Competition in Electricity Spot Markets Economic Theory and International Experience

by

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1. Introduction[1]

The introduction of competition in the generation of electricity has been a key aspect of electricity industry reform and decentralisation which has recently been occurring around the world. A central feature of decentralised electricity markets is the wholesale electricity spot market, or pool. 'Competitive' pools - by which we mean electricity spot markets in which generators compete to supply energy through their supply prices or bids2 - have been introduced in a number of countries since 1990, and are in the process of being adopted elsewhere. The first fully competitive pool was introduced in England and Wales (E&W) in 1990. In Norway a competitive pool for 'marginal' energy trades was created in 1991. In Australia two new power pools have recently been set up in the states of Victoria and New South Wales respectively, and these are now in the process of being merged into the National Electricity Market which began operation in April 1997. Competitive pools subject to various degrees of regulatory oversight have also been created in Chile, Argentina, and Alberta, Canada. And in California a major project to design a competitive electricity auction is currently underway.

The creation of a pool raises a number of fundamental questions concerning industry market structure, the role of regulation, and the design of the electricity auction itself. A key issue is the horizontal structure of generation, and whether the large, typically publicly-owned, generating companies should be left intact, or broken up into several smaller competing units in order to limit the potential for the exercise or abuse of market power. Experience with competitive pools to date - for example in England and Wales, and in Norway - has amply demonstrated that this potential exists, and that this may frustrate the aims of the electricity market reform process, and prevent the achievement of economic efficiency. It may also create a need for more interventionist regulatory regimes than envisaged at the time reforms are introduced, in order to compensate for the lack of effective competition in the pool.

An equally important set of issues concern the design of the pool bidding process, or auction. Should electricity auctions be 'one-shot' or iterative? Should there be a single market-clearing price, or should prices be determined by individual transactions (i.e. as in a dynamic 'bid-ask' market)? Should a uniform first-price or a discriminatory second-price auction be used? Should there be a single market, or separate markets for energy and supply security? Should generator bids include elements of fixed costs, or be for energy only? What constraints on generator bidding behaviour should be imposed? Should capacity bids be revocable, or should generators be financially penalised for failing deliver on promised capacity? What role should be accorded to demand-side bidding? And so on. Not all of these issues will be explicitly addressed in any detail in this paper, however most will be touched on in passing (see in particular Section 5). We mention them here to illustrate the types of questions which are being increasingly raised as experience with one or another form of pool increases, and different problems emerge.[3]

One important question which has been little studied to date, is the form of the pool pricing mechanism itself. Most pools implement some approximation or other of a peak load pricing formula. However as pointed out in von der Fehr and Harbord (1995)(1997b) the peak load pricing literature has little to say on the question of how generators should be remunerated in

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1 We are grateful to Tony Curzon Price and Steinar Strom for useful comments on an earlier version of this paper.

2 In some pools consumers also compete to purchase energy by submitting demand-side bids.

3 Binmore and Harbord (1997) touches upon many of these and other issues.

competitive electricity markets. Rather, it is concerned entirely with determining *optimal* consumer prices for electricity subject to informational and capacity constraints. Since the standard pool pricing mechanisms have the form of reverse, multi-unit, first price auctions, in our papers on electricity spot market competition we considered the effects on despatch efficiency and generator payments of an alternative pool pricing mechanism, modelled as a generalised 'Vickrey' auction. This is discussed further in Section 5 below. However the general issue of the performance of alternative 'second best' pool pricing mechanisms in markets in which generators are able to exert market power remains to be studied in greater detail.

A number of questions therefore need to be addressed in creating or reforming electricity spot markets or pools:

- should existing generation companies be broken up into smaller units (i.e., horizontally disaggregated) in order to encourage more competitive market behaviour, or left intact?
- what auction form should be used and what should the pool pricing mechanism be?
- what constraints should be placed on generator offers or bids?
- should pool bidding behaviour or pool prices be regulated?

International experience to date highlights the importance of assessing these issues using economic analysis which takes into account the specific institutional and economic features of electricity markets. In particular, the policy debate in the UK prior to privatisation was based largely upon economic models which were not well-suited to answering these questions, and at considerable subsequent cost in terms of economic efficiency.

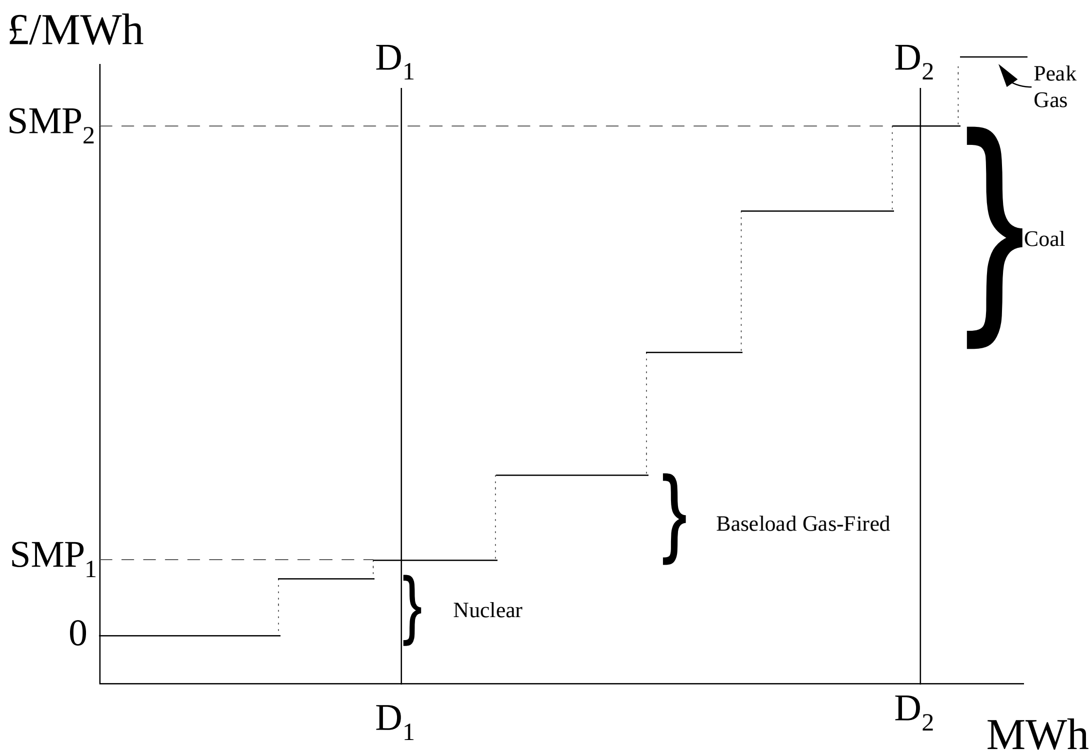
The main purpose of this survey paper is to consider the attempts that have been made to apply economic theory and empirical methods to the analysis of electricity markets, and to evaluate them in light of theoretical considerations and empirical evidence. This is done in Sections 3 to 5. Section 2 however, first describes in simple terms the basic pool pricing mechanism, and experience with pools in a number of countries. It is worth emphasising that it is not our purpose here to treat in extensive detail the structure of electricity pools around the world. Rather we describe the key features of the markets in England and Wales, Norway and Australia in order to allow for a comparison of design issues and evaluation of competitive performance, which is taken up in the subsequent sections.

2. Competitive Pools

An electricity spot market or pool is unlike virtually any other market since it must match demand and supply continuously to maintain network 'electrical equilibrium.' This requires that each generating unit follow the operating instructions of a central despatcher. It therefore fulfils the function of simultaneously permitting generators to compete to supply the market, whilst allowing for overall co-ordination of generation and transmission. Competition in electricity spot markets occurs by generators submitting price bids which specify the minimum prices at which they are willing to supply energy, and the amount of capacity of each type they expect to have available. On the basis of these 'offer prices', a least-cost plan of generating units is drawn up for despatch, taking into account transmission costs and constraints. This 'rank order' (i.e. merit order) of generating units, together with a forecast of demand, determines which units will be despatched in any particular period.

The pool determines electricity prices for each period (e.g. hourly or half-hourly) to reflect the changing balance between demand and supply over the day. As demand varies, different types of plant, with different operating and capital costs, are despatched at the margin to meet it. The short-run marginal cost of electricity production - or *system marginal price (SMP)* - which is used to determine prices, varies correspondingly. Ex ante, or expected, pool prices may be published in advance to allow larger electricity consumers to adjust their demands to this price information. Actual prices are typically determined by the interaction of the generators' bidding behaviour with demand, random capacity outages and transmission constraints. Figure 2.1 below depicts the price determination process in electricity pools, based upon a stylised 'merit order' or generation supply curve.

Figure 2.1 Stylised Pool Merit Order



Electricity pools, are thus well-defined market institutions designed to permit trade and competition in the supply of energy whilst simultaneously allowing for the overall co-ordination and control of generation and transmission. As such they provide a well-specified market mechanism by which generator price and quantity bids are translated into market prices and quantities. This pricing mechanism is not the standard one employed in economic textbooks to describe pricing behaviour in decentralised markets (i.e. it does not correspond to either Bertrand or Cournot competition). Therefore, in studying strategic behaviour in pools, it is both possible and necessary to employ models of the actual market institution in question, and in particular the pool pricing mechanism, since this will typically have profound effects upon the outcomes of strategic behaviour and interaction.

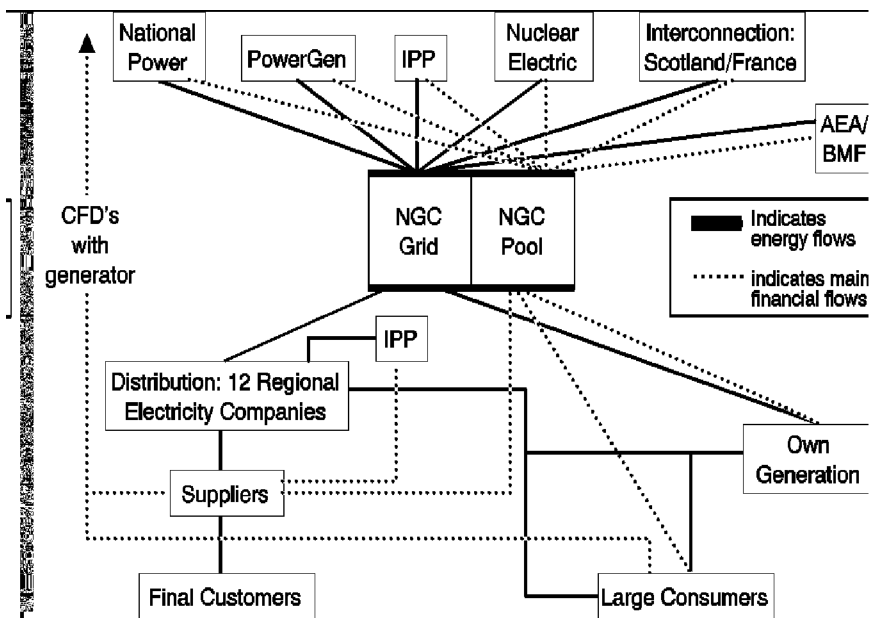
The following subsections describe the competitive pools in England and Wales, Norway and Australia. The issues currently being considered in the design of the California electricity auction are briefly discussed in Section 5 below.

