different environment. The plan of action to solve the problem was the creation of the Crisis Cabinet⁵, a program for the reduction of demand⁶, an emergency program to increase the energy supply and the revitalisation of the model. Above all, the main objectives of the revitalisation project have been the following: the prevention of a possible crisis in the future, the reinforcement of market-based mechanisms, the creation of an environment to ensure adequate expansion of supply, stimulate competition, solve controversies related to non-manageable costs (as in the case of the prices of natural gas set previously in long-term contracts indexed to the US\$ dollar) and reduce its impact on prices.

III. The Market

The main characteristics of the Brazilian electric market are the high dependence on hydrology and the huge transmission network lines. The 91 main hydroelectric plants belong to seven different hydrologic regimes and require more than 69.000 km of transmission lines to connect them with local distribution.

The main premise in the Brazilian generation planning is that the system is able to supply energy for the country 95% of the time. There is a risk of failure in hydroelectricity system of 5% (one year in a period of twenty years). The total current generation capacity of the inter-linked system is 72,810 MW⁷, as Table 1 shows below.

Table 1. Installed capacity in 2001

SOURCES	MW	(%)
Hydroelectric	61,555	82%
Conventional thermal	6,944	9%
Nuclear thermal	1,966	3%
Wind and /small hydros	2,345	3%
TOTAL	72,810	92%
Imports from Paraguay (Itaipu)	5,500	7%
Imports from others countries	1,150	1%
TOTAL SUPPLY	79,460	100%

Source: Administrative Committee of the Electric Sector Crisis

Although Brazil has currently a generation capacity higher than the demand⁸, the country has faced a supply crisis, as the level of water in the reservoirs decreased sharply in relation to historical levels. The structural program to solve the problem was created with the objective to increase additionally, until 2004, transmission lines by 9.250 km and power generation by 28,040 MW, as shown in Table 2.

Table 2. Increase of supply in the structural program

SOURCES	MW	Investments (R\$ Million)
Hydroelectric	9,990	11,239
Natural Gas Thermal	11,434	16,776
Emergency Thermal	2,153	2,974
Others (small hydros/cogeneration/wind))	2,067	6,195
Imports	2,386	1,317
TOTAL SUPPLY	28,040	28,040

Source: Administrative Committee of the Electric Sector Crisis

In reality the efforts to improve the supply of energy in Brazil started recently in 1995, when the government implemented the first steps in the privatisation programme. At first, the privatisation was based above all on the decisions of the National Privatisation Council - CDN. In this period, Light (EDF) and Escelsa (IVEN), two large distribution companies, were privatised. From this period until 1997, the Government, with the support of the World Bank, hired some consultants from the British Company Coopers & Lybrand to collaborate in the privatisation process. Many other electricity companies were privatised, such Eletropaulo Metropolitana - Eletricidade de São Paulo S.A. (AES), Eletricidade e Serviços S.A. (Enron), Companhia de Geração de Energia Elétrica Paranapanema (Duke), Companhia de Geração de Energia Elétrica Tietê (AES), Companhia Energética de Pernambuco (Iberdrola) and Cia. Energética do Maranhão (Pennsylvania Power & Light). Tables 3.1 and 3.2 below present the main players on the generation and in the distribution market.

Table 3.1. Main generation players

AGENT	Market Share
Eletrobrás S/A (Federal Government)	39,03 %
São Paulo State Government	13,54 %
Eletronorte S/A (Federal Government)	13,28 %
Tractebel Energia S/A	7,71 %
Minas Gerais state government	7,57 %
Furnas Centrais Elétricas S/A (Federal Government)	7,41 %
Paraná state government	6,28 %
VBC Energia S/A	5,46 %
Serra da Mesa Energia S/A	5,45 %

Source: ANEEL (Brazilian Electricity Regulatory Agency)

Table 3.2. Main distribution (retail) players

AGENT	Market Share
AES International Holding Ltda.	16,12 %
Minas Gerais state government	12,27 %
EDP – Electricidade de Portugal	7,36 %
Paraná state government	6,32 %
Guarania Comércio e Serviços S/A	6,18 %
Enerpaulo – Energia Paulista Ltda.	5,56 %
Endesa	5,47 %
EDF – Electricité de France	5,22 %
Bank of Brazil Investment Fund	4,98 %
Santa Catarina state government	4,64 %
VBC Energia S/A	4,05 %
Enron South America Ltd	3,55 %
EPC – Empresa Paranaense de Comercialização Ltda.	3,55 %
Serra da Mesa Energia S/A	3,14 %
Iberdrola S/A	2,41 %

Source: ANEEL (Brazilian Electricity Regulatory Agency)

The changes in the regulatory field and the participation of private capital allowed the companies in the sector to recover their investments. The annual average growth of energy supply has increased from 2,428 MW (between 1981 to 1985) to 3,100 MW (1996-2000) and is expected to reach 8,432 MW (2001-

2005). The basic transmission network has increased from an average of 686 km/per year (1990-1994) to approximately 2,500 km in 2002. In 2003, a substantial increase of 5,565 km is expected.

IV. Competition

The regulatory objectives of the Brazilian government is to promote competition, in order to allow consumers to obtain energy with fair prices and investors to receive a fair return on their assets. The main Rule in the field of competition is Resolution 094 set by ANEEL, which established the following market concentration limits: (i) in generation, the agent may not hold more than 20% of the national installed capacity and if its operates in the interconnected system of the South, Southeast and Middle-West regions may not hold over 25% of the installed capacity of this system and in the interconnected system of the North and Northeast regions may not hold over 35%⁹; (ii) in distribution, the agent may not hold more than 20% of the national distribution market and if its operates in the interconnected system of the South, Southeast and Centre-West regions may not hold over 25% of the distribution market of this system and the agent operating in the interconnected system of the North and Northeast regions may not hold over 35% and also (iii) when a single agent is operating as generation and distribution, the arithmetic sum of its share of the national installed capacity and its share of the national distribution market may not exceed 30%, but this agent may acquire new stakes through the privatisation processes even if this exceeds the limits established within no more than 24 months. The distribution agent may not acquire more than 30% of energy from a generation agent that belongs of the same economic group. The Table 4 below presents these limits.

Table 4. Market share limits for agents

	NATIONAL	SOUTH/SOUTHEAST/ MIDDLE-EAST	NORTH/NORTHEAST	OBSERVATION
GENERATION	≤ 20%	≤ 25%	≤ 35%	Higher level allowed when there is one plant in the area
DISTRIBUTION	≤ 20%	≤ 25%	≤ 35%	-
GENERATION + DISTRIBUTION	≤ 30%	-	-	-

Even if ANEEL determines ex-ante the rules for the maximum market share allowed by the agents, ex-post analyses are done by the Brazilian System for Competition Defence – SBDC¹⁰. The SBDC is composed of the Secretariat for Economic Monitoring (SEAE) of Ministry of Finance, Secretariat of Economic Law (SDE) of the Ministry of Justice and the Administrative Council for Economic Defence (CADE)¹¹, an independent body administratively linked to the Ministry of Justice. Also, the SBDC investigates and punishes anticompetitive practices cases. In order to improve the competition defense in the electrical sector, ANEEL and the entities of SBDC signed collaborative agreements. As agreed, ANEEL states its opinion in mergers and provide technical support in cases involving anticompetitive practices whenever it is necessary.

The sequential five-step framework for horizontal merger analysis presented at SEAE's and SDE's common guidelines are the following: (i) step I: consists in defining the relevant markets through the "hypothetical monopolist test"; (ii) step II: consists in calculating market-shares of the merging firms. The Guidelines assume, in general, that no unilateral market power is involved if post-merger market-share of the merged firm is less than 20%. The Guidelines also assume that non co-ordinated market power is

generated if post merger market-share of the merged firm is less than 10%, or if the combined market-share of the four largest firms is less than 75%. Mergers that do not involve substantial market-shares are cleared without further analysis. If market-shares are significantly high, the analysis is carried on to the next step¹²; (iii) step III: corresponds to the examination of the probability of the exercise of market power. The Guidelines consider that a firm will find it profitable to increase its prices above competitive levels if its own demand is sufficiently inelastic. At this stage, the agencies will analyse, among other aspects, the volume of imports in the market; the likelihood, timeliness and sufficiency of entry; and effective rivalry between competitors. The assumption is that if the demand is inelastic enough, market power will probably be exercised if imports are not in place; if entry is not timely, likely or sufficient; and if competition among incumbents is low. If the agencies conclude that the firm is likely to exercise its market power, the analysis will then proceed; (iv) step IV: refers to the assessment of possible economic efficiencies of the merger. Economies of scale and scope; transaction costs reductions; the introduction of a new technology; the internalisation of externalities and the creation of countervailing market power are arguable efficiencies. However, any efficiency argument has to be merger-specific, and explicitly excludes pecuniary gains and any other income transfer between economic agents. In particular, the agencies will not consider to be merger-specific the ones that can be reached, in a period shorter than two years, by alternative means that involve less risks for competition and (v) step V: introduces a “balancing-test”, where the agencies will weight the efficiency argument against the possible anticompetitive effects. The agencies will clear the merger whenever benefits are likely to be higher or equal than its costs; and recommend the merger to be blocked or conditioned to specific remedies, whenever the efficiency argument is not sufficient to counteract the possible anticompetitive effects of the transaction.

In order to allow open accesses to the transmission grid, the Government created the Independent System Operator – ONS that provides transmission services on behalf of transmission companies. All users (generators, distributors, retailers, and large consumers) contracted with ONS the conditions to use the grid in accordance with the provisions of the regulator, independent of the grid owners.

The activity of buying and selling energy, known as retailing, traditionally performed by distribution utilities, is considered an independent segment. Although several new firms have already been authorised by the regulator to operate as retailers, the distribution agents continue selling energy for their consumers. At the moment, ANEEL is determining that distribution companies have to separate their accountings in distribution and retailing, in order to provide services to all consumers in a non-discriminatory basis.

Consumers with a demand higher than 3 MW, connected to 69 kV and above are currently considered free consumers. They have the right to choose their suppliers: a producer, a retailer or even another distribution company that operates as retailer in another region. Although, according Light Company, the distributor in Rio de Janeiro, free consumers prefer to buy energy from the distribution agents because the tariffs, controlled by the regulator, remain subsidised. ANEEL has already announced that in the next few years, it will promote total competition in all levels of consumption. This means that distribution companies will loose the monopoly to sell energy for the non-competitive segment of market - small consumers, called captive consumers. In this sense, it is worth mentioning that the size of free consumers is decreasing. In July 2000, free consumers’ size were set in ≥ 3 MW (69kV), will decrease to ≥ 50 kW in July 2003, until they become all free by January 2005.

V. Prices

Until now, as captive consumers have not the right to choose their suppliers, ANEEL regulates their tariffs. The index to readjust annually energy tariffs is obtained with the formula below:

$$IRT = \frac{(VPA_1 + VPB_0) \times (IGP-M)}{RA_0}$$

Where, IRT is the readjust index; RA is the total revenue earned by utility in the past twelve months; VPA is the total distribution exogenous (not manageable)¹³ cost, like the total energy purchase, subsidy for expensive energy suppliers and payments to access transmission system; VPB refers to the distribution endogenous (manageable) costs, fixed when the company was privatised; IGP-M¹⁴ is inflation index.

Also, in Brazil, concession contracts preview the revision of tariffs levels in order to verify if the economic and financial balances of the companies are being maintained as agreed in the concession contracts. After an initial period of 4 or 5 years, the regulator have to revise the tariffs and define an X factor, which will be added or subtracted from IGP-M for the next period¹⁵, with the purpose of sharing efficiency gains with the consumers.

Energy can be purchased in different ways. When distribution companies were privatised there were contracts between them and power generation companies. These contracts, called “initial contracts”, will be finalised from 2003 to 2006 (25% each year, that is, 25% finishes in 2003, 25% finishes in 2004, and so on). This measure was adopted to avoid sudden rise in electricity prices for the captive consumers. The prices of energy of the initial contracts increase annually based on the IGP-M index.

With the end of the initial contracts, bilateral contracts¹⁶ must be signed between producers and retailers or consumers, or between retailers and consumers. The Brazilian regulation rule determines that distributors must contract 85% of the energy in the long run, and 95%, considering long and short run. These contracts contain terms, price, duration, point of delivery, guarantees and other conditions. The duration, from two to six years¹⁷, serves as a hedge against fluctuations of spot prices. A general rule defined by the regulator is that every retailer, including distribution companies and producers, must have at least 85% of its energy sales covered by bilateral contracts. The companies are free to negotiated bilateral contracts, but the prices could not be higher than the reference prices (VN) established by ANEEL¹⁸. In February 2001, the reference prices, by source, were: competitive energy = R\$ 72,35 MWh, coal thermoelectric plant = R\$ 74,86 MWh, small hydroelectric plant = R\$ 79,29 MWh, biomass and residue-fuelled hydroelectric plant = R\$ 89,86 MWh, wind-powered plant = R\$ 112,21 MWh and photovoltaic solar plant = R\$ 264,12 MWh¹⁹.

Bilateral contracts are made directly between agents or through bids. Some private distributors buy through bids operated by the Bank of Brazil. A large bid occurred on last September 19 th, when 25% of the energy initial contracts was negotiated. Exceptionally in this case, the Government determined that the Wholesale Energy Market – MAE (where short-term transactions of energy charged by spot prices occur) would be responsible for the supervision of the bid process. It was the biggest bid already done, corresponding to 3,900 MW of energy offered by the federal companies. The bid was mandatory for the federal generation companies (the “old energy”), but voluntary for some other companies (state owned and private joined the bid).

Since the amount of energy that would be offered was very big (3900 MW, in packs of 0,5 MW, in contracts for terms of 2, 4 or 6 years, for the interconnected system), it was possible for some buyers to acquire huge amounts of energy and after the bid use market power to resale the energy for very high prices.

In order to avoid this problem and other anti competitive practices, a set of rules was established by ANEEL. The main rules established were: (i) distribution companies and retailers could participate only as buyers; (ii) generation companies could participate only as sellers; (iii) those who participate as buyer

cannot participate as seller and vice-versa; (iv) to participate in the bid, companies had to respect the restrictions about market share, self dealing, cross-participations in other companies and other societary vinculations; (v) the total bidding of a potential buyer (or group of buyer under the same holding company) cannot be bigger than 70% of the total energy offered for each term (2, 4 or 6 years); (vi) it was not applied for products with less than 100 packs of energy (50 MW) and (vii) sellers had to offer at least 10% of their total offers for each term of supply. It was not applied for products with less than 100 packs of energy (50 MW).

Before the bid, the agents (buyers and sellers) were invited by ANEEL to discuss the rules and their application. The bid took place in a internet site and about a third part of the offered energy was sold, and most of dealt prices were inferior to current prices contracted bilaterally.

When the level of energy contracted is different from the level of energy produced or needed, producers, retailers and free consumers can buy or sell energy in the spot market at the Wholesale Energy Market - MAE. Initially, the spot market was designed to allow agents themselves to create the rules. However, between 1998-2001, agents were not able to reach an agreement about the accountings rules, which forced the Aneel to interfere in the market by indicating the directors and the President of the MAE to regulate these accountings. Currently, prices are set weekly, but with three different prices during the day (hours with high demand, with low demand and with normal demand) based on statistics provided by the ONS20. Prices established by the MAE are based on: (i) information received by the ONS related to the quantity of energy dispatched; (ii) bilateral contracts registered at the MAE and (iii) mathematical model used by the ONS. MAE is still elaborating its accountings to proceed the payments among agents²¹.

The spot market in Brazil has a special peculiarity as the energy produced is basically from hydroelectric power mills, belonging to different hydrologic regimes and, in many cases, disposed in cascade along the rivers. For this characteristics, and in order to reduce risks, the Brazilian systems consider the stock of energy as the stock of water in the reservoirs in the entire interconnected systems. That is, each generator company has a stock of energy (water) which is made available to its interconnected system²². The ONS decides on how much and when these agents have to deliver energy through the interconnected grid, based on the water regimes; on how much water is accumulated in water power mills; on the expected level of rains for the next 2-3 years²³ and on the hour of the day, optimising the use of the water. It is important to underline that water belongs to the system, and each plant has its own "ensured energy". Revenues are based on the "ensured energy", not on the amount of water that effectively passed in the turbines.

Although this system reduces risks, because its acts as a hedge for all the participants in the interconnected system, it also creates a complex accountings procedures. Regulators, particularly the ANEEL and the MAE are elaborating the accountings methodology of the 105 agents involved in short-term operations. After this methodology is set, the MAE will proceed with the payments among the participating members through the Brazilian Company of Clearing and Custody ("CBLC-Cia. Brasileira de Liquidação e Custódia).

In Brazil, the operational costs of thermal energy are higher, because it uses gas, coal or similar inputs, but the cost to implement a thermal mill is much lower than a hydroelectric mill. Under normal circumstances, the price of water is equal to the marginal operational cost. If the price of water is higher than the marginal cost of thermal energy, than these mills are requested to operate. Also thermal energy plants are requested to produce when a water mill is being repaired or in hours with high demand. The same is valid when nuclear mills are being repaired (as in the recent case of Angra I Nuclear Plant). The obligation of the ONS is to ensure the correct level of supply in the country, in spite of the short-term costs.

The transmission tariffs are established by a different methodology, called revenue cap. The revenue of each agent is defined in a competition process promoted by ANEEL. Winners of these tender offers are selected by their ability to conduct energy at the lowest transmission revenue. Their revenues are modified annually, by using the index IGP-M. Transmission costs (sum of the revenues of the transmission agents) are divided and paid by all consumers. According to the agents in private sector, there are not major problems with transmission of energy in the country. The transmission services fees can be compared to the fees charged for general Internet services, when only one fee is charged to obtain services in a certain period of time, regarding of the geographical area covered by these services. In the future, ANEEL intends to change the model by providing economic signals for generators and consumers to use the transmission system efficiently. It includes different tariffs for each node of the system to be applied to generators and, for the demand side, an average tariff to be applied to all consumers in each state of federation.

VI. Conclusion

Although the government has made structural reforms to improve the market mechanism on the electric sector, many problems still occur. According to the agents of the energy sector, the market is not working as expected because consumers would not be able to pay the prices necessary to maintain the financial and economic balance of firms. Demand is currently lower than the forecasts done in the year 2000, reflecting the supply crises that happened last year (there was a decrease of 15% consumption in the last year). On the other hand, agents, mainly private distributors, are facing serious financial problems because they have contracted many loans in US dollars and with the devaluation of the Brazilian currency Real in relation to US dollars, these loans became an additional burden to their financial health.

In order to reduce their financial problems, private agents in the energy sector are requesting that ANEEL increases the tariffs charged to the industrial sector (currently they consider this tariffs as low), or charges old energy (initial contracts) to residential consumers and new energy (more expensive in the bilateral contracts) to industries. However, these proposals can increase industrial costs and diminish national competitiveness.

Although in this year many important decisions are being taken, in the next year, Brazil will have another government (elections will occur in October 2002). Decisions taken by the new government are going to be fundamental to the future success of the Brazilian energy market.

NOTES

1. Federal companies: Eletrosul, Furnas, Chesf and Eletronorte. States companies: more notably, São Paulo State Company - Cesp, Paraná State Company - Copel and Minas Gerais State Company – Cemig.
2. Light, in the State of Rio de Janeiro, and Escelsa, in the State of Espírito Santo.
3. Also, their decisions are taken under collegiate rules of procedure.
4. The retailer (or broker) is a new agent that could operate in the electricity industry just buying and selling energy, without needing to own or build any facility such as generation plant, transmission lines or distribution network.
5. The Crisis Cabinet (or Administrative Committee of the Electric Sector Crisis) was created at the highest government level and its decisions did not depend upon other government instances. The head of the crisis cabinet was the Minister of the Civil Cabinet of the Presidency of the Republic.
6. The reduction of demand was 19% in average, comparing with the same period one year later. For the households it was 24,4%.
7. There are some local systems, mainly at the Amazon Region, that have more than 1.200 MW of capacity.
8. The peak demand before rationing was 56,000 MW. During the rationing it was 44.000 MW.
9. Stakes larger than the limits established above will be permitted, if there is only a single power-generation plant in a specific region.
10. Recently, SEAE analysed some cases with respect to concession of new hydroelectric plants and selling of shares in hydroelectric plants already auctioned. All of them were approved without restriction.
11. CADE is an administrative tribunal and its decisions can only be reviewed by the judicial courts.
12. Some authors argue that market shares (or concentration indexes, like HHI) are not the best way to infer the existence of market power in electricity markets. At this moment SEAE is studying alternative market power indicators for electricity markets.
13. It includes items as energy bought from Itaipu, which price is quoted in US\$, as established in an international treaty with Paraguay.
14. General Prices Index Market, calculated by Getulio Vargas Foundation.
15. It takes into account the utility costs, a fair return on assets considering an ideal structure of capital and a fair return on equity and tries to share with consumers' part of the gains in efficiency achieved in the precedent period.

16. Also, a kind of long-term bilateral contract called Power Purchase Agreement – PPA has been promoting new investments in generation, as it reduces market risks to investors.
17. According Light, as the demand level reduced and an excess of supply in energy is expected for 2003-2004, the current prices are low and companies prefer contracts for two years.
18. VN takes into account the projects underway, the expansions foreseen for the generating complex, the updating of plant costs, the bilateral contracts signed between the agents, and the policies and guidelines issued by the Federal Government.
19. The average exchange rate in September 2002 is R\$ 3,1/US\$.
20. Each Friday, the Wholesale Energy Market Agent sets the three prices of energy for the next week. Each price corresponds to 8 hours-period, when daily demand changes. These prices are identical to all participants. Currently, are around US\$ 5,00 MWh. However, during the supply crisis in 2001, they reached up to US\$ 200,00 MWh.
21. As the accountings rules are being established, in September 2002, the amount to be set among companies since 1998 are estimated to be around US\$ 2 billion. Companies that have to pay are saying that they can be bankrupt after these payments, while those companies that are going to receive financial resources are pushing the Government to finalise the process. Meanwhile, several companies are informing that they will prosecute the Government (and block temporarily the distribution of financial resources) if the rules are not satisfactory to them.
22. These interconnected systems were developed according to the location of the power mills and the demand. A new legislation are been proposed to transform the four interconnected systems in two energy markets in order to improve competition. However, as the linkage among them is still not perfect, it can be affected by the ONS dispatch decisions and also by the prices in the spot market.
23. In order to support its decisions, it is developing a mathematical model that considers the hydrology in Brazil in the last 70 years.

BRAZIL¹

Contribution from CADE²

Overview of Regulation

Since the beginning of the 1990s the Brazilian government has taken significant steps towards a better regulatory framework in the electricity sector. The general direction has been the transition from a State-centered system (where the activities of generation, transmission and distribution were in the hands of State-owned enterprises), to a market-oriented one, with a greater role of the private sector and the enhancement of government functions as a regulator. The process, however, is not so straightforward, and the Brazilian electricity sector faced a serious energy crisis during 2001. But the threats derived from the shortage of energy prompted a complete revision of the regulatory framework, as will be seen in this short article.

During the early stages of the Brazilian industrial development, the government assumed the pivotal role of providing infrastructure services. This decision rested on economic and political reasons, among them the significant amount of capital investments needed, the lack of industrial groups capable of providing these resources, and also national security reasons. Thus, the design of the electricity sector in Brazil was based on the State planning and the exploitation of natural monopolies, as occurred in various other developing and developed nations. The responsibilities for the generation, transmission and distribution of energy were shared among the federal government and the states.

Due to the dimension of the Brazilian territory and the abundance of hydrological resources, the exploitation of regional monopolies was one of the main features of the Brazilian system. Four state-owned companies were created in the beginning of 1960s, each one responsible for the generation of energy in the main river basins: Chesf, Eletronorte, Eletrosul and Furnas. Another generator, Itaipu, was also built in association with the Paraguayan government. The equity control of all these companies, as well as the responsibility for their transmission lines, was gathered on a single holding company, Eletrobras, which is still the main player in the production and transmission of energy in Brazil.

Following the same logic of exploitation of regional monopolies, the distribution of energy was delegated to the state governments. It is noteworthy that some of the richest states (like São Paulo, Minas Gerais, Paraná and Rio Grande do Sul) also established generation plants and transmission lines, besides their distribution duties – in order to stimulate the industrial development of their regions.

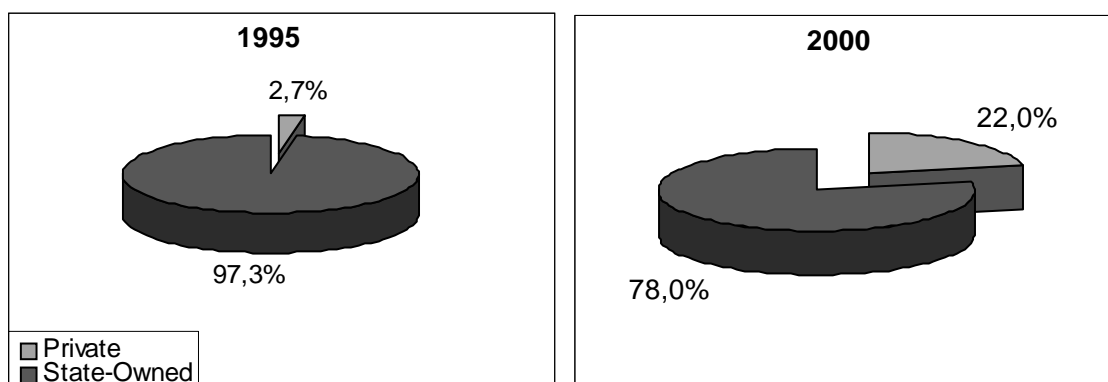
The choice for a State planning design of the electricity sector in Brazil brought implicit the idea of coordination of operations. Two agencies were established to guarantee the best functioning and the expansion of the system. The decisions about the generation of energy of each plant were taken by a central agency, the Coordinating Body for the Interconnected Operation³ (GCOI). This agency acted like a central planner, determining the appropriate amounts of energy each plant had to produce, as well as the distribution of this energy, in order to assure the maximum efficiency of the system as a whole. Another agency, the Coordinator Body for the Planning of the Electricity System⁴ – GCPS, was responsible for the schedule of investments necessary to match the growing demand for electricity in Brazil. In both of these agencies, Eletrobras had the leading position. Moreover, the former regulatory agency, National Department for Water and Energy⁵ – DNAEE, was subordinated to the Ministry for Mining and Energy, without operational autonomy.

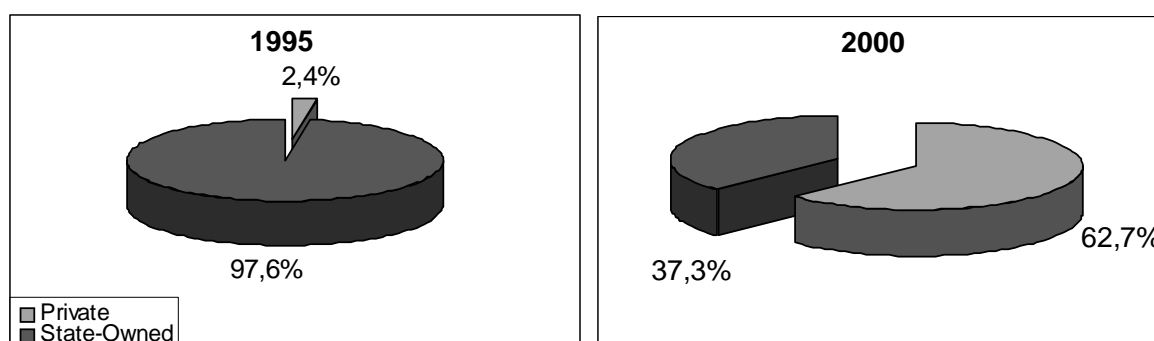
This framework functioned pretty well during the decades of 1960 and 1970, with a considerable expansion of the generation capacity and the transmission and distribution lines. Notwithstanding its satisfactory performance in providing the basis for the industrial development in Brazil, the sector was seriously affected by the foreign and domestic crises that hit the Brazilian economy during the 1980s. The scarcity of capital inflows since the Mexican debt crisis in 1982, the necessity of fiscal adjustments and the rampant inflationary process pressured the investment schedule. Unfortunately, this adverse scenario was observed in an environment of growing demand, aggravating the situation.

The lack of the government capability to continue to provide infrastructure services, expanding the system and making the investments needed to improve its efficiency, was not observable just in the electricity sector. It was explicit the necessity for reforms. With this objective, a national program of privatization has been in force since 1990. But the idea of a regulator State in substitution of a producer State gained momentum only in the first mandate of President Fernando Henrique Cardoso. The reform of the Brazilian electricity system was part of this new concept of State.

The restructuring of the Brazilian electricity sector is being implemented step by step. The first fundamental measure was taken with the approval of the Law 8,987, from 1995, known as the General Law of Concessions. This law provided the general rules for the delegation of the right to exploit public services to the private sector, including the electricity sector. Following the determination of this new rule, the federal and the state governments started a process of privatization of generation and distribution companies. This movement was stimulated not only by the necessity of private investments in the electricity sector, but also because of the serious fiscal constraints that these levels were facing. A considerable share of the distribution market was privatized, as well as some generation companies. The graphs below offer a comparison between the state-owned and private-owned shares of both of these markets before and after the reform.

Graph 1 – Participation of Private and Government Control over Generation Capacity



Graph 2 – Private and Government Shares on Distribution Capacity

Despite the increasing participation of the private sector into the electricity market, the system also demanded a general regulatory framework. This lacuna was fulfilled by means of a set of laws. The first of them was the Law 9,427, from 1996, that created an independent agency to deal with the electricity sector: the National Agency for the Electricity Sector – Aneel. This agency has autonomous powers to define the policy for the sector. This is a fundamental departure from the previous system, where very often the other policies, especially macroeconomic ones (like inflation control, for example) bypassed the microeconomic electricity policies. The directors of Aneel have fixed and staggering mandates, which render stability for the implementation of measures.

Completing this framework, the Law 9,648, from 1998, creates the Wholesale Market for Energy, the agency responsible for the exchange of energy between the generators and the distributors, through bilateral contracts, as well as the spot market of energy. The centralized agency that coordinated the production of energy of each plant was replaced by the National Operator of the System, a non-profitable and independent agency responsible for the management of the transmission system.

In spite of the conclusion of this general framework, several mechanisms necessary for a complete transition to a market-oriented system remained to be done when a severe drought hit the country. As will be seen in the next parts of this article, the regulatory uncertainty and the lack of incentives impeded the conclusion of important investments in the expansion of the generation capacity. With the historical low rainfall, the Brazilian economy was trapped in an energy crisis, which demanded a rationing program.

The first governmental action to deal with the crisis was the creation of a special committee to coordinate the government actions. The efforts of the Interministerial Chamber for the Management of the Energy Crisis⁶ – GCE were concentrated in three directions: (i) a rationing program intended to reduce the energy consumption; (ii) an emergency program to increase the energy supply in the short-term; and (iii) a complete revision of the regulatory framework. From June 2001 to February 2002, the Brazilian economy was compelled to reach a general goal of reducing 20 percent of the energy consumption. The success of the program was fundamental, and despite the reduction in the path of the economic growth (as a result of a smaller supply of energy), it was possible to avoid supply shortages and blackouts. The emergency plan to increase the supply of energy in the short-term was also important to reduce the uncertainty, by means of energy imports, the purchase of energy generated by independent generators and electricity-intensive consumers. The revision of the regulatory framework is still in place, and the main issues will be discussed throughout this document.

Before dealing in more detail with the specific subjects regarding the electricity sector in Brazil, it is important to provide an overview of the basic structure of the sector. As December 2001, the generation capacity of electricity energy in Brazil was around 75.5 GW. Near 6.7 GW were derived by

imports, most of them from the Paraguayan government share in Itaipu, but also from Argentina, Uruguay, and Venezuela. Taking the Brazilian generation of energy, the major part is derived from hydroelectric plants (82.6%). The thermoelectricity accounts for the remaining 17.3%. Needless to say that this dependence on the hydroelectricity was the cause behind the energy crisis of 2001.

Market Structure

The Brazilian electricity sector is featured in four different segments: generation, transmission, distribution and trading. The guidelines of the Brazilian policy for the sector is to stimulate the competition in the generation and trading segments, and to guarantee free access to agents in the transmission and distribution ones.

As it was mentioned before, the structure of the generation market in Brazil before the reform of the sector was dominated by the subsidiaries of the State-owned enterprise Eletrobras (subordinated to the federal government) and a few generator companies owned by state governments. After the Law 8,987 (Law of Concessions) the government was allowed to transfer the energy companies (generation and distribution) to the private sector. Diversely from the distribution companies, the privatization of the generation companies faced a strong political opposition. For this reason, few companies were privatized, and the market is still dominated by State-owned companies. The chart below presents the proceeds of the privatization of generation firms.

Brazilian Privatization Program - Electricity Generation Companies		
<i>Company</i>	<i>Date</i>	<i>Proceeds (US\$ million)</i>
1.1 Federal Government		
Escelsa	07/11/1995	522,0
Light	05/21/1996	3.094,0
Gerasul	09/15/1998	1.962,0
Federal Government	1995 through 2002	3.893,1
1.2 State Governments		
Cachoeira Dourada	09/05/1997	854,0
CESP Paranapanema	07/28/1999	1.164,0
CESP Tietê	10/27/1999	1.140,0
Total		12.629,1

Source: BNDES

Note: The values include debt transfers to the private sector.

Among the main players in this segment, the three remaining federal companies can be listed (Chesf, Furnas and Eletronorte) besides state companies (Cemig, Copel, CEEE, CESP Paraná) and privatized ones (like Paranapanema, Tietê, and Gerasul).

The government policy towards the transmission segment is to reduce to the minimum the possibility of discrimination and the reap of extraordinary profits due to the congestion of lines. In this regard, the decision to break the vertical companies into generation, transmission and distribution ones is the first step towards this goal. But important agents in the market are still vertically integrated, as the federal and state companies.

In the distribution segment, a wave of privatizations was observed in the last years. As it was showed before, the majority of the distribution segment is dominated by private companies nowadays. The former state companies were sold to the private sector, as the following table shows.

Brazilian Privatization Program - Electricity Generation Companies

<i>Company</i>	<i>Date</i>	<i>Proceeds (US\$ million)</i>
2.1 State Governments		
CERJ	11/20/1996	951,0
Coelba	07/31/1997	1.811,0
CEEE Norte-NE	10/21/1997	1.635,0
CEEE Centro-Oeste	10/21/1997	1.436,0
CPFL	11/05/1997	2.833,0
Enersul	11/19/1997	783,0
Cemat	11/27/1997	814,0
Energipe	12/03/1997	560,0
Cosern	12/12/1997	718,0
Coelce	04/02/1998	1.246,0
Eletropaulo Metropolitana	04/15/1998	3.018,0
Celpa	07/09/1998	504,0
Elektro	07/16/1998	1.701,0
EBE	09/17/1998	1.235,0
Celpe	02/17/2000	1.135,0
Cemar	06/15/2000	447,0
Saelpa	11/30/2000	185,0
Coelba*	1996 through 1998	154,0
Copel*	1996 through 1998	413,0
Coelce*	05/09/1997	92,0
CEB*	04/30/1997	74,0
Cemig*	05/28/1997	1.053,0
Eletropaulo Metropolitana*	12/16/1997	427,0
Elektro*	02/18/1997	216,0
Total		23.441,0

Source: BNDES

Notes: *Minority Sharehols Sell-off

The values include debt transfers to the private sector.

Finally, the reform of the electricity sector in Brazil also allowed the presence of electricity traders and retailers. These agents can buy energy for distribution or generation companies and sell it to large consumers (above 10MW). The transactions take place at the Wholesale Energy Market, by means of spot or long-term contracts.

This market structure has had significant effects over the performance of the electricity sector in the last years. The transition from a coordinated system to a competitive one, as it was intended in the beginning of the process, was not put into practice in part because of the coexistence of privatized and state-owned companies. The regulatory and planning bodies were not capable to implement the right incentives to deal with rules for these different regimes. The lack of competition, as well as the uncertainty over the future of the system, was crucial to the crisis the Brazilian electricity sector faced in 2001.

Regulation Issues in the Brazilian Electricity Sector

The Transmission Network

As mentioned on the first part of this document, under the older regime, a central planner, the CGPS, was responsible for the coordination of the production and dispatch of energy. The decisions were taken with the objective to minimize the costs of generation and transmission, among others. With the entrance of private agents into this sector, the transmission fee was supposed to be the guiding element for the investment decisions of the agents.

Transmission fees in Brazil are defined by the regulatory agency as it procures new transmission lines. These fees are paid by the generators and the distributors, and are composed of two elements: the location component and the “seal” component. The location component is responsible to provide the investors and the consumers the incentive to locate their plants or distribution lines near the transmission network. So, it is variable according to the location of the agents. The second element, known as the “seal” component, is a constant fee shared in equal parts by all the users of the transmission network, wherever they are located. It is based on nodal (or zonal) prices.

During the transition period, it was decided that the weight of the location component would be smaller than the seal one. The trend would be a gradual change for the prevalence of the location component. Today the relative share is such that the seal component represents around 70 percent of the fee and the location one, 30 percent. The conclusion is that there is little incentive for the generation to be built near the consumers, what is an adverse situation especially for the thermoelectricity plants. Under the current system, therefore, the hydroelectricity plants tend to be in a better position, which is a deterrent to the entry of the thermoelectric plants and to the diversification of the use of primary sources of energy.

Regarding the upgrade and expansion of the transmission lines, the National Operator of the System (ONS) is the body that has the duty to analyze the cases and suggest to the national regulatory body, Aneel, to establish a procurement process to concede new lines. The Ministry for Mining and Energy has also a leading role in this process, by means of its planning studies.

Market Rules

The Wholesale Market of Energy – MAE was created in 1998 with the mission to intermediate all the transactions of buying and selling electricity in Brazil. The central role of MAE is with the spot market, where the differences between the agreed quantities in the bilateral contracts and the actual production are netted. Due to the existence of various hydrological basins in Brazil, four sub-markets were created in order to account for the differences between their system. So, a different spot price at MAE is defined for each period on each sub-market.

The performance of MAE as a short-term market for energy was considered disappointing due to several reasons. The first, is the still unfinished transition of the Brazilian system. The current situation implies that the amounts of energy produced and the prices are still established by the National Operator of the System on the grounds of the centralized dispatch. The price of the energy is calculated by an ONS' software that minimizes the average operational cost⁷, based on probability scenarios (regarding rainfalls, supply and demand for energy) for the following five years. The objective is to optimize the operation of the generation plants taking into account each hydrological basins. This methodology is considered imperfect by many experts, mainly due to unrealistic parameters of supply and demand, as well as the lag between the calculated prices and the perception of the agents (generators and distributors) regarding the real conditions of the market.

A solution for these problems can be the transition to a new model of price determination, based on the “price bid” approach. Under this model, the energy price is determined by the matching of the producers’ proposals regarding the price-quantity combinations for the next day and the consumers’ demand pairs. This approach would have the benefits of reduced informational costs (compared to the ONS model currently in place), and also the inclusion of the own risk expectations of the agents into the price formation process. So, the prices would be more consistent and endogenously determined. But the necessary condition for reaping these benefits is a competitive environment in the generation system, where the generation companies are able to manage their own risks. On the contrary, it will be difficult to avoid situations where the generation firms manipulate the prices, which can lead to crises similar to that observed in California in 2000/2001. Keeping in mind of this problem, this approach of “price bids” would be more coherent with the MAE functioning. The government is spending great efforts in studying this subject.

In fact, the experience of the spot prices as the guiding device for the investment schedules in Brazil was in large unsatisfactory. Taking into account that the hydroelectric plants have in general a huge water storage capacity, the energy price has a very volatile behavior. As MAE defines the price according to the marginal operational costs, during the periods where the droughts are more severe the price skyrocket, but under “normal” conditions the spot price is very low, near zero. This volatility affects the investment decisions, because the spot price is not a good leading indicator for the future price. As a consequence, the energy prices determined by the ONS and the MAE spot price do not provide an efficient incentive to guide market strategies.

Besides the difficulties related to the energy prices, the wholesale market also was affected by governance problems. During the analyses carried out just after the energy crisis, many factors can be listed: (i) rules excessively complex; (ii) worries about inconsistencies of some rules, (iii) gridlocks among agents. With the intention to eliminate the uncertainty and the lack of credibility implicit in its structure, the government recently approved a law streamlining and reformulating MAE. The Law 10,433, from April 24, 2002, classified MAE as a non-profit private organization, regulated and monitored by the regulatory agency, Aneel. Under this new legal apparatus, it reinforced MAE’s responsibility for the financial and accounting settlement of energy transactions. The creation of an arbitrage chamber will be an important forum to settle disputes between agents, and the greater role of Aneel will impinge more confidence and credibility to the wholesale market.

The participation in the MAE is compulsory for: (i) generation companies licensed or authorized by the government with capacity superior to 50 MW; (ii) companies licensed or authorized by the government to trade energy to a market with demand above 200 GWh per annum; and (iii) companies authorized to import or export energy superior to 50 MW. Other generation, trade or import/export firms can also be part of MAE, as well as self-producers. As can be seen below, energy sellers and buyers are also authorized to sign bilateral contracts.

Bilateral, Long-term and Forward Contracts

As it was noted in the section before, the spot price of energy in Brazil was not a good indicator for the expansion of the generation capacity. As a result of the highly volatile spot prices, both generators and distributors try to reduce to a minimum this risk by means of bilateral contracts. According to these contracts, the amounts and the price of the energy to be supplied by the generators are established for a longer period. If there are differences between the amounts agreed with the distributor company and the actual production, extra amounts are sold or bought in the MAE spot market.

Under this system, the expansion of the generation capacity is determined by the distributors' demand, and not the perspective of profits indicated by the spot price. If a distributor decides to match an increase in the demand for energy, it signs a bilateral long-term contract with a generator, which then has a guarantee to expand its generation capacity. Taking these features into account, the government intends to increase the minimum coverage of the distributors by bilateral contracts, from the current 85% to 95%. This measure is part of the strategy of the regulatory bodies to increase the supply of energy, stimulating investments.

Competition Issues in the Brazilian Electricity Sector

Vertical Integration

Among the many undesirable features of the market structure, probably the most important one is the existence of vertically integrated firms operating in the generation and/or transmission and/or distribution segments.

After the permission to the private sector to participate more effectively in the electricity sector, the Law 9,074, from 1995, established that the electricity sector concessions in that time, still in place, could not be renewed unless the company was divided into different companies dealing with generation, transmission and distribution. This measure was intended to prevent the exercise of market power in the electricity sector by the State-owned companies. Despite its very valid purpose, the measure was not put into practice until today, except for one federal company (Eletrosul, in which its generation component was privatized in July 1995) and a few state companies, mainly those from the São Paulo⁸ and Rio Grande do Sul⁹ states. The important state companies Cemig and Copel are still vertically integrated.

The remaining companies still stay vertically integrated, including the state ones. The equity reengineering of the subsidiaries of Eletrobras was the focus of the Law 9,648, from May 1998, and is part of the Brazilian program of privatization. The plan is to divide Furnas into two generation firms and one transmission. The same is expected to occur with Chesf. The last, Eletronorte, due to this peculiar characteristics (it attends the Amazon region), is expected to be shared into three generation companies, two vertically integrated (the isolated systems of Manaus and Boa Vista) and one transmission company. But due to the supply crisis and the discussions regarding the improvements on the regulatory framework, the privatization process was halted.

The main problem regarding the presence of vertically integrated companies is related to the market power exerted by firms providing services of generation and transmission simultaneously. These companies can make difficult and even impede the action of another firms by means of the conditions of access established by contract. Although the access to the transmission network is free, under the current legislation these contracts are freely established, without rules limiting the market power of the owners of the transmission lines. This topic has been addressed under the recent discussions regarding the improvement of the Brazilian system. The main idea is to limit the participation of the same company in the transmission and generation segments. This involves the restructure of the state and federal companies. Regarding the latter, the proposal is to transfer all the generation companies to the National Treasury (as a first step before their privatization) and let Eletrobras to be the sole owner of the transmission assets. This project still needs further details, but constitutes an important measure towards a more competitive system.

Besides the vertical integration, another problem observed in the electricity sector is the cross participation in different segments. This is particularly evident regarding the state companies that possess generation assets. The Resolution Aneel 278, in 2000, does not prohibit the cross participation, but sets limits on it. It is important to note that this regulation is not out of tune with the international experience.

The problem observed is that some companies tend to privilege their own production (or the production of other firms from the same group) when selling energy to the final consumers. This behavior represents a disincentive to the production of independent producers, diminishing the competition in the sector.

Entry Condition

The preceding sections stressed various aspects of the configuration of the Brazilian electricity sector that impede the entry of new agents and a more competitive environment. Vertical-integration, cross participation (above certain limits), transmission fees disregarding the location component and even the distorted price mechanism are all hurdles that must be eliminated to facilitate entry and foster competition. But there are other aspects that make matters worse.

An important issue that must be addressed in the near term is what will occur after the complete liberalization of the market. According to the government schedule, the free determination of prices will be in place in phases, during the next few years¹⁰. The liberalization will cause the price to be defined by the marginal cost, which in the Brazilian case tend to be increasing with the system expansion. Without measures, an unequal competition between the older and already amortized hydroelectric plants (the so called "old energy") and the new hydro and thermoelectric plants (similarly, known as "new energy"). Conscious of the impact over the competition, the government is studying a model of auctioning the old energy, with minimum prices. The idea is to prevent that the stated-owned companies mix the old and the new energy aiming to put aside the new competitors. With the auctioning of the total amounts of old energy, there will be space for new investments in generation and new companies.

Another impediment to a more competitive market is the absence of incentives to large firms become free consumers. According to the Brazilian legislation, the free consumer is an agent that is able to negotiate directly with the generation companies the supply of energy that it needs. The more free consumers, more the competition pressure for lower prices and alternative sources of energy. There are some proposals under discussion intended to increase the number of free consumers. One of them is to establish that all the consumers above certain consumption limits will become free. Connected to this determination, those consumers that do not desire to become free will set a bilateral contract with the distribution company. These measures can also stimulate the entry of new generation companies.

Finally, the historical existence of a cross subsidy between industrial and home consumers is another obstacle to a greater competition. As part of the Brazilian process of industrialization, the government also provided a subsidy for the industrial sector implicit on the electricity prices. In place until today, this cross subsidy causes a disincentive for the industrial firms to become free consumers. These firms prefer to continue to access the distribution companies, which charge regulated (and subsidized) duties. The regulatory body, Aneel, is already in charge of the design of a gradual elimination of these cross subsidies, probably in the mid term (five years or so).

Competition Policy in the Electricity Sector

As it was mentioned before, the reform of the electricity sector has the objective to stimulate the competition in the generation and distribution segments. In this sense, the regulatory agency, Aneel, published the Resolution 278, from 2000, that sets forth limits for the participation in the electricity sector. This resolution updates the Resolution 94, from 1998.

In general terms, Resolution 278 establishes that an agent can respect a maximum limit of generation capacity in the generation segment, defined as follows: (i) 20% for the national system; and (ii) 25% for the sub-market South-South East-Middle West; and (iii) 35% for the sub-market North-North

East. For the distribution segment, the limits are the same, taking into account the market share of each agent in the distribution segment. Agents have to communicate to Aneel every transaction that changes their shares in the generation capacity or the market share of the distribution segment. The chart below presents the outcomes of the Aneel analysis of the transactions in the electricity sector during the last years.

Regulatory Law Enforcement - Aneel Decisions

	1999	2000	2001	2002*
Type of Operation				
Purchasing of Equity Shares or Control	5	23	19	7
Merger	-	-	1	-
Association	-	-	2	-
Joint-Ventures (Consortia)	-	1	3	7
Total Number of Operations	5	25	25	14
Operations Approved Without Restrictions	5	24	25	14
Operations Approved With Restrictions	-	1	-	-
Operations Reproved	-	-	-	-

Source: Brazilian Regulatory Agency - Aneel

** January-July 2002*

In just one case Aneel decided to impose a restriction on the operation. The acquisition of the distribution company Eletropaulo Metropolitana by Lightgás resulted in an increase of the share of the shareholder Light in the distribution segment higher than the limits defined by the regulatory body. But according to a special provision established by the privatisation program in Brazil, the buyer has a transition period to adjust itself to the limits. That is why Aneel decided to approve the operation, but with the condition above. This condition was fulfilled after the groups EDF International and AES Corporation decided to restructure their operations in Brazil in order to respect the limits above.

After the Aneel analysis of the regulatory aspects of the operation, the Brazilian Competition System examines the case in light of the Competition Law. The System comprises the Administrative Council for Economic Defence – CADE, the Ministry of Finance’s Secretariat for Economic Monitoring – Seae, and the Ministry of Justice’s Secretariat of Economic Law – SDE. The decision of CADE has been based on the Aneel opinion, but the recent developments in the electricity sector demand a new approach for the sector.

The gradual movement towards a deregulated system has stimulated the entrance of new agents and then a greater role of the competition authorities. The privatisation of the Brazilian state-owned enterprises increases the risks of the negative effects derived from vertically integrated companies, as well as the cross participation in different segments described below. According to the literature, problems such as entry deterrence, collusion and circumvention of the regulation can be observed during this process. Taking into account that the majority of the energy generation capacity is still at the government’s hands, future privatizations will increase the probability of existence of these negative effects. That is why the Brazilian Competition System is committed with a proactive approach regarding non-horizontal mergers.

Conclusion

The objective of this short document was to provide a brief description of the Brazilian electricity sector. During the last years, the Brazilian experience can be characterised as an example of the liberalisation process in this sector. The transition from a State-oriented regime to a market one showed

good advances (as the privatisation process and the creation of an independent regulatory agency) but there are still much to be done. Unfortunately, the energy crisis of 2001 was a terrible way to recognise the effects derived from the lack of competition in a fundamental sector as the energy over the whole economy. But the government reaction has been very successful and the outcomes of a full reform of the regulatory framework will be felt in the near term.

As it was seen in this short analysis, the electricity sector poses some challenges to the Brazilian government, in special the Brazilian Competition System. Regulatory and competition subjects are interconnected in such a way that the use of market power is a threat to the development of the system as a whole. Issues like transmission fees, price mechanisms and incentives to entry, as well as vertical integration and cross participation have been studied by the regulatory and the competition bodies and changes are expected to be implemented in the short term, as a way to prevent further crises and stimulated a competitive environment in the electricity sector.

NOTES

1. Paper prepared by Cleveland Prates Teixeira (Commissioner of Administrative Council for Economic Defense – CADE) and Bruno Carazza dos Santos (Economist of CADE)
2. This paper does not necessarily represent the opinion of all Commissioners of CADE.
3. In Portuguese, *Grupo de Coordenação para Operação Interligada*.
4. In Portuguese, *Grupo de Coordenação do Planejamento do Sistema de Energia Elétrica*.
5. In Portuguese, *Departamento Nacional de Águas e Energia Elétrica*.
6. In Portuguese, *Câmara de Gestão da Crise de Energia Elétrica*.
7. Variable costs plus the deficit cost. This latter is calculated according to the probability of deficit in the supply of energy.
8. The former energy companies from the State of São Paulo were Eletropaulo and CESP. They were divided into separated firms, as follows: (i) generation companies: CESP Paranapanema (privatized in July 1999), CESP Tietê (privatized in January 1999), and CESP Paraná (still in the hands of the state government); (ii) distribution companies: CPFL (sold in November 1999), Eletropaulo (privatized in April 1998), Elektro (sold in July 1998) and Bandeirante (transferred to the private sector in September 1998).
9. The Rio Grande do Sul government enacted on 1996 a law approving the split of its energy company into generation, transmission and distribution companies. Two distribution companies were privatized in October 1997.
10. After January 2003, 25% of the market will be liberalized in each year, until 2005 when the market is expected to be totally free.

CANADA

Electricity markets in Canada, for jurisdictional and other reasons, have traditionally been segmented along provincial lines. While there are interties between provincial electricity systems, they tend to be small in relation to provincial supply and demand, and of less capacity than interties with bordering US states.¹ Outside of certain aspects of trans-border and interprovincial trade, responsibility for electricity systems in Canada resides with the provincial governments.

The degree of electricity sector restructuring that has taken place, or is projected in near future, varies greatly from one province to the next. However, two provinces, Ontario and Alberta, have undertaken extensive pro-competitive restructuring. Both provinces now have competitive markets for both wholesale and retail power. Other provinces, while they may have made some reforms, have not undertaken basic pro-competitive restructuring.²

This note focuses on competition issues in Ontario electricity markets, the largest in Canada.³ Section 1 outlines the basic generation, market design and regulatory structure of the Ontario electricity market structure. Section 2 discusses specific competition issues arising in the Ontario market including: a) controlling the dominant generator's market power, b) transmission related market power, c) promoting new entry and d) market oversight agency cooperation and coordination. Section 3 discusses the competition law enforcement activity of the Competition Bureau ("the Bureau") in competitive electricity markets in Canada.

1. The Ontario Electricity Market Structure

a. Background

Prior to restructuring, Ontario's electricity sector was dominated by the government-owned, vertically-integrated Ontario Hydro (OH). The company controlled over 90% of in province generation as well as the provincial transmission grid. OH also controlled distribution to some areas of the province. However, the vast majority of distribution assets were controlled by municipal utilities that numbered in excess of 300.

Legislation to open the Ontario electricity system to competition was adopted in October 1998. Subsequent competition related developments included completion of the Market Power Mitigation Agreement (the "MPMA") which sets out the approach to be followed for de-control by OH of generation assets to promote a competitive marketplace. The Ontario electricity market opened to both wholesale and retail competition on May 1, 2002.

b. Generation Supply and Demand

Generation available to the market includes a large amount of in province generation and a substantial amount of intertie capacity. Maximum in province capacity is approximately 27,500 MW, 32% of which is nuclear plants, 27% coal and 27% hydro. The remaining capacity (13%) is fuelled by natural gas and oil and a limited amount of renewable energy. Most of the power actually generated comes from the base-load nuclear plants (55%), followed by coal (29%) and hydro (11%). Gas, oil and renewable represent the remaining 5%.

As indicated in Table 1, the main price-setting capacity is coal. Higher-priced gas, oil and hydroelectric also play an important role although it varies according to demand and supply conditions and water availability. The latter is an issue in Ontario, as hydroelectric generation was price-setting only 10% of the time in August, even though it represents a quarter of total capacity. Nuclear power has played no role in price setting, reflecting its base-load nature and current size in relation to Ontario demand.

Table 1: Share of Real-Time MCP Set by Fuel Type, 2002

Fuel	May	June	July	August
Oil / Gas	1%	5%	19%	16%
Coal	75%	80%	70%	68%
Nuclear	0%	0%	0%	0%
Hydroelectric	24%	15%	10%	16%

During the first four months after market opening, the average hourly price of Ontario's spot market was \$46.74 / MWh, but this value rose progressively from \$29.19 / MWh in May to a high of \$64.18 / MWh in August. Average peak prices also rose from \$34.59 / MW to \$83.42 / MW, with a four month average of \$58.75 / MW. These price figures are consistent with high demand associated with high temperatures through the July/August period, as well as the depletion of hydroelectric resources. The MSP has not found the prices increases to be due to abuses of market power.

Ontario is interconnected with the neighbouring provinces of Manitoba and Québec, as well as with the states of New York, Michigan and Minnesota. Total intertie capacity is about 5,300MW in the summer and 5,600MW in the winter, but actual capability to import is only about 4,000MW for technical reasons. This represents approximately 15% of domestic installed capacity.

The OEB has granted Hydro One (the publicly-owned company which controls OH's former transmission assets) a Transitional Transmission Licence which requires best efforts on its part to expand intertie capacity to neighbouring jurisdictions by approximately 2,000MW within 36 months of market opening. Planned expansions to the transmission system include a joint-venture between Hydro One and TransÉnergie for a 990MW line across Lake Erie, the commercial feasibility of which is not yet established.

With the increased use of air-conditioning systems, the province has recently changed from winter- to summer-peaking electricity demand. In August this year, peak demand reached 25,414MW. Average peak-demand for 1997-2001 was 23,354MW, and is expected to grow at an annual rate of 0.9%. Announced planned new generation to 2006 is close to 10,000MW or about 40% of demand. However, the amount of this capacity that is actually constructed may be much less. For 2003/2004, most of this capacity reflects plans to bring back the laid up Bruce nuclear facilities. Only two of the projected greenfield generation projects, representing about 1000MW, (both natural gas) are currently under construction.

Under the 1998 restructuring legislation OH's generation capacity was transferred to a separate corporation, Ontario Power Generation (OPG). OPG remains the dominant generator in the province owning about 90% of in province capacity, consisting of nuclear, hydro-electric, coal and oil assets. Recently, OPG has started to divest some of its plants through two transactions. The first involved the sale of hydro-electric facilities to Brascan Corporation. These assets account for about 872MW or about 3% of capacity. The second involves the entry into an 18-year lease agreement with British Energy for the Bruce

A and B nuclear plants: 8 reactors, 4 operating, 4 in lay-up. These facilities have a current operating capacity of 3000MW. However, this may be increased to 6500MW if the laid up reactors are brought back on-line. The Bruce lease represents the largest transfer of control of nuclear capacity in history.

Imports have been playing a major role in Ontario electricity supply since market opening. The average import schedule for August 2002 reached 1487MW, or about 8% of average load. However, imports have frequently exceeded 3000MW on average for some days with incidences of import demand exceeding the interconnection capacity.⁴

c. *The Ontario Wholesale Electricity Markets*

Electricity wholesale markets in Ontario consist of a real time energy market and 3 real-time markets for operating reserves: 10-minute spin, 10-minute non-spin, and 30 minute reserve. Ancillary services other than operating reserve are acquired under contract by the Independent Electricity Market Operator (the "IMO"). Market participants wishing to compete in both the energy and reserve markets provide a combined bid consisting of price quantity pairs for the respective markets.⁵ The IMO calculates an unconstrained optimal merit order for both energy and operating reserves. Where deviations from the unconstrained merit order are required due to congestion, the dispatched higher cost generation receives its bid price subject to possible rebates or restrictions reflecting local market power.⁶

The real-time energy market operates as follows. For each hour of the day beginning one day ahead, licensed market participants can place offers or bids on the real-time energy market. Offers can be fully revised up to four hours ahead of market hour and at most by 10% up to two hours before market hour. Using an unconstrained model, the IMO calculates a market-clearing price (MCP) for five-minute intervals of every hour. The load-weighted average of the twelve MCPs of a particular hour constitutes the Hourly Ontario Energy Price (HOEP).

While this price is paid to in province generation, subject to possible out of merit dispatch for reliability reasons, the prices and quantities for imported and exported power are set differently. These are established using an hour ahead pre-dispatch price and quantity. The use of this approach reflects the lack of integration between Ontario and neighbouring markets, requiring that imports be scheduled an hour ahead.

A form of physical bilateral contracting for energy is allowed in Ontario. Companies wishing to engage in such contracts may choose to submit the contract data to the IMO, but they are not required to do so. If they do submit the data, the IMO uses it to adjust the energy market statements for the consumer and supplier involved in the contract. If the contract does not cover the full amount of consumption, the amount in excess of the contract quantity is priced at the market price. It may be noted that the IMO does not provide a scheduling service for bilateral contracts based only on declared quantities. Rather, all suppliers must provide energy market bids.

The IMO does not run a day-ahead market, although this is under consideration. Efforts are being made by private parties to develop further forward markets. However, these are still at a preliminary stage, in reflection of the opening, only recently, of the real-time markets.

d. *Regulatory Structure*

Oversight of competition issues in the Ontario electricity system is a shared responsibility of the IMO, the Ontario Energy Board (the "OEB) and the Bureau. The IMO was established by the Electricity Act, 1998 (the "EA") to direct the operations of the electricity transmission system, maintain the reliability

of the IMO-controlled grid, and to establish and operate the IMO-administered markets, Ontario's wholesale electricity markets. The IMO is responsible for the market rules governing the IMO-administered markets. Like the OEB, the IMO is charged with facilitating competition in the generation and sale of electricity and facilitating a smooth transition to competition.

A Market Surveillance Panel (MSP) monitors, investigates and reports on market behaviour, including suspected abuse of market power, in Ontario's competitive electricity market. The MSP has been appointed by, and reports to, the independent directors of the IMO Board. It consists of independent members and currently includes two academic economists (Fred Gorbet and Don McFetridge) and one engineer, Tom Rusnov. While located within the IMO, the MSP may conduct independent examinations of competition abuses and reports on these matters to the OEB. The MSP also closely monitors the wholesale electricity markets to identify: 1) inappropriate or anomalous market conduct, 2) flaws in the market rules, and 3) flaws in the overall structure of the markets. The MSP has access to all the operating information available to the IMO, supplemented by confidential information obtained directly from market participants.

The OEB is required to monitor all electricity markets and may report to the Minister of Energy, Science and Technology on the efficiency, fairness, transparency and competitiveness of those markets. The OEB directly regulates the monopoly sectors of the electricity industry (transmission and distribution) and has broad authority over the entire sector, as described further below. All participants in the electricity industry are licenced by the OEB. Under the Ontario Energy Board Act ("the OEBA"), the objectives of the OEB include facilitating competition in the generation and sale of electricity in Ontario, ensuring a smooth transition to competition, and providing generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario.

The regulatory authority of the OEB is conditioned by provisions in the OEBA requiring it to refrain from exercising its regulatory authority under certain situations. Specifically, where the OEB, on an application or in the course of a proceeding, determines that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest, the OEB is required to refrain, in whole or part, from exercising any power or performing any duty under the OEBA. An OEB decision to refrain can be made in relation to any matter, any licensee, any person subject to the OEBA or any classes of electricity products or services. The OEB must notify the Minister if it makes a determination to refrain and an OEB decision to refrain can be rescinded by a later OEB decision.

The OEBA further specifies that where the OEB refrains, in whole or in part, nothing in the OEBA limits the application of the Competition Act ("CA") to those matters with respect to which the OEB is refraining. This provision was added to the OEBA to ensure that the potential for the OEB to re-regulate an activity will not bring into play the so-called "regulated conduct defence" with respect to the CA.

The Bureau is responsible for the administration and enforcement of Canadian competition law as embodied in the CA. The purpose of the CA is to maintain and encourage competition in the marketplace in order to promote the efficiency and adaptability of the Canadian economy, to ensure all businesses have an equitable opportunity to participate in the Canadian economy and to provide consumers the benefits of competitive prices and product choices. The CA achieves this purpose by stopping anti-competitive practices. The Bureau conducts investigations under the CA which includes both criminal and civil provisions.

The roles and responsibilities of the respective agencies with respect to specific competition related matters is as follows.

i. Anti-competitive Practices

All three agencies (the IMO, the OEB and the Bureau) have important roles with respect to anti-competitive practices, activities that have the effect of preventing or lessening competition among businesses in a market. The Bureau's responsibility derives from its role in ensuring that companies comply with the relevant criminal and civil provisions of the CA pertaining to price-fixing, bid-rigging, abuse of a dominant market position and other anti-competitive acts.

The IMO's responsibilities derive from its role as monitor and investigator of the IMO-administered markets. The MSP's authority encompasses investigations and the issuance of reports and recommendations. Apart from the MSP, the IMO may address issues by changing the market rules to help prevent the use of anti-competitive practices in markets it administers.

The OEB may deal with anti-competitive abuses through the imposition of related licence restrictions. If the OEB receives a report from the MSP that contains recommendations relating to the abuse or possible abuse of market power, the OEB may conduct a review of the market rules or the licence of any market participant. If directed to do so by the Minister, the OEB must conduct a review to determine whether the market rules or the licence of any market participant should be amended.

Upon completion of the review, the OEB may amend the licence of any market participant or make an order directing the IMO to amend the market rules for the purposes of reducing the risk of, or mitigating the effects of an abuse of market power. Also, on the application of any person, the OEB may amend the licence of any market participant if it considers the amendment in the public interest, having regard to the objectives of the OEB and the purposes of the EA. In addition, if the OEB finds that a market rule is inconsistent with the purposes of the EA, it can direct the IMO to amend the market rule.

ii. Market Power

In the initial stages of Ontario electricity market restructuring, the principal area of market power concern will be OPG's control over generation in the province. The means by which this is to be managed is the MPMA. The MPMA is a condition of OPG's generation licence enforced by the OEB. It sets out market share reduction targets for OPG and provides incentives to meet these targets. In addition, the MPMA revenue cap mechanism provides a measure of protection for Ontario consumers of electricity from high prices. The revenue cap mechanism expires four years after market opening, or after the OEB determines that OPG has met its decontrol obligations in full, whichever date comes sooner.⁷

The IMO's responsibility with respect to the MPMA is confined to calculating and distributing rebates to consumers annually, according to the formulae contained in the OPG Transitional Licence. However, the IMO has the lead responsibility for detecting and controlling locational market power in Ontario. The IMO's approach for dealing with this matter is discussed in section 2.b below. The Bureau has no role in controlling the use of market power merely to obtain higher prices as this does not contravene the CA.

iii. Mergers and Acquisitions

Under Ontario electricity legislation, an electricity transmitter or distributor may not sell, lease or otherwise dispose of any part of a transmission or distribution system without approval from the OEB. In addition, leave of the OEB is required for a person to acquire voting securities of an electricity transmitter or distributor if, after the acquisition, the purchaser would directly or indirectly hold more than twenty percent of the voting securities of the transmitter or distributor. The OEB has a right to review proposed

vertical mergers between generators and distributors or transmitters. More generally, if the merger of any market participant requires a new licence or an amendment to an existing licence, the OEB, or the director of licencing, may choose to review the competitive effects of such merger as part of any licencing review.

Under the CA, all mergers and asset acquisitions are potentially subject to review and transactions which exceed prescribed asset/sales thresholds must be prenotified to the Bureau. The Bureau's examination of mergers and acquisitions relates exclusively to competition and efficiency effects. The IMO does not have a specific role in mergers and acquisitions.

iv. Transmission and Distribution Pricing Access

Providing "generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario" is one of the core objectives of the OEB. The OEB has extensive powers to regulate the pricing of and access to transmission and distribution in Ontario. It may be possible to address discrimination with respect to transmission and distribution access, in certain circumstances, under the CA. However, the establishment of non-discriminatory access to transmission and distribution systems is not a specific objective of the CA.

2. Competition Issues in the Ontario Electricity Sector

a. Controlling the Dominant Generator's Market Power

The MPMA, noted above, provides the primary means by which OPG's dominant position in electricity generation for Ontario is to be controlled and eventually eliminated. The agreement, which is overseen by the OEB, contains measures designed to reduce the incentives for OPG to exercise its market power while it remains dominant and includes requirements and incentives to divest control of capacity toward the creation of effective competition. The key terms of the MPMA are as follows.

i. Decontrol Measures

The MPMA makes a distinction between "tier 1" (all hydro and nuclear generation) and "tier 2" (all other generation in Ontario, the transfer capability of the interties and demand-side bidding). Although some hydro plants can store water to increase supply during peaking hours, the agreement considers tier 1 capacity as baseload.

Decontrol requirements under the MPMA have two dimensions. First, within 42 months of market opening, OPG must decontrol the greater of 4000MW of tier 2 capacity or enough capacity to bring down its tier 2 market share to 35%. Second, OPG must reduce its share of total tier 1 and tier 2 capacity to 35% within 10 years of market opening.

It is up to the OEB to determine if a transaction between OPG and an acquirer represents the transfer of effective control. If, as a result of a transaction, the acquirer controls more than 25% of either 1) tier 2 or 2) tier 1 and tier 2, the transfer will not count towards OPG's decontrol targets. The same applies if there exist ongoing arrangements between OPG and the acquirer, facilitating interdependent behaviour.

ii. *Revenue Cap*

Similar to a vesting contract, the MPMA is intended to reduce the incentive to exercise interim market power by reducing the amount of power for which OPG can receive high prices. However, it does not directly restrict OPG's bidding or contract pricing behaviour.

The means by which the MPMA is through a cap on the revenues it may receive on a specified amount of its generation. If the average yearly revenues from a pre-determined quantity of OPG power sold exceeds \$38 / MW, OPG must rebate the excess to the IMO. **Hourly quantities were set in 1998 and were intended to represent approximately 90% of OPG's expected production for Ontario load in each hour of the year, as forecast at that time.**⁸ Negative rebates can be carried forward and applied against a positive rebate in a subsequent year. The current revenue cap will terminate four years after market opening, or earlier if OPG meets its 10-year decontrol requirements before this deadline. In order to provide OPG with the incentive to meet its decontrol targets rapidly, upon determination by the OEB that a transaction represents effective decontrol, the quantity used to calculate OPG's output subject to the revenue cap is reduced by 110% of the energy associated with the decontrolled generation asset.

iii. *Import limitations*

In order to ensure that OPG does not control imports across the interties, the amount as well as the capacity of power it can import is also restricted by the MPMA. During the winter season, OPG is restricted from importing more than 7.24 TWh (7.28 TWh in leap years). During the summer season, it is restricted from importing more than 6.58 TWh. These import limits are independent of the tier 2 decontrol measures discussed above, and will gradually cease as transfer capacity through interties is upgraded.

The MPMA is beginning to affect the structure of the Ontario generation market. In the last two years, OPG has divested four hydro plants (bought by Brascan Corp.), and has signed a lease agreement with British Power for the Bruce A and B nuclear facilities. In total, these transactions represent the potential decontrol of approximately 14% of OPG's total generation assets in operation, or 25% if the laid-off Bruce reactors are included.⁹

However, the effectiveness of the MPMA decontrol measures in achieving a competitive wholesale electricity market will depend on the manner its terms are fulfilled and other developments in the market. Even after the de-control targets are met, OPG may unilaterally possess a high level of market power depending on the types of price setting capacity it continues to hold. In addition, depending on the manner in which control of OPG generation capacity is divested, the overall level of market concentration may remain high. Under the terms of the MPMA, OPG may divest control of as much as 25% of Ontario capacity to any single third party. If this is done, the 3 firm concentration ratio for the Ontario market may be as high as 85%. A study of the MPMA under this scenario concluded that it could leave OPG with a high level of market power.¹⁰

b. *Transmission Related Market Power*

Market power concerns relating to transmission congestion may be separated into short run concerns, preventing non-competitive pricing, and longer run concerns, enhancing the transmission system or locating new generation to reduce local market power. This section discusses measures applying in Ontario in regard to both types of concern.

i. Short-Run Issues

Ontario energy legislation gives the IMO primary responsibility for detecting and preventing local market power. The means by which such market power may be exercised is through the submission of high energy bids resulting in the collection of excessive Congestion Management Settlement Credits (CMSC's). CMSC's represent compensation to generators whose bids are above the MCP but are nevertheless dispatched due to congestion on the transmission grid.¹¹ The need for CMSC's is a direct result of the requirement for a uniform energy price in Ontario. As a consequence, purchasers in high electricity supply price areas do not pay the full cost of power supplied to their areas. Rather, they pay the uniform energy price equal to the MCP plus an uplift charge to reflect CMSC's spread equally across all demand in the province.

