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ABBREVIATIONS

ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
AESIRB	Australian Electricity Supply Industry Research Board
COAG	Council of Australian Governments
ERDC	Electricity Research and Development Corporation
ESAA	Electricity Supply Association of Australia
ESIRU	Electricity Supply Industry Reform Unit (Victoria)
ETSA	Electricity Trust of South Australia
GTE	government trading enterprise
kWh	kilowatt-hours
MW	megawatts
NECA	National Electricity Code Administrator
NEMMCO	National Electricity Market Management Company
NGMC	National Grid Management Council
OFFER	Office of Electricity Regulation (United Kingdom)
QEC	Queensland Electricity Commission
SECV	State Electricity Commission of Victoria
SMHEA	Snowy Mountains Hydro-Electric Authority
SMP	system marginal price
TFP	total factor productivity

TERMS OF REFERENCE

Industry Commission Research Project into Implications for the National Electricity Market of NSW Generation Options

The Industry Commission is requested to undertake a review of the electricity generation industry in New South Wales to determine the implications for competition of the market power that could be exercised by Pacific Power operating as a single entity.

In undertaking this review, the Industry Commission should have regard to the consistency of Pacific Power's market position in the electricity generation sector with:

- the principles for structural reform of public monopolies contained in the Competition Principles Agreement; and
- the operation of a competitive national electricity market.

In relation to its assessment of market power in the electricity generation industry, the review should specifically examine (but without limitation) the ability of Pacific Power to:

- set prices for the market for significant periods of time to increase revenue or profit without engendering actions by customers or competitors which cause it to lose market share;
- force an allocation of capacity onto the market so that more efficient plant is kept idle and less efficient plant operates for significant periods of time;
- drive out competitors that are more efficient; and
- prevent entry of new capacity that is more efficient.

The review should assess whether likely patterns of usage and capacity constraints of major interconnectors would contribute to the extent of Pacific Power's market power in relation to consumers in New South Wales or relevant regions within the State.

The review should also consider the implications for electricity consumers and competition of alternative structures of the electricity generation industry in New South Wales, including the trade-off between benefits from a competitive generation sector and the costs association with the possible loss of economies of scale and scope.

The Industry Commission is requested to report within 45 days of receiving these terms of reference.

EXECUTIVE SUMMARY

This report assesses the market power that could be exercised by Pacific Power — the nation's largest electricity generation business — and the implications of alternative structures for the generation sector in New South Wales.

The report follows a request by the New South Wales Government to the Commonwealth Assistant Treasurer, asking that the Industry Commission examine these matters within 45 days.

A national electricity market

Australia's electricity supply industry is in the midst of far-reaching change. It is evolving from a system in which electricity supply in each jurisdiction was the sole responsibility of a large, vertically integrated publicly owned authority, to a competitive environment in which corporatised and private utilities will compete in the generation and retailing of electricity.

Reforms thus far, while not all directed at enhancing competition, have resulted in substantial improvements in efficiency: industry-wide productivity has increased, real electricity prices have fallen, payments to governments have risen and debt levels have declined significantly. Pacific Power itself has achieved productivity increases of around 35 per cent since 1987–88, as well as improving its generating plant efficiency, lowering its prices and increasing its profitability.

If competitive pressures can be increased, further improvements in efficiency are possible. To this end, governments are working towards the establishment of a national electricity market, to permit direct competition among generators and among retailers in the participating jurisdictions. At present, only the electricity grids of South Australia, Victoria and New South Wales (including the ACT) are linked, but it is likely that Queensland will also be connected by the time the national market becomes fully operational in 1999. Tasmania may, at some future time, also be linked into the interconnected system.

Assessing Pacific Power's market power

The potential gains in efficiency and lower prices from the national market depend on achieving effective competition among the suppliers within that market. In the case of electricity generation, this means first, that each participant would need to minimise its production costs, and second, that no generating company, acting alone or in concert, would find it profitable to price above costs. Otherwise, the loss of market share to rivals (and entrants) would be too great. If Pacific Power had market power, it would have the ability to charge higher prices — whether reflecting higher costs or higher profits — than would be possible under more competitive conditions.

Assessing whether a firm has market power is inherently difficult. There is no single indicator or definitive set of procedures that can provide a precise answer. Moreover, there are firms in most markets that will have a degree of market power from time to time. Consequently, assessments of market power, and whether its costs warrant government action, inevitably involve a degree of judgment.

The Industry Commission's approach to assessing Pacific Power's market power has involved:

- defining the relevant markets;
- determining Pacific Power's share of the relevant markets;
- considering the scope for existing rivals and new entrants to constrain Pacific Power's market conduct; and
- evaluating the potential market consequences.

Pacific Power has more than one market

Pacific Power, like other electricity generators, essentially supplies two markets:

- an 'exclusive' market for which there are no reasonable substitutes for electricity (eg lighting and many domestic appliances), in which Pacific Power competes only with other sources of electricity; and
- a 'shared' market in which electricity competes with natural gas and other forms of energy (eg natural gas for heating and cooking).

Electricity sales to the 'exclusive' market segment are important: they account for about 60 per cent of all electricity sales in New South Wales.

The geographical dimension of a market defines the relevant competitors. In Pacific Power's case, this is complicated by the existence of the transmission 'interconnections' between state electricity grids. As long as they are unconstrained, it is appropriate to consider Pacific Power's market as encompassing all interconnected jurisdictions. However, at those times when the linkages into New South Wales are constrained, Pacific Power's market would be most appropriately viewed as New South Wales.

Pacific Power's market shares vary widely

In 1993–94, Pacific Power held over 90 per cent of the New South Wales electricity market, and supplied about 36 per cent of electricity consumed in those states that are to participate in the national electricity market (including Queensland). In the relevant energy market, Pacific Power's market shares were about 20 per cent for New South Wales and 7 per cent for all interconnected jurisdictions.

By conventional yardsticks, Pacific Power's shares of the electricity market — whether within New South Wales or the four states — are high enough to trigger concerns about market power. But such indicators in themselves are of limited usefulness.

- As in other markets, the real determinant of market power is the ability of rivals and entrants to respond to excessive prices.
- In addition, the particular characteristics of the electricity market's operation mean that conventional thresholds may overstate the market share needed to exercise market power in electricity generation.

A special characteristic of the new national electricity market arrangements is the procedure to determine which generators are in operation at any one time. The choice is to be determined by a bidding process. Generators with the lowest bids will be 'dispatched' first, with the pool price for all being set by the highest bid capacity within the limits of existing demand. In these circumstances, a strategy of bidding high at the margin will tend to favour any generator which controls a high proportion of the available capacity at a given time. This advantage is magnified by the inability to store electricity and the insensitivity of demand to price changes in the very short term.

Competition from other generators

The ability of existing generators within the interconnected market to capitalise on price increases and take market share from Pacific Power will be determined by their production costs and their generation capacity, and the available transmission capacity. The scope for a competitive response will also vary according to the time of day:

- At times of peak demand, the ability of generators in other states to 'export' to New South Wales is limited. Although the Snowy Mountains Hydro-Electric Authority (SMHEA) has no ability to increase its overall market share, it is likely to supply a higher proportion of its output during peak periods.

- Off peak, there is most potential for interstate competition, but this must occur within the limits of the interconnect capacity and with little support from the SMHEA.
- At ‘shoulder’ periods of demand, the ability of both the SMHEA and the interstate generators to export power to New South Wales may be limited.

Pacific Power will be able to set the market price by withholding capacity and raising the price at the margin for some of its generation. In doing so it would lose some market share, the extent depending in part on the time of day. But on average it would be guaranteed around 60 per cent of the New South Wales market.

Barriers to entry

Competitive pressures would be increased if there was a significant influx of new entrants to generation, especially in New South Wales. The likelihood, and extent, of this depends crucially on the ease of entry and perceptions about future electricity prices.

Most regulatory barriers to entry (eg legislation restricting the generation of electricity for public sale) are being dismantled, and all governments have agreed to provide non-discriminatory access to their transmission grids and distribution networks. Similarly, structural separation of most state electricity authorities means that vertical integration — which some view as a barrier to entry — is now of little relevance.

The Commission does not view economies of scale and scope as barriers to entry in themselves. But they may pose a barrier in combination with ‘sunk costs’ (those costs which cannot be recovered in the event of a firm’s failure). In the case of electricity generation, potential entrants could face significant sunk costs because of the immobility of large scale generating plant (although gas-fired turbine generators are supplied in modular form and could be relocated).

Ultimately, the decisions of potential entrants or existing rivals to invest in new generator capacity will be influenced by expectations about post-entry electricity prices and the behaviour of incumbent generators. There is considerable uncertainty about both of these matters.

Assessments of price outcomes are clouded by the surplus of generating capacity in the national market. This is likely to persist until around 2005. In addition, Pacific Power has substantial sunk costs. This creates further uncertainty because its prices could, in principle, be reduced when necessary to levels which would be well below those justifying entry. Finally, there is also the prospect that Pacific Power itself may invest in new capacity at some point.

Potential entrants could seek to avoid price risks by entering into contractual arrangements with distributors or larger users. Indeed, some investment in new gas-fired plant will almost certainly proceed on this basis. And some entry could occur relatively quickly — new gas-fired plant can be built in 2-3 years. However, given the considerable uncertainty about future electricity prices, some large users and distributors may be reluctant to make the long term commitments that new entrants would prefer to ensure a return on their sunk costs. For example, a distributor may be unwilling to commit to a long term contract knowing that, in the event of prices falling, major customers could be lost to other distributors. In the face of this uncertainty, the level of new investment in generation may be relatively modest, and the competition that Pacific Power would encounter from new entrants — both in New South Wales and the other states — could be limited for some time into the next century.

Electricity competes with other forms of energy, especially gas, in a range of end-uses, and this also can provide some discipline on its market power. However, most consumers would not immediately switch to gas if the relative price of electricity is increased. And in many applications there is no ready substitute for electricity.

Based on all these considerations, the Commission considers that Pacific Power has significant market power in the electricity market both in New South Wales and in the four (interconnected) states.

How might market power be used?

The types of strategies adopted by Pacific Power, given its market power, will depend in part on its underlying commercial motives. These could be oriented to achieving high levels of profitability or achieving high volumes of sales or perhaps some combination of the two, such as maximising sales subject to a rate of return decreed by its owner government.

In any case, a generator with market power can engage in diverse strategies: to achieve multi-dimensional objectives, to discourage entry to the market or avoid losing customers, and also to reduce the likelihood of investigation by a regulatory body.

The most likely outcome, given that a significant proportion of electricity customers would still have to deal with Pacific Power due to the lack of alternative suppliers, would be for it to bid up (or maintain) prices significantly above their short run marginal costs. This would increase Pacific Power's profitability, but would deny consumers the potential benefits of a competitive market.

It is difficult to predict the likely price increase, or the period over which the excessive prices would continue. Even if prices rose no higher than the price required by new entrants to yield a return on their investments, it would be more than 50 per cent greater than the likely competitive price in the face of significant excess capacity. The price differential would be expected to fall over time as the excess capacity was wound back. But it could also be argued that the price increase would be greater if entry was weak, or if Pacific Power adopted strategies to discourage entry, such as occasional predatory (low) pricing, or contributing to price volatility, or announcing an intention to build more capacity.

The exercise of market power would impose three types of costs on the economy:

- There would be efficiency costs if some of the market power was dissipated via lower productive and dynamic efficiency.
- Consumers would be disadvantaged. They would have less income to spend on other goods and services, or would be induced to substitute socially more costly energy sources. Consumer's losses would depend on how much they spend on electricity, how high the price is and how responsive they are to price changes, 'Back of the envelope' calculations by the Commission indicate that these losses could be substantial.
- Costs would result from the financing of additional capacity induced by higher prices. These costs (in interest and depreciation) could also be very high. In other words, new entry — to the extent that it occurred prematurely — could be a very expensive way of curbing market power.

Means of reducing market power

The Commission considered three major options for reducing Pacific Power's market power: regulatory action; expanding the interconnections between interstate electricity grids; and disaggregating Pacific Power into a number of separate business entities.

Regulation

Largely because of the bidding process and the nature of the arrangements that will govern the marketing of electricity, very detailed regulation and ongoing monitoring would be required to ensure that Pacific Power did not exploit its market power. However, controlling market conduct would be a formidable task, as illustrated by the UK experience. There is a distinct possibility that regulation would not be successful in preventing the exercise of market power. Furthermore, regulation can impose considerable costs on both generators and the community generally, especially if the regulator 'gets it wrong'. A fundamental weakness with the regulatory approach is that it treats the *symptoms* of the problem, and ignores the underlying cause — the limited competition facing Pacific Power in some market segments.

Expanding the state interconnections

The interconnections convert the state markets into a national market. To the extent that they become congested, the scope for interstate generators to compete with Pacific Power in New South Wales would be reduced and Pacific Power's ability to exact high prices in the New South Wales electricity market would be enhanced.

Some options for relatively minor upgrades of the linkages could be implemented fairly quickly. However, major upgrades involving new lines would take some time and require substantial investment. Moreover, as a number of participants emphasised, they may face regulatory difficulties, including significant environmental obstacles. In any case, given the uncertainty about the future utilisation of the interconnections, such investment could not be justified until it is clear that there is sufficient demand.

A more basic drawback with this option is that it would not substantially reduce market power. Even if the capacities of the interstate linkages were significantly expanded, Pacific Power would still be able to exercise considerable market power.

Disaggregation

The third way of reducing Pacific Power's market power is disaggregation. It would involve dividing Pacific Power into a number of independent generation businesses that would compete directly with each other, as well as with other generators.

Some contend that a drawback of this option is that significant costs would arise because of the loss of economies of scale and scope, and because of certain other 'one-off' and establishment costs.

Most economies of scale appear to be at the unit or power station level and would not be affected by disaggregation, provided it does not proceed beyond this level. One possible exception is the cost of debt finance. Smaller generation businesses would be exposed to greater risks (notably the risk of plant failure). While the new marketing arrangements will help generators to manage these risks (eg by co-insuring with other generators), financiers could still perceive disaggregation as increasing risk. Thus, the cost of raising finance for disaggregated generation businesses could increase.

Economies of scope appear to be less significant. For example, there seems to be little reason why international activities or research and development could not continue if disaggregation takes place.

Other costs include legal costs and the recurrent costs of maintaining separate boards, management structures and certain corporate functions (such as treasury operations and marketing). However, although these functions would be duplicated in each organisation, costs and staff numbers need not increase significantly. Indeed, it is possible that some costs would fall. For example, experience in Victoria suggests that, in a more competitive environment, there are strong incentives to reduce management and corporate staff numbers.

The Commission considers that costs associated with disaggregation would be substantially outweighed by the benefits from reducing Pacific Power's market power.

Form of disaggregation

Determining the optimal level and composition of disaggregation is more difficult and requires more information than was available to this study. However, the Commission has given some consideration to what the *minimum* level of disaggregation should be. Its judgment is that disaggregating into two firms would not adequately reduce the potential for the exercise of market power. This judgment is supported by the modelling commissioned for this project. There would be significantly less risk in having at least three firms. The costs are unlikely to be much greater and would be more than offset by the additional benefits.

In determining the composition of power stations in each generation business, the major objective should be to achieve a balance between the groups so that there is the greatest potential for competition among the disaggregated businesses. To facilitate this outcome, within the limitations of public ownership, each generation business would need to be established as an independent corporation, with an independent board reporting directly to the appropriate minister.

Summary of conclusions

1. If maintained as a single entity, Pacific Power is likely to have significant market power for some years to come. Its market power could result in electricity prices being well above the levels expected if there were effective competition in generation. This would involve substantial social costs.
2. Future utilisation and development of the interstate interconnections is uncertain. However, at times they are likely to be constrained. This would add to Pacific Power's market power.
3. The market power available to Pacific Power by operating as a single entity, if exercised, would seem inconsistent with the goals of the Competition Principles Agreement and with the effective operation of a competitive national electricity market.
4. Competitive pressures would be increased if action were taken to disaggregate Pacific Power into a number of independent generation businesses. The costs of disaggregation are likely to be small relative to the potential costs of Pacific Power exercising its market power.
5. It would be necessary to disaggregate Pacific Power into at least three independent generation businesses of comparable strength, in order to adequately reduce its market power.
6. In relation to specific issues raised in the terms of reference about the manner in which Pacific Power could exercise market power, the Commission considers that:
   (i) Pacific Power would have the capacity and incentive to set prices and increase profits for significant periods of time, despite losing some market share.
   (ii) In some circumstances, Pacific Power could force an allocation of its own capacity onto the market so that more efficient plant was kept idle and less efficient plant operated for a significant period of time.
   (iii) While Pacific Power could conceivably drive out existing competitors that are more efficient, this is unlikely to be in its longer term interests.
   (iv) Pacific Power could discourage, but not prevent, entry of new capacity which is more efficient than some existing capacity.

1 INTRODUCTION

1.1 Background to this project

This research project was initiated following a request to the Assistant Treasurer from the New South Wales Government asking that the Industry Commission review certain aspects of electricity generation in New South Wales. More specifically, the Commission was asked to assess the implications for competition in the New South Wales and national electricity markets of:

- the market power that Pacific Power could exercise by operating as a single entity; and
- alternative structures for the electricity generation sector, taking account of the tradeoff between the benefits of a competitive generation sector and any possible losses of economies of scale and scope.

The full terms of reference are set out on page viii. Associated correspondence from the Acting Premier of New South Wales and the Assistant Treasurer is reproduced at Appendix A.

The Commission's assessment is intended to assist work being undertaken by a Review Committee, chaired by Professor Fred Hilmer, which has been established to advise the New South Wales Government on whether, and if so how, the state owned electricity generation business — Pacific Power — should be disaggregated.

This project is not an inquiry under section 7 of the *Industry Commission Act 1990*. Nevertheless, consistent with its Act, and its approach to inquiries and research projects generally, the implications of Pacific Power's present structure and possible alternative arrangements have been evaluated taking into account the interests of the community as a whole, rather than simply that of Pacific Power or the electricity supply industry generally. To this end, the Commission has sought, within the time constraints, to achieve the participation of all relevant parties (see Appendix B).

This project has been undertaken against a backdrop of considerable change in the electricity supply industry throughout Australia (see next chapter). While major improvements in efficiency have been achieved, the industry is presently in a transitional stage. Indeed, some of the issues needed to permit electricity to be traded in a competitive market have yet to be resolved.

However, the Commission has assumed that implementation of a number of important mechanisms to promote competition in electricity generation and facilitate the development of market trading (such as open access and non-discriminatory pricing arrangements for transmission and distribution networks and the exposure of publicly owned utilities to competition policy principles) proceeds as is currently envisaged.

While much of the discussion in this report presumes that all facets of the new market trading arrangements will be in place as planned by around 1999, the Commission has not confined its consideration to 1999 and beyond. It has also considered developments and policy implications in the intervening period.

In undertaking this project, the Commission has been requested to have regard to the principles for structural reform of public monopolies contained in the Competition Principles Agreement and the operation of a competitive national electricity market. These two matters are interrelated.

A national electricity market

The concept of a national electricity market evolved in the early 1990s at a time when all governments were seeking to improve the performance of their electricity supply industries. The underlying notion — recommended by an Industry Commission inquiry into *Energy Generation and Distribution* — is to increase competitive pressures in the industry, and promote efficiency, by introducing measures to permit competition both within and between states.

Following the Industry Commission's report, the July 1991 Special Premiers Conference established the National Grid Management Council (NGMC) to coordinate the development of the electricity industry in eastern and southern Australia, with a view to allowing a competitive market in electricity to commence from 1 July 1995 (the target commencement date is now July 1996, with a fully competitive market scheduled to be operating by July 1999). The market will encompass all states and territories for which interconnection of transmission grids is economic.[1]

Electricity has been on the agenda of every subsequent Heads of Government and Council of Australian Governments (COAG) meeting, culminating in the agreement of April 1995 to implement the Competition Principles Agreement.

[1] Western Australia and the Northern Territory will not be involved because of the transmission distances involved. The inclusion of Tasmania depends upon decisions about establishing a connection between the Victorian and Tasmanian grids — 'Basslink' — under Bass Strait.

The Competition Principles Agreement

This Agreement is one of three intergovernmental agreements on competition policy supported in general terms in 1994 by heads of government and formally agreed to by all governments at the April 1995 COAG meeting.

It is based on the principles of competition policy articulated in the report of the *National Competition Policy Review* and provides for:

- the extension of the Trade Practices Act to cover public utilities;
- structural reform of public monopolies;
- regulation of monopoly pricing by government business enterprises;
- competitive neutrality policy and principles; and
- open access to essential facilities such as the electricity network.

COAG agreed that the Trade Practices Commission and the Prices Surveillance Authority will be merged to become the Australian Competition and Consumer Commission, and a new advisory body, the National Competition Council, will be formed.

The *Competition Policy Reform Act 1995* provides for the processes and institutions required to implement the agreed arrangements on competition policy. Under these new arrangements, market conduct and pricing oversight throughout the economy will be managed and controlled according to national competition law. As a result, most economic activity in Australia will be covered by the new competition policy and will come under the purview of the one regulator of market conduct.

In brief, the application of these principles to electricity means that generation, distribution and retailing will be subject to greater competition, and publicly owned utilities will no longer be exempted from the Trade Practices Act. Cost reflective and transparent transmission charges will be introduced and the retailing and network functions of distributors will be ‘ring-fenced’.

The Commonwealth has agreed to make a series of special payments to the states, subject to agreed progress on implementing competition policy.

1.2 Public participation in this project

In view of the tight timetable, the Commission invited contributions from individuals and organisations with experience and expertise in the issues concerned, and undertook visits to supplement this information and its own research. This involved meeting Pacific Power and some interstate generators, electricity distributors, large industrial users and government bodies. A list of all participants, visits and meetings is provided in Appendix B. The Commission thanks all those who provided assistance or advice.

In addition, the Commission arranged for London Economics to prepare a consultancy report analysing possible market outcomes under the alternative assumptions that it operated as a single entity, as two entities and as three entities. The consultancy was funded by the New South Wales Government. Copies of the report are available from the Commission on request.

1.3 Report structure

The next chapter briefly outlines the nature and extent of reforms that have been undertaken in Australia's electricity supply industry over the last five years or so. Chapter 3 describes the arrangements being put in place to develop a market for electricity and profiles the major participants. Pacific Power's market power is assessed in Chapter 4. The final two chapters (Chapters 5 and 6) discuss possible outcomes resulting from the exercise of market power by Pacific Power and options for addressing the resultant costs.

2 REFORM OF THE ELECTRICITY SUPPLY INDUSTRY

This chapter briefly outlines changes that have occurred in Australia's electricity supply industry. The main focus is on recent reforms in those jurisdictions participating in the national market (New South Wales (including the ACT), Victoria, Queensland and South Australia), the benefits that have been realised and the scope for further improving performance.

2.1 Early development

Electricity was introduced commercially into Australia in the late 1880s. From the outset, both small private companies and public authorities were involved in generation and distribution, and it appears that private or joint private-public institutions dominated in the early days (Butlin, Barnard and Pincus 1982, p. 253). However, in later years there was a movement towards a more coordinated industry under the control of one or more statutory authorities in each state.

By the 1930s, public enterprises accounted for about two-thirds of total generation. This increased to about 90 per cent soon after the second world war. At about this time, the Commonwealth Government also became involved in electricity generation through the Snowy Mountains Scheme.

Increasing public ownership was followed by the establishment in each state of a statutory authority to oversee the development of the industry. This was supported by regulations giving each authority extensive control to coordinate most aspects of electricity supply within its jurisdiction (eg sales of privately generated electricity were subject to approval by state electricity authorities).

An important factor behind the move to a more centralised system was a desire by state governments to ensure that industrial development was facilitated by the availability of ample, reliable and cheap electricity. The development of large scale generating units which could achieve significant scale economies and the realisation that total generating capacity could be reduced by pooling reserve capacities reinforced the trend towards centralisation. In addition, public authorities were exempt from taxation, and could raise funds at concessional rates of interest because of government guarantees. This was a major benefit to them in view of the highly capital intensive nature of the industry and technological changes which favoured the development of larger generating units.

This process of consolidation led to a situation where electricity supply in most states was dominated by a single large vertically integrated authority, in most cases responsible for generation, transmission and distribution activities. In New South Wales, the situation was a little different, with distribution being undertaken by county councils. In Queensland, distribution has been nominally the responsibility of regional electricity boards but, in practice, these boards were subjected to considerable control by the former Queensland Electricity Commission. In some states, the electricity authorities also owned some of the coal mines which supplied their generators.

The state electricity supply systems developed in isolation. However, New South Wales and Victoria were interconnected in 1959, and South Australia joined that interconnection in 1989. Future connections with Queensland (Eastlink) and Tasmania (Basslink) have been mooted (see Chapter 3).

2.2 Processes of reform

During the 1980s, concerns about the performance of electricity utilities, and a series of formal inquiries, pointed to serious operating inefficiencies, substantial over-investment and inefficient pricing practices throughout Australia's electricity supply industry. State budgetary pressures and demands to reduce electricity costs for firms operating in an increasingly open economy provided additional pressure for reform. These developments were not confined to Australia — similar pressures to improve the performance of the electricity supply industry had emerged, or were emerging, in other countries such as the United Kingdom, the United States, New Zealand and several Western European nations.

Reforms have been undertaken at both the state and Commonwealth level. Individual states and territories have introduced measures to improve performance which, as mentioned below, vary quite markedly between jurisdictions. However, the involvement of COAG has provided a national focus to reforms and resulted in a more coordinated approach in a number of key areas. Hence, individual states and territories are presently continuing to reform their utilities according to their own microeconomic agendas, but with a view to likely future developments nationally.

Early stages of reform focused on the 'commercialisation' or 'corporatisation' of state electricity utilities with the intention of improving performance by placing utilities on a more commercial footing. This has involved introducing measures to provide managers with greater autonomy, but with increased accountability, and changes to create a more neutral environment between public and private enterprises (such as requirements to pay taxes and charges, and to pay dividends to government).

Later stages of this process have emphasised the separation of responsibility for generation, transmission and distribution functions and, in some jurisdictions, disaggregation of generation and distribution activities. This has been accompanied by significant reform of pricing practices (eg the winding back of cross-subsidies that favour residential users) and the privatisation of some assets. However, individual states have implemented reform in quite different ways and at different speeds.

New South Wales

Until recently, Pacific Power (and its predecessor — the Electricity Commission of New South Wales) was responsible for electricity generation and transmission in New South Wales. However, in 1991, Pacific Power was internally restructured into commercially oriented business units related to its generation and transmission activities.

In May 1994, the New South Wales Government set in train the formal separation of transmission and generation when it established Pacific Power's network business unit as a separate legal entity. In February 1995, the transmission activities of Pacific Power were separated out to become the responsibility of the Electricity Transmission Authority (trading as TransGrid).

Within Pacific Power, a notional electricity exchange market operates as a spot market for wholesale electricity: power stations submit bids which result in prices for electricity supply being established each half hour. This is intended to increase internal efficiency by emulating some of the disciplines which an external market would provide.

New South Wales recently announced a further program of reform, including a reduction in the number of distributors through a process of mergers, and their subsequent corporatisation into 'wires' and 'retailing' agencies. The Electricity Transmission Authority has been directed to establish a market in New South Wales to become operational during the first quarter of 1996.

The future structure of the Government's generation business — Pacific Power — is now under review, with this research project and the related Hilmer Review intended to provide advice on this matter.

Victoria

Like most other states, Victoria initially focused on corporatising its electricity authority (the State Electricity Commission of Victoria). Since then it has embarked on an extensive program of reform which will see some of the state's generation and distribution businesses sold to private sector interests.

The process started in October 1993 with the separation of generation, transmission and distribution. Subsequently, a majority interest in one power station (Loy Yang B) has been sold, and the remaining generation assets have been divided into five separate businesses. The distribution sector has been divided into five regionally based companies and one, United Energy, has recently been sold. A separate statutory corporation — PowerNet Victoria — is responsible for transmission functions. Another statutory corporation — the Victorian Power Exchange — has been formed to develop and administer a wholesale electricity market (VicPool) in Victoria. It is intended that this corporation will ultimately be owned by the industry.

Other jurisdictions

Reforms have also been undertaken in the other states which will become involved in the national electricity market. For example, in Queensland, the generation sector has been separated from transmission and distribution. On 1 January 1995, the Queensland Generation Corporation (trading as Austa Electric) and the Queensland Transmission and Supply Corporation were established. The latter corporation encompasses the seven regional distribution agencies and the transmission business, although separate accounting will be maintained. The state's largest power station — Gladstone — has been sold to a consortium headed by Comalco. In South Australia, the Government is corporatising the Electricity Trust of South Australia (ETSA) and, within the new body, forming separate business units for generation, transmission, distribution and related services.

Reform of the Snowy Mountains Hydro-Electric Authority (SMHEA) is also under way. The three parties to the existing Snowy Mountains Agreement, the Commonwealth, New South Wales and Victorian Governments, are committed to the corporatisation of the Authority to allow it to compete as an independent commercial operator in the national electricity market. To date, each party has been entitled to receive specified amounts of electricity at cost. Under the new arrangements, the parties will give up that entitlement in exchange for equity in the new corporation.

2.3 The benefits of reform

There is widespread acknowledgment of the gains which have been generated by reforms already introduced. Significant improvements have been achieved in productivity and prices have been more closely aligned with their underlying costs. As a result, considerable benefits have accrued to households, businesses and governments.

Pacific Power has achieved substantial efficiency improvements in recent years. Its 1994 annual report noted that the real average price of its electricity fell by 5.6 per cent between 1992–93 and 1993–94 to one of the lowest in the world for coal-fired generation. Its real costs of generation and transmission were reduced by one-third between 1988–89 and 1993–94 (New South Wales Government Pricing Tribunal 1994, p. 83). During 1993–94, its overall total factor productivity rose by 1.8 per cent to a level some 35 per cent higher than in 1987–88. In an environment of lower prices and cost containment, profit increased to $779 million in 1993–94 and debt was reduced by $540 million (Steering Committee 1995, vol. 2, p. 3).

However, improvements in efficiency have not been confined to Pacific Power — gains have been achieved throughout Australia's electricity supply industry. For example, in a submission to this project, the Electricity Supply Association of Australia stated that between 1989–90 and 1993–94 the industry achieved:

- a 17 per cent reduction in real costs per kWh;
- a 22 per cent reduction in business tariffs;
- a 56 per cent improvement in labour productivity[1];
- a 26 per cent improvement in supply reliability; and
- a 22 per cent reduction in real debt per kWh.

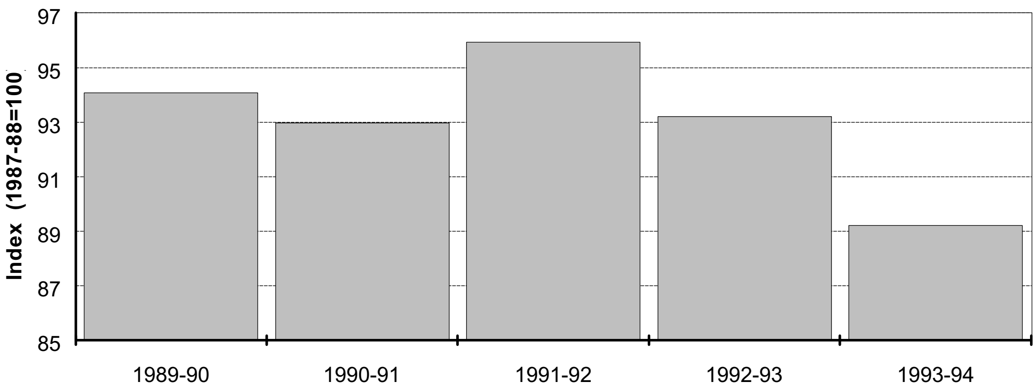
In comparison with some other industries in which government trading enterprises (GTEs) play a significant role, the electricity supply industry has made considerable progress in reforming its activities in recent years. For example, the 1995 report by the Steering Committee on National Performance Monitoring of GTEs (established by COAG) noted that integrated[2] electricity GTEs achieved an average real return on assets (before interest and tax) of

1 According to ESAA data, the industry's labour force has fallen by almost 40 per cent between 1985 — when numbers peaked at around 65 000 — and 1994.

2 Fully integrated electricity authorities provide generation, transmission and distribution services. Partially integrated authorities provide generation and transmission only.

between 8 and 11 per cent over the five years to 1993–94.[3] By comparison, the average for all GTEs for 1993–94 was 7 per cent (Steering Committee 1995, vol. 1, p. 29). Similarly, the average real price index for selected integrated electricity supply businesses fell by 4 per cent over the 12 months to 1993–94, compared with a 1 per cent average decline for all GTEs subject to monitoring by the Steering Committee. Figure 2.1 shows real price movements over the past five years for those integrated electricity GTEs for which data are available.

Figure 2.1: Real prices (selected integrated GTEs), 1989–90 to 1993–94[a]



a Includes Pacific Power, ETSA, the Hydro Electric Commission of Tasmania, the Power and Water Authority of the Northern Territory, and SMHEA. Excludes Generation Victoria, National Electricity, Queensland Electricity Commission and the State Energy Commission of Western Australia.

Source: Steering Committee (1995, vol. 1, p. 28).

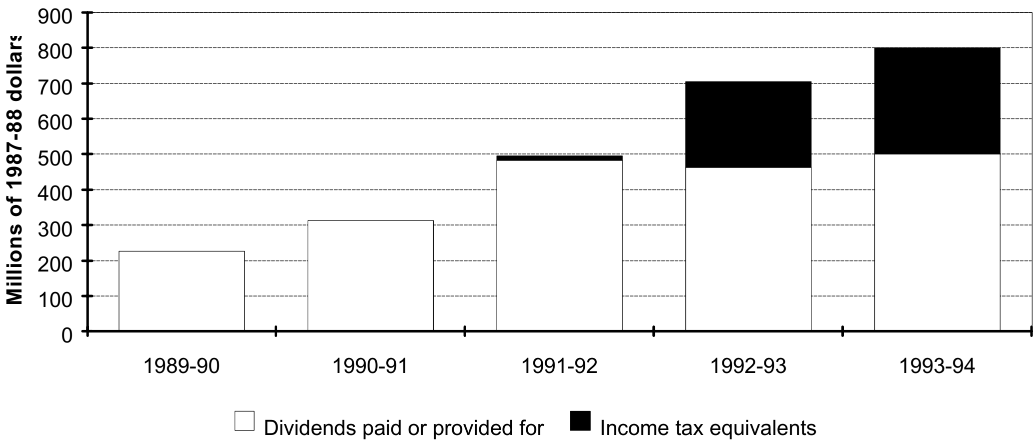
Payments to governments by electricity supply authorities, whether as dividends or 'income tax equivalents', have also increased significantly — from about $200 million in 1989–90 to around $800 million in 1993–94 (see Figure 2.2).

The Steering Committee also noted that the labour productivity of integrated electricity supply GTEs has improved continuously over the past five years, as has capital utilisation. For example, average real revenue per employee

3 Excludes Generation Victoria, National Electricity and the State Energy Commission of Western Australia.

increased by 45 per cent over this period (Steering Committee 1995, vol. 1, pp. 21, 30).[4]

Figure 2.2: Payments to government (integrated GTEs), 1989–90 to 1993–94[a]



a See footnote (a) in Figure 2.1.

Source: Steering Committee (1995, vol. 1, p. 28).

While labour productivity provides a partial indication of productivity, a better measure is *total factor productivity* (TFP), which takes into account all inputs used to produce outputs.[5] The Bureau of Industry Economics estimated that TFP in the electricity supply industry grew at an average annual rate of just under one per cent for the two years to 1991–92 (BIE 1994, p. 40). This was less than the rate recorded in earlier years. However, the Bureau reported that the TFP gap between the industry in Australia and the average investor-owned utility in the United States fell from 29 per cent to 27 per cent over the same period, because of:

> ... a continuing steady improvement in TFP levels in Australia and a reduction in TFP levels in the US (p. 40).