2.1 The England and Wales Pool

The reform of the electricity supply industry in England and Wales in 1990 involved its wholesale reorganisation, and brought to an end the nationalised system created in 1947. Under this system the Central Electricity Generating Board (CEGB) owned and operated over 90% of approximately 60GW of installed generating capacity, and had a virtual monopoly of public electricity supply. Distribution and sales were undertaken by twelve publicly owned regional electricity boards, each with a local geographical monopoly.

Following the reforms generation, transmission, distribution and supply (i.e. electricity retailing) were 'unbundled' into separately accounted and administered functions within seventeen newly established electricity companies. The CEGB itself was broken up into four companies: National Power (NP) and PowerGen (PG), and Nuclear Electric (NE) which took all of the thermal and nuclear generating capacity, and the National Grid Company (NGC) which became responsible for the high voltage transmission network.[4] The former 12 area distribution boards remained intact and were re-named Regional Electricity Companies (RECs). All of these companies have now been sold into the private sector, and competition has been introduced in wholesale generation and supply.

Figure 2.2



The focal point for the new England and Wales electricity market is the wholesale spot market, or pool. The pool is operated by the NGC, and generators and suppliers - with a few exceptions - are required to sell or purchase all of their output via the pool. Figure 2.2 illustrates the institutional market structure created in 1991.

A key feature of the privatisation process - as is well known - was the creation of a virtual duopoly in thermal generation. The two privatised generation companies, National Power and PowerGen, received 62% and 38% respectively of the CEGB's thermal generating capacity, while the recently privatised Nuclear Electric received all of the nuclear capacity. The creation

4 As well as the CEGB's pumped storage hydro capacity.

of a duopoly in thermal generation did not bode well for the performance of the new market or industry, as was pointed out by numerous observers at the time (see in particular Vickers and Yarrow, 1990). The focus of regulatory policy - and much well-aimed criticism - concerning the operation of the new market has since been overwhelmingly concerned with the deleterious effects of this initial design decision. The market structure of the E&W industry at privatisation is depicted in Table 2.1.

Table 2.1 Market Structure in E&W, 1990/91

	Capacity	**Capacity %'s**	**Energy %'s**
National Power	30 GW	48%	46%
PowerGen	19 GW	30%	28%
Nuclear Electric	8.8 GW	14%	17%
Electricite de France	2.0 GW	3.2%	5%
Scottish Interconnector	.85 GW	1.3%	3%
Pumped Storage	2 GW	3.0%	1%
TOTAL	**62.5 GW**	**100%**	**100%**

2.1.1 Price Determination and Bidding in the England and Wales Pool

The pool in England and Wales operates as a centralised exchange for the wholesale purchase and sale of electricity. It determines the prices and quantities of energy exchanged in a daily, day ahead auction, and operates a financial settlement system.[5] All licensed generators and suppliers of electricity are pool members, and pool members are obliged to sell all of their output, and to purchase all of their energy requirements, through the pool trading arrangements.[6]

Like virtually all other electricity spot markets, the England and Wales pool is a daily *reverse auction* in which each generator bids:

- the amount of capacity of each type it has available each day, and
- the price(s) at which it is willing to sell output from each capacity unit

The generators' price and capacity bids are used to construct a 'merit order' of generating units, i.e. a supply curve is constructed. The intersection of the day ahead supply curve with estimated demand determines 'system marginal' price (SMP) for each half-hour of the following day. The generators' price bids are fixed for the subsequent 48 half-hour periods and SMP for each half-hour is determined up to twelve hours in advance. Capacity bids however, can be altered up to the moment of operation. Figure 2.1 above illustrates the determination of SMP.

The pricing mechanism in the England and Wales pools bears some resemblance to a (simplified) stochastic peak load pricing formula. Although demand and supply conditions

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5 Actual scheduling and despatch is carried out by the Grid Operator which is the NGC

6 More detail on the institutional structure of the E&W pool can be obtained from The Electricity Pool (1994a) (1994b); see also OXERA (1995).

may vary more or less continuously over the day, pool prices are determined in advance for discrete (i.e. half-hourly) time periods. This means that in any period there is some non-zero probability that supply will be insufficient to meet demand and rationing or "loss of load" may occur.[7] This probability is denoted by LOLP. The E&W pool determines Pool Purchase Price (PPP) - the price paid for "in merit" or scheduled generation - for each half hour by the formula:

$$PPP = (1\text{-}LOLP)\times SMP + LOLP\times VLL$$

where SMP = system marginal price, and VLL = the value of lost load. The value of lost load is intended to reflect the consumer welfare loss from being denied supply, and hence the value of an additional unit of capacity in the event of rationing (i.e. consumers' marginal or average willingness to pay for electricity). VLL was set initially at £2 per MWh, and has increased at the rate of inflation since.

The formula for PPP is often written:

$$PPP = SMP + LOLP\times(VLL\text{-}SMP)$$

and LOLP×(VLL-SMP) referred to as the "capacity element." The interpretation usually given is that SMP is the price generators that are paid for "energy," and the "capacity element" is intended to recompense them for providing capacity or "security of supply" to the system.

Bids and Costs

Daily and half-hourly generation costs for different types of generation capacity are characterised by differing combinations of fixed and energy-related costs. The structure of bids in the E&W pool reflects these cost characteristics. Generators can submit up to six price bids per generating unit per day. These are:

(i) a start up rate (£);

(ii) a 'no load heat' rate (£/hr);

(iii) 3 'incremental heat' rates (£/MWh); and

(iv) a 'maxgen' price (£/MWh) for operation above normal operational limits.

The elements of bids reflecting generator fixed costs, i.e. the 'start-up' and 'no load' rates, are averaged over periods of continuous running to determine an average price. This average price is then used to rank generating units and determine SMP in most periods.[8] Price bids for each generating unit (or 'genset') are binding and cannot be altered. Capacity bids however are not binding: on the day of actual operation generators may reduce or increase their operating availability.

Transmission Constraints and Losses

System marginal price is determined in the E&W pool by the bid price of the marginal generating unit in what is termed the *unconstrained merit order*, i.e. the supply curve constructed ignoring transmission constraints and losses. Actual generation will typically differ from this. After using the unconstrained merit order to determine a single system-wide

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[7] In electricity parlance "load" = "demand", and hence loss of load refers to the event that a consumer or consumers may be temporarily prevented from consuming.

[8] In Table B (i.e. low demand) periods only incremental heat rates are used to determine SMP.

energy price for each half hour, the Grid Operator calculates a revised despatch schedule. Some generators previously “in merit” will not be scheduled to supply because of transmission constraints, and some previously “out of merit” generators will operate (i.e. they are “constrained on”). Payments to generators are calculated to take account of this. Payment for generation ‘scheduled’ in the unconstrained merit order is made at PPP, and payment for scheduled reserve at PPP minus the generating units incremental cost. Payment for availability is determined by LOLP*(VLL - Max {SMP, Average bid price}). ‘Constrained on’ generating units are paid their bid price plus the capacity payment, and ‘constrained off’ units are paid at PPP minus their bid price.

Consumer Payments

Because payments are made to generators which are not supplying scheduled energy, and transmission losses are ignored, the wholesale purchase price is adjusted accordingly. The pool selling price (PSP) is determined as follows:

$$PSP = PPP + Uplift$$

where Uplift includes the costs of ancillary services, reserve, availability payments and constraint costs. Losses are allocated pro rata to consumer demand and charged at PSP. Uplift is determined so as to make pool revenues balance pool payments each day.

2.1.2 Performance and Design Issues in the England and Wales Pool

The intention at privatisation was that the pool in England and Wales would be unregulated, despite the virtual duopoly in non-nuclear generation that was created.[9] The conviction that generation did not require regulation was, according to some observers, based upon two arguments.[10] First, the belief that the two major generating companies - National Power and PowerGen - would compete on price as ‘Bertrand’ oligopolists, and the resulting fierce competition would result in prices being bid down to near marginal costs. And second, that free entry into generation - in particular using high-efficiency combined cycle gas turbine technology (CCGTs) - would be simple and quick and place further strong competitive pressures on the incumbent generators to price competitively. These expectations have not been borne out by experience however. Pool prices in England and Wales have been significantly higher than they would have been in a competitive market, and the regulator has now intervened on numerous occasions to prevent certain types of manipulation of the pool pricing mechanism from occurring. From February 1994 moreover, average pool prices were subject to a two year regulatory price cap agreed between the regulator Offer and National Power and PowerGen. In addition, high pool prices appear to have been partially responsible for inducing excessive entry by independent power producers (IPPs), and the risks of these

9 The Electricity Act of 1989 set up the Office of Electricity Regulation (Offer) headed by the Director General of Electricity Supply (DGES) to administer and execute the regulation of the industry. The Act provides the DGES with authority to ensure adherence to the conditions of licenses which are required by all companies operating as generators and suppliers as well as licenses specifically covering the activities of the RECs and NGC. The DGES's primary duties are to (i) secure all reasonable demands for electricity; (ii) ensure that all licence holders are able to finance adequately the activities for which they hold a licence; and (iii) promote, where possible, competition in generation and in supply which includes ensuring open and fair access to the grid networks. Where competition is insufficient, the DGES is charged with protecting the interests of consumers.

10 See Green and Newbery (1992) for instance.

investments have been passed on to franchise consumers via contracts with RECs, who have taken equity stakes (see Helm, 1994).

The competitive performance of the England and Wales pool has now been treated at length in numerous places, and will not be discussed in any detail here.[11] Suffice it to say that a number of features of the operation of the pool, and the way in which generators are remunerated, have been sources of competitive problems:

- the duopoly generators National Power and PowerGen have been able to exert their market power in the pool to maintain SMP and PPP above competitive levels. Despite significant efficiency improvements, net of fuel cost consumer prices have not fallen in real terms, so practically all of the benefits of increased efficiency have gone to shareholders (see Newbery and Pollit, 1996 for this evidence);
- capacity declarations and redeclarations have been manipulated to increase the capacity element (LOLP) and SMP. By declaring capacity unavailable initially and then subsequently redeclaring it available, both of these elements of PPP are likely to be increased. Re-declared capacity is then paid at least the capacity payment (LOLPxVLL), and, if despatched, it is paid PPP;
- generating stations which have been predictably `constrained on' have been bid in at very high prices to maximise their revenues; generating units which are predictably 'constrained off' have been bid in at very low prices to ensure that they are in merit, and to maximise their payments (i.e. the difference between PPP and their bid price).