In order to prevent a generator enjoying local market power from increasing its CMSC payments through a modification of its offer or bid prices, the IMO has put in place "local market power screens". Once it has assessed that there is a transmission flow constraint or a security limit causing constrained-on dispatch, the IMO compares the offer or bid price with a reference price. The reference price is the unweighted average of the price contained in all energy offers or bids submitted by the market participant for the investigated facility during all on-peak or off-peak periods in the ninety days preceding the date for which the prices under consideration were submitted.

If it has established that the investigated price exceeds this price screen, the IMO determines if there was sufficient competition to respond to the constraint, by looking at the number of participants able to meet demand and their respective capacity, and other factors. If competition was deemed insufficient, other variables are taken into account, such as cost components, changes in bidding behaviour, variability of bids over time and shadow prices.¹² The investigated market participant may also make representations to explain the prices offered.

If, after investigation, the IMO finds that the investigated prices are due to local market power, it may reduce CMSC payments and / or assign a penalty to the market participant. The market participant can also ask for an inquiry, and may appeal any penalties to the OEB.

Since market opening, persistent transmission constraints have led to relatively large CMSC payments in Ontario, amounting to approximately \$78 million, or 28% of total hourly uplift payments for the first four months of the market. However, local market review so far has found relatively few instances involving local market power abuse that have, in turn, lead to the recovery of only a small fraction of CMSC payments made. Rather, the amount of CMSC's has generally been found to be acceptable because effective competition to supply the congested area existed or the offer reflected legitimate cost and other considerations.¹³

ii. Long-Run Issues

The potential benefits of transmission enhancements for promoting the competitive and efficient supply of electricity in Ontario has been recognized throughout the restructuring process. For this reason, the licence of the provincial transmission company established through the restructuring process, Hydro One, requires it to increase intertie capacity by 2000 MW within 36 months of market opening. However, beyond this requirement, the current market structure provides limited market-based incentives for beneficial transmission enhancements within the province.

The lack of these incentives is due to the requirement for a uniform price to be charged for electricity in the province. While the ability to obtain CMSC's may provide incentive for generation to be located in high cost areas, the requirement for these costs to be recovered through a uniform uplift charge

on all power weakens potential demand-based incentives for increasing transmission to these areas. That is, rather than getting the full price benefit resulting from a transmission enhancement to a high price area, electricity users in the area are entitled to only a portion of the benefit determined by the reduction in the uniform CMSC uplift charge.¹⁴

It may be noted that this concern regarding the current approach for dealing with congestion in Ontario has been recognized by the IMO and others. One year after market opening (in May 2003), the IMO is to conduct a review of locational marginal pricing for Ontario. A decision will then be made on whether to switch to locational prices, or another appropriate pricing scheme.

c. *Promoting New Entry*

In addition to the MPMA and the manner in which it is implemented, an important determinant of the competitiveness and efficiency of Ontario electricity markets will be the level and nature of new entry. As indicated in section 1(b) above, a substantial amount of planned new capacity has been announced for Ontario in addition to the return to service of nuclear generation facilities. However, construction has begun on only 2 projects with the fate of the others still to be determined.¹⁵

The development of this and other new capacity in the Ontario marketplace will depend on the existence of appropriate climate for investment. As stated in the *Market Surveillance Panel Report on the IMO-Administered Electricity Markets for the First Four Months, May - August 2002*:

It is critically important that market participants receive signals that enable them to plan their actions with a high degree of confidence. In a competitive marketplace, these signals come through price determination that is the result of the interactions made by many independent buyers and sellers.¹⁶

However, as further pointed out by the MSP, Ontario does not have a competitive market structure due to OPG's dominant position with respect to generation. Rapid implementation of the de-control targets in the MPMA would help to achieve that goal. But, as discussed in section 2.a above, OPG market power concerns may continue to exist after the MPMA de-control targets are met depending how this is done and other developments in the generation market.

A further important consideration with respect to new investment is the uncertainty surrounding the plans to bring back nuclear generation facilities. Due to the large capacity of these facilities, the laid up Bruce facilities alone have capacity in excess of 10% of peak demand for Ontario, and their low marginal costs, they have the potential to greatly affect the market clearing price and displace a large amount of capacity that might have otherwise been installed by new entrants to the market.

Also important will be the reaction of the provincial government to competition. In any electricity market, it can be expected that there will be periods of high prices and low prices reflecting the need for capacity or an excess of capacity. If the Ontario electricity market is to provide the right signals for efficient new generation to be developed, it will be important that efficient pricing signals not be unduly distorted by government intervention in the markets.

d. *Market Oversight Agency Cooperation and Coordination*

As indicated by section 1.d.i above, there is a high degree of overlap between the roles of the OEB, the IMO and the Bureau in dealing with competition matters in Ontario electricity markets. In respect of this overlap, the agencies have developed the *Joint Statement on Competition Oversight of the Ontario Electricity Marketplace* (the "Joint Statement").

The Joint Statement clarifies the respective agencies' jurisdictions with respect to Ontario electricity sector competition and provides a framework for cooperation and coordination in dealing with matters for which there is shared jurisdiction. Under the Statement, the agencies mutually recognize their jurisdictions in the relevant markets and indicate their intent to form working relationships, where appropriate, as well as work together to avoid the duplication of efforts in competition oversight wherever possible. The agencies further commit to: designating persons responsible for coordinating implementation of the Joint Statement; consulting on a regular basis on competition oversight matters; and notifying the others of matters likely to fall within their jurisdictions at the earliest opportunity.

Schedule 1 of the Joint statement outlines each agency's responsibilities on competition matters in 8 key areas including: anti-competitive practices; ongoing monitoring of electricity markets; implementation of the MPMA; excessive pricing due to market power; mergers and acquisitions; deceptive marketing practices; transmission and distribution access; and matters for which the OEB is refraining from regulation. In certain cases, the schedule provides guidance on how the agencies may manage overlap. For example, the sections on anti-competitive practices and deceptive marketing practices indicate that the Competition Bureau's policy is not to enforce the *Competition Act* in regard to anti-competitive practices that are the subject of an enforcement action by either the IMO or the Board.

While the Joint Statement has only been in effect for a short period of time, it has provided an effective mechanism for maintaining open lines of communication and ensuring the agencies are informed of each others' competition related actions in the Ontario electricity markets. This is being achieved through regular bi-weekly communications involving representatives from each of the agencies.

3. Competition Law Cases in Deregulated Electricity Markets

The application of competition law in deregulated electricity markets in Canada has been limited due to the small number of provinces with such markets and the newness of these markets where they do exist. Nevertheless, the Bureau has conducted a significant number of matters in electricity markets over the past 5 years though none has challenged.

a. Mergers

The Bureau has examined several mergers in electricity markets involving the transfer of generation, distribution and transmission and retail market assets. Most of the transactions involving generation assets did not raise a competition issue as they involved a new entrant to the relevant electricity markets. As an example, the above-noted Bruce Power lease agreement could not raise an issue under the CA merger provisions as it involves the decontrol of assets to a new competitor rather than a horizontal combination of assets.

Of potentially greater concern have been horizontal mergers and acquisitions involving two generation companies in the same province. In examining such mergers the Bureau has taken into account the size of the relevant facilities in relation to demand, the nature of the capacity (e.g., price-setting versus base-load, type of fuel), the mix of generation facilities being created, whether local market power may be created, the potential effects on markets for ancillary services, market design, remaining regulation and other matters.

While a number of horizontal mergers have been reviewed in the Canadian electricity sector over the past five years, none have been contested due to the relatively small amount of capacity involved and because combination of the assets did not provide excessive price-setting power or result in a substantial lessening of competition in an ancillary service or geographic sub-market.

Mergers involving only transmission and distribution assets have not raised a concern under the CA due to the natural monopoly nature of these facilities within an area and the existence of direct regulation of pricing of and access to them. Where transmission and distribution mergers have raised potential concerns, they have been in regard to the role of the relevant utilities as the provider of regulated standard electricity supply and/or as an unregulated competitor in the retail electricity market.¹⁷ The Bureau has also not contested any mergers on these grounds as it has not found that competition would, or would likely be substantially lessened in a retail market.

b. *Criminal Matters*

On the basis of information from the Alberta Market Surveillance Authority, the Bureau, in 1999-2000 conducted an investigation into alleged bid-rigging by two importers of electricity to the Power Pool of Alberta (the province's real-time energy market). The investigation related to import bid restatements permitted under the Alberta electricity market rules. Although the rule was amended to restrict such bid restatements, the Bureau examined the behavior to determine whether it involved criminal bid-rigging behaviour.

The Bureau conducted an intensive investigation which included the use of formal search powers and the seizure of records. In the face of the evidence, the Bureau concluded that the behaviour did not constitute bid-rigging under the *Competition Act*. Specifically, no evidence of an agreement between the parties was found, and it was determined that the market outcome could also have been the result of independent action by one of the two market participants, using information on demand, supply and pricing available to all market players.

c. *Civil Matters*

While some related complaints have been made to the Bureau, there have been no formal inquiries by the Bureau under the civil provisions of the *Competition Act*, such as abuse of dominant position, in deregulated electricity markets.

4. *Conclusion*

Progress toward the creation of competitive electricity markets in Canada has varied widely from one province to the next. The Ontario electricity market, while unique in many ways in Canada, provides an example of many of the types of competition concerns that can be expected in other provinces as they implement competitive markets. These concerns include dealing with the generation market power of dominant incumbents, controlling and reducing local market power, promoting new entry and managing overlap between the electricity market oversight agencies.

Increasing deregulation of electricity markets in Canada will inevitably mean broader scope for application of competition law in the sector. The Bureau is starting to see an increase in related cases, and it is anticipated that electricity market matters will eventually arise in regard to all aspects of Canadian competition law. A key related consideration will cooperating and coordinating effectively with provincial market oversight agencies. In this regard, the Bureau generally supports the development of interface documents as has been done in Ontario.

NOTES

1. Exceptions are PEI, Newfoundland and Labrador and Nova Scotia which do not border on US states. However, power from Labrador supports large power exports to the US through Quebec. Alberta, while it borders on the US, has no direct tie-lines South. However, it has substantial interconnection to the US through the neighbouring B.C. and Saskatchewan electricity systems.
2. For example, a number of provinces have posted transmission tariffs, revised their regulatory regimes and undergone vertical functional separation to comply with US Federal Energy Regulatory Commission requirements for access by Canadian utilities to US wholesale power markets. However, these provinces, which include B.C., Quebec and Manitoba, have not established market structures and mechanisms for either wholesale or retail competition.
3. This note draws extensively from the analysis in Gorbet, F., McFetridge, D. and Rusnov, T., *Market Surveillance Panel Report on the IMO-Administered Electricity Markets for the First Four Months, May - August 2002*, released October 7, 2002. This report can be obtained at <http://www.theimo.com/imoweb/marketSurveil/mspReports.asp>
4. There are various structural reasons for this having occurred including the shut-down of nuclear generation capacity, dry weather, unseasonably high temperatures and the taking of plants off-line for maintenance.
5. OPG, due to its dominance, is required to provide bids for both the energy and reserve markets.
6. This matter is discussed in section 2.b.i below.
7. For further discussion of the MPMA, see section 2.a below.
8. Adjustments to the rebate are allowed for price spikes and force majeure events.
9. The Bruce lease is subject to OEB assessment before being considered effective decontrol under the MPMA, and the Brascan divestiture occurred before the MPMA entered into force. OPG is also trying to auction off some of its coal and gas plants, so far unsuccessfully.
10. A.J. Goulding, Julia Frayer and Nazili Z. Uludere, *Dancing with Goliath: The Break-up of Ontario Hydro*, March 1, 2002.
11. CMSC's are also provided to generators that bid below the MCP but are constrained off due to congestion. The CMSC in such circumstances is based on the difference between the generator's bid price and the MCP.
12. Shadow prices are produced by the optimization program every 5 minutes, and are projected locational prices.
13. For example, a large portion of the CMSC's have been provided in regard to imports. However, the IMO concluded that competition to supply the imports to the congested area was sufficient and, therefore, that further market power related investigation was unwarranted.

14. The use of a uniform price reduces the incentive for demand-side responses to deal with congestion leading to high cost, as well as the incentive to enhance transmission.
15. New generation may be important not only for competition reasons, but also to meet electricity demand. As reported by the IMO, in the last five years, load has been growing steadily and capacity has been removed rather than added. Summer-peaking demand is moving closer to total capacity, and reliability could be an issue in the future if the trend is not reversed.
16. *Supra.* note 3, at p. 133.
17. It may be noted that in both Ontario and Alberta legislation and regulations are in place requiring utilities to maintain their unregulated competitive market activities in separate affiliates.

CHINESE TAIPEI

I. Introduction

Chinese Taipei is well on the way to deregulating and re-regulating its electricity sector. As a state-owned monopoly, Taiwan Power Company (Taipower) managed and operated the entire electricity sector -- from generation, transmission and distribution to sales. Even today, while still enjoying its monopolistic status, Taipower remains responsible for maintaining both the stability of the power supply and generally keeping electricity prices reasonable.

Starting in 1995, however, a three-stage process of licensing private generators to facilitate Taipower's provision of power was initiated. After Chinese Taipei reviewed the market structure in depth, the end result was its opening up the electricity sector and the introduction of competition into the generation, transmission and distribution of the supply while still maintaining the vertically integrated structure of Taipower.

Later in 1999, the Government re-drafted the existing Electricity Law, with a view to fully liberalizing the market and setting up mechanisms to promote efficiency and fair competition in the newly-deregulated electricity market. The draft amendment is currently under the Parliament's review.

II. Overview of the Regulations

Generation

Taipower is presently the only vertically integrated electricity enterprise in Chinese Taipei. With its status as the sole operator in distribution, only through contracts can the electricity generated by private generators be sold to Taipower. Thus, Taipower maintains its grip in being the sole electricity provider throughout all regions of Chinese Taipei.

At the end of 2001, the total installed capacity in Chinese Taipei was 39,348 MW. Taipower and private generators own 72 power plants altogether, and their total installed capacity amounts to 30,136 MW. The total installed capacity of private generators in operation is less than one-sixth of that (4,600 MW), and four more private generators are currently building their power plants and expect to be in business by 2004 with a total installed capacity of another 2,620 MW. There are also enterprises which generate electricity for their own use, for an additional total installed capacity of 9,212 MW.

Various fuels are used by Chinese Taipei in its generation of electricity. Among these, coal-fired amounts to 27%, oil-fired accounts for 15%, gas-fired is equal to 17% and nuclear provides another 17% of the total generation. Hydropower is also used to generate electricity, accounting for 15% of the total generation.

Due to its geographical isolation, Chinese Taipei's power system is separated from any other countries' systems. No electricity is imported or exported. On the other hand, it is worth mentioning that the imported energy, including coal, crude oil and natural gas, accounts for 97% of all fuels used in electricity generation. The dependence of the imported fuel sources obviously is very high for Chinese Taipei's electricity market.

Regulatory Authority

The Ministry of Economic Affairs (the MOEA) is responsible for energy supply issues and the regulation of state-owned energy enterprises, including Taipower. It is the MOEA that estimates the demand for electricity and decides the capacity for would-be investors who want to bid for the setting up of new power plants.

To ensure that the monopolistic pricing of electricity is not only in the public interest but also transparent, the MOEA established the Policy Consulting Commission for the Prices of Petroleum and Electricity and, in doing so, appoints experts and representatives from industrial organizations, consumer organizations, the Government and the Parliament to review pricing proposals made by Taipower.

Whenever Taipower plans to set or change its prices in their purchase of electricity from private generators or in the sale of electricity to end-users, it is required to apply for approval from the MOEA or other governmental agency for review by the Policy Consulting Commission for the Prices of Petroleum and Electricity. Taipower is also obliged to regularly report relevant information, including its finances and operations to the MOEA and Parliament.

III. Regulatory Reform of the Electricity Sector

The legal framework of the electricity sector in Chinese Taipei is the Electricity Law which the Government revised in its entirety and presented the draft amendments of to the Parliament in 1999 in order to restructure the sector into a competitive market and set up regulatory rules to establish and maintain trading order.

Market Structure

The draft amendment does not structurally break up the incumbent Taipower or prohibit the establishment of new vertically integrated electricity enterprises. Investors can still apply for approval from the MOEA to participate in the generation, transmission and distribution or even to form a vertically integrated electricity enterprise.

In addition to a vertically integrated electricity enterprise which is responsible for providing electricity, a distribution enterprise also has the right to invest in the generation or purchase of electricity from generators for the purposes of selling it to end-users.

Vertically integrated electricity enterprises, transmission enterprises and distribution enterprises are responsible for securing the power supply for end-users, and they heavily affect public interest. The draft amendment has thus defined the aforementioned businesses as utilities and has placed them under the MOEA's supervision. However, to encourage generation, there is no such obligation imposed on generators; it is the market which regulates in this area.

Unbundling

The utilities, i.e. vertically integrated electricity enterprises, transmission and distribution enterprises must seek approval from the MOEA prior to their engagement with other non-electricity businesses. The reason for this is to prevent any misuse of the utilities' market position, which might impede fair competition or damage normal operations of electricity-related businesses.

Also to prevent cross-subsidies, a vertically integrated electricity enterprise, an enterprise that operates in two different kinds of electricity business or in two business areas shall keep separate accounts for their generation, transmission and distribution activities in their internal accounting.

Transmission Network

To ensure fair access, and the economic success as well as safety of power grid systems, the draft amendment requires the MOEA to set up and fund a legal entity, namely the “Independent System Operator” (the ISO) two years after the draft amendment enters into effect. The ISO is responsible for dispatching electricity independently in accordance with the grid code as defined by the MOEA.

Power grids of all vertically integrated electricity enterprises and transmission enterprises shall be interconnected. Besides this, power plants and power grids of vertically integrated electricity enterprises and transmission enterprises shall be subjected to the operations of the ISO.

Market Rules

No power exchange is designed in the draft amendment.

The draft amendment provides three ways for generators to sell its electricity: by wholesaling generated electricity to any electricity enterprises except transmission enterprises; setting up power lines of its own to sell electricity directly to its customers; and thirdly, by selling electricity to customers via the power grids.

Under the new framework, users have the right to request any vertically integrated electricity enterprise or distribution enterprise to provide electricity within its business area. The enterprise that is requested does not have the right to refuse unless there is due reason and permission from the MOEA.

Price or Quantity Controls

The draft amendment of the Electricity Law authorizes the MOEA to draft the formula for calculating the prices charged by vertically integrated electricity enterprises and distribution enterprises as well as the tariffs collected by the ISO. The draft formula has to be approved by the Government before entering into effect.

The electricity utilities and the ISO shall set up or change their prices or tariffs in accordance with the approved formula for calculation, apply for approval from the MOEA and finally publicly announce any changes.

To facilitate drafting the formula for calculation, the MOEA has the right to establish the Review Committee for the Price and Tariff of Electricity with members, including experts, representatives from professional organizations, consumer organizations, government authorities, public utilities and the ISO.

The draft amendment requires that generators not change their installed capacity without permission from the MOEA. Violation may lead to an administrative fine ranging from NT\$ 300,000 to NT\$ 1,500,000. The MOEA may request the violator to correct the issue within a set time frame, and failure to comply with the order will result in further fines until the situation is rectified.

IV. Competition Law Enforcement

The Fair Trade Commission (the FTC) is responsible for enforcing the Fair Trade Law, the objective of which is to maintain trading order and to ensure fair competition in Chinese Taipei's domestic markets, including the electricity market.

In foreseeing that the liberalization of the electricity sector could give way to serious competition concerns, the FTC has actively been involved in the drafting of the amendments to the Electricity Law, has commissioned scholars to conduct research on related issues and has presented numerous workshops and public hearings to discuss options and opinions. The FTC realizes that to prevent the possible misuse of the market position of the long-established Taipower after the market is opened up, an effective competition regime and enough tools and mechanisms need to be incorporated into the new legal framework.

As any disputes concerning operation issues will be handled by the ISO and the MOEA under the draft amendment, there shall still be room for the FTC to closely monitor the market structure and the market power of the electricity market. Mergers between electricity enterprises might have to be reviewed by the FTC. Further, the FTC shall also investigate any misuse of market position behaviour which endangers trading order within the electricity market.

DENMARK

Introduction and general view

The Danish electricity market is in the last phase of a gradual opening. Generation and the wholesale market are liberalised as well as large end-users have market access. The end-user market will be opened also for households January 1st 2003.

Geographically the Danish market is placed between bigger power markets to the south (Germany) and to the north (Norway and Sweden). The Danish market is traditionally facing north playing an important role in the trading between the hydro dominated system (Norway/Sweden) and the Danish thermal production primarily based on coal and gas.

The Danish power market is in general competitive and well functioning. In 90-95 percent of the time (in normal years) the Danish power market is a part of the much larger Nordic market. In these hours there are no signs of weak competition due to abuse of market power in the two Danish bidding areas. Even in a competitive and well functioning Nordic power market strong price variations and price spikes are common. In the 5-10 percent of all hours, where the Danish bidding areas become separate price areas, there are indications of the abuse of market power by the two Danish generators. The DCA is presently investigating into this matter.

Excess capacity in generation, strong transmission capacity (including the interconnectors to the surrounding countries), relatively few congestion problems, a decentralised ownership structure of the transmission system and the Danish implementation of the EC Directive seems to be basic characteristics of the Danish electricity sector. This has been the framework for liberalisation and integration with the more developed markets in Norway/Sweden. Liberalisation and integration has taken place in spite of a high concentration in generation – a concentration due to politically driven mergers in 1999/2000.

The legal framework of the power market in Denmark is the electricity bill (bill no. 767 of August 28th 2001), that implements the EC Directive of electricity (96/92EC). Concerning market access and framework for market opening the Danish implementation of the directive goes further than the minimum required. Examples of this are regulated access to the network, legal unbundling between infrastructure activities and generation/trading and a full quantitative market opening in 2003.

Environmental problems have – until now – played a prominent role in the energy policy in Denmark. This has resulted in high subsidies to renewable power production – wind and small scale CHP. Analysis has shown that the large subsidies given to the production of renewable power have been an expensive and rather ineffective way to obtain a reduction in CO₂-emission. The bill is paid by the end-users through an obligation to buy renewable power. Today about 40 percent of the consumption is allocated outside the market.

The reduced size of electricity allocated on the market and the high Danish energy taxation facing household consumption means that the functioning of the power market does not have a crucial influence on the price of power (at least) at the household level. Contrary to the current situation in the power market at the industrial level (where competition is tough and the rate of switching supplier is high) it is the expectation, that the Danish households will not pay much attention to the full market opening January 1st 2003. The competitive pressure on this market might, therefore, be relatively low.

There are several challenges facing the Danish electricity market and the authorities in the future:

- The Danish government has announced that all power consumption will be allocated through the market in the future. This abandons the legal obligation to buy the renewable power production. The implementation will be stimulating for the market.
- The decentralised ownership structure of the Danish electricity sector will be challenged by the consolidation of the industry at European level. This development of consolidation has not yet affected Denmark.
- The present picture of excess generation capacity will in a couple of years lead to a situation, where trading between the countries in the northern part of Europe will be necessary not only for an efficient allocation of resources but also for security of supply. Most likely the lack of generation capacity will be concentrated in the countries north of Denmark. Denmark will in this scenario strengthen its position as a power exporter.
- Lack of capacity, increasing demand and consolidation in the sector may result in a more congested transmission system and the potential exercise of market power in the future.

Overview of Regulation

The Danish electricity market consists of two sub-markets, west (DK1) and east (DK2). The two sub-markets are not interconnected but are part of the joint Nordic power market consisting of Norway, Finland, Sweden and Denmark. Interconnectors between DK1 and Norway and Sweden exits connecting DK1 with the Nordic market. An interconnector joins DK2 with Sweden. Both DK1 and DK2 are connected to the German power market.

Two generators dominate the Danish market: Elsam A/S in DK1 and Energi E2 A/S in DK2. The total installed capacity is 7.000 MW and 5.500 MW (including windmills) in DK1 and DK2 respectively. Of the total installed capacity in DK1 Elsam owns approx. 50 percent. In DK2 Energi E2 A/S owns approx. 80 percent. However, for competition policy considerations the relevant market shares of the two generators are closer to 100 percent. As primary fuels the generators use coal, oil and gas. The generators are not active in the transmission or the distribution markets.

The Danish whole sale market is part of the Nordic power exchange, Nord Pool. DK1 and DK2 constitute two separate bidding areas in the Nord Pool region. Substantial imports and exports occur. The interconnectors joining the two Danish markets with the Nordic market have limited capacity. In certain years these capacity constraints frequently becomes binding.

Expansion of generation capacity has to be approved by the regulating authority. In reality the incentive to enter into generation is limited due to the existing excess thermal capacity in both Denmark West and Denmark East.

The regulatory authority does not have powers to intervene to collect information and set prizes in the generation market. The pricing of the TSOs is regulated by an ex-ante approval procedure. Income caps set up by the regulator regulate the grid companies' tariffs.

Factors Affecting Market Power

Market Structure

Two generators dominate the Danish market: Elsam A/S in DK1 and Energi E2 A/S in DK2. The total installed capacity is 7.000 MW and 5.500 MW (including windmills) in DK1 and DK2 respectively. Of the total installed capacity in DK1 Elsam A/S owns approx. 50 percent. In DK2 Energi E2 A/S owns approx. 80 percent. However, for competition policy considerations the relevant market shares of the two generators are closer to 100 percent. As primary fuels the generators use coal, oil and gas. The generators are not active in the transmission or the distribution markets.

Both generators use thermal production technologies – combining power and heat production – and hence, fuel costs constitute the largest part of production costs.

The domestic generators set the market price in hours where the import capacity of the interconnectors is fully utilised and the generators obtain a de facto monopoly on the residual demand. In hours where import demand is low or export occur the price is set by the marginal supplier in the Pool which can be a Danish generator. If the interconnectors are blocked by imports the two generators hold a dominant position – measured by installed capacity – in the local markets. This happens most frequently in peak load hours with low non-commercial generation (windmills and small scale CHP).

Generation has to be legally separated from transmission, and each activity has to be carried out in separate companies. Furthermore the management of the two kinds of companies has to be done by different people, and the same people are not allowed to be board members in the two types of companies.

Ownership however, vertically integrates the industry. Generation companies are not allowed to own a significant share of transmission companies, but the grid companies own the transmission system / transmission system operators as well as the two large generation companies.

The structure of ownership in the Danish electricity sector is very fragmented. About 100 grid companies (owned by the consumers directly or by municipalities) each have a small share in one of the two transmission companies (in east- and west Denmark respectively). No company has a majority influence in any TSO. One interpretation could be that the decentralised ownership structure is one reason why the access to the transmission seems to work. An indication of the well functioning network is that the regulator does not receive complaints about access to the infrastructure. On the other hand the fragmented structure seems to be an ineffective way of operating the grids not gaining the advantages from economics of scale.

The Danish government has recently announced that it will work for a further separation between generation and transmission by ownership. On the other hand the government has announced, that it will not hinder a consolidation process concerning the presently fragmented ownership structure. The risks of consolidation concerning the function of the network, when the activities of the TSO are mixed with the interests of generators, are thereby reduced.

The regulator is not entitled to impose separation requirement or divestments. The regulator makes according to the electricity act an ex-ante approval of the tariffs and conditions of the TSO concerning access to the transmission system.

Congestion and Pricing of the Transmission Network

Presently an internal bottleneck in DK1 reduces the import capacity available for imports via the Nordic interconnectors. However, in order to ease this constraint new transmission capacity is being built and expected to be operational in 2004.

Total import capacity into both west and east Denmark is approx. 2.000 MW. The maximum consumption in the two regions was for comparison 3.700 MWh/h in west Denmark and 2.700 MWh/h in east Denmark (2001 figures).

When the international interconnectors are congested by imports the two Danish generators gain a dominant position. Correlation analysis shows that the two Danish bidding areas are not integrated with the Nordic market in hours where interconnectors are congested by imports. No matter status of the Nordic interconnectors the Danish markets are not integrated with the German power market. Correlation coefficients are shown below.

Table 1. Partial correlation between electricity spot-prices in DK1 and surrounding areas in 2001

	At least one Nordic line open	Both Nordic lines congested
DK West (DK1) – Sweden	~1	0,15
DK West (DK1) – Norway	~1	0,21
DK West (DK1) – Germany	0,17	0,28

Table 2. Partial correlation between electricity spot-prices in DK2 and surrounding areas in 2001

	Nordic line open	Nordic line congested
DK East (DK2) – Sweden	1	0,55
DK East (DK2) – Germany	0,17	0,34

* Oct. 2000 – Dec. 2001.

The pricing of access to the domestic transmission system is fixed and published. Capacity across the borders to Germany is auctioned and priced separately. The interconnectors to Sweden and Norway are fully at the disposal of the Nordic power exchange Nord Pool.

The tariffs of the transmission system are separated into an entry charge (generation) and an exit charge (consumption). The main part of the charge is put on the exit charge. Tariffs vary across the day but not by location. All charges are put on flow (contrary to fixed tariffs or capacity). It is the general view, that the tariff systems by the TSOs are transparent and facilitates an easy access to the network.

Concerning the establishment of new generation capacity the Danish authorities are at the moment forming rules containing criteria for getting authorisation. This will implement the electricity directive on the subject. The authorisation for establishing new capacity will be based on objective criteria leaving other planning/environmental matters to the local/regional authorities. It is not clear, whether the criteria create special incentives about location in relation to the transmission system. In practice other criteria – physical planning, environment and access to fuel/water – play a much bigger role when deciding where to locate.

Except for the construction of subsidised renewable power production no plans for the construction of new generation has come up in Denmark in recent years. The main reason is the present low price of electricity compared to long run costs (reflecting a situation with excess capacity). A new large plant – decided 8-10 years ago – has started production this year. The plant is located at the coast near the capital, Copenhagen. The reasons for this location are easy access to fuel/water and demand for the production of heat (CHP-production) in the well-organised district heating system. The upgrading of the transmission system at that occasion did not play any major role.

There are two different sets of rules governing the capacity of the interconnectors joining Denmark with the Nordic market and the German market.

Within the Nord Pool area Nord Pool allocates the transmission capacity of all interconnectors as part of the market mechanism. The available capacity of the German interconnectors is allocated via yearly, monthly and daily auctions. Long term contracts still block large parts of the available capacity between DK2 and Germany (Kontek). The auctions are carried out by the TSOs.

Bottlenecks occur more frequently in some years than in others depending mainly on fluctuations in regional supply. In wet years – where the supply of hydro-produced electricity is large – the imports from especially Norway into western Denmark congests the interconnector relatively often. In 2000 the interconnectors from Norway and Sweden into western Denmark were simultaneously congested in 34 percent of the time. In 2000 the interconnector between Norway and western Denmark was reserved for bilateral contracts. This explains some of the 34 percent. These contracts were abandoned January 1st 2001. In 2001 the interconnectors into western Denmark from Norway and Sweden were blocked simultaneously in 7 percent of the time. The interconnector between eastern Denmark and Sweden were in 2001 blocked by imports in 5 percent of the time.

It is the business of the TSOs to examine and plan the need for extensions of the transmission system. The plan has to be announced to the authorities and published. The TSOs (in corporation with the transmission companies who also work under authorisation) have to apply for projects according to the plan. The TSOs (with the governmental authorities) have a crucial influence when deciding extensions in the transmission system.

According to the Danish electricity act it is possible to construct so called direct grids designed for the supply of electricity from an electricity producer to certain customers replacing the utilisation of the collective grid system. Prerequisites for this are refusal of access to the collective system and permission from the authorities. In practice this opportunity has not been used in Denmark so far.

Market Rules

The spot market at the Nord Pool Power Exchange is a day-ahead-market. Participants submit bids consisting of price-quantity pairs reflecting their demand or supply schedule in every hour of the following day. Buyers can place bids directly into the pool. Participation in the spot market is not compulsory.

Participants are free to sign bilateral contracts but inter-Nordic bilateral shipments can only take place if the relevant interconnector is not fully utilised by Nord Pool.

Since Nord Pool spot is a day-ahead-market the price is determined ex ante on the basis of forecasts of demand and supplies from wind-generation.

There are no mechanisms other than the market price designed to enhance investment in generation capacity. However, there are rules governed by the TSOs that tries to enhance the availability of generation capacity. For instance there are rules that put restrictions on when and for how long generators can take blocks out for revision.

The flow of information incorporated in the market mechanism can affect the incentive of firms to act strategically. Most important is the release of information from Nord Pool regarding expected utilisation of the interconnectors the following day prior to the bidding procedure. This supplies the generators with excess information and can potentially be used to gain market dominance on the residual demand.

Bilateral, Long-term and Forward Contracts

The regulatory regime does not prevent the use of long-term or forward contracts for the sale and purchase of electricity. At Nord Pool financial forward contracts are traded for a period of up to three years.

Long term contracts between generators involving reservation in the transmission system (and interconnectors) to and from Denmark West previously were common. The interconnectors from Denmark West to Norway in the north and partly to Germany in the south were until January 1st 2001 occupied by long term contracts between generators in the three countries. This disturbed trading across the borders. With the intervention of the EU-Commission the agreements were abandoned.

Still a part of the interconnector between Denmark East and Germany is occupied by long term contracts between generators in Sweden, Denmark and Germany. This is reducing the capacity that is available for competitors in the market and seems to be an obstacle for integration between Germany and Denmark.

The adverse effects of long term contracts on transmission capacity probably are the reason why trading patterns on the Danish-German interconnectors not always are/were in concordance with relative spot prices.

Price or Quantity Controls

The wholesale electricity prices are set through a market mechanism. Either bilateral or at the power exchange Nord Pool. Nord Pool operates with a (very high) ceiling for the price equilibrium, where supply meets demand. The regulation in Denmark does not set rules for the size and the kind of bidding on the wholesale market.

Presently it is the business of the TSOs in Denmark to secure that enough generation capacity is available. The TSOs have in this regard entered into contracts with the two large generators to maintain a certain generation capacity. This capacity constitute more than the Danish consumption. Furthermore, according to the contracts the generators are obliged to supply power in situations, where more supply is needed on the power exchange in order for supply and demand bids to meet. The mentioned contracts run in a transitory period to the end of 2003. It is the expectation, that they will not be continued.

Entry

Except for the construction of subsidised renewable power production no plans for the construction of new generation has come up in Denmark in recent years – and therefore no new entry. One main reason is the presently low price of power when comparing to long run costs of new production. This is a reflection of the present excess capacity.

About 40 percent of the Danish power production stems from renewable sources and are allocated outside the market. When this prioritised production system is changed and the production sold on the market, there will be more generators competing. The two generators, Energi E2 A/S and Elsam A/S will, however, continue to hold a dominant position in the Danish market.

A new large plant decided 8-10 years ago (before the opening of the market) belonging to the incumbent company, Energi E2 A/S, has started production this year. This plant is located near Copenhagen with easy access to water and fuel and access to a market for the production of heat in the CHP-production. The plant is flexible concerning fuels (biomass, natural gas and orimulsion).

A key issue in setting up new generation capacity in Denmark will definitely be location with the present lack of sites – especially because of local resistance due to environmental problems. Location can in this way become a barrier to entry in the market. At the moment it is not a requirement for the incumbent generators to offer sites to competitors when plants are shut down.

Competition Law Enforcement

There has not been considered any mergers between electricity generators or between electricity and gas producers since the introduction October 1st 2000 in the Danish Competition Act of the merger-approval procedure. The two large generators, Energi E2 A/S and Elsam A/S, are the result of mergers between a number of companies before that date.

There have, however, been a few attempts of take-overs in the sector. These have been driven by the energy company DONG (state owned) or by large grid companies (which own shares in generation and transmission). Lack of transparency concerning the capital in the grid companies (affecting the price of the companies) seems to be the main explanation for the lack of consolidation.

The DCA have not made any investigation of collusive behaviour in the electricity sector. When there is only one generator in respectively Denmark-east and Denmark-west any collusive behaviour concerning generators must be border crossing.

Presently the DCA is investigating into the possible abuse of market power of both Elsam A/S in western Denmark and Energi E2 A/S in eastern Denmark. The investigation is not yet complete and hence, the conclusion not yet known.

Besides defining the relevant market on the basis of the partial correlation coefficients above the investigation has revealed indications of abuse of market power. The indications are founded on calculated Lerner indices and contribution margins. Both show significant increases when the generators obtain a dominant position in their markets.

Table 3. Lerner index Elsam (DK1) 2001

	At least one Nordic line open	Both Nordic lines congested
Mean all hours	0,02	0,40

Table 4. Lerner index Energi E2 (DK2) Oct. 2000 – Dec. 2001

	Nordic line open	Nordic line congested
Mean all hours	0,04	0,43

The Lerner index is calculated as $(p-mc)/p$: The spot price less marginal costs divided by the spot price. The calculation is done for all hours in the period.

Calculations of contribution margins confirm the indications given by the Lerner index. The margins are calculated in terms of øre per kWh for all hours in 2001.

Table 5. Contribution margin (price less short run average costs) Elsam (DK1) 2001

Øre/kWh	At least one Nordic line open	Both Nordic lines congested
Mean all hours	4,18	15,05

Table 6. Contribution margin (price less short run average costs) Energi E2 (DK2) 2001

Øre/kWh	Nordic line open	Nordic line congested
Mean all hours	1,19	12,77

FRANCE

Conformément à la directive européenne de 1996 sur le marché intérieur de l'électricité, la France a mis en place les mesures nécessaires à l'ouverture à la concurrence du secteur de l'électricité, mettant ainsi fin à un monopole public plus que cinquantenaire. Certes, l'ouverture du secteur peut paraître limitée, mais elle a le mérite de ne pas se contenter d'un faux-semblant juridique : elle se traduit par une application tangible du jeu de la concurrence. Parallèlement, toutes les précautions ont été prises pour que soient sauvegardées les obligations de service public liées à ce secteur, vitales pour la population. La concurrence devrait s'élargir encore de façon à améliorer la fluidité des échanges communautaires, au bénéfice des professionnels comme des consommateurs.

L'ouverture du marché français de l'électricité se fait par le biais de la fourniture, conformément au choix communautaire. Les réseaux publics de transport et de distribution sont et resteront des monopoles naturels. Mais l'accès à ces réseaux est encadré et les tarifs d'acheminement sont réglementés par les pouvoirs publics.

Surtout, se posait le problème de la séparation entre les activités relevant du monopole – notamment la gestion du réseau de transport – et celles - électriques ou non - du secteur concurrentiel. Le législateur a tranché en faveur du maintien de l'ensemble de ces activités au sein d'une même entreprise intégrée (EDF), assorti de garanties permettant d'empêcher tout abus de position dominante. Ainsi, au sein même d'EDF, la gestion du réseau de transport fait l'objet d'une séparation comptable stricte par rapport aux autres activités de l'entreprise. De même, est instaurée autour du gestionnaire du réseau une véritable « muraille de Chine », en particulier pour protéger les informations commercialement sensibles qu'il est amené à connaître.

Enfin, le contenu du service public et ses modalités de financement sont désormais expressément définis par le législateur. Ce dispositif permet de mettre en œuvre la politique énergétique, notamment en matière de soutien aux énergies renouvelables, et de concourir à la cohésion sociale.

Certes, l'ouverture du secteur peut paraître limitée, mais elle a le mérite de ne pas se contenter d'un faux-semblant juridique : elle se traduit par une application tangible du jeu de la concurrence.

Au niveau international, si l'on compare les degrés d'ouverture à la concurrence des marchés de l'électricité sur la base de critères purement légaux, l'ouverture affichée du marché français, tout en restant conforme à la directive, apparaît minimale. En effet, seuls les clients les plus importants, dits « éligibles », consommant plus de 16 GWh par site et par an et qui représentent 30 % de la consommation nationale, peuvent choisir librement leur fournisseur d'électricité.

Pourtant, la comparaison doit être nuancée : il faut aussi tenir compte du caractère effectif de cette ouverture, même partielle, du marché français.

Du côté de la demande, la concurrence joue déjà dans les faits. Un nombre significatif de clients éligibles ont changé de fournisseur, obtenant ainsi de meilleures conditions de prix de la part de producteurs essentiellement étrangers. Ces derniers ont pu prospecter les clients français parce que des capacités d'interconnexion sont disponibles.

S'agissant de l'offre, il n'y a certes pas encore de véritable compétiteur national face à EDF, hormis la SNET (filiale électrique de Charbonnages de France) et la Compagnie Nationale du Rhône (CNR, producteur français d'hydroélectricité représentant 4 % de la production nationale), qui ont accédé au statut de producteurs indépendants, mais les capacités d'interconnexion avec les réseaux des autres États membres sont amplement suffisantes pour considérer la France comme électriquement perméable aux producteurs et grossistes européens.

Par ailleurs, lors du contrôle de concentration opéré en février 2001 par la Commission européenne dans l'affaire Energie-Baden-Württemberg (EnBW), les engagements pris par EDF ont permis à la Commission de considérer que le marché français allait être suffisamment ouvert pour autoriser l'entrée d'EDF dans le capital de cette société allemande. Parmi les engagements d'EDF figurent, notamment, la mise à disposition de ses concurrents de 6 000 MW de capacités de production, la renonciation à ses droits de vote dans la CNR ainsi que des mesures de nature à permettre à la SNET et à la CNR de ne pas être empêchées de contribuer à la liquidité du marché français.

Si la position fortement dominante d'EDF sur les marchés français de l'électricité est en voie de s'atténuer, l'entreprise acquiert simultanément, par démarchage direct de clients et par des acquisitions de sociétés (London Electricity, EnBW, Italenergia), des parts de marché dans les pays voisins. EDF assure encore 94 % des consommations françaises d'électricité, détient déjà 18 % du marché européen et en vise 22 à 23 % pour compenser les parts du marché national qu'elle est susceptible de perdre.

Le contrat de groupe négocié entre l'État et EDF pour les années 2001-2003 prend d'ailleurs acte de la nécessité d'élargir la concurrence sur le marché français de l'électricité afin que l'entreprise publique ne soit pas gênée dans sa politique de développement international, centrée en particulier sur l'Europe (EDF prévoit d'investir 19 milliards d'euros d'ici 2005).

Un processus d'accélération de l'ouverture du marché intérieur de l'énergie s'initie au niveau européen.

Le Conseil européen de Lisbonne des 23 et 24 mars 2000 avait convenu d'accélérer l'ouverture des marchés du gaz et de l'électricité. Cette dernière énergie n'est ouverte qu'à hauteur de 66 % en moyenne européenne, cette moyenne recouvrant une disparité dans les degrés d'ouverture selon les pays.

La Commission européenne a donc soumis aux quinze États membres lors du sommet de Stockholm, les 23 et 24 mars 2001, une nouvelle proposition de directive. Son objectif est double : ouvrir davantage à la concurrence des marchés nationaux encore cloisonnés et façonner un véritable marché intérieur européen, alors que les échanges internationaux ne concernent actuellement que 8 % de la consommation d'électricité.

Les trois principaux points d'accord acquis au Sommet de Barcelone des 15 et 16 mars 2002 sont une libéralisation d'ici 2004 des marchés du gaz et de l'électricité pour tous les consommateurs autres que les ménages avec un minimum d'ouverture des marchés à hauteur de 60 %, l'adoption, avant le Sommet du printemps 2003, d'une décision sur « *d'autres mesures tenant compte de la définition des obligations de service public* » et l'objectif de parvenir d'ici 2005 à un niveau d'interconnexion électrique équivalent à 10 % des capacités de production.

Par ailleurs, un projet de règlement sur l'accès aux réseaux pour le commerce de l'électricité intra-communautaire est proposé par la Commission. Une généralisation de l'accès réglementé des tiers aux réseaux - déjà adopté par la France - est en outre envisagée, dans l'intérêt de la concurrence. L'objectif est, dans la lignée du « processus de Florence » - qui réunit chaque année depuis 1998 les régulateurs et les gestionnaires de réseaux de l'Union européenne -, d'améliorer les modalités de tarification des échanges

transfrontaliers d'électricité et, plus généralement, de faciliter la fluidité des échanges à l'intérieur de l'Union européenne.

Le système électrique français

Avec une consommation de près de 500 TWh en 2001, la France est un pays qui dispose de peu de ressources fossiles pour produire de l'électricité. C'est une donnée dont tient compte la politique menée par les pouvoirs publics français dans le secteur électrique. Cette politique, parallèlement au développement de la concurrence, poursuit des objectifs de nature industrielle, sociale et environnementale :

- la sécurité d'approvisionnement à long terme ; elle constitue une préoccupation majeure qui a conduit au choix d'une composante nucléaire forte au sein du parc de production ;
- la garantie des missions de service public : obligation de fourniture, égalité de traitement, qualité et continuité de la fourniture ;
- la compétitivité ;
- la contribution à un développement durable, respectueux de l'environnement.

L'indépendance énergétique de la France est passée de 23,9% en 1973 à 50 % en 2001 grâce notamment au programme électronucléaire. Les principales sources de production d'électricité que sont le nucléaire (75%) et l'hydraulique (15%) ne contribuent pas, ou du moins pas directement, à l'émission de gaz à effet de serre et ont permis de réduire les pollutions acides. Les prix de l'électricité française se situent en bonne position en Europe et le solde des exportations et importations de l'électricité est largement positif.

La loi de modernisation et de développement du service public de l'électricité du 10 février 2000 a transposé la directive 96/92/CE du Parlement et du Conseil du 19 décembre 1996 relative à des règles communes pour le marché intérieur de l'électricité. Les choix français de transposition sont les suivants :

- l'accès des tiers aux réseaux réglementés, système préconisé par la Commission européenne et qui permet plus de transparence et d'efficacité concurrentielle, a été retenu ;
- pour la production, un régime d'autorisations et d'appels d'offres a été mis en place ;
- la loi définit également les missions du service public de l'électricité et ceux qui en sont chargés, ainsi que le financement ;
- elle prévoit également une procédure de reconnaissance de l'éligibilité, essentiellement déclarative, et une publication de la liste des éligibles qui vise la transparence et une stimulation de la concurrence ;
- une autorité sectorielle de régulation indépendante, la Commission de régulation de l'électricité, a été instituée ;
- le gestionnaire du réseau de transport est indépendant sur le plan de la gestion (une « muraille de Chine » a été instituée) et il fait l'objet d'une comptabilité séparée du reste d'EDF ;

- le seuil d'éligibilité à 16 GWh par site marque l'ouverture effective du marché de l'électricité à la concurrence à hauteur de 30 % de la consommation totale (ce seuil devrait être abaissé à 9 GWh début 2003) ;
- une programmation à long terme des investissements de production est établie par le Gouvernement ;
- de même, est élaboré un schéma de développement du réseau public de transport d'électricité ;
- le ministre en charge de l'économie et le ministre de l'énergie fixent les tarifs de l'électricité pour les clients captifs ;
- enfin, l'Etat définit avec EDF, dans les contrats d'entreprise, les grandes lignes du développement de l'entreprise.

La structure du marché français de l'électricité

1. Une dynamique d'ouverture à la concurrence est désormais enclenchée.

Les clients dits « éligibles » sont ceux qui peuvent faire jouer la concurrence. Ce sont ceux dont la consommation annuelle d'électricité sur un site dépasse un certain seuil, actuellement fixé en France à 16 GWh, seuil qui sera ramené à 9 GWh au plus tard début 2003. Ce seuil de 16 GWh représente 1 300 sites éligibles et environ 30 % du marché ouvert à la concurrence. Le passage du seuil de consommation à 9 GWh rendra environ 3 000 sites éligibles ce qui ouvrira 34 % du marché à la concurrence.

Les consommateurs éligibles se font connaître auprès du Ministère en charge de l'énergie au moyen d'une déclaration. L'éligibilité est acquise pour 3 ans, quelle que soit l'évolution de la consommation du site au cours de cette période.

Le client éligible doit passer deux contrats : un contrat de fourniture avec le fournisseur de son choix et un contrat d'acheminement avec le RTE, le gestionnaire du réseau de transport. Celui-ci est, de par la loi, responsable de la qualité et de la continuité de la fourniture, de sorte que le changement de fournisseur ne modifie pas les conditions d'approvisionnement du client.

Sur le marché de la fourniture de l'électricité aux clients éligibles, les prix sont libres, sous réserve du respect des règles habituelles de concurrence. Eurostat publie deux fois par an des indicateurs de prix pertinents à une échelle géographique locale. Il convient de noter que l'électricité échangée sur des bourses correspond en général à des livraisons de gros (400 kV, blocs de puissance échangés sur la journée ou une partie de la journée, sans ajustement).

2. L'offre émane d'une pluralité d'acteurs français et étrangers, mais les producteurs français sont de taille très inégale.

Les producteurs français d'électricité de taille significative sont très peu nombreux : EDF, la Compagnie Nationale du Rhône (CNR) associée à Electrabel et la Société Nationale d'Electricité et de thermique (SNET) associée à Endesa. Encore faut-il souligner qu'EDF dispose d'une très nette position dominante, puisqu'elle a (chiffres 2000) une capacité installée de 102 800 mégawatts (MW), tandis que la CNR a une capacité de 3 000 MW et la SNET de 2 600 MW. Leurs productions respectives d'électricité sont 482 TWh, 16,2 TWh et 8,1 TWh. En application de la loi électrique du 10 février 2000, deux Comités

arbitraux ont déterminé les conditions de révision des conventions qui liaient, d'une part, EDF à la SNET, d'autre part, EDF à la CNR.

A côté de ces trois principaux acteurs français, existe une multiplicité de petits producteurs français décentralisés, qui sont toutefois liés à EDF par des contrats de vente dont le cadre est fixé par les pouvoirs publics à des fins de politique énergétique et de promotion de nouvelles technologies de production d'électricité.

Pour autant, en France, la concurrence joue pleinement dans la partie du marché qui est ouverte, car les producteurs et fournisseurs étrangers peuvent réellement exporter de l'électricité vers la France et venir concurrencer efficacement les fournisseurs français auprès des clients éligibles. La CRE publie, sur son site Internet, la liste des fournisseurs que les clients éligibles peuvent mettre en concurrence. Ils sont environ une cinquantaine.

3. Les contrats de fourniture d'électricité sont essentiellement bilatéraux, mais une bourse de l'électricité a été créée à Paris (Pownext).

Pownext SA assure la gestion de la bourse française de l'électricité ; elle est opérationnelle depuis le 26 novembre 2001. Pownext est un nouvel outil de négociation à la disposition des opérateurs européens du trading de l'électricité.

Dotée d'un capital de 10 millions d'euros, la société Pownext SA réunit des acteurs majeurs du négoce de l'électricité et des marchés financiers. Euronext Paris et un holding de gestionnaires de réseau européens, dénommé HGRT, détiennent respectivement 34% et 17% de la société. RTE (Réseau de Transport de l'Electricité), actionnaire fondateur de HGRT, a été rejoint par les gestionnaires des réseaux belge et néerlandais, ELIA et TENNET. Chacune de ces deux sociétés détient 24.5% du capital de HGRT. RTE reste actionnaire majoritaire avec les 51% restants. HGRT et Euronext constituent un noyau d'actionnaires neutres. Les 49 % restants sont répartis entre des professionnels européens de la finance et du marché de l'électricité : Atel, BNP PARIBAS, Electrabel, EDF, Endesa, Société Générale et TotalFinaElf. Le marché scandinave Nordpool s'est avéré un partenaire industriel particulièrement important, en mettant à la disposition de Pownext sa plate-forme de négociation EIWeb et en participant à l'élaboration du modèle de marché.

Pownext est un marché organisé, facultatif et anonyme. Il offre à la négociation des contrats horaires standardisés portant sur la livraison d'électricité le lendemain sur le "hub" français. Pownext organise la liquidité des transactions par une concentration des ordres sur un fixeage. Clearnet, chambre de compensation européenne et filiale d'Euronext, garantit la sécurité des transactions en s'interposant comme contrepartie centrale entre l'acheteur et le vendeur et en exigeant des membres un dépôt de garantie ajusté quotidiennement en fonction des positions prises sur le marché. La livraison physique de l'électricité est placée sous la responsabilité de RTE. Pownext SA indique tous les jours à RTE les quantités négociées par ses membres sur son marché.

Les objectifs de Pownext sont notamment :

- de créer une référence de prix incontestable en stimulant le développement de la concurrence en France par un nouveau vecteur de négociation, en augmentant la diversité des acteurs et en bénéficiant de la position géographique privilégiée du réseau électrique ;
- d'être un acteur de la rationalisation des marchés électriques européens en fournissant un service « day-ahead » aux dimensions européennes (produits blocs, compensation des contrats bilatéraux, indices, élargissement à d'autres « hubs »).

4. EDF, opérateur historique, est resté verticalement intégré, mais des mesures ont été prises pour garantir un accès des tiers au réseau non discriminatoire.

EDF est resté un opérateur verticalement intégré, présent dans la production, le transport et la distribution de l'électricité. En revanche, conformément aux termes de la directive de 1996, le gestionnaire du réseau de transport a fait l'objet de dispositions visant à en assurer l'indépendance, ceci devant permettre la neutralité de l'accès au réseau dont il a la charge.

La directive de 1996 sur le marché intérieur de l'électricité laisse en effet aux États membres la possibilité de conserver le réseau de transport au sein d'un opérateur électrique intégré. Aussi, le législateur français a-t-il prévu des règles de transparence et de séparation comptable entre les grandes activités d'EDF, en vue d'éviter « discriminations, subventions croisées et distorsions de concurrence ». Ce dispositif doit avoir des effets équivalents à ceux qu'aurait pu avoir une séparation juridique du gestionnaire de réseau.

La dissociation comptable et la transparence de la comptabilité constituent en outre des moyens clés, sous la responsabilité du régulateur spécialisé (CRE), pour lutter contre la tentation que le maximum de charges soient placées sur les activités en monopole au bénéfice des activités en concurrence de l'opérateur historique.

5. Le mécanisme d'ajustement est un outil fonctionnant selon les règles du marché.

La conduite du réseau de transport d'électricité consiste à assurer en temps réel l'équilibre entre la consommation et la production d'électricité. Plusieurs types d'incidents peuvent perturber cet équilibre (unité de production défaillante, ligne de transport endommagée, écarts de consommation). RTE doit alors faire appel aux producteurs et aux consommateurs directement connectés au réseau de transport d'électricité pour qu'ils modifient très rapidement leur régime de fonctionnement.

RTE a donc besoin de connaître en permanence les différentes solutions disponibles, ainsi que les conditions techniques et économiques de leur mise en œuvre pour retrouver le niveau d'équilibre du réseau de transport.

Pour déterminer équitablement les meilleures solutions à mettre en œuvre en pareil cas, RTE expérimente la mise en place d'un « Mécanisme d'ajustement ».

Le mécanisme d'ajustement est un outil fonctionnant selon des règles de marché, destiné à contribuer à la sûreté du système électrique et à fournir une référence de prix au règlement des écarts.

La loi électrique française a en effet créé les conditions de la mise en place par RTE d'un tel mécanisme d'ajustement. Participant à garantir la sûreté du système électrique, il permettra à RTE:

- de mobiliser des réserves pour assurer en temps réel l'équilibre production - consommation ;
- de contribuer à la résolution des congestions du réseau ;
- de produire un prix de référence légitime qui puisse être utilisé pour le règlement des déséquilibres.

Par un système d'offres à la hausse et à la baisse, les acteurs du marché communiquent les conditions techniques et financières auxquelles RTE peut modifier leurs programmes de production ou de consommation. RTE compense les déséquilibres en sélectionnant des offres, après les avoir interclassées selon un critère de préséance économique.

La mise en place en France d'un mécanisme ouvert d'ajustement constitue une contribution importante à la construction du marché intérieur européen de l'électricité.

6. *La gestion des écarts est assurée grâce à un contrat de « responsable d'équilibre ».*

Afin de faciliter les conditions d'accès au réseau, d'offrir plus de souplesse et d'améliorer la fluidité du marché de l'électricité, RTE a mis en place des contrats de « responsables d'équilibre ». Ce dispositif concerne l'ensemble des clients éligibles du réseau, qu'ils soient raccordés au réseau public de transport d'électricité ou au réseau de distribution.

Le « contrat de responsable d'équilibre » permet aux utilisateurs du réseau de mutualiser leurs écarts individuels de production et de consommation et d'en minimiser le coût. Le responsable d'équilibre est l'intermédiaire qui garantit auprès de RTE le règlement des écarts pour l'ensemble des consommateurs et fournisseurs qui l'ont choisi à cette fin. Le dispositif de responsable d'équilibre permet en particulier aux clients éligibles de disposer d'un accès facilité aux fournisseurs étrangers, en leur permettant de mutualiser l'ensemble des écarts entre leurs consommations et les importations correspondantes.

7. *RTE, le gestionnaire français du réseau de transport, procède à une mise en concurrence pour acheter l'énergie électrique dont il a besoin pour compenser les pertes sur le réseau de transport.*

En tant que gestionnaire du « Réseau de Transport d'Electricité », RTE a pour mission de veiller à la compensation des pertes électriques résultant du transit sur le réseau de transport d'électricité haute et très haute tension (effet Joule). Ces pertes représentent environ 12 TWh (Terawatt-heures) par an.

Pour compenser ces pertes électriques, RTE organise périodiquement des consultations auprès des producteurs, qu'il met en concurrence, pour leur acheter l'électricité nécessaire. EDF (production) est donc mis en compétition avec d'autres producteurs pour cette quantité non négligeable d'énergie électrique, ce qui contribue encore à la liquidité du marché. EDF ne détient plus qu'une partie de ce marché de la compensation des écarts.

8. *Le Fonds de service public de la production d'électricité (FSPPE) a été mis en place pour assurer un financement transparent des obligations de service public.*

Créé par la loi électrique française du 10 février 2000, le F.S.P.P.E. est destiné à financer les surcoûts résultant des politiques de soutien à la cogénération et aux énergies renouvelables, ainsi que les surcoûts de production dans les zones non interconnectées (départements d'outre-mer et Corse).

EDF, pour l'essentiel, et certains distributeurs non nationalisés, sont en particulier tenus d'acheter l'électricité produite sous le régime de l'obligation d'achat, mais bénéficient d'une compensation de cette charge par le FSPPE. Ce fonds, dont le montant prévisionnel pour 2002 s'élève à 1 306 millions d'euros, est alimenté par des contributions versées par tous les fournisseurs installés en France vendant à des consommateurs finals en France, par les autoproducteurs au-delà d'un seuil annuel de 240 GWh, et directement par tous les consommateurs finals achetant leur électricité auprès d'un fournisseur installé à l'étranger. Ce fonds est géré par la Caisse des dépôts et consignations et son montant est fixé par la Commission de régulation de l'électricité.

Le montant prévisionnel de la contribution au fonds du service public de la production d'électricité pour l'année 2002 est de 3 € /MWh. Ce montant a été déterminé par la Commission de régulation de l'électricité.

Les missions de la Commission de régulation de l'électricité

La CRE est une instance indépendante mise en place principalement pour garantir l'accès aux réseaux. En effet, la concurrence ne peut s'exercer sur le marché que si les producteurs et les consommateurs éligibles peuvent accéder aux réseaux dans des conditions équitables et non discriminatoires.

1. Le GRT (*Gestionnaire de Réseau de Transport*).

Le gestionnaire de réseau doit être « indépendant sur le plan de sa gestion » des autres activités d'EDF.

La CRE contribue à cette indépendance en :

- participant à la désignation du directeur de RTE (émet un avis sur les trois candidats proposés par EDF au Gouvernement) ;
- émettant un avis sur le cahier des charges de RTE qui détermine les conditions d'exercice des missions que lui confie la loi ;
- approuvant le programme annuel d'investissement de RTE ;
- émettant un avis sur le schéma pluriannuel de développement du réseau dans lequel il s'inscrit,
- approuvant les règles comptables de séparation des activités entre production, transport et distribution, et autres activités, non seulement d'EDF, mais aussi des autres opérateurs intégrés ;
- exerçant une fonction de veille et de surveillance concrétisée par l'exercice éventuel de ses pouvoirs d'enquête et de sanction (pour vérifier la bonne application de ces principes de séparation, de façon à prévenir toute subvention croisée, toute discrimination ou toute entrave à la concurrence).

Ces compétences sont exercées en liaison avec le Conseil de la concurrence, qui émet notamment un avis préalable à l'application des principes comptables, et qui peut être saisi à tout moment par le président de la Commission de régulation de l'électricité.

La CRE œuvre en faveur de la transparence des informations sur le fonctionnement du GRT en communiquant le budget annuel du GRT à toute personne qui le demande.

2. L'accès au réseau.

La CRE est garante du droit d'accès aux réseaux publics de transport et de distribution. A ce titre la CRE :

- propose les tarifs d'utilisation de ces réseaux, qui sont ensuite arrêtés par le ministre chargé de l'énergie ;

- est destinataire des contrats (conclus entre les utilisateurs et RTE) et protocoles (conclus entre EDF et RTE) d'accès au réseau ; la Commission reçoit également notification des refus de conclure des contrats ou protocoles ;
- peut être saisie des différends entre utilisateurs et gestionnaires du réseau de transport et distribution en cas de refus d'accès aux dits réseaux ou à leur utilisation, ou en cas de désaccord sur la conclusion, l'interprétation ou l'exécution des contrats et protocoles ;
- peut également être amenée, dans ce cadre, à prononcer des mesures conservatoires ou des sanctions ;
- émet un avis sur les projets de refus par l'autorité administrative compétente d'autoriser la construction d'une ligne directe (réseau privé).

3. *Le fonctionnement du réseau.*

S'agissant du fonctionnement du réseau, la CRE :

- supervise l'organisation du mécanisme d'ajustement ;
- peut elle-même ordonner des mesures conservatoires dans le cadre du règlement des différends liés à l'accès au réseau pour assurer la continuité du fonctionnement des réseaux ;
- a un pouvoir de proposition à l'égard du ministre chargé de l'énergie pour les mesures conservatoires que celui-ci peut ordonner en cas d'atteinte grave et immédiate à la sûreté et la sécurité des réseaux publics d'électricité.

4. *L'entrée de nouveaux producteurs sur le marché.*

La CRE :

- émet un avis sur les demandes d'autorisation d'achat pour revente des producteurs, sur le décret précisant les obligations d'achat aux installations de petites taille (obligation faite à EDF et aux distributeurs non nationalisés de racheter l'énergie produite par ces producteurs) et sur les conditions d'achat de l'électricité ainsi produite (arrêtés tarifaires) ;
- met en œuvre les appels d'offres demandés par le ministre dans le cadre de la programmation pluriannuelle de la production, si les capacités de production ne répondent pas aux objectifs par le simple jeu des initiatives des opérateurs établis.

5. *Les tarifs.*

La CRE formule un avis sur les tarifs de vente appliqués aux consommateurs non éligibles qui sont encore largement majoritaires. Cette démarche a pour but de s'assurer à la fois que ces clients bénéficient des améliorations escomptées de l'ouverture du marché, notamment des baisses de prix à qualité constante, et que le maintien du monopole accordé à EDF, pour ce qui les concerne, ne se traduise pas par des pratiques tarifaires qui conduiraient à ce que les activités d'EDF soumises à la concurrence soient subventionnées par ses activités encore en monopole.

6. Le service public.

L'ouverture progressive du marché doit s'opérer en conciliant l'introduction de la concurrence avec l'accomplissement des missions de service public. Dans cette perspective, la CRE joue un rôle dans la conciliation de ces objectifs dès lors que l'organisation ou le financement du service public ont un impact sur le fonctionnement du marché.

C'est à ce titre que la CRE :

- évalue le montant des charges résultant, soit des obligations d'achat imposées à EDF ou aux distributeurs non nationalisés, soit des surcoûts de production existants dans les zones non interconnectées (dans les DOM TOM et en Corse où les prix de vente peuvent être plafonnés après avis de la CRE), compensées par le fonds du service public de la production d'électricité FSPPE ;
- propose aux ministres du budget et de l'énergie le montant des contributions nettes versées au fonds par les producteurs et importateurs ou versées par le fonds aux producteurs ;
- évalue son fonctionnement dans son rapport annuel ;
- émet un avis sur le mécanisme tarifaire à visée sociale destiné à garantir le droit à l'électricité des personnes en situation de précarité, prévu par la loi ;
- émet un avis sur la tarification appliquée par EDF aux producteurs qui solliciteraient une fourniture exceptionnelle en cas d'interruption de leur production - pour entretien ou pour tout aléa - afin de garantir à leurs clients la fourniture d'électricité.

Le Conseil de la concurrence français

Le Conseil de la concurrence a naturellement vocation à participer à la régulation du secteur de l'électricité, que ce soit à l'occasion de ses fonctions consultatives (demandes d'avis, concentrations) ou à l'occasion de son activité contentieuse (répression des ententes, répression des abus de position dominante ou de dépendance économique).

Ainsi, le Gouvernement français avait-il sollicité l'avis du Conseil de la concurrence en 1998, dans le cadre de la préparation de ce qui devait devenir la loi électrique du 10 février 2000, sur les principes à respecter ou les dispositions à prévoir pour assurer le fonctionnement concurrentiel du marché électrique dans le cadre tracé par la directive européenne de 1996 (avis du 28 avril 1998).

Mais, le Conseil de la concurrence a en outre vocation à élargir le champ d'analyse au-delà du marché de l'électricité, en intervenant par exemple pour sanctionner des pratiques anticoncurrentielles survenues sur des marchés situés en amont du marché de l'électricité, dans le domaine des achats effectués par les opérateurs électriques par exemple, ou en se prononçant sur la concurrence entre les énergies (cf. décision du 20 juillet 1999 relative à des pratiques constatées dans le secteur des applications thermiques de l'énergie), ou encore en portant son analyse sur des marchés de diversification de l'opérateur électrique historique situés en aval (cf. deuxième paragraphe ci-dessous).

La Commission de régulation de l'électricité (CRE) et le Conseil de la concurrence ont des domaines d'intervention propres, mais la loi électrique organise un système de saisines croisées entre les deux autorités.

La loi électrique du 10 février 2000 définit avec précision l'articulation entre les compétences sectorielles de la CRE, principalement centrées sur les problèmes d'accès aux réseaux, et celles, horizontales, du Conseil de la Concurrence.

L'acheminement par les réseaux de l'électricité provenant des fournisseurs indépendants peut éventuellement donner lieu à des litiges non susceptibles d'être analysés en termes d'abus de position dominante ou d'entente anticoncurrentielle. C'est pour régler ces litiges courants à caractère technique marqué, mettant en jeu de simples intérêts particuliers sans renvoyer à des pratiques affectant le fonctionnement du marché, que la CRE a été dotée d'attributions en matière contentieuse.

Toutefois, le président de la CRE doit saisir le Conseil de la Concurrence de ce qui lui apparaîtrait comme un abus de position dominante ou comme des pratiques entravant le libre exercice de la concurrence dont il aurait connaissance dans le secteur de l'électricité. Dans ce cas, la CRE ne doit pas statuer elle-même.

La CRE peut aussi saisir le Conseil de la concurrence pour avis. Ainsi, cela a-t-il été le cas par exemple sur les règles qui doivent régir la dissociation comptable et la transparence de la comptabilité dans le secteur de l'électricité (avis du 30 novembre 2000), ou encore en ce qui concerne la méthode d'évaluation des coûts évités de production d'électricité pour le fonctionnement du fonds du service public de la production d'électricité (avis du 20 novembre 2001).

En sens inverse, le Conseil de la Concurrence peut transférer à la CRE toute saisine qu'il estimerait être plutôt du ressort de la CRE que du sien, et il peut également, le cas échéant, saisir la CRE pour avis. Le dispositif de saisines croisées prévu par la loi électrique est donc complet.

Les décisions de la CRE sont portées en appel devant la Cour d'Appel de Paris, qui est déjà le juge en appel des décisions du Conseil de la Concurrence. Une cohérence pourra donc toujours être assurée entre les décisions de la CRE et celles du Conseil de la concurrence dans le secteur électrique.

Le Conseil de la concurrence a été amené à plusieurs reprises à se prononcer sur des diversifications d'EDF, soit dans le cadre d'avis demandé par le Gouvernement, soit dans le cadre de contrôle de concentration, soit dans le cadre de contentieux.

Le Conseil de la concurrence s'est prononcé en 1994 sur les principes qui devaient présider à la diversification d'EDF dans d'autres secteurs que celui de l'électricité (avis du 10 mai 1994).

Plus récemment, le Conseil de la concurrence a eu à se prononcer sur l'acquisition de la société Clemessy, spécialisée dans les travaux électriques, par les groupes EDF, Cogema et Siemens, opération qui avait notamment pour objectif de permettre à EDF de compléter son offre d'électricité par des services liés à l'installation et à la maintenance des équipements de ses clients, dans le cadre d'« offres globales » (avis du 22 février 2000). Sur la base des principes définis dans son avis précité de 1994, le Conseil a considéré qu'EDF doit s'abstenir de mettre en œuvre, dans le cadre des offres globales proposées aux clients éligibles, des pratiques susceptibles de constituer des abus de domination, telles que des conditions de vente discriminatoires, des ventes liées, des ventes à prime, des ventes à prix prédateurs, notamment en usant de procédés de compensation entre les prix de l'énergie et les prix des services associés.

En ce qui concerne les clients non éligibles, il a observé que, compte tenu du monopole que conserve EDF pour la fourniture d'électricité à l'égard de ces clients, toute possibilité qui lui serait laissée

de continuer à proposer à ces mêmes clients des prestations techniques ou commerciales liées à la fourniture d'électricité, reconstituerait *de facto* la possibilité pour EDF de proposer une offre globale à ces clients, ce que la loi électrique lui interdit, et lui permettrait de capturer une partie du marché des prestations associées à la vente d'électricité. De telles propositions créeraient pour EDF des avantages artificiels et discriminatoires à l'égard des concurrents, en particulier lorsque les clients sont sur le point de franchir le seuil d'éligibilité.