4 Excludes Generation Victoria, National Electricity, Queensland Electricity Commission and the State Energy Commission of Western Australia.

5 For example, if capital is substituted for labour, labour productivity will rise even though overall productivity — total factor productivity — may not have changed or may have fallen.

Performance comparisons between utilities are fraught with difficulties (eg outcomes vary depending upon the range of performance indicators used). However, measured against other integrated generators for which comparable data are available, Pacific Power performs reasonably well. For example, it produced price reductions similar to those of ETSA and SMHEA, although greater reductions were achieved by the State Energy Commission of Western Australia. Pacific Power's average level of operating sales margin was higher than that of ETSA and SMHEA, but fell short of those generated by the Queensland Electricity Commission and the Hydro Electric Commission of Tasmania (see Steering Committee 1995, vol. 2, p. 2). However, irrespective of its performance relative to others in the electricity supply industry, it is clear that Pacific Power has achieved significant improvements in performance.

Scope for further gains

While considerable gains have been made, it is widely recognised that further gains are possible. For example, the chief executive of Pacific Power recently exhorted governments to speed up the introduction of a national electricity market. He argued that significant gains in price and technical performance have been made, but added:

> ... we can do better and a national market will be an essential part of that improvement. In such a market good performance will be both recognised and rewarded (Bunyon 1995, p. 1).

Similarly, in its recent *Electricity Reform Statement* (May 1995), the New South Wales Government highlighted the need for further improvements in performance, noting that:

> The Bureau of Industry Economics has estimated a productivity gap between the NSW industry and investor owned utilities in the United States of over 20%. The Government Pricing Tribunal's Interim Report on Paying for Electricity indicated that productivity improvements of at least that order of magnitude were possible over the next five years, providing the basis for significantly lower prices (Egan 1995, p. 4).

In Victoria, the Government has announced a timetable for the introduction of further reforms, and it expects to realise a 22 per cent reduction in real prices to small and medium businesses over the next four years (Office of State Owned Enterprises 1994, p. 8). It expects that competitive pressures and independent regulation will provide ongoing cost reductions. The Victorian Electricity Supply Industry Reform Unit (ESIRU) estimates that future reform will bring benefits of about $10 billion to Victoria between 1994 and 2004.

The Commonwealth Government also sees increased competition as providing significant additional gains. For example, the Assistant Treasurer recently commented that:

> ... it's the gains of the next phase of reform which will bring greatest benefits to the entire community. Firms will have clear commercial incentives to increase efficiency, to be innovative and to improve their service delivery. Competition creates the pressures to pass on all these gains to consumers (Gear 1995, pp. 3–4).

Future improvements are likely to stem from reforms in all parts of the industry. However, as the highest proportion of industry costs (around 70 per cent) are accounted for by generation activity, the potential gains are greatest in this area. In particular, substantial improvements are possible in the utilisation of generating plant, particularly in New South Wales where the reserve plant margin in 1993–94 was 48.4 per cent (Steering Committee 1995, vol. 2, p. 5).[6,7] While there are differing views about what constitutes an efficient level, international best practice is commonly regarded as around 20 to 25 per cent. In this context, the New South Wales Government stated that:

> The present value cost of excess generating capacity has been conservatively estimated at more than $1 billion, a figure which would be greatly increased if the cost to the environment were properly included (Egan 1995, p. 4).

In its work for COAG on *The Growth and Revenue Implications of Hilmer and Related Reforms*, the Commission estimated the effects of achieving a wide range of microeconomic reforms across the economy. For electricity, it examined the possible effects of introducing best practice capital and labour usage, eliminating cross-subsidies, imposing competitive neutrality arrangements and changing the construction cost arising from improved capital investments. Estimated benefits (some of which have already been achieved) included reduced prices to large users (26 per cent) and to other industries (29 per cent), a 50 per cent increase in labour productivity and a 4 per cent increase in capital productivity (IC 1995, p. 20 and Chapter B5). Full implementation was estimated to raise GDP by 1.4 per cent (equal to about one quarter of all of the benefits identified in the report). While the analysis was heavily qualified and subject to a range of assumptions and uncertainties, it lends support to the view that there are considerable gains still available from reform in the electricity supply industry.

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6 The reserve plant margin is total plant capacity available less the actual maximum demand for electricity in a particular year, expressed as a percentage of the maximum demand.

7 The New South Wales figure includes the SMHEA but excludes Blowering and non-winter hydro power stations. Reserve plant margins for South Australia and Queensland were 20 per cent and 28 per cent respectively. Comparable data for Victoria are not available.

3 THE NATIONAL ELECTRICITY MARKET

In Australia — and many other nations — the marketing arrangements for electricity have differed considerably from those in place for most other goods and services. For example, electricity supply in Australia has been predominantly on a regional basis, with only minor trade between jurisdictions. Responsibility for generation in each region has been delegated to a single government owned supplier which, in many states and territories, also has been responsible for transmission and distribution functions. For the most part, pricing and investment decisions have been determined administratively through centrally planned processes rather than through market oriented mechanisms. However, in recent years, there has been growing recognition that, in many respects, electricity can be regarded as similar to other goods and services, and that benefits can be derived from interstate trade and by creating a more competitive market for electricity, with competition among both generators and retailers.

After briefly outlining some distinguishing characteristics of electricity (Section 3.1), this chapter discusses the new national electricity market, focusing on the form it will have in 1999, rather than at the present time when certain transitional arrangements are in place (Section 3.2). The major market participants are identified in Section 3.3.

3.1 Characteristics of electricity

Electricity generation is very capital intensive, a characteristic it shares with many other industries such as telecommunication networks, paper production, plantation forestry and electricity and natural gas transmission and distribution. However, electricity has several distinctive features that affect the way in which it is marketed and used. For example, electricity cannot be economically stored in large quantities, it is a 'fungible' commodity and there must be a balance of supply and demand at all times (see Box 3.1). Largely because of these characteristics, some features of the new market arrangements are different from those which apply in other commodity markets. In particular, procedures need to be in place to ensure the overall integrity of the system. Nonetheless, the new national marketing arrangements will have many similarities to trading arrangements employed for other commodities.

Box 3.1: Distinguishing characteristics of electricity

Storage

Once produced, electricity is difficult to store in significant amounts. In this regard, electricity has more in common with the characteristics of a service than of a manufactured good.

Fungibility

Once electrons flow along a conductor, it is impossible to tell their origin. Consequently, where there are several producers (generators), there need to be individual meters at supply points (station send-out terminals) and at delivery points (eg houses and business premises), and some form of market settlement process is required to ensure each producer is paid and customers are billed appropriately.

Physical equilibrium

The electricity system needs a constant balancing of the demands of many customers and the output of a relatively small fleet of generating units. At all times, the electrical energy supplied must equal the quantity demanded (transmission losses aside). If this balancing is not achieved, system collapses and blackouts may occur. Hence, a central control mechanism is needed to ensure that the system remains in balance. The result is a complex integrated network which, to some extent, shapes the financial and marketing arrangements for the industry.

Need for reliability

There is a high cost if electricity supply fails, and substantial funds need to be invested to limit this possibility to acceptable levels. On the other hand, it is costly to ‘gold plate’ systems to preclude any failure. There is also a requirement for clear lines of responsibility and legal liability to allow loss recovery when power fails. Risk management by power users includes back-up generating sets and interruptible power supply contracts.

3.2 Development of a national market

The establishment of the national electricity market and the associated restructuring of state and territory electricity supply enterprises are expected eventually to provide several important advantages for the Australian economy. In an environment where there will be direct competition between generators and between retailers, the costs of electricity supply are expected to be significantly reduced, prices will become more cost-reflective and investment decisions will more closely reflect market conditions. Key related benefits will include:

- traditional generation technologies will face competition from newer generation methods;
- barriers to interstate trade will be largely removed;
- customers will be able to choose between suppliers; and
- customers will be able to enjoy higher and more varied levels of service than were available to them in the past. For example, those wishing to accept lower levels of power reliability and to modify their usage patterns will be able to negotiate lower electricity prices. Similarly, periods of supply interruption could be negotiated to avoid peak rates (which could also defer the need for new generation investment).

The initial impetus for the development of a national electricity market was provided by a joint Commonwealth–States–Territories leaders' decision in July 1991 to establish the NGMC. It comprises representatives of the Commonwealth, New South Wales, Victorian, Queensland, South Australian, Tasmanian and ACT Governments, plus an independent arbitrator. Its charter is to encourage open access and free trade in bulk electricity, and to coordinate the most efficient, economical and environmentally sound development of the interstate electricity supply industry in eastern and southern Australia.

Since that time, COAG, in conjunction with the NGMC, has addressed a wide range of matters relevant to the establishment of a national market which will, in many respects, ultimately parallel trade in other goods and services. This has entailed reducing artificial barriers to entry and exit and promoting open competition between buyers and sellers. Key components of the process have been:

- the structural separation of vertically integrated utilities;
- the disaggregation of generation and distribution in some jurisdictions;
- the development of open access regimes for the perceived natural monopoly segments of the industry (ie transmission and distribution); and
- the development of market regulation arrangements, particularly those governing the operation of the market trading system.

After some delays, the national electricity market is due to start operation on 1 July 1996 and to become fully operational after a transition period of about three years. In the interim, vesting contracts between generators and their existing clients will limit the amount of electricity traded which is subject to the new rules and provide a degree of protection for incumbent generators and distributors. It should be noted that some elements of a more competitive electricity market have already been installed at the state level, most notably in Victoria through structural separation and the establishment of the Victorian Power Exchange.

The following discussion outlines some of the more significant arrangements put in place to establish the environment in which increased competition can develop, including a brief outline of the proposed market rules and trading arrangements.

National Grid Protocol

The centrepiece of the national electricity grid reforms to date is the National Grid Protocol, which has been endorsed by the Heads of Government of New South Wales, Victoria, Queensland, South Australia, Tasmania, the ACT and the Commonwealth. Published in December 1992 following a year of widespread consultation, the document supports a competitive market approach by providing non-discriminatory access to the electricity grid. The Protocol also provides guidelines for the competitive sourcing of new generating capacity. The objectives of the Protocol are shown in Box 3.2.

It is intended that the Protocol will be subsumed into an industry Code of Conduct (the Code), which is now under development.

Code of Conduct

COAG has agreed that management and control of market conduct and pricing oversight of the national electricity market should be vested with the soon to be established Australian Competition and Consumer Commission (ACCC). To address a range of other matters, COAG agreed that a Code of Conduct should be developed and administered by the NGMC (or its successor(s)) following wide consultation and ACCC authorisation of the Code. It is intended that all participants in the national electricity market will have to adhere to the Code.

At the time of writing, work on the Code was still in progress. However, the Code, which will be enforceable, will deal with: code administration; market rules; system security; network connection; network pricing; metering; administration functions; and transitional matters. Drafts of all sections except for the transitional matters are publicly available at present.

Box 3.2: Objectives of the National Grid Protocol

The National Grid Protocol has been developed, inter alia, to satisfy the following objectives:

- to encourage the most efficient, economical and environmentally sound development of the electricity industry consistent with key national and state policies and objectives;
- to provide a framework for long-term least cost solutions to meet future power supply demands, including appropriate use of demand management;
- to ensure that benefits and costs of interconnection extensions are properly identified and accounted for;
- to maintain and develop the technical, economic and environmental performance and/or utilisation of the power system; and
- to enable private generation and publicly owned generation to compete on equal terms.

Source: NGMC (1992).

The Code will be administered by a private limited liability company called the National Electricity Code Administrator (NECA). As well as monitoring compliance with the Code, NECA will have a role in resolving disputes and modifying the Code.

Some matters, such as franchise customer pricing and environmental and safety regulation will remain state and territory government responsibilities.

Another limited liability company — the National Electricity Market Management Company (NEMMCO) — will have overall responsibility for market operations, including the dispatch of generators. Regional system operators in each jurisdiction will acts as agents for NEMMCO in this latter capacity.

Grid access

In terms of network connection (grid access), it is intended that the Code of Conduct will comply with the access provisions of the *Competition Policy Reform Act 1995* by being a "single, effective access regime" supported by cooperative legislation in the relevant jurisdictions. Transitional arrangements are likely to apply for some time before these developments are settled, with regulatory oversight initially being shared between the ACCC and state authorities such as the Regulator-General in Victoria. Whilst high voltage power transmission within and between states may be subject to ACCC oversight, access to (and pricing of) the lower voltage intrastate subtransmission and distribution systems may remain in the hands of state regulators, albeit applying the principles (if not the fine detail) of the national competition law.

Under the Code, market participants will be able to obtain non-discriminatory access to the electricity network forming the national grid. This will be achieved through physical connection supported by connection agreements between each participant and its network service provider. To protect the integrity of the system, the agreements will specify a range of technical matters with which those connected to the network must comply.

Network pricing and augmentation

A key matter in the encouragement of grid access and of competition at the generation and retail ends of the electricity market is the pricing of the use of high capacity power lines, especially transmission wires.

Under the new arrangements, it is proposed that there will be separate charges for electrical energy and for the use of the transmission (and distribution, where applicable) wires which convey that energy to each customer. Both generators and customers will be liable to pay for their use of grid assets. This will facilitate development of a competitive electrical energy market, including spot, contract and forward sales. Customers will pay a fixed annual fee for grid access and a separate variable charge for delivered power. The structure of the transmission and subtransmission network fees payable by each generator will comprise:

- a generator entry price payable as a fixed annual charge, and based on the entry cost; and
- a generator ‘use of system price’ applied to the generator’s nominated capacity. For major generators connecting directly to transmission wires, this price will be equal to the long run marginal costs of augmenting the network so that it can cater for the additional generation at the point of connection. For generators ‘embedded’ within a network, a subtransmission price determined in like manner will also be payable.

Charging for the grid — the natural monopoly part of the electricity supply industry — has to fulfil several criteria of which perhaps the most crucial is to provide sufficient incentives for economically efficient expansion and maintenance of the transmission and distribution networks. COAG has decided that, in principle, cost reflective pricing should apply after a transition period, with assets to be valued using the 'deprival' method.[1] Thus, when the new arrangements are fully in place, the cost of new transmission assets will be met by beneficiaries (ie individual participants, or groups of participants[2]). Further, it will be possible for private firms to build and own these assets, whether they transport electricity within or between states.

According to the present draft of the Code of Conduct, the need for the construction of new electricity transmission infrastructure will be facilitated by the annual production of a Statement of Opportunities by NECA or NEMMCO which will detail the performance of the existing grid as well as transfer capabilities between and within transmission networks. It will also assess the adequacy of the network to meet the forecast requirements over a period of ten years (five years in the case of distribution networks). The statement will be made available to existing and provisional participants in the national electricity market. Another mechanism for signalling the desirability of increased interconnector capacity will be provided by the prices at which long term inter-regional hedges are traded (see later discussion).

Under the draft Code, decisions about the need for building new network infrastructure will not be the exclusive preserve of incumbent transmission corporations or other existing network service providers. Instead, such decisions will be made following a process of consultation between network planners and affected participants and network service providers. The latter groups will have the benefit of formal review periods of 30 business days followed by dispute periods of 40 business days for any proposal that will change their network service price by more than two per cent. Once determined, the decision to augment the network will be binding on all parties and the relevant network service provider *must* ensure the project is implemented. The implementation may permit construction and ownership by any participant.

Participation in the national electricity market

The Code of Conduct will define the roles, responsibilities and obligations of market participants (generators, customers, retailers and traders) and NEMMCO in the conduct of the market.

1 The deprival method, in which an asset is valued according to the loss that would be incurred if its owner were to be deprived of the service potential or future economic benefits of the asset, is explained in Steering Committee (1994a).

2 In this context, 'participants' can include generators and customers.

Generators with a capacity of at least 30 MW must submit for dispatch in the national electricity market. Smaller generators may elect to participate with NEMMCO approval. Customers who have demands of at least 10 MW and are capable of being dispatched are likely to be obliged to participate. (Other customers may participate with NEMMCO's approval.) COAG has agreed to develop a timetable for progressive reductions in the threshold, which may differ between jurisdictions. While Victoria has already published its program, the New South Wales Government has yet to announce its timetable. The Commission understands that, following some initial disparities, the New South Wales and Victorian customer thresholds will converge (at nil) around 1999–2000. Other states have made no commitments to lowering customer thresholds below 10 MW as yet. The Commission understands that all these timetables will be published in the Code and subjected to the ACCC authorisation process.

When the initial phase of the national electricity market commences, there are expected to be approximately 10 generating enterprises, 50 network owners and hundreds of major customers participating. Lowering of the customer threshold is likely to add thousands of participants.

Market rules for generators

Like some other parts of the Code, the market rules are still under development. However, substantial progress has been made in the draft set of rules that has been published. The following discussion briefly outlines key components of the proposed market trading arrangements. A more comprehensive guide to the proposed rules is in NGMC (1994a, 1995a).

The national electricity market will cover all interconnected states (including Queensland) and the ACT. It will involve a common electricity pool with central dispatch of generating plant and demand-side options determined by a bidding system (after accounting separately for transmission and system security requirements). The arrangements will provide mainly for three functionally independent forms of electrical energy trading:

- bilateral contracts;
- short term forward contracts; and
- spot market sales.

Other important features concern the arrangements for dealing with differences in pool prices between regions and the provision of ancillary services and reserve trading. Each of these components is briefly outlined below.

Bilateral contracts

Contracts may be entered into and traded by any party, whether they be formal market participants or not. They may be of any type, form and duration allowed by law. Such contracts are essentially financial instruments and will not affect the way in which generators or loads are dispatched, the calculation of the spot price, nor any party's obligations under the Code.

Long term contracts provide generators (retailers) with a means of 'locking in' their revenues (electricity costs) and managing their long term risk positions by reducing their exposure to spot prices. This is a crucial feature of a workable wholesale electricity market. For example, in the absence of contractual arrangements, resellers would be unable to enter supply contracts or even to establish annual tariffs without incurring high risk exposures.

It is expected that generators will seek to cover most of their output with contracts and that retailers will also secure a high proportion of their electricity needs via contracts.

Short term forward markets

Forward financial markets will be operated and cleared by NEMMCO for each of the two days prior to actual dispatch of electricity. Participants will be able to offer to buy or sell hedging contracts for each trading day.

According to the NGMC's Market Rules Sub Group (1995, p. 34), participants will use the forward market for a number of reasons including:

- To assess alternative short term planning options (eg to commit or decommit a generating unit).
- To adjust their trading pos itions so as to best manage risks and lock in returns.
- To update their trading position to reflect changed circumstances (eg an updated weather forecast might lead a distributor to review load projections) and minimise exposure to the potentially volatile spot trading.

Generators with slow start plant (eg coal-fired plant) that need to make unit commitment decisions ahead of time and cannot respond immediately to actual spot prices can use the short term forward market to provide a firm contract price on which to base their short term planning. By having a large number of buyers and sellers adjusting their overall contract positions, a market value for the forward price is determined.

Spot market

NEMMCO will also operate the spot market, the primary purposes of which will be to value the economic dispatch of plant and to establish a spot price for electricity in each half-hour trading interval. Generators and users will bid into a single national market, with the spot price being that required to equate demand and supply. Generator price bids will be ordered from lowest to highest, forming a supply schedule, while users' offer price bids will be stacked from highest to lowest, forming a demand schedule for the period. The intersection of these schedules in a given period will determine the price paid to generators for all electricity sent out and that paid by all customers.

Thus, spot prices will be market determined, reflecting the interplay of customer demand, plant availability and offers of generation and demand-side management. Pool payments to all generators, and prices paid by customers purchasing on the spot market, will be based on half-hourly spot market prices.

Long term contracts and the short term forward markets will allow participants to hedge against spot prices. The remaining risks for participants, which will be subjected to the vagaries of the spot market, will include:

- for users, the risk on the difference between the amount contracted (which will necessarily be based on forecast load) and their actual load;
- for generators, the risk that they have an unplanned outage or some other limit on availability; and
- for users and generators, risk on the difference between the spot price in their region and the spot price in another region against which they have contracted (see below).

Largely because of these risks, it is expected that the spot market will normally be used to clear only a small share of the electrical energy actually traded in a given half hour. It will, however, set the local spot prices for all energy injected and taken from the grid. Differences between local spot prices and contract or other hedge prices will be cleared through NEMMCO's settlements function.

Inter-regional trader

The national electricity market will comprise several regions. Under certain operating conditions (ie when transmission links are constrained), there may be price differences between the reference nodes (usually capital cities) in adjacent regions. This introduces an element of risk for parties engaged in inter-regional trade. However, the financial risks associated with these price differentials may be reduced using various instruments such as cash settled forward contracts or specific inter-regional hedges.

To facilitate the management of risk arising from pool price differences between regions, within NEMMCO there will be a commercially separate inter-regional trader to buy and sell one-way and two-way hedges (ie options and swap contracts) against differences in spot prices between nominated regional reference nodes. Box 3.3 describes how hedging may work. The term of the facilities is proposed eventually to run from one day ahead to a decade ahead, although initially the maximum term would be just one year.

Box 3.3: Inter-regional hedging

Participants in the national electricity market who have traded electricity supply contracts with participants in another region are at risk if the pool prices vary significantly between the regions. This can occur when the interconnections between the regions become constrained.

Participants will be able to manage this risk by buying hedging contracts for inter-regional price differences. The holder of such a contract would, in effect, be buying or selling not in his local region (Region A) but in the same region as the participant with whom they have an electricity supply contract (Region B). As such, there is no longer any exposure to inter-regional price differences which may occur.

There are two basic types of hedging contract. An *option*, or one-way hedge, involves the purchaser being recompensed with the spot price difference if the spot price in Region B exceeds that in Region A. A swap, or two-way hedge, operates in the same way but, if the price in Region A is the higher, then the purchaser of the hedge contract must pay the difference to the contract seller.

An important feature of the proposed national electricity market is that it is intended that NEMMCO's inter-regional trader *must* stand in the market to sell both options and swaps (up to physical interconnection capacity limits). Other participants *may* also sell such contracts at their discretion.

Sources: NGMC (1994a), NGMC Market Trading Working Group (1995).

The details of these hedging facilities are yet to be firmly established within the Code of Conduct, and there is some uncertainty about just how they will work. Consequently, perceptions vary as to whether they will effectively overcome all price risks. Nonetheless, there is no doubt that these hedging devices will be a very important feature of the national electricity market.

Other services

Beyond the contract, forward and spot markets, and inter-regional trading arrangements, the market rules also provide for ancillary services trading and reserve trading. An ancillary services trader will be established, as a separate commercial function within NEMMCO, to purchase NEMMCO's requirements for:

- system regulating capability needed to absorb fluctuations in the supply/demand balance within each half-hour period;
- reactive support to guard against system failure through voltage collapse, additional to the local requirements provided under connection contracts; and
- 'black start' capability to allow restoration of electricity supply after a complete failure.

As a safeguard against market failure, NEMMCO will also include a reserve trader as a separate commercial function. This trader will be able to enter into contracts to secure the availability of plant, which would otherwise be unavailable, for reserve duty.

Market oversight

With regard to the trading of electrical energy at the wholesale level (as against its transportation along transmission and distribution wires, participants will be protected against anti-competitive conduct by the Trade Practices Act and the Prices Surveillance Act as extended by the *Competition Policy Reform Act 1995*. Both Acts are to be administered by the ACCC. The ACCC will have powers to act against the misuse of market power and against contracts, mergers and acquisitions which substantially lessen competition and other forms of anti-competitive conduct. It will also have functions of prices surveillance, monitoring and inquiries. The Code of Conduct itself is to be submitted for ACCC authorisation under the Trade Practices Act.

Beyond national competition law, there may also be state agencies with market oversight responsibilities within their jurisdictions. This will be the case during the transitional period (eg the New South Wales Government Pricing Tribunal and the Victorian Office of the Regulator-General will continue to play a role). However, the precise relationship between the ACCC and state based regulators in the longer term is yet to be established and could be affected, for example, by various derogations yet to be added to the Code by governments (which have the responsibility for writing the final chapter on Transitional Matters of the Code of Conduct).

The most recent draft of the Code of Conduct provides no direct scope for market oversight in the sense of limiting or punishing any misuse of market power. The operation of the national electricity market should, however, provide information to help determine if such misuse has occurred. While the Code's dispute resolution mechanism is not intended to resolve market power issues, some of the cases which come before it may also assist in identifying when market power is being used.

3.3 Major market participants

As in other commodity markets, the major market participants will be producers (publicly and privately owned generating enterprises), retailers and merchants (eg electricity distribution companies and energy traders) and users (eg large industrial companies). The following sections identify, first, the major generators and, second, larger retailers and other users.

It should be noted that preliminary work is now well advanced for a new electricity transmission interconnection between New South Wales and Queensland ('Eastlink'). It may become operational within the next five years or so. Preliminary analyses have also been undertaken for a connection between Victoria and Tasmania — 'Basslink'. If it is decided to proceed, the project is unlikely to be commenced within the next decade. For the purposes of this study, it is assumed that Queensland will become interconnected with New South Wales, Victoria and South Australia in the near future, but that Tasmania will not.

Pacific Power

Pacific Power Corporation is essentially the generating arm of the former Electricity Commission of New South Wales.[3] It has the status of a commercial, dividend and tax paying government owned trading enterprise. Its assets presently have a book value of around $10 billion.

The bulk of Pacific Power's assets comprise seven large, black coal-fired power stations with generating capacity totalling 12 120 MW, hydro plants with a capacity totalling 335 MW and some (liquid-fuelled) gas turbine plant

[3] Management of the state's high voltage transmission system was separated from Pacific Power and became the responsibility of the Electricity Transmission Authority on 1 February 1995. Distribution assets (lines under 132 kV) are owned and managed by distribution authorities (mainly county councils).

totalling 295 MW. The major Pacific Power stations and their outputs in 1993–94 are shown in Table 3.1.

Figure 3.1 shows the location of Pacific Power's main power stations. Until recently, these stations were organised into three business units for the purpose of bidding to supply electricity on behalf of Pacific Power. Power stations were grouped on a regional basis:

- Hunter Group — Bayswater and Liddell;
- Central Coast Group — Eraring, Munmorah and Vales Point; and
- Western Group — Mt Piper and Wallerawang.

Table 3.1: Electricity generating capacity and output in New South Wales, 1993–94[a]

Ownership	*Power Station*	*Capacity*	*Energy sent out*
		MW	GWh
Pacific Power	Bayswater	4 x 660	15 957
	Eraring	4 x 660	12 422
	Liddell	4 x 500	6 588
	Mt Piper	2 x 660	4 814
	Munmorah	4 x 300[b]	1 485
	Vales Point	2 x 660	6 023
	Wallerawang	2 x 500	2 035
	Hydro	335	202
	Gas Turbines	295	2
Private[c]	Various	147	908
Total		12 897	50 438

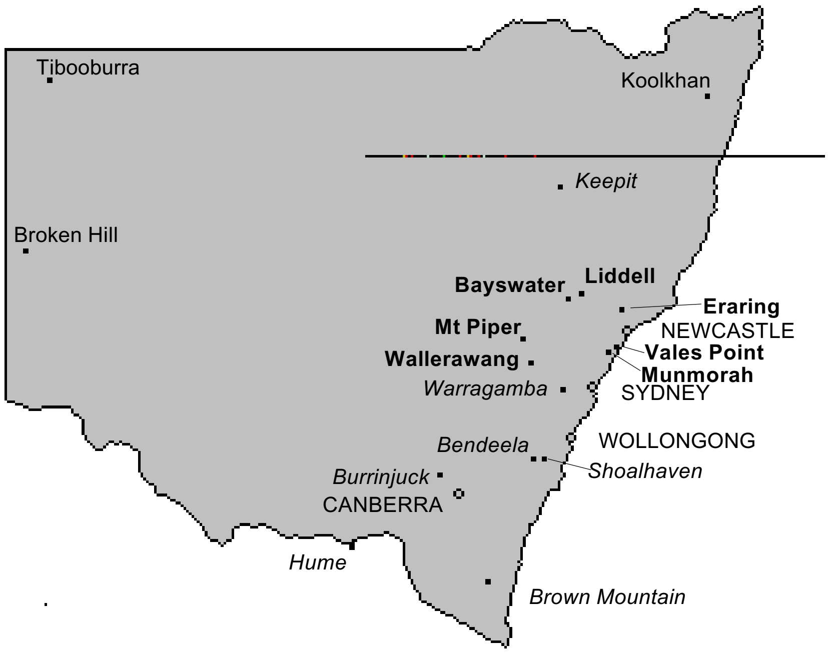
a Excludes Snowy Mountains Hydro-Electric Authority capacity.
b Includes two units in storage.
c Represents only isolated power stations owned by private companies who are ESAA members.
Sources: Pacific Power (1994a), ESAA (1995).

Pacific Power is the nation's largest electricity generator. In 1993–94, it accounted for 43 per cent of the generating capacity in those jurisdictions which are likely to be interconnected in 1999 (including Queensland). Austa Electric — Australia's second biggest electricity generator — accounts for about 16 per cent of generation capacity in the interconnected system.

In 1993–94, Pacific Power sent out 49 530 GWh of electrical energy, of which 1648 GWh was sold to the ACT (see Figure 3.2). Only 21 GWh was sold interstate to Victoria and South Australia. In 1993–94, Pacific Power purchased 3329 GWh from the SMHEA and 465 GWh from Victoria.

Electricity sent out by Pacific Power in 1993–94 was considerably greater than that of any other generation business (see Figure 3.3). In that year, output was some 60 per cent higher than its next largest competitor — Austa Electric. Energy sent out by Pacific Power represented 36.8 per cent of the electricity generated in the interconnected system (including Queensland).

Figure 3.1: Pacific Power power stations



Coal-fired stations
Hydro stations
Gas turbine stations

At the present time, Pacific Power has considerable excess generation capacity. This will continue for some years (see Appendix D).

One way of measuring surplus capacity is by reference to the reserve plant margin. In all electricity systems, some level of reserve plant is required to meet plant breakdowns and unexpected outages. While the efficient level of reserve plant is determined by a range of factors, typically the efficient reserve plant margin is around 20–25 per cent. In some cases, notably where large ‘tight’ power pools exist with strong transmission links, the efficient size of the reserve plant margin could be as low as 15 per cent. However, in 1993–94, Pacific Power’s reserve plant margin was 48.2 per cent (including the Snowy but excluding the Blowering and non-winter hydro power stations). The corresponding figure for Queensland was 27.5 per cent.[4]

[4] Comparable figures for Victoria are not available.

About 40 per cent of Pacific Power's coal needs are sourced from mines it presently owns through Powercoal Pty Ltd. It is intended that the mines be separated from generation and corporatised (Egan 1995).

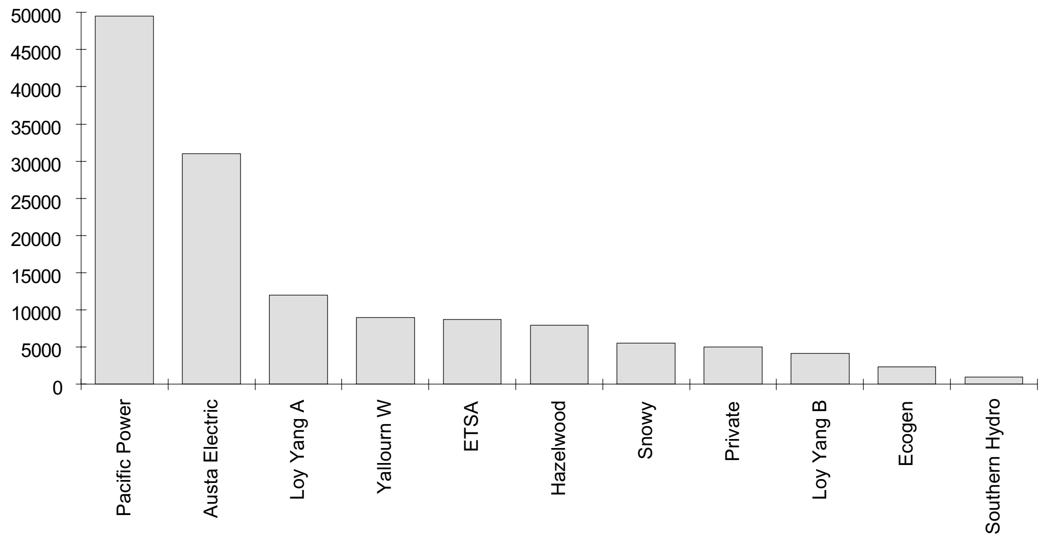
In common with many other large scale and long term industrial activities in Australia and elsewhere, fuel supplies (coal and natural gas) for most generators are provided under take or pay contracts. All of the coal used by Pacific Power — including coal sourced from its own mines — is supplied under long term contracts incorporating similar take-or-pay provisions. These require that specific quantities of coal be paid for each period, irrespective of whether or not it is used. The contracts provide Pacific Power with the option of taking delivery of less than 80 per cent of the contracted base volumes, but it must pay for at least that much. Coal which is paid for but not delivered can be 'banked' for later use in times of high demand or at the expiry of the contract period. The present contracts were negotiated in 1991 with maturities of 5–10 years, so that the first contract expires in 1996.

Some facilities are shared between Pacific Power's major power stations. For example, seven coal mines feed the Bayswater and Liddell stations through an integrated supply system. These power stations also share other infrastructure (eg water treatment facilities). Some plant fleets and operative training programs are also shared.

Snowy Mountains Hydro-Electric Authority (SMHEA)

The SMHEA is presently a Commonwealth Government trading enterprise operated (on a non-commercial basis) under an agreement between the Commonwealth, New South Wales and Victorian Governments. Its primary function since its inception in 1949 has been to divert water westward for irrigation purposes, but it also has 3740 MW of hydro-electric generating capacity that is available subject to its water supply obligations. Each participating government is entitled to a share of the SMHEA's electricity output.

Figure 3.3: Electricity generation in the interconnected system, 1993–94 (GWh)



a AUSTA Electric's output includes some generation by the Gladstone power station before it was sold to private interests.

Sources: ESAA (1995, Table 2), SMHEA (Sub. 26) and Commission estimate for Loy Yang B.

Reform of the SMHEA has been discussed between the respective governments for some time. The announced intention is to corporatise the SMHEA in early 1996 and to introduce it as a key source of competitive generation in the interstate electricity market. The new corporation will be owned jointly by the Commonwealth Government (with 13 per cent of the shares), the New South Wales Government (58 per cent) and the Victorian Government (29 per cent). The shareholdings are in line with each owner's present entitlement to the Scheme's power output. In the meantime, the Authority has moved to ring-fence its transmission grid assets from its generating plant pending the transfer of those assets to a grid corporation.

The SMHEA produced 5526 GWh in 1994–95 which was 'exported' to New South Wales, the ACT and Victoria. Output varies considerably from year to year depending on rainfall, but has averaged 5107 GWh over the past two decades. Presently the SMHEA's power output is sold to participating governments according to a statutory formula which does not take account of plant refurbishments or inflation. The charge for electrical energy to New South Wales, Victoria and the ACT is 3.12 ¢/kWh (SMHEA 1994, p. 4). To obtain a 10 per cent return on the scheme's assets, it has been estimated — using the Australian Gas Association's model — would require a charge of about 13 ¢/kWh (Jones 1994).

As the SMHEA's generating capacity is constrained by the availability of water and water release commitments for irrigation purposes, as well as by tunnel and headpond capacities, its electricity output in any one year is, on average, only a small percentage (about 15 per cent) of its theoretical generating capacity.[5] This level of output is broadly equivalent to the output which is attainable from one of the four units at larger Pacific Power Stations (ie Bayswater and Eraring). Coupled with the inherent flexibility of hydro plant (eg quick start up times), these constraints result in the SMHEA being used mainly to supply electricity during peak and shoulder periods.

The Authority has the ability to use relatively cheap off-peak power to pump some of the water that has passed through its turbines back into higher storage dams for reuse at times when market demand (and prices) are higher. In particular, it has three pumps at the Tumut 3 Power Station with a combined capacity of 600 MW. Like all of the Scheme's generating assets, these pumps have been under the control of the Victorian and New South Wales generating authorities (two have been controlled by New South Wales and the other by Victoria). Until the recent changes in the structure of the Victorian power industry, all pumps had lain idle for many years. Recently the Snowy Trader in the Victorian Power Exchange has caused the pumped storage within its control to be dispatched. This can be seen as one positive outcome of the more competitive and commercial market arrangements now in place in Victoria.