Each of these issues, and numerous others, have been the subject of investigations by the regulator Offer, which has taken steps to alleviate them within the limits of its authority. This has included the imposition of a two year price cap from February 1994, coupled with an enforced change in market structure via capacity divestitures, agreed between Offer and National Power and PowerGen. Indeed the market structure in the England and Wales pool has now changed significantly since privatisation because of:

- the introduction of over 6 GW of independent CCGT capacity between 1993 and 1997;
- the retirement of coal-fired plant owned by National Power and PowerGen;
- the upgrade of the Scottish interconnector from 850 MW 1650 MW; and
- the recent divestment of 6 GW of coal plant by NP and PG, which has been sold to Eastern Electricity Group.

One important impact of these developments has been to reduce NP’s and PG's share of ‘baseload’ capacity, making them effectively ‘mid-merit’ generators. In particular, practically all of the new CCGT stations - because of take or pay gas contracts and financial contracts with the RECs - bid into the pool at very low prices and operate as baseload plant. Consequently the new CCGT plant rarely, if ever, determines SMP. Table 2.2 depicts the market structure as of November 1996, and Table 2.3 shows statistics on bidding behaviour and price determination prior to the recent capacity divestments.

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[11] See, for instance, the numerous reports by Offer cited in the references. Also von der Fehr and Harbord (1993), Green and Newbery (1992), and Armstrong, Cowan and Vickers (1994). For more recent evaluations of the evidence see Wolak and Patrick (1996), Newbery and Pollitt (1996) and Newbery (1995).

Table 2.2 Market Structure in E&W, 1995/6

	Capacity	Capacity %'s	Market %'s
National Power	20.4 GW	34% (27%)	33% (21%)
PowerGen	16.8 GW	28% (24%)	24% (20%)
Nuclear Electric	10.8 GW	18%	22%
EDF	2.0 GW	3.3%	6%
Scotland	1.6 GW	2.6%	4%
Pumped Storage	2.4 GW	4%	1%
IPPs	6.0 GW	10% (12%)	10% (13%)
TOTAL	**60**	**100%**	**100%**

(*) = estimated 1997 figure given plant divestment by PG and NP

Table 2.3 Bids and Price-Setting

Average Bids of Generators, May 1996

Coal	£3.5 - £100/MWh
Nuclear	£0/MWh
EDF	£7.15/MWh
IPPs	£0 - £7/MWh

Who Sets SMP? (November 1995-1 March 1996)

NP	49%
PG	34%
PS	11%
EDF	2%
Other	4%

(PS = pumped storage)

Given the recent capacity divestments, and the creation of a new significant generator, Eastern Group, which it is estimated will have a 12% market share in 1997, it is currently difficult to predict the effects of all of this on future competitive bidding behaviour.

2.2 Nord Pool

Since January 1 1996, Norway and Sweden have operated a joint, open access electricity pool. Nord Pool is basically an extension of the previous Norwegian pool, which traced its history back to 1971. In 1971, five Norwegian regional power exchanges were merged to form a national Power Exchange ('Samkjøringen'). The Power Exchange was owned by its members, with membership being limited to the major generators. The Power Exchange operated as a wholesale market at the margin, allowing participants to sell surpluses, or cover deficits, relative to their long-term contractual obligations.

With the implementation of the Norwegian 1990 Energy Act, ownership and operation of the pool was taken over by Statnett Marked, a subsidiary of the grid company Statnett SF. The restriction on membership in the pool was lifted, allowing for entry by a range of new participants, including smaller producers, retailers, traders and large consumers. Foreigners were allowed to trade in the pool, although under special arrangement.[12] In 1996, following the deregulation of the Swedish electricity supply industry, a joint Norwegian-Swedish pool was formed owned on a 50-50 basis by Statnett and Svenska Kraftnät, the Swedish grid company. Open access to the pool was extended to Swedish participants and Statnett Marked changed its name to Nord Pool ASA.

Nord Pool is not currently required by the Swedish authorities to operate under any particular licence, but new regulations which will change this are being introduced. Nord Pool does operate under a Norwegian licence, which gives it the nonexclusive right to organise physical trade in energy. Unlike in England and Wales, pool membership is voluntary and the pool therefore continues as a wholesale market for marginal energy exchanges. Although the share of energy traded through the pool is increasing, most energy is still traded under firm contracts outside of the pool (see below). In 1996, 16% of total energy consumed in Norway and Sweden was traded through the pool.

2.2.1 Nord Pool Market Structure

There are approximately 140 participants trading in the Nord Pool markets. These include generators, distributors, large power consumers, brokers and traders. The majority of traders are from Norway and Sweden, but there are also some members from Denmark and Finland. Since the markets in Denmark and Finland are heavily regulated, with limited opportunity for utilities to trade in the wholesale electricity market, here we limit attention to the markets in Norway and Sweden.

Generation capacity is dominated by hydro power, which accounts for more than 99% of Norwegian energy capacity, more than 40% of Swedish capacity and for about 70% of the combined energy capacity of the two countries (Table 2.4 below). In addition, Sweden has a considerable capacity of nuclear power, which accounts for more than 25% of the average annual output of Norway and Sweden. Thermal power is relatively unimportant, and less than 5% of total output is produced by thermal technologies.

On average, both countries are self sufficient in electricity. However, depending on demand patterns and meteorological conditions, there may be considerable yearly and seasonal trade with the thermal-based systems in neighbouring countries (Denmark, Finland, Russia and Germany). In 1995, imports accounted for about 3% of total electricity consumption in Norway and Sweden. The trade deficit turned to a surplus in 1996, equivalent to 6% of total energy consumed.

In both countries, electricity production is dominated by one or two large generators which compete with a fringe of smaller firms. On average, the four major Norwegian and Swedish

[12] Trade with Elsam, the Danish electricity corporation responsible for energy supplies in western Denmark (Jutland), was organised via Statkraft, the main Norwegian (state-owned) generator. In Sweden, the main generator, Vattenfall, had a monopoly on external trade and submitted its bids via Statnett Utland, a subsidiary of Statnett SF.

generators account for 60% of total output (Table 2.5 below). The retailing business is not very concentrated and there exist in each country a large number of distribution/retailing companies, most of which are very small.

Table 2.4 Generating Technologies, GWh

	1996			1995		
	Total	Norway	Sweden	Total	Norway	Sweden
Hydro	155 187	104 091	51 096	189 938	122 845	67 093
Thermal	14 306	780	13 526	10 280	645	9 635
Nuclear	71 385	-	71 385	66 978	-	66 978
Total	**240 878**	**104 871**	**136 007**	**267 196**	**123 490**	**143 706**
Net export	15 168	9 047	6 121	-8 770	-7 069	-1 701
Total consumption	**256 046**	**113 918**	**142 128**	**258 426**	**116 421**	**142 005**

2.2.2 Bids and Price Determination

Nord Pool operates two separate markets; 'Elspot', a day ahead market for physical deliveries, and 'Eltermin', a futures market which deals in financial futures contracts for up to three years ahead. Here we limit attention to Elspot.

In Elspot, participants bid for day ahead contracts for physical deliveries. A trading day consists of 24 different hourly markets and separate bids are made for each of these markets. On the basis of the received bids, the market operator clears each market by determining market clearing prices. The clearing process results in a series of contracts between Nord Pool and each of the market participants. A contract is related to a specific hour and consists of an amount of power (measured in MW) and the price of that hour (in NOK/MWh). Contracts are binding and consequently financial settlement can be undertaken as soon as the clearing process is finished. Deviations between demand/supply in the spot market and actual consumption/generation is priced in a separate 'balancing' market operated by the system operator (see below).

Bids are submitted electronically or by fax. A bid is in the form of a series of price-quantity pairs which determines how much the bidder is prepared to sell or buy at different prices. We illustrate the bid format by an example:[13]

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[13] The example is taken from Nord Pool's information brochure 'Elspot'.

Table 2.5 The Largest Generators in Norway and Sweden, 1995			
	Country	Average yearly output TWh	Installed capacity MW
Vattenfall	Sweden		16,.725
Statkraft SF	Norway	31.7	8,264
Sydkraft	Sweden		6,567
Stockholm Energi	Sweden		2,345*
Norsk Hydro AS	Norway	9.4	1.720*
Oslo Energi AS	Norway	7.8	2,265
Bergenshalvøens Kommunale Kraftselskap (BBK)	Norway	5.4	1,444
Lyse kraft	Norway	5.3	1,518
Other			
Total Norwegian and Swedish generating capacity			(.%)
Danish interconnectors			
Finnish interconnectors			
Other			
Total			(100.0%)
* 1990 figures			

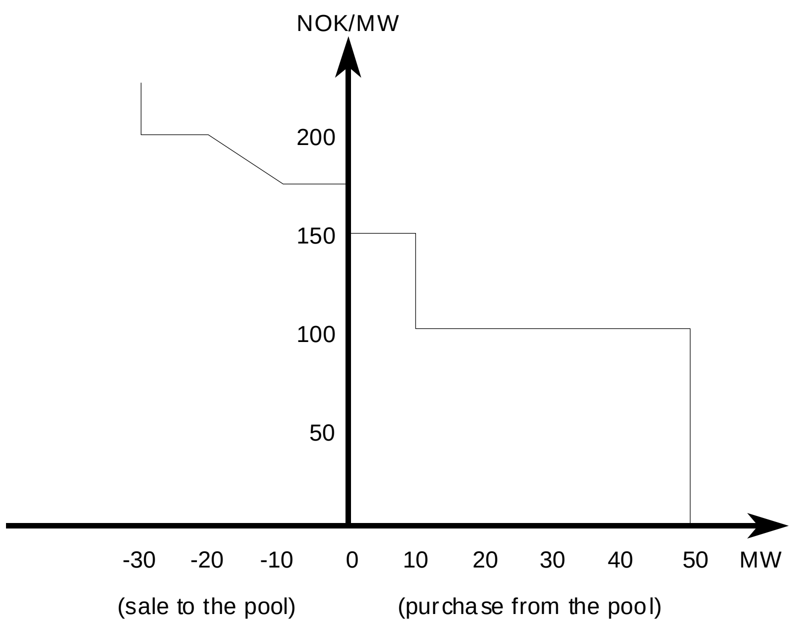
Consider a utility which has an obligation (i.e., a fixed price contract) to supply 30MW. In addition, it has a contract to supply 10MW conditional on the spot price being below 200NOK/MWh, and another 20MW conditional on the spot price being below 100NOK/MWh. These contracts are backed partly by the utility's own generation capacity and partly by contracts with independent generators. In addition, supplies may be obtained in the spot market. We assume that if the spot price is below 100NOK/MWh, the utility prefers to honour its contractual obligations by supplying 10MW from own generation and buying the rest (50MW) in the pool. If the spot price is in the range 100-200NOK/MWh, the utility prefers to reduce its purchases from the pool and rely more on own generation and contracts with independent generators. At prices above 175NOK/MWh the utility wants to sell to the pool. Its maximum sale is 30MW at prices above 200NOK/MW. The utility may obtain such a profile in the spot market by submitting the following bid:[14]

Table 2.6 Nord Pool bidding format, example

NOK/MW	0	100	101	150	151	175	176	200	201	900
MW	50	50	10	10	0	0	-10	-20	-30	-30

The bid can be translated into a (piece-wise linear) demand-supply schedule, as illustrated in Figure 2.4 below:

Figure 2.4 Nord Pool bid schedule



The market closes at noon the day before the actual trading day. Within two hours (i.e., at 2 PM), individual bids are aggregated, a market clearing price is found, individual spot contracts are determined and participants are informed about the results. Any complaints must be submitted to Nord Pool within the next half an hour. Participants who trade on their own account trade with Nord Pool as their counterpart. Clearing customers trading via a broker are also required to settle directly with Nord Pool. Settlements are made weekly and in Norwegian kroner (NOK) (however, the pool offers an currency exchange service so that Swedish customers may trade in Swedish kroner (SEK)). All participants must provide a bank security to back their financial obligations. Operation of the pool is financed by members'

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[14] Price bids have to be within a band set by the pool operator, and bidders are required to indicate their purchase/sale both at the minimum price (here set to 0 NOK/MW) and the maximum price (here set to 900 NOK/MW).

fees, including a one-time membership fee, a yearly fee and a fee related to each members volume of trade.