Le Conseil a également souligné le risque de subventions déguisées qui pourrait résulter de la centralisation des achats entre EDF et Clemessy et de l'utilisation, par Clemessy, de la puissance commerciale d'EDF, sans que les avantages obtenus fassent l'objet de contreparties financières reflétant la réalité des coûts.

Enfin, il a mis en garde EDF contre la mise à disposition de Clemessy du fichier, dont il était le seul détenteur, et qui porte sur l'ensemble des consommateurs français d'électricité, éligibles et non éligibles. En effet, EDF dispose, par ce fichier, de la connaissance des entreprises proches de l'éligibilité, en raison soit de l'augmentation de leur consommation d'électricité, soit de l'abaissement du seuil d'éligibilité, tandis que les autres fournisseurs d'électricité n'en disposent que lors de la publication par les autorités compétentes des listes de clients ayant accédé au marché concurrentiel. Le simple fait que Clemessy dispose directement de cette information donnerait à cette entreprise un avantage substantiel au détriment de ses concurrents sur le marché des travaux d'installation électrique.

Le Conseil de la concurrence a également eu l'occasion de se prononcer sur la diversification d'EDF dans un cadre contentieux, tel que celui qui a donné lieu à la décision du 22 novembre 2000, qui concernait la société Citelum, agissant dans le secteur de l'éclairage public. Dans cette affaire, le Conseil a indiqué qu'une entreprise publique disposant d'un monopole légal, qui utilise les ressources de son activité monopolistique pour subventionner une nouvelle activité, ne méconnaît pas, de ce seul fait, les dispositions du code de commerce qui prohibent l'abus de position dominante. En revanche, est susceptible de constituer un abus le fait, pour une entreprise disposant d'un monopole légal, c'est à dire un monopole dont l'acquisition n'a supposé aucune dépense et est non susceptible d'être contesté, d'utiliser tout ou partie de l'excédent des ressources que lui procure son activité sous monopole pour subventionner une offre présentée sur un marché concurrentiel, lorsque la subvention est utilisée pour pratiquer des prix prédateurs ou lorsqu'elle a conditionné une pratique commerciale qui, sans être prédatrice, a entraîné une perturbation durable du marché qui n'aurait pas eu lieu sans elle.

Le transport de l'électricité entre pays européens

Il n'existe pas de congestion dans le sens Pays européens - France. De la sorte, tous les fournisseurs étrangers peuvent effectivement approvisionner les clients en France ou entrer en France pour livrer à l'étranger.

La situation dans le sens France – Pays européens pose, en revanche, problème aux frontières italiennes et espagnoles, où des congestions sont constatées. L'interconnexion entre la France et l'Angleterre (IFA) fait l'objet d'un processus spécifique d'allocation des capacités depuis mars 2001. Sur les autres frontières, les interconnexions autorisent d'importants flux exportateurs.

Le mécanisme d'allocation en commun des ressources d'interconnexion entre l'Italie et la France est un exemple intéressant à exposer à titre d'illustration.

Les régulateurs français et italien de l'électricité, la CRE et l'AEEG, ont conclu en décembre 2001 un accord sur le mécanisme commun d'allocation des capacités d'interconnexion entre l'Italie et la France pour 2002 en vue de leur utilisation maximale. Cet accord augmente les capacités disponibles. En effet, il

met fin à un système dans lequel les deux pays organisaient séparément le transit transfrontalier, ce qui conduisait à une complication excessive pour les utilisateurs des réseaux désireux d'effectuer des transactions internationales. Cet accord permet ainsi d'améliorer substantiellement la liberté et le développement des échanges internationaux d'électricité qui sont indispensables au bon établissement du marché intérieur européen de l'énergie. Il porte sur une capacité nette de transit entre le bloc France - Suisse et Italie de 5 400 MW (valeur d'hiver). L'AEEG et la CRE ont fixé une répartition équilibrée de la capacité nette de transit avec l'Italie : Suisse : 2 800 MW et France : 2 600 MW.

L'accord distingue une allocation primaire et une allocation secondaire des capacités d'interconnexion avec l'Italie.

L'allocation annuelle primaire des capacités d'interconnexion avec l'Italie.

Une capacité d'interconnexion de 800 MW avec la Suisse est allouée au titre des contrats antérieurs à l'entrée en vigueur de la directive européenne du 19 décembre 1996. La moitié de la capacité restante, soit 1000 MW, est allouée par les compagnies d'électricité suisses concernées, selon les modalités qu'elles déterminent librement.

Une capacité d'interconnexion de 1 800 MW avec la France est allouée au titre des contrats antérieurs à l'entrée en vigueur de la directive européenne du 19 décembre 1996. La capacité restante, soit 800 MW, et la part de la capacité d'interconnexion avec la Suisse, soit 1000 MW, sont allouées conjointement par les gestionnaires des réseaux nationaux GRTN et RTE selon un mécanisme commun annuel au prorata des demandes, déduction faite d'une capacité de 155 MW réservée aux besoins d'alimentation de la Cité du Vatican, de la République de San Marino et de la Corse (via le réseau italien).

L'allocation secondaire des capacités d'interconnexion avec l'Italie.

Afin d'améliorer l'utilisation des capacités disponibles et en fonction des besoins du marché, les gestionnaires des réseaux procèdent à des allocations secondaires sur des durées inférieures à l'année. Ces allocations portent sur les capacités allouées annuellement et restituées par les acteurs, et sur les capacités d'interconnexion supplémentaires lorsque que la situation réelle du réseau permet de transporter plus que l'évaluation annuelle de 5 400 MW. Les gestionnaires des réseaux nationaux GRTN et RTE proposent dans les meilleurs délais à l'approbation des deux régulateurs des règles d'allocation secondaire fondées sur des mécanismes de marché.

Les concentrations intervenues dans le secteur de l'électricité

La prise de participation d'EDF dans Dalkia marquait la volonté d'EDF de se diversifier dans les services énergétiques.

Le ministre français de l'économie a autorisé sous conditions, le 12 décembre 2000, l'opération de concentration entre EDF et Dalkia, filiale de Vivendi Environnement.

Cette opération complexe consistait principalement, d'une part en l'apport à Dalkia par EDF de ses filiales actives dans le secteur des services énergétiques, d'autre part en la création de trois filiales communes à Vivendi Environnement et EDF (Dalkia Offre Globale, Dalkia International et Dalkia Investissement), dont l'objet est de fournir des services énergétiques, incluant le cas échéant un volet de fourniture d'électricité, aux clients étrangers et aux clients éligibles en France. A l'issue de l'opération, EDF devait détenir 34% de « Dalkia holding », holding de tête du nouveau groupe, Vivendi Environnement détenant le solde du capital.

La préoccupation du Ministre dans cette affaire a été double :

- Prendre les mesures nécessaires pour que l'opération ne crée pas une position dominante au profit de Dalkia sur les différents marchés sur lesquels elle est active, position qui pourrait résulter soit de son renforcement par l'absorption des filiales du pôle services d'EDF, soit de ses liens avec EDF, opérateur en position dominante sur les marchés amont de l'électricité ;
- Proscrire toute influence d'EDF sur Dalkia, filiale de Dalkia holding regroupant les activités de service énergétiques de la nouvelle entité en France. Une telle influence aurait en effet été contraire aux dispositions de la loi du 10 février 2000, qui interdit à EDF d'intervenir « en aval du compteur » au profit de clients non éligibles et aurait pu être de nature à renforcer la position dominante d'EDF sur les marchés de l'électricité et à créer une position dominante au profit de Dalkia sur les marchés des services énergétiques.

L'opération de concentration entre EDF et Dalkia a fait l'objet d'une large consultation du marché. La décision du Ministre a pris en compte les préoccupations exprimées et s'est inscrite dans la logique définie par le Conseil de la concurrence dans son avis du 22 février 2000 concernant la concentration entre EDF et Clemessy, qui présentaient des problématiques concurrentielles analogues.

Les engagements souscrits par Vivendi Environnement et EDF ont visé notamment à limiter très strictement les échanges d'information entre EDF et le groupe Dalkia ou ses filiales, à éviter toute discrimination de la part d'EDF entre le groupe Dalkia et ses concurrents en termes techniques, de tarifs et de délais, à éviter que la puissance d'achat d'EDF ne permette au groupe Dalkia de s'approvisionner à des tarifs inférieurs à la norme du marché.

En ce qui concerne plus spécifiquement l'offre globale, qui consiste à offrir simultanément de l'électricité et des services, EDF et Vivendi Environnement ont confirmé à la DGCCRF que Dalkia Offre Globale fournirait à la demande du client, dans le cadre de ses négociations commerciales avec celui-ci, le prix de la composante « fourniture d'électricité » au sein des contrats d'offre globale. Afin de lui permettre de s'assurer qu'EDF ne consent pas à Dalkia Offre Globale des prix de vente d'électricité discriminatoires, VIVENDI ENVIRONNEMENT et EDF se sont engagés à communiquer à la DGCCRF la partie du prix de l'offre globale correspondant à la fourniture d'électricité et à ce que Dalkia Offre Globale tienne une comptabilité lui permettant de respecter cet engagement.

La décision du Ministre a pris explicitement en compte la préoccupation de certains concurrents de la nouvelle entité, qui craignaient que la « muraille de Chine » établie entre EDF et Dalkia soit de pure forme et ne résiste pas à l'épreuve du terrain. La décision du ministre a précisé que, s'il devait être avéré qu'EDF exerce *de facto* une influence déterminante sur Dalkia, cette situation s'analyserait comme une nouvelle opération de concentration, contrôlable à ce titre par le ministre.

Enfin, Vivendi Environnement s'est engagé à décroiser certaines participations communes à Dalkia et Suez-Lyonnaise, afin d'éviter tout risque de création de position dominante collective au profit de ces deux groupes.

La décision du Ministre a donc pris en compte les préoccupations exprimées par les professionnels du secteur. A l'occasion de cette opération, l'État a matérialisé sa volonté d'assurer le libre jeu de la concurrence sur les marchés amont et aval du secteur énergétique.

La mise aux enchères par EDF de capacités de production d'électricité dans le cadre de l'exécution de la décision de concentration communautaire EDF / EnBW du 7 février 2001.

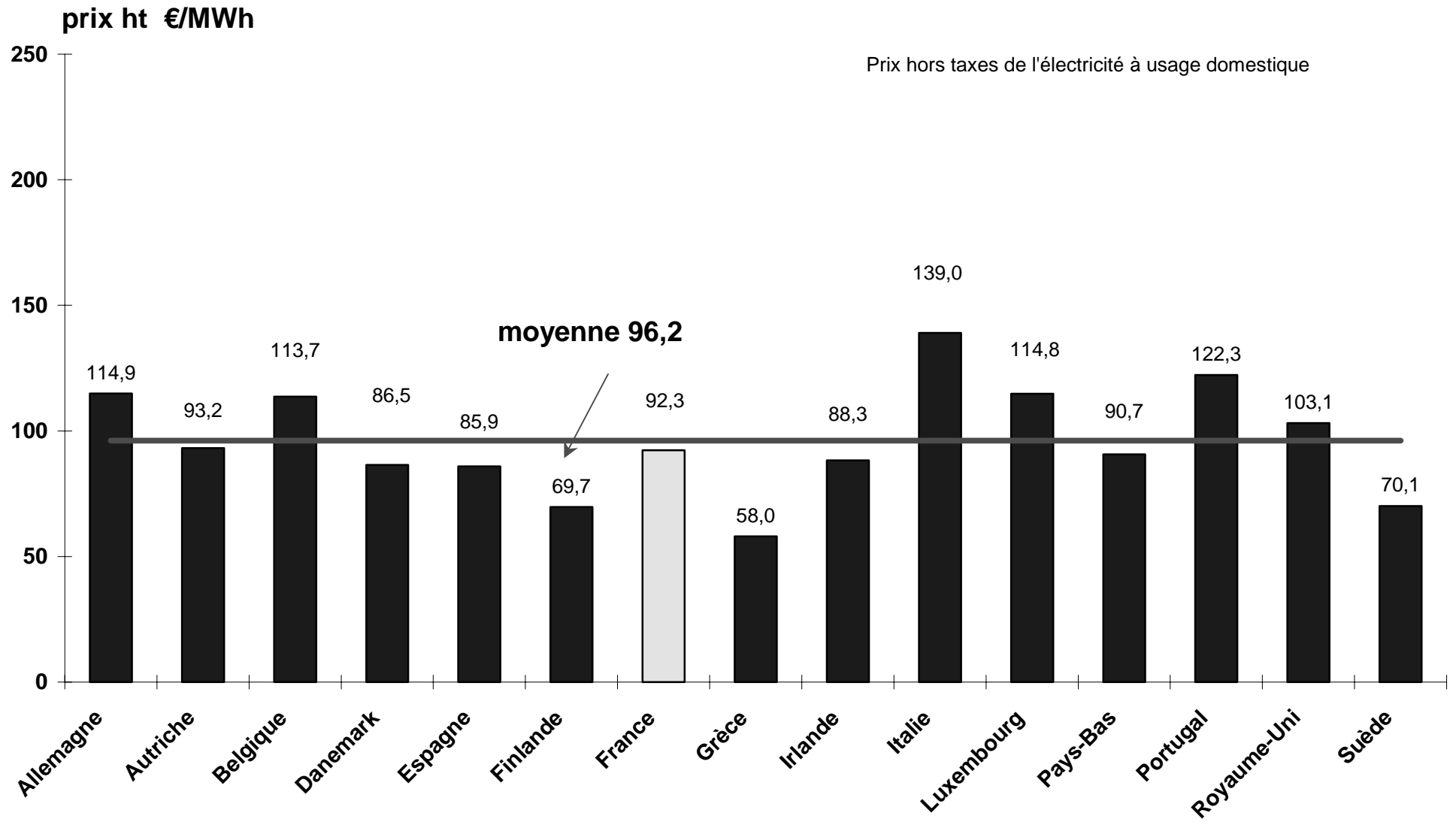
En vue d'obtenir de la Commission européenne son feu vert pour l'acquisition d'une participation de 34 % du capital de la société allemande EnBW, EDF a pris notamment l'engagement de mettre à la disposition de ses concurrents français et européens 6.000 MW de capacités de production situées en France, dont 5.000 MW sous forme de « centrales virtuelles » et 1.000 MW sous forme d'accords adossés aux contrats actuels de fourniture liant EDF à des entreprises de cogénération.

L'accès à cette capacité s'est effectué au travers de ventes aux enchères préparées et a été mis en œuvre par EDF sous la surveillance d'un administrateur. C'est ainsi environ 30 % du marché des clients éligibles qui verra sa liquidité accrue au terme de ces opérations d'enchères. L'engagement d'EDF a une durée de cinq ans. Après cette période, s'il existe suffisamment de ressources alternatives aux capacités mises aux enchères, la Commission européenne pourra décider de mettre fin à l'obligation d'EDF. Cet opérateur pourra toutefois, après un délai minimal de trois ans, solliciter de la Commission qu'elle anticipe la fin de ses engagements.

EDF a séparé les droits de tirage d'énergie en trois : 4.000 MW « en base » (électricité produite en continu ou en ruban), 1.000 MW « en pointe » et 1.000 MW issus des contrats de cogénération. EDF a prévu d'avoir vendu toute la capacité de 6.000 MW d'ici octobre 2003. Les enchères ont lieu à intervalles réguliers, selon la capacité d'absorption du marché. Une autorité de contrôle des ventes de capacités a fait l'objet d'un agrément par les services de la Commission européenne.

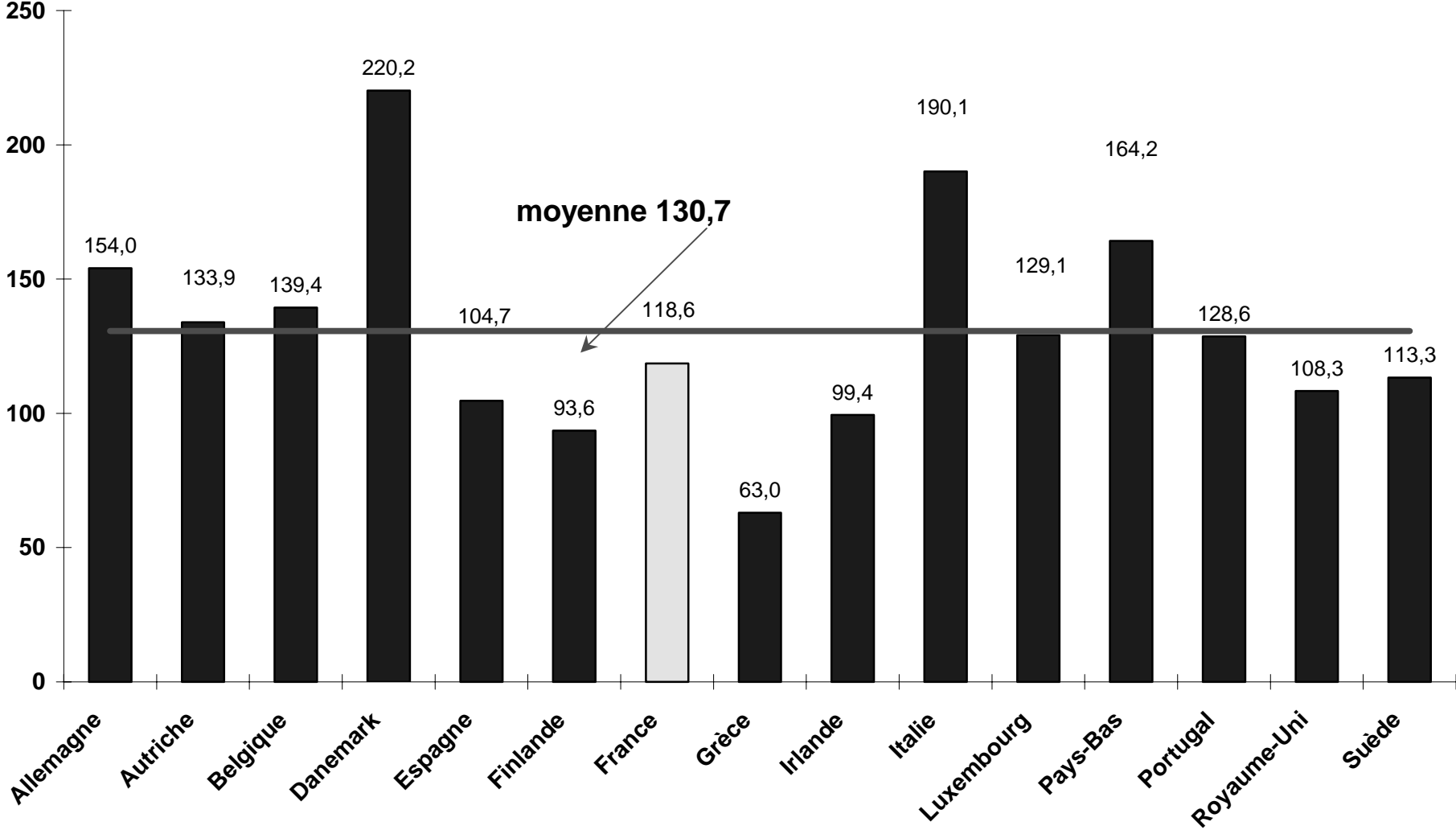
EDF a ainsi mis en vente à plusieurs reprises des tranches de capacités de production et les enchérisseurs ont ainsi pu se porter acquéreurs d'un droit de tirage dans le cadre des contrats de durées variables (3, 6, 12, 24 ou 36 mois) pour un nombre entier de MW. Les acquéreurs ont donc disposé d'un portefeuille diversifié en termes de produits et de durée. Ils ont ainsi obtenu le droit d'acheter à EDF, dans la limite de capacité contractée, de l'électricité à un prix déterminé. Les prix atteints par ces enchères ont semble-t-il été relativement élevés.

Cette technique des enchères, qui existe aux Etats-Unis, a participé, avec la création de la bourse de l'électricité de Paris (Powernext), au développement du marché de gros qui, en France, est optionnel.



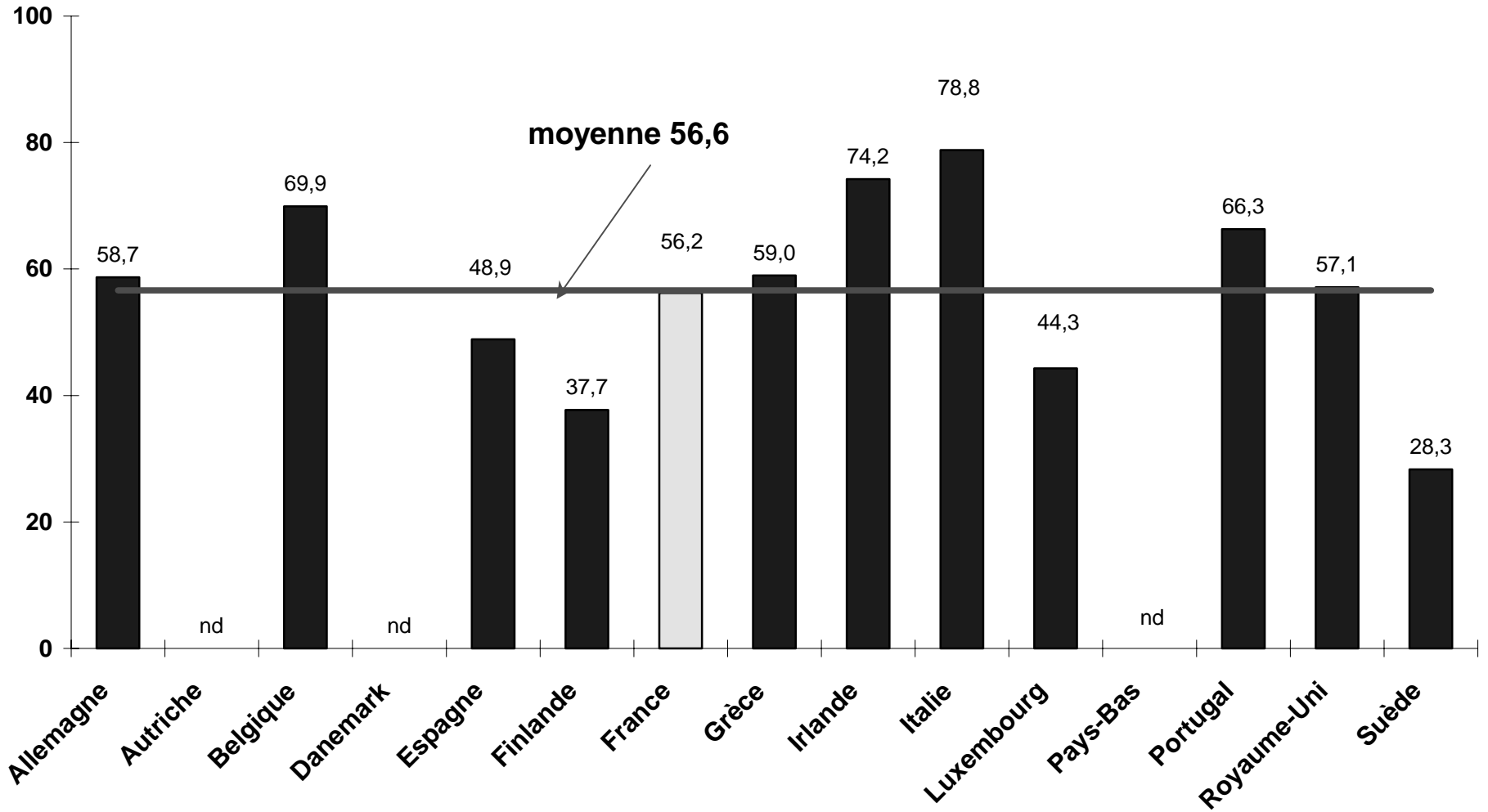
prix ttc €/MWh

Prix TTC de l'électricité à usage domestique



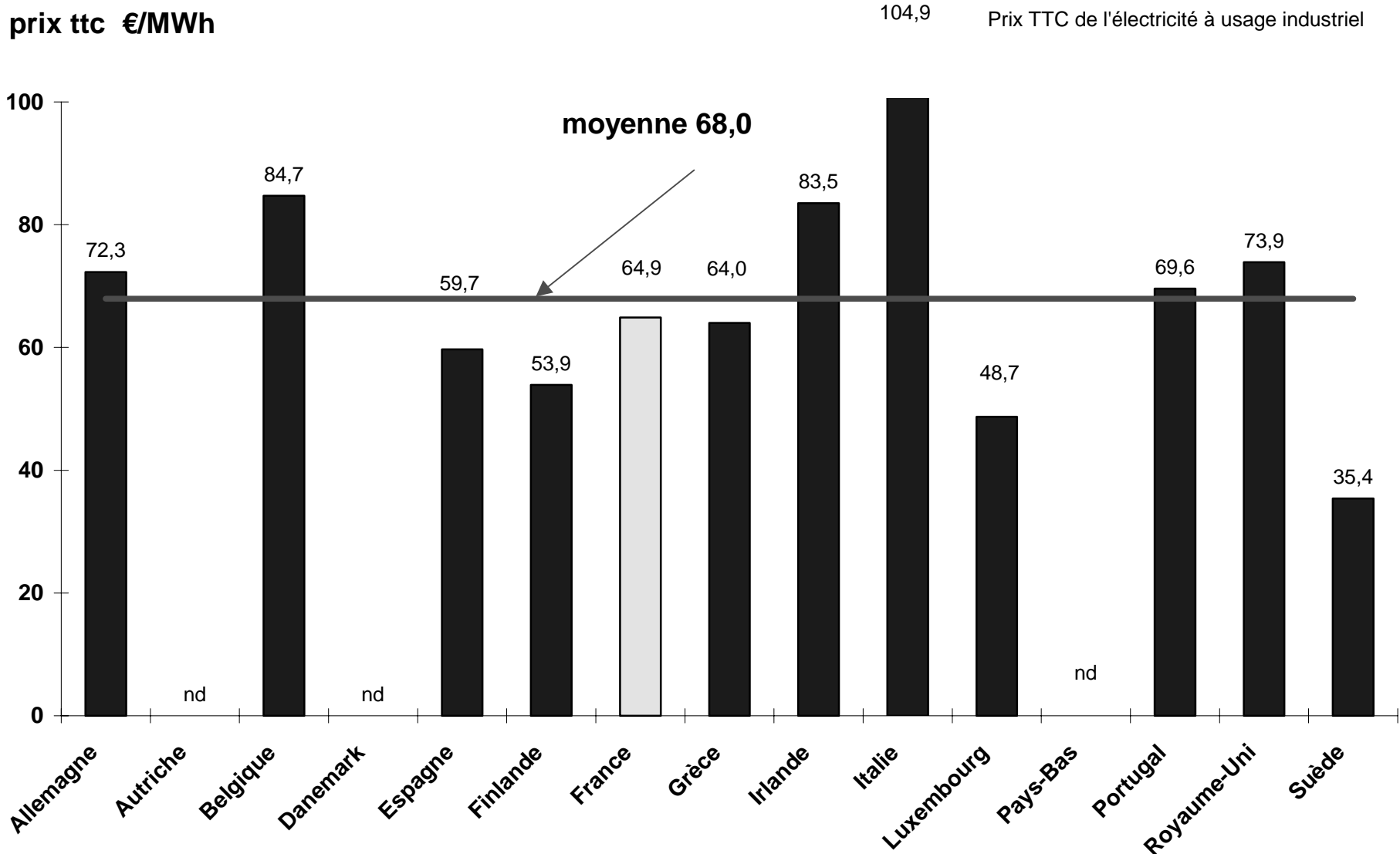
prix ht €/MWh

Prix hors taxes de l'électricité à usage industriel



prix ttc €/MWh

Prix TTC de l'électricité à usage industriel



GERMANY

Overview of Regulation

Liberalisation

In 1998, the German Parliament implemented the Electricity Directive of 1997 into national law as part of the reform of the Energy Industry Act. The key issue of the energy law reform was the abolishment of privileging demarcation and exclusive concession agreements under competition law in the gas and electricity sector which had applied up to then. By completely opening up the market from the outset Germany went far beyond the European legislative requirements providing for the possibility of gradual liberalisation. On the basis of the amended energy law and the so-called Associations' Agreement on electricity, competition has developed in a positive direction in many electricity markets since liberalisation.

Regulatory Regime

The German Parliament opted for negotiated third party access (NTPA) as opposed to regulated third party access (RTPA). Market liberalisation is based on the relevant legal provisions and is put into concrete terms by third-party access to existing networks which is negotiated between the market participants. Network access is secured by the control of abusive practices under competition law. The Associations' Agreements, which are negotiated autonomously between associations of the energy industry and customers, are of crucial importance for determining a practicable form of network access. They contain modalities for handling network access and calculating fees for network use, thus forming the basis for individual network access. The energy industry is subject to *ex post* control under competition law by the Bundeskartellamt and the *Land* competition authorities, also with regard to the issues laid down in the Associations' Agreements. As part of the most recent amendment of the Act Against Restraints of Competition (ARC) the refusal to grant access to networks was introduced into Section 19 (4) no. 4 of the ARC as a concept of abuse. Accordingly, a monopolistic network operator acts abusively if it denies non-discriminatory access to its networks. This provision is of central importance particularly in the energy sector and, among others, forms the basis for many proceedings against network operators on account of excessive or inadmissible charges for network use.

In 2001, a task force on network access was established at the Federal Economics Ministry which, jointly with the partners of the Associations' Agreement as well as with new suppliers and consumer associations, inter alia, works towards a smooth functioning of the change of suppliers in the area of households and small customers.

General Structure of the Electricity Market

The German electricity market is characterised by a multitude of market participants active in the electricity supply sector. According to the 2001 data provided by the German association of the electricity industry (*Verband der Elektrizitätswirtschaft, VDEW*), more than 700 municipal utilities, about 200 new market participants, 100 small private suppliers, 70 regional suppliers, 50 companies which exclusively generate electricity as well as grid companies are active in the German market. As a result of mergers the number of grid companies has decreased from 8 to 4 since 2000. These companies are RWE, E.ON,

Vattenfall Europe and EnBW. Many small, regional or local companies are also active in the electricity generation sector. Both the market for electricity generation and the market at the wholesale level can be considered as competitive.

All of the four major electricity generators are vertically integrated, i.e. they are also active in the areas of transmission/distribution and sales. Hence they are also network operators. In recent years the grid companies have acquired numerous shares in regional and local suppliers (municipal utilities). In 2000 the two biggest grid companies, RWE and E.ON including their group companies, achieved a joint market share of about 67 per cent in the market for the supply to distributors (regional suppliers/municipal utilities; excluding traders and other grid companies), based on the total amount supplied by the domestic grid companies generating and importing electricity. They were followed by Vattenfall Europe's legal predecessors with a joint market share of approx. 25 per cent. EnBW achieved a market share of approx. 8 per cent. In the market for the supply of large electricity customers, RWE and E.ON achieved a joint market share of 43.6 per cent in 2000. This calculation is based on the total domestic electricity supply from the public network (excluding output from industrial electricity autoproduction) to large electricity customers. The duopoly's market share advantage vis-a-vis its nearest competitors, i.e. Vattenfall Europe's legal predecessors with approx. 7 per cent market share and EnBW with approx. 6 per cent market share, is significant. At present, the market share influenced by the duopoly, taking into account its associated companies, is even around 65 per cent in this market.

Electricity Generation and Trading

According to the preliminary data provided by the German association of the electricity industry, VDEW, the net electricity output generated by electricity suppliers in Germany in 2001 was 477.5 billion kWh. RWE and E.ON accounted for about 70 per cent of the net domestic electricity generation, excluding industrial autoproduction. Taking into account not only electricity suppliers, but also the amount fed in by industry, the railway sector and private generators, the total generation was 534.2 billion kWh. Of this total electricity generation, 30 per cent were accounted for by the primary energy nuclear energy, 27 per cent by brown coal, 23 per cent by hard coal, 9 per cent by natural gas, 1 per cent by oil, 7 per cent by renewable energies, i.e. wind, water, sun, biomass and waste, and 3 per cent by other energy carriers such as mine gas.

While nuclear and brown coal power stations generate power in particular for the supply of base-load electricity, gas and oil power stations are mainly used to cover peak load.

In 2001 approx. 44 billion kWh of electricity were exported and imported, respectively, that is 8 per cent of the total electricity generated in Germany.

At the wholesale level (besides trade on the basis of bilateral contracts with durations generally varying between one and five years) Germany has an electricity exchange, the "European Energy Exchange (EEX)" located in Leipzig, where about 8 per cent of the German electricity consumption is traded.

For one or two years there have been some significant peaks in energy prices at the spot markets as well as a general trend towards higher prices.

In 2000 the Federal Government and the energy groups agreed on a phase-out of nuclear energy use for generating electricity. Since 1991 electricity generation on the basis of renewable energies has been encouraged under the "Act on Feeding Electricity from Renewable Energies into the Public Grid". On 1 April 2000 it was replaced by the "Act on Granting Priority to Renewable Energy Sources" – short: Renewable Energy Act (REA)¹. Under the Renewable Energy Act, electricity network operators are required to purchase electricity generated from renewable energies at certain minimum prices that are

above market prices. A similar obligation is provided for by the Co-Generation Act² for electricity from co-generation plants. However, the Co-Generation Act is based on a bonus solution.

Factors Affecting Market Power

Market Structure

All of the four major electricity generators in Germany, i.e. RWE, E.ON, Vattenfall Europe and EnBW, rely on a mixture of different primary energy carriers. RWE uses nuclear energy, hard coal and brown coal as most important primary energy carriers and, to a lesser extent, natural gas and water power. E.ON generates electricity mainly in nuclear power and hard coal power plants and, to a lesser extent, also in gas, water, oil and brown coal power plants. For EnBW nuclear power is the most important primary energy carrier. In addition, the company generates electricity in coal, water and gas power plants. The Vattenfall group's electricity generation in eastern Germany is mainly based on brown coal. Hard coal and gas play a minor role in this region. In western Germany, the company also operates nuclear power plants for generating electricity.

Taking into account contractually secured supplies, RWE has a plant capacity of 32,339 MW, E.ON of 34,000 MW. EnBW's overall capacity is approx. 11,000 MW, that of the German Vattenfall companies 16,877 MW (VEAG: 10,166 MW, HEW: 3,727 MW, BEWAG: 3,003 MW (data for the year 2001.)

There is no general obligation for grid companies to split off individual parts of their groups. Transmission networks have to be organised as separate operating divisions. In addition, the companies are obliged to separate accounts in the corporate segments generation, transmission and distribution (Section 9 (2) of the Energy Industry Act). A separation under company law is not prescribed by law. Nonetheless the major grid companies either have already partially effected such separations (RWE, E.ON and EnBW) or are in the course of doing so (Vattenfall Europe).

Congestion and Pricing of the Transmission Network

There are practically no bottlenecks with regard to capacity in national electricity networks.

However, in 1999 the Berlin energy supplier Bewag denied third companies access to its network on the grounds that it allegedly suffered from capacity bottlenecks (which have meanwhile been removed). It thus intended to use 100 per cent of its transmission capacities itself. The Bundeskartellamt did not accept this "internal requirements" argument and obliged Bewag, as the operator of the network, to treat its own company in exactly the same way as any other electricity supplier, i.e. to allocate available capacities in a non-discriminatory manner among all purchasers.

In liberalising the German electricity markets, the lawmaker opted for the concept of negotiated third party access (NTPA). This means that the fees for network use are determined by the market process. The Associations' Agreements provide for the framework conditions for calculating these fees. Initially, network users applied a transaction-dependent fee model which has meanwhile been replaced by a transaction-independent model, the so-called "postage stamp".

In spite of this substantial improvement of the pricing system, the Bundeskartellamt and the *Land* competition authorities observe that in some cases network operators demand excessive fees for network use thus abusing their dominant positions. It can at least not be ruled out that these integrated companies use profits gained from network operation to cross-subsidise their own electricity prices.

Currently, twelve proceedings against network operators on suspicion of abuse of dominant positions are pending at the Bundeskartellamt alone.

The German network operators participate in the system of the European Transmission Systems Operators (ETSO) which has agreed on a provisional mechanism for the cross-border determination of fees. The scarce capacities of the international network interconnectors in some cases result in network use being settled by way of auctions. In this way purchasers have the possibility of buying at auction yearly, monthly and in some cases daily capacities of those interconnectors that are not yet bound by contracts.

The responsibility for maintaining and expanding cross-border networks lies with their respective owners. Current expansion projects involve the introduction of a cross controller between the networks in Germany (E.ON) and the Netherlands (TenneT) as well as the creation of an additional circuit in the Uchtelfangen (RWE/Germany) – Vigy (EdF/France) connection.

Market Rules

The major part of electricity trade is dealt with on the basis of bilateral contracts. There is no obligation to trade at the energy exchange. 8 per cent of the trade volume is dealt with at the German electricity exchange EEX. The common duration of bilateral contracts is one to five years.

Bilateral, Long-Term and Forward Contracts

Long-term contracts increase links between customers and suppliers and thus impede, in the case of dominant sellers, the development of competition for the duration of the respective contracts. This, in turn, strengthens the supplier's market power. If at all, it is only in the case of dominant companies that the durations of these contracts are subject to a certain control under competition law. The EEX electricity exchange also provides for the possibility of trade in futures.

Price or Quantity Controls

Electricity prices in the wholesale sector are in principle formed by the market process. There is no obligation to obtain a state authorisation in this area³. If there are indications of an abuse of market power, the Bundeskartellamt and the *Land* competition authorities intervene on the basis of general abuse control under competition law. There is also the possibility of bringing the case before the civil courts. There is no statutory or other fixed upper limit for wholesale prices.

The Energy Industry Act obliges supply companies to operate their supply network in such a way as to guarantee sufficient electricity supply at all times (Section 4 (1) of the Energy Industry Act). This means that supply companies must compensate for possible fluctuations in supply and demand. The necessary reserve capacities are available. Excessive fees for this so-called balancing energy were the subject-matter of previous abuse proceedings under competition law.

Entry

The construction of power plants is subject to general authorisation whereby construction planning and building regulations as well as environmental law aspects have to be taken into account. Taking up energy supply services requires an authorisation under energy law which is generally granted if the applicant in question has the necessary personnel, technological and economic capacities (Section 3 of the Energy Industry Act).

The construction of plants for generating electricity from renewable energies is particularly promoted. The Renewable Energy Act obliges network operators to purchase electricity from these plants at a higher price⁴. The new Co-Generation Act also supports the further development of certain co-generation plants (for example fuel cell plants).

Competition Law Enforcement

The basis for applying competition law is market definition. In the electricity sector, the Bundeskartellamt defines the relevant product markets according to the demand structure and thus distinguishes between markets for the supply of distributors and markets for the supply of end customers. In addition, energy trade is considered as a separate market. The redistribution market may, under certain circumstances (if third-party network use does not work), be further divided into national or long-distance and regional redistribution. End customer markets are in any case to be further divided into industrial and large customers on the one hand and household and small customers on the other.

Before and in the first years after liberalisation the Bundeskartellamt applied a regional geographic market definition since there was a lack of possibilities for third parties to use networks, which is a precondition for competition.

In the electricity sector horizontal concentration has increased since liberalisation. In this regard the RWE/VEW (now RWE) and Veba/Viag (now E.ON) mergers were of particular importance for the further development of the market. The latter merger was examined by the European Commission in close coordination with the Bundeskartellamt and cleared subject to far-reaching obligations. The first merger was examined by the Bundeskartellamt itself and also cleared subject to strict obligations.

In the RWE/VEW case the Bundeskartellamt, in view of the increasing significance of network use for competition, assumed for the first time that national instead of regional markets would develop within the foreseeable future. The aim of the obligations was to maintain the preconditions for effective competition in the electricity market or even improve them by diverging the four companies' joint shares in other companies. For example, RWE and VEW were obliged, by means of appropriate obligations relating to sales, to sell their shares in the eastern German VEAG to a third company. In 2001 the Bundeskartellamt cleared the acquisition by Vattenfall of stakes in the network operators VEAG, HEW and Bewag. Including all the mergers referred to above, the number of grid network operators has decreased from eight to four since 1998, as already mentioned.

The additional regulatory obligations imposed under the merger decisions did not prevent the Bundeskartellamt from returning, in contrast to its prognosis in the RWE/VEW decision, to a regional market definition for household and small customer markets in the area of electricity supply in the RWE/GEW Rheinland merger case examined in early 2002⁵. The reason for this was that the development of competition in the small-customer electricity market had meanwhile stagnated.

The Bundeskartellamt prohibited the merger of E.ON and Ruhrgas. The merger of the gas importer and largest gas supplier Ruhrgas and the electricity and gas supplier E.ON would result in dominant positions being strengthened both in the gas and electricity sales markets. At the grid gas level, the combination would structurally secure Ruhrgas' sales to E.ON affiliates and holdings. E.ON affiliates located in Ruhrgas' transmission area would be able to strengthen their dominant positions in supplying large gas end customers and local gas distributors (municipal utilities) since after the merger they would no longer have to expect potential competition from Ruhrgas. In the electricity sector, E.ON's major influence on the primary energy supplier Ruhrgas would strengthen its dominant position (duopoly of E.ON and RWE) in the national markets for supplying industrial/commercial electricity customers and distributors, i.e. regional electricity suppliers and municipal utilities. Effective competition would thus be prevented.

At the request of E.ON the Federal Ministry of Economics and Technology granted a so-called ministerial authorisation (which is explicitly provided for in the ARC) subject to far-reaching obligations. In this case greater weight was attached to the overall economic advantages resulting from the merger, i.e. it would ensure the supply of energy and strengthen Ruhrgas' international competitiveness, than to the likely restraints of competition.

So far, the merger has not been put into effect since the Düsseldorf Higher Regional Court issued a preliminary injunction against the ministerial authorisation. Taking into account the court's legal opinion, the Federal Economics Ministry repeated its public oral proceedings, which generally precede a decision, in early September with a view to remedy the formal errors established by the court. On 18 September 2002, having examined the matter again, the Federal Economics Ministry confirmed its ministerial authorisation of 5 July 2002 of the takeover by E.ON of a majority stake in Ruhrgas, subject to more rigid obligations.

In the years since the liberalisation of the network-based energy markets there has also been an increasing vertical integration of supply companies both in the electricity and gas sectors. The major grid companies acquire stakes in small regional and local (municipal) suppliers. The Bundeskartellamt takes a critical view on this development. From a competition point of view there is the danger of fixed supply relationships being established between grid companies and suppliers in which they hold stakes. This way of securing sales prevents effective competition for customers between suppliers. As a result, traditional market structures are substantially reinforced. This applies to both the electricity and gas markets. In recent years the Bundeskartellamt therefore cleared a number of mergers only subject to obligations designed to improve the competitive situation in regional markets⁶.

Non-discriminatory third-party access to existing networks is secured by means of competition law, in particular the prohibition of abusing dominant positions. It is enforced by the Bundeskartellamt, the *Land* competition authorities and also the civil courts. According to Section 19 (4) no. 4 of the ARC, the refusal by a dominant company to grant network access against appropriate remuneration is to be considered as abusive conduct. In the area of the control of abusive practices, in the first years after liberalisation particularly cases of complete denial of network access were of significance. A landmark decision in this respect was the Bundeskartellamt's decision of 1999 mentioned above, by which it prohibited the Berlin energy supplier Bewag from denying third electricity companies access to its network.

The competition authorities also regarded the so-called "double contract model" as an unfair hindrance by a dominant company. Under this model, network operators required private end customers wishing to switch to a third supplier to conclude separate network use contracts.

Likewise the so-called "transfer fees" charged by many network operators had deterrent effects on customers wishing to switch to another supplier. In order to settle this dispute, a regulation has been introduced into the currently applicable Associations' Agreement (Associations' Agreement on Electricity II plus) according to which the network operators agreed to refrain from charging transfer fees until a decision in this matter is given by the Supreme Court.

The problem of complete denial of network access has meanwhile been largely eliminated. However, excessive fees for network use continue to be a factual obstacle to effective competition in the supply of end customers on the basis of third-party network use. In recent times the Bundeskartellamt conducted preliminary investigations against 23 network operators on suspicion of their charging excessive fees for network use. Formal proceedings have meanwhile been instituted against twelve of them. The Bundeskartellamt discontinued other formal proceedings after the company concerned had reduced its fees by 20 per cent. In one of the twelve proceedings a warning has meanwhile been issued. The *Land* competition authorities conduct further proceedings whose significance is limited to individual federal *Länder*.

In addition, the Bundeskartellamt has initiated investigatory proceedings against two electricity network operators on suspicion of their charging abusively excessive fees for metering and billing prices.

Finally, abuse proceedings were conducted against four grid network operators on suspicion of their charging excessive fees for balancing energy. The first proceedings were discontinued in February 2002 upon the parties' commitment to introduce by August a tendering system for the procurement of balancing energy and to use, with retrospective effect, a modified accounting system applicable until the introduction of the tendering system and designed to prevent the negative effects of the system objected to. The other parties concerned meanwhile agreed to modify their accounting systems accordingly. As a result the proceedings could be discontinued.

In addition, the Associations' Agreement contains a regulation designed to limit the level of fees for network use. Annex 3 of the Associations' Agreement on Electricity II plus contains principles for establishing prices. This Annex was supplemented as of 23 April 2002, in particular by a guideline for calculation. The guideline should serve to calculate reasonable fees which are proportionate to the actual costs of the network operators. As agreed in the Associations' Agreement on Electricity II plus, the association of network operators, VDN, in September 2002 published an overview which groups network operators into 18 structural categories (ranging from rural to urban) and provides the current fees for network use. Those operators whose fees are in the upper 30 per cent of the range of fees can be brought before an arbitration board where they have to confidentially disclose their calculations.

NOTES

1. Full text available on the Internet at http://www.bmwi.de/Homepage/download/eeg_neu.doc
2. Full text available on the Internet at <http://www.bmwi.de/Homepage/download/energie/KWK-Gesetz.pdf>
3. Only the fees charged by the respective incumbent supplier in the area of households and small customers are subject to state authorisation.
4. In the case of co-generation plants, network operators are obliged to pay a surcharge on the usual feed-in price of currently 1.53 to 5.11 cents per kWh, depending on the type of plant. In the case of energy fed in from plants powered by renewable energy sources, minimum prices are between 7.67 cents for electricity from water power and 50.62 cents per kWh for electricity from solar plants.
5. Cf. decision in the EnBW/ZEAG case of 29 July 2002
6. Example: EnBW/Stadtwerke Schwäbisch Gmünd, decision of 26 January 2001; EnBW/ZEAG, decision of 29 July 2002

HUNGARY

Overview of Regulation

The main regulatory change during the last years on the electricity market was the adoption of the new Electricity Act by the Hungarian Parliament in December 2001. The act and the related new regulations will implement the EU Electricity directive and open gradually the market for competition. This step by step liberalisation means that during a transitory period two regimes will be present on the Hungarian electricity market: the public utility supply and the competitive supply of electricity. The effective market opening is planned for the 1st of January 2003 and the ongoing regulation process leaves some uncertainties concerning the future electricity regime.

The market structure of the sector is an oligopoly on the generation and distribution segment, the transmission is a monopoly. The state ownership in the sector was restructured under the privatisation process launched six years ago. Some generations (more than 60%) and the whole distribution (around 90%) were privatised for foreign investors, but the transmission remained completely in the hands of the Hungarian state. Regarding the whole electricity sector the share of domestic (public and private investors) and foreign invested capital was 47,55% and 51,97% respectively¹.

The main structural changes in this sector were due to privatisation preceding the market opening. The privatisation act tried to consider some competition issues during the privatisation, as it prohibited for example that the same group should acquire more than two distribution companies.

The share of electricity from the total energy consumption takes 10,8% of the country. The total generation capacity was 35 506 GWh in 2000. Three new generations (Csepel, Újpest and Debrecen) entered the electricity system during 1998-2000 due to the reorganization of some old generations, which were sold to foreign investors.

2002 is the last year when the single buyer model dominates the market relations in the electricity sector. In this model MVM (Magyar Villamos Művek, Hungarian power utility), the incumbent company plays an important role being the unique wholesaler and importer of the market. Everyone else has to buy and consume the electricity from what is contracted and assured by the incumbent MVM.

The primary fuel sources used on this market are mainly covered by nuclear power (35-40%), which is the base load and is completed by natural gas, oil and coal. The role of green energy resources are quite reduced in Hungary, a very minimal amount of hydro energy is present.

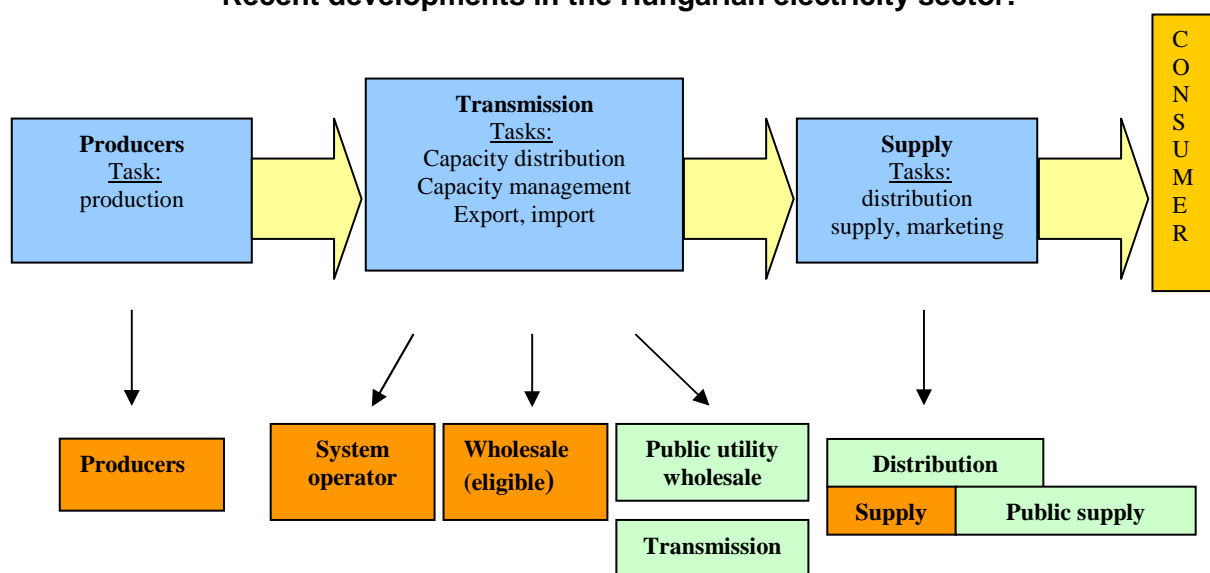
Hungary is a potential regional transit country, mainly in the North South dimension. The import turnover in 2000 was 6469,9 GWh, and the export was 3023 GWh, resulting a balance of 3439,9 GWh, which is about 10% of the total consumption of the whole electricity system. The main importing countries are Slovakia and Ukraine, the main export partners of Hungary are Croatia, Austria and the ex-Yugoslavia. It is important to add that on the level of primer energy imports (uranium, gas, oil) Hungary's dependence is very high.

No special environmental regimes are in force to constrain the expansion of the generation capacity or the development of the transmission network. The environmental policies in the sector appeared quite recently due to the EU enlargement process. Actually the new Electricity Act introduces the system of green certificates on the electricity market and encourages the production of green energy.

Few rules and regulations remain undone before the market opening, which will take place on the 1st of January 2003. The major rules (the Electricity Act and the majority of the government decrees) are already prepared, but there are uncertainties how this market opening will take place. The act makes possible for the eligible customers (30-35%) to serve themselves from the liberalised market, separated from the market served by public utility wholesaler, MVM – the incumbent energy company - and public utility supply. Maybe some other economic instruments will be defined on the open market, for example the law makes possible for the participants of the competitive market to establish a power exchange.

On the other hand until the end of year 2002 there will be no market opening, but those interested in the opening are already trying to make the necessary preparations, especially the power plants and the potential wholesalers. The following schema might model the recent developments that will under come in the electricity sector. This schema unifies the still working single buyer model adding the structural amendments due to the implementation of the 96/92/EC directive on electricity. In this respect MVM the incumbent company will be still responsible to satisfy the electricity demand of the public sector composed by non-eligible customers based on the resources provided through importations and the long-term contracts signed with its own and other independent generation plants (AES, RWE, EdF).

Recent developments in the Hungarian electricity sector:



The actual market scheme preserves a prominent role for MVM who has important shares on the generation market (33%) completed by those long-term contracts that might moderate the intensity of the future competition. The main achievement of the regulation is that it will put end to the integrated transmission (including system operation)-generation MVM portfolio. In this respect MVM was obliged to separate the system operator activities into an independent company (MAVIR) controlled by the Ministry of Economy and Transport from the 1st of February 2001. The new electricity law also recommended some other kind of separations for example between the generation plants and the public utility wholesale trade. MVM has no assets in distribution companies.

The share of capital assets on the Hungarian electricity sector may be of some interest:

Share of capital in % (2001)

Ownership	Generation	Transmission	Distribution	Electricity sector
State	5,85	99,87	0,09	39,89
Municipalities	0,26	0,11	3,81	1,67
Other Hungarian investors	59,21	0,02	8,65	5,99
Total Hungarian	65,32	100,00	12,55	47,55
German investors	6,64	0,00	58,90	26,49
French investors	4,47	0,00	16,79	8,91
Belgian investors	8,75	0,00	0,00	4,63
US investors	11,32	0,00	1,39	6,53
Other foreign investors	0,02	0,00	9,67	5,41
Total foreign investors	31,20	0,00	86,75	51,97
Other	3,48	0,00	0,70	0,48
Total	100,00	100,00	100,00	100,00

Source: Hungarian Energy Office, Annual Report 2001, p.37.

The Hungarian electricity sector on both generation and distribution side is quite concentrated. The C_6^2 in generation sector was over 80% in 2000 shared only by the four groups, MVM (33%), Tractebel (25%), AES (15%) and RWE (10%). RWE has also interests in electricity distribution. Six regional licence holders, serving a definite geographical territory and owing the physical assets related to this activity distribute and supply the electricity. Three major groups control the whole distribution sector in Hungary: E.on, RWE, EdF. RWE and E.on cover 77% of the market (based on sales revenues). Most important is that under the new regulation what market outcomes might be expected. Another statistic shows that the potential eligible customers are situated on the territories served by E.on and RWE (95% of them).

The rules related to the regulatory authority were modified in December 2001 giving more powers and autonomy (its decisions should be appealed in court) to the Hungarian Energy Office (HEO). As a consequence, the president of the office is appointed by the Prime Minister for a six years term, and he reports annually to the Parliament. The principal legal instruments of the office were established by the act, namely to take part in the licensing of energy sector activities, to publish decisions concerning the notifications and complaints of the sector and to specify the general principles of access to the network.

On the other hand the HEO is entitled to inspect documents related to the activities subject to licensing including documents containing business secrets and to make copies or extracts of these documents. The office can also ask for regular and ad hoc information from the licensees. Under the new Electricity Act it is the minister who sets officially the regulated prices of the sector, but practically it is the role of the regulatory authority to prepare and calculate these tariffs. Some other new activities will fall under the responsibility of the office as: consumer protection of the sector, the issue of the green certificates and a special control activity regarding the concentrations in the electricity sector.

As an accession country to the European Union, Hungary has implemented the electricity directive (96/92/EC). In this respect the new Electricity Act created the independent system operator (MAVIR), prohibited discriminatory access to the networks, adopted unbundling for all electricity and non-electricity activities, introduced regulated TPA and a step-by-step market opening method. The Hungarian regulation went further in unbundling as it prescribed for certain activities to be organized in separate companies (public supply, public utility wholesale).

Some specific rules were introduced too on the proposal of the HEO. In accordance with the law during the pre-accession period to EU certain thresholds will be applied in case of electricity concentrations. These thresholds serve as a moratorium to stop the reintegration of the electricity sector. The moratorium idea reflects HEO's position on electricity competition submitting that at early stages of liberalisation it might be very difficult to prove the adverse effects of certain mergers under antitrust legal standards given the lack of empirical, experience-based data on the electricity market, therefore an ex ante

regulation might be useful in the electricity legislation. The Hungarian competition authority's (Gazdasági Versenyhivatal, GVH) position in this question was subtler, as it found this aspect of the regulation too rigid namely, the introduction of the thresholds³, to promote competition, but finally GVH accepted this solution as a second best one.

Factors affecting market power

Market structure

The structure of the generation sector is estimated to be the less troublesome under the process of market opening. Even if MVM has 33% of shares in the generation sector, Paks Nuclear Plant is part of the MVM shares with 23% shares on the national market. Some officials in the HEO think that the specific regulation for the nuclear plant will make very difficult for MVM to play out the card of the leading player. Some other voices – for example the president of Tisza Power Plant (owned by AES) – worry on the attitude of MVM after the liberalisation of 2003. His opinion was that MVM could strongly defend its interests due to its control over the long-term contracts.

To give a proper answer in this respect, the regulation sets up the gradual elimination of these contracts by letting possible the renegotiation of them up to the extent of the consumption of the eligible customers, giving an increasing significance to the market forces. As a consequence, if customers holding the right to be eligible decide to leave the public supply services, then that amount of electricity contracted for their supply on long term will be auctioned.

The resources used by the generation segment are quite coloured. Besides the nuclear-based electricity production, coal heating and hydrocarbons produce mainly the remaining 60% of the capacity.

The primary fuel sources used by the electricity sector in 2000

Fuel	Production of electricity		Production of heat		Total	
	PJ	%	PJ	%	PJ	%
Nuclear	151,2	44,3	0,7	1,5	151,9	39,3
Gas	50,6	14,8	26,4	57,8	77,0	19,9
Oil	39,7	11,7	3,4	7,4	43,1	11,1
Coal	99,5	29,2	15,2	33,3	114,7	29,7
Total	341,0	100,0	45,7	100,0	386,7	100,0

Source: MVM Közleményei, 2001 July, vol. XXXVIII., nr.2, p.20.

The actual cost structure of different fuel resources can be only deduced from the minister's decree on electricity prices (55/1996 (XII.20.) IKIM). As the liberalisation process is still under preparation the single buyer model is still functioning in Hungary. In this regime each generation plant has its own regulated price, which is technically a maximum cap. The regulated prices are composed by two principle cost elements: capacity fee and energy fee. The nuclear plant works with high fix costs (capacity fee) but its variable cost is far the cheapest (energy fee), and for some other technical reasons too Paks Nuclear Power Plant gives the base load to electricity consumption. Some coal-based plants have very good cost structure to enter in competition with the hydrocarbon-based power plants (ex. Mátra I-II: based on lignite extraction).

At the moment one electricity wholesale company serves the distribution. In the absence of competition, it is difficult to measure the role of the import too. The main electricity importer is Slovakia; as a consequence the more congested cross border connection functions at the Hungarian-Slovak border on maximal capacity level. Certain import dependence exists, but the large amount of free capacities in Slovakia and the technical structure of the Hungarian electricity system were estimated strong enough to

ensure the competition on the opening market. More interesting is that Hungary is strongly dependent on the imports of primer energy coming from CIS countries, therefore the government took some steps to diversify the flow of energy resources by making the Adrian transmission line (which ends in Rijeka – Croatia) working in two ways.

The concentration of the market related to certain time or level of demand cannot be analysed in a non-competitive market situation. A future monitoring system in the HEO will be responsible to prospect and analyse the information gathered in respect to detect the daily concentration of the demand. GVH has no instruments to take part in this specific measurement. Under the new regulation regime GVH is and will be partner on the call for investigation of HEO, especially if the investigation of abuse of dominance in electricity markets should be completed by the results of this monitoring.

Some participants of the market are vertically integrated, as MVM or RWE for example, but the new Electricity Act introduced accounting separation and legal separation for certain activities. The legal separation was required for the network licensees, but the transmission licensee can hold public utility wholesale licensee and the distribution licensee may exercise public utility supply activities within the same company. The system operator and the licensee of electricity market exchange may not pursue any other electricity sector activities subject to licensing.

The regulatory authority is responsible to enforce the law and to grant the non-discriminatory access to the networks. The Energy Office has to investigate any abuse in this respect and publish its decision within eight days after receiving of the complaint. This is the only serious corollary in case of abusing free access to the networks.

The new regulation stipulated only one divestiture forcing MVM, the state owned incumbent to abandon its control over the system operator company, MAVIR. The MAVIR assets will be managed directly by the Ministry of Economics and Transport instead of MVM. This operation is technically a reorganisation of the state assets with the purpose to create a distance between the MVM group and the system operation activities. The hoped effect of this regulatory action is to ensure the non-discrimination on the open market. As a consequence of the regulation on MAVIR, the future ISO has not the rights of a TSO. The transmission lines will remain at MVM, but only MAVIR will have the right to decide over the development of the lines, including the distribution networks too.

Congestion and Pricing of the Transmission Network

Before the market opening is difficult to predict the potential congestion problems in the transmission network. Some officials suppose that the internal network system will not face severe congestion under competition circumstances. The only exception might be the interconnection between Slovakia and Hungary. If the electricity prices are lower in Slovakia and free power capacities would be available for imports, then the congested interconnection should have a certain impact on the market power of the firm able to export electricity from Slovakia. It will be the role of MAVIR, responsible for the management of foreign trade to ensure the respect of the non-discriminatory use of the network.

At the moment the prices of the transmission is not separated from other energy costs, it is included in the prices of electricity. From the 1st of January 2003 it will be an equal price differentiated only on the level of electric potential in the whole country. If this tariff system will be judged to be inefficient the proposed regime will be reviewed and changed to a regional tariff system.

As the market is still before opening and the foundation of an electricity exchange is not mandatory no specific financial instruments are present to hedge against some market movements or to hold financial transmission rights exercising market power.

During the period of economic transition the location of new generations was not on the agenda. It seems that the foreign investors tried to avoid the green field investment in the sector. Generally, they preferred the reorganization of the old firms and the change of old-fashioned techniques. In some cases it was very important factor to have access to the gas network and facilities. The strategy of the companies was completed by a second feature represented by the Hungarian government, which has strongly supported the establishment of small cogenerations mainly by financing these projects by competition and by obligating the network licensees to accept the produced power.

The new Electricity Act will put end to the import monopoly of the incumbent company, but practically the eligible customers can purchase only 50% of their capacities from imports to grant the use of domestic power plants during the transition period to the complete liberalisation of the markets.

Some other measures constraining imports will be applied, as environmental issues in case when the import capacity was not produced conform to certain requirements. It is not still obvious how the market of foreign trade will function in the coming years; to what extent will independent importers dismantle the system and the role of MVM, the public utility wholesaler. Due to the market opening some consumers will leave publicly bought capacities of MVM and these capacities will be auctioned under the direction of MAVIR, the independent system operator. If the auction cannot be applied for certain reasons, then the import orders must be carried out on first served basis to ensure the transparency of the market transactions.

The upgrade of network will be the task of the independent system regulator. The network licensees may propose plans in respect of the development of the grid, but the system regulator takes the decision. If despite of the request of the system operator, a network licensee fails to carry out the intended development, then the system operator may announce a tender to achieve its goal. It is also possible for any participant of the market to build new network elements, but each development must be preceded by the approval (the authorisation) of the HEO in harmony with the agreement of the system operator and the competent network licensee of the area. The new market conditions might affect the incentives of the firms to take part more actively in the development of the networks.

Market rules

The law allows for the market participants to establish a stock exchange on electricity, but it is probable that in the first phase of the market opening direct contracts will be preferred. These contracts will function so as to set the spot prices on the market.

The regulation did not bind the market participants to open a power exchange. As a consequence the foundation of an organized market will depend on the amount of free capacities and on the number of market participants. If these capacities and market players are numerous enough there will be a potential for a liquid market, which may force them to set a date to the opening of an electricity exchange.

During the regulatory process, it seemed that there is a certain interest to establish an electricity exchange. The Budapest Stock Exchange and the majority of the regional suppliers founded an association to work out the details concerning the exchange. Later on this enthusiasm disappeared, as the international experience was that only a small amount of energy is placed on such spot markets.

Bilateral, long term and forward contracts

At the beginning of the market opening long-term contracts will not lose their importance on the market. There are some competition concerns on those long-term contracts, which are held by the Hungarian incumbent and might affect negatively the competition pressure of the competitive segment.

The contracts managed by MVM will be removed on step-by-step basis. Each case, when an eligible consumer will choose the competitive market leaving the capacities contracted by the public utility wholesaler, the capacity in question will be auctioned for the rest of the market. In this case stranded costs will be supported partly as a result of the auctions. The goal of the regulator is to limit the dimension of the long-term contracts, but the fear persists in connection with the long-term contracts that let MVM to exercise its potential market power.

It is estimated by 2004 that a definite interest will rise on the part of the domestic generations and MVM to renegotiate certain long-term contracts binding them. It is important to add that the government policy prefers in any case the auctions instead of non-public, bilateral bargaining.

The new market regulation does not prohibit, but allows long-term contracts in the future too. Those not leaving the public utility sector are already constrained in this system, but it is not evident what strategy will choose the competitive segment vis-à-vis to the long-term contracts or any other type of contracts, as forward ones for example.

Meanwhile it seems that even the regional supplying firms (of the actual single buyer model) will be interested to contract on long-term with their major industrial customers. These trade contracts may undermine the market system as these customers may be offset with a better distribution quality. It is crucial to block the incentives of public suppliers to tie the eligible customers to the public sector.

Price or Quantity Controls

Due to the step-by-step market opening, in the first phase only 32-35% of the consumers will be eligible to choose their electricity supplier. This gradual liberalisation is due to reduce the burden of the cost of market opening and to spread it along the time. During this period a double wholesale mechanism will be present: a competitive wholesale working under rules of the market and a public utility wholesale following the regulation. The regulation seeks from the public utility sector to follow the prices published in the government decree on the principle of the minimum cost.

Maximum caps will direct the prices in the public utility supply (distribution and retail), but at the moment the concrete price decrees are not yet available for the liberalised market period. As a consequence there is a guessing how these price decrees may influence the strategies of the firms. These decrees should provide more transparent pricing and freeze certain cross-subsidising methods.

There are no special provisions governing when firms are allowed to withdraw capacity from the market except the crisis situation. In those situations when generation firms for example would say that due to technical disturbances they couldn't supply what was declared to be available earlier, the Hungarian Energy Office or the courts have to act. In the same time the energy regulator has the powers to investigate power outages and unavailability of generation capacities if some producers raise the prices on a certain market segment.

Entry

The special rules encouraging entry are generally part of the actual economic policy of the government. In the last years the government supported the small cogeneration firms. There is no significant new entry on the generation market. Some investments were initialised to enlarge the existing plants, but it is estimated that the national system is reliable enough to be able to serve its customers. The new entries possibly will not modify considerably and will not offset any of the existing market power.

It was also estimated that under the new circumstances the international background of the liberalisation process would be very important; the existence of sufficient free capacities, the successful integration of the new system operator in the electricity system to be able to offset the negative market incentives and tendencies, the cooperative strategy of the multinational companies that integrated the distribution sector.

Competition law enforcement

All mergers considered in this paper were approved in the last four years. The most important ones were generation acquisitions. After the privatisation process some investors decided to reorganize their portfolio and to leave the country in order to invest elsewhere. NRG Energy, an American company wishing to buy from Powergen its assets in the Csepel Power Plant, initiated one of these acquisitions. Under the investigation proceeded by the competition authority, it was analysed, if NRG Energy had any relations with the firms already established in Hungary. The investigation focused especially on the possible relation between NRG Energy and AES, another American company owning important generation assets in the Eastern part of the country. The merger was cleared, as no competition concern was proven.

It was very similar the case of Budapest Power Plant where the Japanese-Finnish consortium decided to sell its assets. The buyer, Electricité de France was already owner of two distribution companies (ÉDÁSZ, DÉMÁSZ), but the generation under acquisition served another distribution area owned by the German RWE. The merger therefore was allowed.

The distribution sector was similarly subject of ownership changes. The German E.on has acquired a distribution and supply company (TITÁSZ) from an Italian investor in the Eastern region of Hungary. This region very poor in industrial customers and full of small settlements was not profitable enough for the Italians. E.on had further distribution assets in the Western part of the country, but it was measured that the regulatory background did not let too much scope of action for the E.on group and as a consequence the acquisition was cleared.

Recently, GVH manage the review of another merger notification. This case is an acquisition of control over a distribution company. The investor group already has important assets in some other distributors and due to this acquisition its market shares will grow up closely to 50% on the distribution/public utility supply market⁴. The Electricity Act stipulated only accounting and legal separation on the liberalised market. In this case GVH has to evaluate what would be the impact of a strong public supply company after the market opening and what Chinese walls should be required between the public supply (owning the distribution assets) and its potential free market wholesale company.

The competition authority has not yet investigated allegations of collusive behaviour in the sector.

In contrast with collusion cases, the office investigated some cases of abuse of dominance, but none of them were of special interest except of a recent case. In this case of abuse of dominant position GVH took very seriously the abuse. The parties in the proceedings of the GVH were two integrated distribution and supply companies in the Southeastern and Eastern part of the country controlled by the French EdF and the German E.on respectively. These companies tried to limit the entry on the market segment of public lighting, which would be subject of the market opening from January 2003.

Under its investigation, the competition authority proved that the market entry of the alternative suppliers on the segment of public lighting modernization was made very difficult. Those firms who intended to replace the old city lamps and to modernize the public lighting of some smaller settlements was delayed by distribution companies who retained certain data necessary for the approval of the modernization plans of the alternative suppliers, but available only at the distributor. In some cases the

alternative suppliers were forced to purchase the old lamps of the cities that was not needed for the potential investments.

Another investigated infringement in these cases was that these distribution companies signed long-term contracts on public lighting with some local governments responsible for the supply of public lightning in the settlements. These contracts contained high forfeits in case if the local government would change to another supplier due to the possible opportunities offered by the market opening. The competition authority considering the fact that the abuse was committed just before the market opening and made more difficult the potential entry on one of the competitive segment of the electricity markets proposed a serious fine for both distributors.

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NOTES

1. The rest was not registered capital.
2. Six companies are included in this group: Paks Nuclear Power Plant, Vértes Power Plant, some MVM gas turbines, Dunamenti Power Plant, AES Tisza Power Plant and Mátra Power Plant.
3. The major rules restricting mergers are the as follows:
 - No one may control more than 30% of domestic generation
 - No one may control more than 3 distribution/supply companies or 50% of domestic distribution/supply
 - No one may control more than 15% of domestic generation if it possesses more than 15% of domestic distribution/supply, and vice versa
4. See footnote 2.