Victorian generators

In 1993, the State Electricity Commission of Victoria (SECV) was split into three statutory corporations, one of which was Generation Victoria, a holding structure comprising generating units that traded as independent producers. Subsequently, Generation Victoria has been divested to five independent generation companies, all of which are to be sold.[6] The businesses are shown in Table 3.2.

5 Output if all plant is operate d continuously throughout the year.

6 Similarly, Electricity Services Victoria has been split into five competing distribution utilities which are also to be sold.

Each of the brown coal power stations is supplied by an adjacent open cut mine, owned by the station itself.

The five generation businesses have a total installed generating capacity of 6482 MW, consisting of 81 per cent brown coal steam plant, 6 per cent natural gas-fired steam plant, 6 per cent hydro and 7 per cent gas turbine plant. The businesses compete with each other, as well as with Victoria's entitlement to Snowy power, Energy Brix (170 MW)[7] and interstate generators.

As well as the former SECV generators, there are two other significant power stations in Victoria. The Loy Yang B brown coal power station (500 MW) is 51 per cent owned by private interests (Mission Energy) and has a long term contract for all its output. A second 500 MW unit is due to be commissioned at Loy Yang B in 1996–97. The privately owned Anglesea power station (brown coal, 150 MW) is dedicated to supplying the Alcoa aluminium smelter.

Table 3.2: Electricity generating capacity and output in Victoria, 1993–94

Company	*Power Station*[a]	*Capacity*	*Energy sent out*
		MW	GWh
Loy Yang Power[b]	Loy Yang A	4 x 500	15 430
Yallourn Energy[b]	Yallourn W	2 x 350, 2 x 375	9 852
Hazelwood Power[b]	Hazelwood	8 x 200	4 664
Energy Brix[c]	Morwell	170	116
Ecogen[b]	Newport[d]	500	1 979
	Jeeralang[e]	465	251
Southern Hydro[b]	Hydro[f]	467	1 117
Privately owned	Various	682[g]	5 125[h]
Total		7334	38 534

a Fuel is brown coal unless otherwise stated.
b Formerly part of Generation Victoria and presently wholly owned by the State Government.
c Ownership passed to Energy Brix Australia Corporation from Generation Victoria in October 1993.
d Natural gas-fired steam generator.
e Gas turbines running mainly on natural gas.
f Kiewa, Dartmouth and Eildon hydro-electric power stations.
g Includes Loy Yang B (500 MW) and Anglesea (150 MW).
h Estimated as the residual of ESAA state total and the outputs listed above.
Sources: Generation Victoria (1994), ESAA (1995).

7 A state owned enterprise which produces electricity as a by-product of briquette manufacture.

In 1993–94, Victoria's generators produced about 39 000 GWh. The contribution by individual stations is shown in Table 3.2. The data highlight the difference in size between Pacific Power and the individual Victorian generators. For example, the output of the largest Victorian business, Loy Yang Power, was less than 35 per cent of Pacific Power's output in 1993–94. The next largest generators (Yallourn Energy and Hazelwood Power) produced around 20 per cent and 9 per cent respectively of Pacific Power's output in 1993–94.

Victoria's interstate trade in electricity in 1993–94 was significantly larger than that of New South Wales, but relatively small compared with total Victorian demand (eg exports amounted to around 2 per cent of electricity sent out — see Table 3.3).

Table 3.3: Victoria's interstate trade in electricity, 1993–94 (GWh)

Exports		*Imports*	
To NSW	385	From NSW	20
To Snowy	0	From Snowy	1450
To SA	504	From SA	1

Sources: New South Wales Department of Energy (1995), National Electricity (1994), ESAA (1995), Steering Committee (1995).

Recent figures for reserve plant margin in Victoria are not available. The level in 1992–93 was 23.1 per cent (including Snowy entitlements), down from 42.9 per cent in 1987–88 (Steering Committee 1993, 1994b). Despite growth in demand since 1992–93, the commissioning of the Loy Yang B power station would have added to the margin, as will the second unit at Loy Yang B in 1996–97.

ETSA Corp

ETSA Corp is a South Australian Government corporatised entity. It has been recently established from the old Electricity Trust of South Australia. It comprises four business units, including power generation, transmission, distribution and retail services.

In 1994, ETSA had an installed generating capacity of 2230 MW. This comprised gas-fired steam plant (54 per cent), brown coal plant (31 per cent) and gas turbines (15 per cent). The largest station (Torrens Island) has eight units with a nominal capacity of 1280 MW.

As shown in Table 3.3, ETSA purchased approximately 500 GWh of electricity from Victoria in 1993–94 and supplied about 1 GWh to Victoria. Interstate purchases of electricity contribute around 15 per cent of South Australia's energy needs.

Austa Electric

Austa Electric is the trading name for the Queensland Generation Corporation. It was established on 1 January 1995 from the generation arm of the former Queensland Electricity Commission (QEC). It is a corporatised body and is required to pay dividends and income tax to the State Treasury.

The intention is that Queensland will participate in the national electricity market whether or not it becomes interconnected with other states. From the viewpoint of this study, Austa Electric is not a player at the moment, but it will become involved if the 500 MW Eastlink transmission line between New South Wales and Queensland is constructed.

In 1994, the QEC had an installed capacity of 4406 MW consisting of about 87 per cent black coal fired plant, 10 per cent hydro and 3 per cent gas turbine plant. Since that time, an additional 350 MW unit has been completed at Stanwell. The largest power station — Tarong — has a nominal capacity of 1415 MW. The former QEC plant at Gladstone (1664 MW) is now owned by Comalco.

It has been estimated that Queensland will need about 300 MW of new capacity annually from 1998. The Queensland Government has indicated that Eastlink may be initially used under a ten-year contract for the sale of power from Pacific Power to Queensland users, and that subsequently it is likely that there will also be some opportunities for Queensland generators to supply New South Wales during periods of significant differences between regional pool prices (McGrady 1995).

A new 350 MW coal-fired unit is due to be brought into service at Stanwell in 1995–96, and the Collinsville power station (180 MW) is to be recommissioned in 1998. Apart from Eastlink, other options for increasing capacity include:

- recommissioning the Callide A power station (120 MW);
- building a combined cycle gas turbine power station fuelled by natural gas from the state's south-west once a pipeline is laid; and

- adding further coal-fired plant either at Callide B (350 MW) or Tarong (700 MW), or constructing new 1400 MW power stations at Wandoan, Brigalow and Millmerran (McGrady 1995).

Private generators

The major private generators at present are the Loy Yang B, Gladstone and Anglesea power stations. Loy Yang B has a 33 year contract with the Victorian Government for most of its output. Gladstone and Anglesea mainly supply neighbouring aluminium smelters.

A relatively small amount of electricity is generated privately in New South Wales and the other states. In New South Wales, the main player at present is BHP at its iron and steel production facilities (where it has generating capacity of about 100 MW). A range of smaller industrial generation and cogeneration facilities also exist in New South Wales and the other states. These mainly provide power for on-site use.

Unlike the traditional state owned generators, private generators generally face commercial constraints in their ability to raise capital and need to plan over shorter time frames. Consequently, they tend to favour investing in power station technologies that permit smaller capacity increments and staged investment decisions. Currently the preferred technology is likely to involve gas turbines or natural gas engines rather than coal-fired systems (see Box 3.4).

Major buyers

The major buyers in the wholesale electricity market presently comprise the electricity distribution utilities and some large industrial companies. Figure 3.4 shows the 1993–94 market shares held by the biggest 20 of these players in the jurisdictions which will be participating in the national market.

In New South Wales, electricity distribution is presently undertaken by 25 local government bodies (mainly county councils). However, the New South Wales Government has recently announced its intention to merge these bodies so that the number of distribution utilities is reduced to “a small number” by late 1998 (Egan 1995). At present, 14 of the 25 distributors each account for less than one per cent of total electricity sales in New South Wales. The four largest distributors are:

- Sydney Electricity (with 1993–94 sales of 16 272 GWh);
- Prospect Electricity (8290 GWh);
- Orion Energy (formerly Shortland Electricity) (3668 GWh); and
- Illawarra Electricity (2636 GWh).

Box 3.4: Generating technologies

For most of this century, the bulk of electricity production has come from large power stations using coal to fire steam-driven generators. It has been demonstrated that substantial scale economies are associated with coal-fired generation. Hence, many central generating utilities employ coal-fired units of 350–700 MW capacity. About 80 per cent of Australia's electricity is generated from large coal-fired power stations.

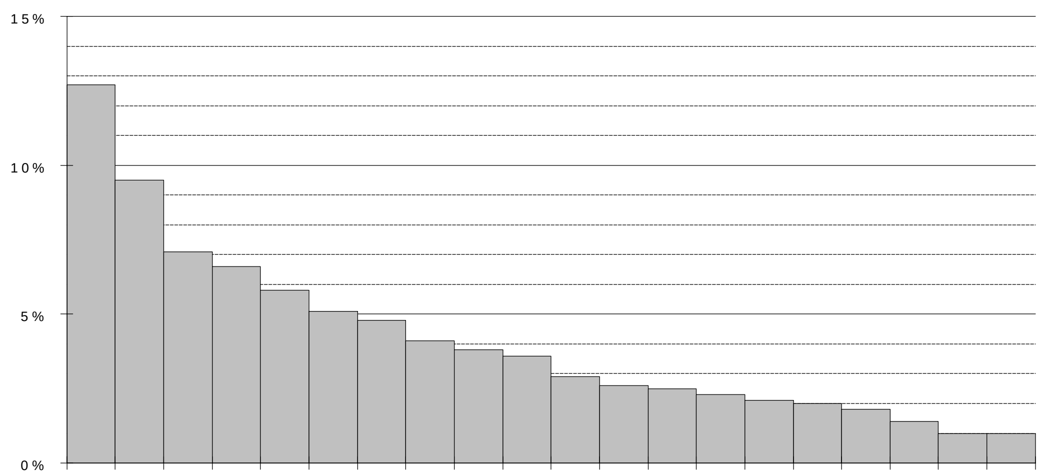
In recent years, other generation methods have become established as cost-competitive for large scale generation, most notably gas turbines in open-cycle or closed-cycle configurations. Largely because of the long asset lives of generating plant and a reluctance to downsize and to accept new gas technologies, the impact of this technological development has yet to be fully applied to the world's electricity generation industry, much of which remains in public ownership.

Gas plants offer many advantages over coal-fired plants including low capital cost per unit of capacity, shorter establishment and start-up times, high thermal efficiency, relatively low emission levels and, perhaps most crucially, cost-effectiveness in much smaller configurations (from about 100 MW for open cycle systems and approximately 300 MW for closed cycle gas turbines). This means that relatively small capacity increments can be made in a technically efficient manner with less risk of over-investment (which has been a major problem in many jurisdictions in Australia and elsewhere).

The preferred fuel for gas turbines will often be natural gas (including conventionally extracted gas as well as coalbed methane), but they can run on a variety of fuels, including LPG, distillate and a range of liquid fuels. The small gas turbines presently operated by Pacific Power run on liquid fuels.

Other technologies for power generation exist, particularly for small units which produce under 5 MW. Some are the subject of technological development — most notably fuel cells which offer high efficiency generation with minimal noise or air pollution. Indeed, fuel cells could turn out to be capable of providing electricity at a uniform cost over a wide output range. Consequently, if they can be established as low-cost facilities, the need for large coal-fired power stations and medium-sized gas turbine power stations will be significantly reduced. Instead, it may become economically sensible for large buildings and groups of smaller buildings (including houses) to share small scale generators, eliminating losses associated with the transmission of power over long distances. These developments are not expected to impact substantially on the electricity market in the next decade, but may well do so at some later time.

Figure 3.4: Major wholesale electricity purchasers in the four states, 1993–94 (Percentage share)



Sources: New South Wales Department of Energy (1995) and information supplied by Pacific Power.

Sales by Sydney Electricity and Prospect represented about 33 per cent and 17 per cent respectively of all New South Wales sales in 1993–94. Apart from the state distributors, other large purchasers of wholesale electricity within the New South Wales region include the Tomago aluminium smelter, Alcan, BHP (mainly at Port Kembla and Newcastle) and the ACT's distribution corporation, ACTEW.

When the national electricity market becomes fully established, it is likely that many more medium to large industrial and commercial users will become involved in the wholesale market (eg by entering into contractual arrangements with generators). Large corporate and government users, including those which use electricity at several sites such as supermarket and fast food chains, are likely contenders. Another group which may emerge and could eventually account for a significant proportion of purchases is electricity brokers which on-sell to defined retail customer groups in a way similar to the brokers that are now competing in Australia's telecommunications market.

4 PACIFIC POWER: WHAT SCOPE FOR MARKET POWER ?

4.1 Introduction

If there is effective competition, market outcomes are generally consistent with economic efficiency. This means that three types of efficiency criteria are met:

- inputs are combined to produce a given level and quality of good or service at minimum cost (productive efficiency);
- prices reflect minimum costs given customer preferences (allocative efficiency); and
- over time, changes in technology and customers' preferences are reflected in investment decisions that lead to the production of existing goods or services at lower cost, and of new and better quality goods or services (dynamic efficiency).

In a highly competitive environment, a firm would not be able to raise prices above minimum production costs for long. Rivals would find it profitable to take that firm's business by offering a lower price to customers. Similarly, potential entrants attracted by the existence of excess profits would find it profitable to enter the market and offer a lower price.[1]

Without effective competition, a firm has significant ability to influence price — it has 'market power'. In these circumstances, it can constrain output in order to raise prices above minimum production costs and earn excess profits without attracting a timely or adequate response from rivals or potential entrants. It may also be able to engage in strategic (or 'anti-competitive') behaviour. Predatory pricing is one example. It involves lowering prices (sometimes below the minimum production cost) in the short term, either to deter entry or to drive out rivals. The objective of this short term strategy is to raise prices in the longer term.

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[1] Excess profit is above 'normal' profit. Normal profit is the amount just necessary to attract and retain the resources employed in the industry. It will vary among industries and even over time because, as McCloskey has said, it is the reward for:

> ... taking the bother, knowing the market, seeing the opportunity, [and] assuming the risk (1985, p. 293).

There are costs to society associated with the exercise of market power. Allocative inefficiencies arise because prices are higher and output lower than if there was effective competition. And there may be productive inefficiencies because of weaker external pressures to keep costs down. For example, the excess profits earned from the exercise of market power may result in inefficient ‘cost-padding’. Similarly, dynamic inefficiencies may emerge as there is reduced incentive for the firm to make sound investment decisions. All of these inefficiencies may have economy-wide ramifications. In particular, the competitiveness of user industries may be affected.

It is important to emphasise the difference between short term and long term market power.

It is possible for any firm to hold market power at a point in time. For example, a firm may find itself in this position if it emerges from a bout of vigorous competition as the lowest cost producer in the industry. Alternatively, it may be most productively efficient for only one firm to supply goods and services in a particular region (the case of natural monopoly).

However, a firm is only able to sustain a price rise and earn excess profits for as long as it takes its rivals, or potential entrants, to respond. If a competitive response occurs within a short period, market power would normally not be of undue concern. In most instances, some delay would be expected because it takes time to acquire information about market conditions. Indeed, it would be unusual for rivals or potential entrants to respond instantaneously to a price rise. On the other hand, if it takes a long time for a competitive response to emerge, or if no competitive response is forthcoming, the social costs of market power may be large and warrant government action.

In this research project, the central question is whether Pacific Power in its current form has significant market power in electricity generation. Under the centralised system that has previously operated in each jurisdiction, Pacific Power (and generating authorities in other states), have clearly had very substantial market power. However, as barriers to entry and impediments to trade in electricity are removed, the extent of this power is reducing. Thus, the focus of this report is on Pacific Power’s future market power.

More specifically, there is a concern that Pacific Power, if maintained as a single entity, would be in a position to use market power either to raise prices above efficient levels or to engage in strategic behaviour (eg through predatory pricing or through the strategic use of its excess capacity) so that it can earn excess profits for a period of time sufficient to warrant action to mitigate the social cost.

The specific types of behaviour of concern identified in the terms of reference are:

- setting prices for significant periods of time to increase revenue or profit without risking loss of market share;
- forcing an allocation of capacity on to the market so that more efficient plant is kept idle;
- driving out more efficient competitors; and
- preventing the entry of new, more efficient capacity.

In addressing issues of this nature, the Trade Practices Commission, the Prices Surveillance Authority and the courts generally undertake assessment in two stages. These are to:

- define the relevant market; and
- assess the strength of competition (or conversely the degree of market power).[2]

As discussed below, these tasks are closely related in that both involve consideration of the extent of substitutability between goods or services.

4.2 Defining the relevant market

In broad terms, a 'market' consists of buyers and sellers of a good or service. It is generally defined to encompass firms which are sufficiently in competition so that a price increase by one would cause a significant number of customers to switch to another firm or would elicit a competitive response

[2] The Trade Practices Commission 1992 Draft Merger Guidelines examine merger applications in five stages with 'the intention of minimising the costs of compliance and enforcement and providing the market with a reasonably clear indication of the Commission's likely approach to mergers' (Hay and Walker 1993, p. 41). These stages are:

- defining the relevant market;
- calculating market shares and concentration ratios which are then compared with two threshold tests. Where a merger results in the merged firm supplying 40 per cent or more of the market or the four largest firms supplying 75 per cent or more of the market, the Trade Practices Commission undertakes further analysis;
- assessing import competition;
- assessing barriers to entry; and
- consideration of other relevant factors such as countervailing power (TPC 1992b, pp. 4-5).

from existing firms. Delineation of the relevant market, therefore, takes account of:

- existing domestic firms selling the same good or service;
- domestic producers of close substitutes; and
- imports.

Competition from any of these existing rivals can place a ceiling on the extent to which a firm can raise its prices.

Determining the extent of substitutability between goods or services can help determine which firms should be included in the relevant market. The extent to which customers substitute one good or service in response to a change in the price of another is called the 'cross-price elasticity of demand'. Similarly, the response of sellers of similar goods or services is called the 'cross-price elasticity of supply'.

High cross-price elasticities between products or suppliers suggest that goods or services are highly responsive to changes in relative prices and should, thus, be included in the relevant market. On the other hand, low cross-price elasticities suggest a more narrow definition of the relevant market. For example, if there is low substitutability between goods or services produced in different regions, the best approach to defining the market may involve drawing regional boundaries. Similarly, low substitutability between different goods or services may suggest that separate markets exist for each product.

There are, however, three practical issues with the use of estimated cross-price elasticities to delineate markets. First, obtaining accurate estimates depends on the availability of suitable data and the application of appropriate econometric techniques. Second, deciding what is a 'high' level of substitutability for the purpose of delineating market boundaries is a matter of judgment.[3] Third, it is also necessary to determine the relative importance of estimates of short run and long run elasticities (the appropriate time dimension for the analysis).

In the absence of quantitative estimates of the relevant elasticities, some guidance about market definition could be sought from the market players. Firms generally have a perception of the market that they are in and the intensity of the competition they face from other products and from suppliers in other regions. However, this may not always be a practical option for policy makers because firms in a position to provide such advice are likely to have vested interests in the outcome of the issue in question.

3 Another complication may arise if a firm has significant market power and chooses to raise prices by restricting supply. In this situation, it is possible that its measured price elasticity of demand at this higher price would be relatively high (see IC 1994).

Whatever approach is adopted, any market definition needs to be flexible. For example, it is important that, having drawn market boundaries, the likely impact of new substitutes or technological developments that reduce transport costs and, thus, extend regional and product boundaries, are not ignored. If these developments are not recognised, there is a danger that some competitive discipline is effectively excluded from the assessment of market power.

Pacific Power's market

In practice, there is no clearcut definition that can be used to define Pacific Power's market. Ultimately judgments must be made about several features which shape the definition of the market that is adopted. These involve consideration of whether Pacific Power's market should be viewed as comprising:

- several regional New South Wales markets, the whole of New South Wales (including the ACT), or all interconnected states;
- electricity or all final energy; and
- within electricity, particular market segments (eg base, intermediate, peak and reserve loads, and spot, contract markets etc).

In addition, it needs to be determined whether it is appropriate to consider the market (however defined) at this point of time, in 1999 when the transition to the national electricity market is expected to be complete, or at some date.

Time frame

As noted earlier, the new market trading arrangements are still evolving and certain transition measures are in place (eg vesting contracts). Consequently, much of this report focuses on the market circumstances once the present transitional arrangements have lapsed and all facets of the new market trading arrangements are in operation. This is expected to occur around 1999. However, if market power is found to exist, it may be appropriate to take action to reduce the associated social costs well in advance of 1999. Hence, the Commission has also given some consideration to possible developments in the intervening period.

Substitution with other energy forms

The question of whether the relevant market is electricity or a wider energy market hinges on the extent of substitution between electricity and alternative forms of energy (in particular, natural gas).

Electricity can be considered as meeting the energy requirements of two broad end-use categories :

- first, those end uses for which no alternative form of energy can be used (the 'exclusive' market); and
- second, end uses for which gas and/or other energy sources can be substituted for electricity (the 'shared' market).

The first category encompasses lighting, many domestic appliances (eg dishwashers, washing machines and clothes dryers) and a range of commercial and industrial equipment (eg electronic equipment and refrigeration). The second category includes hot water, space heating and temperature control for commercial and industrial applications. Over the last twenty years or so, it has become possible to use gas in a wider range of applications. However, the scope for further reducing electricity's 'exclusive' market is limited.

Relatively little data are available to estimate the relative significance of these two market segments. However, one recent study (Grimwade et al 1993) estimated that, in Victoria, 56 per cent of total electricity sales are open to competition to gas (ie about 44 per cent of sales are to the 'exclusive' market). The study was based on actual energy usage in 1991–92. Based on information in Pacific Power's draft Strategic Plan (1994b, Appendix 5), the 'exclusive' market share in New South Wales is estimated to be significantly higher than in Victoria, at around 60 per cent.[4]

In the competitive market segment, substitution in the case of planned new business investments or for new residential developments could occur fairly quickly in response to relative price changes (provided that commitments have not been made with equipment suppliers). However, in other instances, substitution may only be feasible in the medium to longer term. This is because substitution often does not just involve a change in energy source — it frequently also requires changes to, or the replacement of, the appliance/machinery using the energy source. For example, in the case of households, switching to gas for hot water heating requires the purchase of a new hot water system. Similarly, conversion of some existing industrial plant to an alternative energy source is technically not feasible — a new plant would have to be purchased. The timing of such acquisitions will depend mainly on the costs of replacement plant, the remaining life of existing plant and the energy cost differential. Thus, in some circumstances a change in the price of

4 This figure is higher in New South Wales because, first, in the residential and commercial segments, competitive energy uses play a smaller role because of smaller heating demands due to the warmer climate and, second, the industrial segment in New South Wales accounts for a bigger proportion of energy demand there, and is estimated to require the use of competitive energy sources less than in Victoria.

electricity relative to other energy sources could result in substitution in a relatively short time frame while, in other instances, there could be a lag of many years.

In summary, the Commission considers that Pacific Power operates in two distinct market segments. One part supplies an ‘exclusive’ electricity market in which there is no economic alternative to the use of electricity (lighting, domestic appliances etc), and the remainder supplies a broader ‘shared’ market in which electricity competes vigorously with other forms of energy (in particular, natural gas), although more readily in some areas than in others.

While it is convenient to regard Pacific Power as primarily serving two market segments classified by end use, consideration also needs to be paid to what might be termed ‘sub-markets’ within each of these market segments. In particular, it is necessary to consider how Pacific Power’s market share, and its market power, might vary across base, shoulder and peak load periods. Account also needs to be taken of Pacific Power’s position in relation to different market transactions (eg spot and contract sales).

Geographic extent of the market

The geographic area which is now serviced, or able to be serviced, by Pacific Power and the area in which it will be able to compete (in physical terms) in the future are mainly determined by constraints on the transmission of bulk electricity. These limits are imposed by:

- first, unavoidable losses associated with long distance transport of electricity; and
- second, the capacity of the high voltage power line network.

The delivery of electricity over long distances through high voltage transmission lines is subject to significant energy losses. For example, a loss of five to ten per cent is often experienced, depending largely on the distance involved. The Commission was told that, in extreme circumstances, such losses can be as high as 20 per cent.

In the national electricity market, transmission losses will be accounted for on a regional basis. A loss factor will be calculated for each generator (and customer) depending on the region in which they are located and their distance from the reference node for the region. Inter-regional losses, which vary depending on the operating characteristics of the system, can be significantly higher than intra-regional losses. This can place interstate generators at a disadvantage relative to local generators.

Another important factor which impinges on the definition of Pacific Power's market concerns the capacity of the transmission linkages between jurisdictions.

With the exception of the Snowy Mountains Scheme, each state has developed its electricity supply system more or less unilaterally and with a view to self-sufficiency. Today, the transmission grid reflects these past policies, with only limited interconnections existing between some of those states that are close enough for such links to be economically feasible.[5]

New South Wales (including the ACT) is interconnected with Victoria and the Snowy Mountains Scheme. Victoria is also interconnected with South Australia. These linkages and their estimated capacities, based on information supplied by the NGMC, are shown in Figure 4.1.

Pacific Power contends that the stated capacities are conservative:

> The model used to determine the interconnector limits makes no allowance for the sophisticated automatic control systems which are fitted to all of the generating units. The limits that have been determined are thus necessarily conservative (Sub. 36, p. 1).

The Commission sought advice on this matter from the NGMC and was referred to the publication upon which Figure 4.1 is based.

While the published interconnection limits may be conservative, it also needs to be recognised that the capacity of the links can vary according to the load on the system.[6] For example, the capacity of the link between Victoria and the Snowy, and hence Victoria's capacity to export to New South Wales, is reduced if there are concurrent exports to South Australia. Accordingly, the capacity of the links will frequently be somewhat less than the capacities cited in Figure 4.1.

Planning is now well advanced for a two-way linkage of 500 MW between New South Wales and Queensland ('Eastlink'). If approved, it is expected to become operational around 1999. Discussions and preliminary analyses have also been undertaken for a connection between Victoria and Tasmania — 'Basslink'. However, if it is decided to proceed, this project is unlikely to be

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5 There are also some intrastate transmission capacity constraints. For the purposes of this study, the most relevant are transmission constraints sometimes encountered between the northern and southern regions (south of Marulan) of New South Wales.

6 There are several technical limits to electricity transmission. The NGMC (1993a, pp. 33–4) has identified five constraints: thermal rating; transient stability; steady-state stability; voltage stability; and frequency stability. The overall power transfer limit is determined by applying the most restrictive of these constraints.

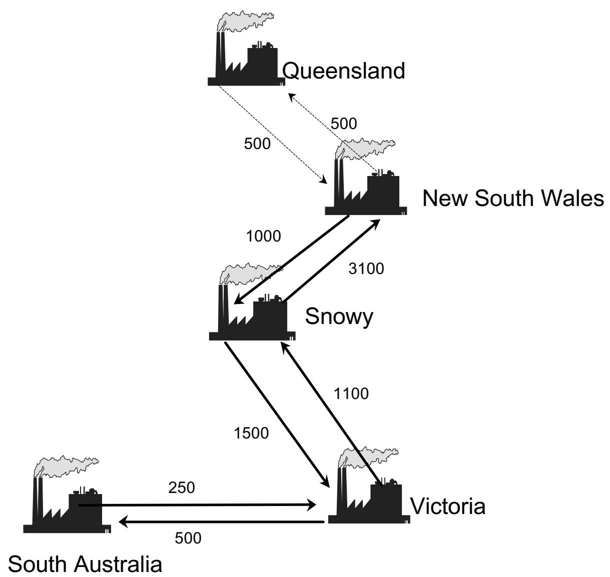
commenced within the next decade.[7] As generating capacity and electricity use in Tasmania is small relative to that in the mainland states, its inclusion would have relatively little impact on the analysis in this report.

The capacity of the interconnections linking interstate markets is a key factor in determining Pacific Power's market. If the capacity of the interconnections is large enough not to impede interstate trade in electricity, the geographic extent of Pacific Power's market can include all four interconnected states. On the other hand, if the interconnections inhibit trade in electricity so as to effectively isolate the New South Wales market for significant periods of time, Pacific Power's primary market would most appropriately be defined as New South Wales (including the ACT).

Many participants in this project supported the latter interpretation. For instance, Western Power stated:

> The scope for interstate competition is limited to the present capacity of the [New South Wales-Victorian] interconnector which is relatively small compared with the maximum demand in each State. This capacity is further reduced when the Snowy is operating (Sub. 5, p. 1).

Figure 4.1: Major interstate transmission linkages in eastern Australia[a] (MW)



7 The Tasmanian Government (Sub. 35, p. 1) stated that "there are no plans for Tasmania to be connected to the proposed national grid in the near future".

a Excludes some minor linkages (eg between Victoria and New South Wales at Redcliffs).

Source: Based on information in NGMC (1993a, Appendix D).

The links are of modest capacity relative to demand and supply capacity in New South Wales. For example, the nominal capacity of the link from Victoria to New South Wales (via the Snowy) is 1100 MW (although, like most of the interconnections, it can be significantly less under certain operating conditions, and sometimes higher). This represents around 10 per cent of peak demand in New South Wales. The link between the Snowy and New South Wales is of larger capacity — around 3000 MW. However, the SMHEA's capacity is constrained by factors such as the availability of water, obligations to provide water for irrigation purposes and headpond and tunnel capacities. Hence, the link would generally only be fully used to supply New South Wales at times when demand is high. The proposed linkage with Queensland will be relatively small — 500 MW — and, in the initial years at least, it is likely that the majority of energy flows will be from New South Wales.

Information on past use of the interstate linkages suggests that they have sometimes been utilised to capacity. For example, a 1992 study carried out by the electricity authorities of New South Wales, South Australia and Victoria estimated that, based on historical usage, the Snowy to Victoria link is fully utilised, on average, on about 30 days each year (Pacific Power et al 1992, p. 9). According to the NGMC (1993a, p. 53):

> The highest past usage of the interconnections relative to their capability has been in the directions from New South Wales to Snowy, from Snowy to Victoria and from Victoria to South Australia. However, even these links are used at near their full capacity for less than 15% of the time.

However, to date the linkages have not been exploited in a commercial manner. They have essentially been used to take advantage of generating cost differentials 'at the margin', and not as a means of displacing, on an ongoing basis, capacity in those states where generating costs are relatively high. Demand for access to the linkages has also been limited by the tradition of each state investing in sufficient generating capacity to service all customers in the state.

Trading arrangements for electricity were tested in a so-called 'Paper Trial' in late 1993 and 1994. Based on 'paper trading', the links would have been constrained up to a maximum of 13 per cent of the time over the period between November and March. However, it is generally conceded that little weight should be placed on the outcomes of the paper trial as, for many participants, it was a time for experimentation and testing of bidding strategies. In this regard the NGMC commented:

> ... because trial participants have a different set of incentives to those which would exist in a real market, behaviour in the trial is likely to deviate significantly from that

> in a real market. Both for this reason, and because of some of the arbitrariness of some of the operational and pricing rules, it would be unwise to attach any significance to financial outcomes (Sub. 31, p. 1).

Indeed, given that the financial flows derived from the trial were only 'paper transactions', it is possible that Pacific Power and other generators could have bid their capacity into the market in a manner designed to ensure that the interconnections were not constrained.

In a more competitive market, it is possible that use of the linkages would increase significantly. Indeed, a major goal of the national market is to encourage interstate trade (eg generators submitting the lowest bids are despatched first, irrespective of location). However, mathematical simulation of the new market arrangements suggests that the links will not often be constrained.[8] It is unclear how accurate these simulated outcomes are. Actual use once market trading commences will largely depend upon the nature and extent of the competition that emerges. While this is extremely difficult to predict, it is reasonable to presume that the frequency of constraints will be greater than in the past when trade in electricity was rarely subject to commercial pressures.

With these considerations in mind, and recognising that inter-regional transmission losses are also likely to vary quite considerably, it is appropriate to consider Pacific Power's geographic market as having two dimensions: on most occasions it should be regarded as the national (or more accurately a four-state) market but, at other times, transmission constraints may be such that the appropriate market would be New South Wales.

When there is a national market, spot market prices will be uniform across the interconnected system whereas, when there is a state market, prices will vary between regions.

4.3 Indicators of market power

Assessing the degree of market power involves examining the extent to which market conditions diverge from those that would exist under effective competition. It involves assessing whether any firm (or a number of firms in the position to collude) could have sufficient power to enable outputs to be priced at levels which are significantly different from those which would result

8 For example, modelling undertaken for the Victorian ESIRU shows that, with Pacific Power disaggregated, the only link close to saturation would be the Victoria to South Australia link.

if there was effective competition. As a rule, market power would need to be assessed as substantial to ensure that government intervention — which itself is not costless — would lead to a net improvement in community welfare.[9]

It needs to be recognised that competition can be a relentless and ruthless process. A wide variety of firms, products, technologies and industry structures will emerge or be displaced over time. In this context, the Commonwealth Treasury observed:

> Competition is dynamic in that it is necessary to be continually changing in order to provide better offers to consumers than rivals are offering. It is necessary to move forward or be overtaken (1991, p. 9).

Thus, in assessing market power, consideration needs to be given to pressures from potential sources of competition, not just from existing rivals, and to how these pressures may emerge over time.

In the remainder of this section, a number of key indicators are used to help assess the extent of competition. These are:

- market shares of existing firms;
- the ability of existing firms to respond to a price rise; and
- barriers to entry.

Market shares

Market shares (and industry concentration)[10] have traditionally been used to assess the potential for market power. They are usually derived from the value or volume of domestic sales or turnover.

In most markets, firms with low market shares can be presumed not to have market power. A firm with a high market share may have market power because other firms may not be able to expand production at a fast enough rate to make a price rise unprofitable. However, care must be taken when interpreting market shares. First, high market shares may merely indicate that some firms are selling at a favourable price and are highly productive. Second, while market shares disclose what a firm has recently sold, they do not indicate how much business the firm would lose to rivals or potential

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9 Thus, the merger provisions of the Trade Practices Act refer to " *substantial* lessening of competition in a substantial market".

10 One measure of concentration is the Herfindahl-Hirschman Index (HHI). This is calculated by summing the square of each firm's market share. There are two advantages of an HHI compared with simple market shares: first, it takes account of all firms in the market and, second, it gives more weight to the market shares of larger firms.

entrants if it attempts to raise prices. Indeed, a firm with a high market share may have little or no market power if, in response to a discretionary price rise, smaller rivals can expand rapidly or new entry can occur quickly. Hence, a high market share is only likely to be a reliable indication of market power if there are no significant alternative sources of supply, no substitutes from the customer's perspective and little possibility of new entrants.

A central issue is the level of market share which signals the possibility of substantial market power.

A number of government bodies in Australia and elsewhere use a specific threshold level of market share to determine whether further examination of market power is warranted. For example, the Trade Practices Commission (TPC) currently investigates merger applications if they lead to the merged firm having 40 per cent of the market. In the context of determining whether prices surveillance of a firm should proceed, the Industry Commission (IC 1994) advocated a two-thirds market share test as part of a sequential series of tests. Internationally, there is a large variance in the thresholds employed. For instance, while the United States appeal courts rarely regard a market share below 50 per cent as evidence of market power, merger investigations in the United Kingdom may be initiated if the combined market share of the parties to the merger exceeds 25 per cent.

It is important to recognise that, first, these thresholds are 'industry-wide' guidelines and, second, they are in some cases set at a high level in recognition of the costs associated with government intervention. For example, the market share threshold of two-thirds nominated by the Industry Commission for price surveillance was set at this level to limit the use of price regulation — which has significant costs — to those circumstances where the costs of not taking action could be even larger.