Individual bids and contracts are treated as confidential information by the pool operator. The market price and aggregate volumes are however publicly available. Statistics on reservoir fillings (which are very important information in a system heavily dependent on hydro power) is published weekly on an aggregate, regional basis by the central bureau of statistics (Statistics Norway).

2.2.3 Imbalances, Transmission Constraints and Losses

Bottlenecks in the system, i.e., when the system is unable to despatch units according to the unconstrained merit order, are handled differently in Norway and Sweden.

In Norway, spot market bids are used to level the market on each side of the constraint. When a bottleneck problem is expected, the system operator separates the Norwegian market into two or more regions depending on where the bottleneck is expected to occur. Bidders in the pool are required to submit separate bids for each region, and these bids are used to equate demand and supply within each region. When a bottleneck occurs, the market price in the constrained off region will be lower than in the rest of the market.[15] Consequently, electricity flowing over the bottleneck is in effect taxed, with revenue (capacity times the price difference between the two regions) accruing to the grid company.

In Sweden, bottlenecks are dealt with by buyback arrangements organised by the system operator. When a bottleneck problem occurs, the system operator pays for output reductions in the surplus region and, similarly, output increases in the rest of the market. The costs of the buyback agreements are covered by the transmission tariffs. Consequently, Swedish pool participants always face the same spot market price.

If a bottleneck should occur in one of the interconnectors crossing the border between the two countries, separate market prices are determined for each country according to the Norwegian system for dealing with transmission constraints.

Imbalances between actual trade and trade prognosticated by bidding behaviour in the pool is dealt with by additional ‘regulation’ or ‘balancing’ markets. These markets are used to ensure that given the production plans of each generator, and the actual off take by customers, the system remains in balance. In each country, the system operator is responsible for ensuring system stability.

The Norwegian ‘Regulation Market’ (‘Regulkraftmarkedet’) was previously operated by Nord Pool on behalf of the system operator, but is now run by the system operator himself (the grid company Statnett). Before each trading day, bids are accepted for the Regulation Market. These bids represent the prices at which participants are prepared to increase/reduce their output (or increase/reduce their demand) on the central grid. Participants are required to respond to notification of the need to adjust their production/demand within 15 minutes. Regulation prices are used to price discrepancies between participants’ contracted generation or consumption (including the spot contracts) and their actual generation or consumption. About 5% of total energy consumed in Norway is traded through the regulation market.

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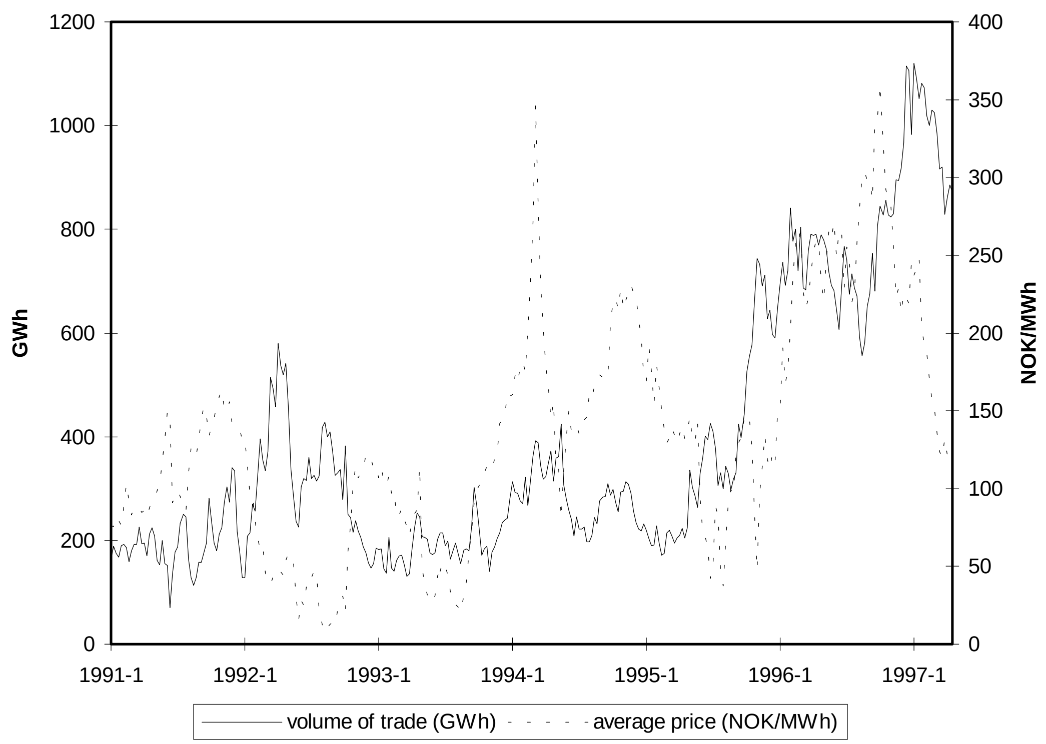
[15] The system operator (Statnett SF) may determine that there are two few participants within a region for competition to be effective. In such cases, the ‘monopoly region’ will be considered as part of the neighbouring region when price is set (i.e., the bottleneck is neglected as far as price determination is concerned).

In Sweden, the system operator (the grid company Svenska Kraftnät) operates a similar market, the ‘Balancing Market’ (‘Balansetjänesten’).

2.2.4 Market Performance

As seen from Figure 2.5 below, during the first few years after the opening of the new spot market trade volumes were increasing very modestly. This reflects the continued reliance on trade in long-term firm contracts outside of the pool, and the relatively slow development of competition in the retail market. The trend however, is partly overshadowed by idiosyncratic events, such as the huge water inflow during the first half of 1992 which lead to very high volumes of trade. Since the end of 1995, volumes in the spot market have increased sharply, mostly reflecting the opening of the market to Swedish participants. In 1996, 40,3 TWh was traded in the spot marked, compared to 10,1 TWh in 1991. These figures may be compared to total electricity generation in Norway and Sweden, which was 240,9 TWh in 1996 and 258,7 TWh in 1991. Consequently, the pool now accounts for about 16% of total volumes traded, compared to 4% in 1991.

Figure 2.5 Statnett Marked/Nord Pool, trade and prices, weekly 1991-97



In a system highly dependent on hydro power, prices naturally vary considerably, both between seasons and between years. As can be seen from Figure 2.5, prices exhibit a strong seasonal pattern and are generally much lower in spring and in summer than in winter. Water inflow is high in spring and summer due to snow melting and rainfall, while in winter water inflow is almost nil as rivers and streams freeze and precipitation is mostly in the form of snow. The seasonal price effects of varying hydrological conditions are exacerbated by demand variations. The peak in February 1994 was caused by the combination of extremely low temperatures and problems with securing supplies over the Danish interconnectors. Yearly price variations reflect the differences in hydrological conditions between 'wet' and 'dry' years.

After deregulation, and until the autumn of 1992, prices in the spot market were quite low. Although some blamed the new and more competitive environment, it would seem that the low prices were mainly caused by unusually large inflow of water (due to the combination of heavy rainfall and mild winters) and lower demand due to the warm weather and economic recession affecting the energy intensive industries.

In the beginning of October 1992, spot market prices suddenly increased sharply. It seems clear that this was due to the main producer, Statkraft SF, publicly announcing a new policy not to supply at prices below 100 NOK/MWh. After some initial turbulence, when Statkraft apparently demonstrated its determination to discipline the market (punishing 'deviators' by momentarily flooding the market and pushing the market price down to zero), prices stabilised at considerably higher levels than those prior to October 1992.

While it seems clear to most observers that there had been an deliberate attempt at pushing up the spot price, it is less clear that the effect was lasting. Prices soon started to fall back, reflecting the underlying abundance of supply. The Norwegian Competition Authorities (Prisdirektoratet) investigated the matter but decided that there was insufficient evidence of collusion to warrant specific actions.[16] Claims of collusion and abuse of market power have since been voiced at numerous occasions - usually when prices have been particularly high - but so far there is little hard evidence to substantiate such claims. The very high prices in 1996 seem to be explained by unusually dry weather conditions during both 1995 and 1996.

The pool rules have been changed a number of times since the opening of the new pool in 1991. Originally, trading days were divided into different periods in which aggregate output was expected to be fairly similar (with five periods for each week days and three at weekends). This system was eventually dropped in favour of 24 hourly periods. The pool also operated a forward market for long-term firm contracts (the so-called 'weekly' market). In September 1995, this market was reorganised and turned into a purely financial market in which trade occurs in futures contracts.

2.3 The Australian National Electricity Market[17]

In Australia a large-scale reform of the electricity supply industry has been taking place. Transmission and distribution are being progressively separated from generation, the monopoly generation utilities are undergoing privatisation or corporatisation, and a new national spot market for the purchase and sale of electricity is being created. The spot market, or pool, will co-ordinate virtually all trade in electricity, determine market prices from the bid prices of individual generators, and allow for the centralised despatch of generating units to meet demand on the basis of a generation 'merit order'. At the current phase of the reform process two similar electricity spot markets have been created in Victoria (VICPOOL) and New South Wales respectively. These pools were integrated in April 1997 to form the National Electricity Market I (NEMI).

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16 The Competition Authorities commissioned a report from SNF, an independent research institute, which concluded that although certain aspects of the market might be conducive to collusion, no firm evidence that such collusion had occurred, or would be successful, was found (Sørgard, 1993).