IRELAND

1. Introduction

At the twenty-second meeting of the OECD Competition Committee's Working Party 2, it was agreed that the next meeting of Working Party 2 (which is scheduled for the start of the week beginning 21 October 2002) would feature a roundtable discussion on competition issues that have arisen in liberalised electricity markets.

The following is the Irish Competition Authority and Commission for Energy Regulation's joint response to the questionnaire. The structure of sections 2 and 3 follows that of the questionnaire.

2. Basic Structure

Please summarise the basic structure of the electricity sector in your country including recent and imminent developments. You may like to specify:

Total generation capacity:

The Total Generation Capacity of the Republic of Ireland is 5122 MW at present. Peak demand in 2002 is estimated as 4218MW, rising to 5000MW by 2007/8. Ireland has experienced sustained growth in electricity demand per annum in the region of 5%, and is expected to continue to do so over the next 3 to 5 years.

Primary fuel sources:

Fuel types include Gas, Coal, Oil, Turf, Hydro and Wind. ESB Power Generation's 800MW Moneypoint station is a coal-fired plant and represents the largest generator on the system, accounting for approximately 20% of demand. The most significant recent additions to the Irish generation portfolio are the 353MW Huntstown Power Company station, and the 400MW Synergen station, a joint venture between Statoil and ESB Power Generation. Both Huntstown and Synergen are Combined-Cycle Gas Turbine plants.

Primary sources of imports (or destinations for exports):

The Republic of Ireland currently operates one major interconnector facility, the Louth-Tandragee Interconnector, linking the Republic with Northern Ireland. This interconnector has a capacity of 600 MW. However, due to system requirements and transmission constraints in the Republic of Ireland, only a proportion of this is used. The Available Transfer Capacity (ATC) from North to South is 50 MW. The South to North equivalent is 120 MW.

The interconnector was recently upgraded to the level of 600MW and the standby interconnectors to 120MW. This is an AC link built for emergency and reserve sharing purposes: it is not DC, and this means that to affect a transfer of electricity from one jurisdiction to the other, both systems are dispatched

to give effect to the trade. A further difficulty with importing or exporting energy at present is that the Irish transmission network is very constrained, especially in the region of the N-S interconnector and therefore the physical transfer of power is very dependent on other system and generation conditions.

Any constraints on the expansion of generation or transmission and any environmental policies affecting electricity?

Statutory Instrument No.445 of 2000 provides for a statutory separation of functions between the ESB as electricity transmission network owner and a new State owned company, EirGrid as network operator. In order to enable EirGrid to discharge the functions of TSO, the SI requires that the ESB and EirGrid enter into a contract known as the Infrastructure Agreement. At present, the Infrastructure agreement is the subject of on going legal proceedings between the Commission for Energy Regulation and Eirgrid with ESB being a named party to the proceedings.

Pending the resolution of the Infrastructure Agreement, EirGrid will succeed ESB National Grid as the Transmission System Operator (TSO). ESB National Grid's **Forecast Statement 2001/2-2007/8** included an Incremental Transfer Capacity (ITC) study that revealed limited opportunities for new generation. However, the completion of the infrastructure investment program in 2004/5 will open up new locations for generation development. Limits to the expansion of transmission are fiscal rather than technical.

A Public Service Obligation (PSO) levy is imposed on consumers, parts of the proceeds of which are used to support renewable energy. Government commitments to international environmental policies such as the Kyoto protocol also influence the electricity market.

Is there an established market or pool in wholesale electricity?

February 19th 2000 saw the introduction of an interim market structure (bilateral contract market with an imbalance market) in the Republic of Ireland. A revised market structure is due to be in place in 2005. The details of this revised market structure are currently being designed.

What are the basic features of this market?

Supply: 40 % of the electricity market is open to competition; the entire market is open to suppliers sourcing their electricity from 'green' sources. The ESB's Public Electricity Supplier services customers not supplied by independent suppliers.

Generation: Generators sell their output to suppliers via bilateral contracts. Non-contracted energy is sold on the imbalance market. ESB Power Generation acts as an imbalance market maker, buying and selling imbalances. The purchase price (called top-up) is set by the Commission for Energy Regulation. The calculation of the Spill price is set down in the Trading and Settlement Code and is ex-post and determined by generator incremental bids.

Distribution: is managed and owned by ESB Distribution System Operator (DSO). The DSO is ring-fenced from (independent of) other arms of ESB.

Transmission: is owned by ESB and is managed by (to be known as) Eirgrid. Eirgrid carries out the dispatch and settlement functions for the market.

Are parts of the transmission network congested at certain times?

Past under-investment in the transmission and distribution systems has resulted in significant network constraints (as discussed below). The current 2001-2005 network infrastructure investment program has been implemented to address this infrastructure deficit.

Who are the key players in the generation market?

The key players in the generation market are ESB Power Generation, Huntstown Power Company, Synergen and Edenderry Power Ltd. There are various small CHP and Green producers.

Generator	Fuel Type	2002 Max. Export Cap.
ESB Power Generation	Portfolio	4548
Huntstown Power Company	CCGT	353
Synergen	CCGT	400
Edenderry Power	Peat	118

Are these firms integrated into transmission or distribution?

ESB is an integrated utility owning the transmission and distribution networks and having generation and supply businesses also. Huntstown Power is a part of the Viridian group, which owns the transmission and distribution networks in Northern Ireland.

What is the market share of the largest players at different levels of demand?

Information is not available.

Finally, what is the nature of the regulatory authority?

The Commission for Electricity Regulation (CER) is an independent body established under the Electricity Regulation Act, 1999. This Act supplements the original Act of 1927 which established the national electricity utility ESB – Electricity Supply Board – and provides the regulatory framework for the introduction of competition in the generation and supply of electricity in Ireland. The CER licenses and regulates the generation and supply of electricity, authorises the construction of new generating plant and oversees third party access to ESB's transmission and distribution systems.

Does the regulatory authority have powers to intervene to collect information and set prices? If so, which prices? Under what circumstances?

Under Section 35 of the Electricity Regulation Act, 1999, and as part of its remit to oversee third party access to the electricity network, the Commission determines the tariff structure for access to the network. CER also determines top-up price as a tariff and the spill price calculation in the imbalance market. The CER also approves the downstream retail PES tariffs.

In the case of EU countries (for which regulatory reform has primarily been a matter of implementing the relevant EC Directives) we invite you to focus on the approaches you have chosen to comply with the Directives or where you have gone further than the minimum required by the Commission:

Almost all Member States have passed appropriate legislation to transpose the Directive. In terms of market opening, a number of Member States have either already opened their markets more rapidly than the minimum requirements of the Directive or plan to do so.

The Irish electricity market has gone further than the EU Directive in a number of ways. The EU Directive sets a minimum eligibility threshold of 4GWh whilst the Irish threshold is 1GWh. In addition, the Irish non-eligible market, i.e. that sector of the market whose annual consumption is below the threshold, is also open to competition from renewable, alternate, sustainable and CHP sources of electricity.

Table 1 below is taken from the European Commission's "First Benchmarking Report on the implementation of the internal electricity and gas market" (SEC (2001) 1957; updated version with annexes March 2002). However, it should be noted that this table is out of date and the comments and analysis require updating.

The report identifies the key barriers to competition in the sector as:

- excessively high network tariffs, which form a barrier to competition by discouraging third party access, and may provide revenue for cross-subsidy of affiliated businesses in the competitive market;
- a high level of market power of existing generation companies combined with a lack of liquidity in wholesale and balancing markets which is likely to expose new entrants to the risk of high imbalance charges;
- network tariff structures which are not published in advance or subject to ex-ante approval; which may lead to uncertainty and create costly and time-consuming disputes unless combined with full ownership unbundling;
- insufficient unbundling, which may obscure discriminatory charging structures and lead to possible cross-subsidy.

Table 1 Implementation of the Electricity Directive

	Declared market opening	Full opening date	Unbundling of TSO ¹	Regulator	Network tariffs	Balancing market	Biggest three generator share (%)	Obstacles to competition responses mentioning: ²
Austria	100%	2001	L	ex-ante	high	Y	68	X
Belgium	35%	2007	L	ex-ante	medium	N	97 (2)	D, B, R, X
Denmark	90%	2003	L	ex-post	low	Y	75 (2)	D, X
Finland	100%	1997	O	ex-post	low	Y	54	U (for DSOs)
France	30%	none	M ³	ex-ante	medium	planned	98 (1)	D, B, U, X, R
Germany	100%	1999	M	nTPA	high	only 2/6 TSO	63	U, R, X, T
Greece	30%	none	M	ex-ante	n.a.	N	100 (1)	no responses
Ireland	30%	2005	L	ex-ante	medium	N	97 (1)	D, B, U, X
Italy	45%	none	L	ex-ante	medium	planned	79 (2)	D, B, X
Neth	33%	2003	L	ex-ante	medium	Y	64	X, D
Portugal	30%	none	L	ex-ante	high	N	85	D, X
Spain	45%	2003	L	ex-ante	high	Y	79	D, X, R
Sweden	100%	1998	O	ex-post	low	Y	77	D, B
UK	100%	1998	O	ex-ante	low	Y	44	D,U (Scot), X (NI)

Potential problem areas are shaded red. Three such areas were identified for Ireland:

- The relatively slow and late market opening – Ireland, along with Belgium, had a one year extension of the deadline for implementation of the Electricity Directive; February 2000 instead of February 1999.
- The declared market opening level of 30% in 2001 was the lowest in Europe;

The current level of market opening in terms of percentage of annual consumption is 40%. The Irish market has a total of approximately of 1.6m customers. As its economy is service industry based (not very energy intensive) and does not have many heavy industrial plants, its large users (i.e. originally >4GWh and now 1GWh) are few in number and do not account for as significant a proportion of demand as may be the case in other countries.

- The lack of a balancing market;

The Irish market has an imbalance market that settles Uninstructed imbalances financially as was the case in Scotland. The Ministers Policy Direction in Trading 1999 put this system in force. Physical imbalances (Instructed imbalances) are settled at spill also. Please refer to the Trading and Settlement Code for details. This mechanism has been in operation since February 2000.

The Irish market complies with the EU Directive regarding transmission and distribution etc as set out elsewhere in this document.

3. Factors Affecting Market Power

3.1. Market Structure

Who are the main players in the generation market?

ESB Power Generation, Huntstown Power Company, Synergen and Edenderry Power Limited.

What fuel sources do they use?

ESB Power Generation controls a portfolio of assets including coal, gas, oil, peat, hydro, and through Hibernia Wind Power, wind generation. Both HPC and Synergen are Natural Gas fired CCGT plants, whilst Edenderry Power Limited has one peat-burning unit. A number of independent wind generators are active in the Irish market, the largest of which is Eirtricity.

What is their capacity and cost structure?

ESB Power Generation's capacity is approximately 4548MW. As stated above, Huntstown Power has 353MW of generation, whilst Synergen (70% owned by ESB Power Generation) has 400 MW of generation capacity.

Electricity generation is a largely fixed-cost enterprise involving significant plant outlays. The extent of the initial outlay, and hence the cost structure of electricity generation is determined in general terms by the type of generation, be it hydroelectric, nuclear, coal, and oil or gas. Within this list, the energy cost is increasing and the capital cost is decreasing. ESB Power Generation's Moneypoint coal fired station, which has the lowest variable cost component, is therefore more efficient when used to meet base-load requirement. Gas generation (Huntstown & Synergen) has a higher variable cost component and a lower fixed cost component when compared with coal generation.

At different levels of demand which firms tend to set the market price?

The price to purchase additional power, called the Top Up price, is set ex-ante as a regulated tariff by the CER. ESB Power Generation plant usually sets the spill price in the imbalance market under the terms of the Electricity Regulation Act and overseen by CER. ESB Power Generation is required to bid its avoidable fuel cost (i.e. cost reflective bids) under the Ministers Policy Directive and the spill price is determined from the most expensive plant's decremental bid of a plant running on the system which can be decremented in that half hour (refer to the Trading and Settlement Code www.cer.ie). This means that the spill price is set ex-post by market bids. Both prices vary across the day by each half hour and over the course of the year.

How important are imports from other regions? Do the imports set the market price? Are the imports capacity constrained?

The 50MW North-South transfer capacity provided by the Interconnector with Northern Ireland represents the only imports into the Irish electricity market. The connection via the Moyle Interconnector of the Northern Irish system with Scotland, and hence the wider European transmission system, is of relevance when considering the scope for imports into the Irish electricity market. The scale of current imports means that they have a negligible effect in determining the market price.

ESB National Grid and the National Grid Company of England and Wales have examined the issue of interconnection between the two markets.

Is the market concentrated at certain times of the day or a certain levels of demand? How do you measure concentration in these markets?

System demand varies around 2000MW between midnight and 6 am each night. It increases sharply to a morning peak at 9 am which is maintained until a dip in early afternoon around 1pm. Demand then increases steadily to a daily peak at approximately 6pm after which it falls back gradually to its lowest night-time level at approximately 5am.

Two new entrants supply approximately 750MW of base load 24hrs a day. Therefore they supply a considerable amount of the night load – 37.5% and assuming an average winter peak of 4000MW

In addition to daily demand fluctuations a seasonal demand pattern is also clearly discernable, with a peak in the winter system. The highest level of system demand is therefore typically experienced on a winter evenings.

ESB Power Generation directly owns approximately 85% of generating capacity. ESB Power Generation's portfolio includes all dedicated peak demand plant, and as such its market share would increase marginally at peak demand.

Is the industry vertically integrated? Is there integration between generation and transmission? If so, how does the regulatory authority prevent discrimination against non-integrated generators?

Whilst competition in generation and supply has been introduced in the Irish market, the transmission and distribution systems remain a regulated monopoly and in the ownership of ESB Power Generation. Eirgrid operates the Irish transmission system. EirGrid is an independent company regulated by the CER, legally separated from its parent company ESB, and will be (and a regulated ESBNG currently is) responsible for ensuring that access to the transmission system is available on a fair and non-discriminatory basis. Any market participant has the right of appeal/dispute regarding connections to the system to the CER under the legislation. In addition, two new entrant suppliers are closely affiliated to upstream generation.

Has the regulator (or some other body) imposed a divestiture or separation requirement? (For example, a requirement to divest a certain proportion of generation capacity) If so, what divestiture or separation was required? What was the resulting effect?

In the Irish context only the central government in the form of the Department of Communications, Marine & Natural Resources can impose a divestiture requirement on market participants. To date no such action has been taken.

3.2. *Congestion and Pricing of the Transmission Network*

Which components of the transmission network are sometimes congested? Under what conditions are these components congested? What are the consequences of this congestion – in particular, does the congestion facilitate market power? If so, for which generators?

The Irish transmission system can be divided in two distinct categories constituting the Eastern and Western halves of the country. The Eastern sector includes the majority of national generation and load is characterised by high levels of congestion. The western sector has a much more sparse network. However, a number of older, 'must-run' generators located in the West can impose constraints on other parts of the network.

Congestion in the Irish market is managed by a central dispatch system controlled by the National Control Centre (NCC). At any time, generators not required will have their output constrained down. Generators have either 'firm' or 'non-firm' access to the transmission system. Those with firm access will receive constraint payments in the event that they are directed to reduce their output below their desired level.

There is no auction for transmission capacity rights and as such problems of market power or deep pockets do not arise. If a generator wishes to locate in a congested part of the network they face higher Transmission Loss Factors (TLFs) and time lags in connecting to the network due to the requirement for extra deep reinforcement of the network. This is operated by the TSO, an independently licensed entity as discussed elsewhere in this document therefore there is no opportunity to use market power.

How do you price access to the transmission network (for example, do you use "nodal" or "zonal" prices)? Does how you price access to the transmission network affect the level of market power? Are there market instruments which allow the market players to hedge against movements in the prices for access to the transmission network (for example, so-called "financial transmission rights"?)? Do these instruments affect the incentives to exercise market power?

Transmission Use of System (TUoS) is the provision of access to the transmission network to transfer energy for trade within the market. Transmission tariffs are charged to users of the transmission system (generators and demand customers). Generation TUoS charges are site specific and differ according to the location (or intended location) of the generator in relation to the transmission system. Financial transmission rights are not employed in the Irish electricity market.

There are no nodal or zonal prices *per se* and therefore financial transmission rights do not arise and thus cannot be used to exert market power.

What are the incentives faced by generators when choosing where to locate? Do generators have incentives to make efficient location decisions? Where has most new generation capacity been constructed?

The market incentives faced by potential generators making locational decisions are threefold.

1. Generators are liable for TUoS charges based on their generation. Transmission connected generators and distribution connected generators above a 10MW threshold are charged for capacity using locational use-of-system charges, which attempt to provide efficient siting signals to new generators in support of an overall efficient transmission system.

2. Given the congestion of the transmission system, generators will find that connections in those areas of the system without constraints will be more expedient, given that typically less reinforcement works are required. Areas suitable for increased generation are identified in the **EirGrid Forecast Statement 2001/2-2007/8**.
3. Transmission losses are incorporated into market structures through the assignment of Transmission Loss Adjustment Factors (TLAFs) to each generator. TLAFs will vary according to how the flows attributable to the generator correspond to existing flows. Generators that reduce aggregate flows by their generation will have positive TLAFs, and in this way recoup the benefits they provide to the transmission system. However, changing transmission characteristics render TLAFs uncertain in the medium to long-term, and as such their effectiveness as locational signals is limited.

A number of smaller generation projects have located in less congested parts of the network. The two recent larger projects, Huntstown and Synergen, have located in the congested eastern region in order to secure access to gas fuel supplies.

Are there special rules governing import/export transmission lines? Are these lines congested for all or some part of the time? How is access to these transmission links rationed at peak times? Do you auction the capacity of these links?

The Total Transfer Capacity (TTC) of the North-South Interconnector is 600MW. However, system requirements and constraints on the local networks either side of the Interconnector, particularly on the southern network, limit Available Transfer Capacity (ATC) to 50MW N/S and 120MW S/N. Interconnector transfer capacity is allocated by annual auctions conducted in conjunction with the System Operator of Northern Ireland (SONI).

Which firm or firms have the ability to upgrade the transmission network to relieve congestion (through the construction of new links or through the enhancement of existing links)? For example, is this the sole responsibility of the transmission network operator, or can independent firms construct new pipelines? What are the incentives on these firms to upgrade the transmission network in this way?

Upgrade of the transmission network has to date been the sole responsibility of the TSO, whilst system maintenance is the responsibility of Transmission Asset Owner, ESB Networks. The possibility of transmission infrastructure, particularly Interconnection with other networks, being delivered on a merchant basis has not been ruled out. However, this issue has not arisen to date.

3.3. Market Rules

Please describe the key features of the electricity “exchange” or “pool” (where there is more than one market, explain the differences between them – which market determines the “spot” price of electricity).

The Irish trading system is currently one of bi-lateral contracts and is not a ‘pool’. The transition to liberalisation of this market has led to the implementation of interim market rules, many of which may change before full market opening.

A trading regime was established and the Trading and Settlement Code that set out the trading rules was put in place. The Code contains the administrative, legal and commercial aspects of the trading and settlement arrangements, as well as the algorithms describing detailed settlement rules.

The Transmission System Operator (EirGrid) performs both the market/settlement function and the dispatch function. The System Settlement Administrator (SSA), a separate unit within EirGrid, performs the market operation and settlement function.

The electricity trading market in Ireland is based on a bilateral trading model i.e. generators (who produce energy) and suppliers (who have signed up customers and hence need to buy energy) arrange bilateral trades for the purchase of electricity. Electricity not traded via bilateral contracts is bought and sold on the imbalance market. Before submitting final bilateral contract nominations, generators and suppliers are provided with information regarding imbalances by the SSA to facilitate them in trading out their energy market positions at mutually beneficial prices and thus avoid having to trade in the imbalance market.

Whether or not participation in the spot market is compulsory (or can sellers sign bilateral contracts directly with buyers)? (In most cases participation is voluntary)

Sellers can sign bilateral contracts with buyers. There is no spot market.

Whether or not buyers are able to submit bids directly into the market mechanism? (In most cases buyers also participate by bidding into the market)

Buyers do not submit bids directly into the market mechanism. This applies both for the wholesale market (where bilateral contracts prevail) and for the imbalance market (where buyers purchase 'top-up' (i.e. when a supply/generator other than ESB Power Generation has an electricity shortfall), they buy energy at a Best New Entrant Price).

What is the nature of the bids – are they simple price-quantity pairs (how many such pairs can each generating firm submit?) or do firms bid other terms such as the rate at which they can ramp up production?

Only generators bid into the imbalance market and they do so in a manner described above (Incremental and Decremental Prices).

Is the spot price determined ex ante on the basis of forecast demand and supply or ex post on the basis of actual demand and supply?

As there is no spot market, this question does not apply.

Is there some mechanism designed to enhance investment in and availability of generation capacity? (In most cases there is no such mechanism – the market price itself provides the incentive for new investment)

A capacity related spill payment is paid on Spill (electricity excess to bilateral contractual needs). This was specifically introduced to encourage investment in generation. Green participants cannot avail of this capacity payment. This payment is paid on the first 350 MW spilled. There is also a capacity margin payment to encourage plant to make themselves available even if they are not base load and may not run at all.

Do the rules governing the operation of the electricity market affect the incentive for firms to act strategically? Are there other ways in which the market rules might influence market power?

In relation to electricity the Commission for Energy Regulation does not discriminate unfairly between holders of licences, authorisations and the Electricity Supply Board (“ESB” – the State-owned electricity operator in Ireland) or between applicants for authorisations or licences. The Commission is also charged with protecting the interests of final customers of electricity. The market rules are designed accordingly.¹

The purchase price for additional power, called the Top Up price, is set ex-ante as a regulated tariff by the CER. Therefore firms acting strategically or using market power cannot manipulate it.

ESB Power Generation plant usually sets the spill price in the imbalance market under the terms of the Electricity Regulation Act and overseen by CER. ESB PG is required to bid its avoidable fuel cost (i.e. cost reflective bids) under the Ministers Policy Directive and the spill price is determined from the most expensive plant’s decremental bid of a plant running on the system which can be decremented in that half hour (refer to the Trading and Settlement Code www.cer.ie).

3.4. Bilateral, Long-Term and Forward Contracts

Does the regulatory regime allow or promote the use of long-term or forward contracts for the sale and purchase of electricity? Are certain firms required or obliged to take out long-term contracts? Does the presence of such contracts affect the level of market power?

The electricity trading market in Ireland is based on a bilateral contract-trading model. The regulatory framework permits the use of long-term contracts. However, there is no specific requirement for players to enter into long-term contracts. The presence of such contracts is not currently a cause for concern regarding market power and is not in great use as the new entrants are small. In the future the ESB Public Electricity Supplier will have an economic purchasing obligation that will aid in the prevention of the abuse of long term contracts.

3.5. Price or Quantity Controls

Are wholesale electricity prices set through a market mechanism or through regulation?

Wholesale prices are set through bilateral contracts between parties. Imbalance prices are set as discussed elsewhere in this document above and below. The Virtual Independent Power Producer (VIPP) Auction capacity and energy price are determined. The VIPP price is set at a discount (currently 8.5%) to the ESB Power Generation element of the Public Electricity Supplier (PES) tariff. The VIPP price is currently €45.75 per MWh.

If they are set through a market mechanism, do there remain some controls on the prices that firms can charge (such as a ceiling on the amount the firm can bid, or a requirement that all bids be based on marginal cost)? If so, which firms and under what circumstances? (For example, are there caps on the prices of firms which are “constrained on” or “reliability must run”)

The price to purchase additional power, called the Top Up price, is set ex-ante as a regulated tariff by the CER. ESB Power Generation plant usually sets the spill price in the imbalance market under

the terms of the Electricity Regulation Act and overseen by CER. ESB PG is required to bid its avoidable fuel cost (i.e. cost reflective bids) under the Ministers Policy Directive and the spill price is determined from the most expensive plant's decremental bid of a plant running on the system which can be decremented in that half hour (refer to the Trading and Settlement Code www.cer.ie). This means that the spill price is set ex-post by market bids. Both prices vary across the day by each half hour and over the course of the year.

The Spill Price, the price received by producers/suppliers from ESB Generation for uninstructed excess energy, has a floor of €28 MWhr. The Top-Up Price, the price paid by producers/suppliers to ESB Generation for uninstructed energy shortfall, is determined ex-ante by the Commission for Energy Regulation.

The Spill Price is based on the avoidable fuel cost of the marginal plant on the system. The Top-Up Price is based on a modelled MWhr cost of a Best New Entrant into the industry. This last point is contingent on the Spill Price being less or equal to this BNE cost. If this is not the case, the Top-Up Price rises above BNE cost.

Are there special rules governing when firms are allowed to withdraw capacity from the market? For example, are there special provisions governing availability of generation capacity? Is a firm penalised when capacity ceases to be available which it declared to be available?

There are no special rules governing when firms are allowed to withdraw capacity from the market. However plant is given incentives to make itself available for the day ahead (e.g. capacity margin).

3.6. *Entry*

Are there special rules which encourage (or discourage) new entry into generation? For example, is there a requirement to maintain a certain level of excess generation capacity?

There is no requirement to maintain a certain level of excess generation. However there is a capacity payment.

Has there been significant new entry in recent years? Which fuel sources have the new entrants chosen, and why? Will the new entry be sufficient to offset any market power?

The most significant recent additions to the Irish generation portfolio are the 353MW Huntstown Power Company station, and the 400MW Synergen station, a joint venture between Statoil and ESB Power Generation. Both Huntstown and Synergen are Combined-Cycle Gas Turbine plants. Eirtricity, is the largest dedicated renewable energy supplier in the Irish market, and is involved in a number of wind generation projects. The Commission is actively encouraging new independent generation in order to improve the competitive landscape in the Irish generation market. Eirgrid's '**Generation Adequacy Statement 2001-2007**' indicated that additions to capacity in 2002 would be equivalent to 17% of 2001 capacity.

3.7. *Competition Law Enforcement*

Which mergers have you considered in this sector (either between generators or electricity and gas producers)? Was the merger approved? What conditions were placed on the merger?

There have been no mergers in the Irish electricity sector. Below is a brief outline of recent developments in the operation of merger control in Ireland.

In April 2002 the Competition Act, 2002 was enacted to consolidate and modernise the existing enactments relating to competition and mergers. It replaces the Mergers, Takeovers and Monopolies (Control) Act, 1978, as amended, the Competition Act, 1991 and the Competition (Amendment) Act, 1996. It also introduces significant changes to Ireland's competition and merger law arrangements.

Under Part 3 of the new legislation, the Competition Authority will take over responsibility for merger control from the Minister for Enterprise, Trade & Employment - with the exception of media mergers. This part of the Act will not come into force until 1 January 2003. Mergers above a certain threshold, where at least two of the merging undertakings carry on business in Ireland must be notified to the Authority (section 18(1)). Mergers below the threshold, or where only one party carries on business in Ireland may be notified. The trigger for notification is when a merger is "agreed or will occur if a public bid is accepted". The thresholds have also been clarified and updated; the Minister can by order disapply the thresholds to a particular class of mergers.

There will be a two-stage process, whereby mergers can either be cleared at Phase 1 or subjected to a more detailed, "Phase 2" investigation (called in the Act a "full investigation"). The Authority may "determine" that a merger or acquisition may be put into effect, may not be put into effect, or may be put into effect only subject to certain conditions. The Act also makes clear that Sections 4 and 5 will apply only to mergers which have not been notified. (See new Section 4(8), Section 5(3)). In practice, this will mean only that it will apply to those mergers below the threshold, or in which only one undertaking carries on business in Ireland, which have not been voluntarily notified under the provisions of section 18(3).

The new Act requires the Authority to approve or reject mergers based on competition criteria only. The test is whether the result of the merger or acquisition will be to substantially lessen competition in markets for goods or services in the State. The new system involves more openness and transparency: all notifications are to be published, and the Authority must consider all submissions made to it, whether in writing or orally, by the parties concerned or by any other party.

Have you investigated allegations of collusive behaviour in this sector? What was the outcome of that investigation?

There have been no investigations of collusive behaviour in the electricity sector.

Have you investigated abuse of dominance in this sector? What was the allegation? What was the outcome?

Synergen, a 70:30 joint venture between Dublin Bay Power, a wholly owned subsidiary of ESB, and Statoil Dublin Bay, a wholly owned subsidiary of the Norwegian state oil company Statoil, was established prior to the liberalisation of the electricity sector with the intention of generating electricity for supply to the eligible market, i.e. that portion of the electricity market open to competition. On the 1st December 1999, the Minister for Public Enterprise, the Minister responsible for overseeing the

liberalisation of the electricity sector and key shareholder in the ESB, wrote to the Chairman of ESB expressing concern over the proposed Synergen generation plant at Ringsend, Dublin:

“...I could only consider giving approval in relation to expenditure for the turbine after I have received a written undertaking from ESB that if I am of the opinion that competition law makes it appropriate, the ESB would sell its interest (including any consortium having interest) in any generating station to be built at Ringsend on appropriate terms.”

On the 29th June 2001, the Authority wrote to the Minister expressing its concerns about the state of competition in the electricity sector, mentioning in particular the “... need to ensure that the regulatory environment is focussed on encouraging greater competition in generation, both in the public interest and to comply with Ireland’s commitments under EU liberalisation.” In the opinion of the Authority, the swiftest and most effective means for achieving this end was for the Minister to call in the undertaking required of the ESB in her letter of the 1st December 1999.

The Minister responded in a letter dated the 7th August 2001, indicating that in the absence of any definitive finding or ruling by an independent body competent in the field of competition law, she would not require the ESB to sell its interest in Synergen. The Authority concluded that the Minister’s view seemed to be so excessively narrow as to rob it of all practical use and meaning. Indeed, it would effectively limit the Minister’s role to endorsing reliefs already ordered by an Irish Court and/or by the European Commission.

Concurrent to these events, the European Commission was investigating the Synergen joint venture under European merger control provisions. In July 2000 the ESB and Statoil had notified four agreements to the Commission which related to the construction and operation of the Synergen power plant. According to the "Partnership Deed" setting up the Synergen joint venture ESB held a 70 % stake in the company while Statoil held the remaining 30 %. Another agreement, the "Supply Agreement", foresaw that a subsidiary of ESB, namely ESB Independent Energy Limited (ESBIE), would market the power generated by Synergen for 15 years. A "Gas Supply Agreement" provided that Statoil supply Synergen with gas for 15 years. Finally the "Operation and Maintenance Agreement" stipulated that the ESB would provide the operation and maintenance services to Synergen for 15 years.

The Commission analysed in particular whether the creation of the joint venture would remove Statoil as a potential competitor from the highly concentrated Irish power market. Statoil, it was argued, was a powerful company with gas reserves inside and outside of Ireland, electricity activities in other countries, a well established brand name in Ireland and financial strength.

For the two markets concerned (electricity production and sales to eligible customers) the Commission established that ESB still held a dominant position. ESB effectively controlled 97% of the electricity production in Ireland and more than 60% of the supply market for eligible customers. Whilst the market structure would become somewhat improved later that year, when Viridian, the Northern Irish electricity company would commission its new 340 MW power plant at Huntstown (Ireland), the Commission took the view that Viridian might not develop into ESB's fiercest competitor. This was due to the fact that ESB and Viridian, were both active in Northern Ireland and the Republic of Ireland which created a certain equilibrium of potential competitive threats.

Under these circumstances, the Commission came to the conclusion that the market structure would be improved on a lasting basis only if a third power producer independent of ESB and Viridian entered the Irish electricity markets. In this respect the Commission noted that Statoil was one of few, if not the most prominent, potential new entrant. But the joint venture agreement prevented Statoil from participating in competing power projects or from entering the market independently.

In the course of the investigation, the companies proposed to address the Commission's concerns. The settlement negotiations were carried out by the Irish Commission for Electricity Regulation (CER) at the Commission's request. The main elements of the commitments submitted by ESB and Synergen were:

- Volumes: ESB and Synergen make available 600 MW of electricity per year until additional sources of electricity of 400 MW become available, of which 300 MW must be produced by a single new plant.
- Origin of the volumes: Of the 600 MW, ESB will provide 400 MW and Synergen will provide 200 MW.
- Sales Modus: The volumes provided by ESB will be sold under an auction system (so called VIPP scheme). The Synergen volumes can be sold on the basis of bilateral contracts and if this fails by means of an auction. ESB companies are excluded from the Synergen sales.
- Maximum volumes: No electricity supplier can acquire more than 400 MW in the ESB auction (VIPP) including its own production and purchases from Synergen. This means for ESBIE that it can buy maximum 200 MW in the auction as it acquires already 200 MW from Synergen.
- Type of contracts: The electricity sold by Synergen is made available by means of contracts running up to three years.
- Non-compete obligation: The obligation imposed on Statoil not to participate in competing power projects is deleted.

The Commission took the view that the commitments would facilitate market entry in the Irish electricity markets. Once Viridian's power plant Hunstown was commissioned, suppliers would be able to buy electricity from at least three different sources: Hunstown, ESB auction and Synergen. New producers would have the opportunity to build up a customer base for their future power plant. In this respect it was also noted favourably that the duration of the supply contracts for Synergen output (up to three years) would provide operators with significant certainty for medium term planning.

The Commission also cleared the gas supply contract, under which Statoil will deliver gas to Synergen (30% Statoil participation) for 15 years on an exclusive basis. The Commission considered that the Irish gas market was still dominated by the incumbent gas supplier BGE. The Commission also noted that the Synergen contract was the first large scale gas supply contract for Statoil in Ireland, which raised Statoil's market share slightly above the so called *de minimis* threshold and which should ensure Statoil's long term presence in the Irish gas market. Furthermore the Commission took into account that Statoil offered a special price formula for its gas, which it would not have offered, if it had not been assured a long-term exclusivity.

4. Concluding Comment

The Competition Authority and the Commission for Energy Regulation are available for comment on or clarification of any of the issues raised in this document.

NOTES

1. For further information on market/regulatory rules see: Electricity Regulation Act, 1999; <http://www.cer.ie>; and <http://www.eirgrid.com>. In addition read the Trading and Settlement Code which can be found on the Commission's website.

JAPAN

Introduction

We will first explain how the Japan Fair Trade Commission approaches competition issues in the electricity sector, and then answer questions from the Secretariat.

Approach to regulatory reform in the electricity sector

1. Approach to system reform

In the electricity sector, system reforms were implemented including partial deregulations in the retail sector through the amendment of the Electric Utility Industry Law in 1999. The Electricity Industry Committee under the Advisory Committee for Natural Resources and Energy, Ministry of Economy, Trade and Industry has followed up these reforms and continued to study the details of the preferred system with an eye toward further deregulation.

Meanwhile, the Japan Fair Trade Commission has studied how to establish an environment to promote competition in the electricity sector at the Study Group on Government Regulations and Competition Policy, which has already submitted a series of proposals. Most recently, in view of the direction of reforms of the electricity sector, the following have been studied:

- measures to encourage new entrants (implementation of efficient and fair connected lines, establishment of power trade exchange, etc.)
- measures to activate wide-ranging competition (abolishment of the current transfer rate system)
- establishment of fair rules in the consignment sector (separation of system operation from operations of electric power companies, etc.)
- ensuring fair rules to promote competition in the electricity sector (establishment of a watchdog commission to ensure neutrality of system operation, etc.)

Based on the above studies, the basic approach toward establishing a competitive environment in the electricity sector has been formulated and the report, "Establishment of Environment to Promote Competition in the Electricity Sector" was released on June 28, 2002.

2. Amendment and publication of "Guidelines Concerning Appropriate Electric Power Dealings"

Outline

To ensure that competition functions properly in the electricity market in conjunction with system reforms in 1999, particularly partial deregulation of electricity, the Japan Fair Trade Commission

jointly with the (former) Ministry of International Trade and Industry drew up and published the “Guidelines Concerning Appropriate Electric Power Dealings” in December, 1999.

Subsequently because cases arose that had not been foreseen in the Guidelines, “Interpretation of the Antimonopoly Act Concerning the Partial Supply of Electricity” was drawn up and published in November, 2001 in order to prevent violations of the Antimonopoly Act.

Looking at these cases as well as the declarations, consultations, and so forth issued after partial deregulation, it was considered important to specify appropriate electric power dealings in greater detail to those concerned, including electric power companies, new entrants and users. Accordingly, the Japan Fair Trade Commission, jointly with the Ministry of Economy, Trade and Industry, amended and published the more substantial “Guidelines Concerning Appropriate Electric Power Dealings” on July 25, 2002.

Main points of the amendments

Electric power companies have retained almost a 100 percent share of the electricity market in their respective service areas even after partial deregulation, and there has been almost no competition among these companies. Where markets are dominated by regional monopolies, deregulated users or new entrants are forced to depend on the existing electric power companies for the supply of electricity as well as transmission lines, service lines, and so forth. It was therefore decided to specify in the Guidelines that, under such circumstances, setting disadvantageous conditions by electric power companies to new entrants or users wishing to start transactions with new entrants may hinder the business of new entrants.

Based on this standpoint as well as the cases examined and discussions with business operators, the following trade practices, for example, have been added to the Guidelines as possible violations of the Antimonopoly Act.

Retail supply and setting of retail rate to deregulated users

- Setting and application by electric power companies of a disadvantageous tariff without proper justification to users who receive a partial supply, without offering the diverse choices normally made available by the companies
- Request by electric power companies of excessive prior notice in case of partial supply to users which follows the loading pattern

Wholesale to new entrants

- Unilateral decision by electric power companies of items to be discussed with new entrants concerning backup support contracts in case of accidents
- Refusal by electric power companies to supply new entrants with that portion exceeding the extent of fluctuation (fluctuation of 3 percent or less of supply and demand) or setting of an unreasonably high rate

Consignment sector

- Unreasonable postponement by electric power companies to new entrants of procedures prior to the commencement of consignment service

- Restriction without proper justification by electric power companies to new entrants on the use of connection line equipment

New or additional construction of facilities by users who have power generation facilities for private use

- Discounting by electric power companies of electricity rates, on condition that the users do not increase the power generation facilities for private use

3. *Future approach*

- The Japan Fair Trade Commission, in order to establish an environment for fair competition in the electricity sector after the system reforms, will continue to actively address the matter based on the fundamental policy of system reform which will be decided at the Electricity Industry Committee.
- Further, in order to secure fair and free competition in the electricity sector, the Japan Fair Trade Commission, based on the above policy, will continue to work to eliminate strictly and swiftly and prevent violations of the Antimonopoly Act. The Commission will also review the above guidelines flexibly and as necessary in line with changes in the competition environment and based on case histories of dealing with violations, etc.

Answer to Questions

Competition Law Enforcement

Q. Which mergers have you considered in this sector (either between generators or between electricity and gas producers)? Was the merger approved? What conditions were placed on the merger?

A. No mergers have taken place in Japan in the electricity sector. The Japan Fair Trade Commission has not set any particular standards for mergers in the electricity sector.

Q. Have you investigated allegations of collusive behaviour in this sector? What was the outcome of that investigation?

A. There has been no case of collusive behaviour in the electricity sector out of legal measures taken or warnings issued by the Japan Fair Trade Commission in the past.

Q. Have you investigated abuse of dominance in this sector? What was the allegation? What was the outcome?

A. There was the following case.

Hokkaido Electric Power Co., Inc. had concluded a “long-term contract” (in principle, 3 or 5 years) with users in the deregulated field, which included discounting the basic rate for the contract electricity guaranteed according to the length of contract, in which the company planned to charge an unreasonably high adjustment fee and penalty for cancellations due to switching the contract to new entrants, etc. The Japan Fair Trade Commission issued a warning to the company on June 28, 2002 as the practice may have been a violation of Article 3 of the Antimonopoly Act (Prohibition of Private Monopoly).

KOREA

I. Introduction

As an industry based on large-scale facilities, the electric power industry has traditionally been managed as a state-monopoly in most countries. However, the reduction of construction periods and development of high efficiency, small volume generators, the electric power industry is seeing greater participation by the private sector. Consequently, growing market participation by private firms is generating some favorable conditions for the industry to shift to a competition regime.

In April 2001, the OECD adopted the 'Recommendation of the Council Concerning Structural Separation in Regulated Industries' to promote competition in industries like electricity, telecommunications, gas and postal services. Since then, some 40 countries have initiated restructuring in the mentioned industries. These countries include developing, South American and Asian countries as well as the more developed countries of Europe or North America.

Similarly, structural reform of the state-run monopoly by the Korea Electric Power Corporation (KEPCO) has also become a pressing task for firmly grounding a market economy and strengthening industrial competitiveness in Korea. Previously, electricity could only be supplied by state-owned KEPCO according to Korean laws. But with the Korean National Assembly's legislation for power industry restructuring, Korea expects to conduct structural separation and build a competition system in the power industry.

As such, the following will introduce the restructuring proposal presently being executed in the power industry and, through its review, examine some competition issues which need to be addressed to prevent the public monopoly from shifting to a private one.

II. Structure of the Korean Power Industry

A. *Basic Structure of the Power Industry*

Electric transmission, distribution and sales were monopolized by KEPCO. While power is generated by 5 thermal power generators and 1 hydropower generator, competition is being introduced with the market entry of private power companies. As of the first quarter of 2002, the total capacity of Korea's power facilities is 50,69 million kw while real power capacity is 74 billion kwh. Sources of power include nuclear materials, hydraulics, coals, oil and LNG. Korea imports all fuels with the exception of coal.

Power Generation by Fuel Source

(unit: 1,000 kW)

Source	2002 (1st Quarter)	Ratio (%)
Hydropower	3,876	7.6
Nuclear Power	13,716	27.1
Coal	1,191	2.3
Briquet	14,240	28.1
Oil	4,658	9.2
L N G	13,018	25.7
Total	50,699	100

Power Facilities Capacity by Company

(unit: 1,000 kW)

Company	2002 (1st Quarter)	Ratio (%)
South-East Power	5,565	10.9
Midland Power	6,393	12.6
Western Power	6,846	13.5
Southern Power	5,765	11.4
East-West Power	7,500	14.8
Hydro Nuclear Power	14,250	28.1
KEPCO	139	0.3
Others	4,240	8.4
Total	50,699	100

Power Facility Performance by Fuel Source

(unit: 1 million kWh)

Source	2002 (1st Quarter)	Ratio (%)
Hydropower	769	1.0
Nuclear Power	1,480	2.0
Coal	26,686	36.1
Briquet	6,153	8.3
Oil	9,695	13.1
L N G	29,229	39.5
Total	74,012	100

Power Facility Performance by Company

(unit: 1 million kWh)

Company	2002 (1st Quarter)	Ratio(%)
South-East Power	7,862	10.6
Midland Power	6,758	9.1
Western Power	8,391	11.3
Southern Power	9,576	13.0
East-West Power	9,703	13.1
Hydro Nuclear Power	29,424	39.8
KEPCO	18	0.02
Others	2,280	3.1
Total	74,012	100

There are two types of electricity prices; wholesale and retail. The wholesale rate is determined by the 'cost-based pool' and the retail rate is differentiated into 6 categories of use; general, industrial, educational, agricultural and public lighting.

B. *Regulatory Framework (Establishment of the Korea Electricity Commission)*

a. *Background*

Until now, the state-owned enterprise KEPCO monopolized all areas of the power industry; generation, transmission, distribution and sales. KEPCO functioned as a quasi-governmental body while the government was only responsible for administration and control over KEPCO. After new laws on power industry restructuring took effect, however, numerous power companies entered the former monopoly and the market began to shift toward a competition framework. To this end, the government saw the need for a separate body to fulfill not only the policy function of promoting the electric power industry but also regulatory functions necessary for the market competition system such as creating a fair competition environment and consumer protection.

Accordingly, Korea chose to follow the global policy trends of many countries that separate the two government functions of policy and regulation by ensuring independence and expertise and, thus, enable consistent task implementation. In doing so, the existing electric power policy function was assigned to the Ministry of Industry and Resource while the a separate body, the Korea Electricity Commission, was set up and assigned to allow the independent and expert implementation of a regulatory function by law.

b. *Korea Electricity Commission*

The legal rationale for forming the Korea Electricity Commission is stated in Article 53 of the Electricity Business Act. The Electricity Commission shall be formed within the Ministry of Commerce, Industry and Energy in order to deliberate and resolve matters with respect to the creation of an environment of fair competition of the Electricity Business and the protection of the rights and interests of electricity consumers and to arbitrate disputes relating to the Electricity Business. The Electricity Commission shall have a secretariat to carry out the affairs of the Commission (The Electricity Business Act, Article 53 ;×1 & 4)

The role of the Electricity Commission is to monitor the market so as to promote a market economic environment and fair competition, to arbitrate disputes between power companies and consumers, to protect consumer rights and to follow through with the restructuring of the electric power industry. It should be noted that, although restructuring in the electric power industry is not just the function of the Electricity Commission, the former Electric Power Industry Restructuring Committee was abolished and its functions taken on by the Secretariat of the Electricity Commission once it was established.

III. *Main Structural Adjustments in the Electric Power Industry*

A. *Need for Adjustments*

KEPCO has grown into a state-owned monopoly enterprise that has exceeded possible economies of scale and, thus, has little or no potential for further improvements in corporate efficiency. KEPCO's budget for 2000 was Won 26.8 trillion; 1/3 of the national budget and twice the national defense budget although KEPCO has been generating diseconomies of scale since 1990. KEPCO's inability to swiftly adapt to the rapidly changing environment is a result of its stringent and rigid management, oriented towards supervision and control rather than rationality and efficiency.

Since electricity rates are determined by rate of return regulation, there is little incentive to cut costs, resulting in inefficiencies. Rather than profitability and maximum gains, KEPCO prioritized the stable supply of electricity and over-invested in excess facilities.

If the state-owned structure is maintained, it will be difficult to secure finances to build new generators when demand increases. Since 1990, KEPCO's liabilities rose rapidly due to loan-based investment in new generators (Won 31.6 trillion in June 2000). There is concern over the potential failure of KEPCO in the future since it can not avoid borrowing (approx. Won 67 trillion) to build new generators that will be needed in 2015.

B. *The Restructuring Plan*

a. *Main Contents of the Plan*

The plan aims to introduce a competition in the sector by long-term stage-by-stage separation of KEPCO's functions in generation, distribution and sales. However, KEPCO will maintain its monopoly over the transmission of electricity to ensure supply stability.

Structural Separation Plan consists of three stages. Stage 1 (1-2002) introduced the competition system in the electricity generation section. The electricity generation section was restructured into several affiliates to introduce competition and privatization has been taking place in stages but with the exception of nuclear power. Electricity generating companies will sell electric power through the Electric Power Trading Center where companies will bid competitively to supply electricity at certain hours.

Wholesale competition will be adopted in Stage 2 (1-2008) of restructuring. In this state, distribution and sales sections will be separated into several companies and privatized. In this case, regular consumers will be supplied by their regional electricity distributors while large scale consumers will be able to purchase directly from the market.

In Stage 3 (after 2009), the industry will introduce perfect competition where regular consumers can chose electricity generating companies directly.

C. *Past Progress in Restructuring*

a. *Successful Legislation of Restructuring Related Laws*

The Act on Promotion of Restructuring of the Electric power industry, which stipulates special arrangements for separation of the generation section, was put into effect on December 23, 2000.

Main Contents

KEPCO's government permits & approvals will be transferred to the newly separated company. (Article 7)

The newly established company will be exempt from **National Housing Bond** and **Metropolitan Subway Bond purchase obligations** which are normally mandatory in business registration or asset listing for a newly separated company. (Article 8)

KEPCO's employment contracts will be comprehensively passed on to the newly separated company. (Article 10)

The 'Electricity Business Act' introducing a competition system took effect on February 24, 2001.

Main Contents

The Act identifies electric power businesses in the 4 areas; generation, transmission, distribution and sales (Article 2), and mandates trade in electric power through the electric power market. (Article 31)

It establishes by law that the Electric Power Trading Center should take charge of the electric power market and management of limited areas of electric power (Article 35)

It provides the legal foundations of the Korea Electricity Commission for the purpose of market monitoring and consumer protection. (Article 53)

Basic Plans for Electric Power Supply and Demand is established and announced to stabilize power supply and demand. (Article 25) The law also newly establishes the power to control power supply and demand in national emergencies. (Article 29)

Retains the government approval system for final consumer rates.(Article 16)

The law set up an Electric Power Foundation Fund for public projects such as supplying electricity to remote areas or islands. (Article 48)

b. Separation of the KEPCO Generation Section

KEPCO will divide its 42 thermal generators between 5 new companies. The basic principles underlying the separation will be the following:

First, the employee composition of each company will be similar to one another and generators will be evenly allocated among the different regions so as to prevent a particular sub-group from becoming price dominant.; Second, the generator section will be divided so that generator fuel, remaining facility life-span, operation rates will be evenly distributed while fuel transport and maintenance costs will be minimized.; Third, while ensuring that no one company is allocated supply responsibility over all or too many isolated areas, all generators within a certain limited geographical area will be allocated to one company.; Fourth, the new generator companies should be arranged so that they have equal profit value and maintain enough value to attract outside investment.

The structural separation will also take place according to the following method; First, the Commission will select core generators which can play a central role in establishing financial independence through a stable income. The 5 generators are in Samchonpo, Boryung, Tae-an, Hadong and Dangjin.

* Note: Taking safety issues into account, nuclear power generators will be passed to a single company.

Distribution of the non-core generators will be centered around the core generators to achieve equal distribution of staff composition, facility size, assets and profit value among the new companies. The most suitable proposal will be selected by comprehensive examination of the 4 proposals in terms of finance, fair competition and technical aspects.

(unit : Won 100 million)

Capacity	South-East Power	Midland Power	Western Power	Southern Power	East-West Power	Hydro Power Nuclear Power Co., Ltd.)
Production Capacity Running	5,565	6,393	6,346	5,575	6,300	14,251
Under Construction	1,600	1,600	1,600	2,300	1,200	4,000
Assets (Won100m)	25,568	23,516	27,043	35,561	47,285	174,095

The privatization of power generation companies took place after establishing the Basic Plans for Power Company Privatization and launch of the 'Power Company Selection Committee'. The first company for sale was the Korea South-East Power Co., Ltd. (July 2002). The privatization of the next company after February 2003 will reflect the results of the first privatization.

In the 2nd stage, the industry will prepare to introduce competition in wholesale by separating KEPCO's distribution section into 6 companies by region. For thorough preparation, KEPCO's distribution section will be restructured as a business group framework by March 2003 and experimentally managed as such for one year, to be legally separated into 6 companies in April 2004.

c. Electric Power Trading Center

The Electric Power Trading Center will be a special non-profit agency that has KEPCO and its power generation affiliates as members. The Center will conduct tasks such as opening and managing the market for electric power, overlooking related businesses and take charge of establishing and amending rules and regulations such as market operation principles (**Cost-based Pool**)

Each generation company will bid daily at the Electric Power Trading Center by notifying the Center of a generator's expected power supply capacity for different times on the following day. The Center will decide generators and power volume by matching generator capacity with demand at different hours of the day in the order of lowest operation costs. After electricity dispatch, the highest operation cost among the generators is designated as the market trading price and this price is applied to all generators.

IV. Competition Policy Tasks in Power Industry Restructuring

A. Regulatory Laws

From the competition policy perspective, there is a need to provide rules for pricing access to transmission and distribution networks. With the introduction of competition through structural separation, ensuring fair access to essential facilities, i.e. electricity transmission and distribution networks, is expected to become a crucial factor in forming a competition system in the power industry. This is because access prices act as signals of investment activity by existing and new market players and also because stable operation of transmission and distribution networks between countries is of major importance. In other words, access rates can influence the investment decisions of a company possessing essential facilities and affect whether a new power company will pay to use existing facilities or undertake investment in their own.

Currently, however, there are no regulations on access pricing in the 'Electric Power Business Act' or the Act on Promotion of Restructuring of the Electric power industry which set the legal

foundations for power industry restructuring. Therefore, it is necessary to establish cost-based rules on access pricing.

Competition policy also calls for preventive measures against cartels and regional monopolies. The basic objective of power industry restructuring is to enhance efficiency in electricity production by making the separated companies or sections compete with one another. Therefore, prevention of potential collaboration or regional monopoly by new companies is crucial. This is essentially because electricity has low price elasticity and, although competition is being introduced on a national level, the regional markets are still very monopolistic.

B. The Sectoral Regulator

The competition authority should also increase its expertise in the field. Especially since privatization in industries such as electricity, gas, roads and railways, like the telecommunications sector, will eventually introduce competition, issues in access pricing for essential facilities will gain even greater importance in various sectors. As can be observed in telecommunications, however, the introduction of high competition brings faster technological development and thus requires greater and more specialized expertise and technical knowledge to calculate access pricing. This means that the competition authority is required not only to regulate general, unjust business practices, but also enhance its expertise to identify anti-competitive behavior in access price calculation or discrimination.

Since it is likely that there will be overlapping tasks among the two government bodies, a division of tasks should be established between the competition authority which aims to diffuse the competition culture and the Korea Electricity Commission which seeks to regulate the relevant industry.

Korea has not yet established separate rules for allocating responsibilities between the competition authority and sectoral regulators. This being the case, there is more possibility of causing friction because their tasks overlap. Issues which can be particularly problematic are "ç overlapping functions in Prohibited Business Practices" "è regulation of unjust labelling or advertisement "éthe present or absence of regulations excluding overlapping penalties.

To address these issues, it is important to establish rational and consistent principles in task division between the Korea Fair Trade Commission and the Korea Electricity Commission and the two agencies must form a close cooperative relationship to better fulfill their respective roles.

LITHUANIA

Overview of Regulatory Framework

Until recently, the Lithuanian electricity sector was characterized as having monopolistic entities with prevailing state ownership, providing no grounds for competition, running huge overcapacities, and obsolete technologies. The major participants in electricity supply and distribution were: state – owned Ignalina nuclear power plant (NPP, a generator producing around 80% of today's electricity need in Lithuania), Lietuvos Energija (a state monopoly for electricity transmission and distribution in Lithuania, however, it also included within its organizational structure two thermo-electric power plants plus a hydro-accumulative power plant and a hydro-electric power plant), and three thermo-electric power plants in major cities owned by local municipalities. The primary fuels used are nuclear fuel (cassettes) and natural gas.

The Lithuanian government recently has initiated the implementation of a new policy in the main objective of which is to abandon monopoly in the sector and to create conditions for freer market and competition to exist.

Two laws were adopted creating the legal basis for the opening-up of the electricity market for competition. First, **Law on the Restructuring of Lietuvos energija (2000)** provided for the division of this huge state monopoly into three independent structures: generation, transmission and distribution. Now, after restructuring LE, it no longer combines all these three functions – it is only a regulated transmission monopoly, and all electric power plants have been separated from LE and are independent electricity producers. The distribution network was also divided resulting in two separate distributors operating in two different parts of the territory.

So at this moment there are several major producers of electricity: Ignalina NPP and five local thermo-electric power plants located in major cities, apart from numerous smaller local electricity producers. However, Ignalina nuclear power plant will be gradually shut-down, responding to the requirements of the European Commission in the pre-accession negotiations. The first reactor will be decommissioned by 2005, and the second – by 2009. At least until 2005 there are very few incentives to build any new power plants. Even following 2005, the still operating second reactor will make any significant new entry into the market very unlikely. There is still a lot of uncertainty as to the situation following 2009 after the second nuclear reactor is decommissioned.

The Electricity Law (2000) provides for the opening of energy market in Lithuania and the creation of possibilities for competition, primarily among generators and to a lesser extent among distributors.

A transmission company (the operator of the transmission network – higher voltage lines) is providing the services of energy transportation via transmission lines, and is also acting as a dispatcher of energy flows and as a balancing unit. Two distribution companies (the operators of the distribution networks – lower voltage lines) are in charge of supplying energy to end-users.

The new law provides for that at the initial stage of the market creation only some major users ('free users', i.e. those which annually consume over 20 million KWH of electricity) are able to choose among electricity suppliers. These major users are free to choose their suppliers at their discretion, and can buy electricity directly from producers or other suppliers, which in their own turn conclude agreements with networks operators to transport energy through their power lines (third party access). However, free

users and suppliers can import energy only with the permission of the Government or an institution authorized thereby. Later on the number of free users will be gradually expanded to include smaller users, and starting from 2010 all users will be free to select their own suppliers.

There are also plans to develop the common electricity market for all three Baltic states – Estonia, Latvia, Lithuania to be implemented prior to the EU accession. Technically this is achievable at reasonable costs due to the transmission lines that have been linking the three nations since the Soviet era, and are relatively modern.

An electricity regulator – the independent Energy Commission appointed by the President of the Republic – regulates electricity prices (indirectly – by establishing price calculation methodology and formulas) of those producers and suppliers which account for more than 25 % of the market. However, free users can buy electricity from whatever supplier at an agreed price. Other users ('non-free users') have to buy electricity at "public prices" from a public supplier – the distributor obliged to supply energy to non-free users in the respective territory. Maximum "public prices" are established by the Energy Commission, however, concrete prices below the established maximum ceiling are not regulated.

The transmission company maintains the monopoly position, however, maximum prices for transmission services, as well as for distribution services by the two separate distributors are established by the Energy Commission, based on the costs of the relevant companies.

The vertical integration between generation and transmission has been dissolved, and it seems that separation of power generation from its transmission and distribution up to now has proven quite successful. The transmission company and both distributors operate at a profit, as well as major generation companies, while the electricity prices remaining stable.

Market Structure and Market Rules

The total generation capacity in Lithuania is 6500 MW, and it is the double of the domestic demand for power. The transmission network, as well as major generating capacities, have been built up in Soviet times and today Lithuania runs power generation capacities by far exceeding national demand. Therefore there are no congestion problems and no need to expand capacities any further. However, any necessary expansion of the generation or transmission capacities is possible only upon the receipt of the licence from the Ministry of Economy

The main power generator is the Ignalina nuclear power plant with around 80% of the market share. The remaining 20% of the market are shared among five thermo-electric power plants and other smaller local power suppliers. Power transmission and distribution are separated from power generation activities. There is one transmission firm and two distributors.

There are actually no commercial imports. Imports are restricted by the law, and only the government or its authorized institution can issue the permission to import, provided that the exporting country has authorized the import of the same volumes of power from Lithuania. Exports destinations are mainly Belarus, Latvia, Russia and Estonia.

A market in wholesale electricity is now in the process of development. The law provides for a market operator which will be organizing a kind of electricity auctions. The market operator will also publicly announce the market-determined power price. However, the market operator (i.e. an electricity auction organizer) has not yet been selected. Also, up to this time, the secondary regulations defining rules by which energy trade is to be organized are still in the stage of drafting and deliberations, i.e. have not yet been adopted. It is not yet decided whether the participation in the spot market will be mandatory or voluntary. So the electricity exchange is in the early stage of its development.

Competition authorities have not dealt with any merger, or established collusive behaviour or abuse of a dominant position in this market, possibly, mainly because the separation of functions and establishment of independent business entities are very recent decisions, and, although there are several operators, in monopolistic sectors a rather extensive regulation of firms' activities remains in place.

NETHERLANDS

I followed the structure of your questionnaire. Except the questions related to new investment in generation: they are all placed under item 7 (Entry).

Overview of regulation

1. Structure of the electricity sector

Generation

The Netherlands depends on conventional thermal generation. Gasfired units account for 56% and coalfired units account for 22% respectively, of a total system capacity of a little more than 20.000 MW. However, in the liberalised market since 1998, there are no complete accurate data available of installed generation capacity.

Auto-producers, or “decentralised” power generation (mostly CHP-plants for the industry), account for 30% of the Dutch consumption.

Alternatives to conventional power plants are limited. The Netherlands has one nuclear plant (Borssele, 449 MW). The renewables sector is growing, but has still a very limited contribution. Annual growth in demand is about 2 %. Dutch import of electricity increased from 11% in 1998 to 20% of the national consumption in 2001. Peak consumption was 14.242 MW in 2001.

Transport

The independent system operator (TenneT) runs the national high voltage grid, provides system services and manages the interconnectors. TenneT, formerly owned by SEP, is fully unbundled. The Dutch State acquired 100% of TenneT in October 2001. TenneT takes care of some reserve capacity (550 MW). Distribution network operators, owned by regional and local authorities, run the regional lower voltage networks.

Access to the network is organised by regulated TPA.

Regulation

The independent Regulator (DTe) operates as a chamber of the Dutch Competition Authority (Nma). The Dte sets tariffs for transmission and distribution, recommends supply tariffs to the Ministry of Economic Affairs and also supervises general compliance with electricity regulations.

Market opening Policy

The Electricity Act of 1998 implements Directive 96/92 of the EU in respect of common rules for the internal Electricity market. The aim was to give consumers and suppliers the freedom of choice and to enhance competitiveness of the energy industry.

In 1998 the market for large consumers (industry, above 2 MW) was liberalised. Since July 1st 2001, all costumers are free to choose a supplier for so called green electricity. From the 1st of January 2002 all consumers between 3 x 80 Ampere and 2 MW are free to choose their suppliers. The remaining captive costumers are those with consumption beneath 3 x 80 Ampere. The planning is that the last segment (the households) of the electricity supply market will be deregulated in October 2003. During that period up to full liberalisation when there are still captive costumers, their supply requires a licence. The Netherlands are in respect to the time schedule of the opening of the market, beyond the requirements of the EU Directive.

Market Structure

The Dutch market for electricity generation has two components, a commodity market (over the counter and day ahead) and a real time balancing market. On the fully liberalised commodity market electricity is sold by generators. On the balancing market TenneT buys capacity to compensate for imbalances in the commodity market.

	Commodity market	Balancing market
Kind of market	Long Term and Day Ahead	Day Ahead, Adjustment, Real Time
Size	102 TWh/year	1 TWh/year
Market-Players	Generators, traders/ brokers/suppliers, consumers	TenneT, generators, consumers with disconnectable load
Means	Commodity capacity (more than 2000 hours/year) Import	Reserve commodity capacity Intra day import/export non-commodity capacity Disconnectable load

Factors affecting Market Power

2. Market Structure

In order to support the below mentioned remarks on the Market structure I enclosed a scheme of the Dutch electricity sector.

Generation

The introduction of competition in the construction of new generation capacity, by a tendering or an authorisation procedure as specified in the Directive, is not addressed under the Electricity Act 1998. The Electricity-Act 1998 does not impose any restrictions on the generation of electricity, which is considered a free economic activity, not subject to specific regulation. In the “SEP-period” (until 1998) SEP always made forecasts of the growth in demand for electricity. As the central organisation SEP worked out the program for building generating facilities, one of the criteria being the

“maximum” avoidance of inability to supply. With the above mentioned liberalisation and the fact that generation has become a free market, investments has become the responsibility of market players.

The four big generators together generate about 60 % of the total power supplied to the Dutch market. Foreign utilities (Reliant, Electrabel and E.ON) acquired three of the generators in 1999. Only one large generator, EPZ, remains in Dutch hands and is still a public company. The market is with four big players, concentrated. CHP is dominant in the industrial sector. It should be noticed that E.on and Electrabel have a dominant or at least an important position in their own countries, which happened to be neighbouring countries (Belgium and Germany).

Estimated capacity, Large scale and CHP:

EPZ (Essent, Netherlands)	22%
Electrabel (Belgium)	19%
Reliant (U.S.A.)	16%
E.on (Germany)	11%
Demkolec (Nuon, Netherlands)	1%

Decentral generation

CHP, auto-production	30%
Renewables	1,5%

There were no significant investments in large scale generation the last few years. Fuel costs are high, compared with prices in neighbouring markets.

Distribution

After significant Merger activities from 1998 to 2000, five large players now dominate the distribution sector of electricity. Essent (42%) Nuon (24%) Delta (13%) Eneco (9%) and Remu (4%), and a great number of small distribution companies. All these players are still owned by public parties.

Vertical integration

Vertical integration is limited in the Dutch market. Until recently only the Dutch distributor Essent was the only player active in both large-scale generation and costumer supply. The situation changed, because distributor Nuon has expanded his generation activities by purchasing the 225 MW Demkolec plant. Plans have been made by a joint venture of Shell/Nuon for an 800 MW CCGT, to be built in Rotterdam.

Unbundling

The distribution network operators have legally separated their distribution network from other commercial activities (retail, generation, etc.) This legal unbundling is mandatory. The members of the management board and the majority of the members of the advisory board shall have no direct or indirect affiliation tot any producer, supplier ore shareholder of the manager of the relevant network. The members of the supervisory board can only be nominated with the approval of the Minister. Shareholders of the grid manager shall refrain from any interference with the performance of the duties of the grid manager.

Privatisation

Privatisation rules allow 100% of the supply business to be sold.

An intensive discussion on privatisation of regional distribution companies has taken place since 1999. This resulted in Policy rules of the former Minister of Economic Affairs of July 2001. On the base of these policy rules 49% of the shares in regional network companies could be privatised. Recently the new Minister of Economic Affairs withdrew the proposal of privatisation (codification of the policy rules) on request of parliament. The minister changed course and proposed to parliament a temporarily hold on privatisation, until January 2004. In the meantime the legislation should be enforced. I.e. more power to the Minister in case grid managers neglect their duties, systematic review and control of performance of the grid manager, etc. In the End Tennet can be appointed a role as temporarily grid manager in cases other measures fail. If implemented the discussion of ownership is no longer relevant, due to the proposed strong regulation. This proposal will be discussed in Parliament on short notice. The new clear course is: "first liberalisation, than privatisation".

Stranded Costs

The electricity Production Sector Transition Act also foresees a mechanism for stranded costs recovery. A number of sources have above-market prices in a competitive market. These supply sources are District Heating contracts, Power purchase-agreements between producers and distributors, international power and gas purchase agreements and the coal gasification plant Demkolec. Dutch authorities have notified the European commission these stranded costs. On 25 July 2001 the European Commission decided that the Act was in accordance with the EU-treaty. Currently a proposal for amending the Act is sent to Parliament in order to finalise the financial completion

Import

Dutch import of electricity increased from 11% in 1998 to 20% of the national consumption in 2001. The Netherlands is a net importer. Almost all imported electricity comes from Germany, due to lower prices on the German market. Export is limited. Import is an important policy issue, also in relation with the security of supply, for obvious reasons. A project group at the Ministry of Economic Affairs investigates how to address this subject, in co-operation with Tennet and the Dte. Dutch Parliament will be informed on this issue by the end of this year.

Environment

The only requirement for the generators is the coal covenant, in which generators deploy the biomass capacity of 475 MW at the existing plants by 2010. This should result in a reduction of Co2-emissions by 3 Mton a year.

Transparency

The Dutch Electricity market transparency is lacking in several respects. The Ministry of Economic Affairs reviews this issue carefully. In the liberalised market no accurate information is available on installed capacity, planned maintenance outages, etc. Therefore, in the interest of providing a level playing field for all participants, you can suggest that information about installed capacity should be made available to the market and to TenneT in a non-discriminatory way. System load information about overall supply and demand is necessary in order to evaluate the evolution of the market and forecast future

developments. The Minister of Economic affairs is preparing a position on this issue and will address this issue in a letter to Dutch Parliament end 2002.

The Dte has the right based on the electricity act to collect all the necessary information from generators, traders, suppliers and grid operators. The Dte can only collect the information required for the performance of its duties.

3. *Congestion and pricing of the Transmission Network*

Transmission congestion within Dutch borders is unlikely, so the Dutch market design treats transmission as a “copper plate” on which a “postage stamp” tariff is applied to users of the transmission network. At the moment nodal or zonal prices are being considered for the longer term - please refer to the consultation document ‘Evaluatie TarievenCode’ on the website www.dte.nl of the Dutch Energy regulator. **On the same website** a description of the current tariff structure for connecting to the transmission network, transport and system services can be found in the Tariff Code.

Maximum price levels for transmission are set by de Dte.

Nevertheless, a large share (around 20%) of Dutch power consumption is served by foreign generation, which leads to frequent congestion on the Dutch-German and to a lesser extent Dutch-Belgian borders. Part of this capacity was allocated before restructuring of the power sector to firm transmission capacity rights for long term contracts, mostly with French and German nuclear units. The remaining capacity is allocated to market parties through explicit auctions for firm capacity rights in year, month, and day (one-hour blocks, day-ahead) auctions (see below).

To mitigate market power the following actions were taken:

- capacity obtained on the year and month auctions not nominated one day in advance is returned to the day auction
- capacity obtained on the day auction must be matched by trades on the APX (i.e. may not be used for bilateral deals) total import capacity for any market participant is restricted to 400 MW

Financial transmission rights or contracts for difference do not exist on the Dutch borders. This limits the possibility of (new) cross-border bilateral contracts with a contract length longer than one year.

The Auction

As said before there is congestion at the interconnectors with Germany and sometimes at the interconnectors with Belgium. Therefore the four concerning Transmission System Operators decided upon the joint auctioning of cross border electricity transfer capacity in 2000. The four TSOs are the Belgian ELIA NV, the Dutch TenneT and RWE Net and E.on Netz from Germany. TSO Auction (daughter of TenneT) auctions the available cross-border electricity transfer capacity in three different kinds of auctions, namely the Day, Month and Year Auction. Above-mentioned auctions include the auctioning of capacity in each of both directions of each of the Interconnections. In order to use the total available capacity it is possible to return or to transfer obtained capacity. When a participant has obtained capacity at the Month or Year Auction, which they do not wish to use, the participant can transfer the capacity (or a part of it) to another registered participant or resell capacity to the Auction Office. Capacity from resells will if possible be added to the capacity for the Month Auction otherwise for the Day Auction.

The revenues of the capacity that has been sold back to the Auction Office benefit the original participant. The revenue of the auction has to be invested in new interconnection capacity.

Expand of the capacity available on the interconnectors is planned. At the moment the capacity is 3650 MW. Plans for expansion will, if no problems occur, result in a capacity of 4600 MW in March 2003, and 5000 MW in June 2003.

The grid manager is responsible for the condition of the regional network. According to article 16 of the Electricity Act, the grid manager in the area assigned to him, shall have the duty: (a) to ensure the operation and maintenance of the grids managed by him;(b) to ensure the safety and reliability of the grids and of the transmission of electricity across the grids; (c) to construct, repair, replace or extend the grids;(d) to maintain sufficient reserve capacity for the transmission of electricity. The Grid Manager draws up capacity plans every two years, for seven years ahead. They describe the expected growth of electricity transport and planned measures (maintenance, investments) to be taken by the grid manager. The Grid Manager can in the end be forced to invest in the network. The Minister of Economic affairs has the right to appoint another company as grid Manager if the Grid manager fails to fulfil his duty.