The focus of this report is on market power in a particular sector of the economy — electricity generation. This provides an opportunity to examine in some detail the characteristics of electricity generation and the way it is marketed, and to then determine the significance of different market shares for market power. In this context, it needs to be recognised that because of certain characteristics of electricity — in particular, the bidding system, the inability to store electricity and the very inelastic nature of demand in the short term — a firm does not need a large market share to have market power in electricity generation (see Chapter 5).

Pacific Power's market share

Pacific Power's market share depends on the relevant market definition. As discussed above, the Commission considers that there are two markets served by Pacific Power (an 'exclusive' electricity market and a 'shared' energy market). These markets are appropriately viewed as integrated four-state markets on some occasions and as the New South Wales market on other occasions (depending on transmission and supply constraints).

Pacific Power's estimated market share varies considerably according to the different market definitions. While various permutations are possible, the range can be illustrated by the estimated shares for the New South Wales electricity market and the four-state energy market. As actual market supplies achieved by individual producers once competitive trading commences is unknown, the estimates reflect 1993–94 data although, where relevant, it is assumed that Eastlink is in place. Hence, the estimated market shares should be regarded as only very rough estimates of the actual outcomes that will result once the national electricity market commences.

New South Wales electricity market

Estimates of New South Wales demand (including the ACT) during 1993–94 are shown in Table 4.1 below. The data show that, in 1993–94, Pacific Power directly supplied 91 per cent of the region's electricity needs. Sales by other generators, mainly SMHEA (in which the New South Wales Government is to hold a 58 per cent interest following its corporatisation), represented a little under 8 per cent of the market.

Table 4.1: Estimated market for electricity, New South Wales,[ab] 1993–94

	GWh	*% of NSW market*
Electricity sent out by Pacific Power	49 530	
Minus interstate sales by Pacific Power	21	
Minus pumped storage use	138	
New South Wales sales by Pacific Power	49 371	91.0
Plus sales by interstate generators [c]	4 797	8.8
Plus generation by NSW distributors	101	0.2
Total New South Wales supply	54 269	100.0

a Includes the ACT.

b Excludes generation by private generators for which no data are available.

c SMHEA, comprising 3329 GWh to New South Wales, 670 GWh to the ACT and 798 GWh to others (mainly Victoria).

Source: New South Wales Department of Energy (1995).

SMHEA's input into the New South Wales grid is presently controlled by Pacific Power in accordance with its entitlements to the scheme output. In these circumstances, it could be argued that Pacific Power's current market share is more realistically viewed as 99 per cent rather than 91 per cent.

Pacific Power provided data on what it terms the 'physically contestable' electricity market in New South Wales (see Table 4.2). This is an estimate of the share of the New South Wales electricity market that would be held by Pacific Power based on the assumption that interstate and private generators provide as much electricity as possible (subject to capacity and transmission constraints) to the New South Wales market. It assumes that Eastlink is in place and that all of the Snowy's output is sold in New South Wales.

Table 4.2: Pacific Power's estimates of physically contestable electricity market shares (% of energy sales)[a]

	Regions			
Electricity sources	*New South Wales*	*Victoria*	*South Australia*	*Queensland*
New South Wales	Pacific Power 55%	34%	b	14%
	SMHEA 10%			
	Private 8%			
Victoria	19%	Gen Vic. 50%	45%	c
		Private 10%		
South Australia	d	6%	ETSA 55%	c
			Private 0%	
Queensland	8%	e	b	Austa 49%
				Private 37%

a See discussion below concerning the base year for the estimates.
b Shared with Victoria, New South Wales and Queensland.
c Shared with New South Wales, Snowy, Victoria and South Australia.
d Shared with Victoria.
e Shared with New South Wales.
Source: Pacific Power (Sub. 25, p. 12).

While comparable shares are calculated for the other states participating in the national electricity market, it needs to be recognised that the estimated outcomes are mutually exclusive in the sense that they cannot occur simultaneously (eg New South Wales cannot be receiving the maximum possible level of 'imports' and be 'exporting' at the same time).

Pacific Power estimates that, in physical terms, 45 per cent of its market is contestable (ie up to 45 per cent of the New South Wales market could be supplied by other generators). The data in Table 4.2 could be interpreted to imply that this is broadly similar to the contestable market share held by electricity suppliers in the other interconnected states in their home market. However, this would not be a valid interpretation. According to Pacific Power's estimates, it would be *guaranteed* a minimum of 55 per cent of the New South Wales electricity market. While the publicly owned Victorian generators would collectively be guaranteed a similar share of the Victorian market (50 per cent), five separate generating companies would have to compete for this share. Hence, individual Victorian generators have no *guaranteed* share. In practice, the share held by any one Victorian generator would be substantially less than the 55 per cent market share guaranteed to Pacific Power.

There are also questions about the basis used by Pacific Power for estimating its physically contestable market share in New South Wales. In particular, the estimates reflect demands in 1994–95. However, if allowance is made for Eastlink and a substantial increase in private generation, there should also be an adjustment to take account of expected growth in demand in the intervening period. Based on NGMC (1994b,c) projections for growth in electricity consumption in New South Wales, this would result in demand for electricity in 1999–2000 being around 15 per cent higher than in 1993–94. Adjusting for this market growth increases Pacific Power's guaranteed market share to 60 per cent. To the extent that the large increase in private generation anticipated in Table 4.2 failed to materialise, Pacific Power's market share would be higher again.

However, the usefulness of this measure is highly questionable. In particular, there are doubts about the likelihood of actual competition approaching this level in the short to medium term. For example, the Commission understands that Eastlink is largely justified by the prospect of sales by Pacific Power into the Queensland market, especially in the period following its commissioning.[11] If this is the case, it is unlikely that the link could be fully utilised by Austa Electric to export electricity to New South Wales, as implied by the Pacific Power calculation. Similarly, to the extent that electricity from Victorian generators is committed to South Australia, capacity may not be available to supply electricity to New South Wales at the volume implied by Pacific Power.

Given its excess generating capacity, Pacific Power would have little difficulty in meeting demand in New South Wales should 'imports' from Victoria and Queensland fall below the levels estimated in Table 4.2. Indeed, although Pacific Power does not have the mix of generating plant types available to economically meet all load at peak, it could theoretically supply around 130 per cent of New South Wales' expected electricity requirements in 1999–2000.[12] Thus, while the minimum share that Pacific Power could hold of the

[11] The Queensland Government's Energy Policy Statement (McGr ady 1995, p. 21) stated that:

> "Under the supply offer from Pacific Power, Eastlink will provide Queensland with reliable access to 500 MW of capacity and a guaranteed quantity of low-cost electricity over a ten year contract period to 2009".

[12] Based on NGMC (1944b,c) projections of consumption in New South Wales (63 510 GWh) and deliverable energy by Pacific Power which has been estimated by the Commission at around 85 000 GWh.

New South Wales electricity market is about 60 per cent, the maximum is 100 per cent.

Four-state energy market

As there is no reliable information available to forecast future market shares for the four-state energy market, data relating to actual shares in 1993–94 have been used. It is assumed that Eastlink is in place. As the potential for electricity to be used for transportation purposes is presently limited, the data exclude energy use by the transport sector.

ABARE's estimates of non-transport energy and electricity consumption in the four states in 1993–94 are shown in Table 4.3. Electricity's share stood at 137 886 GWh, or 19.4 per cent. Pacific Power's sales (less a pro-rata contribution to transport and storage use) translate to a market share of 6.9 per cent of non-transport energy use in the four states that will be interconnected around 1999.

Other market definitions

Two other market estimates are also relevant to the market definitions adopted by the Commission. These are Pacific Power's share of the four-state *electricity* market and its share of the New South Wales (non-transport) *energy* market. Once again, reliable data for future years are not available. Hence, data for 1993–94 have been used, although it is assumed that Eastlink has been constructed.

In 1993–94, Pacific Power's estimated share of the four-state electricity market was 35.9 per cent. The corresponding figure for the New South Wales energy market was 19.6 per cent.

Assessment

The estimated market shares held by Pacific Power in those markets in which it competes vary widely — from less than 10 per cent to over 90 per cent. An estimated market share of over 90 per cent, or even 60 per cent which is Pacific Power's absolute minimum possible share of the New South Wales electricity market, clearly triggers concerns about the possibility of market power. However, in the four-state electricity market, Pacific Power's market share is appreciably lower — around 36 per cent. Nonetheless, this is very similar to the market share held by the largest generator in the United Kingdom (National Power) at the time of the 1994 finding that it, and the second largest generation business (PowerGen — 26 per cent), were able to exercise considerable market power (Offer 1994).

Table 4.3: Electricity and energy consumption in the national electricity market, 1993–94 (GWh)

State	*Total Energy*	*Transport and Storage Energy*	*Non-Transport Energy*
Electricity			
New South Wales[a]	57 842[b]	814	57 028
Victoria	39 689	339	39 350
Queensland	32 025	753	31 272
South Australia	10 258	22	10 236
Total	139 814	1 928	137 886
Energy			
New South Wales[a]	352 839	99 614	253 225
Victoria	306 983	70 567	236 417
Queensland	219 081	60 481	158 600
South Australia	85 200	23 525	61 675
Total	964 103	254 186	709 917

a Includes the ACT.
b ABARE's estimates are compiled on a slightly different basis to that used in Table 4.1.
Source: ABARE (1995).

The nature of the bidding process for the dispatch of generators and the electricity marketing arrangements are such that a very large market share is not required for the exercise of market power (see next chapter). In this context, the New South Wales Government Pricing Tribunal reported (1994, p. 39):

> If retained as a single generator, Pacific Power will account for a large percentage of capacity in the NSW-VIC-SA market. However, market strength is not simply a function of size. In electricity, market strength may well be driven by a generator's position in the cost curve and, importantly, transmission constraints. A small, strategically positioned generator may be able to exercise considerable market strength.

In relation to those markets defined in terms of energy, Pacific Power's market share is under 20 per cent. However, given the delays normally experienced before users find it economic to switch to other forms of energy, there is some potential for the use of market power in the short term.

Nonetheless, as discussed earlier, market shares are most appropriately viewed as merely a first step in assessing market power. Account must also be taken of the other factors discussed below.

Ability of existing rivals to respond

It was noted earlier that the extent to which existing rivals can respond to a price rise — measured by the cross-price elasticity of supply — is relevant for the purpose of market definition. It is also relevant to assessing the strength of actual competition.

Factors that are likely to play a role in determining the nature and extent of any competitive response by existing rivals are technical constraints in transporting the good or service to customers and the availability of production capacity.

Transmission issues

Transmission-related factors, which mainly concern transmission losses and the possibility of the interstate electricity links being constrained, have been discussed above. These factors are, of course, of considerably less relevance to private generation in New South Wales and suppliers of alternative energy.

Transmission losses imply that generating sources are not perfect substitutes for each other. A generator in Victoria, for example, is likely to face greater costs in delivering power (in terms of electricity 'lost') if it is replacing New South Wales generation than if it is replacing other Victorian generation. This provides a certain amount of natural protection against interstate rivals for regional generators located close to centres of demand.

Although transmission losses are typically no more than 5 per cent, inter-regional losses, and hence the degree of natural protection, can sometimes be higher (up to 20 per cent) and can inhibit competition from interstate rivals. Furthermore, some participants contend that the treatment of losses in the national market will increase this protection. For example, CitiPower said:

> The treatment of electrical losses between regional Pools on a 'dynamic' 'marginal' basis will tend to over recover actual losses. This will penalise Victorian generators exporting into NSW and NSW generators exporting into Victoria. The net effect of this treatment of losses is to further isolate regional markets, exacerbating Pacific Power's already substantial market power (Sub. 24, p. 5).

Additional protection is provided to generators in a region if the interconnections are constrained. For example, if the interconnections into New South Wales were fully utilised, Pacific Power would be able to set a higher price throughout New South Wales (see Chapter 5).

Generation capacity issues

Existing rivals to Pacific Power include: interstate generators; private generators in New South Wales; and alternative energy suppliers (mainly gas).[13] Apart from factors relating to the transmission of electricity, the strength of competition from these sources depends on their supply capacity and their cost structure.

The generating capacity available to interstate rivals to take market share from Pacific Power varies between states.

- Generation in Victoria largely comprises brown coal-fired plant with low marginal cost. In peak demand it may have little capacity available to take market share from Pacific Power.
- On average, Queensland is the lowest cost producer. However, its capacity to compete in the New South Wales market is contingent on the construction of Eastlink. The link will be of a relatively small capacity (500 MW) and, in the initial years at least, will mainly be used to 'import' electricity from New South Wales.
- South Australia has a relatively small generating capacity. It is likely to be a net importer of electricity.

With growing demand for electricity, major generators in these other states are not expected to have significant excess capacity beyond that required to meet peak demand and to provide reserve capacity and ancillary network services. Consequently, their ability to compete with Pacific Power will be greatest during off-peak periods.

The other major potential rival to Pacific Power is the SMHEA. In the past, the Snowy has had no ability to compete with Pacific Power — it has provided power only when required to do so by Pacific Power. But, following its corporatisation, it will be free to compete. Nevertheless, as indicated in Chapter 3, the SMHEA is constrained by several factors, notably the availability of water, and it can, on average, only generate at full capacity for part of the day. Hence, it has little capability to increase its market share. Indeed, the SMHEA stated that it:

> ... has a limited ability, by itself, to offer contracts to customers in the [national electricity market]. It cannot sustain base load operation and will see its roles as providing peak energy, standby and risk management contracts to distributors and generators (Sub. 16, p. 2).

Suppliers of gas have the capability to gain more of the 'shared' market if relative prices change in their favour (eg the Moomba to Sydney pipeline has unused capacity and additional gas is available). However, to the extent that users have to acquire new appliances/equipment to convert to gas, any switch

13 In some senses, demand side management strategies pursued by users are al so rivals to Pacific Power.

would be likely to occur over a considerable period of time. In Pacific Power's 'exclusive' market, there can be (by definition) no response from alternative energy suppliers.

While existing private generators are small, Pacific Power anticipates that around 500 MW of new private generating plant will be available by the time the national market is fully operational. The Commission understands that the largest of these — at Smithfield and at Appin and Tower Colleries — will definitely proceed, but some of the remainder (totalling some 250 MW) are still in the early stages of evaluation. More often than not, private generators will be backed by long term contracts. In this context, the chief executive of Pacific Power (Bunyon 1995, p. 3) commented:

> [Pacific Power] will be kept honest in the market place by both the Snowy and private generation. However, I must say that the private generators have been singularly risk averse and all new private plant has been locked-up with long term contracts.

Potential competition and barriers to entry

The notion of contestability is relevant to any assessment of potential competition. A market is said to be contestable if an existing firm is compelled to meet customer demand efficiently or risk losing its business to potential entrants. Hence, a contestable market is one in which an existing firm is vulnerable to 'hit and run' entry. Baumol said (1982, p. 4):

> Even a very transient profit opportunity need not be neglected by a potential entrant, for he can go in, and, before prices change, collect his gains and then depart without cost, should the climate grow hostile.

The conditions for a market to be perfectly contestable are that:

- all firms, whether existing or potential, have access to the same production methods and, hence, have identical cost functions; and
- entry involves no 'sunk' costs — a firm can enter the market without making irrecoverable expenditures, and so there are no barriers to entry or exit.[14]

In practice, perfect contestability, like perfect competition, is rare. There are degrees of contestability providing varying degrees of discipline on market incumbents. Nevertheless, an important implication of the theory of contestable markets is that, even if there is a sole supplier, the threat of entry may be sufficient to prevent that supplier from exercising market power. The

[14] See Baumol and Willig (1982).

likelihood of such a threat depends on the existence and height of barriers to entry.

Identifying relevant barriers to entry is akin to identifying factors which prevent market forces from eroding an incumbent firm's excess profits over time. In the absence of barriers to entry, new suppliers will quickly be attracted into a market if excess profits are being earned. Under these circumstances, existing firms cannot exercise market power indefinitely.

The Trade Practices Commission's draft merger guidelines list as possible barriers to entry: regulation; access to scarce resources or cost advantages enjoyed by incumbent firms; economies of scale; product differentiation and brand loyalty; and the amount of sunk investment in production capacity and other costs.

Some of these 'barriers', however, reflect efficiency-based advantages which accrue to existing firms because of past investments. For example, an efficient production technique may confer a cost advantage to the firm which possesses it, but it need not be a barrier to entry. This is because the cost advantage reflects earlier investment efforts by that firm. Over time, potential entrants may be able to obtain the same cost advantage if they make appropriate investments.

The Commission considers that a useful criterion to use in identifying relevant barriers to entry in electricity generation is to ask whether the advantages that an existing generator like Pacific Power can, in time, be duplicated by a new generator at comparable cost. In the remainder of this section, this criterion is implicitly used to assess factors which may prevent market forces from eroding Pacific Power's ability to earn excess profits over time. The important question of the 'timeliness' of potential new entry is also considered.

Regulatory barriers

State initiatives to reform the electricity supply industry, coupled with reforms flowing from COAG agreements to develop a national electricity market and to introduce a set of competition principles, have removed most regulatory barriers to entry to electricity generation. In particular, a COAG principle underpinning the national electricity market is that there be no discriminatory legislative or regulatory barriers to entry for new participants in generation, retail supply or to interstate and intrastate trade. Nonetheless, some government interventions could give, or have already provided, Pacific Power an advantage that a potential entrant could not duplicate at comparable cost over the long term. These are:

- past state regulation which has contributed to Pacific Power's current market position;
- the public ownership of Pacific Power; and
- arrangements relating to investment in transmission capacity.

The influence of past state regulation

Pacific Power's current market position has not evolved commercially, but has been influenced by past New South Wales Government regulation which shielded it from competitive pressures. Under the umbrella of this regulation, Pacific Power has accumulated considerable excess capacity. As some participants have contended (as outlined briefly below), this excess capacity could be used strategically to deter entry.

Public ownership

The public ownership of Pacific Power may lead to community perceptions that its debts are supported by an implicit government guarantee. Such perceptions could give it an advantage in raising capital compared with a private entrant. On the other hand, any advantage may be offset by New South Wales Government policy that requires its GBEs to pay a government guarantee charge on their debt, and by government controls on borrowings. There are also perceptions that government bodies have relatively few financial constraints and can afford to sacrifice profits in order to maintain market share. While there is ample evidence to suggest that this may have been the case in the past, the corporatisation of authorities such as Pacific Power and accompanying requirements for them to earn a profit and remit dividends to the Government reduces the likelihood of non-commercial behaviour.

Transmission capacity

There is a risk that future investment in transmission capacity may be limited relative to the underlying demand. Community concerns about environmental and potential health risks could lead to investment being focused on augmentation, rather than on the construction of new transmission lines. In the case of interstate linkages, this problem could be compounded because of the need to gain the consent of relevant authorities in two states. If delays are experienced, the opportunity for new entrants to compete in interstate markets will be reduced. In turn, this could reduce expected returns and deter prospective entrants. Reservations held by some participants about the adequacy of provisions to facilitate inter-regional trading — which are still being developed — could have a similar effect

Economies of scale and scope

Economies of scale refer to the reduction in average unit costs from increasing the volume of outputs. Economies of scope refer to the reduction in average unit costs from producing a mix of outputs.

Scale and scope economies dictate the level and mix of output potential entrants must be able to achieve for least-cost entry (minimum efficient scale). Together with demand conditions, they also influence the size of an industry. Hence, if minimum efficient scale is large relative to current demand, the number of efficient firms is likely to be small.

In the context of electricity generation, scale and scope economies are widely perceived to exist. Economies of scale are said to occur at several levels — the generating unit, the power station, the multi-station enterprise and the industry level. As discussed in Appendix C, it is generally agreed that most economies of *scale* can be realised at the unit or plant level, and that the minimum efficient scale at these levels has decreased over time. Broadly speaking, average unit costs are now similar over a wide range of plant capacities.

In relation to economies of *scope*, it is notable that Pacific Power produces not only electricity, but also undertakes activities in research and development, international consulting and project development; and training. Economies of scope may have been relevant in the past when electricity suppliers were all vertically integrated and there were no market based mechanism to supply supporting services. However, as discussed later, their significance is likely to be relatively small in the context of the new electricity trading arrangements.

Irrespective of the significance of economies of scale and scope, their existence does not mean that potential entrants are required to bear a cost that has not also been borne by existing firms. Provided potential entrants have access to the same production technology as existing firms and are prepared to undertake appropriate investments to increase their scale of operation, there should be no cost inequalities between them and existing generators. Thus, scale and scope economies in electricity generation are not entry barriers in themselves. This applies even if it takes time for the potential entrant to develop its business and become profitable. Even though they may not be barriers to entry as such, they can, however, act as a barrier to entry in combination with sunk costs. This matter is considered in further detail below.

Vertical integration

Vertical integration is often claimed to be a barrier to entry because potential entrants must enter at each stage of a market in order to compete. However, as in the case of scale and scope economies, market conditions dictate the efficient size and extent of vertical integration of firms in a market.

Perhaps more importantly, the vertical separation that has occurred in the Australian electricity supply industry (and in some other countries) means that, in most jurisdictions, a new generator will not be disadvantaged by competing against vertically integrated competitors. In this context, the New South Wales Government has announced its intention to separate and corporatise Pacific Power's coal mines. Transmission assets have already been split off into a separate corporatised entity.

Strategic behaviour

A potential entrant's expectation about the reaction of existing firms to entry is sometimes viewed as a barrier in itself.

The range of strategic behaviours is very broad. So-called predatory pricing is one example of such behaviour. Alternatively, an existing firm may manipulate its investments in capacity to influence outcomes in its favour in the event of entry. To the extent that this behaviour is seen as a signal by potential entrants that the firm will supply a high output level, or charge a low price in the market, it will deter entry. Thus, such behaviour is offputting to the potential entrant "not because of its direct effects, but because of its indirect influence upon the outcome of the market game" (Vickers and Yarrow 1988, p. 64).

A number of participants pointed to the potential for Pacific Power to engage in strategic behaviour to deter entry. For example, the Victorian ESIRU claimed that there is no certainty that Pacific Power, under New South Wales Government ownership, will behave in a commercially predictable manner. It contended that the pursuit of non-commercial objectives (such as maintaining loss making plant and mines and seeking to maximise market share as an end in itself) could create significant uncertainty and destabilisation for both customers and other producers.

In practice, it is hard to distinguish the outcomes of strategic behaviour from competitive behaviour. Aggressive price cutting may be indicative of vigorous competitive behaviour. And excess capacity may be carried for several reasons (eg to serve seasonal peaks, because of optimistic expectations about future demand or to cover the risk of plant outage). However, Pacific Power's excess capacity (estimated by reserve plant margin) is high compared with other generators.

The motivation for — and hence the likelihood of — strategic behaviour is not always clear. Some forms of such behaviour would seem unlikely because they would harm the existing firm as much as the potential entrant. Indeed, Pacific Power argued that it has limited incentive to price in a predatory fashion in the national electricity market, mainly because it could be matched by lower cost brown coal plant in Victoria. However, strategic behaviour could be used as a short run strategy. For example, it could be used to deter new entrants. Thus, while it may involve a cost in the short term, the firm could gain an advantage overall because of reduced competition.

The Commission is of the view that the potential for strategic behaviour by Pacific Power, in itself, is not a barrier to entry. If entrants are concerned about it, they could secure protection through long term contracts. However, the potential for strategic behaviour may amount to a significant barrier to entry when considered with other factors such as the level of sunk costs (see below). The types of strategic behaviour that could be employed by Pacific Power and their possible impact are outlined in Chapter 5.

Sunk costs

Sunk costs are unavoidable costs (including exit costs) that, once outlaid, cannot be recovered in the event of failure.[15] The 1992 US Merger Guidelines define sunk costs as:

> The acquisition costs of tangible or intangible assets that cannot be recovered through the redeployment of these assets outside the market. ie. costs uniquely incurred to supply the relevant product and geographic market.

Examples of sunk costs include investment in equipment that is so specialised that its second hand value is minimal, some advertising expenditure and certain research and development.[16] Generating units of the type employed in multi-unit power stations are generally immobile industry-specific assets whose costs are sunk in the sense of the above definition.

Sometimes new entry involves sunk costs that can be recovered after a short period of trading. In other instances, sunk costs may take years to recover. However, at some point, the size of sunk costs may be so large and the pay-back period so long that new entry will be especially risky. In essence, this arises because of uncertainty about post-entry prices. For example, when a potential entrant contemplates entry into a market involving investment in large sunk costs, it faces the additional risk that such entry will lead to a larger

15 Sunk costs can involve, but are conceptually quite distinct from, fixed costs. Some fixed costs can be avoided if the business ceases operation (eg the monthly rent on office space).

16 The magnitude of a sunk cost can be measured as the difference between the purchase price and the maximum resale price of an asset.

than anticipated fall in prices, possibly resulting from strategic behaviour by the incumbent. An existing firm can remain viable in the face of falling post-entry prices for as long as marginal revenue exceeds its marginal costs (that is, the existing firm can ignore its sunk costs when setting prices). In contrast, the potential entrant must take its sunk costs into account because it has not yet borne them.

In principle, if both potential entrants and existing firms have to incur equal outlays in the same production technology that are sunk at the time of their entry into a market, there is no cost inequality and, therefore, no entry barrier as such. However, in combination with economies of scale and scope, sunk costs may represent a significant barrier to entry. For example, if the existence of scale or scope economies suggest that entry would have to be on a large scale in order for a potential entrant to be productively efficient.

The significance of sunk costs as a barrier to entry depends on the size of probable price changes associated with new entry. There is evidence to suggest that once there are several firms in a market, the price impact of further entry is unlikely to be large and, hence, the risk is lower. United States studies of geographically isolated monopolies, duopolies and oligopolies have found that large price reductions accompany the entry of a second or third firm, but once there are three to five firms, further new entry has little or no impact on competitive conduct (Bresnahan and Reiss 1987, 1990, 1991). Studies of airline competition also suggest that the price effects of entry and exit fall away once two to three carriers serve the market (IC 1994, Pautler and O'Quinn 1993).

Another indication of the significance of sunk costs is the payback period. The Commission has suggested that a payback period of five years be used as a benchmark (IC 1994). Given the normal planning and construction lags of new ventures and the tendency for businesses to run at a loss during their start up period, five years is a common milestone in judging the commercial success or failure of ventures.

An investor in new generation plant would be unlikely to embark on a venture that could result in some costs being sunk unless they could be recovered from profits within a reasonable period. New entrants into generation can reduce this risk by arranging supply contracts with users. However, given the long economic life of generation plant, it would not normally be possible to 'lock in' prices to guarantee that all sunk costs will be recovered. Moreover, at the present time, there is considerable uncertainty about the level of future electricity prices. In this situation, which is likely to continue for some years as the transitional arrangements lapse and market trading evolves, customers may be reluctant to make sufficiently long term commitments to moderate entry risks associated with sunk costs. Thus, sunk costs could deter entry into the generation sector.

In the case of electricity generation, it is apparent that technological developments over the last few decades have led to reductions in minimum efficient scale as well as in the real capital costs of generating units. It is now possible for new generators to undertake investments in generating units that are lower than those associated with the coal-fired units used by Pacific Power (see Table 4.4).

Table 4.4: Relative capital costs of different generation plant, 1994
($/kW)

Generating unit	*Total capital cost*
Coal fired	1200
Gas turbines/gas fired	600
Gas turbines/oil fired	500
Hydro	2000

Source: Based on unpublished Pacific Power data in Strong (1995, p. 28).

Given the lower level of capital costs involved with gas-fired generating technologies, the payback period is likely to be shorter than that for coal-fired generating technologies. This suggests that sunk cost in electricity generation is not as significant a barrier to entry as it used to be. Nevertheless, given the size of investments in generating plant, it is highly improbable that sunk costs could be recovered in a five year period.

Timeliness of entry

In the case of electricity, the large excess capacity in New South Wales could deter entry for some time. On the other hand, there is a real possibility of entry if Pacific Power (or any other existing supplier) maintains price around the long run marginal cost of supply. As a result of the increased availability of gas and developments in generating technologies, new gas-fired generators can be competitive at prices of around \$40 to \$45 per MWh.

In assessing the increase in competitive pressures likely to be associated with new entrants, a key issue is the length of time it takes for new entry to occur. How long is ‘too long’ to wait for effective new entry? This is important in determining whether market power is a long term or short term problem. If the competitive response of potential entrants is quick, market power is only of short duration and is unlikely to warrant government intervention.

While there is no objective ‘rule’ to identifying entry that takes ‘too long’, the Trade Practices Commission’s draft merger guidelines indicated a two year period to be an appropriate lag between the post-merger exercise of market power and new entry. In contrast, the European Commission standard for timely entry is between two and five years after a post-merger price increase.

In the context of electricity generation, it is the Commission’s understanding that new gas-fired turbines could be operational within two to three years (see Box 4.1). In comparison, a new large coal-fired power station can take over five years to build. In both cases, additional time is needed to make the necessary financial arrangements, organise contracts with users and gain the environment, planning and other government approvals required before construction can start.

Other influences limiting market power

Two other factors that need to be considered when assessing market power are the potential for users to have countervailing power and the possibility that firm behaviour will be moderated by the threat of regulation

Countervailing power

If major buyers account for a relative large share of market-wide sales, the market power of sellers can be reduced. Firstly, if sellers are colluding, big buyers can play one seller off against another with the promise of long term patronage. Secondly, any threats to organise imports or of backward vertical integration have more credibility if made by big buyers. Thirdly, a large buyer can use the opportunity provided by new location decisions for major investments to extract lower prices from even a regional monopolist.

As there are a number of large volume buyers of electricity (eg distributors and large industrial users such as aluminium smelters), there is a possibility that these customers would be able to exert some countervailing power over any attempt by Pacific Power to act in an anti-competitive manner. These users could threaten to seek supply from other producers or, alternatively, could themselves invest in generation capacity. However, the opportunity for distributors and large users to seek alternative sources of supply will depend upon the way in which the market develops and the willingness, and the capacity, of interstate generators to sell into other regional markets. However, in the short to medium term, the ability of large buyers in New South Wales to acquire their electricity needs from other existing suppliers will be limited.

Box 4.1: Competition from new entrants using natural gas-fired plant

Technology developments in gas turbines (GTs) have led to a substantially increased role for natural gas for electricity generation around the world. There are three streams of these developments:

- aero derivative GTs, which are available in open cycle configurations around 40–50 MW with thermal efficiencies of 36–38 per cent;
- industrial GTs, which are available in open cycle installations at sizes of 230–240 MW and thermal efficiencies of 31–34 per cent; and
- combined cycle GTs (CCGTs), which now range over 340–365 MW and have very high thermodynamic efficiency ratings of 48–53 per cent.

These parameters may be contrasted with coal-fired plant for which the minimum efficient size is much larger — around 500 MW to 660 MW — and thermal efficiencies are lower (about 30–35 per cent). The capital cost per unit of capacity of GT plant is also much lower than coal-fired plant, although fuel prices are often higher.

GT units are available in modular packages and can be installed quite quickly: about two years from commitment to commissioning for open cycle GTs and three years for combined cycle stations. Additional time is required to arrange finance, supply contracts and the necessary government approvals. In contrast, coal plant takes five to six years to commission and may face greater hurdles in obtaining environmental approvals. GTs also have much faster start -up and shut-down times, enabling them to participate more cost effectively in the peak, reserve and intermediate load market niches.

The natural gas pipeline from Moomba has the capacity to supply an additional 100 PJ per annum. This would be sufficient to run CCGT plants totalling at least 1300 MW in capacity. Additionally, BHP has announced plans to build a second pipeline to New South Wales to supply gas from large reserves in the Gippsland Basin. Its pipeline might ultimately be able to supply gas to fuel a further 1300 MW of CCGT in New South Wales and the ACT. In the longer term, further development work could result in additional gas being sourced from the large quantities of coalbed methane located in coal measures in the Sydney, Newcastle and Wollongong region.

As with power lines, gas pipelines will be treated as ‘essential facilities’ under the national competition law, so that open access (as long as capacity is available) and non-discriminatory pricing will be assured to potential power generation entrants.

There is also the potential for distributors and large users to enter, or threaten to enter, into a contractual arrangement with a new entrant. However, the question arises as to whether it would be profitable for a distributor to sign a contract in the knowledge that entry could provoke a 'price war' from which it would potentially benefit if it was not tied by a contract.

The viability, and likelihood, of users investing in their own generation capacity is difficult to judge. Experience in the United Kingdom suggests that distributors may invest in generation capacity. However, to date this has not removed the market power held by the two dominant generators.

Threat of regulation

The threat of regulation could also constrain Pacific Power's ability to exercise market power. Pacific Power could set its prices at a level below that which it would expect the regulator to take action. CS First Boston and KPMG Peat Marwick (1994, p. 27) reported:

> The intense political and public scrutiny which will inevitably continue to apply to an electricity industry whether disaggregated or not will be likely to prevent extreme gaming scenarios and monopoly pricing from occurring.

As with countervailing power, threat of regulation could moderate — but not eliminate — the use of market power by Pacific Power. However, if this is to be an effective discipline, the threat of regulation needs to be credible. To the extent that this requires regulatory action from time to time, there are associated costs (see Chapter 6).

4.4 Assessment of market power

It is likely that Pacific Power has market power in some market segments — particularly in relation to the supply of electricity for those 'exclusive' end uses for which there is no viable alternative energy source (eg for lighting, for many domestic appliances and for electrical equipment used by industry).

Concerns about market power would be magnified to the extent that limited transmission capacity will, for an unknown period of time, constrain competitive from existing interstate generators. New generation capacity in New South Wales would overcome concerns about the transmission constraints and increase competitive pressures. However, in view of the considerable sunk costs associated with entry and varying perceptions about the prospect that Pacific Power will manipulate pool prices and engage in other forms of strategic behaviour, it is not clear how significant new entry will be, or what the timing of such entry will be.

Pacific Power's market power in the 'shared' segment of the market is limited by the capacity of users to substitute alternative forms of energy (particularly natural gas) for electricity. However, as in many applications the change has to be accompanied by the acquisition of new equipment, there may be some potential for Pacific Power to use market power even in that market.

While the Commission considers that Pacific Power potentially has significant market power, consideration also needs to be given to the implications of this finding for market behaviour, and the likely effects of this behaviour on electricity prices and the community generally. These matters are discussed in the next chapter.

5 EXPLOITING MARKET POWER

This chapter is about the ways in which prices might be raised and maintained above competitive levels in the national market by a generating company possessing market power. It is also about the consequences of the exercise of such market power for consumers and other producers.

While some of the analysis is based on a presumption that market power exists, the discussion is also intended to be useful in helping to come to an assessment of the likelihood of market power being exercised. Judgments about whether prices can be maintained above competitive levels in practice will, in part, depend on how plausible the firm behaviour described here appears.

In looking at the possible outcomes if market power is exercised, the chapter is intended also to consider the magnitude of any costs of that market power. The key comparison is between the costs associated with the exercise of any market power, for as long as it exercised, and the costs of removing it.

5.1 Balancing capacity and demand in the electricity market

In examining the possible exercise of market power, it is useful to distinguish between two periods in which:

- capacity does not vary — the short term; and
- capacity can be altered — the medium and long term.

This is especially important in considering the move to the national electricity market because of the current abundance of installed capacity relative to demand. In a competitive market, excessive capacity may influence prices to be lower than they would otherwise be in the short term.

Competitive pricing

An important benchmark for evaluating the extent of market power is what the outcome would be in a competitive market.

Long term

In the long term, if a competitive electricity industry were in balance, with demand broadly matching available capacity, prices in the market would provide returns on capital (adjusted for risk) that were similar to returns available elsewhere — so-called ‘normal’ returns.

In this situation, changes in demand are reflected in alterations in the market prices. These in turn affect the returns of existing generating companies and the prospective returns of possible entrants. If demand rises, prices rise with it and signal higher than normal returns to new investment. If demand falls, or grows less quickly than expected, returns on existing assets are lower than expected and some excess capacity is likely to exist. In many industries, this would result in the redeployment of the surplus capital (for example, business premises can serve a number of different business types). However, large coal-fired electricity generating plant is not suited to other uses, so that accommodation to lower demand will usually occur by running down existing assets which are replaced more slowly than may have been anticipated. (However, gas turbine generators, which are at present a small proportion of current generation capacity but are expected to provide the bulk of additional capacity, may be relocated.)