17 Parts of this section follow closely the report by London Economics (Aust) Pty (1996).

The Australian power system currently comprises five separate regions operating independent market arrangements:

- Victoria, which has led Australian power sector reform with privatisation and restructuring around a power pool;
- New South Wales (NSW), which introduced an experimental pooling system as early as 1992, and in 1995/6 restructured its generation and distribution sectors, and introduced a daily pool;
- The Snowy Mountain Hydroelectric Scheme ("Snowy") which is owned by the Federal Government and which currently trades into both the NSW and Victorian markets through trading arrangements specific to the each recipient pool;
- South Australia (SA), which trades with Victoria and uses Victorian pool prices as a reference for its own power transaction valuations, but does not have open market arrangements; and
- Queensland, which is currently undertaking a reform process but which is not yet interconnected to other systems.

The national market reforms are intended to develop a single market across Queensland, NSW, Snowy, Victoria and South Australia - the National Electricity Market (NEM). The first phase will be the amalgamation of the Victorian and NSW markets. Both the Victorian and NSW markets are currently evolving towards the NEMI. Table 2.7 below summarises recent developments in Victoria and NSW.

Table 2.7 Victorian and NSW Electricity Reforms[18]

State	Ownership	Industry	Generation	Transmission	Distribution	Supply	Trading arrangements
VIC	Private distribution/ retailing. Generation privatisation partially complete. High voltage transmission system under public operation.	Horizontal separation of generation to station level, vertical separation of generation, transmission . 5 privatised distribution businesses.	Prices for wholesale electricity set in pool . No significant entry restrictions. Limits imposed on cross ownership. Vesting contract cover to end by 2000.	Open & non discriminatory access. Prices regulated by Office of Regulator General (ORG)	Accounting separation within distribution & supply business. Open & non discriminatory access to wires. Price cap regulation of wires charges.	Maximum uniform tariffs subject to price controls and in place until 2000 for the franchise market.	VicPool III. All energy traded through the pool. Establishing a joint pool with NSW (NEM 1) .
NSW	All activities currently public. Entry of private generation anticipated and new entry of retailers.	3 generators. Separation of transmission (TransGrid) from generation. Amalgamation of 25 distributors into 2 large metropolitan and 4 rural distribution/retailers.	Prices for wholesale electricity set in pool . Declining vesting contract coverage.	Open & non-discriminatory access. Ring fencing of transmission and market operations. TransGrid revenue capped by CPI-X	Ring-fencing of retail and network operations of distributors. Open & non-discriminatory access to wires. Regulation of wires charges	Gross margin for the retail businesses distributors regulated by CPI-X. Declining franchise	Competitive pool in place from March 1996; franchise market regulated. Currently establishing a joint pool with Victoria.

18 Original table taken from London Economics (Aust) Pty (1996)

Both Victoria and NSW have restructured their generation sectors. Capacity and energy shares in the NSW and Victorian markets are given in Table 2.8 below.

The Victorian and NSW markets have a number of important common features which will be shared with the NEM. In particular:

(i) all energy is traded through the pool; and

(ii) both are *ex post* pools in which spot prices are based on the actual operation of the system rather than the *ex ante* anticipated operation of the system.

Since only in Victoria has there been any significant competitive experience to date, the rest of our discussion focuses on the operation of the Victorian pool.

2.3.1 The Victorian market

VicPool, which is operated by the Victorian Power Exchange (VPX), started operation in July 1994, and all wholesale electricity in Victoria is traded through it. There are four main types of participant in VicPool which will continue to operate in the NEM: generators; distributors who purchase electricity from the pool and sell it onto customers; large customers who purchase energy from the pool to meet their own energy requirements; and 'traders' who deal with the historic contract obligations of the Victorian ESI.

Table 2.8 Generation Capacity and Market Structure in Victoria and New South Wales

State	Portfolio/ Company	Nameplate Capacity (MW)	Percentage of Total Capacity	Energy (GWH)	Percentage of Total Energy
NSW	Macquarie	4,640	20.2	24,000	23.1
NSW	Delta	4,240	18.5	17,500	16.8
NSW	Eraring	2,640	11.5	12,000	11.5
NSW	Snowy*	2,639	11.5	5,500	5.3
VIC	Loy Yang A	2,000	8.7	14,300	13.8
VIC	Hazelwood	1,600	7.0	5,000	4.8
VIC	Yallourn	1,450	6.3	10,378	10.0
VIC	Snowy*	1,131	4.9	2,357	2.3
VIC	Loy Yang B	1,000	4.4	8,383	8.1
VIC	Eco Gen	966	4.2	3,200	3.1
VIC	S Hydro	481	2.1	754	0.7
VIC	Energy Brix	170	0.7	566	0.5
TOTAL		22,957	100	103,938	100

*** Snowy capacity arbitrarily allocated between NSW (70%) and Victoria (30%).**

VPX has two main areas of responsibility: (i) as a market operator, operating and administering VicPool, including controlling dispatch to ensure generation meets demand; and (ii) operating the high voltage network to ensure that system security is maintained at an appropriate level. The Victorian market is small in overall size, and individual generators are significant in terms of overall demand. For example, the larger base-load generators represent as much as 25% of peak-time capacity requirement in a market in which peak demand is about 7,500MW.

Bidding, despatch and price determination

VicPool is an *ex-post* pool which operates broadly in the same way as the proposed NEM. Generators and demand side bidders submit bids to VPX, specifying a price for each quantity and these bids are stacked in merit order. A demand estimate is used to schedule plant and generators are dispatched to provide active power to meet demand.

The bid structure is essentially the same as that proposed for the NEM. Each generating unit may specify ten incremental energy prices ($/MWh bids) per day. The pool rules also allow two bids for revenue in the event that a generator is required to run below its minimum stable generation or below its backoff minimum. The incremental bid prices are fixed for the following day, however capacity bids may be altered under certain specified conditions.

As in NSW and the NEM1, pool prices are determined ex post from actual generator operation schedules and demand. At the time of operation, 5 minute SMPs are calculated from the despatch schedule and half hourly SMPs are then calculated as the time weighted average of these. Because prices are determined in something closely approximating 'real time', at the time prices are calculated it is known whether or not supply is sufficient to meet demand. Therefore the probability of loss of load (LOLP) is equal to either zero (i.e. when supply>demand) or one (i.e. when demand>supply). If demand exceeds supply in any half hour then price is set equal to a pre-specified 'value of lost load.' Otherwise it is set equal to SMP.[19]

Pool rule changes

There have been four main phases of VicPool. Changes have been gradually undertaken to merge the Victorian pool rules and institutions with those proposed under NEM market rules. The latest phase is known as VicPool III enhanced, and commenced operation on 1 September 1996. Several important changes were made to VicPool III as part of the movement towards the NEM arrangements:

- **daily bidding:** previously generators placed weekly bids. Under VicPool III enhanced generators place daily bids with VPX;
- **increments to bids:** previously the generators were able to bid their capacity into the pool in three increments. In VicPool III enhanced generators are able to bid their capacity into the pool in 10 increments; and
- **self commitment:** previously VicPool operated on the basis of central commitment. In their bids generators were required to submit start up costs, start up times and minimum

[19] In the NEM regional prices will be calculated to take account of transmission losses and constraints. Note that prices in Victoria and in the NEM are, or will be, calculated using the actual merit order, rather than the 'unconstrained' merit order as is done in England and Wales.

on and off times. VPX analysed the costs and times presented by each generator and took the start up and close down decisions. Under VicPool III enhanced generators are required to self-commit.

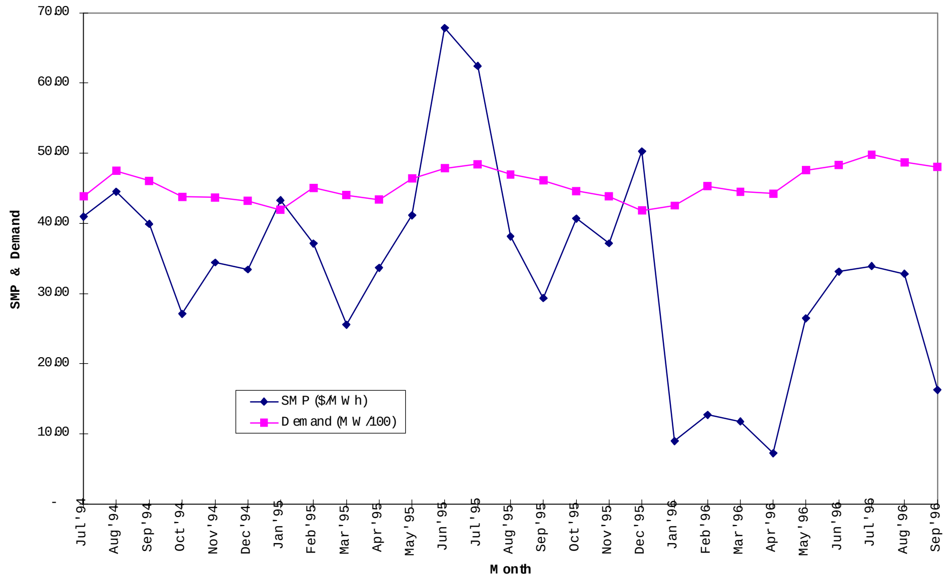
There are still several key differences between the NEM rules, and the VicPool rules currently in operation:

- **regions:** the NEM is a market with a series of regions, linked by interconnects. VicPool operates in a single region. Trade with other States is managed in the context of VicPool by the IOA Trader;
- **short term forward market (STFM):** VicPool has no STFM. To fill the price discovery role performed by the STFM in the NEM, VPX publishes seven day ahead indicative prices. The generators are required to submit to VPX indicative bids on a seven day ahead rolling basis. The generators are not required to submit actual bids related to these indicative bids. VPX then calculates and publishes indicative prices, to provide market participants with an indication of short term prices;
- **moveable elbows:** the bids for VicPool and NEM each contain 10 price capacity bands, however unlike the NEM bids, the VicPool bands do not have ‘moveable elbows’. This means that the MW capacity bid into the pool cannot be sculpted by half hour. Rather the MW capacity in each band are fixed throughout the day, and only the price of each band can vary; and
- **treatment of losses:** in VicPool all customers pay a pro rata share of losses. In the NEM losses within a region are calculated with regard to a reference node. Customers and generators at the same point pay and receive the same price, but customers and generators at different points will pay and receive different prices, depending on loss factors from the reference node. Under the NEM loss factors between regions will be determined dynamically.

Victorian market performance experience

Figure 2.6 shows the monthly, time-weighted average SMP and system demand for VicPool since the market commenced in July 1994. The results show no obvious correlation between pool prices and the seasonal patterns of supply and demand, suggesting that other factors such as generator behaviour, contract cover and regulation were as important as the supply/demand balance.