Only for the construction of cross border capacity other parties than the grid manager or Tennet can be involved in construction. Of course Tennet can ask third parties to construct new grids within the Netherlands, but the management, finance and the full responsibility remains in the hands of Tennet (national grid) or the grid manager (regional grid).

4. *Market Rules*

Buyers and sellers mostly sign bilateral contracts (The Over The Counter-market, OTC). The spot market in the Netherlands is voluntary. The daily spot market (APX) has been operational since May 25, 1999. The spot market enables producers, distribution companies, traders, large consumers and industrial end-users to buy and sell electricity on a day-ahead basis. The transaction limit is low, 0.1 MW/h. The bids are price/quantity pairs. As of early 2002, 15% of the Dutch electricity consumption is traded on the spot market of APX. The market is an Day-Ahead-Market, based on the two side auction model. On the basis of the submitted bids demand and supply are compared on a daily basis. Classification in merit order along with matching, results in a price for every hour for delivery the next day. Based on these results, the APX-index is determined on a daily basis. To serve market players, the APX publishes a volume weighted and time average for base load anoff peak hours. The index can be used as a reference price for spot electricity.

5. *Bilateral, Long-Term and Forward Contracts*

The regulatory regime does not promote the use of long term or forward contracts for the sale and purchase of electricity. This is fully left to the market

6. *Price or Quantity Controls*

Electricity prices are determined in the free market and therefore are not regulated. There is no control on prices that firms can charge on the wholesale market.

There are no specific rules governing when firms withdraw capacity from the market. Rules of play have been formulated for the purpose of safeguarding the performance of the market; the government has these monitored by the Dte. The so-called Programme Responsibility is a prominent instrument used in ensuring the correct settlement of power transactions in the free power market. TenneT is charged with a

central task in the operational implementation of Programme Responsibility. Rules of play are needed in order to ensure the proper performance of free trade involving a system-defined commodity such as electricity. All players have to comply with specific procedures and codes, or the whole system is bound to grind to a halt. Grid companies provide for actual power transmission, infrastructure and dissemination of information. They must have an insight into electricity transactions overall, and must be able to intervene whenever bottlenecks are threatening. This means that they have day-to-day responsibility for striking the right balance, in a technical sense, of the demand and supply having been generated by the market. Preservation of the balance within the system is crucial: it is imperative that the requirement should always be in harmony with what can be supplied. This makes it essential that all scheduled transactions shall actually be carried out. The transactions entered into by generation and distribution companies, traders, brokers and customers - including those being routed through the APX - are included in programmes (quantity, timeframe, from which party, to which party) which are required to be reported to the grid companies one day ahead. Deviations from the programme prompt power transactions to be engaged into with the TSO, which monitors the power balance within the system as such, and have financial consequences. This obligation to report scheduled transactions on a daily basis has been laid down in the above-mentioned instrument entitled Programme Responsibility.

The Ministry of Economic affairs is, as said before, in progress to create a mechanism to collect the necessary information from the generators, in order to make the market more transparent. Results will be published in a letter to Dutch Parliament.

7. *Entry*

There is no mechanism designed to enhance investment in generation. The market price, among other factors, provides the incentive for new investment. The development of the available production is the outcome of what market parties undertake in this regard. The Ministry of Economic Affairs is investigating at the moment the investment climate for electricity production in the Netherlands compared to other European countries. Reason for that is the -possible- trend towards under investment in a free European market in relation with national security of supply.

For all construction purposes for new generation an authorisation procedure applies in which the Ministry of Economic Affairs has no role to play. Depending on the scale of the project, the authorisations needed are being dealt with either by the Ministry of Housing, Spatial Planning and Environment or by lower authorities, depending on the size of the project.

There has been no significant new entry in recent years. Plans have been made by a joint venture of Nuon/Shell (Intergen) for an 800 MW CCGT plant to be built in Rotterdam. Delta made plans as well, but a start to implement them has not been made yet.

8. *Competition Law Enforcement*

The NMa supervises competition and concentration in the electricity sector Mergers. In the so called "SEP-period" in the mid- nineties initial steps toward a merger of the four large centralised generators had been taken. In 1998, a new competition law was adopted and the NMa carried out an initial investigation to the merger. Its initial ruling concluded that the merger would have significant potential to limit competition in the Dutch power market, for obvious reasons. (the four companies have a market share over 60%). The merger was abandoned in April 1998.

The NMa concluded in April this year that the Dutch electricity market is a national market, and mergers have to be judged according to Dutch competition Law.

Market surveillance

The Dutch Market Surveillance Committee (hereafter: 'the MSC') is a committee which is set up by the Dte'. The MSC functions under the responsibility of the NMa. The main task of the MSC is to obtain empirical facts and provide accurate analyses of the actual functioning of the Dutch electricity market, especially with respect to the electricity price development and including the behaviour of individual market parties active on this market. The MSC will focus on an economic analysis of the Dutch electricity market. The MSC is thus primarily concerned to monitor how well the various electricity markets are working and to make sure no one company enjoys an unfair advantage.

There was an investigation that resulted in a report by the Market Surveillance Committee (MSC) on price peaks on the electricity exchange, Amsterdam Power Exchange (APX), in June and July 2001. Although MSC concluded that individual market players may exert considerable influence on prices in periods of scarce supply, this extensive research did not provide concrete evidence of possible price manipulation by individual players in the period studied. In its report, MSC attributed the cause of the price peaks to unforeseen disruptions to service at production plants in the Netherlands and Belgium. As a result, the supply on the electricity market was much lower than normal in the period June - July 2001. In addition, electricity producers were confronted with restrictions on discharges of cooling water imposed by the Department of Public Works and Water Management during this period and by high costs associated with the unforeseen procurement of large quantities of gas. Consequently it was unattractive for electricity producers to meet the unexpected peaks in demand. As a result, gas-fired power stations, which come on line during daytime peak hours and whose capacity is not fully utilised, could not be utilised optimally.

In the same report by the market surveillance committee on the price spikes in June and July, the degree of market dominance was discussed. Reasons for concern were the high degree of concentration of ownership of power generation assets – four players own 68% of domestic generation – and the dependence on imports. This is aggravated by the fact that two of the four large generators are subsidiaries of the vertically integrated foreign utilities that control the cross-border transmission grid to the Netherlands. The investigations led to the conclusion that while in periods of scarcity individual players might have some influence on prices, the MSC could not substantiate claims of abuse of a dominant position, and did not advise the competition authority NMa to start a formal investigation into this matter.

In an earlier instance, Nma carried out an investigation w.r.t. abuse of market power on the basis of a complaint against SEP, the former co-operation of generating companies, case 650/Hydro Energy vs. SEP. The complaint was from the company Norsk Hydro Energy BV. The complaint was that SEP refused to transport imported energy for Hydro Energy from Maasbracht to Borssele, and that it required that Hydro Energy reveal the identity of parties it wanted to supply. Furthermore the complaint was that SEP breached article 6 (“collusion”) by demanding that Hydro Energy would not supply to distribution companies, effectively trying agree to divide the market.

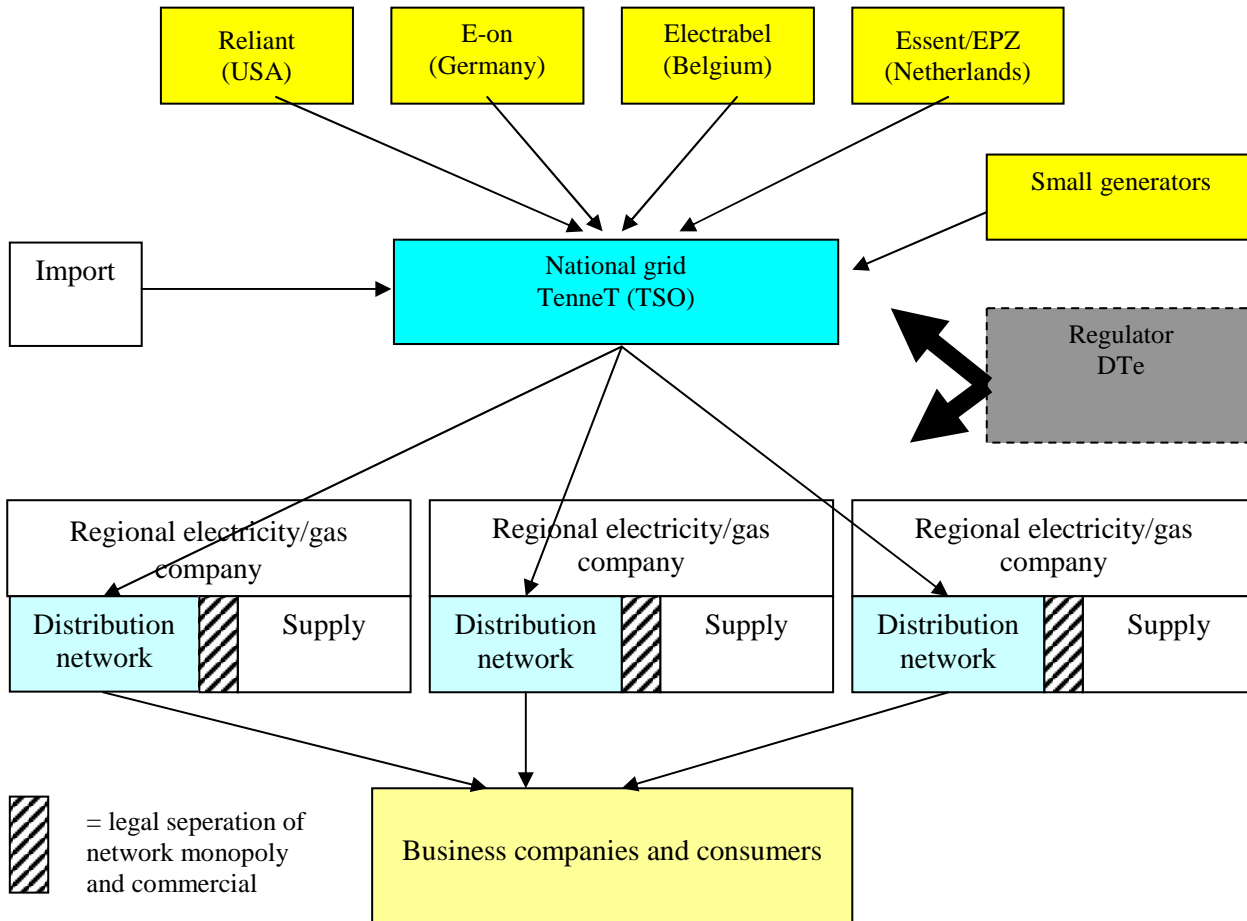
The ruling was that

- SEP was in breach of article 24 (abuse of market power)
- SEP did not violate article 6 (“collusion”)

At the request of NMa and DTe, MSC will continue to monitor the electricity market closely. For instance, MSC will carry out further research into the market power of individual market players on the energy markets and identify obstacles to the optimal operation of market forces.

Electricitymarket

DAFFE/COMP(2003)14



Generation companies: 4 big companies and many small ones:

- fully liberalised market/no license
- ownership: 75% in foreign private hands

TenneT is the Dutch TSO and operates the Dutch national grid:

- monopoly with regulation of tariffs and quality by DTe
- ownership: 100% State owned since 2001

Regional electricity companies: 4 big companies (Essent, Nuon, Eneco and Remu) and a number of small ones:

- monopoly with regulation of tariffs and quality by DTe
- supply of captives until October 2003
- ownership: almost all companies owned by regional and local authorities
- also active in commercial supply

Supply to consumers:

- large and middle large consumers are non-captive
- total market share is over 60%
- small consumers free in October 2003

Regulator DTe regulates:

- quality and tariffs of network operation by TenneT and REC's
- legal separation of monopoly and commercial functions

Indicated are the fysical flows relevant for security of supply. Besides these, there are also brokers and commercial supply companies operating on the market. The Netherlands also has a (voluntary) electricity exchange (APX).

NEW ZEALAND

Question 1: Overview

The New Zealand Electricity Industry has been through major structural reform moving from a largely state-owned centrally controlled system, to a market based competitive model.

The total generation “nameplate” capacity of the system is approximately 8,400 MW, although actual capacity can vary widely depending upon the availability of water for hydro generation. New Zealand is heavily dependent on hydro which makes up 61% of generation capacity, followed by gas (27%), geothermal (5%) and coal (3.5%). The remaining 3.5% is made up of steam, wood, wind and biogas.

Generation is dominated by four major players, State-owned Genesis Power, Meridian Energy and Mighty River Power and privately owned Contact Energy. Generators also dominate the retail market. State-owned Transpower provides transmission services. Power transmission between the North Island (the source of most demand) and the South Island (where the bulk of hydro electricity is generated) is via a high voltage direct current (HVDC) link. There are 29 regional distribution companies.

Although vertical integration between generation and retail is allowed, the Electricity Industry Reform Act 1998 required the split of distribution from generation and supply. At this time most electricity distribution companies decided to retain ownership of their line business and sell their energy business. However a subsequent amendment allows distribution companies to invest in new renewable sources of distributed generation.

Further investment in generation is currently constrained by an uncertainty surrounding the future supply of natural gas following announcements that the Maui gas field (the source of approximately 75% of gross gas production in 2001) would be depleted in 2007, two years ahead of schedule. In addition the Resource Management Act 1991 requires potential generators to undergo a stringent consent process. Nonetheless there are two major generation projects on the horizon, Genesis’ proposed Combined Cycle Gas Plant at Huntly in the North Island and Meridian’s hydro “Project Aqua” in the South.

The sale and purchase of wholesale electricity is organised by the participants in a private sector wholesale market operated by the Marketplace Company (M-co). Spot prices are set half-hourly (two hours in advance) to match supply with demand. Generators and buyers also hedge against spot prices for a part of their supply and demand.

Industrial use accounts for 44% of electricity demand, followed by residential (33%) and commercial (23%). The production of aluminium, the agricultural sector and the pulp and paper industry are the largest sources of demand. The largest single user is Comalco New Zealand Limited which operates an aluminium smelter at Tiwai Point at the bottom of the South Island. Comalco obtains its electricity supply through a long-term contractual relationship with Meridian Energy.

Rising demand, especially in the upper North Island, has led to the emergence of a number of transmission constraints at peak times, these constraints led to occasional spikes in the nodal price at the point of constraint. Transpower is currently looking at methods to address these issues.

Following a Ministerial Inquiry into the Electricity Industry (June 2000), the Government released a Policy Statement (GPS) setting out the Government's expectations for industry action and its views on governance matters. A key expectation is that the industry will establish an independent Electricity Governance Board, which will be responsible for industry rules including aspects of the wholesale market, transmission, distribution and retail. In response, the industry has created an Electricity Governance Establishment Committee to establish a single governance structure for the electricity industry based on a new multilateral contract, and to establish an Electricity Governance Board (EGB) as the primary governing board of the new arrangement. The EGB is expected to be operational by early 2003.

The Government has regulatory powers to establish a Crown EGB and take responsibility for setting industry rules in order to meet the requirements of the GPS if the industry fails to do so.

The Commerce Amendment Act (No 2) 2001 gives the Commerce Commission responsibility for regulating natural monopoly lines companies with regard to prices, service quality and rates of return. The Commission has the ability to impose price control using any appropriate method.

Overall, the New Zealand electricity industry is best described as regulated by a "light handed" regime with very few legislative and Government restrictions. In addition to the industry specific legislation mentioned above, the industry is also regulated by general law such as the Resource Management Act 1991, the Commerce Act 1986 and the Fair Trading Act 1986.

Question 2: Market Structure

Electricity generation is dominated by four major players, who combined make up 79% of total generation. These are state-owned Meridian Energy, Genesis Power, and Mighty River Power and privately owned Contact Energy.

The state-owned generators were formed following the split of the Electricity Corporation of New Zealand (ECNZ) in 1999. Contact was originally split from ECNZ in 1996 before being privatised in May 1999.

Meridian Energy is New Zealand's largest generator, with 2,300 MW of hydro generation in the South Island, representing 28% of New Zealand's total generation capacity. Genesis Power's (19%) main generation capability comes from a 1000 MW gas or coal fired plant at Huntly and 500 MW of hydro in the central North Island. Like Meridian, Mighty River Power (15%) is predominantly a hydro generator with over 1000 MW of hydro capacity in the central North Island.

Contact Energy (24%) is a publicly listed company with Mission Energy Pacific Holdings, a subsidiary of US company Edison Mission Energy, owning approximately 49% of the company. Contact have arguably the most balanced generation portfolio with a mixture of geothermal, gas and hydro generation and are the only major player to have generation assets in both the North and South Islands. Other companies involved in electricity generation include TrustPower, NGC¹ and Todd Energy.

Hydro generators typically meet base load generation, although Genesis' gas or coal fired Huntly plant is increasingly operating as a baseload generator for the northern regions. The marginal generators, those which determine the spot price of electricity, tend to be gas fired plants.

There is a significant degree of vertical integration between generation and retail, with companies seeking to internally hedge against price spikes. The events of winter 2001, where hydro shortages, brought about by abnormally low hydrological inflows, caused significant increases in spot prices, and the subsequent demise of a major retailer, On Energy, has increased incentives for generators to balance their

generation – retail portfolio. The sale of On Energy’s northern customers to Genesis and southern customers to Meridian led to increased “regionalisation” with generators preferring to retail in areas close to their source of generation. Nonetheless, in part due to directives from Government, the level of retail competition has improved with most of the population having the choice of at least three retailers.

The Electricity Industry Reform Act 1998 mandates that line businesses are to be owned separately from retail and generation businesses. At the time of separation most electricity companies decide to retain ownership of their line business and sell their retail business. There are now 29 regional lines companies operating in New Zealand with the largest, publicly listed United Networks, recently announcing its intentions to exit the market. The Electricity Industry Reform Amendment Act 2001 makes provision to allow line businesses to invest in new distributed generation from renewable energy sources.

Question 3: Congestion and Pricing of the Transmission Network

Which components of the transmission network are sometimes congested? Under what conditions are these components congested?

The power transfer constraints that have a significant impact on supply security are:

- Power transfer to the upper half of the North Island, and in particular
- Power transfer to the north of Henderson (just north of Auckland)

There are also security issues (i.e. congestion) in supplying a number of regions and supply buses under certain conditions. These are:

- Power transfer to the Bay of Plenty region (an area which has seen rapid growth in energy-intensive forestry related industries)
- Power transfer to the Hawke’s Bay region
- Power transfer through the Wellington region to the HVDC link between the islands.

See Transpower’s *System Security Forecast 2001/02* at <http://www.transpower.co.nz> for further details, and in particular for further information on the conditions under which these security issues arise.

Under normal conditions, the grid transfers electricity from south (where most generation is located) to north (where most load is located). The grid is designed to do this reasonably efficiently. However, in the winter of 2001 low lake levels in the South Island required the transmission system to work “in reverse” transferring energy north to south. This caused transmission congestion in a number of different locations.

What are the consequences of this congestion – in particular, does the congestion facilitate market power? If so, for which generators?

Transmission constraints mean that prices on different sides of the constraint can be quite different. Constraints can facilitate market power, particularly when all significant generation downstream from a constraint is owned by one company. This problem arises most prominently when there are constraints into the Bay of Plenty region. There is only one generation owner, Mighty River Power, that

owns generation behind that constraint. There have been allegations that generators have exercised market power to push up nodal prices behind constraints (particularly during generation or transmission outages). The extent to which this market power is inefficient or inappropriate is unclear since price spikes signal the need for further investment in generation or transmission in constrained locations.

How do you price access to the transmission network (for example, do you use “nodal” or “zonal” prices)?

New Zealand uses nodal prices. Nodal prices are designed to represent the short run marginal cost of delivered energy to each node² including the marginal effect of transmission losses and constraints. Transmission sunk and fixed costs are recovered from offtake customers on the basis of their Anytime Maximum Demand (AMD), which is the average of their highest 12 half-hourly peaks during the preceding 12 months³. Further information is available at www.transpower.co.nz.

At present there is no financial transmission rights mechanism, however Government is currently discussing with industry the possibility such a mechanism being introduced.

Does how you price access to the transmission network affect the level of market power?

It could be argued that the nodal pricing regime gives too much market power to generators with localised market power during a constraint. However, as explained above, the extent to which this market power is inappropriate is unclear.

Are there market instruments which allow the market players to hedge against movements in the prices for access to the transmission network (for example, so-called “financial transmission rights”)? Do these instruments affect the incentives to exercise market power?

Financial transmission rights (FTRs) funded by transmission rentals are currently under development in New Zealand although they have not yet been implemented. The Government has drafted a Government Policy Statement on Financial Transmission Rights for consultation with industry and consumers. Details of the policy statement and consultation are available at <http://www.med.govt.nz/ers/electric/fttr/index.html>. The statement is likely to be finalised shortly.

Transpower (the grid owner and operator) originally planned to auction FTRs although objections were raised based on allegations that the auction would provide an additional incentive to generators to exercise market power, particularly in regions subject to transmission constraints (such as the Bay of Plenty). The Government’s latest draft policy statement (which outlines the Government’s expectations for the development of FTRs) contains the idea of allocating FTRs using a non-market mechanism with the possibility in some cases of FTRs being sold back into an auction. This could potentially reduce the incentive for generators to exercise market power.

What are the incentives faced by generators when choosing where to locate? Do generators have incentives to make efficient location decisions? Where has most new generation been constructed?

Generators have an incentive to locate where they will receive the highest possible nodal price. This provides an incentive to locate downstream of constraints and in locations close to load (so that losses are reduced).

The availability of fuel sources (namely water and gas) is a primary determinant of location. Two major generation projects on the horizon are Genesis' gas plant to be located at Huntly (close to the major load at Auckland and at the end of a major gas pipeline) and Meridian's hydro "project aqua" to be located on the Waitaki River in the South Island. However, as the use of new generation technologies, such as wind, becomes more widespread and smaller scale embedded generation technologies become more cost effective, the opportunity to invest in generation plant near the source of demand will increase.

Are there special rules governing import/export transmission lines? Are these lines congested...? How is access to these transmission links rationed...? Do you auction the capacity of these links?

There are no import/export transmission lines into/out of New Zealand.

Which firms have the ability to upgrade the transmission network to relieve congestion (through the construction of new links or through the enhancement of existing links)? For example, is this the sole responsibility of the transmission network operator, or can independent firms construct new pipelines? What are the incentives on these firms to upgrade the transmission network in this way?

Transpower has the sole ability to upgrade their transmission network, although other companies can build separate transmission assets (they have to meet Transpower's requirements for connection if they want to connect to Transpower's grid).

At present, Transpower will invest in new transmission assets only if it can obtain satisfactory contracts to cover the cost of the new investment. This process is fraught with "free rider" problems. In addition, without FTRs there is no mechanism to protect an investor against the line becoming re-constrained.

Under proposed new arrangements, an independent Electricity Governance Board will be able to require Transpower to invest in new transmission assets and will be able to require beneficiaries to pay for the investment (if contractual arrangements can not be settled).

Question 4: Market Rules

The New Zealand Electricity Market (NZEM) is a voluntary, self-regulating, multi-lateral trading contract where most (70-80%) of New Zealand's wholesale electricity sales are transacted. NZEM was established in 1996 as a mechanism to ascertain or "discover" the price of electricity. Through NZEM a price is established half-hourly (two hours in advance) on the basis of forecast supply and demand for each of the 48 half-hour trading periods every day, at 244 grid connection points around New Zealand. The price at each of these points incorporates the cost variation of electricity transmission owing to location, system security and constraints. The final spot price at each node is set ex post and represents the marginal cost of delivered energy to each node established by solving a constrained optimisation program, which aims to minimise the overall cost of meeting demand (given generator's offers and demand-side bids). Included within a generator's offer into the "pool" are price, quantity and the ramp up rate at which the generator is able to deliver. Retailers then buy electricity from this pool to supply their customers. There are no mechanisms for capacity payments and the market price provides the only incentive for new investment.

Although NZEM is voluntary and self regulated, its "Guiding Principles" were developed in consultation with Government. The Guiding Principles state NZEM should: Foster efficient and competitive markets; enable the entry of new buyers and sellers; comply with law; be robust and

enforceable; and maintain a process to set and change rules. The NZEM rules impose a self-regulating structure, with mechanisms for selecting a governance board, making rules changes, resolving disputes and enforcing rules. The Rules cover every aspect of trading, from Market Participant entry criteria to physical electricity dispatch. They also include procedures for receiving bids and offers and financially settling transactions between Market Participants.

NZEM is unique in that it is a market with a disciplinary and monitoring committee created by contract, rather than by Government regulation. The Market Surveillance Committee is an elected body of independent members charged with the surveillance and compliance of NZEM rules.

Often described as being subject to “light handed” regulation, New Zealand’s electricity industry has very few legislative and Government restrictions. In addition to industry specific legislation, general regulation also applies.

Question 5: Bilateral, Long-Term and Forward Contracts

Although some 80% of all power is traded on the spot market, a number of bilateral contracts exist between generator/retailers and consumers, the most notable being Meridian Energy’s contract with major user Comalco New Zealand Limited which operates an aluminium smelter at Tiwai Point at the bottom of the South Island. Comalco is one of a small number of consumers who have direct supply from the transmission grid. Many industrial and commercial consumers enter into long term (1,2,3 years +) hedge contracts with retailers, indicative c/kWh prices of fixed price contracts including hedge contracts can be found at www.comitfree.co.nz. Market power is not adversely affected by the existence of such contracts.

Question 6: Price or Quantity Controls

As described above, wholesale electricity prices are set through a market mechanism, and are not subject to price regulation. An expectation of the Government as set out in the Government Policy Statement on Electricity, is that the full costs of producing and transporting each additional unit of electricity are signalled, so that investors and consumers can make decisions consistent with obtaining the most value from electricity. This is effectively an endorsement of the principal of marginal cost pricing.

The NZEM rules discussed above cover every aspect of trading, from Market Participant entry criteria to physical electricity dispatch. They also include procedures for receiving bids and offers and financially settling transactions.

Question 7: Entry

There are no rules designed explicitly to encourage or discourage new entry into generation, and there are no requirements to maintain reserve capacity.

Although electricity generation remains dominated by the original four companies formed from ECNZ (Genesis, Meridian, Mighty River Power and Contact). In all there are a total of 13 companies with at least 6 MW of generation capacity currently in the market, using a wide variety of fuel sources including natural gas, coal, hydro, geothermal, landfill gas, co-generation and wind.

The lack of new investment in major generation projects reflects that until recently New Zealand has been in a period of excess supply over demand.

The Electricity Industry Reform Act 1998 imposed a forced separation of lines and supply (generation/retail) businesses, the Electricity Industry Reform Amendment Act 2001 subsequently relaxed this requirement, allowing lines companies to invest in embedded new (excluding hydro and geothermal) renewable generation.

Question 8: Competition Law Enforcement

Competition Law enforcement is the responsibility of an independent body, the Commerce Commission.

In 1999 TransAlta (an electricity generator/retailer and gas distributor/retailer) was cleared to acquire 40% of Contact Energy (an electricity generator/retailer and gas wholesaler/retailer). In the event TransAlta was unsuccessful.

Since that time the Commerce Act has been amended to strengthen the control of business acquisitions by replacing the existing “dominance” test with the stronger “substantially lessening competition” test.

Chris Fleming
Policy Analyst

NOTES

1. NGC are currently trying to divest of their generation assets in order to concentrate on their gas distribution business.
2. However, generators with market power may influence nodal prices through their offers, in which case the nodal price will not represent short run marginal cost.
3. There is an exception for the HVDC link (those sunk and fixed costs are recovered from South Island generators) and for “connection assets” (i.e. spur lines), for which costs are recovered from the offtake and injection customers served by each connection asset.

NORWAY

1. Overview of Regulation

Generation, transmission and sales are the three basic commercial functions of the power supply system. The 1990 Energy Act sets out framework for the organization of the power supply system in Norway. It encourages competition within power generation and trading and it provides the legal basis for regulation of grid management and operations. The Energy Act also provided the legislative framework for reorganization of the power supply sector in Norway.

In 1992, as a result of the Energy Act, the state-owned administration company Statkraftverkene was divided into two independent state-owned enterprises, Statkraft SF and Statnett SF. Statkraft operates in the competition-based market for generation of power (power stations), whilst Statnett runs the monopoly-based transmission grid of power and has nation-wide system responsibility.

In 1993, Statnett Marked AS was formed as a wholly owned subsidiary of Statnett and put in charge of the Norwegian power exchange. In 1996, Norway and Sweden set up a common market for electricity. Statnett Marked AS expanded its area of operations and was renamed Nord Pool ASA. Svenska Kraftnät became a co-owner of Nord Pool ASA – the Nordic Power Exchange – which means that Statnett and Svenska Kraftnät each own 50 per cent of the Nordic power exchange, and operate a common power exchange for the Nordic region. Later both Finland and Denmark joined the common market. Nord Pool is the world's only multinational exchange for trading electric power. From 2002 Nord Pool Spot AS, owned equally by Nord Pool ASA and each of the Nordic system operators, operates the physical day-ahead spot market.

The authority to make decisions pursuant to the Energy Act has largely been delegated to the Norwegian Water Resources and Energy Directorate (NVE). Because the grid is a natural monopoly, consumers are obliged to buy grid services from the owner of the local grid. The NVE is responsible for monitoring and regulating grid management and operations. The NVE is a subordinate to the Ministry of Petroleum and Energy.

The regulatory authority of Nord Pool ASA, which has received license as a commodity clearing house in September 2001, is the Banking, Insurance and Securities Commission of Norway. The Commission is subordinated to the Ministry of Finance.

The regulatory authority of Nord Pool Spot AS, which has received license as power exchange in physical electricity, is the Norwegian Water Resources and Energy Directorate (NVE).

The Norwegian Competition Authority (NCA) is responsible for supervising competition in all domestic markets, including the market for electricity. The NCA is subordinate to the Ministry of Labour and Government Administration.

Hydropower accounts for 99 per cent of the electricity generated in Norway. A total of 156 companies are engaged in Norwegian electricity generation. There are 857 power plants with a total installed capacity of 27507 MW. The mean annual production capacity is 117.6 TWh/year based on the installed production capacity and the average precipitation. Statkraft SF is the largest producer in Norway. The other production companies are relatively small.

Sweden and Finland have reformed their power markets according to the same principles as the Norwegian 1990 Energy Act. Norway, Sweden, Finland and Denmark¹ now have one common wholesale power market.

There are several grid companies in Norway. A grid company may own a local, regional or central grid. In all, 178 companies are engaged in grid management and operations at one or more levels. Of these, 42 are solely grid operators companies, whereas the remaining companies are also engaged in electricity generation and/or trading. Most grid companies are wholly or partly owned by one or more municipalities. Statnett SF, which owns about 87 per cent of the central transmission grid, is state-owned. It is the operator of the entire central grid.

In all, 136 companies are engaged both in operations that are exposed to competition (production and/or trading) and in grid management and operations. The vertically integrated utilities include 76 limited companies.

Vertically integrated companies are required to keep separate accounts for monopoly and competitive operations. The aim is to ensure that no cross-subsidisation takes place, i.e. production and sales of electricity must not be financed by means from grid management and operations.

Monitoring and regulating monopoly operations involves two main activities. Firstly, the NVE determines an income cap for each grid-owner. This is done to ensure efficient maintenance and development of the grid, and correct pricing of grid services towards customers. Secondly, NVE determines how the point tariff structure must be developed. Point tariffs mean that a grid customer pays the same transmission charge regardless of whom electricity is bought from or sold to.

NVE determines an income cap for each grid company. The regulation of income caps was introduced 1. January 1997. The income cap reflects historic cost-levels and are adjusted by CPI, cost-drivers reflecting demand growth and factors that reflect relative efficiency and general productivity growth. The company's income, which depends on the point tariffs, must not be higher than the cap determined by NVE. The system is intended to ensure that grid companies do not make unreasonable profits on monopoly services and that cost reduction benefits their customers.

Trading companies buy power in the spot and derivatives market for resale to end-users. This corresponds fairly closely to the trading activities of traditional distribution utilities.

In addition to the traditional actors in the power supply sector, other companies have also started sales of electricity, for example oil companies. In all, there are 218 companies engaged in trading, and 68 of them are not involved in any other activities. Most trading companies are organized as limited companies.

The trading companies operate at two levels of the electricity market; the wholesale electricity market and the end-user market for electricity.

The wholesale electricity market

In the wholesale electricity market, producers, grid companies, large industrial enterprises and other large actors buy and sell electricity. Electricity is either traded bilaterally between market actors or on the commodity exchange for electricity: Nord Pool, the Nordic power exchange. A number of electricity transactions are standard bilateral contracts, which is still the main instrument for selling and buying electricity. But a growing proportion of contracts are traded in Nord Pool's markets. Nord Pool organizes the physical spot market Elspot and the financial derivatives market.

While most of the physical trade between the Nordic countries occur on Nord Pool Spot's Elspot market, financial contracts may also be arranged bilaterally between actors in the various countries. Elspot is the market for physical trading of electricity for delivery the following day. Prices for sales and purchases are determined hourly throughout the day. Each participant bids a price/quantity curve for each individual hour of the day. The price/quantity curve provides information on how much the participant wants to produce or consume at given price levels. These bids are not observable for any player except the Exchange. Based on the aggregation of all supply and demand curves, Nord Pool determines the equilibrium price, also known as the system price. This is then the spot price for physical delivery of electricity, equal in Norway, Sweden, Finland and Denmark. The system price is also used as a reference price for trade in the electricity derivatives market.

The Elspot market has an important function in relation to how Statnett fulfils its responsibility as system operator, i.e. to ensure a balance between electricity generation, consumption and power exchange with other countries. The Elspot market fulfils this important function in the other Nordic countries as well.

The System price is determined based on supply and demand in the Nordic region, without regard for physical capacity limits in the transmission grid. However, the Nordic transmission grid has capacity limits, and trade on Elspot will in certain time periods generate congestions in the transmission grid, so-called bottlenecks. Nord Pool handles bottle necks by separating the market into different price areas (Elspot areas).

If contractual flow exceeds a grid capacity limit, two or more price areas are calculated for each affected spot market delivery hour.

For the time being, Norway is divided into two price areas: NO1 (South Norway) and NO2 (Middle and North Norway). The other "permanent" price areas in the Nord Pool area are Sweden, Finland, East Denmark and West Denmark. Occasional and short-term congestions inside the price areas are managed by the system operators applying counter-trading, that is paying generators to regulate up or down to releave the congestion. When transmission capacity between the bidding areas does not bind, the NCA considers that the relevant market for wholesale electricity includes Norway, Sweden, Finland and Denmark. When capacity binds, price areas and combinations of price areas have been considered relevant markets.

Comparing the players in the Nordic generation market, Norway has the least concentrated market. In comparison, the Swedish market has three companies owning more or less all generation capacity, and in Denmark there are two companies with significant generation capacity (for further details see chapter 2).

The end-user market for electricity

Anyone who buys electricity for his own use is an end-user. Small end-users normally buy electricity from a trading company or a distribution utility. Large end- users, for example industrial enterprises, buy directly in the wholesale market. The end-user price of electricity is made up of several components: the price of consumed electricity, a network charge, the electricity tax and VAT. The electricity tax is imposed on all electricity consumed in Norway, independent of where it is produced. Manufacturing industries, mining and quarrying, and greenhouse nurseries are exempt from the tax. Household customers in the county Finnmark and parts of northern county Troms are also exempt. Households in the counties Nordland, Troms and Finnmark are also exempt from VAT on electricity. The price of consumed electricity and the network charge must be separated on the bill.

The taxes on electricity have risen rapidly in recent years. In 1999, the electricity tax was NOK 0,0594 per kWh and VAT was 23 per cent. In 2000, the electricity tax was NOK 0,0856 per kWh. In 2002 the electricity tax is NOK 0,093 per kWh and the VAT is 24 per cent.

All end-users are free to choose from which electricity supplier they wish to purchase² electricity. Large end-users normally have meters that measure electricity use by the hour, which make it possible to buy at hourly prices varying with the spot market. Smaller customers are not metered by the hour but receive invoices based on a predetermined load profile. A small end-user can switch from one supplier to another at any time, without any chargeable switching costs. In the first quarter of 2002, about 17 per cent of household customers had an electricity supplier that was not the main one for their area.

The Norwegian Competition Authority considers that competition in the end-user market is functioning well. There are many competing suppliers and an increasing number of active end-users who swap suppliers. The cost of entering the market is low, although it has been alleged that a newcomer might encounter some barriers in the form of network owners favouring their own suppliers. Despite the fact that suppliers' profit margins increased during autumn 2001, this trend was reversed during the last months of the year. During this period, end-user prices decreased on average, while spot prices increased.

Household customers can choose between three different categories of electricity contracts. The most common is called a variable price contract, for which the supplier can only change the price after notifying the customer in advance. In the 4th quarter of 2001, approximately 68 per cent of all households had contracts based on variable prices. The second type of contract is a fixed price contract, where the time period could for example be one year. The third type of contract is based on the monthly average Elspot price with an added margin for the supplier. With this product the end-user faces the fluctuations in the wholesale market. This product is increasingly popular, and in 4th quarter of 2001, approximately 17 per cent of all households had contracts based on the Elspot price.

2. Market Structure

As mentioned above hydropower accounts for 99 per cent of the electricity generated in Norway and the state-owned Statkraft is the largest producer in Norway.

Statkraft has controlling share holdings of several major electricity producers: The company has a 66.2 per cent share of the electricity producer Skagerak Energi AS, 49 per cent of Hedmark Energi AS and 49.9 per cent of Bergenshalvøens Kommunale Kraftselskap (BKK). These companies are Statkraft's "preferred co-operation partners" and constitute together with Statkraft the so-called "Statkraft Alliance".

Agder Energi and Trondheim Energiverk were intended to be included in the alliance. However, the Norwegian Competition Authority has recently prohibited the Statkraft to acquire the two electricity producers. The parties have appealed to the Ministry of Labour and Government Administration. For more details see question 8.

As mentioned above, Elspot areas are considered as relevant markets at periods with congestion in the transmission grid. The concentration in Elspot areas and combinations of Elspot areas is therefore important when analysing market power.

There are several ways to calculate market shares in the electricity market. In this market the ability to increase or decrease production quickly is of importance for the possibilities to exercise market power. Therefore, share of installed capacity and water reservoirs are meaningful indicators when considering market power.

The market shares for electricity generation when Norway is the relevant geographic market are depicted in table 1.

Other than Agder Energi, the most important competitors to Statkraft in NO1 (Southern Norway) are Lyse Energi and E-CO Vannkraft. Statkraft owns 20% of E-CO Vannkraft. While the minority holding in E-CO Vannkraft is insufficient to have control of the company, the ownership position will increase the incentives to exercise market power.

Table 1: Market shares for electricity generation in Norway

Company	Production		Installed effect		Reservoir capacity	
	TWh	%	MW	%	TWh	%
Statkraft Alliance	47.2	41 %	8558	31 %	39	46 %
E-CO Vannkraft	8.9	8 %	2521	9 %	6.4	8 %
Norsk Hydro	8.5	7 %	1683	6 %	5.4	6 %
Agder Energi	7.4	6 %	1780	6 %	5	6 %
Lyse Energi	5.9	5 %	1780	6 %	5	6 %
TEV	2.9	3 %	658	2 %	1.5	2 %
Hafslund	2.7	2 %	504	2 %	0.5	1 %
Nord Trøndelag El. Verk	2.6	2 %	562	2 %	1	1 %
Akershus Energi	2.4	2 %	531	2 %	1	1 %
Buskerud Energi	2.2	2 %	438	2 %	1.2	1 %
Other producers	23.9	21%	8492	31%	18.3	22%
Sum	114.6	100%	27507	100%	84.3	100%
Approximately HHI		1900		1200		2300

Source: Norwegian Competition Agency

The separate Elspot areas NO1 and NO2 are even more concentrated, see chapter 6 for more details.

In periods when there are no congestions the system price applies everywhere, and the relevant market is Nordic. Vattenfall is the largest actor in the Nordic region, as shown in table 2.

The four largest actors in the market – Vattenfall, the Statkraft Alliance (Statkraft, BKK, HEAS, Skagerak), Fortum and Sydkraft – have a total production share of 57 per cent. The HHI for production is approximately 900, while it is approximately 800 for installed effect.

Statkraft owns 44% of Sydkraft, Sweden's second largest power producer.

Widespread cross-ownership between generator companies reduces incentives to compete. When a company owns a share of a competing company it is natural that the company will act in a way that maximises the sum of the profits of both companies. The company will not only earn extra profits on its own production when prices are raised, but also on the production of the companies in which it holds an ownership share. Thus cross-ownership will decrease competition. There is widespread cross-ownership in the electricity market, making the market more concentrated than the above-mentioned figures.

Table 2: Market shares for electricity generation in the Nordic market:

Company	Production		Installed effect	
	TWh	%	MW	%
Vattenfall	80.2	21%	14324	16%
Statkraftalliansen	47.2	12%	11562	13%
Fortum/Birka Energi	43.5	11%	12599	14%
Sydkraft	27.5	7%	5878	7%
Elsam	16.8	4%	3924	4%
PVO	14,3	4%	3360	4%
Energi E2	14,2	4%	4200	5%
E-CO Vannkraft	8.9	2%	2521	3%
Agder Energi	7.4	2%	1780	2%
Andre	120,0	32%	30648	35%
Sum	380,0	100%	87264	100%

Source: Norwegian Competition Agency

There are also traits in the electricity market that makes it prone to tacit or explicit collusion. Frequent meetings between the players in the spot market make it easier to observe competitors' behaviour. This will lead to increased risk for retaliations and price wars from the competitors if one player starts aggressive price competition. The producers will typically stay in the market for a long time and will therefore be more concerned about their long-term interests than about short-term profits from competing aggressively. When there are a lot of stochastic (arbitrary) variations in the market, it is more difficult to establish a stable collusion. There are stochastic variations with respect to water supply, rain and snow, demand, breakdowns of operations etc. However, statistics on these variations makes this factor less important, meaning that although coordination will probably not be perfect, it may still be important.

Entry conditions in power production are strongly restricted. New generation facilities require large investments, which require high prices to be profitable. Such investments are strictly regulated through concession laws. The Norwegian hydropower projects that are currently being planned are generally small and some of them disputed. Expansion of existing power plants is more likely, but only already established actors can do this.

The current concession law's provisions oblige private undertakings to return acquired waterfalls to the State after a period of 60 years. These provisions do not apply to state or municipal. This generates a difference in the discounted value for an investment done by a private undertaking, compared to a state or municipal company. For further details, see the discussion under question 7

3. Congestion and Pricing of the Transmission Network

All grid companies are required to use point tariffs when charging for transmission. Point tariffs mean that a grid customer pays the same transmission tariff regardless of which actor electricity is bought from or sold to. An individual customer only pays a transmission tariff to the local grid company. Consumers pay one tariff to tap electricity from the grid (tariff for consumption), and generating companies pay another tariff to feed electricity into the grid (input tariff). Point tariffs provide easy market access for customers and thus promote the establishment of a nationwide power market.

The point tariffs consist of several components, and must have at least two. One of these varies with the amount of electricity the customer feeds into the grid (production) or taps from the grid (consumption), and is called the energy component. The others do not depend on energy usage.

The energy component is as a general rule intended to reflect the cost of the change in loss of power resulting from the transmission of an extra kWh (the marginal loss rate). Such losses can be substantial when the capacity of the grid is almost fully utilized. In transmission the energy component must be geographically differentiated by connection point.

Statnett SF is responsible for construction and operation of the central grid. It also owns about 87 per cent of the central grid, and is the operator of the entire central grid. The investment decisions of Statnett are based on economic cost-benefit analysis. Any new investment decisions in transmission capacity are based on comparing the economic benefits from reduced congestion in the network with the costs of constructing the added capacity. Since the costs of the investments are covered through the point tariff system, the other market players will closely monitor that any new investments do not imply unnecessary cost increases.

Furthermore, Statnett is the Norwegian transmission system operator (TSO), and is therefore responsible for short- and long-term system coordination. This means that the enterprise coordinates the operation of the entire Norwegian power supply system. This includes ensuring that the amount of electricity generated is at all times exactly equal to the amount consumed in the Norwegian system.

In addition, Statnett plays a central role in the development and operation of transmission connections to other countries, and must therefore cooperate closely with the system operators in the other Nordic countries. This cooperation is an important basis for the Nordic power market. Cooperation between the Nordic TSOs is also organized through the organization Nordel (see the web-site www.nordel.org for further information).

4. Market Rules

Nord Pool is the Nordic power exchange and operates the following marketplaces and market services:

- A spot market for physical contracts, Elspot
- A financial derivatives market – futures, forward and option contracts
- Clearing services for contracts traded in OTC and bilateral markets

About 280 participants from Norway, Sweden, Finland and Denmark, as well as some from other European countries and the USA, trade through Nord Pool. Participants are power producers, retailers, grid owners, brokers, market makers, traders and industrial companies.

All market participants trade on equal terms on Nord Pool's financial markets. On the spot market, participants from outside the Nordic market that want to import or export from the Nordic market must limit contract volumes to the capacity allocated by the respective transmission system operator.

Participation for trading on Nord Pool is voluntary. However, bilateral physical contracts in Norway must be reported to Statnett, which has the role as a central physical settlement responsible agent. See also question 5.

Each actor signs a participant agreement with Nord Pool obligating him to observe Nord Pool's rules and regulations. Participants must settle their account obligation directly with Nord Pool, and provide security as required.

The spot market

Nordic market participants trade power contracts for next-day physical delivery at Nord Pool's spot market. Hence the market is referred to as a day-ahead-market. Trading is based on an auction trade system. The spot concept is based on bids for purchase and sale of power contracts of one-hour duration that cover all 24 hours of the next day. After the noon deadline for participants to submit bids, the Nordic Power Exchange's spot market gathers all buy and sell orders into two curves for each power delivery hour: an aggregate demand curve and an aggregate supply curve. The spot price for each hour is determined by the intersection of the aggregate supply and demand curves. The spot price is also called the market clearing price or System Price.

Nord Pool's spot market's System Price is the reference price for futures and forward contracts traded on the Nordic Power Exchange. The System Price is also the reference price for the Nordic OTC/bilateral wholesale market.

As mentioned above Nord Pool's spot market is also the primary Nordic marketplace for handling potential grid congestions.

Within Sweden, Finland and Denmark grid congestion is managed by "counter-trade" based on bids from producers.

Grid congestion that occurs in real time is managed by Nordic transmission system operators by calling on bids in real-time market.

The financial derivatives market

The financial derivatives market covers the market for futures, forwards and option contracts. Futures and forward markets are financial markets for price hedging and risk management. Power derivatives enable market participants to hedge purchases and sales of power with a time horizon of several years. Such products can be traded on the Nordic Power Exchange, but there are also other markets that organize trade of these products. Through power derivatives trade at the Nordic Power exchange market participants can hedge purchases and sales of power with a time horizon of up to four years.

Futures and forward contracts are traded continuously. The financial markets at the Nordic Power Exchange trade are based on electronic trading systems. Most participants are connected to the trading system, and do their trading online. Others communicate their bids by telephone to Nord Pool and trade via the Exchange's helpdesk. All participants receive real-time market information throughout the daily trading period, through Nord Pool's electronic trading system and real-time information distributors.

Financial market electricity contracts traded at the Nordic Power Exchange are standardized products that are financially settled; there is no physical delivery of electric power. Settlement is conducted between Nord Pool's clearing service and individual market participants.

Futures contracts consist of standardized day, week and block (4 weeks) contracts. As due dates approach, blocks are split into week contracts and week contracts are split into daily contracts. Product specifications detail the timing of the splits and other contract features.

Forward contracts consist of year and season contracts. There is no splitting of forward contracts, which are standardized in conformity with most Nordic OTC and bilateral market trade.

Power options are also offered in the financial market. Options combined with futures or forward positions, offer valuable strategies for managing risks in the electricity markets. Currently only European style-exercise options³ are approved for trade and clearing.

Contracts for difference

Market participants that use financial-market power derivatives contracts to hedge spot market prices remain exposed to the risk that the system price will differ from the actual area price of their spot purchases or sales. To overcome this potential price differential risk, a new forward contract product – contract for difference – has been introduced.

Clearing services for OTC and Bilaterally traded financial contracts

Financial contracts traded in the Nordic OTC and bilateral power markets may be cleared either by Nord Pool or by an other clearing house.

5. Bilateral, Long-Term and Forward Contracts

Bilateral contracts, both long-term and forward contracts, are allowed in the Norwegian (Nordic) wholesale electricity market. The market players are free to agree on standardized or non-standardized, long-term or forward contracts, either on a bilateral level or through the commodity exchange, Nord Pool. These types of bilateral contracts are neither promoted, nor discouraged by the government.

The state-owned power company Statkraft is obliged by the Storting to provide long-term, fixed price contracts to industrial companies. The older contracts of this type were usually set at prices significantly lower than market prices. However, as of 2001, new contracts are to be set at market prices.

Furthermore, due to the concession regulation in Norway, both the State and municipalities can require a generator to supply a certain amount (about 10% of expected generation) of “concession power” to the state and municipalities at a fixed price. The price of concession power is set by the Ministry of petroleum and energy annually, and is lower than the market price.

It is the view of the Norwegian Competition Authority that bilateral fixed price contracts reduce the incentives for producers to exercise market power on the spot market. Even if the producers succeed in increasing the spot price, the increased price will only accrue to the producer with respect to the volume that is not tied up in long-term fixed price contracts.

This effect will not arise for contract prices that are linked to the development of the spot market prices. The incentives to exercise market power is not reduced by such contracts. Also the fixed price contracts will in the long run reflect expected developments in the spot market.

6. Price or Quantity Controls

Wholesale electricity prices are generally set through the commodity exchange, Nord Pool. The short-term spot price acts as a reference price for bilateral trade. Nord Pool is a common exchange for electricity for the Nordic region, consisting of Denmark, Finland, Norway and Sweden. Market players can trade contracts both on the spot market for physical delivery, and on the financial derivatives market for forward, futures and option contracts.

There is no regulated ceiling on the trading prices on Nord Pool. There is however two forms of market regulation. One form of regulation is in the setting of the equilibrium price of the market. Due to transmission capacity restraints between the Nordic countries there will be periods with high demand in one region and high supply in a different. When transmission capacity is limited, the market is divided into sub-regions where prices are set individually for each region based on a set of market rules. This is described in previous answers.

The other form of regulation is done within a region when there are unpredictable imbalances in the market. The balancing (or regulatory) market is a tool that the system operator in Statnett SF uses to maintain a continuous balance between production and consumption of electricity in the country.

The balancing market opens after prices and quantities have been determined in the Elspot market, Statnett receives quotes from major producers or consumers that are willing to alter their power generation and/or consumption plans at short notice. In this way, Statnett ensures that it is possible to adjust the amount of power in the grid up to the hour of delivery. This may for example be necessary in the event of the sudden failure of a power plant or transmission line, or sudden, unexpected changes in demand. The Norwegian balancing market is a single-price market, with the same price applying to actors engaged in active regulation, and passive actors having differences in the "right direction". Statnett also exchanges power on the balancing market with the other system operators in the Nordic countries. In Sweden and Finland, Elbas - a short term market operating after closing of the spot market - is also used in short-term changes in market positions by major market players.

Furthermore, Statnett has a national options market for fast-operating reserves. In this market Statnett invites participants from both producers and large consumers to enter into contracts where they guarantee that they can supply Statnett with a specific volume of power reserves in the balancing market for a given period of time. This market enables Statnett to maintain a balance between production and consumption even when the power balance is tight.

The contracts for fast-operating reserves specify how much capacity each participant is to make available to the balancing market, the period of time in question, and the price for making this capacity available. The smallest volume that can be quoted is 25 MW within the specified grid area and time period. However, the contracts do not specify the price each bidder is to receive for the specific volume of energy actually used. This price is determined according to the ordinary rules of the balancing market, and the bidders are therefore free to determine their own price for the volume specified in this market. When Statnett has decided which offers in the capacity options market are to be accepted, all the bidders that have made the same type of bid (i.e. bids in the same grid area and for the same period) receive the same price per MW. This price is equal to the highest price accepted for the type of bid in question. These contracts were first used in November 2000. This market has participants both from generators and large end-users.

Although these regulations indirectly affect the price mechanism, none of them directly regulates or sets prices.

7. Entry

There is currently one rule that discourages entry into hydro generation through acquisition of existing capacity. The rule favours Norwegian state and municipally owned producers over foreign or privately owned producers. Foreign or privately owned power plants must be returned, with no compensation, to the government after 60 years of operation. This rule does not apply to the Norwegian

state or municipally owned power plants. Due to complaints from ESA this rule is up for revision in the Parliament.

There has been very little entry into the market for generation of electric power in Norway in recent years. The reason for this is that hydro is the dominant energy source, and there are few available and suitable geographic sites for establishing new generation facilities for hydropower. Furthermore, the level of the electricity prices in the Nordic wholesale market has been so low that there is no room for entry with generators using non-subsidized, alternative energy sources apart from hydro.

The government has granted concessions for building three natural gas powered electricity plants in Norway. There is however reasonable doubt about whether the return on these investments are positive at the current prices of natural gas and current level of technology. Whatever the investment outcome will be, the capacity of the proposed natural gas generators will not be significant compared to existing capacity in the market. The generators will therefore not be sufficient to offset any potential market power.

8. Competition Law Enforcement

The Norwegian Competition Authority has considered several mergers in the Norwegian energy industry. In 2002, the Norwegian Competition Authority prohibited the merger of Statkraft SF and Trondheim Energiverk AS (TEV), and denied Statkraft SF to acquire a 45.5 % share in Agder Energi AS. Both of these acquisitions were considered to lead to a significant lessening of competition in the wholesale market for electricity.

An abstract of the decision of the Norwegian Competition Authority in Statkraft – Agder is provided as an appendix.

The Norwegian Competition Authority has neither investigated any allegations of collusive behaviour nor any abuse of dominance in this sector.

APPENDIX

STATKRAFT HOLDING AS' ACQUISITION OF 45.525 PERCENT OF THE SHARES OF AGDER ENERGI AS

Summary of the decision by the Norwegian Competition Authority 21 March 2002

26 September Statkraft Holding AS entered into an agreement to acquire 45.525 per cent of the shares of Agder Energi AS. The time limit for intervention under the Competition Act section 3-11 concerning control with acquisitions and mergers was 26 March 2002.

The parties

Statkraft Holding AS is a holding company wholly owned by Statkraft SF, which is a state-owned company subordinated the Ministry of Trade and Industry. Having an annual production of approximately 34 TWh in a normal year, or approximately 30 percent of the total Norwegian production, Statkraft is Norway's largest producer of electric power. Statkraft owns partly or wholly 91 power plants, and operates 55 of them.

Statkraft has a 66,2 percent share of Skagerak Energi AS, 49 percent of Hedmark energi AS and 49.9 percent of Bergenshalvøens Kommunale Kraftselskap (BKK). These companies are Statkraft's "preferred co-operation partners" and constitutes together with Statkraft the so-called "Statkraft Alliance", where also Agder Energi is intended to be included. Statkraft also owns 20 percent shares of Norway's second largest hydro power producer E-CO Vannkraft and 35 percent of Sydkraft, Sweden's second largest power producer.

Agder Energi AS is the mother company of the Agder Energi Group and handles its daughters' power production, net operations and power sales. In total the group operates 29 wholly owned power stations and participates in the operation of another 16 power stations through various production companies. Agder Energi is Norway's fourth largest power producer with an annual production of 7.4 TWh in a normal year, or approximately 6 percent of Norway's power production.

The Competition Act section 3-11

The Competition Authority has under Section 3-11 of the Competition Act the authority to intervene in acquisitions of enterprises if the authority finds that the acquisition in question will create or enhance a significant restriction of competition in contravention of the objective in section 1-1 of the Act. The objective of the Act is to achieve efficient use of society's resources by providing the necessary conditions for workable competition.

Any acquisition of shares is to be considered an acquisition of enterprise in the meaning of the Competition Act, as is also the case with Statkraft's acquisition of 45.525 percent of the shares of Agder Energi.

When considering whether the acquisition will increase or enhance a significant restriction of competition one must first analyse whether the acquisition of shares will change the market behaviour of the parties in a way which reduce competition between the parties significantly or totally. A share of 45.525 percent will give Statkraft negative control over Agder Energi. Furthermore, the parties has entered a share purchase agreement, a stockholder agreement and an industrial co-operation agreement. The size of the share ownership seen in connection with the agreements that the parties have entered into in connection with the acquisition, and the fact that Statkraft is the only stockholder with a considerable insight into the market conditions of the power market, gives Statkraft a significant influence on Agder Energi. Thus, the companies will be able to co-ordinate their operations after the acquisition of shares.

Introduction on market power

For an acquisition to create or enhance a significant restriction of competition, the parties must as a result of the acquisition get market power or their market power must increase. A supplier with market power has the opportunity to influence the market price by changing his own behaviour. Utilisation of market power means high prices and an economic loss since the market result is a total use of resources that is less efficient than it might have been.

The residual demand curve for a producer determines what quantity and what price will be most profitable. The residual demand is given by total market demand less the supply of the other producers at each price level. It shows the relationship between the price the producer chooses and the turnover that the producer achieves. The possibility to exercise market power will depend on the elasticity of the residual demand, i.e. the percentage change of quantity relative to the percentage change of price. If the elasticity is small the producer will lose little demand by increasing prices. The more inelastic the residual demand, the larger increase in price as a result of reduced production, and the larger the market power of the producer.

The shape and the position of the residual demand depends partly on the underlying demand and partly on the behaviour of the competitors and their production opportunities. The following factors make the residual demand less price sensitive:

- market demand is not very sensitive to price changes,
- limited production capacities for the competitors,
- import constraints (capacity constraints in the grids),
- weak competition between the producers.

The vital question is therefore whether the acquisition gives rise to increased market power because Statkraft/Agder faces a less elastic residual demand. Increased market power may arise because total production capacity for competitors will be reduced, and/or that the market actors get less incentives to compete.

The relevant market

The relevant market in competition analysis consists of the relevant product market and the relevant geographic market. The market must be so large that it is possible to exercise market power if competition in the market is reduced. In the analysis of acquisition of enterprises, the relevant market is the smallest market where it is possible to exercise significant market power.

The product market

Sales of electric power may be divided into two levels. The first level is the wholesale market, where sales occur between the power producers and large buyers of power like power plants, traders and large end users. The next level is the end-users' market where suppliers sell power for consumption. The demand side of the end-users' market consists i.a. of households, companies and public institutions.

The price sensitivity of demand for electric power is small in short term (on an hourly basis). Only when prices are much higher than today's price level, some industrial firms may find it profitable to decrease their demand. Also in the intermediate term – during a season or some months – is price sensitivity limited. This means that it is possible to exercise significant market power in the wholesale of electric power.

The Competition Authority has not found it necessary to consider the acquisition's impact on competition in the end-user's market for power. On this background the relevant product market is delineated to the wholesale market for electric power.

Traditionally, the actors in the wholesale market has sold and purchased power by means of bilateral contracts of shorter or longer duration. Alternatively, power may be sold and purchased in the spot market, possibly with a connected price hedging in the spot market. Elspot is North Pool's market place for electric power. Elspot covers approximately 25 percent of power consumption in the Nordic region, and in South Norway more than 40 percent. In the regulation market Statnett as a system operator secures momentary balance between production and consumption.

The geographic market

Because of capacity constraints in the network grids (so-called bottlenecks) the structure of the power market can vary from one hour to the next, on a daily, weekly or seasonal basis during the 8760 hours of the year.

In periods where there are no binding bottlenecks the relevant geographic market is delineated to the Nordic region (Norway, Sweden, Finland, Denmark).

When bottlenecks bind in the Nordic transmission grids the spot market is divided into several different areas with different prices (so-called price areas). For the time being Norway is divided into two price areas: NO1 (South Norway) and NO2 (Middle and North Norway). The other price areas in the Nord Pool area are Sweden, Finland, East Denmark and West Denmark. Sometimes, considerable price differences are created between the various price areas. This means that it is a potential for utilisation of significant market power within a price area. Utilisation of market power may also level out price differences between price areas. This means that a price area may be a relevant geographic market even in periods where the capacity in the transmission grids is not fully utilised.

Thus, there may be several temporary relevant geographic markets. The acquisition in question will have particularly strong effects on competition in South Norway. According to Statkraft's calculations South Norway has in the period 1996 to 2001 in average been a price area in 36 percent of the time. Of this percentage South Norway has been a low-priced area (compared to neighbouring areas) in 21 percent of the time and a high-priced area in 15 percent of the time.

When delineating the relevant geographic market one should also take into consideration future import capacity into the area, provided that the plans for future import capacity are relatively concrete and are not to be realised too far into the future. There are no new plans for significant future changes in the

import capacity into South Norway the next four years. It should also be emphasised that consumption and trade are increasing and that bottlenecks must be expected to bind more, not less, in the future.

Market concentration

The Norwegian power production is almost exclusively based on hydro power, as opposed to production in the other Nordic countries. In hydro power one distinguishes between three forms of capacities: installed effect, energy capacity and magazine capacity. Installed effect is the system's maximal production per unit of time and is a form of production capacity. Energy capacity is the system's ability to produce over a given time period. Magazine capacity is a measure for the size of the water magazine and determines how freely the power plant stands with respect to planning of production independent of water supply. All measures are relevant for how the power market functions and the Competition Authority has calculated concentration indices for all three capacity forms.

Effects on competition

The Competition Authority finds that Statkraft's acquisition of Agder Energi will create a significant restriction of competition in such a way that acquisition gives Statkraft increased opportunity to utilise market power. Utilisation of market power is an economic waste since the market result will be a less efficient use of resources than what it might have been.

In the following a more detailed reasoning is given for the acquisition's effects on competition and efficiency.

The Nordic Region

In the Nordic market the acquisition increases the Statkraft Alliance's share of production from 12 to 14 percent, of installed effect from 13 to 15 percent, and of magazine capacity from 30 to 34 percent.

The Swedish company Vattenfall is the largest actor in the Nordic market, having a 21 percent share of annual middle production. At the outset the four largest actors in the market – Vattenfall, the Statkraft alliance (including Agder Energi), Fortum (Finland) and Sydkraft (Sweden) – has jointly more than 50 percent of production. Statkraft owns 35.5 percent of Sydkraft. The Statkraft Alliance including Sydkraft will together after the acquisition have 22 percent of production and effect in the Nordic region, including E-CO, the market share will be 24 percent. Cross-ownership between competing companies may contribute to soften competition, since a company will be more reluctant to compete aggressively against another company in which it holds ownership shares.

Tacit collusion is a situation where no producer finds it profitable to act aggressively in the competition and where every actor adapts to a certain price and production level, even if this is not the result of an explicit agreement among the actors. The wholesale market for electric power has several characteristics that make tacit collusion possible. Among other things, the actors meet daily in the spot market and can therefore react quickly on attempts to compete aggressively. Also, the owners have long-term interests and therefore are less willing to give priority to short-term profits by breaking out of a situation with tacit collusion. Furthermore, the actors have the opportunity to communicate through their behaviour in the spot market and otherwise through information exchange as a consequence of widespread cross-ownership. In the opposite direction goes the fact that arbitrary variations in precipitation and demand create insecurity, which may make it more difficult to establish a tacit collusion.

Because of its size, Statkraft is able to use advanced models, which enable the company to regulate its production in the most optimal way for the company. This gives Statkraft an informational advantage, which may mean that its competitors to a greater extent choose to act in line with the strategy of Statkraft. If they observe that Statkraft holds back production it may be taken as a signal that production will be more profitable in future periods. Other producers with water magazines may in a situation like that find it risky to increase their production and be more prone to look at Statkraft's water management when making production decisions.

Entry conditions in power production are strongly restricted. New power production entails large investments, which require high power prices to be profitable. Such investments are strictly regulated by means of concession laws. The Norwegian hydro power projects that are currently being planned are mostly small and some of them disputed. Expansion of existing power plants is more likely but must be made by already established actors. The concession law's provisions, which oblige private undertakings to return acquired waterfalls to the State after a period of 60 years, limits entry opportunities by means of acquisition of existing hydro power production facilities.

It is the opinion of the Competition Authority that competition in the Nordic region is weakened as a consequence of Statkraft's acquisition in South Norway of independent companies that have the ability to regulate production in the short term. Statkraft's acquisition of Agder Energi reduces the number of competitors that by means of their ability to regulate production may counteract attempts by Statkraft to increase price by holding back production.

South Norway

In South Norway the acquisition will increase the Statkraft Alliance's share of production from 38 to 47 percent, of installed effect from 42 to 50 percent, and of magazine capacity from 43 to 52 percent. In addition, Statkraft owns 20 percent of E-CO Vannkraft, which has 11 percent of the magazine capacity in South Norway.

The acquisition of Agder Energi will reduce the number of competitors and their production capacity, and will thus mean that Statkraft will face a less elastic residual demand.

The producers do not need to forsake production (i.e. let water run past turbines that is free to be operated) in order to utilise market power. The low production costs of a hydro power producer may mean that it is not likely that waste of water will take place, but a producer with market power might behave in a way that increases the risk of waste.

In the power market, price differences between different periods of the day and year will frequently occur, since demand and supply conditions vary. If competition is workable, the companies will wish to produce as much as possible in the high-price periods and as little as possible in the low-price periods. Production will be moved from periods with low price to periods with high price. This means that prices will be evened out between periods, which is economically efficient.

A producer with market power may find it profitable to utilise that price elasticity varies between periods. In a period without binding bottlenecks the residual demand is more elastic than in periods where bottlenecks do bind. The residual demand is also more elastic in periods with a low consumption (low load periods) than in periods with high consumption (high load periods). A producer with market power will wish to have a low production in periods with a low price elasticity and a high production in periods with a high elasticity, meaning that price differences between periods arise. This will be economically inefficient.

A producer in an area where the import capacity is fully utilised (a deficit area) will achieve a higher price than the price in neighbour areas. A deficit area may be due to a particular dry period of time. A producer with market power will find it profitable to hold back production in order to create a deficit area or strengthen the price effects of an already existing deficit area, meaning that price differences will increase between periods.

In a surplus area export capacity will be fully utilised under workable competition and the price will fall below the price of neighbouring areas. A producer with market power will find it profitable to hold back production in order to increase the price. If prices increase sufficiently export restrictions will be lifted, meaning that a surplus area will not actually be created. Bottlenecks with full export out of South Norway will mainly arise during daytime when the price is high compared to the night. The water being saved by reduced production during daytime, can be used by producing during other periods when there are no capacity constraints in the transmission grids and the market is considerably larger. This again means that a producer with market power will behave in a way that increases rather than reduces price differences between periods, and again an economic efficiency loss will occur.

Thus, utilisation of market power means increased price differences between time periods. This gives rise to a loss of economic efficiency in the sense that consumption in periods where prices are high are supplanted by less valuable consumption in periods where prices are low.

The utilisation of market power may also influence price differences between geographic sub-markets. Prices will be higher in a deficit area than in a surplus area. In a deficit area the utilisation of market power will create or increase price differences between sub-markets, while utilisation of market power in a surplus area will reduce or eliminate price differences.

Effects on efficiency

In addition to the negative effects on consumers in terms of price increases several forms of efficiency losses will occur. Utilisation of market power will partly increase the general price level and partly prolong price differences where such price differences would otherwise not have existed. Higher prices and larger price differences lead to an economic loss.

The loss arising from price differences arises when valuable consumption in periods where demand is less sensitive to price, is supplanted by less valuable consumption in periods where demand is more sensitive to price.

Increased prices may be divided into a long range of efficiency losses:

In the solution under free competition available production technology at every point of time is utilised in the most efficient way possible. In this way, one is secured that consumption at any point of time is covered at the lowest cost possible. This will not necessarily be the result if the actors utilise market power. If market power is utilised in hydropower production, the result may be that more expensive production capacity is utilised. If so, the capacity that does not produce (the withdrawn capacity) is cheaper than the most expensive capacity that is utilised in production. This gives rise to an efficiency loss because of a less than optimal usage of the production capacity.

The costs of investing in the network grids should be based on the gains in form of reduced price differences between the price areas. If market power is utilised, price differences may be both increased and reduced. Thus, the prices will not provide the economically correct investment signals.

Likewise, market power may entail that market prices do not give the right signals on surplus and deficit areas, meaning that new production capacity is not located where the gains to society is the largest.

When high power prices are expected decisions on the demand side will be affected. For instance, concern about high prices and market power will contribute to increased insecurity and greater risk of termination of businesses, reduced amount of new investments or that one invests in other types of technology than would otherwise have been the case. High prices will change behaviour also for other demand sectors with respect to investments in power consuming equipment, investments in energy saving equipment, investments in heating technology and in the choice of fuel etc.

The Competition Authority is of the opinion that the acquisition also will give rise to certain efficiency gains. However, some of these can not be realised for some years, and to a large extent they may be realized even if this acquisition will not take place.

Conclusion

The Competition Authority finds that Statkraft's acquisition of Agder Energi will create a significant restriction of competition in the power market. The efficiency gains arising from the acquisition is not large enough to outweigh the economic losses resulting from the restriction of competition. The Competition Authority therefore conclude that Statkraft's acquisition of shares in Agder Energi will create a significant restriction of competition in contravention of the objective of the act, which is efficient usage of society's resources. On this background, and pursuant to section 3-11 of the Competition Act, the Competition Authority has reached the following decision:

Statkraft Holding AS is prohibited from purchasing 45.525 percent of the shares in Agder Energi AS.

The decision is appealed to the Ministry of Labour and Government Administration.

NOTES

1. The last border tariffs between Sweden and Sealand was removed spring 2002.
2. In 1997 the fee per consumer for switching electricity supplier was removed.
3. The main features of the European-style power options (EPOs) are:
 - EPOs can only be exercised at the exercise date, which is stated in the product specifications.
 - The option premium is quoted in Norwegian kroner per MWh; premiums are payable in the following trading day.
 - The energy-size of an option contract is the number of MW multiplied by the number of hours in the underlying forward contract.
 - On listing of a new option, initial exercise (strike) price are set by Nord Pool according to the price of the underlying instrument. Initially 3 strike prices are listed.
 - New strike prices are automatically generated to reflect price movements of the underlying forward instrument.
 - Strike price intervals depend on the price of the underlying forward instrument.