At long term equilibrium in the electricity market, therefore, it might be expected that prices would fluctuate in a band around a trend level of prices that made production of electricity profitable. Prices would be alternatively high when demand was pressing against supply, and low when new increments of capacity were brought into production.

It has been suggested (see, for example, Pacific Power in Sub. 25) that the price that would currently make gas-fired production of electricity profitable is around \$40/MWh. (By way of comparison, the Bulk Supply Tariff in New South Wales is at present around \$50/MWh.)

Short term

A key feature of the existing market, which bears on the impact of the exercise of market power, is the state of oversupply of capacity (see Box 5.1). In this environment, the existence of any market power may have quite a different impact relative to a situation of closer balance between demand and available capacity.

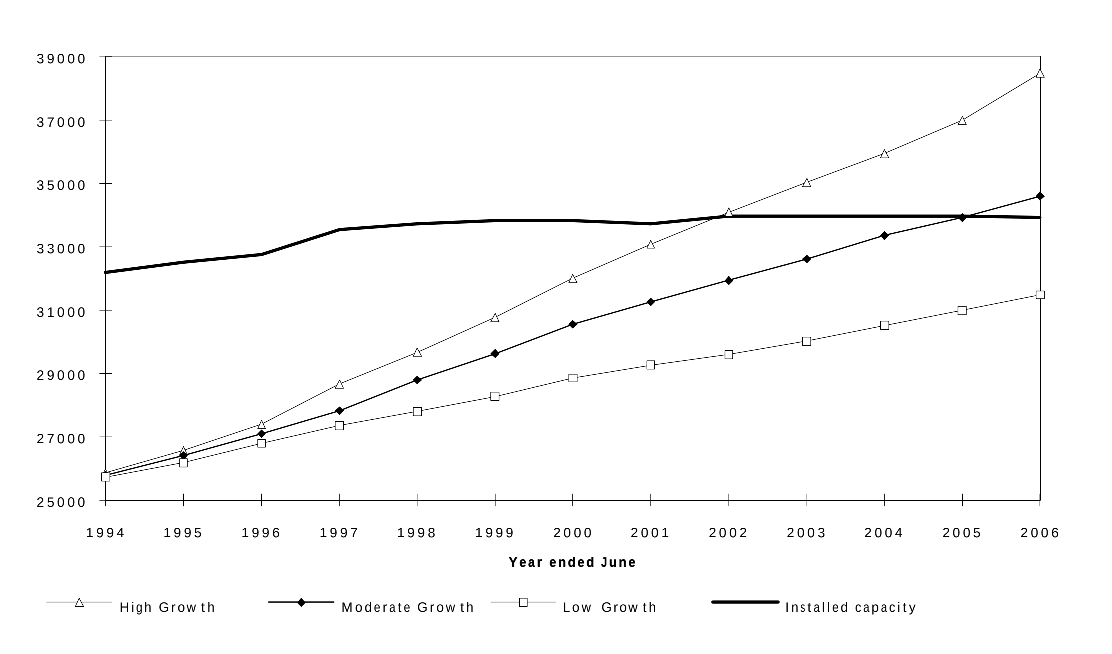
When overinvestment has occurred in the electricity industry, investors are generally required to view those costs as sunk. That is, because coal-fired generating plant cannot readily be turned to another purpose, owners must operate it as best they can to obtain whatever margin is available after paying short run costs.

Box 5.1 Outlook for excess generating capacity

The outlook for the level of excess generating capacity depends upon whether it is New South Wales alone or the entire four-state electricity market that is being considered. In New South Wales, the NGMC's moderate growth projection is for electricity consumption to increase at the rate of 2.3 per cent per annum to 2005–6. For the four states, the projected growth rate is 2.7 per cent.

The supply side is more difficult to project because of uncertainties about such developments as the extent and rate of new entry into the electricity generation industry, plant scrappages and power station prolongation investments. Consequently, the Commission has chosen to be conservative, assessing the outlook using only existing and committed generating capacity, along with already announced plant closures.

Based on mid-range or 'moderate' growth projections, within New South Wales alone, the capacity overhang appears likely to persist until about the year 2002 (assuming some capacity is dedicated to supplying Queensland through Eastlink), while for the four-state region, excess capacity could be expected to 2005. Since the installed capacity projections are necessarily conservative, it is likely that, in reality, this capacity overhang will last somewhat longer. The following figure shows the four-state situation.



Sources: See Appendix D.

In the electricity industry, short run costs largely comprise fuel supply and the costs of operation and maintenance. As long as the price of electricity covers these costs, it will pay owners to continue to run their generators. If owners of generators do not receive a price for electricity sufficient to cover these costs, they may consider scrapping capacity. ('Mothballing' in the hope of better times may sometimes be attractive, but it involves large decommissioning and recommissioning costs, and uncertainties associated with the possibility of the technology becoming obsolete.)

Thus, aside from aberrations for short periods of time, price is unlikely to settle at a level less than that which allows generators to cover short run costs. If overcapacity is high, pricing at this level will not recover all costs incurred (including a return on capital). Nonetheless, since the investment in surplus generating plant is effectively sunk, pricing at marginal cost will result in the most efficient use of existing plant, though such prices would deter future investment.

It has been suggested that a price that would apply in this short run competitive situation could be around $25/MWh.

Pricing with market power

With market power, an electricity generating company may be able to raise the price above that dictated by efficient use of existing capacity.

In considering the extent of market power being exercised, however, it is necessary to distinguish between the situation in which there is short term overcapacity and the longer run. In particular, a price which matched the cost of gas entry may indicate an absence of market power when markets are in long run equilibrium, but would indicate considerable market power if there were overcapacity.

5.2 Some key features of the market

The existence of market power implies the ability to supply output at higher prices to the market than would occur under more competitive conditions. The higher prices may derive from higher markups on costs than would otherwise prevail or from the existence of higher production costs than would be permitted to survive in a competitive market.

Electricity is traded in a number of markets (the contract market, the spot market and various forward markets), making the concept of *the* market price somewhat elusive. Even so, the markets are linked, and market power if it exists, will be evident in all of them in some degree. The link between contract and spot markets is discussed in Box 5.2.

Having regard to this, the discussion that follows is concerned mainly with price setting in the spot market.

Box 5.2: Spot and contract prices

Electricity is likely to be sold mainly by way of long term contract in the national market, with additional sales in the short term forward and spot markets.

Strategies which involve a dominant supplier bidding price up (or down) may appear to be aimed principally at influencing the spot market price. They thus may appear to be somewhat remote from the market in which most trading is undertaken — that is, the contract market.

However, spot and contract prices will tend to be related to each other as the market matures. (Although there may be a systematic differential, with contract prices somewhat above spot prices to compensate for the costs of offering certainty.) The Victorian ESIRU said:

> ... as contract prices and contract structures will generally reflect the expected behaviour of the spot market, the ability of a dominant NSW Generator to influence spot prices will translate substantially into the contract market (Sub. 30, p. 49).

It is true that, day by day, there may be very little observable relationship between spot and contract prices. Not only is there inherent fluctuation in spot market prices but, at times, it can suit the holder(s) of market power to make it fluctuate (see Section 5.5)

But if prices bid in the spot market were such that they were consistently and predictably below the prices at which contracts were signed (after adjusting for the greater degree of certainty in contracts), it is implausible to think that some purchasers would not, over time, alter the balance of their purchases to favour the spot market. As a result, those exercising market power in the prices at which they offer contracts, would need also to exercise it in the spot market over the long haul, unless they wish to have their market power eroded.

Examining the more visible process of price setting in the spot market thus provides a proxy for considering the price in the contract market

Electricity generators are predominantly government enterprises which, in the past, have had a range of objectives in their operations, including making profits, encouraging state development, providing power at affordable prices, building high quality (‘gold plated’) assets and aiming to have under their control as much capacity as possible (‘empire extending’).

While, to varying degrees, these objectives may continue to be held by generators in the national electricity market, the discussion that follows is mainly concerned with the way in which market power may be used to increase profits. With the corporatisation of most generating authorities (and the associated requirement to meet a specified rate of return), they are now more likely to be actively pursuing profitability. However, it cannot be discounted that they may still want to retain more market share than would be consistent with a strategy aimed only at profits.

The bidding process

In the national electricity market, the price of electricity is determined by the bid made by the most costly generator which is dispatched within the limits of existing demand. The way in which the market works requires that bids to be dispatched are stacked in ascending order, with the generator bidding lowest being dispatched first. Ultimately, the bid from the highest priced generator needed to satisfy the level of demand sets the System Marginal Price (SMP) which is received by all generators.

Most generators dispatched do not receive the price they bid. Because of the way bids are stacked, the price each receives— the SMP— will usually be higher than its individual bid price. (In broad terms, generators which are not dispatched receive nothing.)

Generators are not obliged to make a bid which reflects their costs of production. They may choose to bid higher in an attempt to lift the SMP and receive greater returns. For example a generator may have marginal costs of $5/MWh when the SMP is $10/MWh. If it bids $12/MWh, it will then be lifted up the merit order of bids to be above the previous price-setting generator. If there are no other generators offering bids in this price region, this generator will still be dispatched, but the market price will be higher.

The key to success of this strategy, in the electricity industry as in other industries, is the extent to which other suppliers respond to higher prices.

For, if a generator does raise the SMP through this behaviour, it risks the entry of additional supply from a generator which finds the new (higher) price profitable. The new generator may bid under the inflated price and displace the other generator in supplying the market.

The strategy of bidding high in an attempt to manipulate market price will thus be most successful in a situation in which the generating company attempting to increase the market price controls a high proportion of the rest of the generating capacity. In particular, if it can control the prices bid by neighbouring generators in the merit order it can be confident that undercutting bids will not eventuate.

One feature of the electricity market which is relevant here is that the bidding process is highly transparent— everyone is aware of others' cost structures and the bids themselves are to be published. This can assist in setting bids which are aimed at influencing market price.

In raising prices in the short run, the generator must also be aware that, in the longer run, higher prices may encourage new investment in generating capacity which, when it comes on stream, will undercut inflated prices. The exercise of market power may thus also involve attempting to prevent such entry occurring.

Pacific Power's position in the national electricity market

A simple example of market power

A simplified version of pricing choices faced by Pacific Power is presented in Box 5.3, based on material provided by Pacific Power. These are stylised facts and do not capture the full complexities of the electricity market. But they do help to set out the main factors involved in any exercise of market power.

The essence of the example is that Pacific Power can affect the amount of electricity it supplies to the market by setting its price at a level to exclude various possible other suppliers. If, for example, price is set very low, Pacific Power captures a great deal of the available market, but may make a financial loss on its production. As it raises its price it encourages higher cost producers into the market, and sacrifices market share. At the same time, however, it receives higher prices for the output it produces. As prices increase, so, up to a point, do profits. At some stage, when too much market share is sacrificed, profits decline again.

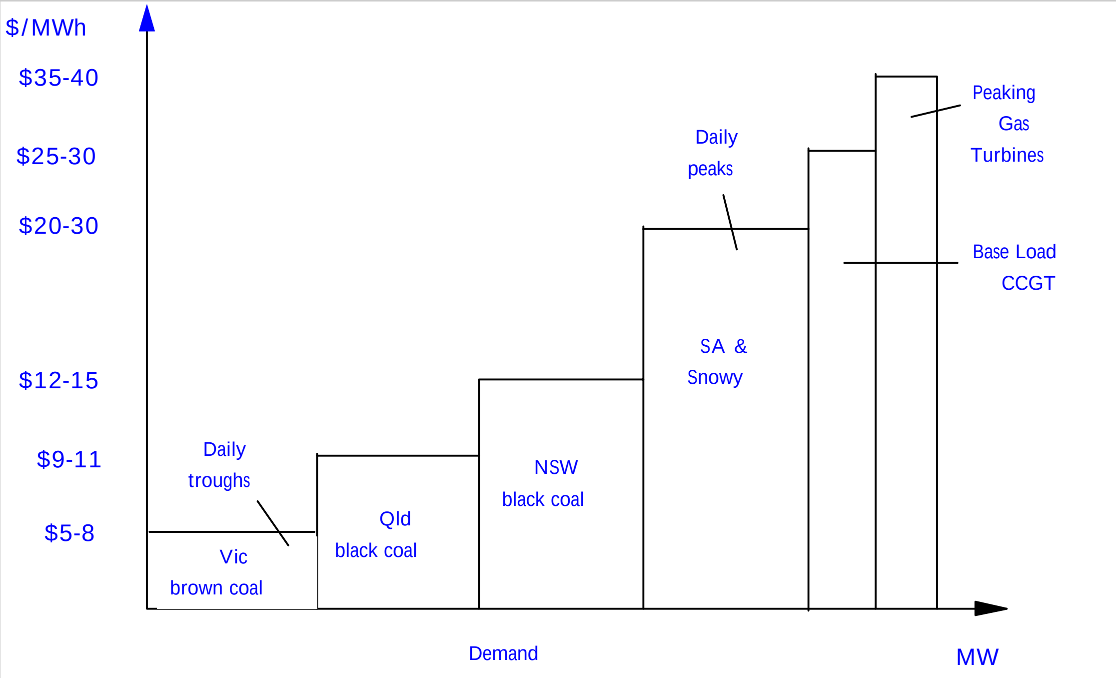
The essence of the problem for Pacific Power in this simple example is to set prices such that profits are maximised.

Box 5.3: Impact of prices bid by Pacific Power: a stylised example

The amount of electricity available to supply the market, and its price, may be represented in a schedule of merit order such as that below. The blocks in the figure broadly represent the comparative costs of generation in each state. For the purposes of this example, the schedule below shows short run marginal costs (essentially fuel costs).

It is possible to make a number of different assumptions about the prices that competitors will bid. They may not bid precisely their short run marginal costs, especially if they too consider that they may have market power. However, the precise assumptions made do not materially affect the point of this illustration.

Marginal cost of electricity supply in merit order



Source: Pacific Power, *Merit order—supply curve (1) short run marginal costs* , Sub. 25, p. 51.

Given this schedule of supply, it is possible to follow what would happen to the market share of New South Wales generation as price rises from low to high levels.

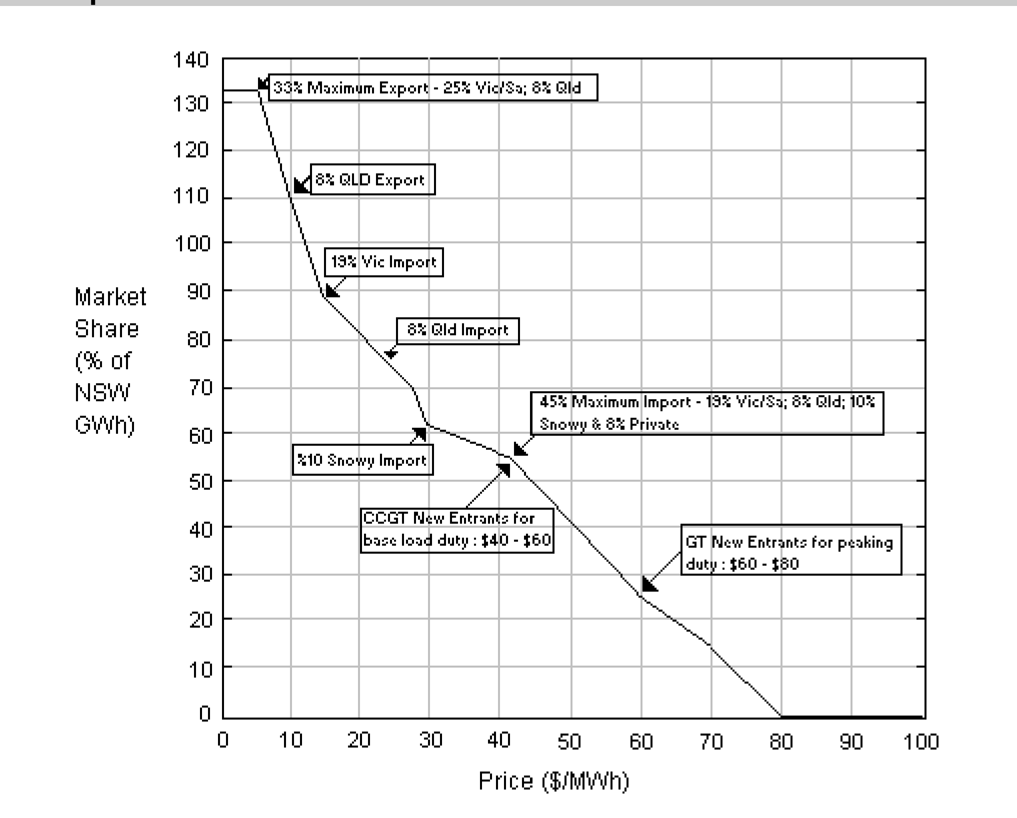
If New South Wales generators were for some reason to charge a price of less than $5 they would, according to this schedule, underbid all other suppliers. This would enable them to sell all the electricity they are capable of generating, which could amount to something over 130 per cent of the New South Wales market. As they raised their prices to the point where capacity from different suppliers was made competitive, their market share would be eroded.

Box 5.3 (cont)

The figure below provides an illustration of the market shares that could possibly be obtained by Pacific Power if it adopted and maintained different price bids (shown on the horizontal axis). As prices rise, more and more expensive generation capacity is drawn in to the market that Pacific Power might hold. For example, as prices rise the first thing to happen is that Queensland and Victoria find it profitable to displace Pacific Power production from their own markets. As prices rise further, the New South Wales market is eroded. Finally, Pacific Power's market is completely eliminated by the entry of new gas producers. (In practice, entry is not costless at these prices and may not be based entirely on pre-entry prices.)

Each price and quantity combination on the figure has different implications for the profits of Pacific Power. In principle, Pacific Power would bid that price which maximised its profit.

Possible price and market share tradeoff



Source: Based on Pacific Power, *National market equilibrium results - Bertrand behaviour, National market equilibrium, results - Cournot behaviour,* Sub. 25, pp. 58–9.

One important observation to make is that if Pacific Power is able to exert market power and the interconnections are unconstrained, the price set would prevail *throughout* the national electricity market. This is because the SMP is set after consideration of the merit order of bids from all generators. Thus, Victorian, South Australian and Queensland customers, like those in New South Wales, would pay more if price were elevated, and generators in those states would also earn more. Yallourn Energy said:

> If Pacific Power were retained intact or as a small number of portfolios it could have a major influence on prices not only in NSW but also, through the interconnectors, on prices in neighbouring States (Sub. 23, p. 3).

If, in this situation, Pacific Power acting as a group achieved a higher price by raising the price at the margin for some of its generation, it is likely to be at the cost to some of its market share being filled by additional generation induced from interstate. (As has been noted, this is quite a likely scenario.)

However, if there were a constraint on imports through the interconnection, Pacific Power could raise the price in New South Wales with little additional scope for its supply to be replaced by competitors. In effect, the capacity to set the price to its best advantage would be limited only by the probability of discouraging customers in the future (that is, switching to gas or consuming less energy), the probability of encouraging competitors (and new entrants) to locate within New South Wales, and any possible regulatory restrictions.

The competitive outcome

In the example in Box 5.3, each price bid by Pacific Power corresponds to a different quantity of its capacity supplied to the market. As prices are increased, Pacific Power must effectively withdraw some capacity. To maximise returns, this should be done in descending order of production cost, with the units that are cheapest to run being withdrawn last.

This can be contrasted with a situation in which the block of capacity represented by a large generator group was instead made up of disaggregated individual generation units.

If individual components of generation were to be bid separately then each would be in grave danger of being displaced by another if it bid too high. In other words, while an aggregated generator may bid high and lose a proportion of its market share, each individual generator when disaggregated may lose its whole market share (and profits) by bidding high.

In this situation, individual generators would have incentives to bid closer to true marginal costs of production. Assuming that the bidding process is a true auction (and that generators do not act collusively and conduct side deals involving compensation for those who withdraw capacity), the generators would have much less scope to affect the price they receive, than they would acting as a group.

At present, Pacific Power has over 90 per cent of the New South Wales market and the Bulk Supply Tariff stands at slightly over $50/MWh. Pacific Power has indicated that it feels that a plausible price in the national market might be $40/MWh, ie around the lowest price at which new entrants could make a reasonable return on their investments. As has been noted, modelling work appears to imply that, in the present situation of overcapacity, the competitive price might be around $25/MWh.

Pacific Power's example illustrates that it could be able to control the quantity it offers to the market in order to achieve higher prices than would otherwise apply. The gap between the competitive price and the price Pacific Power was able to charge is one measure of its market power.

Market power at different times of day

Perhaps the most important factor which needs to be considered in looking at the scope to exercise market power is the balance between capacity and demand at different times of day. The extent to which demand is pressing on capacity in various parts of the system clearly affects the scope for Pacific Power to lift the price in the national electricity market, because it indicates the potential for imports. It also affects the likelihood of interconnects becoming constrained, and market power being amplified by the temporary isolation of the New South Wales market.

Demand for electricity varies greatly according to the season and time of day. An illustration of summer and winter patterns in New South Wales is shown in Figure 5.1.

The most important differences for consideration of market power are those that arise at different times of day. In New South Wales, for example, demand on a given day can almost double from trough to peak.

Peak demand

On the face of it, there appears greatest potential for the exercise of market power at the peak because at that time demand in other states absorbs much of their locally-based generation capacity. This limits the scope for imports into New South Wales, even if prices were to be elevated significantly by higher bids into the national market from New South Wales generators.

Figure 5.1(a): Illustrative winter load trace for New South Wales

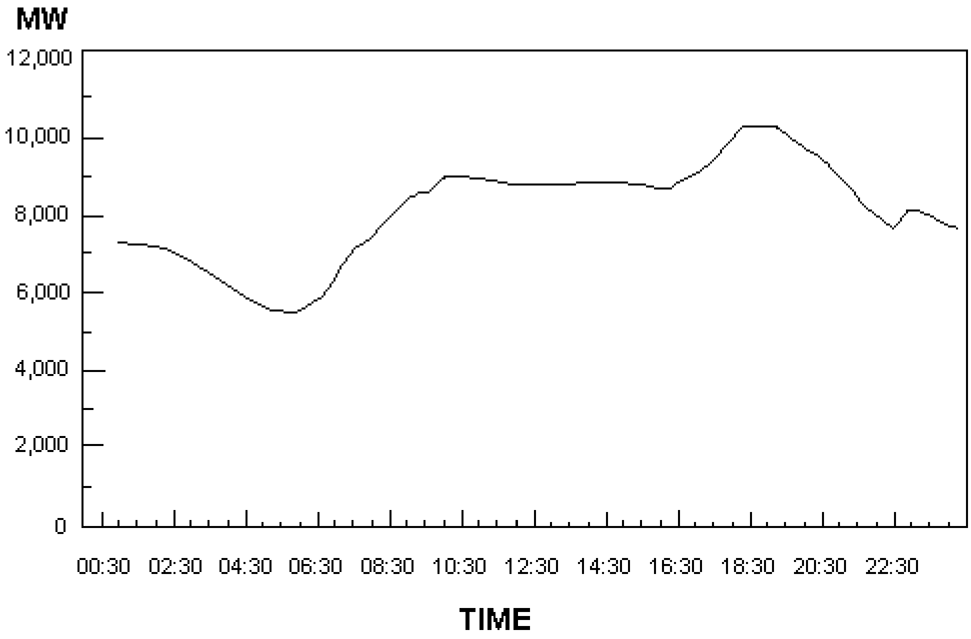
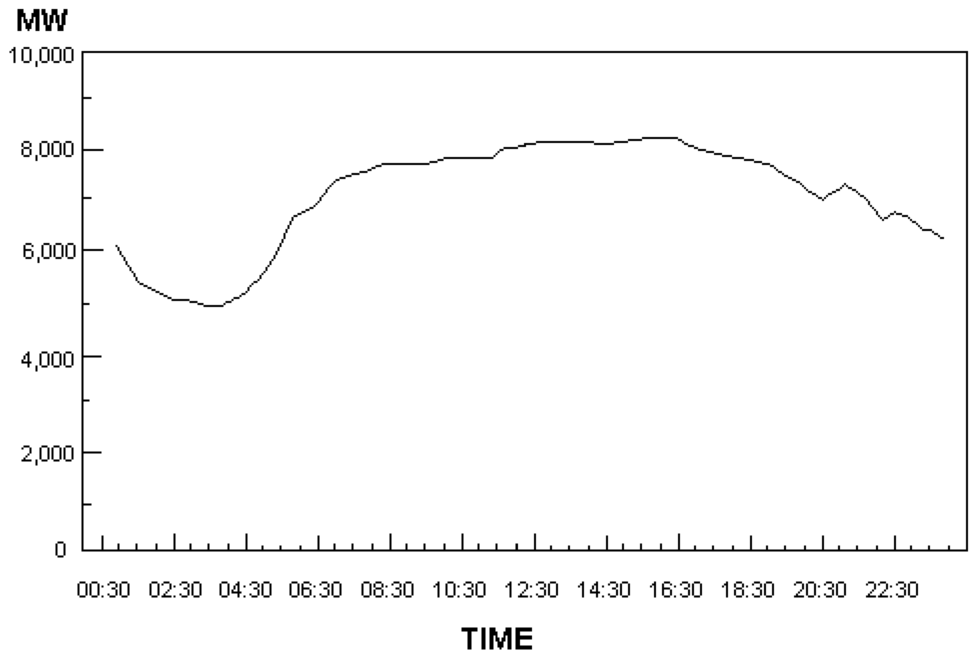


Figure 5.1(b): Illustrative summer load trace for New South Wales



Note: Based on observations for 4 Aug 1993 and 3 Feb 1993.
Source: NGMC (1994c, p. 5).

One indication of the demand-supply balance is given by figures in Table 5.1. They suggest that capacity in other states may not have a large margin over demand at peak demand times. This is even more likely if allowance is made for withdrawals of capacity that occur from time to time, for reasons of equipment failure and maintenance. The Victorian ESIRU said that according to its estimates:

> ... the regional capacity surplus in NSW is estimated at around 2,000/2,500 MW, while that in Victoria, after the completion of Loy Yang B2 is around 500-800 MW (Sub. 30, p. 8).

Table 5.1: Capacity and peak demand

Region	*Peak Demand MW 1993-94*	*Capacity[a] MW June 1994*
NSW	10 433[b]	12 176
Victoria	6 200	6 985
Queensland	4 570	6 283[c]
South Australia	1 900	2 247
Snowy		3 740

a Does not include private generation. Total ESAA private members' production for four states (including Gladstone) is equal to 2276 MW.
b Includes the ACT.
c Includes dedicated capacity associated with Gladstone Power Station. Queensland Electricity Commission (1994) rates the capacity of the system without Gladstone as 4428 MW.
Sources: ESAA (1995); Victorian peak demand from Culy and Read (1994, p. 9).

In commenting on the need to provide additional interconnection capacity to carry additional exports into New South Wales, it went on to say:

> ... only a modest level of potential surplus capacity from Victoria is available to take advantage of any increased link capacity (Sub. 30, p. 8).

If most capacity from other areas which has the potential to underbid New South Wales generators is in use, bids from generators in New South Wales could be decisive in the national electricity market. That is, if New South Wales generators collectively controlled most of the additional capacity that would be called on in the peak, they could collectively produce a more favourable price outcome than otherwise. BHP noted that:

> Under the national grid rules it is the bid of the last dispatched plant which sets the price in any region. This means that unless interstate suppliers can supply 100 per cent of the NSW market, Pacific Power has the ability to set the marginal price at all times of the day. This proposition holds true based on the proposed rules with the assumptions that Pacific Power operates as a single portfolio bidder into the national market and that there are significant transmission constraints into the NSW region (Sub. 21, p. 1).

A complicating factor in assessing the scope for market power in the peak, however, is the role of Snowy. Snowy can operate only for limited periods (see Chapter 3) and consequently is most profitable when used in the peak.

Snowy has the capacity to deliver substantial quantities of electricity to New South Wales for short periods. Potentially it could supply an amount up to the capacity of the link to New South Wales, which could be of the order of 3000 MW (relative to peak demand of the order of 10 000 MW).

In the past, Snowy's scope to do this has been restricted by policies governing the sharing of its load among New South Wales, Victoria and ACT and by the fact that very little pumping has been undertaken. However, with the corporatisation of Snowy, these policies are likely to change. If a large amount of Snowy electricity can be sent into New South Wales when prices rise, price differentials between New South Wales and Victoria are likely to be minimised when Snowy is operating, unless loads are very high.

Within its output constraints, Snowy can be thought of as arbitraging price differentials between New South Wales and Victoria, with the result that price differences will not have the potential to occur until either Snowy is at full production or the interconnections in each direction are congested. CitiPower Ltd said:

> Snowy sits between the Victorian and NSW markets, and will set its bid prices according to which ever regional market has the highest prices. Through this mechanism, it is conceivable that Pacific Power will dictate prices throughout the market, as Snowy follows its bidding regime (Sub. 24, p. 4).

In practice if Pacific Power did exercise its market power to raise price, there would be pressure for additional generation capacity to be brought on stream everywhere in the national grid to take advantage of the situation. To the extent that this occurred, Pacific Power itself would have to reduce its operating capacity.

Outside New South Wales, there would be incentives to minimise outages and generally run capacity 'harder'. As a result, Pacific Power could lose some market share. One way this would manifest itself would be that Snowy's production would be directed to a greater extent than before into New South Wales.

Whether this would then congest the interconnection is not a straightforward question. The national market paper trial did not show many instances in which this did happen, but a number of participants have argued that the trial was not a true reflection of what may happen in the national market.

Off-peak demand

With adequate generating capacity in the national electricity market to cope with the peak, it is clear that competition is potentially likely to be most fierce for the periods in which demand is lowest, that is when there is much greater capacity available.

The likelihood of a more competitive off-peak supply is reinforced by the fact that coal-fired generators are very expensive to start up and shut down. They also have limited flexibility to gear up and down in production. Hydro electricity and some gas turbines are more flexible.

As it turns out, when hydro is fully dispatched, the generators with lowest marginal costs and also with the highest start-up costs are the brown coal generators in Victoria (Table 5.2). Culy and Read (1994, p. 6) described Victorian brown coal generators in the following terms:

> These are typically slow start units which require up to 24 hours from a cold start. They have significant start-up costs and they normally have a minimum loading level, since their incremental costs increase significantly when the unit output drops below around 60%.

This suggests that they are likely to be run fairly intensively during the off-peak, providing a brake on any non-competitive price setting that might occur in New South Wales at that time (within the limits of the interconnection).

Shoulder demand

Pacific Power could also have significant market power at the shoulder period of demand. At this time, when Snowy is not operating continuously, but demand is not necessarily at its lowest level, a group of generators such as Pacific Power may have scope to benefit by acting in concert. The Snowy Mountains Hydro-Electric Authority believes that:

> ... Pacific Power will have the ability to set the price in the region for much of the time. Snowy will not be a significant player in the spot market at shoulder and off-peak times (Sub. 16, p. 3).

A further complicating consideration is that Victorian production can at times be diverted to South Australia, and this reduces its capacity to serve the New South Wales market. This is clearly most likely at times of South Australia's peak, which will not necessarily coincide with the peak in Victoria and New South Wales.

Table 5.2: Operating characteristics of major generators

Station[a]	*Sent-out capacity MW*	*Incremental cost $/MWh*	*Start-up cost $*
NSW			
Bayswater	2 503	13.1	1 500
Eraring	2 503	14.3	1 600
Mount Piper	1 251	12.2	2 000
Vales Point	1 251	14.8	2 000
Liddell	1 896	14.7	2 000
Wallerawang	948	14.8	1 500
Munmorah	626	14.3	1 500
Victoria			
Loy Yang A	1 819	7.0	14 000
Loy Yang B	909[b]	7.0	14 000
Newport	480	22.5	4 000
Yallourn W	1 262	7.5	8 000
Hazelwood	1 299	7.7	6 000
Anglesea	142	4.5	6 000
Jeeralang	432	25.0	200
Queensland			
Callide B	664	8.1	n.a.
Gladstone	1 593	10.8	n.a.
Interruptibles	300	250.0	n.a.
New gas fired plant	598	44.0	n.a.
New coal fired plant	664	9.5	n.a.
Stanwell	1 327	9.5	n.a.
Swanbank B	474	11.3	n.a.
Tarong	1 327	9.0	n.a.
SA			
Torrens Island B	808	18.0	2 000
Torrens Island A	483	19.0	2 500
Playford B	240	19.0	1 500
Northern	495	13.2	2 000
Dry Creek	145	26.8	600
Snowy			
SMS	3 975	24.0	0

a Excludes hydro plant other than Snowy, and generators less than 100 MW.
b From 1996 when the B2 unit of 500 MW is available.
n.a. not available
Sources: London Economics (1994d, 1995).

5.3 How might generators behave in the presence of market power?

An important question is what strategy Pacific Power might follow to influence market price, and what implications this might have for other generators and consumers. The yardstick for measuring the extent to which market power is exercised is the extent to which prices might differ from those in a competitive market.

Possible strategic behaviour

If capacity were to remain fixed, it is possible to anticipate likely pricing behaviour on the basis of some fairly specific assumptions about how a generator with market power might behave. A number of possible strategies are noted in Box 5.4.

Box 5.4: Some short term gaming strategies

1. **Price up:** The marginal station can increase its offer up to the offer price of the first extra-marginal station to increase pool prices without affecting the merit order, or sacrificing generation volume.
2. **Challenge up:** A station can price up above the next station in the merit order, sacrificing quantity for a possible increase in pool prices.
3. **Challenge down:** A station can price below the next station in the merit order in order to increase generation, but at a possibly lower pool price. The challenging station can consider the outcome of counter challenges from the station which has had its output reduced in this move, and avoid challenging down when it calculates that the challenge would eventually have to be abandoned.
4. **Reduce Quantity:** Infra-marginal stations can reduce the quantity offered in order to bring a more expensive station on to the margin, and so increase spot prices on the remaining MW. Note that this strategy is very similar to the challenge up strategy in that a decrease in output is traded off against an increase in spot price.
5. **Increase Quantity:** Infra-marginal stations generating at less than full capacity can increase their quantity offered in order to increase generation, but at the risk of lowering spot prices.

Sources: Culy and Read (1994, pp. 15–16), and Eastern Energy (Sub. 32, p. 2).

As noted previously, one factor facilitating the use of those strategies in the electricity market is that there is substantial knowledge among participants about the cost structures of competing generators. In addition, in the national market, bids are to be published, so generators will also be well informed about rivals' strategies.

There is clearly a diversity of possible strategies that a possessor of market power might follow, and forecasting the outcome in the market when a number of participants hold some degree of market power can be very complex. The Victorian ESIRU said:

> There is a risk in placing too great an emphasis on debating the extent of market power that will be exercised or the mechanisms which would be used. Our analysis indicates that there is a multiplicity of different scenarios involving different cost assumptions and market strategies (Sub. 30, p. 23).

In essence, all these strategies are directed to improving profitability in a situation in which players can influence market price. Where firms have other objectives, such as maximising their size or the quality of their assets, the range of possible strategies expands further.

High prices: strategies to increase revenue

A commonly used hypothesis about behaviour is based on the so-called 'Cournot' game in which each participant treats the output of others as fixed, while bidding a price (and quantity) which maximises its own profits (see Nicholson 1985, p. 590). Essentially, participants withdraw some capacity to obtain a higher price, with the extent of their supply reduction based on their ability to influence price in the segment of the market which they 'control'. This hypothesis was the basis for the simple example discussed earlier in the chapter (Box 5.3).

If, in the national market, Pacific Power were retained as a single entity, there would be quite different degrees of market power for different generating companies. Whether in this situation generators other than Pacific Power would find it feasible to attempt to influence market price is a matter for detailed modelling and, ultimately, outcomes in the market. What does seem clear is that if anyone were to have market power, an aggregated Pacific Power would be the most likely candidate, at least at certain times.