Figure 2.6 Monthly average prices and system demand in VicPool



There appear to have been two phases in the Victorian market: the 'early' period to 1 January 1996, and the period thereafter. In the early period, market prices remained consistently above \$30/MWh; indeed, in 1995 they were above \$40/MWh. In the 'later' period, spot prices fell below \$21/MWh on average and have remained at this level. The early stage of the market was characterised by:

- modest over-supply particularly when one considers that exports from Victoria to more expensive neighbours were restricted in this period;
- common interests amongst the generators which were effectively under common public ownership;
- overall levels of contract cover in the market significantly below the level of expected demand; and high levels of vesting contract cover at prices of between \$35/MWh and \$40/MWh

The net effect of these market conditions was possibly that generators sacrificed output in order to increase pool prices. A reported examination of the bidding patterns of generators at that time shows a degree of consistency in the bids of independent generators, such that:

- base load generators bid between 50% and 70% of their capacity at a relatively low price, but consistently bid the remainder of their capacity at prices between \$30/MWh and \$40/MWh, even though this price was well above their short-run operating cost; and
- mid-merit and peaking generators bid in accordance with the bid of the high price bands of their base-load counterparts, even though these bid prices were well above operating costs.

It has been suggested that this provides evidence of a significant degree of tacit collusion.[20]

'Later' period prices

[20] London Economics (1996)

Prices fell significantly in 1996. The Electricity Supply Industry Reform Unit (ESIRU) commissioned a review of the factors influencing the price.[21] This review, which was summarised in the Hazelwood Information Memorandum, identified a number of factors which contributed to the period of low prices. The reasons cited by ESIRU were:

- in January 1996 a new 500 MW unit came into operation with relatively low marginal cost and a high level of contract cover. It was therefore bidding most of its capacity into the pool at a low price;
- gas station take or pay contracts which encouraged gas -fired stations to bid low to ensure their TOP quantities were utilised prior to the expiry of the contracts; and
- unusually low demand due to a mild summer.

Again it has been suggested that a major factor may have been the breakdown of the market conditions that fostered tacit collusion.

2.4 Concluding Comments

Restructuring and reform of the electricity industry has now occurred in a number of countries, providing a body of international experience. With two notable exceptions however, reforms in most countries are either too recent, or have taken place in within specific regulatory frameworks, which have tended to prevent the problems posed by the exercise of market power from emerging explicitly.[22] The reforms in England and Wales and in Norway however, have both provided useful evidence of the types of competitive problems which must be resolved if reforms of electricity supply industries are to succeed.

The experience in both England and Wales and in Norway makes it clear that the creation of an unregulated wholesale market for electricity, without a sufficient regard to the horizontal structure of generation to ensure competitive behaviour in the pool, may result in serious distortions to economic efficiency. In particular:

- prices which do not reflect costs i.e. allocative inefficiency;
- distortions to merit order despatch, i.e. static productive inefficiency; and
- dynamic productive inefficiency in the form of entry of excess generation capacity.

This means that it is crucial for the success of the electricity market reform process that the issues of market structure and market competition are given careful scrutiny, and that appropriate structural reforms (and possibly other safeguards) are introduced simultaneously with the creation of a national or regional electricity wholesale market.

3. Theoretical Analysis of Electricity Spot Markets

A natural first step in analysing competition in electricity spot markets would be to apply one of the standard models from the theory of imperfect competition. This approach has been

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[21] *A review of the basis for recent low prices in the Victorian Electricity Market* by Hugh Bannister of Intelligent Energy Systems Pty. Ltd..

[22] For instance in Chile, generator bids have been capped at pre-determined estimates of marginal operating costs. See London Economics (1992) for more on the Chilean and Argentinean reforms.

adopted with some success - in particular to demonstrate that competition in the England and Wales pool is unlikely to result in perfectly competitive outcomes (Vickers and Yarrow, 1991; Wolfram, 1996). However, as we have explained above, electricity spot markets possess a number of characteristics which make standard models not well-suited to their study. In particular, the pool pricing mechanism is a uniform first price auction, i.e. generator payments are determined by the bid or offer price of the marginal operating unit, and not by their own price offers, as is the case in most standard models.

In this section we discuss four approaches to understanding the nature of price competition in electricity spot markets which have been suggested in the recent literature. We start with two applications of standard oligopoly models: the *'capacity-constrained Bertrand competition'* model and the *'repeated interaction collusion'* model. We then turn to models that more directly take into account the specific features of electricity pools. The first is Green and Newbery's adaptation of the *'supply function'* model due to Klemperer and Meyer (1989). The second is the *'auction approach'* of the current authors.

3.1 The 'Capacity-Constrained, Bertrand Competition' Approach

In the standard model of Bertrand competition, identical sellers with constant unit costs and no capacity constraints compete to supply the market on the basis of price offers to consumers (see, for instance, Tirole, 1988, Ch 5). This form of competition inexorably leads identical sellers to price at marginal cost; a price offer above cost will be undercut by another seller since it results in positive profits, and a lower price offer would result in losses. Hence if the duopolists in the England and Wales electricity pool had behaved as Bertrand oligopolists in this sense, the expectation that pool prices would reflect the marginal costs of supply may well have been realised.

However the electricity spot market is not a standard Bertrand price game of this kind. At the very least, as has been pointed out by Armstrong, Cowan and Vickers (1994, Ch 9) (see also Vickers and Yarrow, 1990) it is more like Bertrand competition with capacity constraints. Under this form of competition prices will not typically be equal to marginal costs, and indeed may considerably exceed them. Although the analysis of equilibrium pricing behaviour in capacity-constrained oligopoly is complex (Tirole, 1988, 209-216; see also Kreps and Scheinkman, 1983), Armstrong et al provided a simple argument to demonstrate that marginal cost pricing was unlikely to be an optimal bidding strategy in the England and Wales pool. In 1990 the capacities of National Power, PowerGen and Nuclear Electric were approximately 28.7 GW, 18.7 GW and 8.8 GW respectively. The cross-channel interconnector had a capacity of 2 GW, and the Scottish interconnector a capacity of 850 MW. Demand at peak was approximately 48 GW on a typical winter day, with a night-time low of approximately 28 GW. In summer the corresponding approximate range was 13-25 GW. Thus except in summer, neither of the thermal generators alone was typically able to satisfy all of demand. And even if PowerGen, Nuclear Electric and the interconnectors were operating at full capacity, National Power would still retain substantial residual market power. For a large part of the year bidding at cost would not be optimal, and indeed would be a 'dominated strategy', i.e., not optimal no matter what the other generators were bidding. Hence pool prices would be unlikely to reflect marginal supply costs for much of the year.[23]

Armstrong et al recognise that their exposition of bidding strategies in the pool is simplistic, but argue that it is nevertheless sufficient to show that given the duopoly industrial structure created at the time of privatisation, "..*the electricity pool could not be expected to operate for much of the time as a normal competitive market . This is a damaging criticism, not least because of the importance of marginal cost bidding for the efficiency of the system as a whole."*

While highly suggestive, the treatment of Armstrong et al does not formally analyse the equilibrium bidding behaviour of the generators in the pool and is therefore not entirely convincing. In particular, the logic of their 'dominated strategy' argument assumes a pricing mechanism in which each generator is paid its own price bid for each unit of capacity despatched, rather than the price bid of the marginal operating unit, as in the pool. This can lead to fundamental differences in the analysis of equilibrium bidding strategies. For instance - to take their example - even when the other generators are operating at full capacity, National Power might still prefer to bid in its plant at near cost in order to ensure that most of it is despatched, *so long as another generator was setting system marginal price at high enough levels*. Because each generator receives the bid price of the marginal generating unit, it is generally true that a generator with significant market power may optimally choose to bid low, e.g. at or near cost, in the rational expectation that another generator will bid high in order to raise the market price. By doing so more of its capacity is despatched, while it still receives a high price for the energy sold (this is further discussed below).[24] To understand better the likely bidding behaviour of the duopolist generators therefore, it is necessary to model more formally the actual bidding game being played by generators in the pool.

3.2 The 'Repeated Interaction, Price Collusion' Approach

Armstrong, Cowan and Vickers (1994) also note that the repeated nature of the interaction between generators which bid daily into the pool creates a favourable environment for tacit price collusion which may lead to even higher mark-ups of prices over costs. Aspects of the operation of the pool would appear to make this a particularly significant possibility, namely:

- the interaction is repeated daily and market price and quantities sold by each generator are public knowledge, permitting an intimate knowledge to be developed of the consequences of alternative, co-ordinated bidding strategies;
- the price bids and capacity declarations of each generator are published and publicly available, allowing the generators to directly monitor the bidding behaviour of their

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[23] Armstrong et al point out that this would not have been the case if National Power's capacity had been split between three companies and PowerGen's between two, creating five strategic players rather than two.

[24] Note that a low-bidding strategy *does not imply* an absence of market power. On the contrary, this strategy earns the greatest duopoly rents. To see this note that if one of the two major generators was able to commit itself in advance to a bidding strategy - that is, *if we endowed a particular generator with an even greater degree of market power* - its optimal strategy might well be to bid at marginal cost since the other generator would then be forced to bid high to increase the pool price.

competitors, and hence to unambiguously detect - and possibly punish - deviations from collusive or co-ordinated bidding strategies.[25]

These factors would seem to make tacit price collusion in pools particularly likely. Working against this hypothesis however, is the fact that the same bid and price information is available to the regulator, who will clearly have an interest in monitoring the generators' bidding behavior for signs of collusive behavior. To date there has been no suggestion that the bidding behavior of the two thermal generators in the England and Wales pool reveals any clear tendency towards tacit price collusion. However this may be as much due to regulatory scrutiny and regular inquiries into bidding behavior and pool prices, as to other factors.[26] In contrast, in the Norwegian pool there has been (attempts at) explicit price collusion. There is however no clear evidence that pricing behavior in the Norwegian pool have at any time been characterized by tacit collusion (Sørgard, 1993).

In addition, David Newbery (1995) has recently argued that the electricity contract market makes entry into the British electricity market 'contestable,' ensuring that long-run average prices are kept at the competitive entry level. This of course would also imply that attempts to raise prices via implicit or explicit collusion would only succeed in attracting further entry, and hence founder.[27]

3.3 The 'Supply Function' Approach

Green and Newbery (1992)) analysed competition in the British electricity spot market using the 'supply function equilibria' approach of Klemperer and Meyer (1989), and calibrated the model to the circumstances of the industry at the time of privatisation.[28] The approach has since been used to model contracts and capacity divestments in the England and Wales pool (see Green 1992, 1996).

Using the supply function approach, Green and Newbery (1992) assumed that the two strategic generators submit continuously differentiable supply functions to the pool, rather than discrete step functions (i.e., a bid for each generating unit), and that the market equilibrium was the static one-shot supply function equilibrium.[29] As in Klemperer and Meyer (1989), the equilibrium lies between the (price-setting) Bertrand equilibrium and the (quantity-setting) Cournot equilibrium. The following subsection discusses this modeling approach in more detail.