POLAND

Introduction

Poland is accompanying its transition to liberalisation with legislative changes in accordance with Directive 96/92/EC. The Polish Energy Law Act (1997) broadly amended in May 2000, together with the appropriate secondary legislation, have ensured the progress of harmonisation of the Polish Law with EU legislation. The latest amendments to the Energy law accepted by the Parliament on 24 July 2002 and concerning, *inter alia*, the acceleration of the alignment process with EU requirements will come into force with the day of Poland's accession to EU. The most fundamental change is the opening of Polish market for electricity generated in the EU.

In the course of accession negotiations with the EU Poland provisionally closed Chapter 14 "Energy" in July 2001, two months prior to the Chapter 22 "Environment".

In May 2001, the Polish TSO – Polskie Sieci Elektroenergetyczne SA, PSE SA became the founding member of the new UCTE.

PSE SA also applied for the associated membership in ETSO, which was granted on November 30, 2001.

Key Data of the Polish Power Sector (2001)

Installed capacity:	34 272 MW
Gross annual electricity generation:	145 655 TWh
Peak load (on 13 December 2001):	22 868 MW

Poland is a net exporter of electricity. For details of 2001' export/import see chapter X.

Electricity generation in Poland is mainly based on coal, as 94 % of the capacity is installed in coal fired power plants (31 GW in the end of 2001). The remaining 6 % is installed in hydro power plants (2 GW), mainly in pumped storage ones. As the result of this the electricity production from coal amounted to 97 % of total electricity generated in Poland in the year 2001. Roughly one fourth of the generating capacity (7.5 GW) is installed in lignite fired power plants, but since they produce cheaper electricity than hard coal fired ones their share in electricity production is more than one third. The hard coal fired power plants include also the combined heat and power (CHP) plants, which apart from electricity (13 % share in the total electricity production) provide heat for municipal as well as industrial needs. Besides hydro power plants the share of electricity production in the renewable sources is currently very small, but due to legislative incentives there are a lot of projects going on to build new renewable sources (mainly wind farms). The development of the power generation sector is focused on the modernisation of existing power plants with gradual introduction of modern coal technologies (e.g. fluidised bed combustion). Some projects assume change to gas technology (combined cycle gas turbine), however the use of gas in power sector is still very limited to some rather small CHP plants built recently.

Unbundling of the Power Sector

Generation, transmission and distribution have been carried out by different companies for almost 12 years.

TSO unbundling

The legal unbundling, has been already achieved for the Polish TSO. In this respect, PSE was reorganised as follows: independence of the system operator from other activities; creation of a daughter company responsible for electricity trading; unbundling and transparency of accounts. Transparency of Account is guaranteed by the Polish Law of Accounting Rules (Chapter 7 Audit and Announcement of Financial Statement). The “Monitor Polski B” is an official publication of audits of companies. The condensate financial statement is also available on the PSE SA’s website: www.pse.pl in Polish and English version.

Generation subsector

- the number of generating companies which, in aggregate represent at least 95% of net national electricity generation: Considering the structure of generating companies, which creates a Groups of power stations: 20
- the number of generating companies which have at least a 5% share of the net national electricity generation: 9 generating companies
- the share of generation output and installed capacity for each company which has at least a 5% share (calculation of shares based on net production)

Generating Company *)	Share of the market based on net production (%)	Generation Output (GWh)	Installed capacity (MW)
1. Belchatow PS	20.6	27545.3	4370.0
2. PKE Company	16.5	22602.3	4820.0
3. PAK Group	9.8	13356.1	2738.0
4. Turow PS	6.7	9211.4	2070.0
5. Kozienice PS	6.0	7990.2	2760.0
6. Opole PS	5.9	7829.6	1450.0
7. Rybnik PS	5.6	7535.0	1745.0
8 Polaniec PS	5.3	7280.5	1600.0
9. Dolna Odra PS	5.1	6900.0	1768.0

*) Data available for 2000

- Amount of installed capacity by fuel type

Installed capacity (MW) in PP (commercial and autoproducers) at the end of year

Years	Total	Commercial Hard coal	Commercial Brown coal	Commercial HYDRO	Auto >0.5MW
1998	33851	19824	9093	2113	2821
1999	34213	20179	9148	2115	2771
2000	34542	20601	9178	2116	2647
2001 ¹⁾	34272				

*) Detailed statistics under preparation

Polish generating companies are not integrated into transmission or distribution.

Important measures implemented already to improve competition in the wholesale market:

- the implementation of the Energy Power Exchange (1st July 2000)
- the implementation of a day-ahead balancing mechanism (1st September 2001) for all users of the grid (Generators, Final Customers, Distribution Companies, Power Exchanges and Trading Companies).
- the procedure for switching supplier.

To switch the supplier, the customer should:

- comply with legal conditions of access to the network. (Ordinance of the Minister of Economy on detailed terms of connecting entities to the electricity network, trade in electricity, providing of transmission services, network operation and maintenance and the quality standards for customer services signed on 25th September 2000).
- sign the Transmission Agreement with Transmission System Operator or Distribution System Operator (which regulates all issues concerning realisation of supply of energy and balancing matters).
- no penalties if customer returns to the original retail supplier

Transmission subsector:

Polskie Sieci Elektroenergetyczne SA (PSE SA – Polish Power Grid Company) is an owner of the national high voltage network and acts as the Transmission System Operator, based on:

- the Act of 10th April 1997 Energy Law and the latest amendments to the Act
- the Ordinance of the Minister of Economy on detailed terms of connecting entities to the electricity network, trade of electricity, providing of transmission services, network operation and maintenance, and the quality standards for customer services signed on 25th September 2000
- the Licence for Transmission and Distribution granted to the Polskie Sieci Elektroenergetyczne SA by the Regulatory Authority on 1st December 1998,
- the Statutes of the Joint Stock Company Polskie Sieci Elektroenergetyczne SA in the version approved by the PSE SA Supervisory Board on 25th October 2000

PSE SA has been a member of UCTE from May 2001.

PSE SA has been an associate member of ETSO from November 2001

The transmission assets under the PSE SA ownership consists of transmission grid on 750 kV (114 km), 400 kV (4689 km), 220 kV (7875 km) and 110 kV (27 km) as well as 1 substation of 750kV, 28 substations of 400kV and 62 substations of 220kV.

Distribution subsector

There are 33 distributions companies (32 state owned, GZE has been privatised already, G-8 and STOEN are under the negotiations) supplying a total of some 14.8 million consumers.

Name	Number of customers (thousands)	Name	Number of customers (thousands)
STOEN Sto eczny ZE S.A.	743.4	Energetyka Kaliska S.A.	433.4
ZE Warszawa Teren S.A.	740.1	ZE Gorzów S.A.	206.5
ódzki ZE S.A.	510.0	ZE Jelenia Góra S.A.	213.9
Ze ód ż Teren S.A.	580.6	ZE Wroc aw S.A.	446.8
ZE P ock S.A.	339.0	Energetyka Poznańska S.A.	869.3
ZE Bia ystok S.A.	645.5	ZE Szczecin S.A.	392.2
ZE Lublin S.A. LUBZEL S.A.	498.8	ZE Wa brzych S.A.	311.7
Zamojska Korporacja Energetyczna S.A.	419.9	Zielonogórskie ZE S.A.	268.4
Rzeszowski ZE S.A.	639.3	ZE Legnica S.A.	206.8
ZEORK S.A. Skarżysko-Kamienna	728.7	Elbląskie ZE S.A.	175.0
ZE Częstochowa S.A.	322.9	ZE Toruń S.A.	403.6
Beskidzka Energetyka S.A.	437.3	ZE Bydgoszcz S.A.	427.5
Górnośląski ZE S.A.	1121.2	ZE S upsk S.A.	159.6
Będziński ZE S.A.	461.7	ENERGA Gdańska Kompania En. S.A.	564.7
ZE Opole S.A.	410.1	ZE S.A. w Olsztynie	282.5
ZE Kraków S.A.	761.5	ZE Koszalin S.A.	204.6
ZE Tarnów S.A.	245.4	Total:	9 672,0

Electricity market structure

In the year 2000, some changes in Energy Law (dated 1997) and its secondary legislation were introduced. They were necessary to allow the implementation of the decentralised market model accepted by Polish Government in December 1999. The structure of such a market comprises of three mutually supplementary elements: the active energy market, the financial market (financial contract and derivatives) and technical market (regulated ancillary services and must run generation). The active energy market, in turn, consists of three segments: bilateral, power exchange and balancing one.

On the **bilateral segment** the electricity trade is carried out in the form of electricity sale contracts concluded directly between market participants. The trade conditions of the contracts are known only to the parties involved. Settlements are done directly between the parties involved, regardless of settlements on the other market segments. The bilateral market includes electricity sale contracts concluded freely in advance, related to deliveries in individual hours of trading day. This segment includes, among others, the long term contracts for purchase of electricity from generators concluded in mid 90s by PSE acting at that time as single buyer.

On the **exchange-based segment** the electricity trade is carried out in the form of standard transactions or contracts concluded on power exchanges (through auctions). Poland have an energy exchange named Gie da Energii SA. Participation in this exchange is voluntary. Participants of the energy exchange may include: electricity generators licensed by URE; distribution companies licensed by URE; major grid consumers with the right to receive transmission services and wholesale electricity traders holding URE trading licenses and acting as energy trade intermediaries.

At present Gie da Energii SA shall operate and manage two markets: the Day-Ahead Market (DAM), which is spot market, and Future Market with delivery of electricity. GE shall act as the administrator of these markets for the benefit of its Members and has no right to place orders in its own name and on its own account.

DAM

Day-Ahead Market is run one day ahead of the physical energy delivery date and consists of 24 independent, separate "hour" markets. There "hour" markets are run simultaneously. The sale bids are aggregated in total supply curve, while the purchase orders are aggregated in the total demand curve. The hourly clearing price is the price at which supply and demand curves intersect (fixing).

Participants submit bids directly into computer system of energy exchange by Internet. Each participant is allowed to submit both: purchase bid either sell bid.

The bid for each hour may consist of maximum 25 pair, i.e. combination of quantity (expressed in MWh) and price of energy (expressed in PLN per MWh).

On the Day-Ahead Market prices are determined *ex ante* on the basis of forecast demand and actual supply of energy.

Futures Market

In the Futures Market may be traded futures contracts. Futures contract is understood as agreement imposing an obligation on the seller to deliver electricity at a certain date, at a certain price and imposing an obligation on the buyer to purchase electricity at a certain date time, at a certain price.

The market price itself provides the incentive for new investments in energy sector. This price justifies economical legitimacy of building new generating units.

At present time schedule of delivery of hourly working schedules to Transmission System Operator, being the entity running Balancing Market, limits duration Day-Ahead Market session.

In Poland the number of power exchanges, operated on the electricity market, is not limited. Prices set there are published and available to all parties involved as well to observers. Settlements are done regardless of the other market segments.

The **balancing segment** covers balance-adjusting action settlements, which are necessary to execute electricity sale contracts concluded on bilateral and exchange-based segments. First of all, these actions include balancing of the differences between the supply, resulting from bilateral and exchange-based segments, and the actual demand for electricity using the balancing bids of the generators. Transactions, allowing physical execution of the sum of all electricity sale contracts and power exchange transactions are concluded on this market. Settlement prices are published and available to all interested parties. Amount and kind of turnovers on the balancing market depends on the accuracy with which electricity sales contracts on the bilateral and exchange-based markets cover the actual power consumption considering current status and requirements of the power system on a trading day.

The direct contracts between generators and customers (distribution companies, traders and eligible customers), which constitute the bilateral segment, have been signed and executed since 1999. In the year 2001 the eligible customers were the final consumers with consumption more than 40 GWh/year (on January 1st, 2002 this threshold was lowered to 10 GWh/year). The first power exchange in Poland – Gielda Energii S.A. – has operated since July 2000, offering initially only day ahead market. Later on it extended its offer to physical forward market, including contracts for green and brown electricity, also. The trade executed on power exchange was exempted from tariff obligation by Energy Regulatory Office late in 2000. The same has almost applied to all electricity production (apart from must run generation) since June 2001, thus making generation sector competitive. Till that time the balancing mechanism, run by PSE as Polish TSO, had been operated on the monthly basis and switching its operations to hourly basis was the

most important task on the way of implementing competitive electricity market. Finally it happened on September 1st 2001. The main features of this day-ahead hourly balancing mechanism include the following:

- organised in a form of day ahead hourly one side (only generators) auction run by TSO,
- pay as bid pricing system for balancing services,
- two different settlement prices for electricity sale and purchase on balancing market (introduced on July 1st, 2002 instead of previous uniform price scheme – based on experience gained so far).

Large part of demand in Polish power system (60 %) is covered with long term contracts concluded between PSE and generators in the time of single buyer model (mid 90s). These contracts deteriorate the decentralised market model. There were some attempts to solve this issue in the past with the Compensation Fee System based on conversion of the physical contracts to the financial ones, but all of them failed. Today the PSE SA management Board has just started negotiation with banks on long-term contracts restructuring presenting the new proposal of solution worked out together with relevant ministries.

All mentioned forms of contracts are applied in the Polish energy market. Long-term Power Purchase Agreements introduce stability into the system, give clear perspective of costs which must be incurred in the long run. Generally, prices in long-term contracts should offer lower prices than the market average. But in Poland so-called Long-Term Contracts concluded between some generators and the Polish Power Grid Company created unfavourable conditions for the introduction of competition. These contracts concluded in the 1990's where to deliver were to be a pledge for huge credits for modernisation and environmental investments. These investments are absolutely necessary to upgrade the energy Polish sector closer to European standards.

The prices included in these contracts are 20 % higher than market average and they cover 61% of the demand for electricity. Distribution companies have no choice and have to buy energy from long-term contracts and they are obliged by the law also to buy combined and renewable energy so the field of market decision is very narrow.

There have been several propositions to solve this problem one of them proposed by President of Polish Regulatory Authority (ERA) called the System of Compensation Payments and approved by the Government. The System of Compensation Payments created a mechanism that would allow the energy generators to take part in the market play and receive compensation between the market price and long-term contract price. This system has been abandoned mainly due to complicated tax settlements.

Actually there are two main ways of solving this problem, which are being discussed. The one of them is to merge three generating companies with different long-term contract prices and after the consolidation the new average weighted price would be on the market level. The second way is the rest of the contracts would be dissolved and financial costs repaid earlier by the means from the emission of obligations issued by the PPGC. The obligations will be bought out by the financial means coming from a restructurization fee included in the distribution tariffs. These solutions should consider the size of additional costs and the size of benefits and the feasibility of the existing legal frame.

Last year completely changed relations between power sector entities. After introducing the day-ahead balancing mechanism, market participants were able to establish their contract positions by themselves. First experiences from operation of hourly balancing mechanism have revealed its ability to self-regulation and assured the right reflection of electricity economic value variability versus both time

and generation costs. The market participants welcomed this long awaited new mechanism with real interest and great satisfaction, actively participating in its implementation process.

Rules of Balancing Market are published on the PSE SA's website: www.pse.pl/pl/ospwork.

The **electricity market model established in Poland** will evolve in coming years aiming at reaching more effective operation of power sector and at giving market participants more freedom in determining their own contract positions. Further market development will concern, first of all, the following areas (apart from above mentioned issue of long term contracts):

- introduction of self scheduling by creating an intra day market,
- active participation of customers with controlled load through submitting bids for reduction of their load,
- development of new model of technical market for competitive procurement of ancillary services,
- development of new rules for contracting and committing must run generation,
- development of mechanisms allowing to include requirements concerning environmental issues in market rules.

Legal aspects and conditions of Poland's integration with the European Union are fully respected in the process of Polish electricity market creation. The above further modifications of the electricity market rules aim at fulfilling all the requirements determined in the EU Directive 96/92/EC from December 19th, 1996 so that Poland could participate in European electricity market right after its accession takes place.

Rate of deregulation

The existing Ordinance of the Minister of Economy on the schedule for acquisition of rights to use transmission services by individual groups of customers provides for opening of the Polish power market to progressively smaller customers, i.e.:

- customers with total annual purchase of electricity of more than 10 GWh acquired that right from 1 January 2002,
- customers with total annual purchase of electricity of more than 1 GWh will acquire that right from 1 January 2004,
- others will acquire that right from 5 December 2005.

Regulator

The Energy Regulatory Office (ERO) whose President is appointed by the Primer Minister for a 5-year term, is responsible for granting licenses, approving tariffs and settling disputes.

The last year amendments to the Polish Energy Act and the appropriate secondary legislation have resulted in detailed guidelines of tariff settlements and setting principles for connection to the grid and its financing. New regulation has drastically reduced the “connection fees”. The competency of the President of ERO in the process of tariffs approval has been extended within the scope of verification of costs of power enterprises according to the binding law.

The powers of President of ERA to collect information and set prices

According to the Energy Law, the President of the ERA has the power to control and set the prices for the electricity in the tariffication process. Tariffs are set under assumptions that they cover justified costs and protect consumer from the unjustified level of price at the same time. The President of the ERA has power to release energy enterprises from his tariff-setting obligations after acknowledging that they operate on the competitive market.

Currently the President of the ERA sets tariffs for the following:

- distribution companies - separately for transport and supply of electricity to the customers connected to their networks,
- transmission system operator -for transport and supply of electricity to the distribution companies and other customers connected to the transmission grid,
- energy generators - in respect to the cogenerated electricity that is obligatory bought by the transmission and distribution companies under Ordinance of the Minister of the Economy of the 15th December 2000 "on the Purchases of the Energy from the Unconventional, Renewable and Combined power sources".

Other electricity generating and sales companies are released from the tariff-setting obligation.

According to the Energy Law, the President of the ERA has the power to collect any information concerning their licensed activities from electricity companies within the provisions of the state and business secrets.

Pricing of the transmission network

Currently wholesale electricity prices are set on the competitive market (only the prices for the part of the electricity sold by the transmission system operator to the distribution companies are set by the President of the ERA). Wholesale market prices do not exercise administrative limitations but the President of the ERA has the power to withdraw the release from the tariff-setting obligation after acknowledging the lack of the competitive market (in that case wholesale electricity prices would be set accordingly to the Energy Law provisions).

The availability and the size of the generating capacities are set in bilateral agreements between electricity generators and buyers. These agreements contain the provisions for the penalisation for failing to provide the agreed volumes and maintain quality standards.

Episodes of very high prices

From the beginning of the competitive electricity market, improper behaviour of companies willing to receive unjustified profits have periodically been observed. The examples of these actions have been seen in the balancing segment of the Polish market, where short-term increases of prices are frequently seen. Analysis of high congestion costs sources shows frequent abuse of the balancing system scheme due to some generators more favourite position in it. A typical practice is concluding contracts for units, which have to be shut down because of grid conditions. In this case, the given contract should be executed by calling up another unit of the generator, but at much higher price.

The powers of the President of ERA to shape the segments of the energy market

The Polish Law says that the shape of the market is described by the ordinance of the Ministry of Economy, in the part referring to the part on electricity trading. In the field for promotion of competition the President of ERA co-operates with the Ministry of Economy on the adjustment of this regulation to market requirements. The regulations referring to transactions on the Power Exchange are in the legal framework of this institution. Similarly, Balancing Segment Regime is worked out by PPGC - Operator of the Transmission System. The distribution companies also create their Instruction of the traffic and explanation of the distribution system. The energy market is based on the contracts being concluded by participants in the market. This is the drawback of the present system, because of the usually lengthy negotiations of the contracts. The Regulator 'as yet' doesn't have powers to approve a general grid code.

New entry into generation

An authorisation (licensing) procedure is used. The President of the ERO may issue licences for new generation capacity on the basis of the following criteria: technical and financial capabilities, location of facility, professional qualifications of employees, state energy policy and public interest.

The amount of new independent power generation (based on authorisation procedure) [MW]

Generating company	Unit of power generation
Patnow	1 unit 460 MW (2004) (fuel brown coal)
CHP Rzeszow	1 unit (100 MW – 110 kV) (2003) (fuel gas)
CHP Chorzow	2 units (226 MW – 110 kV) (2003) (fuel coal)
CHP Zielona Gora	1 unit 186 MW (2004) (fuel gas)
The amount:	972 MW

Market Opening

The Energy Law and subsequent 1998 Ordinance set out a legal framework and timetable for access to the system to progressively smaller customers who will become eligible to contract for access. The access to the system is provided through the Regulated TPA covering only domestically produced electricity. This is a provisional measure aimed at developing competitiveness in the national market.

Date	Annual purchase level (GWh)	Number of Eligible Customers	Volume (TWh)	% of market opening
4 September 1998	> 500	21	21.5	21
1 January 1999	> 100	83	37	37
1 January 2000	>40	180	44	43
1 January 2002	>10	610	52	51
1 January 2004	>1	3300	60	59
5 December 2005	All	15 million	102	100

The opening of Polish market for electricity generated in the EU will took place at the date of Poland's accession to the EU.

Tariff setting

Generators and electricity traders have been released from to the obligation to approve their tariffs by the regulator (ERO) once they have proved they are operating under competitive conditions. Transmission and distribution companies are obliged to submit their tariffs for ERO approval.

Access to the network

There are transmission tariff documents published in Polish. The documents in Polish are available on the transmission system operator's www site: <http://www.pse.pl/pl/ospwork/>

The binding transmission tariff has been in force since July 2002. The next change will take place on 1 July 2003 (according to the Ministry of Economy ordinance, the tariff year begins every year on July, 1st).

There are not too many congestions within the national network. If any (eg. some "must run" power plants) the transmission system operator resolves them according to internal procedures that provide high level of quality and security of supply. The TSO covers the costs of such activities. The costs are one part of the transmission system operator charges - **system services charge**, for which the tariff carrier is the energy consumed by all the customers connected to all the voltage level network and energy exported abroad.

Distribution tariff documents (available in Polish) are accessible on the Energy Regulatory Office website: http://www.ure.gov.pl/taryfa/teksty_taryf.html

There are 33 main regional distribution companies that operate at voltage levels 110 – 0,4 kV.

The specified customers (large industrial, large commercial, small commercial, domestic) in some cases can be ascribed to different tariff groups and connected both to high and medium or medium and low voltage levels. Moreover, even they are connected to medium voltage levels- the transmission charges can be differentiated according to time of day or season of the year. For some customers the tariffs can be two or one part ones (power component and energy component). Taking all the above into account the below table shows the average yearly and unit transmission charges for the specified customers calculated taking into account all the 33 distribution companies.

The payments and unit charges are shown in gross volumes (data for 2001). The tax rate (VAT) is 22%.

Customer	Connected to	Yearly charge	Unit charge	Average
		[€/a]	[€/kWh]	[€/kWh]
Large industrial	EHV (400, 220 kV)	939291.30	0.0188	0.0215
	HV (110 kV)	1211514.53	0.0242	
Large commercial	HV (110 kV)	55069.93	0.0275	0.0293
	MV (15 – 110 kV)	61957.81	0.0310	
Small commercial	MV (15 – 110 kV)	2372.83	0.0470	0.0660
	LV (0.4 kV)	4193.49	0.0840	
Domestic	LV (0.4 kV)	168.78	0.0482	0.0482

Local distribution charges already include payment made to transmission system operator.

Support for renewable\CHP

According to the ordinance of the Minister of Economy on the obligation to purchase electricity from non-conventional sources and renewables, and co-generated with heat, as well as heat from non-conventional sources and renewables and scope of this obligation (issued on 15 December 2000), all electricity traders, has to purchase some “renewable” energy from RES plants. This amount of energy depends on how much energy the Trading Party sells. There is a timetable according to which the amount of energy to buy is increasing in the following years. In year 2002 the rate is 2.5%.

This obligation is also applied for all the energy produced by CHP plant, for which the overall (heat and energy) efficiency is higher than 65%. Such amount of energy must be purchased by the distribution system operator to whose network such a CHP is connected. Because the tariff energy price for such CHP is higher than the market energy price, the distribution companies that buy that energy, get, from Transmission System Operator, a compensation payment (that is the difference between the tariff CHP energy price and market price determined by the Energy Regulatory Office). The Transmission System Operator’s costs that result from these compensations are covered by the system services’ charge that is paid by each energy consumer in the country.

Tariffs and conditions for distributed generation and autoproducers

According to the ordinance of the Minister of Economy on detailed principles of formulating and calculating tariffs and the principles of settling accounts for electricity trade (issued on 14 December 2000), neither transmission, nor system charges are paid by any producer connected to any voltage network.

Autoproducers in Poland (according to the above mentioned ordinance) are defined as such users that more than 50% of the energy consumed produce in their own plants (there are no autoproducers connected to the transmission network) One of the incentives for such autoproducers is that they pay half of the system charge (for the final customers the coefficient is 1.0684).

Cross-border issues

All high voltage interconnectors are owned by the Transmission System Operator – PSE SA. The transmission use of system costs that refer to the interconnections (in fact performing imports and exports) are being separated from the overall Transmission System Operator’s use of system costs. The costs are being covered by payments paid by Trading Parties that export/import energy. The payments are being in each case negotiated between the Trading Party and TSO and depend on available transfer capacities and

system conditions. The general rule is that the operator should have the separated costs covered by performing export/imports activities.

There are no auctions applied, but some works are started to apply auctions as capacity allocation method for cross-border trade.

All export and import contracts are fully executed. Existing physical flow differences are due to the loop flows.

Power flows in 2001

Country of origin/destination	Import 2001 (GWh)	Export 2001 (GWh)
Germany	1316	1193
The Czech Republic	61	7818
Slovakia	2	2024
Ukraine	590	0
Belarus	637	0
Sweden	1700	0
Total	4306	11035

SWITZERLAND

Generation and Demand

In the last two years, electricity consumption has been increasing steeply and has outpaced economic growth: 2.6% in 2001, and 2.3% in 2000. Electricity consumption in 2001 totalled 53.7 TWh, a new record. The main reasons for this steep rise are demographic growth, economic activity and a harsher heating season. This trend jeopardises the Swiss Government's long-term energy conservation and efficiency programme to 2010, which calls for capping electricity demand at 5% during the decade.

Swiss electricity production totalled a record 70.2 TWh in 2001, 7.4% more than in 2000. Hydropower accounted for 60.2% of electricity output, nuclear power for 36.1%, with the remaining 3.7% coming from thermal (gas) power plants and non-hydro renewable energy sources.

Consumption by sector was as follows in 2001:

Residential	29.9%
Services & commerce	26.1%
Industry	34.1%
Transport	8.0%
Agriculture	1.9%

The Swiss production portfolio is well adapted to consumption patterns. Nuclear and thermal plants provide base load power and hydropower (particularly dams and pumped storage) account for almost all of the daily swing¹ and export surplus.

Investment

The potential for expanding Switzerland's generation capacity is limited. Given current generation capacity and demand trends, the country will remain a net electricity exporter for years to come. Most hydropower sites – both run-of-river and dams – are being exploited². Additional nuclear capacity installation was banned during a ten-year moratorium, which ended in 2000³. Construction of gas-fuelled power plants could be envisaged – e.g. in the event of an unlikely nuclear phase-out – but it would severely impair Switzerland's commitment under the Kyoto Protocol⁴. Therefore, large European power producers are far more likely to seek to acquire equity in Swiss companies than to invest into new capacity.

There is, however, a need to expand transmission and particularly trans-border transit capacity. The large electricity companies, which have boosted their foreign trade volumes in recent years, see an urgent need for capacity upgrades and call for easing administrative hurdles to build new lines.

Trans-Border Transit

A controversy between the French and Italian system operators and regulators on the one side, and the Swiss industry on the other, over transit capacity from France via Switzerland to Italy has been simmering for two years. Total transit capacity to Italy has been constrained to 5,400 MW, because contractually agreed transmission lines have not been built on the Italian side of the border. Historically, 60% of transit capacity has been used by Swiss suppliers, and 40% by EdF, to honour long-term contracts

with Enel and for spot sales. In 2000, however, the Italian system operator unilaterally assigned 48% of the capacity to EdF. This led to capacity overbooking by the Italian and French system operators, which put undue strain on the system during the winter 2001-2002. An appeal against the Italian ruling is pending.

Swiss electricity companies are a party to the European cross-border trade directive.

Electricity Trade

Switzerland is a net electricity exporter. Net exports in 2001 amounted to 10.4 TWh (almost 15% of production), compared to 7.1 TWh in 2000. Total imports amounted to 58.0 TWh, total exports to 68.4 TWh.

On a seasonal basis, Switzerland is a net electricity importer in the winter, when water reservoirs are low and heating demand is high⁵. On a daily basis, Switzerland imports electricity (mainly from French nuclear power plants) during night-time to re-fill its pumped-storage plants, which allow for electricity production and lucrative exports (mainly to Italy) during day-time peak periods.

The main electricity trade partners are France – with a net 19.2 TWh export surplus to Switzerland in 2001 - and Italy – with 24.8 TWh of imports from Switzerland. Compared to these volumes, electricity trade with other countries is relatively modest, i.e.: 0.1 TWh net exports to Germany, although Swiss electricity imports from Germany amounted to 2.0 TWh in winter 2000/2001; 1.8 TWh net exports to Austria, and 2.9 TWh to other countries.

Some 60% of Swiss electricity exports are high-tariff day-time exports. Gross export revenues in 2001 totalled CHF 2.963 billion (€ 1.975 billion) with a kWh fetching CHF 0.046 (€ 0.03) on average. CHF 1.896 billion were spent on imports (CHF 0.0352/kWh). Electricity trade thus yielded a net surplus of CHF 1.067 billion (€ 710 million).

The share of Swiss electricity exports under long-term contracts⁶ has steadily declined since the mid-1990s, from 63% in 1996 to 19% in 2001. Inversely, short-term and spot deliveries have soared from 26% in 1996 to 76% in 2001 of total exports. Electricity imports have undergone a similar, albeit less marked trend: Imports under long-term contracts have decreased from 72% (1996) to 43% (2001), whereas imports under short-term contacts have increased from 27% (1996) to 56% (2001).

Industry Structure and Players

The Swiss electricity sector is extremely decentralised by European standards. Some 1200 companies are active in the sector. Some 200 are involved exclusively in generation. 300 are vertically integrated spanning at least two of the generation, transmission and distribution sectors. This category includes seven vertically integrated supra-cantonal companies. 30 companies are engaged in international trade. The remaining 700 companies are mainly involved in local distribution.

Six integrated companies dominate the Swiss market (*see Table below*), with a share of approximately 80% of the wholesale market. They have formed an industry association called Swisselectric to promote common interests. These companies typically cover a demarcated distribution area with direct sales or with indirect sales through partners or – as for Axpo and EOS - their shareholders. They have their own production capacities, but often jointly own large hydropower or nuclear plants. Furthermore, several companies have drawing rights on French nuclear plants. Because of their stakes in disseminated large production capacities, company-owned grids are sometimes far-flung, jointly owned

and intermeshed. In the absence of transmission capacity of their own, companies have negotiated access to third-party grids.

Company	Type of activity	Commercial activity	Ownership
Atel	<p>Generation Domestic production: 8.2 TWh. Owns fully or partly hydro capacity throughout the country, from which it produced 3 TWh. Owns 40% of Gösigen NPP* and 30% of Leibstadt NPP*, from which it produced 5.2 TWh.</p> <p>Transmission Owns 17% of Swiss HV* transmission and 42% of transit capacity to Italy.</p> <p>Distribution Sold 9.3 TWh in Switzerland through fully or partly owned subsidiaries and partner utilities.</p>	<p>Turnover 53 TWh (+58% vs 2000)</p> <p>Domestic wholesale 9.3 TWh</p> <p>Trade Controls 25% of Swiss exports and 21% of imports.</p>	Motor Columbus 56.7% (UBS 36.5%, EdF 20%, RWE 20%, Deutsche Bank 9.9%), Municipal utilities 27.6%, Canton Solothurn, City of Aarau 9%. Publicly listed.
Axpo/NOK	<p>Generation Generated 22.3 TWh, including 7.1 TWh from hydro owned/co-owned throughout Switzerland, and 15.1 TWh from own Beznau NPP and co-owned Gösigen and Leibstadt NPPs.</p> <p>Transmission Major system within NE Switzerland</p> <p>Distribution 14.1 TWh through shareholding companies, 10.3 TWh through partner utilities outside home area.</p>	<p>Turnover 25 TWh, incl. 22.3 TWh own production and 2.8 TWh purchased from third parties.</p>	Axpo/Nordostschweizerische Kraftwerke: 100% owned by publicly-owned cantonal/regional utilities in NE Switzerland.
BKW	<p>Generation Production: 9.7 TWh, incl. 0.8 TWh from own hydro, 2.8 TWh from own Mühleberg NPP, 3.3 TWh from co-owned hydro, and 2.9 TWh from co-owned Leibstadt NPP and drawing rights in French NPPs.</p> <p>Transmission Major system in Canton Bern.</p> <p>Distribution 6.2 TWh direct sales and through partner utilities.</p>	<p>Turnover 15.4 TWh, incl. 6.5 TWh domestic.</p>	Canton Bern 63.5%, E.On 20%, Canton Jura 4.7%. Publicly listed.
CKW	<p>Generation Production: 5.2 TWh, incl. 1.1 TWh from own hydro, 1.7 TWh from co-owned Gösigen and Leibstadt NPP, 2.0 TWh from drawing rights.</p> <p>Transmission System in Central Switzerland.</p> <p>Distribution 2.4 TWh to own customers, 1.1 TWh through partner utilities, 1.4 TWh traded.</p>	<p>Turnover 5.2 TWh</p>	Watt 66%, Axpo/NOK 6%, others 28%. Publicly listed.
EGL	<p>Generation 4.7 TWh as co-owner of Leibstadt NPP and hydro, drawing rights</p> <p>Transmission Owns major system.</p> <p>Distribution 5.3 TWh domestic sales.</p>	<p>Turnover 44.7 TWh, incl. 11.6 TWh domestic.</p> <p>Major trader: 30.4 TWh sales abroad.</p>	Electricitäts-Gesellschaft Laufenburg: Watt 81.2% (CS 20%, Axpo/NOK 80%), Axpo/NOK 5.38%. Publicly listed.
EOS	<p>Generation 4.6 TWh, incl. 1.6 TWh drawing rights from French NPP. Fully or partly owns hydro (2.6TWh) and co-owns Leibstadt NPP (0.5 TWh)</p> <p>Transmission Major system in Western Switzerland.</p> <p>Distribution EOS's sales account for 60% of distributed power of shareholding companies.</p>		Energie Ouest Suisse: Romande Energie 28.5%, SI Geneva 22.7%, SI Lausanne 19.7%, Ent. Elect. Fribourg 15.6%, Elect. Neuchâtel 5.9%, FM Valais 5.4%.

HV: high-voltage; NPP: nuclear power plant.

There are some 2300 electricity generation plants, the 25 largest of which account for almost 60% of power generation. At the other end of the spectrum, some 800 micro-hydro plants, 450 combined heat and power and 600 photovoltaic and windpower installations contribute just over 1% of electricity generation.

Some 75% of the total electricity sector capitalisation⁷ are publicly owned (federal state, cantons, municipalities). Some 12% of capitalisation are foreign-owned. Five of the seven integrated companies are partly privately owned⁸.

Contrary to some expectations, the sector has not undergone sweeping ownership changes in recent years. In particular, no major privatisation has occurred, as several plans for corporatisation of public (mainly municipally)-owned utilities have been thwarted by popular votes. Nevertheless, there were some important ownership changes. Some large European groups purchased stakes in Swiss utilities⁹. Publicly owned Axpo/NOK bought out both of E.On's and EnBW's 24.5% shares in Watt in 2002.

Most large electricity companies, with the notable exception of EOS¹⁰, display healthy balance sheets in spite of major price discounts given to large customers. The large electricity companies reported efficiency gains over the past few years, which enabled them to lower their average hydro production costs "close to European levels", but companies concede that further cost cuts are needed – mostly through more automation - to become fully competitive at international level. Part of the streamlining, however, is achieved through tax cuts, particularly as regards the water use royalty levied by the cantons¹¹.

Some large Swiss companies geared up for European market liberalisation by creating (joint) purchasing/trading companies and setting up subsidiaries abroad. A group of large municipal utilities formed Swisspower to pool their marketing services.

Thus, the Swiss electricity market is fragmented into a large number of publicly owned regional or local monopolies. Cantonal and local governments intervene through regulation and taxation, and often earnings from their utilities provide a sizeable share of their budget revenues¹². The wide price dispersion across monopoly regions suggests large hidden costs.

On the consumer side, there are some 130 large consumers (more than 20 GWh/year) accounting for some 30% of consumption. Their number is likely to increase as SMEs have and will continue to group themselves to pool purchasing power¹³.

Future changes in the Swiss corporate landscape are difficult to predict, particularly after the rebuttal of the Electricity Market Law (EML, *see below*). Widespread mergers and acquisitions of local utilities, as feared by some in case the EML had been accepted, are unlikely to happen in the near term, since local monopolies received a political plebiscite through the EML vote. Some, however, may spin off their marketing/trading functions to more seasoned larger companies¹⁴. Similarly, there is no reason to foresee massive foreign acquisitions of large Swiss companies, given their robust balance sheets and often sizeable public ownership structure.

Costs and Prices

Although the lion's share of electricity is generated by hydropower and nuclear plants, with relatively low marginal costs, end-user prices are higher than the OECD Europe average. Electricity tariffs are subject to substantial regional variations. The average published tariff for industrial users is CHF 0.145/kWh, although actual negotiated tariffs are likely to be much lower¹⁵. The average tariff for households is CHF 0.20/kWh¹⁶. The average tax level is approximately CHF 0.025/kWh¹⁷. The worst off are the SMEs, which face electricity prices 50% above EU average. Prices for large customers are some 25% above EU average, whereas households face a relatively modest surcharge of 15% above EU average. Historically, industry prices have increased some 40% in real terms since 1965, whereas household tariffs have remained stable since 1980 after declining during the two previous decades.

Production costs (including taxes) for hydro power range from CHF 0.02-0.03/kWh for completely amortised facilities, and from CHF 0.12-0.15/kWh for new facilities. Pumped-storage costs average CHF 0.07/kWh. Nuclear production costs range from CHF 0.02/kWh for fully amortised to CHF 0.13/kWh for non-amortised plants¹⁸.

The Swiss electricity spot market is trading wholesale high-voltage electricity at Laufenburg. The trading volume is relatively low at certain hours of the day. Prices are calculated for the period between 11 and 12 a.m. on the following day. The Swiss Electricity Price Index (SWEP) was launched on 10 March 1998 by the trading companies Atel and EGL. Since then, they have been joined by the trading firms of major Swiss companies¹⁹, but also by foreign companies E.On, MVV, RWE (Germany), Electrabel (Belgium), and trader TXU Europe.

Large generating companies anticipated the adoption of the EML and, in an effort to retain their large customers or win over new customers that were captive of local monopolies, entered contracts with substantial price discounts. Typically, to acquire new clients, the electricity company agreed to pay the difference between its own discount price and the price that the captive client would have to pay its local monopoly supplier in case electricity from the new supplier was denied access. Some of these contracts were subject to the adoption of the Electricity Market Law, whereas others had no opt-out clause. The exact discounts and terms of these contracts have not been divulged, and some could seriously strain the balance sheets of suppliers which bet on the market opening. Some 20-25% of Swiss electricity is now estimated to be traded through such contracts.

The Failed Electricity Market Law

The Electricity Market Law (EML), which was rejected through a referendum on 22 September 2002²⁰, aimed at liberalising the electricity market through a six-year transition phase. It broadly followed the EU's liberalisation approach. It was adopted in Parliament in December 2000 and enjoyed wide support across the political spectrum (from right to left, including initially the Socialist²¹ and Green parties), the economy in general and the electric industry in particular, consumer associations, and environmental NGOs. In spring 2001, however, the trade unions, later rallied by a coalition of various leftist and vested municipal interests, launched a referendum against the EML. The referendum was propped up as a battle against deregulation as such. In an unusual step, the Government chose to elaborate an implementing ordinance to the EML ahead of the referendum, so as to lay down the technicalities of the planned electricity market liberalisation. The second version of the ordinance won widespread support from all parties concerned.

The main features of the EML were:

- Unbundling (at the accounting level) of generation, transmission and distribution;
- Creation of a national transmission system operator (TSO)²²;
- Regulated third-party access and non-discriminatory and transparent transmission tariffs; setting up of a national regulatory authority within the Swiss Federal Office of Energy to oversee transmission tariffs. Transmission tariffs and end-user prices for captive customers were to be capped during a six-year transition period. Cantons may have imposed tariff measures so as to even out excessive tariff distortions within their territory. A Federal Arbitration Commission was to be set up to address disputes between market players and the regulator. Irrespective of the EML, tariffs may be examined by the Federal Price Surveillance Authority, whose recommendations, however, are not binding.

- Gradual opening of the market to eligible customers:
 - Upon the entering into force of the law: a) Consumers with an annual consumption of 20 GWh or more; b) 20% of the annual sales of distribution companies to captive customers; c) producers from renewable energy sources²³. Taken together, some 30% of the market would have been opened upon promulgation of the law;
 - Three years after entering into force, the eligibility threshold was to be lowered to 10 GWh per annum, and 40% of the annual sales of distribution companies to captive customers. That would have represented an additional 20% opening of the market.
 - Six years after entering into force, the market was to be totally opened.
- Explicit mention of public-service obligation, enabling the cantonal or federal Governments to take adequate measures in case electricity supply was at risk.
- Promotion of electricity generation from renewable sources through labelling and free transmission during a ten-year transition period. State loans at market conditions could be granted for the expansion/maintenance of domestic hydropower and to help hydropower companies write off stranded costs.

Following the foundering of the EML, the Government and market players are debating how the electricity market may develop. No clear path is emerging. The opponents to the EML advocate a vague “market law”, which would cement public sway over the electricity sector by establishing a national state-controlled transmission company. Such a law, however, has little chance to pass through Parliament. Another suggestion - such as to convert the draft Nuclear Power Law currently being debated in Parliament into some substitute electricity market law – is not feasible.

Market players and observers pin some hopes on voluntary agreements by the industry – similar to the German “Verbändevereinbarung” - whereby the main integrated companies would agree to negotiated TPA. Whether this option is realistic depends largely on two developments:

Anti-Competition Regulation

Firstly, domestic anti-monopoly regulation: In 2000, the Federal Competition Commission (Comco) was called upon by Watt, then the parent of two large producers, and Migros, the largest Swiss retailer and supermarket chain. Watt and Migros had agreed on a power supply contract, which involved, among others, deliveries to two large Migros users on the monopoly area of EEF, the electricity utility of the canton of Fribourg. EEF refused to afford Watt transit through its grid. In 2001, Comco ruled in favour of Migros/Watt, arguing that EEF could not invoke “legitimate business reasons” to bar access and that EEF’s refusal constitutes an abuse of dominant market power, which contradicts the Swiss Cartel Law. The ruling was confirmed by the Comco appeals commission shortly before the fatal LME referendum. The ruling, however, did not explicitly oblige EEF to open its grid.

The ruling is now likely to be carried to higher instances, i.e. the Federal Supreme Court and the Federal Council (Government). The Supreme Court may not take into account non-specified public interests, such as public service. The Federal Council, however, would have to scrutinise the case from the viewpoint of “public interest”. Some political commentators believe that the Federal Council may find it politically arduous to uphold Comco’s ruling, given that the “public” clearly voiced its view in the referendum. If the Comco ruling is upheld, it would have a bearing on the given case and set a precedent,

but it could not be automatically applied to other cases. Therefore, if large producers or consumers would want to “elbow” access through other operators’ grids with help from Comco, they would need to file on a case by case basis – a long and costly endeavour. Electricity supply obligation is governed by cantonal laws, so that Comco’s findings may not apply uniformly across the country.

Also, the Comco ruling did not address the tariff issue, which was not raised. Comco could examine tariffs only if such tariffs were challenged as being “disproportionate” by a party. Comco had opened several other examinations in the electricity sector, all of which are now shelved awaiting further clarification after the demise of the LME. Of interest is an investigation launched in March 2002 about contracts by four electricity companies of Axpo. The contracts were designed to lock established resellers into long-term commitments so as to prevent them from changing their suppliers in case the market would open. Such contracts to bar new market entrants could be considered as an abuse of dominant position, according to the Swiss doctrine of competition law.

Switzerland in the Context of the European Electricity Market

Secondly, international and EU developments: Switzerland is a major crossroads of European electricity trade and its grid is closely integrated with the European network (*see section on Trade above*). There are questions about how European electricity companies, some European governments, and the European Commission may react to Switzerland’s refusal to open its electricity market. But retaliatory measures, as feared by some, are unlikely as long as Switzerland remains a net exporter. Furthermore, Swiss companies have established subsidiaries in the countries where they export.

At an institutional level, Switzerland and the EU started a second round of bilateral negotiations, which include, among others, trade of services. The Commission has a clear mandate to negotiate energy services and wanted Switzerland to adopt the EU *Acquis communautaire* on electricity market deregulation²⁴. This would have been unproblematic had the EML been adopted. As this report was being submitted (early October 2002), neither Switzerland nor the EU Commission had decided on how to proceed.

Outlook

Thus, one can reasonably expect the following market developments in the short to mid-term:

- The large Swiss electricity companies will pursue their efficiency drive to improve their competitiveness against European competitors in lucrative markets, mainly Italy and Germany. They will also expand their trading business, particularly abroad.
- Large Swiss customers will continue to negotiate discount prices with Swiss suppliers who can deliver electricity to their sites. These prices will remain in the range of what potential European competitors (mainly EdF) would be able to offer, provided they had access to the Swiss grid.
- The large Swiss electricity companies are likely to fend off mounting pressure from large customers by affording negotiated access to their grids. The increasing inter-relationships between the large electricity companies – through short- and long-term delivery contracts, trading, shared generation and transmission infrastructure, and equity swaps/ownership – could foster voluntary arrangements.

- Local/municipal monopolies remain relatively sheltered from competition through politically sanctioned prices. Those, however, which have large captive customers in their area, are likely to concede discounts, which may severely dent their revenues and force them to rationalise or even merge with larger companies.

NOTES

1. Daily swings typically range from 6,000 MW at night to day peaks of up to 11-12,000 MW.
2. Total hydropower capacity is expected to increase by merely 0.4% from 13,240 MW to 13,295 MW until 2008, mostly through expansion of existing plants.
3. A draft Nuclear Energy Law is currently being debated in Parliament. It is likely to enter into force in 2003, as a counter-proposal to two „popular initiatives“ calling, respectively, for phasing out nuclear energy and another ten-year ban. The new law would also allow for extending the operational time of existing plants. Nuclear capacity will therefore remain stable at 3,223 MW for years to come.
4. Ratification by Parliament of the Kyoto Protocol is underway.
5. Swiss electricity companies have drawing rights on French nuclear plants amounting to 2,455 MW (as of end 2001), which corresponds to approximately one-third of gross annual imports.
6. Two years or more.
7. 1998 figure.
8. The exceptions being Axpo and EWZ, which are entirely under public ownership.
9. E.g. E.ON bought stakes in BKW, and EdF and RWE in Atel. EnBW acquired EnAlpin Wallis (the former autoproducer of Lonza chemical works).
10. EOS suffers from massive over-investment at its CHF 1.3 billion Cleuson-Dixence pumped-storage plant (870 MW peak capacity).
11. In 1997, the maximum rate of this levy was raised from CHF 54/kW to CHF 80/kW. Most cantons moved to apply the maximum rate. Royalties and other charges account for 20-25% of total costs of hydro.
12. On average, 25% of electricity prices consist of taxes.
13. Some of these pooling efforts encompass industry sectors like e.g. Swissmem, the Swiss machine and electric equipment industry. After the failed Electricity Market Law, they may need to revisit their strategy because their members are scattered across regional distribution monopolies.
14. On average, Swiss distribution companies have 3,815 customers and annual sales amounting to 48 GWh. By comparison, the average in Germany is more than 42,000 customers and 476 GWh, and in Austria almost 28,000 customers and 370 GWh. Many observers believe that Swiss distributors do not have the critical mass to survive as such.
15. CHF 0.045-0.05/kWh according to some accounts.
16. There are large regional disparities: Household tariffs in the 20 largest Swiss cities vary from CHF 0.148 (Sion) to CHF 0.29 (Neuchâtel). Such disparities bear witness to sometimes high charges by municipal utilities, which pay out dividends to local budgets and cross-subsidise local infrastructure.

17. Including water use royalty, various municipal and cantonal taxes and a 7.6% VAT.
18. Dismantling costs not included.
19. BKW, Axpo/NOK, Avenis Trading SA (the trading arm of EOS), Rätia Energie AG (REPower).
20. The EML was rejected by a relatively low margin of 52.6% of the voters.
21. The Socialist Party later opposed the EML.
22. The TSO was to be a privately owned company, with a Swiss majority ownership, to be established within three years of enactment of the law.
23. Except hydropower plants with a nameplate capacity of 1 MW or more.
24. Particularly Directive 96/92.

UNITED STATES'

Overview of Regulation and the Basic Structure of the U.S. Electricity Sector

(1) Please summarize the basic structure of the electricity sector in your country

Because of the geographic size, population distribution, and history of the U.S. electricity sector, the U.S. has a diverse and geographically segmented electric power system. On average, generation accounts for 62% of retail prices, while transmission accounts for 9%, and distribution accounts for 29%. Coal is the most important fuel for generation (51.8%), but natural gas, nuclear, and hydro are also important fuel sources. Natural gas is the predominant (90%+) fuel for new generators. There are three different transmission interconnection areas in the U.S. The U.S. transmission system was designed to serve the limited purpose of providing backup generation in case of unanticipated generation or transmission shortfalls by individual local, vertically -integrated monopoly utilities that were regulated to be largely self-sufficient. Private, for-profit firms account for approximately 75% of retail sales. Cooperatives, municipal systems, and state and federal power authorities account for the rest of the U.S. industry. Local distribution is generally provided by a franchised utility regulated by the state's public utility commission.

An overview of U.S. electric power institutions, facts, and figures is appended. Additional descriptive material is available on the Internet at the U.S. Department of Energy's Energy Information Administration web page: <http://www.eia.doe.gov>.

Since the early 1990s, the federal government has been implementing reforms to increase competition in electricity markets at the wholesale level. States accounting for approximately half of the U.S. population have implemented some degree of retail competition.² The reform process is still underway at both the federal and state levels. Highly publicized problems in the wholesale and retail markets involving California have increased public scrutiny of regulatory reform in the U.S. electric power sector.³ The most significant recent event to address these concerns is the release of proposals by the Federal sector regulator to implement a standard market design (SMD) for wholesale markets throughout the U.S.⁴

Regulation of the U.S. electricity sector reflects the federal structure of the U.S. government in the U.S., that is, both states and the Federal government have electricity sector regulators with separate, but partially overlapping responsibilities.⁵ At the national level, the electricity sector regulator is the Federal Energy Regulatory Commission (FERC). Historically, FERC's jurisdiction has centered on wholesale electricity sales and associated high voltage transmission services. FERC has legislative authority to establish rates for wholesale electricity sales and for transmission services that are just and reasonable. For several years, FERC has generally granted market-based rate authority (for wholesale transactions) to generators meeting its market power screen.⁶

Historically, state jurisdiction has centered on retail electricity rates and service. Retail service is supplied primarily by private, for-profit, vertically integrated utilities with monopoly franchise areas. States generally regulate retail electric power rates and service through a public utility commission. In a state that has not implemented a retail competition (also termed customer choice) program, the public utility commission typically employs rate-of-return criteria to determine retail prices. Retail rates usually

differ for residential, commercial, and industrial customers. In a state with a retail competition program, rates are often controlled de facto by continued regulation of prices for a state designated provider of last resort (POLR). Prices charged for POLR service remain regulated by the state public utility commission. The POLR supplier is the default supplier if a retail customer fails to select an electricity supplier or if the alternative supplier selected by the retail customer exits. In many states, the regulated prices for POLR service have, for extended periods of time, fallen below prices at which new suppliers can profitably enter.⁷ States also retain control over the siting of generation and transmission lines within their borders.

Authority to review mergers in the electric power industry is held concurrently by FERC and the federal antitrust agencies. For mergers between electricity suppliers, the Department of Justice Antitrust Division is the primary antitrust agency. For mergers between electricity suppliers and fuel suppliers, either DOJ or the Federal Trade Commission is the applicable antitrust agency. State public utility commissions and state attorneys general also review proposed mergers between electricity suppliers (or between an electricity supplier and a firm that supplies fuel to competing electricity suppliers -- a convergence merger).

Recently, a number of traditional divisions in jurisdiction between FERC and the states have come under scrutiny. FERC's proposals for wholesale standard market design include FERC's assertion of jurisdiction over all transmission services. Legislation before Congress on electricity regulation includes provisions for granting transmission siting authority to FERC.

Another recent development is increased awareness of the critical role of POLR prices in retail competition programs. Texas is the most recent state to commence a retail competition program and its POLR pricing, unlike that in most other states, is subject to frequent adjustments based on changes in fuel costs.

Factors Affecting Market Power

Due to the size and diversity of the U.S. electricity sector, conditions affecting market power differ greatly between areas. Consequently, it is not possible to provide a single characterization of U.S. electricity markets. Instead, we identify policy issues and relevant U.S. examples of the various factors affecting market power.

(2) *Market Structure*

Horizontal Market Structure

Note of Introduction: Accurate descriptions of market structure depend on accurate identification of the relevant market or markets. In the electricity sector, market definition is often a substantial and difficult task. Important elements in determining the relevant market include lack of extensive practical storage of electric power, transmission congestion, transmission loop flows, and diversity in the marginal costs of different types of generators. In past investigations, U.S. antitrust authorities have found that each segment of time constitutes a separate product market and that the relevant geographic market fluctuates on the basis of demand levels and associated transmission congestion patterns.⁸ Often, in geographic product market analysis information about transmission congestion in geographic product market analysis is so complex that computer simulations of load flows and prices are the most practical method to access the relevant geographic markets. For this reason, market share calculations such as the HHI, that are relied upon extensively in other contexts, have often been supplemented for analysis of electricity markets. Failure to assess carefully the relevant markets in the electricity sector is likely to result in poor

understanding of market structure and errors in policy formulations regarding market structure and market power remedies.

In the setting of a bid-based electricity spot market,⁹ market structure assessment in the U.S. has generally focused first on overall concentration (usually HHI) and then on concentration of generation in various segments of the supply curve. At any specified position of the demand curve, the generators in one segment of the supply curve are most likely to establish the market clearing price. Concentration among generators is often evaluated in at least three sections. The first section includes the base-load plants with the lowest marginal costs (including nuclear plants, run-of-stream hydro facilities, and some coal-fired plants). These plants are seldom at the margin.¹⁰ The second section consists of the mid-merit plants with intermediate-level marginal costs (typically combined cycle natural gas and coal-fired plants) that are at the margin during periods of intermediate demand. The third section includes the peaking plants with the highest marginal costs (typically conventional natural gas fueled generators, and pump storage or other pondage hydro facilities) that are at the margin during periods of high demand. When considering incentives to raise prices and withhold output of generators at the margin, ownership of inframarginal generators by suppliers with marginal generators is also considered. This is based on concern that holders of inframarginal capacity will have incentives to withhold marginal capacity because of increased margins on sales of electricity from their inframarginal generation units. Again, explicit computer simulation modeling may be informative in conjunction with market structure measures.

Concerns about existing market power in generation are particularly acute in areas where and when transmission congestion limits imports from other areas, concentration among suppliers inside the transmission constraint is high, and entry is impeded.

Vertical Market Structure

The degree of vertical integration differs in different sections of the U.S. at present. FERC policy toward vertical integration between transmission and generation continues to evolve toward increased separation. Until 1996, FERC's approach to reduce discrimination in access to transmission primarily was limited to individual utilities that sought FERC approval for mergers. FERC Orders 888 and 889 in 1996 instituted open access transmission for all areas of the country. Subsequently, FERC found that the behavioral rules in Orders 888 and 889 were not fully effective, although wholesale trading activity increased substantially. At the same time, FERC encouraged the formation of independent system operators (ISOs) that would control transmission in an area, but not own it. Four areas established ISOs under order 888¹¹ and all utilities were required to post (on the Internet) estimated available transmission capacity on their transmission lines. In order to discourage discrimination against competitors in transmission services more effectively, FERC issued Order 2000. Order 2000 further encouraged formation of regional transmission organizations (RTOs) in all areas of the country. This order described the minimum characteristics and functions of RTOs (which were similar to those of existing ISOs).¹² In Order 2000, FERC explicitly recognized that an RTO may be a for-profit independent transmission owner or Transco. Most recently, FERC has proposed implementing a standard market design (SMD) on a nationwide basis.¹³ This latest set of proposals focuses primarily on addressing wholesale market power concerns on a regional basis through independent transmission providers (ITPs). Major market power remedy components of the SMD proposals include market power assessments and monitoring of market performance and participant behavior by an independent market monitoring unit in each area,¹⁴ local market power mitigation through must-run obligations and bid caps,¹⁵ overall safety-net bid caps, triggered area-wide bid caps, and resource adequacy requirements applied to load-serving entities. The SMD proposals also would abolish exemptions from open access policies that have, heretofore, been granted for transmission that serves load subject to retail price regulation by individual states (bundled transmission services).

Divestiture

There have been some divestitures of generation as part of the U.S. regulatory reform process, but most of these have not been associated directly with market power remedies to date. Instead, most have been associated with establishing the market value of generation assets in states that decided to implement retail competition programs. Since most generation assets in the U.S. are owned by for-profit firms and most of these investments were encouraged or required by state regulators, when a state changes its regulatory regime it may decide to compensate owners of generation for any decrease in the value of those assets (stranded costs). Some states (including New York and Massachusetts, for example) determined that the most accurate method to determine the amount of stranded costs is to sell these assets. These states required utilities to divest generation assets if the suppliers wanted to be part of the state=s stranded cost recovery program. In Massachusetts, for example, divestiture was required, but the generation assets of each utility were acquired by a single buyer, so no change in concentration occurred.¹⁶ New York=s divestiture requirements resulted in decreased concentration of ownership of generation because several different buyers acquired generating units. In California, the state did consider market power issues in requiring that half of thermal capacity be divested by the two largest privately owned utilities to divest half of their thermal generating capacity. Some of the Californian utilities also voluntarily sold all of their thermal generating capacity and another large utility was required to do so as a result of concurrent merger proceedings. Overall concentration of generation in California decreased somewhat as a result of the divestitures because multiple buyers were involved in the divestitures.

Evaluation of the effectiveness of state divestiture programs is overshadowed by other decisions that these states made with respect to their retail competition programs. One difference that proved important was the degree to which the divestitures involved vesting contracts¹⁷ for the output of the divested generation. Most states with divestiture programs also included fixed price, multiyear POLR programs that would be supplied by the divested generation units under vesting contracts of the same duration. In most instances, the incumbent utility remains the POLR provider. It remains to be seen how POLR programs will be supplied once these vesting contracts expire.¹⁸ By contrast, the California retail plan called for exclusive reliance on spot market trades to satisfy retail demand by the three largest distribution utilities.¹⁹ As a result, no vesting contracts (and the implied hedges against changes in wholesale prices) were arranged by the largest divesting utilities in California.²⁰

FERC has not required generators to divest transmission capacity. Rather, it has encouraged such firms to relinquish control of transmission facilities to independent regional transmission operators (ISOs in Order 888, RTOs in Order 2000, and Independent Transmission Providers (ITPs) in the SMD proposals). In the Southeast and West (outside of California), RTO formation has been slow and fragmentary. There is widespread agreement that the behavioral rules under FERC Orders 888 and 889 were not fully successful in eliminating discrimination in transmission services. There is general agreement that discrimination in transmission under ISOs is minimal. Remaining discrimination concerns focus on the independence from generators=s interests of the governance processes for determining market rules.

(3) *Congestion Pricing of the Transmission Network*

Congestion in transmission is a growing concern in part due to wholesale market regulatory reforms that have reduced other impediments to wholesale trades. Over the past decade, the volume of wholesale trading has increased sharply. Policy studies have identified several transmission links that are frequently congested. Examples of areas with congestion bottlenecks include Path 15 between northern and southern California, Florida, Michigan, New York City, Long Island, and portions of Connecticut and Wisconsin. Congestion on these and other links in the transmission network are most severe during peak

demand periods (i.e., office hours on weekdays during summer) and when there are generator or transmission outages. Within transmission constrained areas, generators are more likely to have market power. The issue is aggravated by economic growth, slow progress on demand-side participation (i.e., real-time metering and other forms of price-responsive demand), and long delays in siting of additional generation or transmission.

Although a number of transmission pricing arrangements have been used in the U.S., there is increasing agreement that nodal, locational marginal pricing (LMP) represents the best practice available. Under LMP, transmission charges reflect the congestion costs of supplying power at a particular location (node) on the transmission grid. Part of the support for LMP stems from the observed market power drawbacks associated with other approaches. Experience with zonal pricing in California suggests that unless zones are small and frequently adjusted, zonal pricing results in inefficient grid operations and opportunities to game the market. In areas that rely on command and control solutions to congestion, transmission line relief (TLR) orders issued by the grid security organization have been found to be highly inefficient and susceptible to strategic manipulation. LMP also finds support because it provides efficient investment signals regarding the size and location of new generators or transmission lines. Further, LMP (when matched with real-time pricing) fosters efficient investment decisions by retail customers regarding distributed generation and demand curtailment devices.

FERC's SMD, as well as the existing transmission arrangements in the New York and PJM²¹ ISOs, provide for financial transmission rights (FTRs)²² offered by the market operator. In PJM, for example, most transmission risks can be hedged by purchasing FTRs from PJM. PJM estimates that FTRs, in aggregate, provided a hedge against 99% of transmission congestion pricing risk in 2001.²³ Some proposals call for auctioning of these rights under SMD. Other proposals call for distribution of FTRs to existing transmission customers (coupled with an active resale market).

Although LMP and associated FTRs help provide efficient investment incentives to suppliers and help transmission customers to hedge transmission pricing risk, they do not solve market power problems directly.²⁴ Concern has been expressed that some suppliers might monopolize FTRs and try to exercise market power through the market for FTRs. Some proponents of LMP suggest that applying A-use or lose rules to FTRs would reduce such concerns.²⁵ To date, it is difficult definitively to separate the effects of LMP from the effects of other regulatory provisions in actual generation siting decisions. Participants in PJM have indicated recently that siting decisions within PJM appear to be responding to the price signals provided by LMP.²⁶

Generally, we are unaware of special rules associated with transmission lines that facilitate trade with Canada or Mexico. There are two aspects of such lines worth noting, however. First, since individual states control transmission and generation siting, concerns have been voiced that any individual state would be reluctant to authorize siting of a transmission line or generator that is primarily likely to serve customers in another state. Indeed, states with low electricity costs have indicated that they are reluctant to lose the comparative economic development advantage they have from low-cost power. Second, imports from Quebec to the U.S. involve use of DC connections to the U.S. grid because Quebec is a separate, nonsynchronous grid.

Grid expansion is one of the functions of RTOs explicitly identified by FERC in Order 2000. Under Order 2000, RTOs are supposed to develop policies governing grid expansions. Some proposals for grid expansion policies of RTOs allow merchant transmission projects (e.g., a transmission projects undertaken by investors that do not own or operate transmission in the area of the new transmission line). Two merchant transmission projects of this type have recently been approved by FERC. One of these involves an underwater transmission cable between Long Island and Connecticut. FERC's standard market design proposals contain another provision for augmenting transmission investment incentives.

Under this proposal, FERC or a regional advisory siting committee would identify the most significant potential grid additions. If FERC found that the system benefits from a prospective transmission project exceeded the benefits investors would be able to appropriate (by selling the FTRs associated with the project), FERC could, for example, authorize a higher allowed rate of return on that project.²⁷

(4) Market Rules

FERC's SMD proposals include provisions for a voluntary,²⁷ bid-based, security constrained, day-ahead market operated by the ITP in each region.²⁸ Each ITP would also operate a bid-based, security constrained, real-time spot market. Nodal pricing would be used for both buyers and sellers in both markets. Locational energy prices would reflect transmission congestion and line losses. It is anticipated that 80% to 90% of transactions will be bilateral trades, but that spot market pricing will substantially affect pricing of bilateral trades. The FERC proposals combine elements from, and are generally consistent with, actual and proposed market rules in the Eastern U.S. ISOs and the preliminary designs put forward in the Midwest and the California market re-design. (Each ITP would also operate markets for ancillary services.)

To date, only generators or energy traders bid into the day-ahead and real time spot markets as suppliers under normal circumstances.²⁹ The FERC SMD proposals include provisions for adding demand-side bidding. The demand side could participate as sellers by offering to supply operating reserves (agree to reduce consumption at the ITP's direction).

Suppliers can reflect various physical characteristics (such as ramp rates, minimum run times and high/low operating levels and cost components in their offers. In both the day-ahead and real-time markets, sellers would have the option of submitting multi-part bids, e.g. submitting separate but related bids for start-up costs, no load costs and energy are allowed to bid a wide schedule of offers.

The day-ahead market price is a forward price, while the real-time market price is called the spot price, since it is based on the actual physical delivery of energy. In fact, in most of the existing ISO markets, almost all of the power delivery is settled day-ahead, with only minor deviations settled in real time (i.e., to the extent a buyer or seller is short in its power position, it must purchase power at the applicable real-time price for the excess amount). The day-ahead price and real-time price have converged in the more efficient markets, such as the PJM-ISO.

Mechanisms to increase generation investment vary between ISOs. FERC's SMD proposals call for termination of the existing programs in favor of resource adequacy planning requirements. Existing programs entail a capacity market with payments made to generation owners and payments made by load serving entities. Various complaints have been made about existing programs ranging from charges of market manipulation by generation owners to concerns that the present programs are ineffective in promoting new generation investment. Another complaint is that the existing program does not encompass demand-side contracts that are good substitutes for incremental generation. FERC proposes to replace the present programs with a resource adequacy requirement under which load serving entities (retail suppliers) would be required to show that they have sufficient future resource commitments to meet projected future demand.³⁰ Load serving entities could meet this requirement in a wide variety of ways including demand-side load reduction agreements, existing generation, contracts for new generation, firm transmission and generation contracts for supply from outside the ITP area, and contracts for new transmission needed to access outside generation sources. Under FERC's proposals, failure to meet resource adequacy requirements would result in fines and an increased probability of being blacked out during system emergencies.

Assessments of the U.S. experience with wholesale spot markets have emphasized the adverse effect of poorly designed market rules.³¹ One of the widely accepted conclusions of these studies is that poor market rules can result in the exercise of market power. In particular, analysis of the market rules affecting California during the period of high prices and reliability problems suggest that suppliers developed strategies specifically to take advantage of provisions in the market rules that facilitated the exercise of market power.³² Although some suppliers eventually may be found to have violated the market rules, other exercises of market power appear to have been within the rules, even if they were harmful to customers and to market efficiency. A general consensus exists that good market rules are essential to effective competition and that one of the primary responsibilities of market monitoring organizations is to identify revisions in market rules that foster inefficiencies and the exercise of market power and propose improvements.

(5) *Bilateral, Long-Term and Forward Contracts*

With the partial exception of the California ISO prior to 2002, bilateral, long-term supply contracts have been and are allowed in U.S. wholesale electricity markets. FERC's resource adequacy proposals would encourage such contracts in the sense that they are treated as substitutes for owning generation capacity. States with retail competition regimes and generation divestiture requirements often did require multi-year vesting contracts (as part of the POLR program) for generation units that were divested by the incumbent utility. States that have not implemented retail competition often have resource adequacy requirements in place that allow some substitution between owned generation and contracted generation.

The general expectation is that the presence of bilateral long-term contracts reduces volatility in average wholesale electricity prices. The presence of long-term bilateral contracts covering much of real-time consumption limits the magnitude of wealth transfers that would occur in the event of a spot market price spike and requirements that all sales be through the spot market. For example, while wholesale prices surged throughout the western U.S. during latter half of 2000, resulting wealth transfers were proportionately much smaller outside of California because most electricity trades outside of California took place under long-term contracts (or under cost-of-service regulation from the retailer's own generation facilities.). Wholesale electricity customers in California were not hedged against increases in wholesale spot market prices.

(6) *Price and Quantity Controls*

The spot market price increases in California (and price increases for short-term bilateral contracts in the other western states), during the latter half of 2000, resulted in a crisis for wholesale price regulation at FERC. As stated earlier, nearly all generators in nearly all areas of the U.S., including California, were authorized by FERC to charge market-based rates for wholesale electricity sales. Market-based rates were granted because nearly all generators passed FERC's existing ex ante screen for market power. However, FERC determined, on an ex post basis, that some wholesale prices in California were not Ajust and reasonable, as required by law. Subsequently, FERC, the states, and the ISOs have been developing a variety of additional approaches to identify and remedy market power problems in U.S. wholesale electricity markets.

The fundamental market power issues in U.S. electricity markets stem from historical circumstances and cannot be addressed directly by U.S. antitrust laws and agencies. Over the past century when rate-of-return and service regulation was expected to continue indefinitely, mergers generally took place between electric utilities with regulatory review, but without antitrust review. Indeed, local regulated

monopolies were the norm and mergers between neighboring local monopolies offered various cost savings that were shared with retail customers. Further, the grid was not developed with high volume wholesale trading in mind. As a result, high concentration and constrained transmission persist in some areas. Although the U.S. antitrust laws were designed to protect competition and prevent monopolization, they were not designed to create or restore competition.³³ Under U.S. antitrust laws, monopolies and market power are not *per se* illegal and neither is the unilateral exercise of market power. Hence, the burden of ensuring that market structure supports competition in electric power markets falls to FERC and to state utility commissions. Efforts to undertake broad deconcentration of electric power markets through divestitures have not been implemented. Several of the states that decided not to implement retail competition did so in part based on studies of local market power problems that might arise under retail competition.³⁴

Absent structural remedies, efforts directly to curtail market power in U.S. wholesale electric power markets³⁵ have focused on bid and price caps and assessment of capacity withholding.³⁶ For example, FERC imposed a variety of bid caps in response to high wholesale spot market prices in California. FERC also has sought to determine if generators were withholding capacity in order to drive up wholesale prices in California.

Generally, when a generator is determined to be critical for system reliability reasons or because of other indications of market power, the ISO can require that supplier to operate at prices that are based on the plant's costs.³⁷ PJM, NYISO, and NEISO all have \$1,000/MWH bid caps.³⁸ The NYISO has implemented a variety of additional market power mitigation approaches that are triggered by congestion conditions or bids that are high relative to a supplier's previous bids.³⁹

An important new development regarding price and quantity controls is the FERC proposal to require forward contractual commitment of capacity by suppliers with market power. FERC's SMD proposals include provisions that require a supplier contractually to commit itself to supply the market during periods in which the supplier has market power as determined by the annual assessments of the market monitor in the region.⁴⁰ The intent of these proposals is to prevent withholding by suppliers with market power. FERC would institute these requirements as part of the transmission access contract between a supplier and the ITP.