Low and variable prices: strategies to discourage rivals

In general terms, the most likely strategy for an electricity supplier having market power is simply to bid prices somewhat higher than would otherwise prevail and sacrifice a certain amount of market share.

However, at times a generating firm which has caused market prices to rise may wish also to discourage customers and potential entrants who may be planning to take advantage of the higher prices by providing more capacity. The difficulty that the holder of market power faces is knowing how high to raise prices and for how long, and then how much to cut price or destabilise price to deter entry.

Influencing price variability

A number of participants have suggested that a generating group with market power might attempt to make prices more variable.

First, it has been argued that the group might do this in an attempt to create uncertainty for potential entrants and for purchasers. In this way a potential entrant may feel that although prices on average will be above production costs in the electricity market, they may not be so at crucial times associated with entry.

A particular variant of this strategy was thought to be observed in the British market, with spot price volatility being induced just before major contracts were about to be signed. This was said to signal to potential entrants and customers that prices could be manipulated and was intended to encourage adherence to the contract market. Such behaviour could be very difficult to police by regulatory authorities.

Moreover, if the prices that eventuate can be made to vary unpredictably, adding to uncertainty, operators in secondary markets such as the forward market and the inter-regional hedge market may be discouraged. CitiPower said:

> Pacific Power's ability to set the Pool price can make these instruments [inter-regional hedges] extremely risky for arbitragers, who might otherwise add important liquidity to the market. The knowledge that Pacific Power can determine power flows across the interconnector will increase the risk premium associated with these instruments and thereby discourage contracting across inter-State boundaries.
>
> The same problem arises in the short-term forward markets centred on the pool. Pacific Power could refuse to participate, reducing liquidity, hence raising the risks and costs of operating in the market (Sub. 24, p. 5).

Second, it has been suggested that Pacific Power may create uncertainty by not participating in arrangements to share risk among generators (eg arrangements by which small generators agree to cover each other for times when market prices are driven extremely high). Such events can be extremely costly for small generators if they have contractual obligations to supply, but for reasons of equipment failure or other causes are unable to generate.

In this situation, large generators, such as Pacific Power, could potentially self-insure. If so, the remaining generators could conceivably be penalised in their own efforts to insure with each other because of the absence in their arrangements of a major proportion of generation capacity. If Pacific Power were to stand outside, or raise the price of its participation in such mutual insurance schemes and this were to increase the risk suffered by small generators, entry also may be discouraged. (This is elaborated on in Appendix C.) The Victorian ESIRU said:

> ... if Pacific Power remains aggregated it could either decide not to participate in such a scheme (ie refuse to provide capacity support with the other market participants) or it could exercise an unfair commercial advantage in its participation. It is important to note that the costs of generators contracting to participate in the generator co-insurance scheme are not high, provided they all participate (Sub. 30, p. 50).

Third, it has been argued that Pacific Power might be able to exploit the inter-regional hedging market to force competitors to purchase cover against risk which Pacific Power itself would not face.

The operation of the inter-regional hedging market itself is complex. The essence of this argument, however, is that Pacific Power would be able to predict when pool prices would differ between regions, because it has it in its power to determine when the interconnection would be congested. Other participants would not be privy to this knowledge, and thus be forced to purchase insurance in the form of the inter-regional hedge.

The significance of this argument depends partly on the likely costs of hedging (which are perhaps not high relative to other costs). There is also a question as to how much Pacific Power itself would need access to the hedging fund if, for reasons within its control or not, the interconnection became congested.

Keeping prices low

It is also suggested that Pacific Power may attempt to drive prices very low at off-peak times in an attempt to force other generators to decommit (be withdrawn from operation), at their cost.

It is difficult, however, to see how this could be in Pacific Power's interest. In practice, Pacific Power faces lower costs on decommitment than do the Victorian generators. Decommitment in these circumstances would be based on an auction in which continuing generators pay the generator which is decommitted. If Pacific Power were to keep its generators operating instead of those in Victoria, it would be forced to pay the Victorian generators an amount greater than the costs of its own decommitment.

Nor would it appear to be in Pacific Power's interest to force prices consistently low in an attempt to cause existing generator companies to fail. While there is no barrier to the failure of an operating company, the fact is that the generating capacity, once built, will be more valuable to whoever owns it when operating than when not (so long as variable costs are covered). As Pacific Power points out, company failure will simply result in the assets being sold at a price which achieves subsequent viability and being operated by another owner (see *Incentives for Predatory Pricing*, Sub. 25, pp. 56–7).

The greatest disincentive to predatory pricing is that while prices are low, the predator itself receives low returns. However, in the transition to the national market some of Pacific Power's output will be sold at guaranteed prices under vesting contracts. The Victorian ESIRU argued that this increased the probability of predatory pricing occurring:

> ... Victoria is concerned that Pacific Power may be tempted to pursue aggressive price-cutting strategies for a period, while its customer base is predominantly covered by vesting contracts (Sub. 30).

The impact of such behaviour will be less the more other generators in the national electricity market also have vesting contracts with their customers. The Commission understands that vesting contracts will be phased out by 1999–2000.

Another claim made to the Commission is that Pacific Power would favour low prices because 'take or pay' contracts had been signed for unreasonably high levels of coal supply. This is said to have had the effect of requiring generators to maintain relatively high levels of production, forcing prices to very low levels. Put another way: because the coal must be paid for whether used or not, the marginal cost of production is very low. The Victorian ESIRU said:

> ... our understanding is that Pacific Power currently has take or pay contracts for over 10 million tonnes per year (around 40% of the total of its coal contracts) with mines which are owned by Pacific Power. We also understand that without these contracts, Pacific Power's generation operations would not be in a position of having take-or-pay obligations that are excess to its requirements.

> Without such obligations between one arm of Pacific Power and another (which we understand arose in 1990/91 partly in connection with an attempt to sell the mines), it seems likely that bid prices by Pacific Power would reflect true avoidable cost of generation. This perhaps explains why Pacific Power's stated production costs under the Interconnection Operating Agreement have fallen from over $11 per MWh in 1990, prior to the signing of these contracts, to $3.42 today (Sub. 30, p. 1).

In response, Pacific Power stressed the need for long term contracts:

> When these contracts were established, Pacific Power had an obligation to provide reliable electricity supply to New South Wales electricity consumers. For 1994/95 the take-or-pay contract quantity represented 91% of Pacific Power coal consumption, demonstrating that the take-or-pay obligations are not excess to current requirements (Sub. 36, p. 2).

It went on to argue that the price charged properly reflected the costs of coal:

> The current Pacific Power opportunity interchange price quoted under the Interconnection Operating agreement (IOA) is based upon an avoidable coal contract increment for the mines supplying Pacific Power ... it could easily be either a private supplier or a Powercoal mine — there is no connection between this price and the establishment of contracts with Powercoal in 1990/91, which was done to commercialise the relationships and ensure that coal supplies from Powercoal were competitive with private sources.
>
> In a national market, market forces will dictate the appropriate action to be taken in relation to coal supplies, whether that action be to terminate contracts, enter into new contracts or stockpile coal if necessary (with associated holding costs to be considered). Market bid prices will bear no relationship to IOA prices, because they apply to limited incremental quantities of coal and, if applied to all energy production, would not recover the average coal costs, let alone other operating and business costs (Sub. 36, p. 3).

As also discussed in Chapter 4, there is little evidence that over-contracting for coal will be a long term outcome. 'Take or pay' fuel contracts are common in the electricity industry and have the effect of reducing risk for both purchaser and supplier. While Pacific Power may have some contracts which the industry regards as inadvisable, coal supplies are now tendered on a competitive basis. Existing 'take or pay' contracts phase out from 1996. Provided Pacific Power does not come under political pressure to divert from its commercial objectives in signing contracts for coal supply, it could be expected not to undertake contracts that will reduce its profits.

This does not mean that New South Wales generators may not at some stage misjudge the market and order excessive supplies of coal. Like all businesses it would have to pay for such misjudgments. However, it does not seem likely that contracts for excessive coal would be a factor that would cause market power in an aggregated Pacific Power to be dissipated. Nor would there be a systematic tendency to oversupply for this reason by disaggregated generators.

Implications of market power for pricing over time

The exercise of market power by a firm concerned with its profitability is aimed at increasing prices. The firm's main concern is to obtain the required return on its assets. But there is a good deal of uncertainty as to what, in practice, is the best strategy to bring that about, and what prices at a particular time might be needed to achieve it.

The incumbent firm knows that the higher its prices, the more likely they will, in time, attract entrants and erode its profits. Against this, however, it has a weapon: by at times pricing low and only recovering its variable costs it has the power to discipline rivals. (The use of sunk costs as a barrier to entry is discussed in Chapter 4.)

From the point of view of the firm therefore, the broad strategic issue is when to price high (and by how much) and when to price low (and by how much) in order to make best use of its market power.

Pricing with excess capacity: market power puts a floor under prices

While the current situation of excess capacity persists, it seems likely that a firm with market power could raise prices above short run marginal cost.

This is because when there is excess capacity, the *competitive* market price would be likely to be well below the price required for a new entrant to recover costs. Essentially, in a competitive market with excess capacity, firms with installed capacity would not be obtaining a normal return on that capacity. But such a return would be required by an entrant. A firm with market power could, therefore, price up to (or just below) the level which would reward entry with only limited threats to its market share from entrants.

Pacific Power itself indicated that it thought that a limit to the price that might occur in the market would be set by the price of gas entry (Sub. 25, pp. 22–43).

How high would prices go?

The key strategic issue for the firm with market power then is to what extent it might raise prices above the level at which an entrant might obtain a normal return. This is relevant for both the current situation of excess capacity (how much further might prices rise above the relatively safe increment discussed above) and for situations in which demand and supply are in better balance (what premium over the competitive price could a firm with market power charge).

If the firm with market power is to make use of that power in either of these situations, the associated price increases will almost certainly eventually induce entry to some degree, and cause the incumbent to withdraw capacity. But the entry may be delayed for long periods, depending on the situation in the industry and the behaviour of the incumbent.

It is almost impossible to predict the level of prices that might be set in this situation. In principle the incumbent may do any of the following.

- Set prices high and make as much short term profit as is possible in the expectation that entry will come steadily but slowly.
- Set prices close to the competitive level in the expectation that otherwise entry would diminish any inflated prices quickly. This level of pricing would allow the incumbent to continue to provide capacity and not have its market share eroded. The consequence of this is that it would also receive little benefit from its market power.
- Set prices between these two levels in the expectation that the price set will influence entrants' expectations of future prices. In this way the incumbent may hope to influence the rate of entry.

One important consideration in evaluating these strategies is the speed with which new generation plants could be established. In the electricity supply industry, the most likely form of entry is through gas-fired plant which can be installed relatively quickly (the construction phase taking two or three years — see Box 4.1) and at a relatively small scale. However, for a major impact on prices to occur, a number of such installations would be required and there is a question as to how quickly multiple entries could be achieved. For example, to reduce Pacific Power's minimum market share in 2005 from about 60 per cent to 40 per cent in New South Wales would require about 2500 MW of capacity, or perhaps as many as six combined cycle gas turbine power stations. Each entrant would be adding to overall capacity with the risk that this would lower prices if the dominant supplier's market power was eroded sufficiently.

Against this, gas-fired generating plant can, at some cost, be moved from one site to another. Thus the cost of setting up in competition is not necessarily entirely sunk — as it was when entry could only be effected with coal-fired generators — and the risks of entry are lowered.

It is also true that entry did in fact occur very quickly in the England and Wales market (see Newbery 1995, p. 14).

Pacific Power itself operates mainly coal-fired plants. The costs of these are sunk and, as a result, provide a clear threat to entrants (see Chapter 4). This means that Pacific Power has no other possible uses for these assets and could, if necessary, keep them operating at prices that recovered variable costs only. If it did so, entrants would not recover their fixed costs.

Moreover, Pacific Power need not limit itself to its existing level of capacity. Entrants would feel even further threatened if Pacific Power added to its potential generating assets, particularly if they were lightly used or not used at all (that is kept in reserve against the possibility of entry). Even discussion and planning for additional capacity (especially immoveable coal-fired capacity) could discourage entrants in this situation.

While a period of very low prices would hurt the incumbent as well as the entrant, the incumbent may feel that this is an investment well worth making if it discourages future entrants. This, of course is also evident to a firm contemplating early entry, and the mere possibility of a punitive price offensive may be decisive in discouraging entry.

Another relevant factor is the way in which entrants react to current prices as predictors of future, post-entry prices. One possibility is that current prices provide little information about future prices and, moreover, are seen to provide little information. Whatever the current price, entrants might assume that the incumbent has the power to lower prices significantly if they do enter. Moreover, entrants may be unsure about the behaviour of other possible entrants and the effect that their entry would have on market prices. The more this is so, the more scope the incumbent has to lift prices.

Also important is the role of contracts. In the presence of a high market price, entrants may feel that they would wish to sign a long term contract to enter the market to protect the value of their long-lasting assets. In principle, if market power is being exercised, there will be a significant margin between the market price and the cost of provision which can be shared between entrant and customer through a contract.

The customer may nonetheless have some reservations about such a contract. For example, in a situation in which entry is occurring at significant levels, the customer may expect the market price to fall dramatically over time. This will be especially so if the incumbent is left with large blocks of capacity after entry for which there are likely to be few customers. In this situation the customer may prefer not to commit to a long term contract.

Summing up: pricing behaviour

There is a good deal of uncertainty about the level of prices that Pacific Power might choose if it had market power and about the way in which those prices relate to the prices that would otherwise prevail.

Some of the uncertainty has to do with Pacific Power's own objectives as an organisation. As a corporatised entity it would be expected to pursue commercial objectives, which implies a concern with profits. However, it is possible for a culture concerned with market share and asset accumulation to dominate in a government business enterprise of this type. To the extent that Pacific Power behaves in a less than fully commercial fashion, prices and profits may be lower than is assumed in looking at the exercise of market power in conventional terms.

However, assuming that Pacific Power does behave commercially, there are a number of relevant issues.

In the first place it has been shown that even if Pacific Power chooses to price modestly, say below gas entry price, this could still — if there is excess capacity — constitute a significant premium over the price that might otherwise prevail. A key question therefore is about the likely time at which excess capacity might be eliminated.

Secondly, if Pacific Power chooses to price highly, there is a question as to how far it would price above the gas entry price, excess capacity or not. It is possible, for instance, that current prices provide entrants with poor signals about future prices. In that case a short run strategy would be to price high to attempt to gather as much profit as possible as quickly as possible (subject to regulatory oversight).

However, a high price, if maintained, would eventually cause some consumers to consider non-electricity options. Moreover, Pacific Power might also be concerned about the attention that a very high price might draw from the Government Pricing Tribunal or the ACCC.

5.4 Results of economic modelling

Modelling the circumstances in which one of the market participants can influence the market price generally requires information about:

- the costs of operation of individual generators;
- the costs and limitations of transmitting electricity over different parts of the grid;

- the likely demand for electricity in various areas; and
- assumptions about the pricing strategies of generation operators.

A number of such modelling exercises have been undertaken. (Results from broadbrush modelling by Pacific Power have been discussed earlier — see Box 5.3). However, the results must be interpreted carefully because, as well as differing in assumptions about cost, pricing, and the technical operation of the grid, the jurisdictions included differ between models. Particular points of difference include the extent to which Queensland is included and assumptions about how (and in who's interest) the Snowy is operated.

These models also tend take a static view of the market. That is, a fixed level of demand is assumed, with pool prices having no effect on the level of that demand. Similarly, entry of new generating capacity is not determined behaviourally within the model, but rather assumptions about likely entry must be fed in. These are significant shortcomings for consideration of the longer term impacts of market power.

London Economics' simulations of the national market for the NGMC and the New South Wales Treasury

As part of its evaluation of the NGMC national market trial, London Economics undertook some simulation modelling of likely outcomes in the national market (London Economics 1994). The national market was taken to include New South Wales, SMHEA, Victoria and South Australia.

The SMHEA was assumed to operate independently of New South Wales and Victorian generators. No allowance was made for any intra-regional constraints — particularly in New South Wales — that might be expected to enhance opportunities for strategic behaviour.

London Economics stressed that their analysis was not exhaustive and their conclusions tentative.

The test of market power was considered to be whether bids above marginal cost could lift revenue for New South Wales generators as a group. London Economics found that revenue rose when bids were between \$5/MWh and \$10/MWh above marginal cost and fell thereafter. It concluded:

> Pacific Power, the NSW generator, clearly has market power and, absent safeguards, would be able to use this power to increase its revenue. The interconnection with Snowy and Victoria, and the spare capacity that it might export to NSW, is not sufficiently large to discipline this market power (London Economics 1994, p. 78).

London Economics extended this modelling in late 1994 in a study for the New South Wales Treasury. In this study it adopted explicit behavioural assumptions about how generators might behave. In particular, it modelled the outcomes under Cournot bidding (see previous section).

The simulations led to little congestion of the New South Wales–Victoria interconnection.

According to the study:

- When all states adopt Cournot pricing, peak prices in the market rise significantly, from about $40/MWh to about $80/MWh. Off-peak prices do not rise substantially — New South Wales withdraws some capacity in exchange for higher prices and higher revenue, and Victoria exports to New South Wales.
- If New South Wales alone adopts Cournot pricing, the simulations suggest that New South Wales output falls significantly and is made up with flows from Victoria and South Australia. Average pool prices rise from about $38/MWh to $48/MWh.

London Economics reported concerns that this latter scenario could result in increased regulatory action, because of the increased profits to generators outside New South Wales. It suggested that a more collusive outcome among states may be more plausible. One such scenario resulted in average pool prices rising from $40/MWh to $50/MWh. There is, however, considerable doubt about the likelihood of durable collusion across state borders, especially given the disaggregation of generators that has occurred in Victoria.

Victorian Pool Price Working Group modelling

The Victorian ESIRU reported to the Commission the results of the Victorian Pool Price Working Group. The Working Group was established to define assumptions and scenarios and to analyse outcomes for the purpose of setting a price path for vesting contracts and a valuation/capital structure for generators.

In this simulation, it was assumed that the SMHEA was corporatised and operated independently. The study compared market prices in a national market in which Pacific Power was retained as a single entity with prices if Pacific Power is disaggregated into three businesses. The simulations reported price outcomes for the period 1996–2000.

In the simulation in which Pacific Power remained aggregated, Pacific Power increased market price, but sacrificed some market share. However, the loss of market share was small because of the lack of surplus capacity in Victoria and link constraints. The Working Group hypothesised that Pacific Power could price up to the level which would provide opportunities for new gas-fired plants.

In the simulation in which Pacific Power is disaggregated, prices were initially driven very low, which forces some capacity in New South Wales to close. At equilibrium, low prices persist, with any attempt to raise prices disciplined by the recommissioning of mothballed plant. Low prices persist until around 2005. In this scenario there is very little opportunity for one participant to manipulate prices.

The comparison of market prices between the two situations is shown in Table 5.3. There is clear evidence of differential market power.

Table 5.3: Victorian Pool Price Working Group model results: average scenario pool prices, 1996–2000

($/MWh)

Scenario	*On peak*	*Off peak*	*Average*
Aggregated Pacific Power in national market	52	26	39
Disaggregated Pacific Power in national market	32	18	25

Source: Victorian ESIRU (Sub. 30, p. 60).

London Economics' simulations for this project

In association with this project, the New South Wales Government financed a consultancy by London Economics into the possible market power of Pacific Power in the national market.

The model

The model included Queensland, via Eastlink, and treated the SMHEA as an independent generator. No explicit assumptions were made about bidding behaviour. Instead, a range of possible bids for each participant were fed into the model and the results tested for stable equilibria — that is, points from which each participant would obtain a lower profit if it separately varied its pricing behaviour (known as Nash equilibria).

In the model, demand was considered in terms of six different categories of time, based on demand profiles at three different times of year for both business and non-business days:

- cold business and cold non-business days (based on average demand profiles in June and July);
- mild business and mild non-business days (based on average demand profiles in September and April); and
- hot business and hot non-business days (based on average demand profiles in January and February).

The model predicts which generators will be running at each half hour on these typical days, based on the bids they make. It then calculates their profit, based on the prevailing pool price. The pool price is determined as it would be in the national electricity market; that is, by the intersection of demand with the merit order of bids (see Section 5.1.)

Generators are not constrained to bid their costs (which are modelled in some detail in the model), but may bid multiples of their marginal costs. A competitive outcome occurs if participants find it in their individual interests to bid their marginal costs only. (That is, under competition, the structure of the market is such that if any generator raises its bid above marginal costs, it loses market share to such an extent that it is worse off.)

Participants with market power may bid high to influence the SMP. In that case they would generally also sacrifice market share. In some circumstances, however, they may bid low— because if there were another generator setting the price, this would enable the low bidder to sell maximum volume.

The results of simulations

When the model is run in the context of the four-state market, an aggregated Pacific Power is shown to have market power under almost all circumstances. This result is not dependent on the capacity of the interconnection.

The model shows that Pacific Power would increase its returns by bidding well above marginal cost. Given the behaviour of other generators, it would not be able to improve its profits by a different (lower) bid, and neither could the other competing generators.

The result holds true under a variety of circumstances. The equilibrium would involve high bids (that is, bids based above those sustainable in a competitive market) from Pacific Power even if:

- generators in South Australia bid as a group and Queensland generators do the same, but generators in Victoria bid individually;
- generators in South Australia, Queensland and Victoria each bid as a group;
- Eastlink were not to function and there were to be effectively a three state market;
- there was 800 MW of new entry into the New South Wales market (although, in this situation, the output and profits of Pacific Power would fall by about 15 per cent, relative to the first simulation above);
- there was 3000 MW of new entry (although this does cap the Pacific Power bid at a lower level in some circumstances, for example, on a hot business day Pacific Power would find itself losing output and profits to the entrant and would reduce its bid to reduce the impact of its prices on demand);
- the interconnections are expanded by 30 per cent (although Pacific Power's output and profits are reduced, because imports are larger); and
- the interconnection constraints were completely removed (this would have a significant impact on generators in South Australia and Queensland which would bid low in order to export more and, in consequence, Pacific Power's output and profits would suffer markedly — but Pacific Power would still find it worthwhile to raise price to exploit residual market power).

If Pacific Power were split into two groups, some changes would occur in the four-state market. There is no evidence of competitive behaviour emerging in the simulations, but the two Pacific Power groups would make high and low bids together — if one bids high, the other bids low to maximise output at the high price. When the groups are of equal size, the group which bids high is indeterminate. With unequal groups (with one large generator in one group and all of the other stations in the other), the small generator tends to bid low and maximises output because the market power is held by the large group. Two generating groups, however configured, reduce market power by a small margin only.

Another set of simulations investigated the effect of disaggregating Pacific Power into three groups (as described in Table 5.4). The effect is to ameliorate, but not eliminate, Pacific Power's market power. One generator group tends to bid twice marginal costs while the other two bid their marginal costs. The price in the market is capped by the threat of imports from Queensland, and as result market prices fall from \$43/MWh to \$26/MWh. This is not, however, a fully competitive outcome.

Table 5.4: Basis for simulated disaggregation of Pacific Power

Station	*Sent-out capacity*
Group 1	
Mount Piper	1 251
Vales Point B	1 251
Wallerawang	948
Total	**3 451**
Group 2	
Bayswater	2 503
Liddell	1 896
Total	**4 399**
Group 3	
Eraring	2 503
Munmorah	626
Total	**3 128**

Source: London Economics (1995, p. 55).

Summing up

The models described here are broadly consistent in that they show evidence of market power when Pacific Power is retained as a single entity and demonstrate a substantial reduction in that power if it is disaggregated sufficiently. And the reduction in market power is reflected in a much lower market price. Like all models, however, they make simplifications and abstract from reality. In these cases the key features of a market in the longer term which do not form a part of the models themselves are the impact of any entry to the industry— which is treated exogenously— and the responsiveness of consumers to price changes.

5.5 The costs of market power

If prices were elevated by the exercise of market power, losses would be generated for society in two main ways.

- Prices would be higher than the true cost of resources used in generation. This would create incentives for consumers to substitute to forms of energy which actually have a higher cost of supply.
- There would be likely to be an unnecessary provision of new generation capacity. The firm with market power must accept some erosion of its market share by raising prices, and this is likely to involve entry. Entry would bring with it new capacity when the old capacity could be adequate. Associated with this would be the scrapping or mothballing of some existing plant.

In addition it is possible that some element of the higher price would be consumed in less than efficient running of existing plant, which could lack competitive disciplines.

Part of what follows is an attempt to put some broad numerical values on the costs associated with market power. These values should be regarded as broadly indicative rather than estimations. They are not precise — there is uncertainty about the impact of market power on different consumer groups, the different impact of prices at different times of day, and the costs associated with different possible entry scenarios. However, the illustration can help provide some quantitative guideposts for thinking about the cost of market power.

The price level when market power is exercised

The cost of market power is dependent, among other things, on the market price which eventuates. In particular, it is dependent on the extent to which the price exceeds the level that might hold in a competitive market.

The probable absolute price level is uncertain. However, it seems very likely that, in the short run situation of excess supply, at least until the year 2005 (see Box 5.1), if market power were exercised the price would be at least as high as the gas entry price. This could imply an average price of at least 50 per cent above the possible competitive price (making some allowance for the fact that excess supply would gradually decline over the period).

Current expenditure in the region defined as the four-state national electricity market is about $10 billion (ESAA 1995, p. 46). The generation sector accounts for 65 per cent of total costs (Sub. 15, p. 2). Even allowing for a fall in prices from current levels of 20 per cent, consumers might pay a premium of about $1.75 billion per annum (in 1994 prices) above the amount that they would have to pay in a competitive situation.

In addition, however, if a firm possessing market power wished to use it to obtain still greater profits, the price would exceed the gas entry price both for the period of excess supply and beyond.

Losses to consumers

A higher than necessary price does not necessarily imply large losses to society as a whole from the exercise of market power, although it clearly disadvantages electricity consumers. For example, a high price might simply have the same effect as a tax on consumers of electricity which provides revenue to government through dividends from the generators. This revenue could then permit taxes elsewhere to be lower than otherwise.

However, if the higher price causes consumers to alter their behaviour, then net losses in welfare (known as 'deadweight' losses) are created. To the extent that consumers use less electricity, they are obliged to turn to alternatives that have higher costs to society. For example, an alternative energy source which cost 50 per cent more than the competitive price of electricity, would become more attractive to consumers if the price of electricity rose by that proportion when market power is exercised.

But despite an increase in the *price* of electricity, the *cost* to society of supplying it would remain considerably less than the cost of substitutes. So to the extent that people switch to the alternative energy source, additional costs of about 50 per cent extra are imposed in energy consumption.[1]

A measure of the extent to which this substitution would occur is the demand elasticity, which has been estimated in a range of 0.65 to 1.70 in the long run (Strong 1995, p. 32). In the short run, elasticities are lower. Arguably long run elasticities are more important as consumers have no reason to expect that prices will quickly fall from levels that incorporate a premium reflecting the exercise of market power. However, for the purpose of this illustration a conservative range of values from 0.25 to 1.0 is adopted.[2]

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[1] A caveat is that the substitutes must have similar levels of taxation for this to be an accurate measure of the social cost to consumers of market power.

[2] Newbery (1995) assumes a value of 0.5 in his analysis of UK market power.

Using this measure of consumers' responsiveness it is then possible to estimate the additional costs generated for society by those responses.[3] This implies a deadweight loss for consumers from the exercise of market power in the range from $70 million to $280 million per annum.

These losses would be incurred for as long as the higher price is maintained through the exercise of market power.

As noted in an earlier section, it is difficult to predict the precise magnitude of the addition to price that could be attributed to market power (although it is unlikely to be negligible, and may well be above the 50 per cent premium that forms the basis for this illustration). While excess capacity persists, however, it seems likely that a 50 per cent premium is the minimum that could be expected. Thus, even if the field of view is restricted until 2005, substantial losses in consumer welfare could be anticipated.

Losses in production

Other losses occur if new plant which would add to excess capacity is introduced in response to elevated prices. Essentially, new capacity is the entrants' response to higher prices, which the incumbent must accommodate by reducing its use of capacity in order to maintain high prices.

It is difficult to predict the rate of entry. In the United Kingdom (see Box 5.5) entry of gas-fired plant was rapid. There it was concluded that about the half the capacity of 20 per cent which was introduced could have been delayed (see Newbery 1995, p. 14). However, this is not necessarily a good indicator for Australia, since, as has been noted, the behaviour of the incumbent is very important in determining entry and difficult to predict.

There is no doubt that, after 2005, significant additional capacity (probably gas-fired) will be needed. Taking that as given, suppose now that additional capacity is provided by entrants wishing to take advantage of high prices. If the incumbent wishes to maintain the prevailing high prices, some market share must be given up to the entrants, and some capacity prematurely retired.

[3] The formula for the calculation of deadweight loss (DWL) in this situation is a function of the elasticity of demand (ε), the expenditure on the product (E) and the proportion (m) of price which represents the monopoly element (see Newbery 1995, p. 2).

$$DWL = \tfrac{1}{2}\varepsilon m^2 E$$

If this additional entry were limited to a modest scale, say 5 per cent of capacity (around 1500 MW), then the cost of allowing market power to be exercised would be the annual cost of the excess capacity for as long as there was excess.

One estimate of the costs of generation capacity (Sub. 30, p. 11) suggests that combined cycle gas generation could cost \$800 000 per MW to build. On that basis, 1500 MW of redundant capacity might have a cost of \$1.2 billion. If the plant were to last for 50 years (an optimistic estimate) this would suggest an annual cost of equipment of about \$25 million per annum for as long as it was excess. (It would be less to the extent that plant could be mothballed and brought into production again at some later stage.)

In addition, the cost of excess capacity should include the interest cost of financial capital required to fund it. Using a conservative real discount rate of 5 per cent, this implies a financial cost of \$60 million.

Box 5.5 The United Kingdom Experience

The generation arm of the Central Electricity Generating Board was separated into three parts in 1990: the fossil fuelled generators were split between PowerGen and National Power, while nuclear power stations were retained in public ownership in Nuclear Electric. The generators were not subjected to detailed regulation, but to the threat of competition from new entrants, as well as actual competition from each other and with imports from France and Scotland (about nine per cent of the total).

The prevailing view is that PowerGen and National Power acted as a duopoly in the wholesale electricity market, setting pool prices about 90 per cent of the time. As the transitional vesting contracts expired, initial offers from the duopolists to the 12 local distribution companies, known as Regional Electricity Companies (RECs), were at unattractively high prices relative to those offered by independent power producers (IPPs) seeking entry with new combined cycle gas turbine stations. These IPPs were able rapidly to combine 15-year gas purchase contracts backed by 15-year contracts to sell base load power to the RECs, enabling the stations to be financed largely by bank loans with a small equity, typically partly held by the purchasing REC.

The duopolists failed to respond to this threat with counter-offers of comparable long term contracts. Whether this was because they feared that increasing their contract cover would reduce their market power, or whether they were anxious not to forestall entry for fear of a charge of predatory pricing, or whether they just miscalculated, will doubtless remain unclear (and all motives probably played their part). The outcome was 'the dash for gas' — a rapid flurry of entry of new generating enterprises based on new plant using state of the art technologies.

The lack of competition in generation led to high prices which induced excess entry, but unfortunately these entrants supply base load power, while the UK pool price is set by mid-merit and peaking stations whose ownership remains concentrated in the duopolists.

Source: Newbery (1994).

Together these figures imply a cost of additional capacity of $85 million per annum. Put another way: the rental costs of excess capacity of 5 per cent would be about $85 million per annum.

5.6 Assessment of the consequences of market power

In the Commission's view, there is scope for an aggregated Pacific Power to exercise market power in the national electricity market. The extent to which prices might be raised above levels that would apply in a competitive market is difficult to specify precisely, but is likely to be significant in the short to medium term.

While capacity remains excessive, it seems almost unavoidable that prices would be above competitive levels if Pacific Power remains as an aggregated entity. During this time, the efficiency losses could be large, even on the most conservative pricing assumptions.

The degree to which market power might be exercised would be partly influenced by the way in which Pacific Power interprets its role as a publicly-owned entity. If it were to proceed to maximise shareholder value, it would exercise it to the full extent. But if it chose to seek market share and build its asset base, as such authorities have done in the past, market power could be moderated.

Entry and its threat are the most important possible disciplines on the exercise of market power after excess capacity has been worked out and the national market becomes fully operational. But it seems unlikely that this discipline could have much effect on the extent of efficiency losses up to the year 2005, and during this time the importance of electricity in consumers' expenditure implies that these losses could be substantial.

Even in the period after 2005, it is difficult to be optimistic about the prospect of timely entry on a significant scale if Pacific Power remains in its current form. To eliminate the extent of market power that currently is held by Pacific Power would require others to invest in generating capacity on a substantial scale. Even if substantial entry did occur and was sufficient to reduce Pacific Power's market share to levels at which it could not exercise market power, there could be substantial costs. The oversupply of capacity would be perpetuated and inefficient use of generation assets would continue.

On the other hand, if entry occurs at a more modest rate, market power is likely to persist and efficiency losses will occur as a result of the higher than necessary prices that are likely to eventuate.

This situation has come about because Pacific Power has been, for a long period, almost the only electricity supplier in New South Wales. Given the life of its assets, its market power is unlikely to be quickly undone, if it is left as an aggregated body.

In its terms of reference, the Commission was requested to assess whether Pacific Power would have the ability to take various actions connected with the exercise of market power. Specific items in the terms of reference are identified below, together with the Commission's responses.

> *Has Pacific Power the ability to set prices for the market for significant periods of time to increase revenue or profits without engendering actions by customers or competitors which cause it to lose market share?*

The Commission considers that Pacific Power will have the power to influence prices to increase its profits. This power arises from its significant share of the four-state national electricity market (over 35 per cent in 1993–94) and its substantial guaranteed market share in New South Wales (around 60 per cent, even in the year 2000).

When looked at in conjunction with the level of supply that other states can provide in various periods of demand, Pacific Power has influence over major portions of the market. For example, at times of peak demand, all states except New South Wales have demand pressing on capacity. The addition of Snowy's power from the SMHEA will reduce, but not eliminate, Pacific Power's market power at this time. Off-peak, the SMHEA is unlikely to make significant contributions to generation (because it is limited by its water storage capacity and other constraints), and Pacific Power again has the potential to influence price.

Moreover, imports of electricity into New South Wales suffer from energy losses in transmission and there is the likelihood that, at some stages, they will constrain the interconnections. When this happens it adds to Pacific Power's potential market power, although it is not necessary for it to exist.

All the economic models to which the Commission has had access also indicate that Pacific Power will have the scope to set prices in the market for significant periods of time.

It seems reasonable to conclude, therefore, that Pacific Power could achieve higher profits by raising the price of electricity. This would cost it some market share, both to existing generators in other states and to new entrants within New South Wales. And these markets would shrink somewhat as some customers reduced their use of electricity. Such a strategy would almost certainly also cause it to lose additional market share in its 'shared' market as customers turned to alternative energy sources. Even so, higher prices would mean higher profits for Pacific Power.

> *Has Pacific Power the ability to force an allocation of capacity onto the market so that more efficient plant is kept idle and less efficient plant operates for a significant period of time?*

If it were operating without constraint, it is not clear that Pacific Power would seek to force capacity onto the market that was other than its most efficient plant. In the national market there will be no obligation for generators to bid their costs and Pacific Power could achieve a high market price by bidding relatively efficient capacity into the market at a high price.

This strategy, however, would be likely have the effect of keeping some plant owned by Pacific Power idle, since generators owned by other operators which had costs close to the bid price would then be dispatched. To keep the price high, Pacific Power would be likely to be forced to withdraw some capacity, which would be replaced by this plant, generally at higher cost.

If gas-fired plant were to enter while existing (sunk cost) coal-fired plant was prematurely retired, this would constitute a substitution of higher cost capacity for lower cost capacity.

Pacific Power may, however, have concerns that regulatory or other restrictions might be invoked if the prices bid by it were obviously well above its costs. In that situation, it is possible that Pacific Power might bid high cost plant while leaving more efficient plant idle. This would have the effect of creating a higher SMP while allowing the majority of Pacific Power's (more efficient) generating capacity to earn high returns.