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[25] See Tirole (1988) on the importance of this for co-ordinating collusive behaviour. In different countries different policies have been adopted towards the issue of market information dissemination. See David Harbord & Associates (1997) for an analysis of this issue in the context of the Australian National Electricity Market.

[26] There have been numerous regulatory inquiries into pool bidding behaviour. See the reports by Offer cited in the references.

[27] The current authors, however, are on record as disagreeing with this characterisation of entry and contracting in electricity markets. See London Economics (Aust) Pty and D. Harbord & Associates (1995).

[28] Naturally all of their simulation results - discussed in more detail in section 4 below - must be treated with caution, since many important features of the electricity spot market were not included, such as contracts and regulatory uncertainty.

[29] Green and Newbery (1992) assumed that the two thermal generators National Power and PowerGen were the only strategic players in the market, and that Nuclear Electric, Electricite de France and independent power producers simply bid in at zero. This assumption is not far from the truth, as was noted in Section 2.1 above

3.3.1 The supply function model

Klemperer and Meyer (1989) modeled an oligopoly facing uncertain demand, and argued that in such an environment firms would prefer to set supply functions, rather than compete in prices (Bertrand competition) or quantities (Cournot competition). They observed that under demand uncertainty - given any hypothesized behavior by other firms (i.e. price or quantity setting) - the residual demand facing each firm is uncertain, and hence each firm has a set of profit maximizing points (price-quantity pairs), one corresponding to each realisation of its residual demand. If firms must decide on their strategies in advance of the realisation of demand, then they are better off specifying an entire supply curve, rather than a single price or quantity.[30]

Klemperer and Meyer (1989) showed that in the absence of uncertainty (i.e. deterministic demand) then any point along the demand curve in which firms are supplying at a price exceeding their marginal costs (i.e. earning non-negative profits) can be sustained as a supply function equilibrium - that is, a Nash equilibrium in supply functions. Indeed, any such point on the demand curve can be supported by an infinite number of supply function pairs which are best responses to each other. When demand uncertainty is introduced however, the set of outcomes supportable as supply function equilibria is reduced dramatically, and in some cases there is a unique equilibrium.

Klemperer and Meyer (1989)'s principal case analyses a symmetric duopoly under demand uncertainty. They consider a demand curve given by $Q = D(P,\varepsilon)$, where ε is a scalar random variable with strictly positive density on the support $[\underline{\varepsilon}, \infty]$. Any realisation of the random variable ε fixes a unique demand curve, with the properties: $-\infty < D_p < 0$, $D_{pp} > 0$, and $D_\varepsilon > 0$. Klemperer and Meyer consider the special case in which $D_{p\varepsilon} = 0$. The firms have identical costs functions given by $C(q)$, with $C'(q) > 0$, for all $q>0$, and $0 < C''(q) < \infty$, for all $q \geq 0$. They also assume w.l.o.g. that $C'(0) = 0$.

Green and Newbery (1992)'s model of the British electricity spot market is a direct translation of the Klemperer and Meyer (1989) model, in which the random variable ε is replaced by a "time" variable t. "Time" is ordered so that maximum demand occurs at t=0.[31] A supply function for firm j = 1,2 is a function $q^j(p)$: $[0,\infty) \rightarrow (-\infty,\infty)$. Once firms have chosen a supply function, at each time t, the despatcher announces the lowest price p(t) such that $D(p(t),t)) = q^i(p(t)) + q^j(p(t))$. That is, for any time t, a price p(t) is set so that each firm is producing on its supply function, and the market just clears.[32] Firm i then earns profits given by, $p(t)\, q^i(p(t)) - C(q^i(p(t)))$, i = 1,2.

A Nash equilibrium in supply functions is a supply function pair $\{q^i(p),q^j(p)\}$ such that $q^i(p)$ maximizes i's expected profits given that j has chosen the function $q^j(p)$ and visa versa. Attention is confined to supply functions which are twice continuously differentiable. Note that for any choice by j of $q^j(p)$, i's residual demand function is given by $D(p,t) - q^j(p)$. Assuming that i's set of ex post profit maximizing points can be described as a supply function which intersects each realisation of i's residual demand curve once and only once, i's profit maximisation problem can be expressed:

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30 A major difficulty with the theory of course, is to explain how firms are able to commit themselves to a particular supply function. This difficulty does not arise in the application to the electricity spot market, which forces generating companies to commit themselves in advance to a supply schedule.

31 Green and Newbery (1992) interpret D(P,t) as a "load duration curve", so t is "the number of hours of demand higher than D." Green (1996) appears to adopt a slightly different interpretation.

32 If there is no such price, or if there is more than one such price, the firms are assumed to receive zero.

(1) $$\text{MAX}_p: \; \pi_i(p) = [D(p,t) - q^j(p)] - C(D(p,t) - q^j(p))$$

The first order condition is then:

(2) $$\frac{dq_j}{dp} = \frac{q_i}{p - C'(q_i)} + D_p$$

Which in the symmetric case becomes:

(3) $$\frac{dq}{dp} = \frac{q}{p - C'(q\;)} + D_p$$

Following Klemperer and Meyer (1989) one then considers points such that $0 < dq/dp < \infty$ or points such that:

(4) $$C'(q) < p < C'(q) - \frac{q}{D_p}$$

Analysis of boundary conditions then yields the conclusion that equilibrium supply functions are bounded below by "Bertrand" or "perfectly competitive" supply functions, along which $p = C'(q)$, and bounded above by "Cournot" supply functions along which $p = C'(q) - q/D_p$. If demand can be arbitrarily high with some probability (i.e. if the support of the random variable ε is unbounded), then Klemperer and Meyer show that there is a unique equilibrium. Otherwise there is a connected set of equilibria lying between the perfectly competitive and the Cournot solutions, and this applies equally to Green and Newbery's model of course (with respect to D(p,t)).

3.3.2 Discussion

Green and Newbery's (1992) paper is an example of how sophisticated economic analysis may be used to study real-life market institutions, and to address important empirical questions. Their major analytical insight is to have observed that demand uncertainty, as represented in Klemperer and Meyer (1989), is formally identical to demand variation over time, and hence that the Klemperer and Meyer analysis may be used to model competition in the England and Wales electricity pool. In doing so they hoped to characterise the bidding behavior of the generators in the pool.

A number of criticisms of the Green and Newbery (1992) model have since been made however. First, if the range of variation in demand is finite - which it clearly is - then the model appears to have little predictive value, since almost anything between the Cournot and

Bertrand solutions can be an equilibrium in supply functions.[33] Secondly, if the (short-run) elasticity of demand for electricity is zero then the model has no solution in the sense that the Cournot solution is undefined.[34]

Given the result that almost anything between the perfectly competitive outcome and the Cournot outcome may be an equilibrium, the range of possible solutions to the model is probably too large to yield useful predictions (see Newbery, 1996 for a recent discussion). Green and Newbery (1992) go on to argue that when capacity constraints are introduced, the range of possible equilibria is reduced, because no firm will wish to supply along a schedule which reaches its capacity before the maximum demand is reached. However at the time their paper was written, National Power and PowerGen had a total capacity of approximately 48 GW whilst the residual demand (i.e. net of nuclear capacity) they faced never exceeded 40 GW. Hence demand would never have been capacity constrained in the appropriate sense. And in their empirical simulations, Green and Newbery (1992) simply *select* particular supply function equilibria, so no use is made of this fact (see further Section 4 below).[35]

Another serious difficulty with the supply function approach is the assumption that generators submit continuously differentiable supply functions. This is both contrary to reality and allows for equilibria of the pool bidding game which do not exist in models in which generating units are discrete (von der Fehr and Harbord, 1993; see further below). As Green and Newbery (1992) put it, it remains "*an open question whether the bidding strategies of the firms will differ significantly if they are forced to provide a step function, or whether they are allowed to provide a smooth schedule.*"

3.4 The 'Auction' Approach

von der Fehr and Harbord (1992) (1993) modelled price competition in the England and Wales electricity pool as a first-price, sealed-bid, multiple unit auction. They demonstrated that under the existing institutional set-up there was likely to be both inefficient despatching and above-cost pricing, even in the absence of collusion and long term contracts. While these points had been argued elsewhere (for instance, Vickers and Yarrow,1991 or Green, 1991), the arguments had been largely informal and based upon standard models of oligopoly pricing, and hence somewhat inconclusive. A major purpose of the von der Fehr and Harbord analysis was to address these issues in a formal model specifically designed to capture the essential elements of new electricity pricing system in England and Wales.

Unlike Green and Newbery (1992), von der Fehr and Harbord (1993) analysed bidding strategies in the electricity pool for discrete generating units. While the assumption of smoothness in the supply function model perhaps leads to a simpler and mathematically more elegant theory, restricting strategy sets to discrete step functions has the merit of being a more realistic modelling approach. The result is an analysis of pool bidding behavior which is

[33] In particular Bolle (1992) has pointed out that Green and Newbery need to assume that the support of the demand uncertainty (or variability over time) faced by the generators must be unbounded for a unique supply function equilibrium to exist. And Wolak and Patrick (1996) have argued that the demand uncertainty faced by generators in the E&W pool does indeed have finite support.

[34] See Wolak and Patrick (1996) for a discussion. Indeed, from equation (2) above all we learn is that $p>C'(q)$ is necessary for a solution.

[35] In particular they select the supply function equilibrium which yields each firm the highest profits, i.e. the supply function which intersects the Cournot solution at maximum demand, in their "no entry" case, and the lowest price, highest output supply function equilibrium for their "entry" case.

intuitively easier to grasp than Green and Newberys', and for which some empirical support was adduced. In particular, the analysis emphasises the sensitivity of optimal bidding strategies to the relationship between residual demand and the capacities of the strategic generators. The following subsection describes their model and results.

3.4.1 The multi-unit auction model

The analysis of von der Fehr and Harbord (1993) focuses upon the case of duopoly, although many of the results generalise to oligopoly. In the interests of simplicity we limit ourselves here largely to discussing results for the case of two strategic generators, only briefly mentioning how and where results extend to the case of oligopoly.[36]

The generator bidding game is then described as follows: There are 2 independent generators each having constant marginal costs, $c_n \geq 0$, n = 1,2 up to their capacity,[37] while production above capacity is impossible. The index n rank generators according to their marginal costs, so $c_1 \leq c_2$. The total capacity of generator n is given by k_n, n = 1,2. The capacity of generator n consists of m_n generating units, where k_{ni} is the capacity of the i'th generating unit, i = $1,2,...,m_n$, and $\sum_i k_{ni} = k_n$. M denotes the total number of generating units, i.e., $M = \sum_n m_n$. Generators can submit different bids for each of their generating units.