FERC's SMD proposals include penalties for withholding capacity and investigations of unscheduled withdrawals of capacity.⁴¹ Similarly, penalties are proposed for failure to supply power when a generator has bid⁴² or for consumption of power beyond the contracted amount by load serving entities.⁴³

(7) *Policies Affecting Entry and Expansion*⁴⁴

There are a variety of policies that favor or discourage entry in generation. Generation entry is encouraged under a wholesale competition regime by the prospect of earning returns greater than those that were allowed under regulation. Other policies that encourage generation entry include existing installed capacity programs of the ISOs, state resource adequacy requirements for traditional electric utilities, and FERC's proposed resource adequacy requirements. Entry of existing generators into more distant markets (through enhanced transmission access) is encouraged by policies that lower transmission transactions costs⁴⁵ and policies to give to merchant transmission investors the FTRs associated with their investment projects.

Entry is discouraged by policies that delay or increase uncertainty about obtaining permission to site new plants and transmission lines. (Considerable controversy surrounds the appropriate weight that states should give to environmental concerns, neighborhood esthetics, and safety considerations relative to

regional growth and efficiency priorities.) Entry is discouraged by bid caps, other market power remedies, and other sources of regulatory risk (e.g., ex poste refunds). Entry also may be discouraged by the policies that pool capacity reserves creating incentives for load-serving entities to free ride on the capacity reserves of other load serving entities.⁴⁶

The advent of retail competition has prompted a considerable amount of new generation investment in the affected states, primarily by independent generators. In general, areas with retail competition have seen substantial new generation investment.⁴⁷ The vast majority of new capacity has been and is expected to be natural gas-fueled generation.⁴⁸ Natural gas appears to be the fuel of choice for new generation projects in part because of its relatively benign environmental effects, flexibility (low ramp up costs and delays), and technical improvements in the efficiency of natural gas generators. In the case of California, recent entry has also been encouraged by streamlined siting procedures.

FERC's intense interest in resource adequacy as part of its market power mitigation strategy is consistent with research findings of the California ISO's market monitor that when capacity reserves exceed 14% to 19% of reliable capacity, wholesale electricity spot market prices are less volatile and less likely to display increases associated with exercise of market power.⁴⁹

(8) Competition Law Enforcement

Mergers

The most recent publicly disclosed merger investigation between electric power suppliers involved a proposed acquisition of generation assets in Connecticut by another generation owner with plants in the same area. Investigation by the Attorney General of Connecticut indicated that the proposed acquisition by NRG of two generating facilities (with combined capacity of over 1000 MW) in New Haven and Bridgeport from Wisvest would substantially increase generation concentration in parts of the state that faced transmission constraints during peak demand periods.⁵⁰ The Connecticut Attorney General presented his concerns to FERC. FERC subsequently set a technical conference on the competitive effects of the sale. The parties cancelled the sale.⁵¹

The most recent, publicly disclosed convergence merger case involved an electric power distributor (DTE) and a natural gas distributor (MichCon) that both serve the Detroit, Michigan, area.⁵² In that investigation, the FTC staff found that electric power distribution services competed with natural gas distribution services for some customers and that the competition between the two would likely increase over time (absent the merger). The case was settled with an agreement by which the acquirer divested a perpetual right to use a portion of the natural gas distribution system in the Detroit area to a new entrant. The capacity available to the entrant can be increased as demand grows for end uses, subject to competition between gas and electric distribution services. The settlement was modeled on release capacity arrangements, which were effectively implemented previously for interstate natural gas pipelines.

Another notable FTC convergence case involved the acquisition of Peabody Coal Company (the largest U.S. coal supplier) by PacifiCorp, a generation owner in the western states.⁵³ An initial settlement was reached. The FTC complaint found that PacifiCorp would have had the ability profitably to increase prices in its electricity sales by raising the costs of coal to two large coal-fueled generators owned by its generation competitors. Peabody was the only practical coal supplier for these plants. These generators were likely to be marginal units at some times of the year in the Western Interconnect where PacifiCorp made wholesale electric power sales. The FTC staff also found that proprietary information on coal prices and use (available to PacifiCorp from acquiring Peabody) might allow PacifiCorp profitably to increase the prices of its wholesale electricity offers.

Collusion

There have been no recent, publicly announced antitrust investigations of collusion between electric power suppliers. To date, the investigations associated with the period of high prices and reliability problems in California have focused on unilateral activities. However, concerns about coordination between suppliers also have been expressed in the investigation of Enron's trading practices in the Western Interconnect.⁵⁴

Abuse of Dominance

There have been no recent, publicly announced antitrust investigations of monopolization or attempted monopolization by electric power suppliers.

FERC has received various complaints about discrimination in transmission access that entail a vertically integrated utility allegedly acting to increase the generating costs of its competitors. FERC apparently has found enough substance in these complaints to continue to propose additional forms of vertical separation between generation and transmission.

FERC investigations associated with increased wholesale market spot prices in California might also be viewed as investigations of abuse of dominance, however, none of the firms involved were dominant in the sense of owning large shares of the generation in the markets that include California. Part of the crisis in regulation triggered by the California events is that firms accused of exercising market power held relatively modest shares of total capacity in California and the West more generally. This fact has focused attention on aspects of electric power markets that may allow firms with modest market shares to exercise market power. It has also focused attention on assessments of market structure other than overall market concentration.

APPENDIX

**United States Electricity Statistics Excerpted from the Web Pages of the
U.S. Department of Energy
Energy Information Administration**

Data for 2000 (except where noted)

U.S. Net Production (Generation): 3,799,944 Million Kilowatthours

Utility: 3,015,383 Million Kilowatthours (79.4%)
Nonutility: 784,561 Million Kilowatthours (20.6%)

Retail Price Components

	Cents per kilowatthour	%
Generation	4.3	62.3
Transmission	.6	8.7
Distribution	2.0	29.0

Share of Industry Net Generation by Energy Source

Coal:	51.8%
Nuclear:	19.8%
Gas:	16.1%
Hydro:	7.2%
Oil:	2.9%
Other:	2.2%

U.S. Consumption (Retail Sales): 3,421,414 Million Kilowatthours

Average Retail Prices of Electricity Sold by Electric Utilities

(Cents per Kilowatthour)

Total	6.81 cents
Residential	8.24 cents
Commercial	7.43 cents
Industrial	4.64 cents
Gov. & railroads	6.56 cents

Electric Generating Capability (Megawatts)

Total	811,625 Megawatts
Utility	602,377 Megawatts
Nonutility	209,248 Megawatts
Number of Electric Utility Plants: 2,776	

Number of Customers

Total	127,567,517
Residential	111,717,711
Commercial	14,349,067
Industrial	526,554
Other	974,185

Number, Share of Capacity, and Share of Retail Quantity Sold, 1998

Class of Entity	Number	Share of Capacity (Nameplate)	Share of Retail Quantity Sold (Kilowatthours)
Investor-Owned	239	64.2%	75%
Cooperatives	912	3.9%	9%
Non-Federal Public	2,009	11.5%	15%
Federal	10	8.4%	1%
Nonutility Generators	2,110	11.9%	

State With Highest Average Electricity Price: Hawaii (14.03 Cents/ Kwh)

State With Lowest Average Electricity Price: Idaho (4.17 Cents/ Kwh)

Electric Utility Emissions, 1999 (Thousand Short Tons)

Sulfur Dioxide Nitrogen	11,9
Nitrogen Oxides	7,
Carbon Dioxide	2,191,576

Electric Utility Fossil-Fuel Costs (cents per million Btu)

Coal	120.0 cents
Petroleum	445.0 cents
Natural Gas	430.2 cents

Power Transactions

On a national basis in 1999, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased by 50 billion kilowatthours to reach 2,564 billion kilowatthours. Sales to ultimate consumers totaled 3,312 billion kilowatthours (including sales by retail power marketers), and 1,636 billion kilowatthours of this (49 percent) are from wholesale trade with other electric utilities (requirement and nonrequirement sales for resale). To supply electric energy in 2000, electric utilities had planned capacity resources on-hand for the summer of 766 million kilowatts and 779 million kilowatts for the winter, resulting in national capacity margins of 14.8 percent and 25.7 percent, respectively.

Transmission

The U.S. bulk power system has evolved into three major networks (power grids), which also include smaller groupings or power pools. The major networks consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. The three networks are (1) the Eastern Interconnected System, consisting of the eastern two-thirds of the United States; (2) the Western Interconnected System, consisting primarily of the Southwest and the areas west of the Rocky Mountains; and (3) the Texas Interconnected System, consisting mainly of Texas. The Eastern and Western Interconnects are completely integrated with most of Canada or have links to the Quebec Province power grid.

Overall reliability planning and coordination of the interconnected power system are the responsibility of NERC, a voluntary association. NERC has 10 regional councils that cover the 48 contiguous states and portions of Canada and Mexico. The councils are responsible for overall coordination of bulk power policies that affect the reliability and adequacy of service in their areas.

Electric Power International Trade

Imports of electricity in 1999 by electric utilities in the United States increased 3.7 billion kilowatthours to approximately 43 billion kilowatthours, while exports rose 11.7 percent to over 14 billion kilowatthours. Trade with Canada accounted for the vast majority of both imports and exports.

Demand-Side Management

In 1999, 848 electric utilities reported having demand-side management (DSM) programs. Energy savings for the 459 large electric utilities increased to 50.6 billion kilowatthours, 1.4 billion kilowatthours more than in 1998. These energy savings represent 1.5 percent of total annual electric sales of 3,312 billion kilowatthours to ultimate consumers in 1999. Potential peak load reductions of 43,570 megawatts were an increase of 2,140 megawatts over 1998.

NOTES

1. These materials have been organized by John C. Hilke, Ph.D., Economist and Electricity Project Coordinator, United States of America Federal Trade Commission, Bureau of Economics, Division of Economic Policy Analysis (801-524-4440 or jhilke@ftc.gov).
2. Issues regarding state retail competition programs were the subject of a Federal Trade Commission staff report entitled Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform: Focus on Retail Competition. The report was issued by the FTC in September 2001, available at <http://www.ftc.gov/reports/elec/electricityreport.pdf>.
3. See John C. Hilke and Michael Wise, AWho Turned Out the Lights? Competition and California's Power Crisis, Antitrust 15:3 (Summer 2001), for a discussion of the circumstances and policy decisions leading to California's reliability difficulties and unusually high electricity prices. The period of elevated prices and reliability problems in California lasted from approximately May 2000 to September 2001.
4. United States of America Federal Energy Regulatory Commission (FERC), Notice of Proposed Rulemaking (July 31, 2002), Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design.
5. FERC and state commissions also divide responsibilities for regulating the natural gas sector. Most of the natural gas extraction sector has been deregulated through legislation. [See, i.e., Natural Gas Policy Act of 1978 and the Natural Gas Wellhead Decontrol Act of 1989.] FERC retains authority to regulate prices and service levels of natural gas interstate pipelines, but has implemented extensive regulatory reforms in this sector that have substantially increased competition. These measures include standardization of terms of business practices and contracts in natural gas trading and transportation, and market rules by which control of a portion of capacity within a pipeline can be obtained by parties other than the pipeline owner (a Astraw-in-the-pipe concept). State public utility commissions general retain jurisdiction over rates and service for local natural gas distribution. Several states have customer choice programs (retail competition) regarding the supplier of natural gas even though local gas transportation usually continues as a franchised, regulated, monopoly.
6. FERC's market power screen for determining whether market-based rates for wholesale electricity sales should be granted has been subject to considerable debate. Recently, FERC adopted an alternative, more stringent market power screen, but anticipates that the market power evaluation and remedy portions of its SMD proposals may impact substantially the existing market-based rates screening process and may eliminate the need for a market power analysis for individual utilities.
7. Often state legislation to implement a customer choice programs requires that POLR service be offered at a price that is a fixed percentage below previous regulated prices and that this price level be maintained for several years.
8. Although each time period constitutes a separate product market and geographic market, analysis of groups of time periods with similar conditions makes the process more manageable.
9. In a bid-based market, all bidders that are dispatched receive the market clearing price. This price is the bid of the highest priced generator that is dispatched.

10. In a bid-based, single price, market with merit order dispatch, the generator with the highest bid that is dispatched is the generator at the margin. Its bid sets the market clearing price.
11. These areas were California, Pennsylvania and other mid-Atlantic states, New York, and New England. Texas also organized its Interconnect (ERCOT) on this basis.
12. FERC Order 2000 included four minimum characteristics of regional transmission organizations to ensure robust wholesale competition: independence from generation owners, geographically broad scope and regional configuration, authority to operate the grid on a nondiscriminatory basis, and operation of the grid to ensure short-term reliability. FERC also required that each regional transmission organization carry out seven minimum functions: designing and administering tariffs for use of the grid, managing congestion on the grid, managing parallel path flows, offering ancillary services, managing creation and distribution of information on transmission availability, monitoring market behavior, and planning and expansion of the transmission grid.
13. The antitrust agencies have provided comments to FERC during the evolution of unbundling policies at FERC. For example, in its competition advocacy comments on FERC proposals for Order 888, the FTC staff questioned the effectiveness of behavioral rules to prevent discrimination in transmission services. In comments on proposals for Order 2000, the FTC staff generally supported the minimum characteristics and functions of RTOs identified by FERC, but encouraged FERC to add provisions that would increase incentives for RTOs to operate efficiently and to provide customer service. In comments on the initial standard market design proposals, the FTC staff elaborated on its efficiency concerns about RTOs and highlighted the option of requiring forward bilateral contracting by generators with market power as a potential structural remedy.
14. The established ISOs each have a market monitoring unit already. California also has a separate market surveillance committee whose members include academics and other electric power economic experts.
15. The bid cap would prevent a generator from bidding above a given level, but would not prevent it from receiving the market-clearing price if this price exceeded the bid cap and the plant is dispatched by the market operator.
16. This type of divestiture does reduce vertical integration between generation and transmission and may, therefore, reduce vertical discrimination problems.
17. Under a vesting contract, a load-serving entity retains the right to purchase electricity (from the new owner of its divested generation assets) at predetermined prices (sometimes with a fuel-cost adjustment clause, however) for the duration of its POLR obligation.
18. The state of Maine takes a different approach. It bids out the POLR contracts to the lowest priced, reliable generation bidder.
19. Expectations that customer buying groups would form to arrange bilateral contracts at lower prices were not fulfilled.
20. Because the California divestitures of generation did not have associated vesting contracts, the bids for these generators were higher than initially expected. This reduced the amount of stranded costs to be recovered by the divesting utilities.
21. PJM stands for Pennsylvania, New Jersey, and Maryland. The state of Delaware and the District of Columbia are also within PJM.
22. The holder of an FTR is entitled to the revenues charged to users of a transmission line because of congestion on that line over a particular time period. If the holder of the FTR elects to use the line during this period, it is able to use the line with no net financial cost to itself other than the price of obtaining the

FTR. Essentially, it can outbid any other user because it gets back any congestion charges on the line by owning the FTR.

23. PJM Market Monitoring Unit, PJM Interconnection State of the Market Report 2001 (June 2002), p. 119. Pages 115 to 141 of this report provide a description of PJM's FTR process, history, and results.
24. Indirectly, LMP may reduce market power by providing efficient pricing signals for generation and transmission investments.
25. See, for example, Coalition for a Competitive Electric Market, A Capacity Rights Open-Access Tariff for the Pennsylvania-New Jersey-Maryland (APJM) Interconnection, filed before FERC, June 19, 1997, and the CREPC Transmission Pricing Working Group, A Transmission Pricing in the Western Interconnection, November 13, 2000.
26. Transmission policy discussions at the Analysis Group Economics Conference on Electric Industry Restructuring Issues, Chicago, Ill., September 10, 2002.
27. United States of America Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000 (July 31, 2002). Public comments are due on November 15, 2002.
28. By contrast, the major California utilities relied primarily on the spot market until the final weeks of 2000. Most purchases of electricity by the major retail utilities (including procurement from their own generation facilities) were made through spot market purchases on the authorized exchange. Few bilateral trades or trades on private exchanges were allowed for the major retail utilities, although some long term forward contracting was allowed on the authorized exchange starting in 1999. [Carl Blumstein, et al., The History of Electricity Restructuring in California, CSEM working paper #103 (August 2002) available at <http://www.ucei.berkeley.edu/ucei/>.] The requirements for the major utilities to use the authorized exchange appear to have been engendered by a desire to spread the costs of establishing the exchange over a large volume of transactions and a concern that spot market trading would otherwise be thin and subject to inefficiencies. When FERC removed the requirement to trade on the California PX, the volume of trade on the PX declined rapidly and the PX was forced to file for bankruptcy.
29. During the period of elevated wholesale spot market and short-term bilateral contract prices in California and the Western Interconnect in late 2000 and much of 2001, some exceptions were made on an ad hoc basis under which load serving entities (retail suppliers) paid some large industrial users (aluminum refiners, for example) to cease operating entirely for an extended period of time.
30. FERC bases its resource adequacy proposals on two concerns. First, price caps and other constraints that FERC expects to impose to prevent the exercise of market power will, at the same time, curtail investment incentives. Second, FERC perceives that there is a substantial free-rider problem regarding capacity reserves. FERC is concerned that individual load-serving entities underinvest in capacity reserves because these retail suppliers view pooled capacity reserves as a public good to which all load-serving entities have access on an equal, as needed, basis.
31. For example, see, the California ISO's Market Surveillance Committee report of September 6, 2000 entitled An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets.
32. Initial Report on Company-specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies, A Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, in Docket No. PA02-2," issued by FERC on August 13, 2002 and available on the FERC web site at: <http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm>.

33. An exception is when an antitrust agency challenges a completed merger and seeks divestiture of the acquired assets (usually of recently acquired assets). In such cases, the emphasis remains on future anticompetitive effects. Post acquisition evidence of an increased exercise of market power is used primarily to lend credibility to concerns about future exercises of market power.
34. The State of Colorado, for example, studied local market power issues in detail prior to deciding not to implement retail competition at this time. AIn 1998, the Colorado legislature established the Electricity Advisory Panel ... to study restructuring. The panel hired Stone & Webster (consulting firm) to determine whether the price we pay for electricity would be higher or lower than regulated prices if retail competition were introduced. Using complex economic models, Stone and Webster concluded that ... restructuring would lead to prices up to 29 percent higher than prices under regulation. Their conclusion is based on the economics of retail competition in low-cost states like Colorado, and would be exacerbated by Public Service Company's ability to control prices as the dominant supplier...≅ [Office of Consumer Counsel, State of Colorado Department of Regulatory Agencies at <http://www.dora.state.co.us/occ.>]
35. Indirectly, policies leading to elimination of transmission rate pancaking, implementation of organized spot markets, and installation of new natural gas pipeline capacity, for example, also are likely to reduce local generation market power. Pancaking occurs where an ISO (or RTO) is not in operation. In such areas, each time a wholesale electricity trade involves using the facilities of a different transmission owner, additional fees are charged.
36. For discussion of FERC's initial proposals of this type, see the FTC staff comment in FERC Docket No. EL01-118-000, filed on January 7, 2002.
37. In PJM, for example, must-run units built before July 9, 1996 receive the greater of cost plus 10% or LMP. [Joseph E. Bowring, AMarket Monitoring in PJM, presentation to the SSG-WI Market Monitoring Workshop, San Francisco, CA (November 16, 2001); available on the Internet at <http://www.casio.com.>]
38. Alice Fernandez, A Conference on Standard Market Design Issues, January 22-23, 2002, FERC..
39. Alice Fernandez, A Conference on Standard Market Design Issues, January 22-23, 2002, FERC..
40. FERC SMD NOPR, Section IV.I.3.
41. FERC SMD NOPR, paragraphs 445 and 446.
42. FERC SMD NOPR, paragraphs 445 and 446.
43. FERC SMD NOPR, paragraph 534.
44. The policy concern is efficient entry. Encouraging entry per se is not generally the policy objective.
45. Examples of reductions in transmission transactions costs include standardization of trading terms and arrangements, introduction of spot markets, and elimination of pancaked transmission rates.
46. FERC SMD NOPR, paragraphs 460 to 473.
47. For planned generation expansion statistics in the states with retail competition, see the FTC staff report of September 2001.
48. The U.S. Department of Energy's Energy Information Administration reports planned generation additions. The report for 2000 indicates that 91% of U.S. planned capacity is natural gas fueled (47,549 MW out of 52,216 MW on a nameplate basis). At present, natural gas fueled units account for 20% of installed, nameplate capacity. [Table 14. AExisting Capacity and Planned Capacity Additions at U.S. Electric

Utilities by Energy Source, North American Reliability Council Region, Alaska, and Hawaii, 2000," available on the Internet at:

<http://www.eia.doe.gov/cneaf/electricity/ipp/html1/t14p01.html>.]

49. Anjali Sheffrin, APreliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition, California ISO Market Analysis Division (revised, November 19, 2001). [Available on the Internet at the California ISO's web site: caiso.com.]
50. A Attorney General's Statement on Today's Announcement that NRG Will Not Acquire Wisvest's Plants in New Haven, Bridgeport (September 20, 2001) available at: <http://www.cslib.org/attygen/press/2001/nrgno.htm>.
51. A Compilation of Investor-Owned Utility Transactions for 2002, available at: <http://www.appanet.org/about/statistics/plantacquisitions.cfm>.
52. The case, its issues, and the terms of the settlement are described in John C. Hilke, A Convergence Mergers: A New Competitive Settlement Model from Detroit, Electricity Journal (October 2001), pp. 13-18.
53. Analysis of Proposed Consent Order to Aid Public Comment in the Matter of PacifiCorp et al., FTC File No. 971-0091 (February 18, 1998). This settlement became moot and was never finalized because another buyer outbid PacifiCorp.
54. FERC letter to El Paso Electric Company, regarding Show Cause Order in PA02-2. Available on the Internet at: <http://www.ferc.gov/electric/bulkpower/pa02-2.htm>.

EUROPEAN COMMISSION

1. Overview of the regulatory framework

1.1. "Electricity directive" adopted in 1996

At European Union level, the Council of Ministers and the European Parliament adopted in December 1996 a directive, 96/92 EC, establishing common rules on the internal electricity market. This directive entered into force on 19 February 1997. EU Member States had two years to bring into force the laws, regulations and administrative provisions necessary to comply with this directive¹. The directive established common rules for the generation, transmission and distribution of electricity:

- Generation: Member States could choose between two different procedures or mixes of the procedures for the construction of new generating capacity: authorisation or tendering procedures. Whatever procedure chosen it must be conducted in accordance with objective, transparent and non-discriminatory criteria.
- Transmission: transmission is defined as the transport of electricity on the high-voltage interconnected systems. Member States had to designate or require undertakings which own transmission systems to designate a system operator to be responsible for operating, ensuring the maintenance and if necessary developing the transmission system in a given area and its interconnectors with other systems in order to guarantee security of supply.

The transmission system operator (TSO) is responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems. The criteria for the dispatching must be objective, published and applied in a non-discriminatory manner. This implies that the TSO is not allowed to favour its vertically integrated generation branch. Priority in the dispatching could also be given to electricity produced using indigenous fuels but only up to 15% in a calendar year of the overall primary energy necessary to produce the electricity consumed in the Member State.

- Distribution: distribution is defined as the transport of electricity on the medium-voltage and low-voltage interconnected systems. As in the case for transmission, a system operator had to be designated to be responsible for operating, ensuring the maintenance and if necessary developing the transmission system in a given area and its interconnectors with other systems. The distribution system operator is responsible for maintaining a secure, reliable and efficient electricity distribution system in its area with due regard to the environment. For environmental reasons a Member State may require the TSO to give priority in the dispatching to electricity produced from renewable source, waste and from combined heat and power. The operator must not discriminate between the system users and in particular not favour its subsidiaries or shareholders. A Member State may also impose on distribution companies public services obligations.
- Unbundling: vertically integrated electricity companies must in their internal accounting keep separate accounts for their generation, transmission and distribution activities. If they undertake other non-electricity activities these other activities must be accounted for separately just as if

these were carried out by separate undertakings. There should also be a separate management for electricity transport activities. The aim of unbundling is to avoid discrimination, cross-subsidies and distortions of competition.

- **Access to the network:** Member States could choose between negotiated and regulated third party access or a single buyer procedure when organising the access to the transmission and the distribution network. All procedures should be objective, transparent and non-discriminatory criteria.
- **Market opening:** the directive provided for a gradual market opening in three steps on February 1999, February 2000 and February 2003 respectively. The minimum thresholds for opening the markets were fixed at 30% of demand, and have been increased to 40%. Member States themselves define the eligible customers to participate in the market opening. Very large final consumers of over 100 GWh had to be included in the definition of eligible customers.
- **Public service obligations:** Member States can impose public service obligations on electricity companies. These obligations are defined by Member States individually within a Community framework as laid down in the directive. The Member States define these obligations in detail; they must be clearly defined, transparent, non-discriminatory, verifiable and published. The obligations fall into one of the following five categories: security of supply, regularity, quality and price of supplies and environmental protection.

Implementation of the Electricity Directive by EU Member States

The different quantitative and qualitative elements of the implementation by EU Member States of the electricity directive, and, in general, of electricity market liberalisation are presented in the table below².

	Declared market opening (%)	Full opening date	Unbundling: transmission system operator	Unbundling: distribution system operator	Regulator	Overall network tariffs	Balancing conditions favourable to entry	Biggest three generators' share of capacity (%)
Austria	100	2001	Legal	Accounting	ex-ante	above average	moderate	50
Belgium	52	2003/7	Legal	Legal	ex-ante	average	unfavourable	96 (2)
Denmark	35	2003	Legal	Legal	ex-post	average	favourable	78
Finland	100	1997	Ownership	Management	ex-post	average	favourable	45
France	30	-	Management	Accounting	ex-ante	average	moderate	92
Germany	100	1999	Legal	Accounting	NTPA ¹	above average	moderate	64
Greece	34	-	Legal/Mgmt	Accounting	ex-ante	average	moderate	98 (1)
Ireland	40	2005	Legal/Mgmt	Management	ex-ante	average	moderate	90 (1)
Italy	45	nhh ² in 2004	Legal/Own	Legal	ex-ante	average	moderate	69
Lux	57	-	Management	Accounts	ex-ante	above average	unfavourable	n.a.
Neth	63	2003	Ownership	Management	ex-ante	average	moderate	59
Portugal	45	2003	Legal	Accounting	ex-ante	average	moderate	82
Spain	55	2003	Ownership	Legal	ex-ante	average	favourable	83
Sweden	100	1998	Ownership	Legal	ex-post	average	favourable	90
UK	100	1998	Ownership	Legal	ex-ante	average	favourable	36

¹ NTPA=Negotiated third party access ² nhh= non-household customers

1.2. European Commission proposal of March 2001 to modify the "electricity directive"

A relatively rapid advancement could be observed in the liberalisation of electricity markets in the EU, since a majority of Member States decided to open the markets further than required by the directive. However, the directive did not foresee full market opening, and the actual level of market opening achieved differs significantly among Member States.

So as to complete liberalisation and avoid imbalances, the European Commission proposed to the Council and to the European Parliament in March 2001 a directive modifying the directive 96/92³. The Commission transmitted to the Council of Ministers and to the European Parliament an amended proposal in June 2002. This is the so-called "acceleration directive". The main contents of this proposal are the following:

- Full market opening for electricity in two steps:
 - in 2004 all non-domestic consumers should become eligible, that is to say, free to choose their supplier, and
 - in 2005 all consumers should become eligible to choose their electricity supplier.
- New generation capacity can be built on the basis of an authorisation regime only.
- Strengthening of the unbundling provisions safeguarding the independent behaviour of the transmission system operator: a legally separate company is required.
- Same provisions for unbundling of the distribution system operator, however subject to a possible threshold. Companies with less than 100.000 clients can be exempted from the obligation to legally unbundle the distribution system operator.
- Obligation to establish independent national regulators, with minimum powers: the setting or approving of tariffs and conditions for access to the network, responsibility for the national implementation of rules pertaining to cross border tariffication and congestion management. The option currently available to Member States of adopting a network access system negotiated among actors involved disappears.
- Safeguarding high levels of public service through introduction of universal service requirement in electricity, obligation to protect vulnerable customers, protection of final customers, benchmarking existing public service levels.
- Safeguarding security of supply by including yearly monitoring report on Member States of the demand and supply balance, and the obligation to take appropriate action should the demand/supply balance risk to be disrupted. Member States may also impose minimum investment obligations for the maintenance and development of the transmission system, including interconnection capacity.

1.3. *European Commission proposal for a Regulation on conditions for access to the network for cross-border exchanges in electricity*

Cross-border trade in electricity is currently equivalent – in terms of physical flows - only to around 8% of total electricity production, a figure which is relatively modest when compared to other sectors of the economy.

The proposed regulation would help promote cross-border trade in electricity. Its main contents are as follows:

- Creation of a compensation mechanism under which compensation payments are to be received by transmission system operators hosting transit flows of electricity on their network, financed through contributions of those TSOs causing these transit flows. The Commission, as an independent objective body, would finally decide on the level of compensations payable (after consulting a Comitology Advisory Committee made up of representatives of Member States, which would deliver an opinion but cannot block the decision of the Commission).
- As regards the establishment of the costs of transits for compensations are to be received, the concept of “forward-looking long-run average incremental costs” is proposed in the draft Regulation. This concept was developed in the context of interconnection pricing for telecommunication networks (see Commission recommendation of 8 January 1998). Due to the forward looking approach, it ensures adequate compensation and thus return on investment for new installations needed to host transits, in order to provide appropriate incentives for operators to make such investment.
- Harmonisation of national network access tariffs, as far as necessary to ensure a proper functioning of the internal market, i.e. undistorted competition. Most important provision: no specific charge on exporters and/or importers (“socialisation”). However, the level of the tariffs may vary depending on the location of generation and/or consumption, provided that the physical flows and – consequently – costs caused justify such a differentiation (“locational signals”).
- Harmonisation of rules on the allocation of interconnector capacities (congestion management) to ensure that scarce capacity is allocated on the basis of market-based mechanisms, avoiding any kind of negative or positive discrimination.
- Creation of a procedure allowing the adoption and amendment of Guidelines by the Commission, in which the basic principles contained in the Regulation would be further detailed. However, the Commission needs approval (qualified majority) of a Comitology Regulatory Committee of Member States when adopting these guidelines.

The Council of Ministers is currently discussing both the regulation on cross-border trade of electricity and the "acceleration directive".

2. Market Structure and Electricity Prices

A significant degree of concentration persists in electricity generation in many Member States, as the table below shows. The existence of generators with very high market shares is unlikely to be conducive to new entrants without tight control of wholesale and balancing markets. Thus, in order to deliver more effective competition many Member States have already carried out some release of

generation capacity from the dominant suppliers, such as the UK and Italy. Recent divestment by Enel has reduced their market share considerably.

Other Member States, such as France and Ireland, have made capacity from the incumbent generator available to the wholesale market through an auction procedure. In both cases, this was the result of the merger cases dealt with by the Commission.

Another advance has been the spread of power exchanges to almost all Member States. Although there is a significant variation in the degree of liquidity of these markets, they all contribute to the construction of a transparent market price which can only assist the development of the internal market. All Member States except Belgium, Luxembourg, Greece and Ireland have some form of standardised power exchange although some of these might ultimately be expected to use exchanges in neighbouring Member States.

Market Development Indicators: Concentration and New Entry

	Companies with at least 5% share of installed capacity 2000 data	Top 3 share (% installed capacity) ⁴ 2000 data	Installed capacity (GW) a	Import capacity (GW) b	Potential competition from imports b ÷ a	Expected new capacity in next 3 years (% installed capacity)	Power exchange Y/N
Austria	5	45%	18.2	3.8	21%	2%	Y
Belgium	2	96%(2)	15.7	3.9	25%	1%	N
Denmark	3	78%	12.7	5.0	39%	10%	Y
Finland	4	45%	16.6	3.7	22%	1%	Y
France	1	92%	115.4	16.6	12%	0%	Y
Germany	4	64%	118.3	13.1	11%	1%	Y
Greece	1	97%(1)	10.3	1.3	12%	34%	N
Ireland	1	97%(1)	4.8	0.3	7%	17%	N
Italy	4	69%	78.1	10.8	14%	8%	(Y)
Lux	n.a.	n.a.	1.2	1.2	100%	n.a.	N
Neth	6	59%	20.6	3.9	19%	3%	Y
Portugal	3	82%	10.7	3.2	30%	5%	(Y)
Spain	4	83%	52.6	2.1	4%	9%	Y
Sweden	3	90%	33.6	9.9	29%	n.a.	Y
UK	8	36%	78.9	2.7	3%	4%	Y

Source: Eurostat: Competition Indicators in Electricity Market and survey responses

As shown in the table below on customer activity in terms of switching and renegotiating supplier, in almost all Member States, the majority of large eligible customers have by now taken the opportunity to explore alternative suppliers, even if they end up retaining the previous one. For smaller customers it is of particular note that customer switching in Germany and Austria has increased in the last year.

Switching Estimates for the period 1998-2001 (source: Eurostat survey)

	Large eligible industrial users		Small commercial/domestic	
	switch	Switch or renegotiate	switch	switch or renegotiate
Austria	5-10%	unknown	5-10%	unknown
Belgium	2-5%	30-50%	not eligible	
Denmark	unknown	>50%	not eligible	
Finland	unknown	>50%	5-10%	10-20%
France	10-20%	unknown	not eligible	
Germany	20-30%	>50%	5-10%	10-20%
Greece	nil.	nil.	not eligible	
Ireland	10-20%	unknown	not eligible	
Italy	>50%	100%	not eligible	
Luxembourg	10-20%	>50%	not eligible	
Netherlands	20-30%	100%	not eligible	
Portugal	5-10%	unknown	not eligible	
Spain	10-20%	>50%	not eligible	
Sweden	unknown	100%	10-20%	>50%
UK	>50%	100%	30-50%	n.a.

It is worth noting that, as shown in the table below, in a number of cases price trends are distorted somewhat by regulatory rebalancing of distribution tariffs between different customer groups. This has occurred, for example, in Italy in Ireland in recent years. Such rebalancing makes it difficult to come to any conclusions about the effects of market opening in these cases.

It can be seen that prices in the UK, Germany and Austria have fallen across all consumer groups as a result of full market opening while prices in Sweden and Finland are stable at low levels. In other Member States, there is usually a group which is either missing out on falling prices, or experiencing rising prices.

Summary of price levels: January 2002

ELECTRICITY				ELECTRICITY			ELECTRICITY		
Large Users				Small Commercial			Household		
path since 1/1999	Low	Med.	High	Low	Med.	High	Low	Med.	High
Falling	SW	LX UK ES	DE	SW	AT UK IT	DE BE LX	GK	AT ES UK	DE IT
Stable	FI	FR NL	PT	FI	PT ES FR	IR	SW FI	FR NL	BE PT LX
Rising		DK GK	IT IR BE	DK	NL GK		DK	IR	

Austria: no data

The table below reports in wholesale prices prevailing in various power exchanges in each Member State. This shows a degree of price convergence during 2002. However the key exception to this is Spain where prices are significantly higher. This may be a result of the considerable concentration in the Spanish market and this underlines the importance of increased interconnection with neighbouring countries. The planned single Iberian market will also help alleviate these problems.

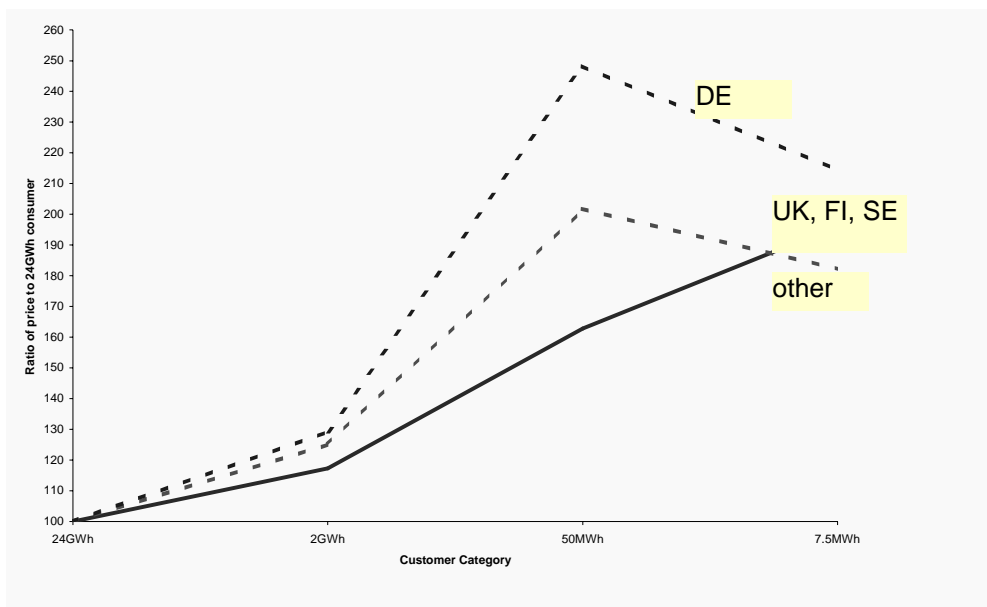
Average wholesale prices (€/MWh)

	FR	DE	AT	NL	Nordic	Spain	UK
Jan 2002 peak	34.1	35.3		35.7	25.7	71.4	38.4
Jan 2002 base	21.5	19.0		15.8	22.1	43.0	25.7
July 2002 peak	24.1	28.6	29.5	30.6	16.4	51.9	21.4
July 2002 base	13.2	12.1	22.3	11.3	14.0	33.8	12.1

Finally, the graph below compares the ratio of prices paid by different user groups. On the graph, the unit price to a customer using 24GWh has been set at 100 and the other user groups have been compared to that level. Countries have been grouped according to their current market opening policies.

Normally one would expect the ratios to be similar in each Member States since prices should reflect the additional network and billing costs of serving small customers. However in many cases the ratio between different prices is erratic and there is a clear indication that certain consumer groups, either households, small businesses or both, are paying disproportionately high prices in some Member States as a result of incomplete or ineffective market opening. This contrasts with the position in the UK and Nordic countries where the ratio between prices would appear to be more cost reflective.

Ratio of retail prices to different user groups



3. Transmission Network Access, Pricing, and Congestion

3.1. Tariffication and other access conditions

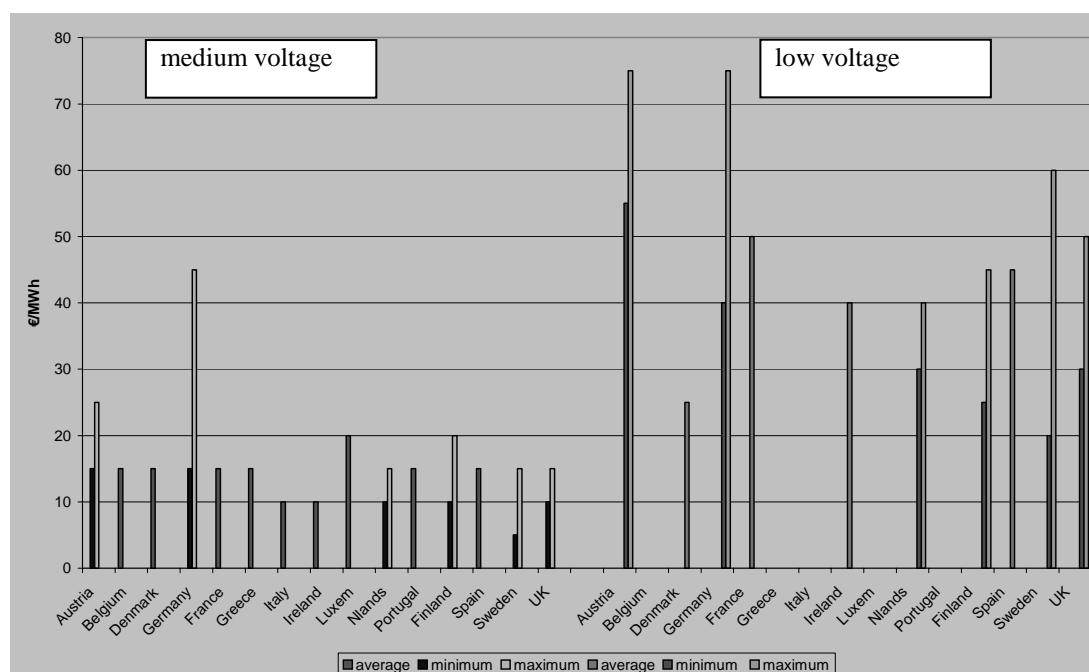
There is a wide variation between Member States in terms of the number of companies owning and operating the different parts of transmission and distribution network. This is, in most cases, a legacy of how electricity supply was organised prior to market opening. In some cases such as in France, Ireland and Greece, there is a single national company that owns both the transmission and most or all of the distribution system at national level. In other cases, like Germany and Austria, transmission systems may be operated on a regional basis, with distribution based on numerous individual municipal areas. Other Member States fall in between these two extremes in terms of the number of system operators.

The graphs below provide an analysis of the total network charges payable by customers in each Member State at two different voltage levels⁵ and other network related data.

Network access⁶

TOTAL NETWORK TARIFFS	Number of transmission companies	Number of Distribution companies	Medium Voltage		Low voltage	
			Estimated average charge (€/MWh)	Approx. range high-low (€/MWh)	Estimated average charge (€/MWh)	Approx. range high-low (€/MWh)
Austria	3	155	20	15-25	65	55-75
Belgium	1	33	15	n.a.		
Denmark	2	77	15	n.a.	25	unknown
Finland	1	100	15	10-20	35	unknown
France	1	172	15	n.a.	50	n.a.
Germany	6	880	25	15-45	55	40-75
Greece	1	1	15	n.a.		
Ireland	1	1	10	n.a.	40	n.a.
Italy	1	219	10	n.a.		
Luxembourg	-	15	20	n.a.		
Neth	1	18	10	unknown	35	unknown
Portugal	1	3	15	n.a.		
Spain	1	297	15	n.a.	45	n.a.
Sweden	1	248	10	5-15	40	20-60
UK	4	15	unknown	10-15	40	30-50

Estimated Level of Network Charges⁷



Unbundling of network operators

	Basic unbundling model		Published accounts		Compliance officer		Separate corporate identity		Separate locations		Total Yes
	TSO	DSO	TSO	DSO	TSO	DSO	TSO	DSO	TSO	DSO	
Austria	Legal	Account	Y	Y (large)	N	N	Y	N	Y	N	4
Belgium	Legal	Legal	Y	not yet	N	N	Y	Y	Y	some	5
Denmark	Legal	Legal	Y	Y	Y	Y	Y	N	Y	N	5
Finland	Own	Manage	Y	Y	Y	Y	Y	N	Y	large	6½
France	Manage	Account	Y	N	Y	N	Y	N	Y	N	4
Germany	Legal	Account	Y	Y (some)	N	N	Y	N	Y	N	4
Greece	Legal/M	Account	not yet	not yet	N	N	Y	N	Y	N	2
Ireland	Legal/M	Manage	Y	in part	Y	Y	Y	N	N	N	4½
Italy	Own/Leg	Legal	Y	Y	N	N	Y	Y	Y	Y	6
Lux	Manage	Account	Y	N	N	N	N	N	N	N	1
Neth	Own	Manage	Y	Y	Y	N	Y	N	Y	N	5
Portugal	Legal	Account	Y	Y	N	N	Y	N	Y	N	4
Spain	Own	Legal	Y	Y	Y	N	Y	Y	N	N	5
Sweden	Own	Legal	Y	Y	Y	N	Y	Y	Y	N	6
UK	Own	Legal	Y	Y	Y	Y	Y	often	Y	often	7

Network balancing

	Balancing period (minutes)	How are charges set	Supernational (S) National (N) or regional (R) balancing	Balancing groups allowed	Intraday market possible	“Gate closure”	Dominant single generator within balancing area?	Overall assessment	
Austria	15/60	market	N	Y	N	day ahead	N	moderate	
Belgium	15	TSO	N	Y	N	day ahead	Y	unfavourable	
Denmark	60	market	S	Y	Y	2.5 hours	N	favourable	
Finland	60	market	S	Y	Y	2.5 hours	N	favourable	
France	30	regulated	N	Y	N	day ahead	Y	moderate	
Germany	15	market	R	Y	N ⁸	day ahead	Y	moderate	
Greece	60	Balancing costs socialised						Y	moderate
Ireland	30	reg/market	N	Y	N	day ahead	Y	moderate	
Italy	60	regulated	N	unknown	N	unknown	Y	moderate	
Lux	15	TSO	N	Y	N	day ahead	N	unfavourable	
Neth	15	market	N	Y	N	day ahead	N	moderate	
Portugal	60	regulated	N	unknown	N	unknown	Y	moderate	
Spain	60	market	N	unknown	Y	0.5-3.5 hours	N	favourable	
Sweden	60	market	S	Y	Y	2.5 hours	N	favourable	
UK	30	market	N	Y*	Y	1 hour	N	favourable	

source: Survey responses

* Balancing groups only allowed within DSO area

3.2. Congestion

There is insufficient interconnection infrastructure between Member States and, where congestion exists, unsatisfactory methods for allocating scarce capacity. The overall situation is summarized in the tables below.

Cross border transactions: electricity

Country 1	Country 2	Capacity ETSO Winter 01-02/MW	Allocation method	Allocation frequency	Capacity tradability	Redispatching to increase:	Netting	Use-it-or-lose-it	Co-ordination of both sides	Long term contracts exist	Congested	Date of introduction of a market based system
CH	IT	2800	Pro rata/Retention	y,d	yes		no	no	no	29%	always	janv-03
FR	IT	2600	Pro rata	y,d	yes	Firmness	no	yes	no	69%	always	janv-03
AT	IT	220	fc-fs	D	no		no	no	no	100%	always	janv-03
DE	NL	2800	Auction	y,m,d	yes		no	yes	yes	57%	frequently	nov-00
FR	BE	2200	fc-fs/Pro-rata	m,d	no		no	yes	no	61%	frequently	
FR	UK	2000	Auction	3y,y,d,o	yes		no	yes	yes	?	frequently	mars-01
DK-W	DE	1200	Auction	y,m,d	yes	Firmness	yes	yes	yes		frequently	sept-00
FR	ES	1100	fc-fs/Pro-rata	D	no	Capacity	no	yes	no	45%	frequently	janv-03
DK-W	NO	950	Market splitting	D	n.a.		yes	n.a.	yes		frequently	juil-99
DK-E	DE	550	Retention/Auction	m,d	no		yes	yes	yes	100%	frequently	janv-02
SE	DE	460	Retention/Fixed pr.	D	no		no	yes	yes	100%	frequently	
UK	IE	120	Auction	y,d	yes		no	yes	yes		frequently	avr-00
FR	DE	2850	fc-fs	D	no	Firmness	no	yes	no	13%	occasional	
NO	SE	2400	Market splitting	D	n.a.		yes	n.a.	yes		occasional	janv-96
SE	NO	2400	Market splitting	D	n.a.		yes	n.a.	yes		occasional	janv-96
SE	FI	2050	Market splitting	D	n.a.	Firmness	yes	n.a.	yes		occasional	juil-99
DK-E	SE	1700	Market splitting	D	n.a.		yes	n.a.	yes		occasional	oct-00
FI	SE	1650	Market splitting	D	n.a.	Firmness	yes	n.a.	yes		occasional	juil-99
SE	DK-E	1300	Market splitting	D	n.a.		yes	n.a.	yes		occasional	oct-00
NO	DK-W	1000	Market splitting	D	n.a.		yes	n.a.	yes		occasional	juil-99
ES	PT	850	Pro rata	D	no	Firmness	no	n.a.	yes		occasional	janv-03
DE	DK-W	800	Auction	y,m,d	yes	Firmness	yes	yes	yes		occasional	sept-00
PT	ES	725	Pro rata	D	n.a.	Firmness	no	n.a.	no		occasional	janv-03
DK-W	SE	610	Market splitting	D	n.a.		yes	n.a.	yes		occasional	juil-99
SE	DK-W	580	Market splitting	D	n.a.		yes	n.a.	yes		occasional	juil-99
DE	DK-E	550	Retention/Auction	m,d	no		yes	yes	yes	36%	occasional	janv-02
DE	SE	370	Retention	D	no		yes	yes	yes	100%	occasional	
FR	CH	3000	fc-fs	D	no		no	yes	yes	?	seldom	
UK	FR	2000	Auction	3y,y,d,o	yes		no	yes	yes		seldom	mars-01
BE	NL	1700	Auction	y,m,d	yes		no	yes	yes	18%	seldom	nov-00
NL	BE	1700	Auction	y,m,d	yes		no	yes	yes		seldom	nov-00
NL	DE	1350	Auction	y,m,d	yes		no	yes	yes		seldom	nov-00
ES	FR	1000	fc-fs/Pro-raa	D	no		no	no	no		seldom	janv-03
BE	FR	3100	fc-fs/Pro-ra	m,d	no		no	yes	no			
IT	CH	3100	fc-fs	D	no		no	no	no			
CH	FR	3000	Retention	D	no		no	no	yes			
DE	FR	2250	First come-first serve	D	no	Firmness	no	no	no			
IT	FR	2200	fc-fs	D	no		no	no	yes			
AT	CH	2000	fc-fs	D	no		yes	no	yes			
CH	AT	2000	Retention	D	no		yes	no	yes			
CH	DE	2000	Retention	D	no		yes	no	yes			
DE	CH	2000	fc-fs	D	no		no	no	yes			
DE	AT	1650	fc-fs	D	no		no	no	yes			
AT	DE	1150	fc-fs	D	no		yes	no	yes			
GR	IT	500	Pro rata	m,w,d	no		yes	yes	yes			mai-02
IT	GR	500	Auction	m,w,d	no		yes	yes	yes			mai-02
IT	AT	220	fc-fs	D	no		no	no	no			
IE	UK	50	Auction	y,d	yes		no	no	yes			avr-00

Cross border transactions eu15+2(continued)

	Import capacity MW	Export capacity MW	Net inflows GWh	Net outflows GWh	% theoretical capacity use
Austria	3870	3370	7906	11465	61%
Belgium	3900	4800	15699	6699	59%
Denmark	4230	4400	n.a.	n.a.	n.a.
France	13550	13350	3842	71146	64%
Finland	2050	1650	n.a.	n.a.	n.a.
Germany	9560	10120	33450	42440	88%
Ireland	120	50	n.a.	n.a.	n.a.
Italy	6020	6020	43887	467	84%
Lux	n.a.	n.a.	6529	1064	n.a.
Neth	4500	3050	21496	4208	77%
Portugal	850	725	3629	3479	103%
Spain	1825	1850	10180	4803	93%
Sweden	6730	6790	n.a.	n.a.	n.a.
UK	2050	2120	10872	203	61%
Nordel total	1720	2210	3408	5478	53%
Switzerland	10100	10100	23108	32509	63%
Total exchanges	57945	57715	184000	184000	72%

Data: UCTE

Theoretical use is sum of inflows and outflows divided by (capacity x 8760 hours)

4. Competition law enforcement

As state and administrative barriers to EC-wide competition are coming down as a consequence of the internal market directive for electricity markets, competition policy becomes the cornerstone to tackle a wide range of remaining obstacles to comprehensive electricity market liberalisation.

The process of market integration is thus supported by the enforcement of the three main competition instruments namely: antitrust (articles 81, 82, and 86 EC Treaty), merger control (Regulation n° 4064/89), and state aid control (articles 87 and 88 EC Treaty). All these instruments interact and reinforce each other in promoting competition.

The European Commission is applying competition rules in the electricity market aiming, among others, to increase supply competition and ensure open and non-discriminatory access to transport networks.

Supply competition

The European Commission approved in 2000 the merger between the German groups VEBA AG, Düsseldorf, and VIAG AG, Munich, subject to stringent conditions. Together with the merger between RWE and VEW, which was investigated at the same time by the German Federal Cartels Office, the Bundeskartellamt, this transaction was expected change the face of the German power industry, especially at the level of the interconnected grid. In its original form the merger of VEBA and VIAG would have resulted in a dominant duopoly between VEBA/VIAG on one side and RWE/VEW on the other on the

market in the supply of electricity from the interconnected grid. The Commission raised objections on competition grounds, and in response VEBA/VIAG proposed that it should dispose of numerous holdings in other companies, and make improvements to the ground rules governing the market in electricity⁹. In particular VEBA/VIAG and RWE/VEW undertook not to charge the transmission fee known as the "T-component", payable where a supplier of energy between the northern and southern trading zones set up by Associations Agreement II (*Verbändevereinbarung II*) could net out the quantities they supply against equivalent quantities in the opposite direction. This commitment, with an amended system of calculation for balancing energy and a detailed statement of electricity prices showing payment for the use of the network, energy price, metering and readings, and other charges, was considered to improve the ground rules governing transmission through the network operated by those two leading interconnected companies.

The CNR case is an example of a case in which both antitrust and merger control instruments were used to tackle an anti-competitive situation. The Compagnie Nationale du Rhône (CNR), a French electricity producer was contractually required to sell all its electricity to Electricité de France (EDF). This implied that CNR could not sell freely in France or elsewhere. As a result of the Commission's intervention in 2001, an end was put to the obligations contained in the contract between CNR and EDF. Today CNR is free to compete with EDF for customers in the Community.

Another major merger was the acquisition of joint control of German electricity company Energie Baden-Württemberg AG (EnBW) by EDF and Zweckverband Oberschwäbische Elektrizitätswerke, an association of nine southwest German districts. The operation, as initially notified to the Commission, would have led to the strengthening of EDF's dominant position on the market for eligible i.e. large customers in France. In order to eliminate these competition concerns, EDF made available to competitors 6,000 Megawatts of generation capacity located in France, equal to 30 percent of the eligible market, besides the commitment to cut its links with CNR, as already mentioned. Finally, the parties commit to divest EnBW's shareholding in Swiss electricity company WATT AG. The commitments offered by EDF were considered appropriate to eliminate the strengthening of EDF's dominant position on the market for eligible customers in France since they outbalanced the loss of EnBW as a potential competitor, the retaliation potential in Germany, the increased foothold in Switzerland and elimination of Watt as potential competitor and the strengthening of EDF's position as a Pan-European supplier.

In another the merger case, EDF/Hidrocantábrico, the European Commission authorised also in 2001, subject to conditions, the acquisition of joint control over the Spanish electricity company Hidroeléctrica del Cantábrico (Hidrocantábrico) by Spanish Grupo Villar Mir and Energie Baden-Württemberg (EnBW), a German company jointly controlled by Electricité de France (EDF). As initially notified to the Commission, the operation would have led to the strengthening of the existing collective dominant position on the Spanish wholesale market for electricity. Commercial capacity on the French-Spanish interconnector is scarce, creating a barrier to Spanish electricity imports and resulting in the market's isolation from other continental electricity markets to the detriment of customers. In order to solve the competition concerns identified by the Commission, EDF and EDF/RTE committed to take all the necessary steps in order to gradually increase the commercial capacity on the interconnector at the French/Spanish border to about 4000 MW from an existing 1100 MW.

Finally, the European Commission decided recently this year to clear the joint venture agreements between Ireland's dominant electricity company ESB and the Norwegian gas company Statoil relating to the Synergen power plant in Dublin. The agreements related to the construction and operation of the Synergen power plant a 400 MW gas fired plant in Dublin, Ireland. ESB holds a 70 % stake in the joint venture while Statoil holds the remaining 30 %. A subsidiary of ESB markets the power generated by Synergen for 15 years. Statoil supplies Synergen with gas for 15 years and ESB provides the operation and maintenance services to Synergen for 15 years. These agreements were cleared subject to compliance with

the commitments given to the Irish Commission for Electricity Regulation, in particular to put 600 MW of electricity at the disposal of the market until additional sources of electricity become available in Ireland. This corresponds to approximately half of the consumption by eligible customers in Ireland, and will thus facilitate market entry in the Irish electricity markets by new suppliers. Furthermore the Commission took into account that Statoil offered a special price formula for its gas, which it would not have offered, if it had not been assured a long term exclusivity.

Access to networks

To ensure open and non-discriminatory access to electricity networks, the European Commission intervened in a number of cases of restrictive transmission pricing systems where anti-competitive behaviour could be observed.

For instance, the second Associations agreement in Germany (*Verbändevereinbarung*) foresaw the division of Germany into two "trading-zones", one covering the North and another the South of the country. The system included a special fee, the T-component, to be levied each time the parties to the transaction are located in different zones or one party operates in another Member State. At the same time, a balancing mechanism was designed so that companies could compensate their flows in opposite directions crossing those borders. In the Commission's view, this system was incompatible with European competition law. First of all, the T-component lacked cost-reflectivity as transmissions over a short distance, but over the borders led to the imposition of the additional fee, whilst transmissions over long distances within one trading zone were free of additional charges. Secondly, the Commission was of the view that T-component was discriminatory since it would have provided to large German electricity suppliers with the possibility to balance counter-directed flows and thus to avoid the payment of the T-component, whilst this possibility was in practice not available to smaller market actors or foreign suppliers. As a result of the European Commission's intervention in this case, combined with the effects of the VEBA-VIAG merger case mentioned before, the T-component was abandoned.

Access to interconnectors are key components of the Trans-European network which itself forms the backbone of the internal electricity market. Importers depend on interconnectors to enter the markets of other Member States.

Thus, the Commission intervened in relation to the France/UK electricity interconnector, which is the only one submarine link between the UK and France. This interconnector has a total capacity of 2,000 MegaWatts (MW) in either direction. It had been operating on a fully commercial basis since 1986. Its operational costs are recovered through the fee paid for its use. In practice, use of the interconnector had been reserved exclusively to EDF for exports into the UK, under an existing agreement governing the management of the interconnector which expired in 2001. The two owners of the interconnector sought the Commission's views before agreeing new rules for managing and allocating capacity on the submarine cable after the expiry of the current rules. Following remarks made by the Commission, the two TSOs decided to open up access to the interconnector, without any reserve being made in favour of any particular company. The first capacity auctions took place in January and February 2001.

NOTES

1. Belgium and Ireland had additional one year and Greece additional two years to transpose the directive.
 2. The Commission has recently published a Staff Working Paper called "second benchmarking report on the implementation of the internal electricity and gas market", from which the tables in this paper are extracted. This benchmarking report can be down-loaded at the following adress: http://europa.eu.int/comm/energy/en/elec_single_market/index_en.html
 3. In parallel work carried is out informally by the Electricity Regulatory Forum gathering the main actors in the electricity sector.
 4. This data may understate concentration to the extent that cross ownership exists (e.g. in Italy, Germany)
 5. Where there is a uniform charging system in the Member State concerned, a single price is given. Where numerous distribution networks exist with different charge levels, a maximum and minimum level are indicated.
 6. Calculations have been made on a consistent basis in that;
 - regulatory charges relating to sunk costs or RES\CHP support have been excluded,
 - taxes have been excluded,
 - transmission and distribution costs have been added together where appropriate,
 - metering costs, losses and system services have been included where possible.

“Medium voltage” is considered to be between 15-50KV and estimates have normally been based on the 24GWh Eurostat example. “Low voltage” refers to connection at <0.4kV and calculations are based on the 3.5MWh Eurostat domestic customer example using a single tariff meter. Estimates rounded to the nearest €5/MWh.
- AT: Medium voltage = “Netzebene 5”, Low voltage = “Netzebene 7”. Average estimate provided by regulator. Range = Kartnen (low) – Burgenland (high).
- BE: Based on connection to elia network at 30KV, annual subscription. Assumes no connection to local distribution
- DK: Based on data provided by Danish regulator
- FI: Data provided by Finnish government. Medium voltage refers to 2GWh Eurostat example.
- FR: Based on newly approved tariff structure as proposed by the CRE
- DE: Based on VDN data, Medium voltage, Customer type “5.000h/a mit Leistungsmessung”. Low voltage = 3.5MWh/year. Does not include “Single Buyer” access.
- GK: Data provided by Greek government
- IR: Based on ESB published network tariff structure, based on DUOS group 8, 38KV looped customers. Does not include transmission G charge. Charges for DUOS group 7 “medium voltage” approx €15/MWh
- IT: Based on data provided by AEEG, excludes “taxes and charges”

- LX: Based on published CEDEGEL tariffs “reseau 20kV” for medium voltage.
- NL: Based on data provided by NL government: medium voltage = “Afnemers TS 25-50kV”, low voltage “Afnemers <3* 25amp (ET)
- PT: Based on data provided by ERSE. Medium voltage = connection at 1-45KV.
- ES: Based on “real decreto 1483/2001”. Medium voltage = Tarifa 3.1A, type 6.1, 1-36 KV. Estimate made of consumption “per Periodo”. Low voltage = Tarifa 2.0A. “Costes con destinos especificos” deducted plus 9% reduction for low voltage due in 2003.
- SE: Based on data provided on regulators website: www.stem.se/english. Medium voltage example Power demand 1MW, energy consumption 5GWh; Low voltage example, household with consumption 5MWh/year.
- UK: Based on Ofgem/Ofreg analysis of distribution costs with estimated NGC transmission costs added.
7. Excludes all taxes and charges relating to public service obligations, stranded costs etc. Transmission costs are included, as are metering costs.
8. An intraday market is being piloted in two regions in Germany.
9. Similar undertakings were given to the Bundeskartellamt by RWE/VEW.

SUMMARY OF THE DISCUSSION

The **Chairman (Alberto Heimler)** opened the roundtable with a look back over developments in the electricity industry since the last OECD roundtable on the electricity industry in October 1996. In those days experience with competition in electricity was limited to the UK and the Nordic countries. The EU Electricity Directive had only just been approved. Since that time many countries have liberalised their electricity market and a growing number of consumers have been able to choose from among a number of suppliers. The sector remains heavily regulated though, probably for good reason, because competition remains limited and some important regulatory issues have yet to be fully addressed.

Certain events have raised public concern about electricity liberalisation. These events include the bad experience in California; the UK example (which was in itself positive but which showed that achieving sufficient competition to discipline market power is difficult); and the experience with the application of the EU directive (which has demonstrated that lifting legal constraints is not enough to create competition). Some competition has been created in the EU, but it has been as a result of decisions going beyond the requirements imposed by the EU Directive. A particular example is the Nordic electricity market where there is a genuine interstate market for electricity. This is perhaps the only example in the OECD where the relevant geographic market is larger than national borders. The creation of interstate markets could be an important policy objective for other countries.

Experiences with electricity liberalisation

The Chairman then invited the US to explain what went wrong in California. A coincidence of different circumstances apparently contributed to the crisis. The problem was not simply excess demand alone. Some of the contributing factors that have been identified are: (a) that market concentration was much higher than believed; (b) prices were driven up by strategic behaviour of generators; (c) wholesale prices were set by the market but retail prices were tightly regulated; and (d) long-term contracts were discouraged by regulators.

The US agreed that articles¹ analysing the situation in California emphasise that the coincidence of both regulatory and natural events led to this crisis. Contributing factors include:

- Severe drought which seriously affected hydroelectric power generation, combined with a heat wave that increased consumption.
- Decision-makers based their strategy on the assumption that wholesale price decreases would continue and prepared no plans for a substantial reversal.
- Reliance on the spot market was higher than in other states where there is substantial reliance on long-term contracts.
- Wholesale prices rose substantially while retail prices were fixed.
- As California did not constitute a separate geographical market, generators were able to sell electricity for higher prices outside the state.

- Due to severe restrictions on the creation of new plants, reserve margins kept shrinking over the period of reform.
- The structure of the market had little relevance as with inelastic demand and short supply even suppliers with small output could exercise market power.
- Few efforts were taken to develop price-responsive demand regimes. In addition, zonal price led to congestion problems.
- Capacity divestiture was not accompanied by vesting contracts.
- Many of the pricing contracts called for adjustments of wholesale prices based on fuel prices and these prices might have been manipulated.

The UK has recently introduced its New Electricity Trading Arrangements (“NETA”) in an attempt to enhance competition in the market. The **Chairman** invited the UK to explain the features of NETA and whether or not it has met expectations.

The **UK** noted that the NETA was designed to promote competitive, market-based trading arrangements while maintaining a reliable electricity supply system. Under the previous arrangements all electricity was traded through the pool. Over time, the generation market became more competitive. Generation costs fell 50% (the efficiency of the best generator increased from 35% in 1998 to 48% in 1999) but wholesale prices did not go down. So the Government decided in 1997 to introduce reforms, effective from 2001.

Under the NETA, the national grid company operates a balancing system, buying and selling electricity as necessary to keep the market in balance. This affects 2% of electricity transactions, while the other 98% is traded as any other commodity. In the first year of the reform, markets emerged in response to demand and more market information is now available for participants. The availability of longer-term price information increased demand-side price responsiveness. Compared to 1998 prices to industrial consumers have fallen by 20-25% and a further decrease of 8 percent is expected in 2002. Prices for domestic customers have dropped 8% overall, while prices for those who switched suppliers have dropped 22% compared to 1998. The regulator (OFGEM) keeps an eye on the overall competitiveness of the market. A report prepared in July 2002 on the experiences of the first year of operation of the NETA is available on the OFGEM website.²

The **Chairman** observed that the Nordic countries are the only OECD countries to have created a common, inter-state electricity market. How did this come about? Were sovereignty issues raised? Is it a problem that there is no Nord Pool-wide transmission planning authority?

Norway explained that back in 1973 Norwegian generators established a pool for trading of electricity. Volumes were then traded between generators, who act both as sellers and buyers in a hydro power system. In 1993, this market opened up to everyone in Norway, and is characterized by an active demand side. This market is a non-mandatory market – bilateral contracts can be freely traded outside the pool, but traders use bilateral contract inside the pool as well. Later, Sweden decided to open its electricity market for competition. But, since its market was isolated and generation concentrated, Sweden decided to join the Nord Pool. Finland and Denmark also subsequently joined the pool.

The Nord Pool trading rules in the spot market have practically not been changed since the establishment, while traded volumes have increased dramatically. The spot market (known as the Elspot market) is the fundamental day-ahead physical market which sets the price for the whole of the market. It

has both a balancing and a regulating function. In times of congestion it sets prices for both sides of the congested network. Over time, market participants have joined the market voluntarily as they have recognised its advantages.

The operation of a supra-national market raises challenges and requires good co-operation among the participating countries. Nord Pool could survive without a single Nordic system-operator, but overall it will function better with co-ordinated system-operation, regulation and Nordic-wide common planning. This is an issue which is currently under discussion. The transmission companies have prepared a Nordic-wide grid development plan, and now they are preparing a grid code. The national regulators have decided to co-operate on this issue.

The **Chairman** turned to the European Commission, noting that the 1996 Directive has not proven sufficient for promoting effective competition and the Council is in the process of discussing a new Directive designed to accelerate liberalisation. The draft Directive does not directly address the need for restructuring of generation markets. Is it possible to develop real competition without structural separation of generation? Is it possible to ensure the enlargement of the electricity system beyond national borders without a central EU-wide transmission planning system?

The **European Commission** replied that the primary competition problems derive not from a lack of transmission capacity but from a lack of interconnection. Therefore, the Acceleration Directive aims at the development of the transmission networks and urges the member states to continue the introduction of competition. The Acceleration Directive envisages the obligation to enlarge the scope of eligible customers to non-domestic consumers in 2004 and all domestic consumers in 2005. It also changes the requirements on vertical unbundling from accounting separation to corporate separation – that is, the establishment of separate corporate entities will be required instead of the present separation of accounts. Regulated third party access will be required instead of the present possibility for negotiated third party access.

The Directive sets out an obligation for the creation of extra transmission capacity if market demand arises. All countries are obliged to ensure that at least 10% of the national demand can be supplied from outside the national borders through interconnection facilities. This obligation is considered enough to create the extra capacity needed in the first phase. The obligation relates to the construction of transmission lines and not to the actual ordering of electricity from abroad. Trade will occur if parties find it profitable, but the infrastructure should be ensured in advance. The construction of new transmission lines can be co-financed by the EU, but private firms will also contribute. The Commission has also required the establishment of new transmission capacity as a condition on a merger.

Promoting a Competitive Structure for Generation

The **Chairman** observed that traditional indicators do not provide reliable measures of market concentration in this industry because of the particularities of the electricity market. How should we measure concentration when generators are capacity constrained?

Darryl Biggar observed that measures of market power attempt to assess the ability of a firm to profitably raise its price. One firm cannot increase the market price if any attempt to do so is met by an increase in output by the other firms in the market. In a market in which some of the firms are operating at their maximum capacity they cannot increase their output in response to an increase in the market price. It is as though the capacity constrained firms are no longer providing a competitive discipline or are, in some sense, “no longer in the market”.

This is particularly an issue in electricity markets. Different generators may have a different marginal cost curve, but at any given moment in time some of them – especially the lowest-cost generators – will have a tendency to be capacity constrained. In a competitive generation market, all those generators with a marginal cost less than the market price will be producing at their maximum capacity – that is, they will be capacity constrained. An attempt to measure market power which takes into account the share of output of these firms is likely to underestimate the true level of market power – the market is likely to look more competitive than it really is. But, on the other hand, simply ignoring the capacity constrained firms is not likely to give a correct impression of the true level of market power either, as the remaining firms in the market don't face the entire market demand, but just the residual demand curve which is likely to be more elastic than the entire market demand.

The background paper for this roundtable presents a new version of the traditional Hirschmann-Herfindahl index (“HHI”) which attempts to correctly measure the HHI in the context of a market in which some firms are capacity constrained. Of course, this HHI would need to be calculated for each relevant geographic and product market.

The **United States** emphasised that defining the relevant geographic market, in particular, is extremely difficult without computer modelling. Computer modelling assists the process of identifying grid congestion and the price and quantity effects of 5% increase in price by one market player. Without computer models it is difficult to assess market definition, changes in concentration and potential anti-competitive effects. In principle, each hour (or part of an hour) represents a different market, but in practice it is necessary to group markets with similar conditions to avoid an overwhelming workload. Again, computer simulations can help with this process. D. Biggar agreed.

Austria brought up the issue of market power in related markets – such as the markets for ancillary services (such as spinning reserves) or capacity. At certain times the system operator may require certain generators to increase their output very quickly. The number of generators which can supply this service may be strictly limited, increasing their market power and leading to substantial price spikes.