The strategy of bidding plant which is genuinely more costly to run would leave a regulator with the difficult task of attempting to judge the cause of the more efficient plant being left idle. While the regulator may suspect a stratagem to raise prices, there are doubts about whether it would prove possible to label it in this way. For example, it could always be disputed whether maintenance of efficient plant had been deliberately prolonged.

Has Pacific Power the ability to drive out competitors that are more efficient?

It is technically possible for Pacific Power to cause owners of generating assets to make consistent losses if it were to choose to price low. However, because this would imply low or negative profits for Pacific Power, it is difficult to see how this could be in its long term interests.

Once capacity is installed, it is most likely to continue to operate provided it can cover its short run costs. Therefore while a private operator can go bankrupt and be forced out of the market, the assets are likely to continue operating in the same market in other hands. (Gas turbines, which can be relocated relatively easily to other markets may be an exception.) While the experience of low prices would be likely to affect the price at which the generators were sold, it is unlikely to affect significantly their capacity to function.

Has Pacific Power the ability to prevent entry of new capacity that is more efficient?

As noted in the previous section, Pacific Power can, for periods of time, maintain low prices and discourage entry.

It is within the power of Pacific Power to influence the scale of entry. One method it could employ is to continue to accumulate excess capacity which would give it the potential to claw back market share by pricing low against an entrant. While this could limit entry, it is unlikely to prevent it in the longer term.

In the long run, Pacific Power will have an interest in setting higher prices to increase profits. This should attract more efficient generation capacity, some of which is likely to be more efficient than currently exists.

6 OPTIONS FOR ADDRESSING MARKET POWER

It is not uncommon for large firms to have some degree of market power from time to time. However, as discussed in Chapter 5, the Commission considers it likely that Pacific Power would have the potential to exercise considerable market power if it were maintained as a single entity. Over time, new entrants would probably dissipate the degree of market power available to Pacific Power. Nonetheless, in the short to medium term, quite significant costs could be imposed on both the New South Wales and Australian economies if Pacific Power opted to exploit the market power at its disposal. Indeed, as outlined in the previous chapter, there is a danger that much of the benefit expected to result from the development of a competitive national market for electricity could be deferred for a significant period of time.

In these circumstances, there is a need to consider options available to government to address problems arising from the misuse of market power. The options considered in this chapter relate to regulatory action (Section 6.1), the expansion of the interstate transmission linkages (Section 6.2) and the disaggregation of Pacific Power (Section 6.3). In all instances, action by government will only be warranted if, first, it can effectively address the problems associated with market power and, second, the costs of such action are likely to be outweighed by the resultant benefits. In this context, another alternative for government is to 'do nothing'.

6.1 Regulatory action

Under the proposed arrangements for the new national electricity market, matters relating to market conduct and anti-competitive behaviour will be addressed at the national level. At its February 1994 meeting, COAG agreed that these issues will be handled by a general body like the Trade Practices Commission, or its successor (the ACCC), rather than by an industry specific body. The necessary legislation has recently been put into effect through the *Competition Policy Reform Act 1995*.

The 'light-handed' regulation proposed by COAG has a number of attractions. Compared with detailed regulation by an industry specific regulator, it can achieve greater consistency in the application of regulation between industries (eg between electricity and natural gas suppliers), it can generally be undertaken at lower cost, and it limits the possibility of regulatory capture.[1] However, given the likelihood of Pacific Power having significant market power and the types of behaviour which could be pursued to exercise such power, it is not clear that regulation of the industry could, in practice, conform with what is commonly perceived as light-handed regulation.

More specifically, it is likely that very comprehensive (and hence, restrictive) rules and close monitoring of the industry would be required in order to ascertain whether particular forms of behaviour are a manifestation of market power or are normal outcomes of a competitive market. For example, to assess whether market power is being exercised, it would be necessary to closely examine Pacific Power's bid structures. In turn, this could require the regulator to ascertain the reason(s) for particular generating plants not being in service, to assess whether they justify the plant being taken out of service and, if so, for how long. In other circumstances it may be necessary for the regulator to assess whether bid prices which are relatively low, or volatile, are commercial responses to market conditions or forms of anti-competitive behaviour. It is difficult to see how such assessments could be made without close regulatory oversight.

The likelihood of relatively stringent regulation being required is increased by the *perceptions* held by many users and some generators that Pacific Power has market power and that, in the event that it is not disaggregated, significant regulation will be needed to curb it. For example, Orion Energy commented that:

> Competition, rather than heavy-handed regulation, is [intended] to be the mechanism keeping prices down. However, customers' concerns about Pacific Power would tend to suggest, on the contrary, an increased need for regulation (Sub. 14, p. 12).

To the extent that there is a widely held perception that Pacific Power possesses substantial market power, governments are likely to be under ongoing pressure to introduce 'heavy-handed' regulation (ie detailed regulations to circumscribe industry behaviour). There could even be pressures for some governments to consider withdrawing from participation in the national electricity market. In this context, the Victorian ESIRU contended that:

> Since the requisite regulations would be relatively heavy-handed, this would be likely to reduce significantly the potential benefits of the National Market. Accordingly, Victoria may be likely to exercise greater caution in approaching any

[1] Regulatory capture refers to the possibility that a specialist regulatory agency may, over time, become so close to the industry it regulates that it virtually becomes an adjunct to the industry, working towards furthering the interests of the industry rather than those of the community as a whole.

> transition from its currently competitive and adequately regulated Victorian market to an inadequately competitive National Market (Sub. 30, pp. 29-30).

The major concerns with heavy-handed regulation of the generation sector are, first, there is a distinct probability that such regulation will not be effective in overcoming market power and, second, it would be costly to administer and would impose significant costs on generators.

Doubts about the effectiveness of heavy-handed regulation largely reflect the difficulty of designing and enforcing regulation to control market conduct. Significant information asymmetries between generators and the regulator would make it extremely difficult to assess whether generators complied with the regulatory requirements. In addition, there would be strong incentives for generators to find, and exploit, 'loopholes' in the 'rules'.

These difficulties can be illustrated by reference to experience in the United Kingdom. Having found that increases in the electricity pool price were caused by the bidding strategies of the two dominant generators,[2] the Director General of Electricity Supply secured certain undertakings from the two companies to mitigate their market power. This included a requirement that the two companies bid in a manner which maintained average pool prices below a specified level. In a subsequent review of this undertaking, the Director General found:

> The two generators were able significantly to increase the differential between peak and off-peak prices. They were also able to reduce average SMP [system marginal price] by 70 per cent over the course of two weeks in January 1995, and to hold it at an unprecedentedly low level for two months ... they constitute further clear evidence of the market power of the two major generators.
>
> ... my enquiries into Pool prices during 1994/95 have reinforced my view that greater competition is necessary, particularly in respect of non-baseload plant, and that competition, rather than price control, is the most effective way of protecting customers' interests (Offer, 1995d, p. 2).

There would clearly be significant costs in applying conduct regulation to the generation sector. While the administration costs to governments could be high, generators themselves would bear a disproportionate share of the costs. They would face the costs of collecting and supplying information to the regulator. However, the more significant costs to generators could relate to the time 'invested' in trying to 'beat the system' and, in the early years at least, to uncertainty caused by the likelihood of future modifications to the rules. Added to this is the danger that the regulator may 'get it wrong' (unnecessarily restrain generators' activities). Although the costs that stem from excessive or

2 At the time, National Power and PowerGen supplied around 60 per cent of the United Kingdom's electricity needs.

inappropriate regulation are initially borne by generators, like all costs they are ultimately passed on to consumers.

In addition to concerns about the effectiveness and cost of using market conduct regulation to address the potential misuse of market power by Pacific Power, there is a more fundamental problem in that the regulatory approach involves treating the *symptoms* of the problem and does not address the underlying cause — the limited effective competition facing Pacific Power in some market segments. An approach which directly targets the cause would, in principle, be a better alternative, depending again on the costs involved.

6.2 Increasing the capacity of the interconnections

The interconnections linking state electricity grids are of relatively modest capacity. Previously this has not been a significant concern as interstate electricity sales have been small and the interconnections have seldom been used to their capacity. However, past usage is unlikely to provide a reliable guide to the utilisation of the interconnections once the new national market is in place.

Until recently, state electricity authorities were not commercially oriented and generally sought to supply virtually all of the electricity requirements of their respective states. However, under the new arrangements, generators will have opportunities to sell interstate and distributors/retailers will have a choice of suppliers. The more commercial orientation of the industry will provide strong incentives to exploit opportunities to increase returns by buying and selling on the most advantageous terms. Thus, it is possible that interstate trade in electricity could increase appreciably, to the point where competition between states may lead to the interconnections being more of a constraint than they are at present.

A number of organisations making submissions to this project subscribed to this view.

> Until the transmission links between Victoria and NSW and Queensland are either augmented or constructed, there cannot be a competitive national grid (North West Electricity, Sub. 10, p. 1).
>
> ... both existing and future interstate interconnections are very limited in capacity. ... In addition, the long distances involved in the interconnections; the very high cost of reinforcing them; and the energy losses on them, will always mean that power sales over the interconnections cannot provide much competitive pressure (Prospect Electricity, Sub. 15, p. 3).

> With the limitations of network links to other states it is hard to see how any effective competition can be introduced to Pacific Power in it's present form (Central West Electricity, Sub. 9, p. 1).

An interconnection augmentation study published in November 1992 (Pacific Power et al 1992) identified some relatively short lead time options for increasing capacity on those linkages which it considered could potentially constrain economic operations of the interstate network (ie the links from New South Wales to Snowy, Snowy to Victoria and Victoria to South Australia). The upgrades would involve the installation or modification of equipment in the main transmission switchyards, but would require no new lines. The costs were, at the time, estimated to range between $28 and $40 million (see Table 6.1).

Table 6.1: Interconnection augmentation options

Link upgrade	*Upgrade MW*	*Capital cost ($ million)*
Snowy to Victoria	300	35
NSW to Victoria	400	40
Victoria to SA	150	28

Source: Pacific Power et al. (1992).

According to the augmentation study, the upgrades shown in Table 6.1 would have "the incidental effect of increasing transfer capability in both directions". Thus, there would also be an increase in link capacity between the Snowy and New South Wales (an additional 800 MW) and South Australia to Victoria (150 MW).

Some higher cost options, involving the construction of new lines, that would provide larger increases in interconnector capacity were identified by the Victorian Power Exchange:

- increasing the capacity of the Victoria–Snowy link by:
  - 1000 MW at a cost of $200 million
  - 1600 MW at a cost of $520 million
- increasing the capacity of the Victoria–South Australia link by:
  - 350 MW at a cost of $130 million

- 500 MW at a cost of $180 million

The time required to implement these options is likely to vary. Some of the upgrades involving only relatively modest expenditure could be undertaken fairly quickly. However, the larger upgrades would involve negotiating additional easements and constructing new transmission infrastructure. This could take a considerable period of time — up to eight years according to the augmentation study — particularly if construction raises significant environmental issues.

Significant delays and difficulties have been experienced in recent years in gaining the necessary approval to construct some new intrastate transmission lines. In the case of interstate linkages, such difficulties and delays could be compounded because of the need to gain approval from two governments and because of existing sensitivities about 'importing' electricity (most recently evident in debate in Queensland about the siting and construction of Eastlink). Thus, any large scale enhancement of the interstate interconnection could take a considerable period of time. Moreover, given that, first, the capacity of the linkages is presently adequate for most of the time and, second, the uncertainty about future demand for interstate transmission capacity, it would be difficult to justify significant investment on expanding the linkages until such time as there is evidence that the links are significantly impeding interstate trade. Thus, expanding the linkages can only be regarded as a medium to longer term option for addressing concerns about market power.

A more fundamental concern relates to the effectiveness of this option as a means of overcoming Pacific Power's market power. Larger capacity linkages would reduce the likelihood of Pacific Power withdrawing capacity, allowing imports to enter up to the maximum possible allowed by the interconnections, and then acting as a monopoly supplier in the residual New South Wales market. However, as demonstrated in the previous chapter, if Pacific Power is preserved as a single entity it would be able to exercise considerable market power even if the linkages remain unconstrained.

In these circumstances, enhancing the interstate transmission linkages would not in itself be an effective means of addressing concerns about market power. It is most appropriately viewed as action which would be complementary to disaggregation, provided that utilisation of the linkages once the new market arrangements are in place suggests that the investment is warranted.

6.3 Disaggregation

A number of organisations expressed the view that the most effective way to curb Pacific Power's market power would be to disaggregate it into a number of smaller businesses. For example, Orion Energy stated that:

> ... customers in the proposed national, or indeed any regional, electricity market have little confidence that arrangements will work well if Pacific Power is left as a single entity. The greatest boost to confidence would be to change Pacific Power from a single entity into a number of smaller, viable, competing, generation businesses (Sub. 14, p. 14).

ACTEW expressed similar sentiments:

> There appear to be clear benefits in breaking up Pacific Power given the proposed operating regime and physical infrastructure in place for the national market. More importantly, if Pacific Power stays as a single entity, this is unlikely to be in the best interests of the market or the ACT region (Sub. 12, p. 10).

On the other hand, a minority of participants argued that Pacific Power should be maintained as a single entity. For example, Illawarra Electricity said:

> ... NSW will have competition for Pacific Power from both Snowy and Victoria while ever there is an over capacity of generation within each state.
>
> To maintain maximum flexibility and economy of scale to both maintain and expand the State's generation sector and to attract future State Development through the generation of adequate capacity from the generation plant within the State, it is recommended that Pacific Power should remain as a single unit (Sub. 7, p. 4).

In essence, debate about the efficacy of disaggregation boils down to an assessment of its benefits in terms of increasing competitive pressures (and reducing costs associated with the use of market power) relative to possible costs (eg forgoing economies of scale and scope).

The notion of restructuring a large electricity generation business is relatively new, but there are precedents. For example, in 1990 the generation arm of the Central Electricity Generating Board — the government body responsible for generation and transmission of electricity in England and Wales — was divided into three operating companies. In New Zealand, the Government has announced plans to split the Electricity Corporation of New Zealand into two independent, state owned generating companies. And, in Victoria, the Government has sold a majority interest in the Loy Yang B power station and divided the remaining generation assets of the former SECV into five separate generation businesses, all of which are to be sold. In all instances, the objective of disaggregation has been to inject competition into the generation sector.

Advantages of disaggregation

If effective competition can be introduced into the generation sector, there would be little need for regulation of market conduct because the scope for a generator to exercise market power would be substantially reduced. This would occur because, in a competitive market, attempts by any single firm to manipulate prices would be likely to make that firm worse off. For example, if a firm continually tried to raise its prices, it would risk a rapid loss of market share to rival generators. Similarly, in a competitive market, a generator would not be able to earn the excess profits needed to make it worthwhile engaging sporadically in predatory pricing.

Given the nature of trade in electricity and the arrangements that will apply once the national electricity market commences, disaggregating Pacific Power into a number of separate businesses would not *guarantee* that it, or other large generators, could not exercise market power at various times. However, establishing competing generation businesses would make it far more difficult for market power to be exercised compared to the situation in which Pacific Power remained as a single entity. For example, disaggregation would result in surplus capacity being distributed between a number of competing businesses rather than being concentrated in the hands of one producer. Thus, when available capacity elsewhere in the integrated system is approaching full utilisation, it would be a risky strategy for any one disaggregated business to assume that it will be the marginal producer with some discretion in the price it can bid into the pool.

In addition to reducing opportunities for exploiting market power, competitive disciplines provide stronger incentives for cost minimisation. For example, the Victorian ESIRU stated that a review of the performance of Victoria's publicly owned generators reported considerable cost savings following disaggregation:

> Direct controllable expenses fell by 10% in 1994/95 with forecasts for a further 13.5% improvement in such costs by 1997/98. This improvement can be attributed to:
>
> - labour costs falling 7% in 1994/95 with expectations of further falls of 25% by 1997/98; and
> - material, contracts and miscellaneous costs falling 12% in 1994/95 with expectations for further falls of 7% by 1997/98 (Sub. 41, p. 2).

In a commercial and competitive environment there will also be much greater incentives to ensure that the timing of new investments is appropriate. Effective competition in generation would also promote competition in other sectors of the electricity supply industry, particularly in retailing. For example, it would enable distributors, large users and energy traders the opportunity to 'shop around' to buy electricity at the most favourable prices. The opportunities for this type of competitive behaviour to develop are clearly limited if supply in any one state is dominated by a single entity.

Governance

While disaggregation would reduce the scope for the exercise of market power, the form of disaggregation would have an important bearing on the extent to which market power is dissipated. In this context, some participants claimed that competition is unlikely to be as effective if it involves disaggregated businesses in public ownership which largely comprise management and staff who formerly worked for the one organisation. For example, the Business Council of Australia said:

> ... the Council firmly believes that separating Pacific Power into multiple generating units with each remaining in public ownership will limit competition between them, compared to the case where they are each under separate ownership. Factors such as common ownership, the lack of a fully commercial organisation and orientation, and conflicting objectives would all combine to suppress competition between generators (Sub. 40, p. 33).

The extent of competition that evolves would depend crucially upon the governance arrangements. If each disaggregated business has an independent board and is required to operate on a commercial footing and meet normal commercial financial criteria (ie to meet a target rate of return), a reasonable degree of competition may evolve. However, competition could be muted by the need for publicly owned bodies to comply with special government requirements covering matters such as industrial relations policy and capital raising. For example, if two competing generation businesses were to concurrently seek government approval to undertake significant new investment, Loan Council limitations or state budgetary concerns could result in one or both proposals being denied.

More importantly, because publicly owned corporations are not subject to some market disciplines — such as the threat of takeover, the risk of bankruptcy and monitoring mechanisms associated with listing on sharemarkets — the intensity of competition and the incentive to minimise costs is likely to be less than it would be if the businesses were privately owned.

Notwithstanding these reservations about the intensity of competition under public ownership, the Commission considers that, provided appropriate governance arrangements are in place (see later discussion), disaggregation of Pacific Power would still bring substantial benefits.

Costs of disaggregation

Cost associated with disaggregation can be broadly categorised as relating to either loss of scale or scope economies or to other transactions costs. The terms of reference for this project ask the Commission to consider the "trade-off between benefits from a competitive generation sector and the costs associated with a possible loss of economies of scale and scope".

Costs relating to scale and scope

The significance of economies of scale and scope in the generation sector are discussed in some detail in Appendix C.

In brief, the available evidence suggests that the most significant scale economies are at the level of the individual generating unit. Cost savings which can be gained at the power station level by operating multiple units are largely captured by stations which operate two or more large units, as is the case with the power stations that presently account for the bulk of generation in the interconnected system. Thus, as long as disaggregation does not proceed below the level of individual power stations (ie does not involve separating units within a station), the majority of scale economies will be preserved.

As discussed in Appendix C, a smaller scale of operation could increase risk. For example, generators face potentially severe financial penalties if a unit fails and they are unable to meet their contractual obligations. A generator with a large portfolio of units can usually manage this risk by replacing the unit with other plant. A small generator is less likely to have the necessary plant to provide this back-up. Thus, it is possible that a small generator will be perceived as a more risky venture, and that this will be reflected in higher capital costs. On the other hand, as noted in Appendix C, small generators can reduce this risk by entering into co-insurance arrangements with other generators (as has occurred in Victoria). Consequently, costs associated with increased risk could be relatively small.

Some other factors sometimes linked to scale — such as the need to minimise reserve plant and to maintain the integrity of the system — may formerly have been most efficiently performed by large (integrated) suppliers. However, once the national electricity market is established there will be market mechanisms available to ensure that these matters are addressed.

It is sometimes argued that maintenance and certain factors affecting overheads (eg spare parts and inventory levels) will be lower in larger enterprises. However, if this is the case, it would normally be possible to avoid additional costs by outsourcing work or entering into cooperative arrangements with other power stations.

As stated in Appendix C, the Commission considers that savings associated with the loss of scale economies that may accompany disaggregation are likely to be small. This view on the limited significance of scale economies at the enterprise level is supported by the recent statement by the New South Wales Government:

> Benchmarking analysis of 153 generation utilities with 477 plant in 11 countries, indicates that the minimum efficient size for generation businesses is in the region of 1000 MW to 5000 MW while the average size of generators displaying constant returns to scale is 3100 MW (Egan 1995, p. 10).

The analysis mainly related to coal-fired thermal plant. Of the major coal-fired power stations in New South Wales, Wallerawang is the smallest with a capacity of 1000 MW.

The potential for the loss of economies of *scope* is also assessed as relatively minor (see Appendix C). Possible sources of economies of scope include international activities (eg power station design and construction and training) and research and development.

Pacific Power considers that, to be effective in international markets, organisations usually need a ‘track record’ as a large and successful generator. The Commission is not convinced that this is the case. There is no evidence to suggest that an enterprise has to have a large generation business to be successful in the international arena. Indeed, some companies that compete to supply power station design, construction and related work in overseas markets have little or no generating capacity of their own. For example, some Australian companies which compete successfully in international markets — such as Kinhill and Merz Sinclair — have no generating capacity. BHP, which is competing for a contract to develop generating capacity worth over $5 billion in India, has a number of generating units in Australia and overseas, but its total generation capacity is very small compared with that of Pacific Power.

Private companies do, however, have a significant advantage over a public sector body in that they are better placed to inject equity into overseas projects. This can improve the prospects of a firm being the successful tenderer by, first, addressing the capital needs of the host country and, second, signalling commitment to the project and confidence in its technical performance. In this context, ACTEW commented:

> ACTEW has listened with interest to the arguments made by Pacific Power about the necessity of having a large electricity organisation in Australia to maintain an

> internationally competitive single organisation within the Australian electricity industry. ACTEW would have some sympathy for such an argument were it not for an awareness that most significant international contracts are now secured as much with financial packaging as with technical expertise and it is unlikely that the NSW Government would allow Pacific Power to hazard large amounts of capital on overseas ventures (Sub. 12, p. 4).

Even if it were possible to demonstrate that disaggregation would lead to an increase in costs because of the loss of economies of scale or scope, the Commission does not consider that the increase would be significant. More importantly, it considers that any such costs would be substantially outweighed by the benefits of disaggregation in increasing competitive pressures and reducing market power.

Other costs

There are a number of other costs that would be involved in disaggregating Pacific Power, including recurring costs and some of a ‘one-off’ nature. The incidence of these costs is likely to be higher, the higher is the number of generation businesses established.[3]

Perhaps the most obvious cost is that of having to establish and maintain multiple boards (and associated senior management structures). There could also be additional recurring costs arising from the need to duplicate certain corporate functions (eg treasury operations, personnel systems and marketing). However, some participants contend that, rather than increasing these costs, disaggregation could in fact reduce corporate overheads. These claims are based on the supposition that, first, in the more competitive environment that would accompany disaggregation there would be far greater incentives for corporate functions and associated staffing levels to be kept to a minimum and, second, in a smaller organisation, corporate productivity is higher because management identifies more closely with the performance of the business and is more focussed on achieving higher returns. In this context, Sydney Electricity claimed:

> Large monoliths tend to over resource head office and support areas. Sydney Electricity contends that dividing Pacific Power into three would actually reduce total overheads (Sub. 19, p. 6).

And ACTEW stated that:

[3] In a study prepared for the Victorian Government (CS First Boston and KPMG Peat Marwick 1994, p. 3), it was estimated that the “once-off and establishment costs” of breaking Generation Victoria into five independent companies would be between $23 and $27 million.

> Individual generation portfolio managers are much more likely to be more focussed on the bottom line, rather than just market share ... (Sub. 12, p. 10).

The Victorian ESIRU noted that "significant savings" in corporate overheads were achieved after Generation Victoria was dismantled and individual generation businesses were established, each with its own "small corporate function".

Assessment

There will be some costs associated with disaggregation. These will include 'one off' establishment costs and some recurrent costs. However, the likelihood of significant costs arising through the loss of economies of scale or scope following disaggregation is, in the Commission's view, very small.

The costs of disaggregation need to be weighed against the possible benefits. In the Commission's view, the benefits would be considerable. Although the nature of the electricity market is such that, at certain times, some generators may still possess a degree of market power, disaggregation could significantly reduce the likelihood and extent of this occurrence. In these circumstances, inefficient use of resources would be reduced and electricity prices would more closely reflect the efficient costs of production. This would provide considerable benefits to users.

In the Commission's view, disaggregation of Pacific Power would be a low cost and effective means of reducing its market power and enhancing competition in the national electricity market.

Form of disaggregation

The terms of reference request the Commission to consider the implications of "alternative structures of the electricity generation industry in New South Wales". This is an important issue, as the structure of generation is directly related to the level of competition that will emerge once the national market is fully operational and, as most participants acknowledged, there are advantages in 'getting it right' from the outset.

Major issues relating to the form of disaggregation include:

- the number of businesses;
- the composition of business groupings; and
- governance arrangements.

Number of businesses

On the presumption that it would not be practical to contemplate separating units within power stations, the possible options for disaggregating Pacific Power range from two separate businesses to seven businesses (or eight if the hydro plant and small turbine plants were operated as a single business).

The lowest level of disaggregation would be to divide Pacific Power into two generation businesses. This would have some advantages. For example, it would minimise initial 'one-off' costs and recurrent costs associated with the duplication of some functions. However, compared with disaggregation into a larger number of businesses, there would appear to be some significant disadvantages. These would, in part, depend on the composition of the two businesses. There are two broad alternatives: two businesses of approximately equal strength, or one large generation business and one small business.

Two businesses of comparable strength

The main potential problem with forming two business of roughly equal size is the risk of being left with two large players in a position to exercise market power. For example, if capacity were divided equally between the two, each business would have around five times the average capacity of the five publicly owned generating corporations in Victoria. Based on 1993–94 data, it would imply that each business might supply around 45 per cent of New South Wales' electricity needs.

As well as the possibility that each would, individually, exercise market power, there would be some likelihood that the two businesses could jointly exercise market power. The shared origins of the two organisations and the detailed knowledge that each would have about the operations of the other, could facilitate various forms of collusive or coordinated behaviour (which regulators would find very difficult to detect).

Similar concerns were expressed by a number of participants. For example, Prospect Electricity observed:

> ... a split into only two component parts would not seem to offer sufficient competition, and would only offer a repeat of the unsatisfactory UK experience. In addition, each of the two companies would still be larger than any other company or organisation operating in the future National Grid, and given the relative strength of the interconnections, each of them would obviously still be dominant within New South Wales. The opportunity for overt or covert collusion (especially when an England/Wales type of trading system is implemented) is simply too great (Sub. 15, p. 9).

The Business Council of Australia expressed similar reservations

> ... a split into only two component parts would not seem to the Business Council to offer sufficient competition to provide adequate user benefit. The opportunity for overt or covert collusion could be present (Sub. 40, p. 28).

Two businesses of unequal size

There are a number of possibilities for creating two businesses of unequal size. For example, the smaller business could comprise the former Western Group (Mt Piper and Wallerawang) or just a single station (say, one of the larger stations — Bayswater, Eraring or Liddell).

A possible reason for breaking up a generation business in this fashion could be to separate one part of the business which is ‘atypical’ and which has relatively few synergies with other generating plant (eg hydro plant which is best suited for meeting peak load). However, as the bulk of Pacific Power’s generating assets are fairly similar (large black coal-fired thermal units), there would seem to be little scope for effective disaggregation in this form.

Another possible reason for establishing one small and one large generation business could be to maintain, within the larger business, a better capacity to deal with large individual users. For example, Tomago Aluminium stated that:

> ... no single small entity would have the size and generating capacity to be considered as a secure and reliable long term supplier to major energy consumers, such as Tomago, in the way that Pacific Power is today (Sub. 37, p. 2).

Companies such as Tomago clearly depend on the security and reliability of electricity supply. However, it is not clear why this would be effected by disaggregation (irrespective of the form adopted). Under the new electricity marketing arrangements, reliability and security of supply should be maintained. Moreover, there seems little reason why a big user, like an aluminium smelter, could not contract with a single station business. Even a user as large as Tomago would consume less than half of the energy that could be generated by a station the size of Bayswater or Eraring. Indeed, given its large and relatively constant electricity needs, such a large user would probably be a sought-after customer for a single station business.

The Commission’s major concern with this option is that, in practice, it may be little different from maintaining the status quo. It is difficult to envisage vigorous competition between the disaggregated businesses as the larger one would have a substantial capacity advantage. For example, even if the smaller business comprised one of the largest power stations — Bayswater or Eraring — its generating capacity would still be less than 30 per cent of the capacity available to the larger business. In these circumstances, the increase in competitive pressures resulting from the activities of the smaller generation business could be relatively minor. Hence, the market power available to the larger business may be only slightly less than that available to Pacific Power in its current form.

The modelling work undertaken for this project by London Economics illustrates these concerns about disaggregating Pacific Power into two businesses. The simulations show that, if Pacific Power were divided into two groups of comparable size, each business would have substantial market power, but that prices would be somewhat lower than they would be if Pacific Power is retained as a single entity. If Pacific Power were broken into two businesses of unequal size — comprising a bigger station like Bayswater or Eraring and a group with all other stations — the modelling suggests that the larger business would posses a similar degree of market power to that of Pacific Power if it was retained in its current form.

In summary, the Commission sees little advantage in disaggregating Pacific Power into only two businesses. Indeed, if the underlying motivation for disaggregation is to increase competitive pressures and gain the benefits associated with improved price outcomes, then, given that the costs of disaggregating Pacific Power into two separate businesses would not be much lower than disaggregating it into three, the tradeoffs do not favour opting for two. The Commission considers that the greater risk is in creating too few, not too many, generation businesses.

In this context, recent experience in the United Kingdom is of some relevance. In the United Kingdom, generation plants were effectively divided between two companies. However, it is now widely recognised that a more competitive (and less costly) outcome would have been achieved if a larger number of generation companies had been established. For example, Newbery (1995, p. 7) commented:

> Had the fossil stations been divided among five instead of two companies, and if collusion could be deterred (by the threat of entry), then competition would have almost completely eliminated these dead-weight losses [of operating at too high a price with too little supply].

Three generation businesses

The establishment of three generation businesses would add to the costs of break-up (ie some establishment and recurrent costs would be higher) but, as noted above, the additional cost is likely to be relatively small. In the Commission's view, these costs would be substantially outweighed by the benefits. In particular, with three businesses of comparable strength, the prospect of attaining effective competitive in the generation sector would be much higher. It would be less likely that any one business would be dominant and it would be more difficult for any collusive activity to take place.

The modelling undertaken by London Economics also suggests that, while some market power could remain, there would be significant benefits in a three-way disaggregation relative to two.

It is difficult to determine the optimal level of disaggregation. Nonetheless, the Commission considers that, *as a minimum*, Pacific Power should be disaggregated into three independent generation entities.

It is more difficult to know whether it would be desirable to break Pacific Power up into more than three separate businesses. Some participants considered that three (based on the old ELEX groupings) would be sufficient, while others contend that each major power station should be constituted as a separate business entity. This latter approach, which has been followed by Victoria, was advocated for Pacific Power by Yallourn Energy:

> Given the success of the Victorian disaggregation, there appears no scale-related reason why Pacific Power should not be split up into generation companies comprising individual power stations. Indeed the disaggregated NSW generators are universally larger than their opposite numbers in Victoria. Even fully aggregated generation in South Australia would not be dissimilar in size to the larger of the suggested fully disaggregated NSW generating companies (Sub. 23, p. 3).

Given the assessment that cost disadvantages from operating on a smaller scale are relatively minor, there is clearly a case for establishing major power stations as a separate business on the grounds that this would maximise competition. However, it would first be necessary to verify that an individual power station could operate viably on a stand–alone basis. The Victorian Government considers that its brown coal power stations, which are far less flexible in operation than the black coal stations in New South Wales, will be financially viable.

Composition of business groups

If it is decided not to disaggregate to the single power station level, a decision has to be made about how power stations should be grouped.[4]

In the United Kingdom, initiatives to reduce the market power of the two dominant generators — National Power and PowerGen which between them have around 60 per cent of the market — have included undertakings that the

[4] New generation businesses could, of cours e, consist of (say) one or two single station entities and a number of businesses with more than one major power station.

two generators sell or dispose of 6000 MW of coal-fired or oil-fired generation plant. The undertakings are intended to increase competition by increasing the capacity of plant owned by independent generators.

A major disadvantage with this form of action is that decisions about disposal are made by the generators themselves. If a variant of this approach were adopted in New South Wales, it could lead to one ‘elite’ group comprising the most efficient generators, with the less efficient units grouped together in a number of other generation business. In these circumstances, competitive pressures between the groups would not be strong as they could be. In the Commission’s view, this is clearly a matter to which the Government needs to give close attention.

As implied by its previous comments, the Commission believes that the grouping of power stations into generation businesses should be done with the objective of maximising the potential for competition. One way of achieving this objective would be to allocate power stations to groups having regard to their cost structures. More specifically, stations with similar operating costs would be allocated to different groups. This would provide strong incentives for managers to try to reduce costs, as even small cost reductions could be sufficient to permit a station to undercut the bid by its rival(s) in the other groups. Application of this criterion could result in the composition of generation businesses not being solely based on locational considerations as was previously the case in New South Wales.

The Commission considers that the composition of business groups should be determined by the Government with a view to increasing competition between the new entities. To this end, each group would need to be of comparable competitive strength.

Governance

One participant — Prospect Electricity — raised the possibility of Pacific Power being retained as a holding company to oversee the operations of the new generation businesses. The Commission believes that this form of governance — along with structures which involve ‘ring-fencing’— does not guarantee the independence needed to ensure that rigorous competition evolves. There would be a danger that, over time, and perhaps unwittingly, the somewhat artificial separation imposed by these measures would break down, and that control over the generation sectors would again be effectively centralised.

The Commission considers that each new disaggregated generation business should be established as an independent corporation. Each

corporation should have an independent board, with the head of the board reporting directly to the appropriate minister.

6.4 Summing up

There are three major ways of addressing the significant social costs that could arise from the exercise of Pacific Power's market power.

One way is to rely on regulation to prevent the use of market power. However, it is doubtful if this would be effective as market conduct has proved to be notoriously difficult to control by means of regulation. Regulation would also be costly — both for the industry and the broader community. And more fundamentally, regulation would not remove the underlying cause of the problem — the lack of competition faced by Pacific Power in certain market segments.

Although the capacity of the interconnections is not the key source of Pacific Power's market power, another option is to increase their capacity. However, large scale enhancement cannot be justified at present. Moreover, while it may reduce Pacific Power's market power, the company would still retain sufficient market power to be of concern.

The third option — which the Commission sees as the only cost-effective one, — is to disaggregate Pacific Power into a number of independent businesses. The Commission has not attempted to determine the optimal structure. However, in its judgement, disaggregation should involve the establishment of at least three independent generation businesses of comparable competitive strength.

APPENDIX A: MINISTERIAL CORRESPONDENCE

This appendix consists of the text of:

- a letter from the Assistant Treasurer to the Chairman of the Industry Commission which accompanied the terms of reference for this study; and
- an earlier letter from the Acting Premier of New South Wales to the Assistant Treasurer proposing that the Commission review certain aspects of electricity generation industry in New South Wales.

ASSISTANT TREASURER
PARLIAMENT HOUSE
CANBERRA ACT

29 June 1995

Mr Bill Scales
Chairman
Industry Commission
Nature Conservation House
Emu Bank
Belconnen ACT 2617

Dear Mr Scales

I have received a letter from the Acting Premier of New South Wales (copy attached) proposing that the Industry Commission review the electricity generation industry in NSW to determine the implications for competition in both the State and national electricity markets of Pacific Power's market power in generation.

As the letter indicates, the New South Wales Government is aware that the structure of the State generation sector can significantly influence the success or otherwise of the national electricity reforms. The State Government has established a Review Committee, chaired by Professor Fred Hilmer, to advise on whether and how Pacific Power might be disaggregated.

I welcome the NSW proposal and attach terms of reference for a research project by the IC as requested by the State, and a copy of my reply to the Acting Premier. You will note that the terms of reference provide for the study to be completed within 45 days: to meet the tight timetable of the Review Committee, however, I ask that you liaise with Professor Hilmer with a view to providing earlier advice if this is necessary.

Yours sincerely

GEORGE GEAR

Premier of New South Wales
Australia

23 June 1995

The Hon George Gear, M.P.
Assistant Treasurer
Parliament House
CANBERRA ACT 2600

Dear Mr Gear,

As you are aware, my Government announced on 30 May a reform strategy for the State's electricity supply industry to *inter alia*, lower the cost of electricity, reduce greenhouse gas emissions and provide competitive market arrangements that are consistent with, and support the development of, the national electricity market.

The generation side of the industry is clearly vital to achieving the outcomes we seek from the electricity reforms and the Government is committed to establishment of effective competition in the generation sector. In recognition of this, we have established a Review Committee, chaired by Professor Fred Hilmer, to advise on whether, and if so how, Pacific Power should be disaggregated. The Review Committee will have regard to the State's obligation under the Council of Australian Government's agreement on implementation of national competition policy.

I note that, given New South Wales' size and importance in the national market, changes to the State's electricity supply industry, particularly the generation sector, will significantly influence whether reform initiatives at the national level are successful or not. Against this background, it would be helpful to have the Industry Commission provide to the Hilmer Review Committee its assessment of Pacific Power generation's market power and the implications of this for both competition in regional markets and the implementation of a competitive national market for electricity generation. The Review Committee is to report by mid-August on the general question as to whether and how Pacific Power might be disaggregated. Consequently, a report from the Industry Commission would need to be available by no later than the end of July.

I attach a draft terms of reference that I consider would provide a suitable basis for an Industry Commission examination of Pacific Power's market power in electricity generation.

I look forward to your agreement to this proposal and to the draft terms of reference, and request that you refer such a study to the Industry Commission as a matter of urgency.

Yours sincerely,

Andrew Refshauge, M.P.
Acting Premier

APPENDIX B: PARTICIPATION IN THE INQUIRY

The Commission received the terms of reference for this study on 30 June 1995. It sent copies to a range of interested parties, inviting them to submit their views. Section B.1 provides a list of the organisations which responded. The Commission met with the organisations listed in Section B.2.

B.1 Submissions received

During the course of the study, the Commission received the written views of those organisations listed below.

Organisation	Sub. No.
ACT Government	22
ACTEW Corporation	12
Australian Consumers' Council	2
BHP	21
Business Council of Australia	40
Central West Electricity	9
CitiPower	24
Department of Energy, New South Wales	6
Department of Minerals and Energy, Queensland	8
Eastern Energy	32
Electricity Supply Association of Australia	11
Energy Victoria	1
Environment Protection Agency	29
Electricity Supply Industry Reform Unit, Victoria	4, 28, 30, 33, 38, 41

B.2 Visits and meetings

The Commission held discussions with the following organisations during the course of the study.

New South Wales

New South Wales Government Pricing Tribunal

New South Wales Treasury

Pacific Power

Snowy Mountains Hydro-Electricity Authority

Sydney Electricity

Tomago Aluminium

Victoria

BHP

Business Council of Australia

Department of Agriculture, Energy and Minerals

Eastern Energy

Electricity Supply Industry Reform Unit

London Economics

National Grid Management Council

Office of the Regulator-General

Snowy Trader

Victorian Power Exchange

Australian Capital Territory

Commonwealth Department of Primary Industries and Energy

Trade Practices Commission

APPENDIX C: ECONOMIES OF SCALE AND SCOPE

This appendix discusses the economies of scale and scope that are likely to be available to an electricity generating enterprise. These issues are central to the question of whether and how Pacific Power might be disaggregated. If the benefits of economies of scale and of scope due to the retention of Pacific Power as a single generating enterprise were judged to exceed the costs that could arise from the exercise of market power, there would be a case for retaining the present structure, and controlling the exercise of such power in some other way.

C.1 Economies of scale

Scale economies are said to exist in a firm when average costs decline as output expands. In the context of electricity generation, this concept can be considered at several levels:

- a generating unit or an individual power station;
- an enterprise with more than one power station; and
- the generation industry or the electricity market.

Each of these levels is discussed below, with particular reference to Pacific Power's situation and participants' views.

Generating unit and power station levels

A review of the empirical literature relating to steam-based technologies employed in the United States identified studies undertaken in the 1970s that suggest that generating plants up to 250 MW in capacity exhibited increasing economies of scale (London Economics 1994d, pp. 4–6). However, it appears that, with improved technologies, the significance of scale economies in electricity generation is declining. For example, material provided by Sydney Electricity (based on work undertaken by the Boston Consulting Group) indicates that:

- in 1980, generating costs across the full spectrum of technologies fell steeply as capacity of plant increased;
- by 1990, unit cost differences across a range of plant sizes had fallen; and

- the cost curve is likely to fall and flatten even more by around 2005 (Sub. 19, Attachment A).

In the future, the advent of fuel cell technologies with competitive cost structures may lead to a situation where generating costs per unit of energy remain constant over a wide output range. There are also strong scale economies in much of the fuel supply infrastructure for electricity generation, perhaps most notably in natural gas pipelines, so that bigger generating units can allow operators to appropriate cost savings beyond those deriving from the innate technical characteristics of their own plant.

For most generators, however, the attainment of scale economies at the unit level is almost wholly at the *ex ante* stage of unit design and installation. Once a generator is installed, the opportunities for lowering unit costs are limited.

Generating unit economies, while important in their own right, are thus of limited interest in the context of this study. There is no suggestion by the Commission that Pacific Power should be split up on the basis of individual generating units (ie disaggregated below the power station level), and nor has any participant sought such action.

There may also be some economies of scale in operating power stations with more than one generating unit. Although the scale economies that can be attained at this level may be more limited, two notable areas of savings exist:

- additional unit(s) will protect the station owner from losing all revenue during a planned or unplanned unit outage, and will reduce the costs of obtaining insurance or similar cover from external organisations (which, if they possess market power, may choose not to supply such cover at reasonable prices); and
- a power station with two open cycle gas turbines can increase output by about 50 per cent at relatively low cost — certainly at lower cost than by adding a third gas turbine — by installing a steam turbine driven by the waste heat from the existing units. That is, a combined cycle operation can be built up by modular expansion of the power station.

The Victorian ESIRU noted that, in recent decades, there has been a substantial reduction in the most efficient size of generating plant due to technological developments and the increased availability of natural gas. It stated that the minimum efficient (power station) size has reduced from around 1000–1200 MW down to a capacity of 200–400 MW.

In the context of this study, the Commission takes the view that the presence of cost economies at the power station level are of limited significance because none of the possible structural reforms would involve disaggregating individual power stations. The key scale issues are about multi-station enterprises together with the impact of the national electricity market arrangements.

Enterprise level

A study undertaken for the New South Wales Treasury by London Economics (1994d) concluded that, for steam-based electricity generation technologies:

- previous studies have shown that the minimum economic size of a generation business is likely to be in the range of 1500 MW to 4000 MW;
- data envelopment analysis (DEA) shows that the average size of plant operating at an optimal scale (at which constant returns to scale are achieved) is around 3000 MW. However, there are firms operating at constant returns to scale between 60 MW and 28 000 MW; and
- the DEA modelling also shows that decreasing returns to scale appear in generation firms that are 6000 MW and over.

The study referred only to steam-based generators reliant on coal for 90 per cent or more of their fuel intake and therefore did not address the wider issues of scale economies applying over the full range of commercial generating technologies (which will determine the future operating environment for all generating enterprises). It also did not investigate scale economies for enterprises with generating fleets which contain a mix of technologies. Consequently, the Commission has not relied heavily upon this study.

Some participants made general remarks about the significance of scale economies at the enterprise level. For example:

- BHP noted that some scale economies might exist in the sharing of overheads and scarce technical skills, but it suggested that the nature of these benefits should not be overstated (Sub. 21, p. 2).
- ACTEW noted that splitting Pacific Power might involve losses in economies of scale, but identified offsetting advantages. It considered that smaller generation groups would squeeze out cross-subsidies between generators, and argued that managers of smaller enterprises would be more likely to moth-ball inefficient plant and cut overheads, amongst other savings (Sub. 12, p. 9).
- Sydney Electricity suggested that economies of scale considerations point to *gains*, not losses, in the disaggregation of Pacific Power. It cited work by the Boston Consulting Group in concluding that there would be

no loss of economies of scale in breaking up Pacific Power (Sub. 19, p. 5).

- Eastern Energy Ltd wrote that:

  ... the stated economies of scale of large integrated monopolies are often inflated. The big savings come from reform due to the threat of competition and control passing from a centralised bureaucracy to station managers. What has been happening in Victoria is credible evidence of this, with each station seeking innovative ways to be as efficient as possible (Sub. 32, p. 1).

With these views in mind, this section examines scale economy issues at the enterprise level in four broad categories. These deal with the extent to which disaggregation may affect: operating and maintenance costs; financing costs; corporate governance costs; and the risks faced by generators.

Operating and maintenance costs

There are several ways in which scale economies relating to operating and maintenance costs could be lost by breaking up a multi-station generating utility. These include: fuel purchasing; consumables purchasing; waste handling; technical skills; overhead costs (including management as well as administration); and research and development.

The Victorian ESIRU suggested that none of the potentially scale-sensitive cost items for electricity generation would require the combining of two or more of the larger New South Wales coal-fired power stations into a single company in order to achieve economies of scale.

Although the Commission is aware that some infrastructure is shared between some of Pacific Power's major stations (eg between Bayswater and Liddell), no information was submitted about the extent of the cost savings (if any) in the areas listed above. Scale economies in these areas are much more likely to be strong and significant at the level of generating units within a particular power station. Nonetheless, even if it could be demonstrated that economies of scale exist in these areas, their presence would not provide strong grounds for not proceeding with disaggregation. If savings do exist, they could be preserved by outsourcing or the use of joint venture arrangements. For example, Orion Energy cited a Victorian Government document (Office of State Owned Enterprises 1995b) which stated that:

> It is more efficient to outsource maintenance services, materials supply and storage to the private sector on a competitive tender basis where the private sector can capture the economies of scale and pass these through in competitive pricing (Sub. 14, p. 8).

It might be argued that, because some of their work is intermittent and unpredictable, maintenance teams can be more effectively employed if they are spread over many stations. However, if this is the case, it is not obvious why this should require that several power stations be part of the same enterprise. Other mechanisms exist whereby a generating enterprise's maintenance costs can be lowered — for example, by retaining internal expertise only to do regular tasks, with larger or more difficult jobs being tackled by external specialists as required. Indeed, the Commission understands that some of the larger power stations within Pacific Power have let contracts for major maintenance works which include clauses covering emergency work, and that these contracts are seen to be superior to moving internal maintenance teams between the power stations.

Disaggregation may lead to changes in the way in which maintenance is performed so as to decrease, not increase, these costs. The borderline between internal and external maintenance support should be a commercial decision for each generating enterprise (and it bears on risk management, which is discussed below). In general, as the complexity of maintenance tasks increases, there is an increased likelihood of bottlenecks in getting suitable specialists to do the work, especially at short notice, since such specialists tend to be scarce. While this is the case whether the generating enterprise obtains those resources internally or externally, smaller businesses will be more likely to outsource, being less able to carry expensive maintenance infrastructure as a fixed cost. External maintenance would, however, have the advantage of being available on a price-related and competitive basis so that delays in obtaining repairs will tend to be minimised using this avenue.

Finance costs

The cost of raising capital could be affected by the size of a generating enterprise. Lenders may regard bigger companies to be less risky and therefore be prepared to offer them lower interest rates and more capital than they would smaller businesses. For example, the impact of a forced generating unit outage on a smaller business could be greater than on a larger business with more reserve plant. In these circumstances, the availability of capital, and its cost, could disadvantage small generators relative to larger businesses.

The Victorian ESIRU contended that there could be an increase in the cost of debt finance in a disaggregated generation industry under full competition. However, it stated that Victorian experience suggests that this is likely to be small — of the order of $5 million in the case of Generation Victoria. In Victoria, the increase in debt costs associated with disaggregation was independently assessed at between zero and 1.0 per cent, depending on the particular power stations or enterprise involved, their sales contracts and the strength of the purchaser (CS First Boston and KPMG Peat Marwick 1994, pp. 43–4).[1]

Corporate governance costs

Corporate governance costs comprise an enterprise's spending on its board of directors and general management, and may cover a multitude of activities if provided 'in house', including the company secretary, external affairs unit, and legal, environmental and insurance services. Disaggregation would clearly lead to a duplication of some of these functions. Perhaps the most obvious cost is that of having to establish and maintain multiple boards (and associated senior management structures). However, it does not follow that this would necessarily mean an increase in staff numbers and in overall costs. To the extent that disaggregation of large generating enterprises into several smaller ones creates more competition in the market for electricity, each enterprise will have strong incentives to pare back its corporate governance costs and other overheads. Such conditions lessen the ability to indulge in excessive central spending and other forms of 'X-inefficiency'.

According to the Victorian ESIRU, disaggregation in Victoria has reduced these costs. It noted that significant savings have been achieved by removing the corporate overhead formerly in Generation Victoria, with each generator operating its own small corporate function.

Risk management costs

As noted above, another potential cost from having smaller generation businesses is a reduced capacity to self-insure against maintenance and unexpected plant outages.

More generally, the magnitude of the problem depends very much on whether there is an insurance mechanism available at the industry or market level, whether through a cooperative arrangement or from commercial insurers. The national electricity market arrangements will go a long way to providing such mechanisms, both directly (eg via a comprehensive pool settlements process) and indirectly (eg by providing a commercial environment which insurers may find attractive to enter). Risk management is treated in more detail in the following section.

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[1] The New South Wales Government has stated that public ownership is to continue (Egan 1995). One consequence is that equity capital will be supplied from the Government and not the commercial market. The other major consequence is that it will be difficult for the Government to avoid being seen as guarantor by prospective lenders. Generation Victoria was quoted in 1994 as arguing that such a guarantee would reduce the cost of debt by 0.25–0.5 per cent.

Industry or market level

The existence of a formal national electricity market offers the prospect of lowering costs across the electricity generation industry. In the context of the risks stemming from disaggregating multi-station generation businesses, the national electricity market will provide mechanisms to ensure the preservation of scale benefits that formerly tended to be obtained by having large generation utilities, principally in the area of managing the risks associated with plant outages at times of very high pool prices.

CitiPower Ltd, a Victorian electricity distributor and retailer, addressed the issue of risk management as follows:

> Economies of scale in generation derive primarily from plant level economies, and economies of integrated operation. The pool itself ensures that these need not be lost, even if single stations are under different ownership. Since the national market is based on a pool, portfolios are not needed to reap scale economies (Sub. 24, p. 6).

It needs to be recognised that with improvements in technologies and management techniques, the rate of forced outages has fallen sharply in recent years. For example, the forced outage rate for Pacific Power's thermal (ie non-hydro) plant has dropped from 19 per cent in 1987–88 to 3 per cent in 1993–94 (Steering Committee 1995 and previous issues). Nevertheless, unplanned equipment stoppages still present a significant source of risk to generators.

One strategy that generation enterprises might pursue to manage their outage risks is to enter into co-insurance contracts with major users who are able to shed loads under specific conditions. The effectiveness of this strategy depends partly on the structure of the generating industry — where large generators have sufficient market power to self-insure, risk sharing mechanisms between the remaining players will be less efficient because they cover only part of the market. The Victorian Power Exchange stated that Pacific Power has a significant advantage over single power stations (as in Victoria) in offering firm hedging contracts to distributors. However, it noted that such risks can be managed through co-insurance schemes in a disaggregated generation industry, but that it remains to be seen if such schemes can pass ACCC scrutiny.

Yallourn Energy acknowledged the need for a small generation business to seek insurance cover. However, it contended that the cost of such cover is offset by the payments it receives to cover other generation businesses:

> Yallourn's position is that, while it pays more for obtaining this cover from other generators, this extra cost is more than offset by the payments it has the opportunity to receive following commercial negotiations with these same generators for

> covering their outages. The claimed benefits of “self insurance” may be ephemeral in a competitive commercial market and more than offset by the other benefits of such a market (Sub. 23, p. 3).

The Generation Victoria Disaggregation Study discussed the costs of obtaining back-up capacity with a disaggregated generation structure compared with the corresponding costs involved in retaining a multi-station enterprise (CS First Boston and KPMG Peat Marwick 1994). It concluded that:

- Outages impose costs whether they are borne by a single entity or shared between contracting generators. With separation, these costs may become explicit as an element of an ‘insurance’ premium paid by each enterprise. An aggregated generator can bear these costs as they occur. However, the underlying cost is not increased by disaggregation.
- Centralised systems have often performed badly in terms of providing incentives to gather and act on relevant information and to meet customer needs. For example, centrally coordinated generation systems have often resulted in over capacity at relatively high capital cost, which effectively transmutes the risk from one form (low back-up capacity) to another (higher debt and financial risk).
- Although specific contracts may be needed to coordinate separately owned generators, the same coordination is not achieved costlessly within a single organisation. Scheduling of maintenance must still be agreed between the different stations, and contingency plans must still be formulated and agreed upon in the event of unscheduled outages.
- In the national electricity market, generators and customers will be able to purchase back-up supplies in the spot market (and the forward market) at all times. Contracts between generators and with customers will therefore be undertaken by parties who prefer to pay a premium over the spot price during normal periods so that they can pay less than the (potentially very high) spot price during abnormal periods. The existence of the spot market will limit the price that parties will be prepared to pay for back-up or for supply from each other. There is likely to be a variety of ways in which generators and customers can obtain the coverage they prefer.

Other options for risk management that may develop more strongly as the national electricity market matures are stronger forward market arrangements and commercial insurance products to accept at least part of these risks. It would appear that adequate avenues exist for risk management by disaggregated generating enterprises.

C.2 Economies of scope

This section discusses Pacific Power's product range and the extent to which output costs are lowered by having a portfolio of output types (ie economies of scope). Pacific Power's core business in the future (when coal mines have been separated from it, as announced by the State Government) will be electricity generation for the wholesale market. In that context, it is sensible to consider whether separate products exist within the wholesale market. Pacific Power's other outputs include international consultancies, developments and training, and research and development. The potential for economies of scope to be realised across these activities is discussed in the following sections.

Electricity products

It might be argued that Pacific Power's participation in the wholesale electricity market is, in reality, made up of separate sales of electrical energy for base load, intermediate load, peak load, reserve and ancillary services purposes. If these were treated as definable products, then it could be relevant to consider the economies of scope in producing combinations of them.

In theory, such economies would be seen to accrue if an enterprise with plants which were each specifically set up to supply, say, peak, intermediate or base load demands separately were to have lower average costs, per unit of output, than another of the same capacity but which directed all its plants to supplying just one of these categories. It is difficult to see how this could be so and, in any event, a multi-plant enterprise will usually seek to provide at least some measure of generator back-up within its group, even if insurance mechanisms are also available externally (as discussed in section C.1). Further, most generating plant types have at least some capability to supply into market segments other than those where their strengths lie, which blurs the issue of scope economies even more. Only detailed empirical analysis for a given enterprise could reveal the extent, if any, of such scope economies.

International consulting and investment projects

Pacific Power (International) Pty Limited was formed some years ago as a wholly owned subsidiary of Pacific Power to market the skills developed by Pacific Power to overseas clients on a commercial basis. It has been consulted on coal-fired generation, high-voltage transmission, utility management and environmental technologies. Many assignments have also involved the provision of training to overseas utilities in managing generating businesses by applying practices developed by Pacific Power. In 1993–94, when Pacific

Power still had responsibility for the high-voltage transmission assets now managed by the Electricity Transmission Authority, Pacific Power (International) earned $6.1 million, with an operating profit before tax of only $65 000.

In the context of economies of scope, it is relevant to question, first, the extent to which the provision of international services depends upon the services being linked to a generating company and, second, the effects of disaggregation upon such services.

CitiPower Ltd suggested that, given the separation of coal mines from power stations in New South Wales, no significant economies of scope are readily apparent, except possibly in design and construction activities of new power stations. However, it expressed reservations about this possibility:

> Even this is doubtful; smaller generators can access a huge body of international expertise (Sub. 24, p. 6).

CitiPower also stated that, even if smaller companies cannot afford to spend much on their own on broader, longer term issues, like strategic research or international consultancies, there is no reason why they cannot form separate and ad hoc joint ventures to pool their resources to undertake such activities.

Some within the power industry contend that a consultant needs direct experience with all aspects of coal-fired generation on a large scale in order to win overseas jobs associated with that technology. The experience does not necessarily bear this out — some players who have won substantial international consultancies are not active power companies, such as the Merz Sinclair and Kinhill engineering groups. Such firms are, of course, able to hire specialists who have previously worked in large generating enterprises.

Be that as it may, it is difficult to see why the assembly of such expertise could not be achieved through joint venture arrangements or companies attached to Pacific Power progeny. In fact, versions of this already exist:

- SECV International Pty Ltd was formed following the structural separation of the SECV to continue the overseas consulting business built up by the former vertically integrated utility;
- the Snowy Mountains Engineering Corporation Ltd was formed several years ago to formalise and develop the Snowy Mountains Authority's international consulting business, which has been in high demand; and, perhaps most significantly,
- under the auspices of Austrade (the Australian Trade Commission), the Austenergy consortium has been operating for some years to coordinate participating Australian energy sector companies in obtaining and

> undertaking international consultancies and projects, mainly in the electricity field. Pacific Power is a prominent member of Austenergy. Consequently, as with research and development (discussed in the next section), an organisational infrastructure already exists which would reduce any international consulting and project costs associated with disaggregation of Pacific Power.

Further, just because a consulting company is small does not mean that its ability to attract international work will be hindered — for example, the Hydro Electric Commission of Tasmania has been quite successful.

With regard to participation in international projects involving direct foreign investment like build-own-operate schemes, it may be that many such activities would in any case remain effectively beyond the reach of Pacific Power, or any offspring it may have upon disaggregation. The New South Wales Government has made it clear that public ownership is to be maintained whatever structure is adopted in future (Egan 1995). The constraint that this implies for equity participation in international projects may serve to limit the ability of Pacific Power to participate in some of the more lucrative international projects. In particular, its potential may be more limited to the role of adviser or project manager, rather than in construction or being involved as an equity holder.

Research and development

It is sometimes suggested that beneficial research and development programs will flounder if disaggregation occurs. Smaller firms may not have the resources to invest in the larger projects individually, and may be reluctant to do so in cooperation with their peers. Further, smaller firms face coordination costs in identifying the projects that are likely to benefit them collectively.

On the other hand, in a more competitive market, there may be gains from better targeting of research and development funds, and less risk of overspending on such projects. As the Victorian ESIRU commented:

> In respect of new generation technologies, the open access regime currently in operation in Victoria, and as proposed for the National Market, provides the necessary price signals to allow entry at an appropriate time, but only if an economic return from the new technology is available. The removal of barriers to entry, and breaking up of generation monopolies, can only serve to promote private sector interest in prospective energy R&D (Sub. 30, p. 15).

In any event, a useful framework already exists for cooperative research funding. The Australian Electricity Supply Industry Research Board (AESIRB), a wholly-owned subsidiary of the ESAA, has operated for many years to coordinate funding and selection of studies on behalf of the electricity supply industry (including generators, transmitters and distributors). In 1994–95, it spent $48 million, which can be compared with Pacific Power's research and development spending of $15 million in 1993–94. It has a statutory relationship as the electricity industry's representative group with the Commonwealth Government's funding agency, the Electricity Research and Development Corporation (ERDC).

The existence of AESIRB and, to a lesser extent, the ERDC, would tend to limit the research and development losses that might accompany restructuring in the electricity supply industry. This is reinforced by the existence of further groupings in which generators maintain individual funding equity such as the Ceramic Fuel Cells Ltd consortium.

For all that, there may well be some studies that are of interest to Pacific Power and not to other generators, where AESIRB or ERDC support has not been forthcoming or is inadequate. For example, Pacific Power currently holds large petroleum exploration permits in the Sydney Basin for the purpose of investigating the viability of using the large coalbed methane reserves there as a fuel. A disaggregation of Pacific Power should not preclude its progeny from cooperating on such research and development projects, perhaps through joint venture arrangements. In any event, New South Wales electricity generators will still have an incentive to coordinate in order to better attract resources from the State Energy Research and Development Fund.

APPENDIX D: HOW LONG WILL THE EXCESS GENERATING CAPACITY LAST?

A key issue in assessing likely electricity price levels and the market behaviour of large generators is the level of excess generating capacity in the industry. With excess supply and a competitive market, prices would be expected to fall to levels which only cover variable costs. On the other hand, a generating company which controls a high proportion of capacity may be able to withdraw it from commitment to dispatch (or bid it at extremely high prices) and increase prices. The presence of excess capacity simply means that more units would be withdrawn to attain a given price outcome.

This appendix examines the outlook for electricity generation and consumption in the four-state region over the period to around 2005. The Commission has drawn on the NGMC's latest review of its *Statement of Opportunities*, published in May 1994.[1] The NGMC employed a set methodology for considering both future consumption and generating capacity.

- On the consumption side, individual state economic and demographic growth scenarios were prepared using consistent methodologies which translated to credible national growth assumptions. Each state utility then undertook detailed forecasting analysis, using knowledge of regional market conditions, to translate the expected future economic and demographic environment into electricity forecasts under high, moderate and low growth scenarios (NGMC 1994b). Since the national electricity market will accord an even-handed role to demand-side and generators' bids, the NGMC's electricity usage projections make allowance only for existing or committed energy efficiency programmes and trends.
- On the capacity side, account was taken only of existing and committed new generating plant, along with unit retirements for future years that had already been announced (NGMC 1994c).

The New South Wales outlook is considered first, followed by the four-state outlook.

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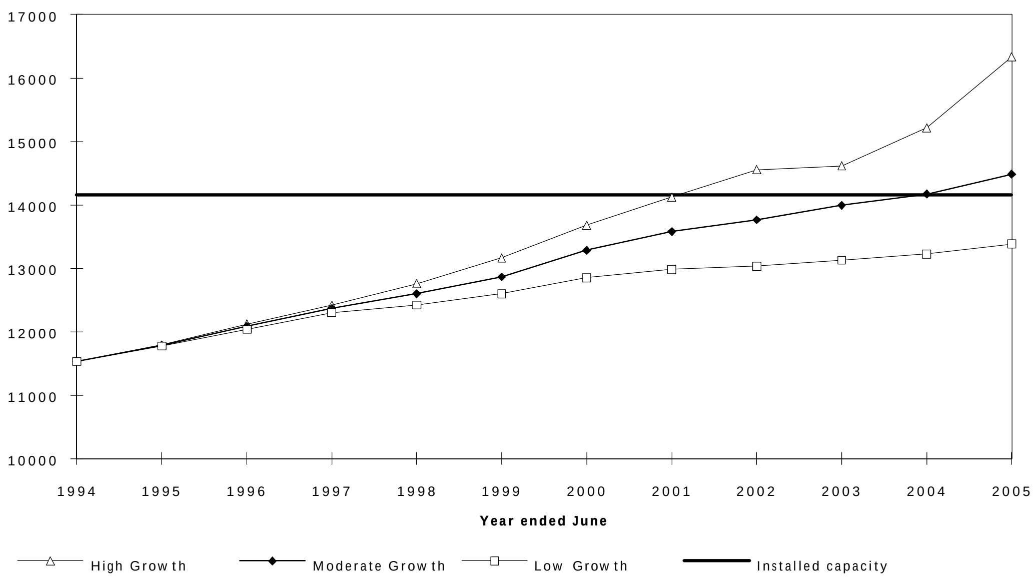
1 The Commission understands that there is not to be a 1995 update on the basis that little has changed over the past year.

D.1 New South Wales outlook

Figure D.1 shows the NGMC's May 1994 projections for electricity generating capacity required to reliably supply projected loads in New South Wales under high, medium and low growth assumptions to the year 2005–6. The load projections relate to peak demands, which are expected to be in winter in most years, and include an allowance (made by Pacific Power and not disclosed) for reliability of supply. Growth in electricity consumption is projected to be at the rate of 2.3 per cent per annum in the moderate growth forecast, with a range of 1.1 per cent (if growth is low) to 3.5 per cent (under high growth assumptions).

Figure D.1: Forecast electricity consumption and capacity levels in New South Wales, 1994–2006 (MW)



Source: NGMC (1994c).

Figure D.1 also shows the level of installed and committed generating capacity within New South Wales as projected by the NGMC. The Figure indicates that excessive levels of generating capacity will remain until about the year 2004 (based on the moderate growth projection).

The outlook projected in Figure D.1 is conservative in two senses. First, some new commitments to install generating plant have been made since May 1994, notably:

- the commitment to develop the 160 MW Smithfield power station; and
- the increased possibility that Eastlink will be commissioned, with a firm base load contract effectively transferring 500 MW of Pacific Power capacity for Queensland use for several years.[2]

The impact of these developments would be to require new generating capacity to serve New South Wales and ACT customers around the year 2002 under the medium projection, or as early as 2000 if growth in demand is high. Low demand growth would still see no new capacity requirement before about 2010.

Second, there is a strong likelihood of additional commitments by private ventures between now and 2005. Indeed, Pacific Power suggested that private generating capacity in New South Wales could expand fourfold over the next five years to reach around 8 per cent of the total capacity in the state (see Table 4.2). If that amount of new private capacity is installed in addition to Smithfield and Eastlink, the surplus could remain — under the moderate growth scenario — until about 2006.

The introduction of the national electricity market arrangements will not change the underlying factual situation reported by the NGMC (1994b,c), which implicitly sees each plant being used to the end of its technical operating life. However, it may radically change the capacity utilisations of high-cost plant (especially plant with high variable cost in the period in which excess capacity persists across the interconnected market). For example, in Box 5.2 (see Chapter 5) evidence from Pacific Power is reproduced which indicates that its plant has higher variable costs than power stations in Victoria and Queensland. As noted above, Pacific Power also expects a substantial rise — about fourfold — in the level of private generation in New South Wales over the next five years or so, a high proportion of which could be committed under long-term contracts. Under these conditions, when the national electricity market becomes fully operational (ie when the vesting contracts have lapsed), Pacific Power could *lose* sales to Queensland, Victorian and private generators, so that it will have a larger degree of excess capacity (at least in proportional terms) than at present.

2 For the purposes of this section, only developments of over 100 MW in capacity have been taken into account. However, there may well also be a significant number of new generators in the 5–100 MW size range.

D.2 Four-state outlook

Figure D.2 shows projections for electricity demand to 2005–6 in the combined market of New South Wales, Victorian, Queensland, South Australian and the Australian Capital Territory. As in Figure D.1, scenarios for low, moderate and high growth are presented. The NGMC did not publish this figure. Instead, it has been produced by drawing on the NGMC's 1994 individual state projections using a three-step process.

First, it was necessary to align the peak electricity consumption projections for each state with each other. This is required because it is rarely the case that two (or more) states experience peak electricity demands on the same day. To effect this alignment, each state's projected winter and summer peak loads were multiplied by 'diversity factors' published by the NGMC and reproduced in Table D.1. These diversity factors are averages for the period 1988 to 1993 and should be interpreted as follows. On the day of peak summer demand for the four-state region:

- the demand in New South Wales (and the ACT) was 96 per cent of that area's peak summer demand;
- the demand in Victoria was 97 per cent of that state's peak summer demand;
- the demand in Queensland was 93 per cent of that state's peak summer demand; and
- the demand in South Australia was 93 per cent of that state's peak summer demand.

Table D.1: Average diversity factors in the four-state region, 1988–93

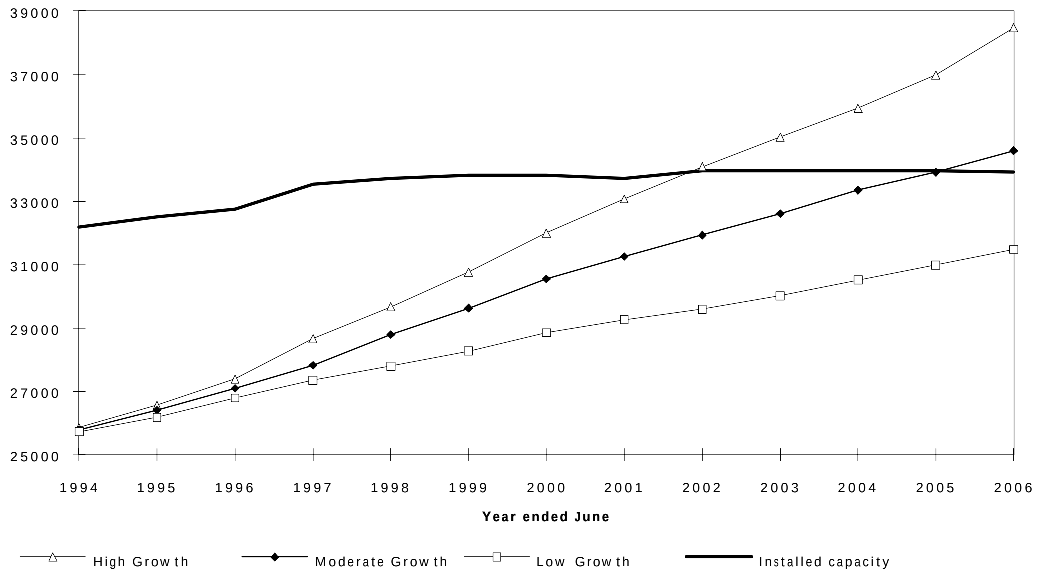
State	*Summer*	*Winter*
New South Wales[a]	0.96	1.00
Victoria	0.97	0.98
Queensland	0.93	0.98
South Australia	0.93	0.94

a Includes the Australian Capital Territory.
Source: NGMC (1994c).

Second, the higher of the four-state summer and winter projections was used for each year.

Third, to make an allowance for reliability needed to maintain supply, the projections were increased by 20 per cent, which represents a rough estimate of the level of reserve plant margin (RPM) that will be required to maintain supply in the four-state region.

Figure D.2: Forecast electricity consumption[a] and capacity levels in the four-state region, 1994–2006 (MW)



a Accounts for load diversity between the states and a reserve plant margin assumed at 20 per cent — see text.

Source: NGMC (1994b,c).

Figure D.2 also shows a projection of installed generating capacity for the four states. These take into account the sent-out capacity levels and changes published in NGMC (1994c) and the following commitments to new generating plant which have been made since that document was prepared in early 1994:

- the Smithfield 160 MW cogeneration plant near Sydney which, as noted above, has been announced;
- another 250 MW unit at the Northern power station in South Australia, as indicated by ABARE (1995);

- development of a 180 MW cogeneration plant to produce base load power for ETSA Corp, which has recently been announced in South Australia;
- the refurbishment of the Collinsville (180 MW) power station in Queensland, which is expected to be back in service by 1998; and
- the refurbishment of Queensland's Callide A (120 MW) power station.

As with Figure D.1, the installed and committed generating capacity projections in Figure D.2 are conservative in the sense that they take no account of likely (but uncommitted) developments, and there are considerable uncertainties about the extent and rate of new investment in generating plant. Consequently, no account is taken of the fact that the increase in private generation within New South Wales to which Pacific Power alluded is likely to be parallelled to some extent in the other states. Similarly, no account is taken of the Queensland Government's recent announcement foreshadowing (but not committing) developments over 2003–6 that will be needed in that state (whether built by government or private enterprises) and which include:

- 600 to 1400 MW of new base load capacity; and
- 440 MW of new peaking plant, of which 110 MW will be at Townsville (McGrady 1995).

Figure D.2 indicates that new capacity commitments will be required to supply the four-state region from around the year 2005 under the medium growth scenario. Low growth will defer the need for additional generating capacity to well beyond 2006. If growth is higher than expected, new capacity will be required by about 2002. This analysis is incomplete in the sense that no account is taken of any transmission constraints (ie neither losses nor link capacity limits), and it may be that, in some parts of the four-state region, either new power lines or new generating capacity will be required earlier to reinforce local electricity supplies.

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