Canada echoed this concern noting that where you have different types of generating capacity within an area some can ramp up or down more quickly than others. (For example, gas plants can ramp up more quickly than coal plants). This further complicates market definition in these markets for ancillary services.

Norway observed that, especially in an “energy only” market (i.e., a market with no separate market for ensuring adequate capacity), price spikes are necessary to induce new capacity to enter the market. It is difficult to distinguish price spikes which are consequence of market power from price spikes which are a signal of the need for new generation.

Ensuring that a competitive structure is put in place

The **Chairman** noted that relatively few countries have split up incumbent generating firms to promote competition. New Zealand, which started with a state-owned monopoly, created three separate state owned companies, one of which has subsequently been privatised. The Chairman also noted that New Zealand has a for-profit transmission operator but no transmission regulator. Investment in transmission has been lacking – is this due to the for-profit character of the grid operator?

New Zealand responded that the necessity of horizontal separation was generally accepted (since the alternative was a monopoly). The three generators are totally independent of the state in their pricing behaviour. They differ in their geographic locations and in the fuel they use. A greater degree of privatisation is envisaged in the future.

Italy noted that 3 years ago the vertically-integrated incumbent, ENEL was a monopoly. Its present market share of 50% is still high; the market is considered concentrated. The basic strategy of the regulator is to rely on entry to increase capacity. To encourage such entry the state is focusing on lowering administrative barriers to entry. Further divestment will also be requested from ENEL, but the amount is not yet determined.

In response to a question from the Chairman about plans to enhance (rather than reduce) concentration in generation, **Austria** noted that its wholesale market is integrated with the markets of Switzerland and Germany. The prices in Switzerland and Germany are similar in peak and off peak times to those in Austria.

The Swiss submission states that the liberalisation of the Swiss electricity market was set back by the rejection of the Electricity Market Law in a referendum. The **Chairman** asked why prices are higher in Switzerland if production is based on cheap hydro and nuclear power. Do competition concerns arise from the activities of the two associations Swiss Electric and Swiss Power?

Switzerland agreed that Swiss electricity prices are generally higher than the European average, particularly for SMEs and households, but this is because there are non-amortised plants that have an impact on the electricity price. Although published prices are higher, negotiated prices for large consumers are similar to European levels. The tax component is also high. Also, generators are usually owned by municipalities, many of which use the proceeds from electricity to cross-subsidise other activities. The rejected electricity law intended to increase transparency in this practice. SwissElectric is the association of the 6 largest vertically-integrated electricity producers. Its role is to promote their common interest, resource pooling etc. It is not an embryonic cartel. Swisspower is an association of some municipal generators to pool resources (mostly marketing resources) across their geographical borders.

Transmission

Turning to transmission issues, the **Chairman** observed that issues related to the continuing regulation of transmission (and, to an extent, distribution) are among the most difficult issues that remain to be resolved in the electricity industry. Some of the more important transmission issues include the issue of how to price access to the transmission network, sending the right signals about congestion to users (generators and consumers) and creating the right incentives for investment in the transmission network (including investment that crosses boundaries between networks). Another important set of issues relate to structural separation – how to separate planning and operation of the transmission network from the interests of, say, generators.

On pricing of transmission networks, **Darryl Biggar** observed that this is one issue in which there is still no uniformity of practice, even amongst those countries which have liberalised their electricity markets (e.g., the UK and the US). Ideally, a pricing system would (a) send the right signals about congestion on the network (signalling to generators and consumers when to increase or reduce supply and demand and to provide efficient signals about where to locate); (b) would promote competition between generators (especially in the light of generator market-power); and (c) would facilitate the process of achieving efficient investment in the transmission network.

In order to achieve allocative, productive and dynamic efficiency it is essential for transmission prices for electricity to be geographically differentiated in real-time. The arguments are very similar as to the reason why it is necessary to have electricity prices differentiated by time of day. If electricity prices were not differentiated according to the time dimension, consumers would not be able to curb their consumption at peak times, peaking generators would not know when to turn on and there would not be

efficient levels of investment in peaking plant (and the right mix of plant more generally). These same arguments apply to geographic differentiation of electricity prices – location-based pricing of electricity allows congestion to be priced in real time, so that consumers know when to turn off and both generators and consumers can make the right location decisions.

But very fine geographic differentiation of prices raises a different concern – it may enhance market power. The opposite of geographic differentiation is geographic averaging. When electricity prices are geographically averaged, generators that are very far away from load face no disadvantage compared to generators located near the load – the size of the geographic market is enhanced, so the level of competition is enhanced. In some cases the benefits of enhanced competition may outweigh the gains from more efficient dispatch or location decisions. Conversely, geographic differentiation of electricity prices decreases the size of the geographic dimension of the relevant market – this will have a tendency to increase market power. The increase in market power may outweigh any gain in efficiency.

Finally, getting the incentives right for investment in the transmission network is a very difficult problem. Although nodal pricing provides good signals of congestion it turns out that it is not immediately obvious how those signals can be converted into incentives for investment, especially as investment on one part of the network may affect flows and congestion on other parts of the network. If the transmission network is rewarded on the basis of the “congestion rents” it may have an incentive to build the network in such a way as to increase rather than reduce congestion.

For many countries there are capacity constraints on transmission links with other countries. The Netherlands has chosen to establish auctions for the limited capacity on interconnecting transmission links. These auctions are carried out for year, month and day ahead demand. The **Chairman** asked whether participants are satisfied with the results of these auctions.

The **Netherlands** explained that it imports 20% of total consumption, with the majority coming from Germany. Long term contracts have been signed with German and French nuclear plants. To promote capacity utilisation and competition in the market, a use-it-or-lose-it rule is in place. Previously obtained import capacity has to be used or returned to the day-ahead auction market. The public in general is satisfied with the present system. The Netherlands is planning further investment in new interconnection links.

The **Chairman** asked the United States to give an assessment of the FERC order 888 which led to the creation of independent system operators and an initial indication of the outcomes of FERC order 2000 which has encouraged the formation of regional transmission organisations. In particular, has there been adequate investment in transmission, especially at interconnection points?

The **US** originally started out with a behavioural approach to access to transmission networks based on the assumption that if we tell people not to discriminate then they would not. In the last 6-7 years behavioural rules have been found to be insufficient and the structural approach has become more preferred. The first step (under order 888) was to allow ISOs to be formed. More recently (order 2000) the FERC has required the formation of RTOs. Outstanding issues include the need to encourage independent transmission providers, especially where ISOs have made little progress in expanding the transmission network.

The **Chairman** noted that Italy has already put in place an independent system operator. The Chairman asked why Italy is now considering moving to ownership separation of generation and transmission.

Italy responded that the establishment of the Italian ISO, assisted free access to the network, strengthened interconnections at an international and national level (an increase of capacity of 20% across the Northern border), as well as helping to avoid the application of separate zonal prices.

Italy is considering re-unifying ownership and management of the network (which are separated under an ISO). There are two reasons for this re-unification. The first relates to the incentives to invest in new lines. In Europe it is very difficult to get local authorisation to build new high-voltage lines. Re-unification may strengthen the incentives on the network provider to overcome these difficulties. In addition, separation raises some security issues that have to be resolved through regulation and co-ordination. There also may be the possibility for some private investment in transmission.

The **Chairman** then turned to Germany, noting that Germany is the only country that has not adopted ex ante regulation but relies on ex post antitrust enforcement. Charges for access to the transmission network are established by an association of market participants. Are consumers involved in this decision making? How do they assess their ex post regime? Would a move to an ex ante regime reduce the case load burden and reduce the administrative cost?

Germany acknowledged that the agreement of the associations of industry players has been in place since 1998. Parties to the initial agreement included the associations of electricity companies, network operators, industrial customers and the Confederation of German industry. The first agreement set out the initial framework for the establishment of conditions for granting network access. This first agreement was followed by two subsequent revisions, bringing about important improvements for third party network access. With these subsequent revisions, the consumer association was also involved in the discussions. The association agreements do not set the actual prices for network access. Also, they do not in any way exempt network access matters in the energy sector from the application of competition law. The criteria and conditions laid out in the association agreements are subject to scrutiny by the competition authorities and can be overturned.

The Bundeskartellamt's and the Länder authorities' interventions have an important effect on the market. The authorities are conducting numerous formal proceedings against network operators; due to these proceedings several network operators have already chosen to reduce their access charges. Ex post control is considered effective in Germany. The Länder authorities and the Bundeskartellamt co-ordinate their activities, in part through a conference that is held twice a year.

The **Chairman** asked Denmark about the periods of time when Denmark is isolated from the rest of the Nordpool network.

Denmark reported that for about 5% of the year, Denmark is separated from the rest of the Nordpool network. In these times, the two Danish operators have a dominant position that raises the question of possible abuse. However, the small amount of time when the lines are congested has to be taken into account when deciding whether to establish new transmission lines."

The **Chairman** raised two issues relating to the Brazilian submission. The spot market price seems to depend primarily on long term factors (such as the amount of water in the reservoirs, forecasts of rain etc). How can the traditional thermal generators participate in the market if decisions are not based on price but on these long-term factors? In addition, there is a requirement that all eligible customers must have at least 85% of consumption covered by a long term contract combined with a ceiling on the contract prices. Why not rely more on the market to determine the price?

Brazil agreed that it is difficult for thermal generators to participate in the market as hydro plants from different catchment areas co-operate with each other so as to prevent the price rising during drought periods (to discourage thermal plants from entering the market). The Brazilian government therefore provides regulatory help for thermal generators, by reducing the price of gas and gas transportation and by offering more flexible gas consumption contracts. Transmission tariffs with stronger geographic differentiation will also be introduced. These favour thermal plants as they can locate closer to consumers than hydro plants.

Price determination is primarily left to the market. 25% of the energy production is sold through auction processes and this amount will be increased to 100% in the next three years. Eligible free consumers are not obliged to enter into long term contracts; rather utilities are obliged to contract on behalf of captive consumers. In 2005 all consumers will be free to select their supplier. The market will set the prices and there will no longer be any need to set reference prices based on a computer program.

In the general discussion, the **US** addressed a question to Italy. The US noted that the model used in Italy, where the transmission network is in the hands of a single private transmission company, is called a Transco in the US. The US has considered this model because of its efficiency benefits. However, the concern arose that even if a Transco might have less incentive to discriminate than a vertically-integrated electricity supplier they still have some incentives to discriminate against generators who are closer to load as this closeness is a substitute for transmission.

Italy responded that all distributed production is a problem for the transmission company. There is no easy answer.

Austria expressed concern about location-based price signals based on short-run marginal cost. They are afraid that these signals are effective only in special cases, in unrestrained situations and relating to one technology. The locational signals might be unimportant compared to other factors such as access to fuels. It may be necessary to introduce additional measures if we are to have a strong influence on the location of generators.

Norway noted that it is straightforward to introduce locational signals by pricing expected marginal losses per node on the transmission network. Marginal loss pricing does provide some long-term location signals for new investment. Norway expressed hesitancy at moving to full dynamic nodal pricing because of the significant information requirements. The result maybe a highly-computerised and non-transparent market which is largely closed to demand-side participants. In additional nodal pricing will still not lead to efficient signals for new investment. Lumpiness of investment means that there are significant challenges in creating the right incentives for efficient levels of new investment. This is an issue which requires careful investigation.

Institutional issues and regulatory structures

The **Chairman** observed that the Australian Competition and Consumer Commission is both antitrust enforcer and regulator for natural monopolies, so in principle it is able to resolve any conflicts between regulation and antitrust enforcement. But a number of other regulators exist, especially at the state

level. How was this structure developed? How is co-ordination between these different institutions managed and what are the prospects for simplification?

Australia acknowledged that the national antitrust agency is also the utility regulator. It was the Government's decision to keep the role of the regulator and the antitrust authority in the same hands. But a compromise was made with the states to allow the establishment of state-level agencies as well. The states wanted to deal with their own local issues. The last 6-7 years of experience with this system shows no negative tendencies and these agencies are now fully developed.

The existence of so many regulators appears worse on paper than it is in reality. Very little duplication exists in regulation. The law administered is common to all the state regulators. They have authority for electricity distribution and local retail issues rather than broader issues. Formal and informal mechanisms also exist to deal with issues arising from the co-existence of these authorities. Some of the formal mechanisms include the national electricity code which is uniformly applied to the whole of the electricity sector and the participation of the heads of the state authorities in a decision making body (the Energy Committee within the ACCC). Overall the regulatory approach is fairly consistent across Australia. Having a large number of regulatory bodies does not in itself necessarily imply inconsistency.

The **Chairman** pointed out that the institutional structure is also quite complicated in Ontario. In that province there is, in addition to the Competition Bureau, the Independent Electricity Market Operator (IMO) and the Ontario Energy Board (OEB). In addition, the IMO has set up a Market Surveillance Panel to identify abuses. Who would handle any abuses identified by the Panel, under what law and with what powers?

Canada agreed that the regulatory situation in Ontario with respect to competition is quite complicated. In addition to federal competition law, the provincial agencies play a major role. The Market Surveillance Panel consists of independent members - 2 academic economics, and an engineer. The Panel surveys the IMO markets and related developments. It can identify two basic types of abuses. One is the exercise of market power to obtain higher prices. The second is the class of anticompetitive practices that can also be dealt with under Canadian competition law. The Panel is an investigative body; it does not bring cases. It may refer competition matters to the OEB, the Bureau or the IMO as warranted.

There are some guidelines on the separation of jurisdictions. For example, the detection and prevention of locational market power is the responsibility of the IMO while the pricing of transmission and distribution is the responsibility of the OEB. However, there remains a high degree of overlap. The OEB licenses market participants. It may include license provisions prohibiting anticompetitive practices of a type that may also be dealt with under competition law. Compared to competition law, it may be able to hold quick hearing processes but it does not have the search powers available under competition law. The authority of the Bureau depends on the nature of the infringements. Abuse of dominance is a civil matter subject to a possible prohibition order. Bid rigging and price fixing are criminal matters and, in addition to prohibition orders, are potentially subject to fines as well as well prison terms. It is envisioned that criminal matters will be referred to the Bureau, but it is not always clear in the electricity market whether an action amounts to a conspiracy that can be established to a criminal level of proof. In unclear cases, the OEB might deal with the matter. Abuse cases can be handled by both the OEB and the Bureau, depending on which agency is in a better position to deal with a particular matter.

There is an "interface agreement" between the IMO, the Bureau and the OEB which seeks to establish greater level of clarity as to the roles of each agency. Its aims are to promote greater certainty regarding the legal and regulatory framework; to avoid overlap and, duplication; to ensure that problems are addressed; and to avoid forum shopping. The interface agreement does not restrict jurisdiction but creates an obligation to co-operate. It further provides that the Competition Bureau's policy is not to

enforce competition law against anticompetitive practices or false or misleading representations that are the subject of an enforcement action by the OEB. Implementation of the agreement is assured through regular bi-weekly communications between the authorities.

The **Chairman** asked Hungary about issues raised in the regulatory reform review a year ago. At that time the suggestion was made to balance tariffs and to reduce the extensive powers of the Ministry over tariffs. What progress has been made on these questions?

Hungary explained that in the Hungarian legal system it is not possible to delegate formal pricing authority to the energy regulator. The regulator can, however, have some role in recommending the appropriate price. In fact, the price is calculated by the Energy Office who makes a recommendation to the Minister who has the right to decide the final price. The price level is a politically sensitive issue, so the final decision must take into account political considerations. The Government is reluctant to allow an independent authority to set prices. In the field of policy-making the regulatory authority co-operates closely with the Ministry, but in the field of prices it has a purely advisory role.

One of the main issues raised in Poland's regulatory reform review was tariff re-balancing. The **Chairman** asked whether any progress is expected in this direction.

Poland responded that it is taking into account the recommendations of the review and trying to follow them. This year the Parliament adopted an amendment to the Energy Law which enters into force on 1 January 2003. Secondary legislation is also under discussion. A special inter-ministerial task force has been established for the analysis of this issue.

The **Chairman** observed that Ireland has excluded the possibility of a spot market, by introducing an invasive regulatory system in which the price to purchase additional power is regulated. What ensures that there will be adequate supply at that price?

Ireland responded that the present rules are only transitional and were introduced to get the market open for February 2000. At that time the Minister asked the regulator to take another look at the trading agreements in 2004 to be able to introduce a more robust trading system for the full market opening in 2005. Because of issues of uncertainty of the regime in 2005 and capacity problems this review has been brought forward.

Adequate capacity is an important issue in the Irish market, with its limited interconnection, high growth rates and large number of old plants. In 2000-2001 there were serious capacity shortages requiring the importation of emergency generators from California.

There are a lot of difficulties with relative prices. Despite large increases, retail prices are not high enough and do not reflect the price of adding new capacity as they are based on the ESB's historical cost. The VIPP (virtual independent power producer) prices are discounted, but if they are not discounted enough customers do not switch to the independent suppliers while if it is discounted too much the independent generators can not compete.

Two new generators are coming into the Irish market. Ireland is still an attractive location for generators as it still has a high growth rate, even with the downturn and little competition from interconnection. The major reason for slow market entry of new generation capacity (according to the generators themselves) is the uncertainty about what will happen in 2005. The announcement of new trading arrangements and consultations over the next 6 months will help resolve this uncertainty

Antitrust enforcement in electricity markets

The **Chairman** introduced the final section of the roundtable noting that there have been a lot of antitrust cases in the electricity industry but not primarily cases of abuse of dominance. Rather most enforcement cases have been concerned with mergers.

In France the EDF-Dalkia merger was cleared subject to an extensive number of conditions. These constraints were so onerous as to remove the possibility of efficiencies between the two parts of the post merger entity. Why was the merger cleared if there is no possibility of resulting efficiencies? In addition, the authority imposed on itself a substantial administrative burden to supervise the fulfilment of the obligations. The Chairman asked the French authorities for their general opinion on behavioural obligations.

France explained that Dalkia provides energy-related services. EDF acquired 34% of the shares of Dalkia in order to diversify its services. They intended to create a totally new, previously non-existent, market providing certain services to industrial customers. Therefore no market shares were calculated on this market, which was considered to be global. The merger did not pose problems as it was only a new product market which was affected. However as one of the parties was (a) a dominant generator, (b) the transmission network operator, and (c) present on the market for supply, the concern was raised whether this transaction would reinforce the already strong position of EDF on the French market.

The decision established a Chinese wall prohibiting access by EDF employees to documents on the activities of the other firm in France. This provision is the main one and is structural in nature. Other conditions were also applied, such as the condition that prescribes the information of Dalkia's clients on the prices of electricity supplied by EDF.

Often, the EU has relied on improving the conditions for potential competition as a condition for merger, noted the **Chairman**. In the EDF-Hidrocantábrico merger case, the EC approved the merger subject to the requirement to improve the capacity of the interconnection between France and Spain. What was the outcome? Did French exports expand as was expected and what was the merger's effect on the Spanish generation industry?

The **European Commission** noted that the requirement, to strengthen the France-Spain two way interconnection link was significant. It requested the upgrading of the present capacity of 1100 MW to over 4000 MW. However the upgrading is to take place over 4-5 years and until it is finalised no measurable effect will appear in the market.

In Japan the JFTC has issued a 'warning' to the Hokkaido Electric Power company regarding exclusionary practices. The **Chairman** asked **Japan** to describe the case and the meaning of a 'warning' under Japanese law.

In 2001, the JFTC set up a task force to supervise the public utility sector, including the electricity industry. It has investigated several cases. There is relatively little competition between generators. Each generator serves its own area. Hokkaido Electric Power is in a monopoly position on its service area. It entered into long term agreements with end-users. In these contracts an excessively high fee was imposed for switching to the purchase of new entrants' services. The JFTC issued a 'warning' as the practice may have been a violation of the Antimonopoly Act.

A warning is not a legal action of the JFTC. Warnings are issued when there is not enough evidence to declare the violation of the Antimonopoly Act but the authority considers that some action should be taken. The JFTC issues 15-20 warnings a year. The JFTC also issued guidelines listing types of

behaviour by participants in the electricity market that might raise competition concerns. The guidelines are based on experience in preceding cases and discussions with business operators.

Discussion

In the general discussion, the **United States** emphasised that the correct design of the market rules before the introduction of competition is extremely important. The US hoped that the experience in California will help other countries to avoid such mistakes in the liberalisation of their electricity markets. They noted in particular, the need for consideration of reserve margins and the consideration of the way to make the market more price-responsive.

Norway noted that the Norwegian Competition Authority has recently handled a case involving the merger of Statkraft with two competitors in the southern and the northern parts of Norway respectively. The authority prohibited both mergers even though market concentration would not have increased significantly. However it was considered that northern and southern Norway were separate geographic markets and in these smaller markets concentration would have been raised from 40% to 50%. Both firms had large capacity in water reservoirs so both producers were flexible in supply. Furthermore both had market power at certain times of the year. Both prohibitions were appealed. The Ministry cleared one of them subject to strict conditions. The other is still pending.

Austria brought up the role of market design which is emphasised in the background paper, but was not discussed during the meeting. Austria also emphasised the importance of considering how information is dispersed within the system. In particular, information on changes in demand and supply which is critical information for new entrants.

UNCTAD noted that many developing countries face similar problems to those that have been raised. UNCTAD raised in particular the question as to who should be responsible for the extension of the transmission system. Many African countries have privatised and opened the market, but the lack of access to capital has caused problems in financing network development.

The **US** noted that a significant amount of discussion has gone into how you go about making sure that the pricing signals are correct for efficiency and new investment. This is a combination of getting the right information, the right incentives and the right ownership. Having just one of these without the others may be ineffective.

Summary

The **Chairman (Alberto Heimler)** concluded the meeting noting the large difference between the roundtable in 1996 and the present. The Chairman noted in particular:

- The importance of structural issues, particularly vertical of the transmission network, and horizontal separation to promote competition in generation.
- The importance of flexibility. Our original ideas on how to reform the market were very rigid. Norway made clear the importance of flexibility both in structure and in markets. The possibility of generators to act as buyers and the possibility for traders to act as both buyers and sellers introduces flexibility and makes it possible to discipline market power.

- Consumers need education to be able to respond through changes in demand from price changes. This is not an easy issue as it costs to install real-time meters and there is relatively little experience in the world in how big or small customers react to electricity price changes.
- Institutional structure is important, especially in federal governments where co-ordination of authorities in different levels is an additional problem. These issues clearly came out in the submissions of Canada, Australia and the EU.
- The relevant geographical market can not be easily identified, and this makes difficult the creation of a regulatory structure that facilitates the proper functioning of the market. Country borders are not necessarily the same as those of the relevant geographic market.

The Chairman concluded by noting that we are in a process of evolution both in regard to market mechanisms and institutional development. In 5 years time, it will be possible to see which of the present approaches will succeed.

NOTES

1. See, e.g., John C. Hilke and Michael Wise, "Who turned out the lights? Competition and California's Power Crisis", *Antitrust*, Summer 2001, 15, 76-81
2. www.ofgem.gov.uk/newprojects/neta_index.htm

RÉSUMÉ DE LA DISCUSSION

Le **Président (Alberto Heimler)** ouvre les débats par une récapitulation des évolutions de l'industrie électrique depuis la dernière table ronde de l'OCDE sur la concurrence dans le secteur de l'électricité d'octobre 1996. A cette époque, seuls le Royaume-Uni et les pays nordiques avaient expérimenté la concurrence dans ce secteur. La directive de l'Union européenne concernant les règles communes pour le marché intérieur de l'électricité venait d'être approuvée. Depuis, de nombreux pays ont ouvert leur marché de l'électricité, et un nombre croissant de consommateurs ont pu choisir leur fournisseur. Pourtant, le secteur reste fortement réglementé, probablement à raison, car la concurrence est encore limitée et certains problèmes réglementaires importants n'ont pas encore trouvé de solution pleinement satisfaisante.

Plusieurs événements ont suscité la méfiance du public à l'égard de cette ouverture. Il s'agit notamment de l'expérience malheureuse de la Californie, de l'exemple du Royaume-Uni (expérience en soi positive, mais qui a démontré la difficulté de parvenir à un niveau de concurrence suffisant pour éliminer les pouvoirs de marché), et de l'application de la directive de l'Union européenne (prouvant qu'il ne suffit pas, pour créer la concurrence, de lever les contraintes juridiques). La concurrence qui s'est instaurée dans les pays de l'Union européenne est pourtant le fruit de décisions dépassant les exigences de la directive européenne. Le marché nordique de l'électricité où il existe de véritables échanges entre Etats en est une illustration. Il s'agit probablement du seul cas dans les pays de l'OCDE où le marché géographique pertinent dépasse les frontières nationales. D'autres pays pourraient suivre cet exemple et faire figurer en bonne place parmi leurs objectifs la création de marchés entre Etats.

Expériences de la libéralisation du secteur électrique

Le Président invite le délégué des Etats-Unis à expliquer pourquoi l'expérience californienne a été un échec. La crise semble résulter d'un concours de circonstances. On ne peut pas l'imputer seulement une demande excédentaire. Parmi les facteurs de cette crise, on a identifié : (a) une concentration du marché bien supérieure à ce qui avait été estimé ; (b) des prix poussés à la hausse par le comportement stratégique des producteurs ; (c) le fait que les prix de gros aient été déterminés par les conditions sur le marché tandis que les prix de détail étaient strictement réglementés et (d) le fait que les autorités de régulation aient découragé la signature de contrats à long terme.

Le délégué des **Etats-Unis** convient que les articles¹ analysant la situation en Californie soulignent la concomitance de problèmes réglementaires et de phénomènes naturels, à savoir :

- Une forte sécheresse qui a eu des répercussions graves sur la production hydroélectrique, associée à une vague de chaleur provoquant une hausse de la consommation.
- Le fait que les décideurs aient tablé sur la poursuite de la baisse des prix de gros et n'aient pas prévu une forte inversion de tendance.
- La forte proportion de transactions sur le marché spot par rapport à d'autres Etats où les contrats à long terme pèsent nettement plus lourd.
- Le fait que les prix de gros se soient envolés alors que les prix de détail ne pouvaient évoluer.

- La Californie ne constituant pas un marché géographique séparé, les producteurs pouvaient vendre leur électricité plus cher à d'autres Etats.
- La construction de centrales étant soumise à des restrictions strictes, la réserve de puissance n'a cessé de diminuer sur toute la durée de la réforme.
- L'inadaptation de la structure du marché étant donné que l'inélasticité de la demande et la pénurie de l'offre permettaient même à des petits producteurs d'exercer un pouvoir de marché.
- Le peu d'efforts consentis pour s'assurer que la demande soit sensible aux prix. En outre, la tarification zonale a créé des problèmes de congestion.
- Le fait que la cession d'actifs de production n'ait pas été assortie de contrats pour différences.
- Une bonne partie des contrats de tarification prévoyait des ajustements des prix de gros fondés sur le prix des énergies. Or ces prix pourraient avoir été manipulés.

Le Royaume-Uni vient de créer le NETA (New Electricity Trading Arrangements) qui a pour objet de renforcer la concurrence sur le marché. Le **Président** invite le délégué du Royaume-Uni à expliquer en quoi consiste le NETA et s'il a répondu aux espérances.

Le délégué du **Royaume-Uni** explique que le NETA a pour but de favoriser la mise en place d'un système d'échanges concurrentiels obéissant aux lois du marché, sans nuire à la fiabilité du système électrique. Dans le système précédent, toutes les transactions passaient par le pool. Peu à peu, le marché de la production est devenu plus concurrentiel. Les coûts de production ont diminué de 50 % (l'efficacité du meilleur producteur est passée de 35 % en 1998 à 48 % en 1999), mais les prix de gros n'ont pas diminué. C'est pourquoi en 1997, le gouvernement a décidé de procéder à de nouvelles réformes devant prendre effet en 2001.

Dans le NETA, le gestionnaire du réseau national gère un mécanisme d'ajustement, achetant et vendant l'électricité de façon à assurer l'équilibre du marché. Cette activité représente 2 % des transactions, les 98 % restants étant échangés comme n'importe quel autre bien. Au cours de la première année de la réforme, des marchés ont vu le jour pour satisfaire la demande, et les participants disposent aujourd'hui d'informations plus fournies sur les marchés. La disponibilité d'informations tarifaires à plus long terme a stimulé la réactivité de la demande au prix. Par rapport à 1998, les prix payés par les industriels ont diminué de 20 à 25 %, et l'on prévoit en 2002 une baisse supplémentaire de 8 %. Quant aux tarifs demandés aux ménages, ils ont globalement fléchi de 8 % par rapport à 1998, contre 22 % pour les consommateurs qui ont changé de fournisseur. L'autorité de régulation (OFGEM) surveille l'évolution globale de la concurrence sur le marché. On trouvera sur le site web de l'OFGEM² le rapport de juillet 2002 sur la première année de fonctionnement du NETA.

Le **Président** note que les pays nordiques sont les seuls pays de l'OCDE à avoir établi un marché commun de l'électricité. Comment y sont-ils parvenus ? La création de ce marché a-t-elle posé des problèmes de souveraineté nationale ? L'inexistence d'une autorité de planification du transport sur l'ensemble réseau desservi par le Nord Pool pose-t-elle un problème ?

Le délégué de la **Norvège** explique que, déjà en 1973, les producteurs norvégiens avaient établi un pool d'échange d'électricité. Les transactions avaient lieu entre producteurs qui vendaient et achetaient l'électricité dans un système dominé par l'hydraulique. En 1993, ce marché s'est ouvert à la totalité des opérateurs en Norvège, avec une forte participation des intervenants côté demande. Il s'agit d'un marché

facultatif, avec possibilité de négocier librement des contrats bilatéraux en dehors du pool, bien que les négociants passent également des contrats bilatéraux au sein du pool. Par la suite, la Suède a décidé d'ouvrir son marché de l'électricité à la concurrence. Toutefois, l'isolement de ce marché et la concentration de la production l'ont incitée à rejoindre le Nord Pool, suivie en cela par la Finlande et le Danemark.

Les règles sur le marché spot du Nord Pool n'ont pour ainsi dire pas changé depuis sa création, malgré l'explosion des volumes échangés. Le marché spot (du nom de Elspot) est le marché où se négocient les échanges physiques la veille pour le lendemain qui définissent le prix sur l'ensemble du marché. Il possède à la fois une fonction d'ajustement et une fonction de régulation. Aux périodes de congestion, il définit les prix des deux côtés du réseau touché. Avec le temps, les avantages du marché ont attiré de nombreux participants.

Le fonctionnement d'un marché supranational soulève quelques problèmes et exige une bonne coopération entre pays participants. Le Nord Pool pourrait survivre sans gestionnaire de réseau unique mais, globalement, une exploitation coordonnée ainsi qu'une régulation et une planification communes du système sont la garantie d'un meilleur fonctionnement. La question est en discussion. Les entreprises de transport ont établi un plan de développement du réseau nordique et sont en train de préparer un code de réseau. Les autorités de régulation nationales ont décidé d'apporter leur collaboration.

Le **Président** s'adresse au délégué de la Commission européenne, à qui il fait remarquer que la directive de 1996 n'a pas suffi à promouvoir une concurrence efficace puisque le Conseil travaille à l'élaboration d'une nouvelle directive destinée à accélérer l'ouverture du marché. Le projet de directive ne concerne pas directement la restructuration des marchés de la production. Est-il possible de parvenir à une concurrence réelle sans séparation structurelle de la production ? Est-il possible de développer le système électrique au-delà des frontières nationales sans un système central de planification du transport à l'échelle européenne ?

A ces questions, le délégué de la **Commission européenne** répond que les principaux problèmes de concurrence découlent non de l'insuffisance de la capacité de transport mais d'un manque d'interconnexions. C'est pourquoi la directive d'accélération vise à développer les réseaux de transport et exhorte les Etats membres à poursuivre l'ouverture à la concurrence. Elle prévoit d'étendre l'éligibilité à toute la clientèle non résidentielle en 2004 et à toute la clientèle résidentielle en 2005. En matière de séparation verticale, les exigences jusque-là restreintes à la dissociation comptable, sont étendues à la séparation juridique. En d'autres termes, on exigera la constitution d'entités séparées au sein des entreprises au lieu d'une simple dissociation de leurs comptes. L'ATR réglementé sera imposé à la place de l'ATR négocié, possible aujourd'hui.

La directive prévoit l'obligation d'augmenter la capacité de transport si la demande l'exige. Tous les pays sont tenus de faire en sorte que les ouvrages d'interconnexion permettent aux opérateurs étrangers de satisfaire la demande nationale dans une proportion minimale de 10 %. Cette obligation est jugée suffisante pour créer la capacité supplémentaire nécessaire dans la première phase, dans la mesure où elle concerne la construction de lignes de transport, pas les commandes passées à l'étranger. Les échanges auront lieu, si les parties les jugent rentables, mais l'infrastructure devra être en place. La construction de lignes de transport peut être cofinancée par l'Union européenne, bien que des entreprises privées y contribuent également. La Commission a également exigé, comme condition d'une fusion, la création de nouvelles capacités de transport.

Favoriser une structure concurrentielle de la production

Le **Président** observe que les indicateurs traditionnels ne permettent pas de mesurer de façon fiable la concentration du marché, et que cela tient aux spécificités du marché de l'électricité. Comment est-il possible de mesurer la concentration lorsque les producteurs sont limités par la capacité ?

Darryl Biggar note que les mesures du pouvoir de marché sont des moyens d'évaluer la capacité d'une entreprise de relever ses prix pour en tirer des profits. Une entreprise ne peut relever le prix du marché si les autres entreprises réagissent chaque fois par une augmentation de leur production. Autrement dit, si certaines entreprises sur le marché fonctionnent au maximum de leur capacité, il leur est impossible d'accroître leur production pour faire face à une hausse du prix du marché. Ces entreprises n'ont plus aucun effet sur la concurrence, autrement dit, "ne sont plus sur le marché".

Le problème touche tout particulièrement les marchés de l'électricité. Le coût marginal peut varier pour les différents producteurs mais, à un moment donné, certains d'entre eux, et en particulier ceux qui produisent à moindre coût, sont aux limites de leur capacité. Sur un marché de la production concurrentiel, toutes les entreprises produisant à un coût marginal inférieur au prix de marché produiront au maximum de leur capacité, en d'autres termes connaîtront des contraintes de capacité. Toute tentative pour mesurer le pouvoir de marché qui serait fondée sur la part de la production assurée par ces entreprises, risque de sous-estimer l'importance réelle de ce pouvoir de marché - et le marché de paraître plus concurrentiel qu'il n'est en réalité. D'un autre côté, on ne devrait pas non plus obtenir une image correcte du pouvoir de marché en laissant de côté ces entreprises aux limites de leurs capacités, dans la mesure où les autres entreprises opérant sur le marché ne doivent pas, dans ce cas, assurer la totalité de la demande mais uniquement la demande résiduelle, *a priori* plus élastique que la demande totale.

Le document de référence établi pour cette table ronde présente une nouvelle variante de l'indice d'Herfindahl-Hirschmann (HHI) permettant de l'adapter à un marché où certaines entreprises sont aux limites de leurs capacités. Il est bien évident que cet indice devrait être calculé pour chaque marché géographique et chaque marché de produit.

Le délégué des **Etats-Unis** souligne que, sans modélisation informatique, il est extrêmement difficile de définir le marché géographique pertinent. La modélisation informatique facilite l'identification des congestions du réseau ainsi que des effets sur les prix et les quantités d'une hausse de 5 % des prix pratiqués par un intervenant sur le marché. Faute de modèle informatique, la définition du marché, les évolutions de la concentration et des éventuels effets anticoncurrentiels sont difficiles à évaluer. En principe, à chaque heure (ou division temporelle inférieure) correspond un marché différent, mais, dans la pratique, on est obligé de regrouper les marchés analogues pour éviter une charge de travail écrasante. Là encore, la simulation informatique peut faciliter le processus. M. D. Biggar partage ce point de vue.

Le délégué de l'**Autriche** évoque la question des pouvoirs de marché sur des marchés associés, par exemple celui des services auxiliaires (de la réserve tournante) ou de la capacité. A certains moments, le gestionnaire du réseau peut demander à certains producteurs d'augmenter très vite leur production. Le nombre de producteurs en mesure d'assurer ce service peut être extrêmement limité, ce qui renforce leur pouvoir de marché et peut provoquer une flambée des prix.

Le délégué du **Canada** partage la même crainte. Dans les zones où le parc de production est diversifié, certaines installations peuvent augmenter ou, au contraire, réduire leur production plus vite que d'autres. (Par exemple, les centrales au gaz sont capables de monter en charge plus vite que les centrales au charbon). C'est pourquoi la définition du marché est si compliquée lorsqu'il s'agit des services auxiliaires.

Le délégué de la **Norvège** observe que, sur un marché purement énergétique (au sens où il n'existe pas d'autre marché pour garantir une capacité suffisante), les hausses de prix sont nécessaires pour que de nouveaux moyens de production entrent sur le marché. De ce fait, il paraît difficile de distinguer les hausses de prix résultant de l'exercice d'un pouvoir de marché de celles qui sont un indicateur de la nécessité de mettre sur le marché des nouveaux moyens de production.

Mise en place d'une structure concurrentielle

Le **Président** relève que la séparation des producteurs historiques pour favoriser la concurrence a été assez peu pratiquée. La Nouvelle-Zélande, où opérait un monopole d'Etat, a créé trois entreprises publiques séparées, dont l'une a été ultérieurement privatisée. Il existe dans ce pays un gestionnaire de réseau qui est une entreprise à but lucratif, mais pas d'autorité de régulation du transport. L'investissement dans le transport a fait défaut et on peut se demander si cela tient au fait que le gestionnaire du réseau soit une entreprise à but lucratif.

D'après le délégué de la **Nouvelle-Zélande**, la nécessité de procéder à la séparation horizontale de ces entreprises était bien acceptée (l'alternative étant le monopole). Les trois producteurs jouissent d'une indépendance totale vis-à-vis de l'Etat pour leur politique de tarification. Ils se distinguent par leurs zones de desserte géographique et par les énergies primaires qu'ils utilisent. A l'avenir, on prévoit de privatiser davantage.

Le délégué de l'**Italie** explique que l'opérateur en place, ENEL, était, il y a trois ans, un monopole verticalement intégré. Sa part du marché actuelle, de 50 %, est encore élevée, et le marché est jugé concentré. L'autorité de régulation a choisi de tabler sur l'entrée sur le marché de nouveaux opérateurs pour augmenter la capacité. Afin d'encourager les entrées, l'Etat cherche avant tout à alléger les obstacles administratifs à l'entrée. Il sera exigé d'ENEL de se dessaisir de nouveaux actifs, mais on ignore encore dans quelle mesure.

Répondant à une question du Président concernant les projets en vue d'accentuer (et non réduire) la concentration dans la production, le délégué de l'**Autriche** observe que le marché de gros de son pays est intégré aux marchés de la Suisse et de l'Allemagne. Les prix de l'électricité en Suisse et en Allemagne sont identiques à ceux de l'Autriche tant en période de pointe qu'en période normale.

La contribution de la Suisse explique que l'ouverture du marché dans ce pays a été retardée par le résultat négatif de la votation sur la loi sur le marché de l'électricité. Le **Président** demande pourquoi les prix de l'électricité sont plus élevés en Suisse étant donné que ce pays produit de l'électricité hydraulique et nucléaire. Les problèmes de concurrence sont-ils liés aux activités des deux organisations Swisselectric (Organisation des entreprises du réseau d'interconnexion suisse d'électricité) et Swisspower ?

Le délégué de la Suisse reconnaît que les prix de l'électricité sont, en général, supérieurs à la moyenne en Europe, en particulier les prix payés par les PME et les ménages, et cela parce que certaines centrales ne sont pas encore amorties. Bien que les prix publiés soient plus élevés, les prix négociés par les gros consommateurs sont d'un niveau comparable aux prix européens. La fiscalité est lourde en Suisse. En outre, les producteurs appartiennent en général aux municipalités qui sont nombreuses à subventionner d'autres activités avec les bénéfices tirés de l'électricité. La loi sur l'électricité qui a été rejetée devait apporter plus de transparence dans cette pratique. Swisselectric est l'association des six plus grands producteurs d'électricité verticalement intégrés, qui a pour mission de promouvoir leur intérêt commun, de conjuguer leurs ressources, etc. Il ne s'agit pas d'un embryon de cartel. Quant à Swisspower, elle regroupe des producteurs municipaux qui mettent ainsi en commun leurs moyens (aux fins de marketing essentiellement) dans leurs zones de desserte.

Transport

Passant à la question du transport, le **Président** note que les problèmes liés au maintien de la réglementation du transport (et dans une certaine mesure de la distribution) comptent parmi les questions les plus difficiles qui restent à résoudre dans l'industrie électrique. L'un des plus importants concerne la tarification de l'accès au réseau de transport, car il faut envoyer aux utilisateurs (producteurs et consommateurs) des signaux justes concernant les congestions et inciter à investir dans le réseau de transport (sans que ces investissements s'arrêtent aux frontières entre réseaux). Parmi les autres problèmes notables, on retiendra la séparation structurelle, qui pose la question de savoir comment isoler la planification et l'exploitation du réseau de transport des intérêts des producteurs, par exemple.

S'agissant de la tarification du réseau de transport, **Darryl Biggar** constate qu'il s'agit là du seul problème qui n'ait jusqu'à présent pas trouvé de réponse uniforme même entre pays ayant ouvert leurs marchés de l'électricité (par exemple, le Royaume-Uni et les Etats-Unis). Dans l'idéal, le système de tarification doit (a) envoyer les signaux adéquats sur la congestion du réseau (indiquant aux producteurs et aux consommateurs le moment où augmenter ou, au contraire, réduire l'offre et la demande et leur signaler de manière efficace où se positionner sur le réseau); (b) favoriser la concurrence entre producteurs (d'autant que les producteurs jouissent de pouvoirs de marché); et (c) faciliter des investissements efficaces dans le réseau de transport.

L'efficacité allocative mais aussi productive et dynamique veut que les prix du transport de l'électricité soient géographiquement différenciés en temps réel. Les arguments sont à peu près identiques à ceux avancés pour justifier la différenciation du prix en fonction de l'heure de la journée. En effet, si l'électricité était facturée au même prix en permanence, les consommateurs ne seraient pas incités à moins consommer pendant les pointes, les propriétaires des centrales de pointe ne sauraient pas quand démarrer leurs installations, et l'investissement dans les moyens de pointe risquerait d'être insuffisant (et le parc de centrales en général ne serait pas optimisé). Ces arguments valent pour la différenciation géographique des prix de l'électricité : une tarification en fonction de l'emplacement sur le réseau permet de facturer le juste prix de la congestion, indiquant aux consommateurs quand s'effacer et donnant aux producteurs comme aux consommateurs une information exacte concernant la localisation optimale.

Toutefois, une différenciation géographique des prix extrêmement fine peut renforcer le pouvoir de marché. A cela s'oppose la péréquation géographique, qui fait que les producteurs très éloignés des centres de consommation ne sont absolument pas défavorisés par rapport aux producteurs plus proches - le marché géographique s'étend et la concurrence s'accroît. Dans certains cas, les avantages d'une concurrence renforcée peuvent équivaloir aux effets de décisions plus efficaces en matière de dispatching ou de localisation. A l'inverse, la différenciation géographique des prix de l'électricité réduit la taille du marché géographique pertinent et aura donc tendance à renforcer les pouvoirs de marché, un effet qui pourrait annuler tout gain d'efficacité.

Enfin, il est très difficile de produire des incitations appropriées à investir dans le réseau de transport. Bien que la tarification nodale envoie des signaux efficaces de congestion, la façon dont ces signaux peuvent se transformer en incitations à investir n'est pas évidente, d'autant que les investissements réalisés sur une partie du réseau peuvent se répercuter sur les transits et les congestions ailleurs. Si la tarification du réseau de transport est rémunérée en fonction des "rentes de congestion", elle incitera à construire le réseau de façon à favoriser, plutôt que réduire, la congestion.

Nombreux sont les pays dont les liaisons de transport avec l'étranger fonctionnent aux limites de leur capacité. Les Pays-Bas ont choisi de recourir à des enchères pour attribuer la capacité limitée des lignes d'interconnexion. Ces enchères portent sur la demande annuelle, mensuelle ou du lendemain. Le **Président** demande si les participants sont satisfaits des résultats de ces enchères.

Le délégué des **Pays-Bas** explique que le pays importe 20 % de sa consommation totale, essentiellement d'Allemagne. Il a signé des contrats à long terme avec des producteurs nucléaires allemands et français. Pour favoriser l'exploitation de la puissance et la concurrence sur le marché, tout contrat qui n'a pas été honoré est perdu. En d'autres termes, la capacité d'importer obtenue antérieurement doit être utilisée ou remise sur le marché spot physique (la veille pour le lendemain). Le public est en général satisfait du système actuel. Les Pays-Bas prévoient de construire de nouvelles interconnexions.

Le **Président** demande au délégué des Etats-Unis de donner son avis sur l'ordonnance 888 de la FERC qui a conduit à la création de gestionnaires de réseau indépendants, et de fournir une première indication des résultats de l'ordonnance 2000 de la FERC encourageant la formation d'opérateurs de transport régionaux. Notamment, a-t-on investi suffisamment dans le transport, et notamment aux points d'interconnexion ?

Les **Etats-Unis** avaient initialement adopté une approche comportementale de l'accès aux réseaux de transport, partant de l'hypothèse que condamner la discrimination suffirait à l'empêcher. Au cours des six à sept dernières années, cette démarche n'a pas atteint l'objectif voulu et l'on s'est tourné vers l'approche structurelle. La première étape (ordonnance 888) consiste à favoriser la création de gestionnaires de réseau indépendants. Plus près de nous (ordonnance 2000), la FERC a exigé la constitution d'entreprises de transport régionales. Reste à encourager l'apparition de transporteurs indépendants, en particulier là où les gestionnaires de réseau ne sont pas parvenus à développer le réseau de transport.

Le **Président** note que l'Italie s'est déjà dotée d'un gestionnaire de réseau indépendant. Il demande pourquoi l'Italie envisage désormais de procéder à la séparation de la production et du transport.

Le délégué de l'Italie répond que la création d'un gestionnaire de réseau indépendant a facilité l'accès au réseau, renforcé les interconnexions aux niveaux international et national (augmentant la capacité de 20 % par la frontière nord) et permis d'éviter l'application de tarification zonales différentes.

L'**Italie** envisage de fusionner de nouveau la propriété et la gestion du réseau (séparées actuellement et confiées à un gestionnaire de réseau indépendant). Et cela pour deux raisons. Premièrement, il s'agit d'inciter à investir dans la construction de lignes, car, en Europe, il est très difficile d'obtenir des administrations locales l'autorisation de construire des lignes à haute tension. Par ce retour en arrière, on espère pouvoir mieux encourager le gestionnaire de réseau à surmonter ces difficultés. En outre, la séparation pose des problèmes de sécurité dont la résolution passe par la régulation et la coordination. Des investissements privés dans le transport sont également possibles.

Le **Président** se tourne alors vers l'Allemagne, observant que ce pays est le seul qui n'a pas de réglementation *ex ante*, mais s'en remet à l'application *ex post* du droit de la concurrence. Les tarifs d'accès au réseau de transport sont établis par une association de participants au marché. Le Président souhaite savoir si les consommateurs sont associés à cette décision et quel ils jugent portent sur ce mode de fonctionnement *ex post*. Peut-on penser que le passage à une réglementation *ex ante* allégerait le contentieux et les coûts administratifs ?

Le délégué de l'**Allemagne** précise que l'accord passé par les associations d'industriels est en vigueur depuis 1998. Etaient parties à l'accord initial les associations d'électriciens, les gestionnaires de réseau, les clients industriels et le Bundesverband der Deutschen Industrie. Le premier accord définissait le cadre initial destiné à créer les conditions d'accès au réseau. Il a été par la suite révisé deux fois de façon à apporter d'importantes améliorations de l'accès des tiers au réseau. Au cours de ces deux révisions, l'association des consommateurs a participé aux discussions. Ces accords ne fixent pas les prix réels de l'accès au réseau, de même qu'ils ne font pas échapper à l'application du droit de la concurrence les

problèmes d'accès au réseau dans le secteur énergétique. Les critères et conditions fixés dans ces accords sont contrôlés par les autorités de la concurrence qui peuvent les annuler.

Les interventions du **Bundeskartellamt** et des autorités des **Länder** ont d'importantes répercussions sur le marché. Les nombreuses procédures engagées par ces autorités à l'encontre d'opérateurs de réseau en ont convaincu plusieurs à réduire leurs tarifs d'accès. C'est pourquoi le contrôle *ex post* est jugé efficace en Allemagne. Les autorités des **Länder** et le **Bundeskartellamt** coordonnent leurs travaux et notamment se retrouvent pour une conférence deux fois par an.

Le **Président** demande au délégué du Danemark des éclaircissements sur les périodes de l'année où le Danemark se trouve isolé du réseau du Nord Pool.

Le délégué du **Danemark** explique que son pays se trouve coupé du reste du réseau du Nord Pool environ 5 % de l'année. Au cours de ces périodes, les deux opérateurs danois détiennent une position dominante qui soulève la question des abus éventuels. Toutefois, la décision de construire de nouvelles lignes de transport doit tenir compte du peu de temps pendant lequel les lignes sont surchargées.

Le **Président** évoque deux problèmes soulevés par la contribution brésilienne. Le prix spot dépendrait, semble-t-il, de facteurs à long terme principalement (tels que la quantité d'eau dans les réservoirs, les prévisions de la pluviométrie, etc.). Comment les producteurs qui détiennent des moyens thermiques classiques peuvent-ils participer au marché si les décisions ne sont pas fondées sur les prix mais sur ces facteurs à long terme ? En outre, ce pays exige de tout client éligible qu'il assure au moins 85 % de sa consommation par des contrats à long terme dont les prix sont plafonnés. Pourquoi ne pas se fier davantage au marché pour fixer les prix ?

Le délégué du **Brsil** convient que les producteurs thermiques ont du mal à participer au marché sachant que les producteurs hydrauliques des différents bassins versants coopèrent pour que le prix n'augmente pas en période de sécheresse (et pour décourager les centrales thermiques d'intervenir sur le marché). Le gouvernement brésilien a donc donné un coup de pouce aux producteurs thermiques, en abaissant réglementairement le prix du gaz et du transport de gaz et en assouplissant les contrats de consommation du gaz. Il est également prévu d'inaugurer des tarifs de transport avec une plus forte différenciation géographique, ce qui devrait favoriser les centrales thermiques qui sont situées plus près des consommateurs que les centrales hydrauliques.

C'est essentiellement le marché qui détermine les prix. Vingt-cinq pour cent de la production d'énergie sont vendus par des procédures d'enchères, pourcentage qui sera porté à 100 % au cours des trois prochaines années. Les consommateurs éligibles ne sont pas tenus de conclure des contrats à long terme. En revanche, les compagnies d'électricité ont l'obligation de passer des contrats pour le compte des clients captifs. En 2005, tous les consommateurs seront libres de choisir leur fournisseur. Le marché déterminera les prix, et il ne sera plus nécessaire de fixer des prix de référence à l'aide de programmes informatiques.

Au cours du débat général, le délégué des **Etats-Unis** demande des éclaircissements à son homologue italien. Le modèle utilisé en Italie, à savoir un réseau de transport aux mains d'une seule entreprise de transport privée, serait ce que l'on appelle un **Transco** aux Etats-Unis, modèle que ce pays avait envisagé d'adopter en raison de son efficacité. Cependant, il était apparu que si cette entreprise de transport privée était moins incitée à opérer une discrimination qu'un fournisseur verticalement intégré, elle aurait néanmoins des raisons de l'exercer à l'encontre des producteurs plus proches des consommateurs, dans la mesure où cette proximité se substitue au transport.

Le délégué de **l'Italie** répond que toute production décentralisée pose à l'entreprise de transport un problème qui n'a pas de solution facile.

Le délégué de l'**Autriche** exprime des réserves quant aux signaux envoyés par des prix spatialement différenciés qui seraient fondés sur le coût marginal de court terme. Il est à redouter que ces signaux ne soient efficaces que dans certains cas particuliers, à savoir en l'absence de contraintes ou lorsque l'on n'utilise qu'une technologie. En effet, par rapport à d'autres facteurs, comme l'accès aux sources d'énergie primaire, ces signaux peuvent se révéler insignifiants. Par conséquent, s'ils doivent avoir un effet déterminant sur la localisation des moyens de production, il faudra parfois prévoir des mesures d'accompagnement.

Pour le délégué de la Norvège, il suffit, pour envoyer des signaux géographiques, de calculer les prix d'après les pertes marginales prévues par nœud du réseau de transport. La tarification en fonction des pertes marginales fournit effectivement des signaux de localisation à long terme. Les Norvégiens hésitent à adopter une tarification entièrement nodale dynamique en raison du volume d'informations nécessaire. Et qui, de plus, pourrait dessiner un marché hautement informatisé et non transparent, peu accessible aux participants côté demande. Par ailleurs, la tarification nodale ne fournira toujours pas de signaux efficaces pour l'investissement. Les investissements sont si irréguliers qu'il est extrêmement difficile de créer les incitations adéquates pour obtenir un niveau d'investissement efficace. Il s'agit d'un sujet qui mérite une analyse approfondie.

Institutions et structures réglementaires

Le **Président** observe que l'Australian Competition and Consumer Commission joue à la fois le rôle d'autorité de la concurrence et de régulateur des monopoles naturels, ce qui devrait lui permettre en principe de résoudre les contradictions entre la réglementation et le droit de la concurrence. Il existe toutefois d'autres régulateurs, notamment au niveau des Etats et territoires. Comment est-on parvenu à cette structure ? Comment s'opère la coordination entre ces différentes institutions et quelles sont les possibilités de simplification ?

Le délégué de l'**Australie** confirme que l'autorité nationale de la concurrence est également l'autorité de régulation de l'électricité, et cela parce que le gouvernement avait décidé de laisser ces deux fonctions entre les mains du même organisme. Il a fallu toutefois consentir un compromis avec des Etats, qui souhaitent conserver le contrôle des problèmes d'intérêt local, et autoriser la création d'autorités à leur niveau d'administration. L'expérience des six à sept dernières années n'a pas révélé d'évolution négative, ces autorités sont maintenant pleinement opérationnelles.

La multiplication des autorités semble pire en théorie qu'elle ne l'est en réalité. En fait, il existe peu de doublons dans la réglementation. Le droit appliqué est le même pour toutes les autorités des Etats. Ces autorités ont compétence pour les problèmes de distribution et de fourniture locale de l'électricité, plutôt que pour des problèmes généraux. Il existe aussi des mécanismes, officiels ou non, pour résoudre les problèmes liés à la coexistence de ces autorités. Les mécanismes officiels comprennent notamment le code national de l'électricité, qui s'applique uniformément à la totalité du secteur électrique, et la participation des chefs des autorités des Etats à un organe de décision (l'Energy Committee de l'ACCC). Dans l'ensemble, l'approche réglementaire est globalement cohérente sur tout le territoire australien. Par conséquent, on ne peut pas dire que la multiplication des autorités réglementaires conduise nécessairement à l'incohérence.

Le **Président** note que la structure institutionnelle en place en Ontario est également assez compliquée. Dans cette province, on observe, outre le Bureau de la concurrence, la présence d'une Société indépendante de gestion du marché de l'électricité (SIGMÉ) ainsi que de la Commission de l'énergie de l'Ontario. La SIGMÉ a, par ailleurs, créé un Comité de surveillance du marché afin de détecter les abus. Qui aura la charge des abus détectés par le Comité, en vertu de quelle loi et avec quelles prérogatives ?

Le délégué du **Canada** convient que la réglementation en Ontario concernant la concurrence est assez compliquée. En plus du droit fédéral de la concurrence, le droit provincial joue un grand rôle. Le Comité de surveillance du marché est constitué de membres indépendants : deux économistes universitaires et un ingénieur. Ce Comité contrôle les marchés de la Société indépendante de gestion du marché de l'électricité (SIGMÉ) ainsi que les évolutions dans ce domaine. Il peut identifier deux types fondamentaux d'abus : l'exercice de pouvoir de marché pour faire monter les prix et un ensemble de pratiques anticoncurrentielles qui relèvent également du droit canadien de la concurrence. Le Comité est un organe d'investigation, il n'a pas de compétence juridictionnelle. Il peut saisir, pour les questions de concurrence, la Commission de l'énergie de l'Ontario, le Bureau de la concurrence ou la SIGMÉ, selon le cas.

La séparation des compétences obéit à quelques principes. Par exemple, la détection et la prévention de l'exercice de pouvoirs de marchés locaux relèvent de la responsabilité de la SIGMÉ, tandis que la tarification du transport et de la distribution relève de la CEO. Toutefois, il reste de nombreux domaines où ces compétences se recoupent. La CEO accorde des permis aux participants sur le marché. Ces permis comportent parfois des dispositions interdisant des pratiques anticoncurrentielles qui peuvent également relever du droit de la concurrence. Par rapport aux procédures normales de l'application du droit de la concurrence, la CEO peut tenir des audiences accélérées, mais n'a pas les pouvoirs d'investigation que confère ce droit. Les pouvoirs du Bureau de la concurrence dépendent de la nature de l'infraction. L'abus de position dominante relève du droit civil et peut donner lieu à une ordonnance d'interdiction. Les soumissions concertées et les prix imposés relèvent du droit pénal et, outre des ordonnances d'interdiction, peuvent donner lieu à des amendes ainsi qu'à des peines de prison. On peut penser que le Bureau de la concurrence sera saisi des affaires pénales bien que, en matière d'électricité, il ne soit pas toujours possible de prouver qu'un acte constitue un complot à renvoyer devant une cour pénale. En cas de doute, la CEO pourra se saisir de l'affaire. Les abus de position dominante seront pris en charge par la CEO ou le Bureau de la concurrence, selon l'affaire particulière en question.

La SIGMÉ, le Bureau de la concurrence et la CEO ont conclu un accord afin de clarifier les rôles respectifs de chacun d'entre eux. Il s'agit par là de lever des incertitudes concernant le cadre juridique et réglementaire, d'éviter les doublons, de faire en sorte que les problèmes soient résolus et d'éviter la recherche de la juridiction la plus favorable. Cet accord ne délimite pas les compétences respectives, mais crée une obligation de coopération. Il dispose, par ailleurs, que le Bureau de la concurrence n'est pas compétent à l'égard des pratiques anticoncurrentielles, des assertions fausses ou trompeuses qui relèvent de la CEO. La mise en œuvre de l'accord est assurée par des communications régulières bi-hebdomadaires entre ces autorités.

Le **Président** demande au délégué de Hongrie d'apporter des éclaircissements sur l'examen de la réforme réglementaire qui a été organisé il y a un an. Il avait été proposé à cette époque d'équilibrer les tarifs et de limiter les pouvoirs étendus du ministère en matière de tarifs. Quels sont les progrès réalisés dans ces domaines ?

Le délégué de **Hongrie** explique que la loi hongroise ne permet pas de déléguer des compétences officielles en matière de tarification à l'autorité de régulation de l'énergie. Le régulateur jouit cependant d'un pouvoir de proposition pour ce qui concerne les tarifs. En fait, les prix sont calculés par le Bureau de l'énergie (Magyar Energetika Hivatal) qui soumet une recommandation au ministre, seul compétent pour décider du prix définitif. Le prix étant un sujet politiquement sensible, la décision finale intègre des facteurs politiques. C'est pourquoi, le gouvernement n'est guère disposé à confier à une autorité indépendante la possibilité de fixer les prix. Pour définir la politique à suivre, l'autorité de régulation travaille en collaboration étroite avec le ministère, mais pour ce qui est des prix, son rôle est purement consultatif.

L'un des principaux problèmes mis au jour lors de l'examen de la réforme de la réglementation en Pologne était le rééquilibrage des tarifs. Le **Président** s'enquiert des progrès accomplis dans cette direction.

Le délégué de la **Pologne** répond que son pays tient compte des recommandations figurant dans l'examen et s'efforce de les suivre. Cette année, le parlement a adopté un amendement à la loi sur l'énergie qui est entré en vigueur le 1er janvier 2003. Les textes d'application sont également à l'étude, un groupe de travail interministériel a été constitué afin d'analyser cette question.

Le **Président** note que l'Irlande a exclu la possibilité de créer un marché spot en se dotant d'un système réglementaire très développé dans lequel le prix d'achat d'un supplément de puissance est réglementé. Qu'est-ce qui garantit que l'offre sera suffisante à ce prix ?

Le délégué de l'**Irlande** répond que les règles actuelles sont transitoires et qu'elles ont été adoptées dans la perspective de l'ouverture du marché en février 2000. A l'époque, le ministre avait demandé à l'autorité de régulation de revoir en 2004 les contrats d'échange, ceci afin de mettre en place un système d'échange plus robuste en prévision de l'ouverture totale du marché en 2005. Etant donné l'incertitude quant à la nature du régime en place en 2005 et les problèmes de capacité, la date de cette révision a été avancée.

Le marché irlandais, qui possède peu d'interconnexions, connaît un taux de croissance élevé et exploite beaucoup de centrales âgées, la capacité pose un problème important. En 2001-2002, de graves pénuries ont exigé l'importation de groupes de secours de Californie.

Les prix relatifs posent de multiples problèmes. Malgré d'importantes hausses, les prix de détail ne sont pas suffisamment élevés et ne reflètent pas le coût de l'ajout de nouvelles installations dans la mesure où ils sont fondés sur les coûts historiques d'ESB (Electricity Supply Board). Les producteurs indépendants éventuels (VIPP) pratiquent des prix moins élevés. Toutefois il leur est difficile de trouver le juste prix qui doit être assez intéressant pour inciter un nombre suffisant de consommateurs à changer de fournisseur et néanmoins leur permettre de concurrencer ESB.

Deux nouveaux producteurs sont en train de s'implanter sur le marché irlandais. L'Irlande reste un marché prometteur pour les producteurs, qui continue de se développer à un rythme rapide malgré le ralentissement de l'activité et le peu de concurrence que permet l'interconnexion. Aux dires des producteurs eux-mêmes, les incertitudes quant à la situation en 2005 sont la principale raison de la lente apparition de nouveaux moyens de production sur le marché. L'annonce du lancement d'un nouveau système d'échange et de consultations au cours des six mois qui viennent permettra de lever ces incertitudes.

Application du droit de la concurrence sur les marchés de l'électricité

Le **Président** ouvre ce dernier débat en observant que les activités de l'industrie électrique ont été émaillées d'affaires de concurrence, bien qu'il ne s'agisse pas pour l'essentiel d'abus de position dominante. La plupart de ces affaires concernent en fait les fusions.

En France, la fusion d'EDF et de Dalkia a été autorisée, mais assortie d'un éventail de conditions si contraignantes qu'il devenait impossible aux deux parties du groupe né de la fusion de réaliser des gains d'efficacité. Pourquoi cette fusion a-t-elle été autorisée si elle n'autorise pas de gains d'efficacité ? En outre, pour l'autorité, contrôler le respect des obligations de l'entreprise représentait une charge administrative considérable. Le président demande aux autorités françaises de faire connaître leur sentiment général quant aux obligations imposées.

Le délégué de la **France** explique que Dalkia est une entreprise de services énergétiques. EDF a acquis 34 % du capital de Dalkia pour diversifier ses services. Ces deux entreprises avaient l'intention de créer un marché totalement nouveau de services aux industriels. C'est pourquoi, les parts obtenues sur ce marché, considéré comme global, n'ont pas été calculées. La fusion ne posait pas de problème dans la mesure où n'était concerné que ce nouveau marché. Cependant, comme l'une des parties était (a) un producteur en position dominante, (b) le gestionnaire du réseau de transport et (c) présente sur le marché de l'offre, on s'est demandé si cette transaction renforcerait la position déjà forte d'EDF sur le marché français.

Cette décision interdit aux employés d'EDF d'accéder aux documents sur les activités de l'autre entreprise en France. Cette disposition structurelle est la principale. D'autres conditions ont également été imposées, telles que l'obligation d'informer les clients de Dalkia des prix de l'électricité fournie par EDF.

Il est fréquent que l'Union européenne ait choisi de subordonner l'autorisation de fusion à l'amélioration de conditions favorisant la concurrence, note le **Président**. Dans le cas de la fusion d'EDF avec Hidrocantábrico, la Commission européenne a assorti son accord de l'obligation d'améliorer la capacité d'interconnexion entre la France et l'Espagne. Quel a été le résultat ? Les exportations françaises ont-elles augmenté comme il était prévu, et quel a été l'effet de cette fusion sur la production espagnole ?

Le délégué de la **Commission européenne** insiste sur l'importance de cette obligation de renforcer la liaison d'interconnexion entre la France et l'Espagne. Il s'agit de faire passer la capacité d'interconnexion actuelle de 1 100 MW à plus de 4 000 MW. Cette opération doit prendre quatre à cinq ans, et il ne sera pas possible d'en détecter des effets mesurables sur le marché avant cette échéance.

Au Japon, le JFTC a lancé un "avertissement" à l'entreprise Hokkaido Electric Power concernant ses pratiques d'exclusion. Le **Président** invite le délégué du **Japon** à décrire l'affaire et à expliquer ce que signifie un "avertissement" en droit japonais.

En 2001, le JFTC a créé un groupe de travail dont la mission était de contrôler le secteur des entreprises de service public, et notamment l'industrie électrique. Il s'est occupé de plusieurs affaires. Il existe une concurrence relativement faible entre producteurs, chacun d'entre eux ayant sa propre zone de desserte. Hokkaido Electric Power est en position de monopole dans sa zone de desserte. Cette entreprise a passé des contrats à long terme avec ses clients, dans lesquels était prévue une pénalité excessivement élevée pour tout client souhaitant acheter les services de nouveaux entrants. Le JFTC a par conséquent lancé un "avertissement", car l'on peut soupçonner une infraction à la loi contre les monopoles.

Un avertissement n'est pas une sanction juridique du JFTC. Les avertissements sont donnés lorsqu'il est impossible de prouver qu'il y a eu violation de la loi anti-monopole et que l'autorité juge qu'il faut néanmoins intervenir. Le JFTC donne 15 à 20 avertissements par an. Cet organisme établit également des recommandations identifiant des types de comportements sur le marché de l'électricité qui pourraient être contraires à la concurrence. Ces recommandations se fondent sur l'expérience et sur des discussions avec les entreprises.

Débat

Au cours du débat général, le délégué des **Etats-Unis** souligne le caractère primordial d'une conception adéquate des règles du marché avant l'introduction de la concurrence. Il espère que l'expérience de la Californie aidera les autres pays à éviter de telles erreurs au moment de l'ouverture de leur marché. Il s'agira en particulier de tenir compte de la puissance en réserve et d'étudier les moyens de créer un marché qui soit plus sensible aux prix.

D'après le délégué de la **Norvège**, l'autorité de la concurrence vient d'instruire une affaire concernant la fusion de Statkraft avec deux concurrents respectivement du sud et du nord du pays. L'autorité a interdit les deux fusions qui pourtant n'auraient pas fortement accru la concentration du marché. Cependant, il a été jugé que le nord et le sud de la Norvège constituaient des marchés géographiquement séparés et, qu'étant donné leur petite taille, la concentration serait passée de 40 à 50 %. Ces deux entreprises disposent d'une importante puissance installée grâce à leurs réservoirs d'eau, ce qui leur laisse une certaine souplesse. En outre, elles détiennent un pouvoir de marché sur certaines périodes de l'année. Ces deux décisions ont fait l'objet d'un recours. Le ministère a autorisé une fusion en la subordonnant à des conditions strictes. L'autre recours est en instance.

Le délégué de l'**Autriche** revient sur le rôle de la conception du marché, souligné dans le document de référence, mais laissé de côté au cours de la réunion. Il importe également d'étudier la façon dont les informations sont diffusées, notamment les informations concernant les variations de l'offre et de la demande, essentielles pour les nouveaux entrants.

Le représentant de la **CNUCED** observe que bien des pays en développement rencontrent des problèmes analogues à ceux qui ont été évoqués. Il soulève la question de la responsabilité du développement du réseau de transport. De nombreux pays africains ont privatisé leur industrie et ouvert leur marché, mais l'absence de capitaux freine le financement du développement des réseaux.

Le délégué des **Etats-Unis** est frappé par le fait qu'une bonne partie des débats a été consacrée à la façon de s'assurer que les signaux de prix sont favorables à l'efficacité et aux investissements, ce qui revient en fait à obtenir les informations correctes et à mettre en place les bonnes incitations et le régime de propriété approprié. Toutes ces conditions sont indispensables.

Résumé

Le **Président (Alberto Heimler)** clôt la réunion sur le contraste entre la table ronde de 1996 et celle d'aujourd'hui. Il note en particulier :

- L'importance des problèmes structurels, en particulier la séparation verticale du réseau de transport et la séparation horizontale destinée à favoriser la concurrence à la production.
- L'importance de conserver une certaine souplesse, contrairement aux conceptions initiales très rigides de la façon de réformer le marché. La Norvège a bien démontré l'intérêt d'introduire une certaine souplesse dans la structure et dans les marchés. La possibilité pour les producteurs de jouer le rôle d'acheteurs et, pour les négociants, de vendre et d'acheter est un gage de souplesse et permet de contrôler les pouvoirs de marché.
- La capacité pour le consommateur de faire varier sa demande lorsque le prix change exige une certaine éducation. Or l'installation de compteurs en temps réel coûte cher et, dans le monde, l'expérience que l'on possède sur la façon dont les consommateurs, qu'ils soient gros ou petits, réagissent à des variations des prix de l'électricité est assez limitée.
- La structure institutionnelle joue un rôle important, en particulier dans les Etats à structure fédérale où la coordination des autorités aux divers niveaux d'administration vient ajouter à la complexité du problème. Les contributions du Canada, de l'Australie et des Etats-Unis l'ont bien montré.

- Le marché géographique pertinent n'est pas facile à identifier, ce qui rend plus difficile la création d'une structure réglementaire propice au bon fonctionnement du marché. Les frontières d'un pays ne coïncident pas nécessairement avec celles du marché géographique pertinent.

En conclusion, nous nous trouvons dans une phase d'évolution tant en ce qui concerne les mécanismes du marché que la mise en place des institutions. Dans cinq ans, on saura quelles méthodes, parmi celles préconisées aujourd'hui, étaient efficaces.

NOTES

1. Voir, par exemple, John C. Hilke et Michael Wise, "Who turned out the lights ? Competition and California's Power Crisis", *Antitrust*, Été 2001, 15, 76-81.
2. www.ofgem.gov.uk/newprojects/neta_index.htm