Before the market opens, the generators simultaneously submit bids specifying the prices, $p_{ni} \leq \bar{p}$, $i = 1,2,...,m_n$, n = 1,2, at which they are willing to supply electricity from each of their generating units.[38] On the basis of these bids, or offer prices, the market organiser - or 'auctioneer' - ranks the generating units and constructs a market supply curve. If two or more generating units (of any generator) are offered at the same price, they are assumed equally likely to be called into operation. When the market opens, demand *d* is determined as a random variable independent of price;[39] in particular, $d \in [\underline{d}, \bar{d}] \subseteq [0,K]$, $K = \sum_n k_n$ according to some probability distribution G(*d*). The auctioneer, by calling suppliers into operation, equates demand and supply. Despatched units, i.e., units called upon to supply electricity, are paid the market clearing price, which is equal to the offer price of the marginal operating unit.

Generators are assumed to be risk neutral and hence aim to maximise their expected payoff in the game. All aspects of the game, as well as the players' marginal costs and capacities and the probability distribution G(*d*), are assumed to be common knowledge.

The model may be interpreted as a first-price, sealed-bid, multiple-unit, private values auction in which all units are sold simultaneously (McAfee and McMillan, 1987). It is 'sealed-bid' because of the simultaneous move structure; 'first-price' in the sense that the market price is determined by the marginal successful supplier, and 'private values' because generators' payoffs are determined by the difference between the market price and their marginal costs.

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36 The presentation here closely follows that in von der Fehr and Harbord (1993). For technical details and proofs see von der Fehr and Harbord (1992).

37 The analysis extends to cases in which generators have sets of different technologies, albeit at the cost of some added complexity (see von der Fehr and Harbord, 1997).

38 Note that generators' offer prices are constrained to be below some threshold level $\bar{p}$, since otherwise, in cases when there is a positive probability that all sets will be called into operation, expected payoffs could be made infinitely large. In the England and Wakes pool, system marginal price cannot exceed the value of lost load (approx. £2 per kWh). More importantly, the threat of regulatory intervention may impose an effective cap on bids (see Wolak and Patrick, 1996, for a discussion).

39 The assumption of inelastic demand is realistic (in the short run), but could nevertheless easily be dispensed with (see von der Fehr and Harbord, 1997).

This interpretation is particularly convenient for analysing alternative pricing rules (see Section 5 below).

Analysis and Results

Before discussing particular equilibrium outcomes, we present a basic result characterising the types of pure-strategy equilibria that can occur in the model.

Proposition 1*: If $c_1 \neq c_2$,, in a pure-strategy equilibrium only one generator will determine system marginal price with positive probability.*[40]

The intuition underlying this result is simple, and worth understanding. A player which owns a set that has a positive probability of becoming the marginal operating unit, will always want to increase the bid of that set by some small amount towards the next higher bid, since that does not affect the ranking, but increases the generator's payoff in the event that this is the marginal set. On the other hand, it cannot be optimal to submit a bid equal to or just above that of a set of another player, since as long as the bid is above marginal cost (which it will be) profits can be increased by undercutting the rival slightly, thereby increasing the probability of being called into operation, without significantly reducing the price received in any state. These two opposing forces destroy any candidate for a pure-strategy equilibrium in which two or more generators both have sets which with positive probability will become the marginal operating unit.

Proposition 1 is important because it implies that the types of pure-strategy equilibria that may exist are very restricted, and, furthermore, it rules out the existence of pure-strategy equilibria for a wide range of demand distributions. From this it follows that the types of equilibria found by Green and Newbery (1992) in their model, do not generalise to the case where individual generating sets are of positive size. The reason that such equilibria exist in the supply function framework is that when individual sets are of size zero (viz., the cost and supply cost functions are continuously differentiable everywhere), the effect on the system marginal price from a bid of any individual set is negligible, and thus the first part of the above argument does not apply.

Below we consider circumstances under which pure-strategy equilibria will exist, as well as presenting examples of mixed-strategy equilibria when pure-strategy equilibria are non-existent. The existence, multiplicity and the type of equilibria will be seen to depend crucially on the support of the demand distribution. We therefore distinguish between three cases: 'low demand periods' in which a single generator can supply the whole of demand; 'high demand periods' in which neither generator has sufficient capacity to supply the entire market (as discussed by Armstrong, Cowan and Vickers, 1994 above); and 'variable demand periods' in which there is positive probability for both the event that a single generator can supply the whole of demand, and the event that both generators will have to be called into operation, irrespective of their bids.

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[40] If generators have identical marginal costs there may exist 'Bertrand-like' equilibria in which generators submit offer prices equal to the marginal costs of each set, and in which more than one generator owns sets which with positive probability may become the marginal operating unit.

Low Demand Periods

This case corresponds to the standard Bertrand model of oligopoly in the sense that there is a unique equilibrium in which both generators offer to supply at a price equal to the marginal cost of the least efficient generator:

Proposition 2 *If $Pr(d < \min\{k_1,k_2\}) = 1$, there exist pure-strategy equilibria, in all of which the market clearing price equals the marginal cost of the least efficient generator, c_2, and only generator 1 produces.*

Since, with probability 1, demand can be met by a single generator, there will be competition to become the single operating generator. In particular, a generator will always undercut its rival so long as its rival's bids are above its own marginal costs. Thus any equilibrium must have the most efficient generator (generator 1) submitting offer prices for a capacity sufficient to meet demand, at or below the marginal cost of the least efficient generator. Since in this range, generator 1's profit is increasing in its own offer price, these bids must equal c_2. We conclude that in low demand periods, the system marginal price is bounded above by the marginal costs of the less efficient generator.[41]

High-Demand Periods

We now consider the case when, with probability 1, both generators will be called into operation. Since the high-pricing generator will be operating for sure, and in equilibrium generators never submit equal bids (see Proposition 1), its profit will be increasing in its own offer price. Thus, the extreme opposite to the result of the previous section holds; whereas in low-demand periods the system marginal price equals the marginal cost of the least efficient generator, in high-demand periods it always equals the highest admissible price.

To take a simple example, suppose that both generators have a single generating unit each with a capacity of 100 MW, and identical operating costs of £2 per MWh. Further suppose that the highest admissible price bid for a generating unit is £10 MWh, and that demand is 150 MW and perfectly price inelastic up to the maximum bid of £10 MWh. Both generators would like to be despatched with all of their capacity (i.e. 100 MW) but receive the maximum price for it. Assume that one generator bids in its capacity at a price of £2 per MWh. If the other generator makes a similar bid, then both will produce 75 MWh and earn zero profits. If the other generator bids at £10 per MWh on the other hand, it will produce 50 MWh and earn a profit of £400, while the first generator produces 100 MWh and earn profits of £800. Clearly the second option is preferable for both generators, however both would like to be the generator which makes the low bid. This simple example of the generator bidding game in the 'high demand' case is depicted in the figure below.

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[41] A similar result can be shown to hold in the oligopoly model. If, with probability 1, demand is less than the total capacity of the n most efficient generators ($n < N$), then in an equilibrium system marginal price cannot exceed the marginal cost of the n+1st most efficient generator.

Figure 3.2 Simple bidding game in 'high-demand' case

	Generator 2	
Generator 1	Low Bid (MC)	High Bid ($\overline{P}$)
Low Bid (MC)	£0, £0	£800, £400
High Bid ($\overline{P}$)	£400, £800	£600, £600

In Figure 3.2 pure strategy equilibria are given by the shaded cells. In each possible equilibrium one generator bids high whilst the other bids low. The low-bidding generator achieves a larger payoff since it sells more output at the price determined by the high-bidding generator. Slightly more elaborate examples of bidding games of this type are given in Lucas and Taylor (1993) (see Section 4 below).

In this type of period therefore, when neither generator has sufficient capacity to supply the entire market, but both generators together have excess capacity, the market price will be high with one generator bidding the maximum admissible price, while the other generator bids low and sells more output. Which generator makes which bid cannot be determined a priori. However in equilibrium the generators should behave in this fashion.[42] The characterisation of pure-strategy equilibria is summarised in the following proposition:

Proposition 3*: If Pr (d > max{k_1 k_2}) = 1, all pure-strategy equilibria are given by offer-price pairs (p_1,p_2) satisfying either $p_1 = \overline{p}$ and $p_2 \leq b_2$ or $p_2 = \overline{p}$ and $p_1 \leq b_1$, for some $b_i < \overline{p}$, i = 1,2.*

As already noted, the intuition for the result is straightforward. The high-bidding generator will always determine the system marginal price by Proposition 1. Therefore its payoff is increasing in its own offer prices and profit maximisation requires bidding at the highest admissible price. The low-bidding generator is indifferent between offer prices lower than that of the high-bidding generator. However, to ensure that the high-bidding generator does not deviate, the low-bidding generator has to bid low enough so that the high-bidding generator's payoff from undercutting is less than the payoff earned in equilibrium. Thus the upper bound on the low-bidding generator's offer price.

In all of the equilibria characterised by Proposition 3, the system marginal price equals the highest admissible price. The low-bidding generator is despatched with full capacity while the high-bidding generator supplies the residual demand. It follows that both generators prefer equilibria where they act as the low-bidding generator, since the received price is the same while a generator's output is greater in the equilibrium in which it is ranked first.

Note that some of these equilibria involve inefficient despatching: the high-cost generator may be the generator with the lowest bid and thus will be despatched with it's total capacity, while

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42 Since in this game there are two asymmetric pure-strategy Nash equilibrium outcomes, in the absence of further information the equilibrium solution reached cannot be predicted from first principles. One solution is to consider the symmetric mixed strategy equilibrium, in which each generator plays its low bid with probability 0.36. Another would be to predict that the generators would alternate between pure strategy equilibria. Other factors - such as the relative sizes of the generators - may single out certain equlibria as 'focal' (see Lucas and Taylor , 1993, for more on this).

the low cost generator is only despatched with part of its capacity. In such equilibria, generation costs are not minimised.[43]

Variable Demand Periods

We turn now to the third case in which either generator may set system marginal price with positive probability independently of its bid (i.e. rank). In the England and Wales pool generators bid daily, and (depending on the season) their bids may consequently be constant for time periods in which demand is expected to be high (morning and afternoon) and periods in which it will be low (night time).[44] This can be modelled as if the generators face a single period in which demand could be low or high with some probability. Equilibrium bids in this case are not the simple 'high-low' bids of the high-demand period case, nor the fiercely competitive bids of the low-demand period. In fact, pure strategy equilibria do not exist in this case and hence equilibria are in 'mixed strategies.' Under their mixed strategies, in equilibrium, both generators randomise over their price bids from an interval bounded below by the least efficient generator's marginal costs, and above by the highest admissible price. Expected pool prices still exceed the marginal costs of generation, however what the pool price will be is the result of a random process and cannot be predicted exactly.

The non-existence of pure-strategy equilibria follows from observing that bid pairs like those in Proposition 3 cannot constitute equilibria in this case since the low-bidding generator will now always wish to increase its bid; in doing so it thereby increases the system marginal price in the event that it becomes the marginal operating generator. We therefore have the following result:

Proposition 4*: If $\bar{d}-\underline{d} > \max\{k_1,k_2\}$, where $[\underline{d}, \bar{d}]$ is the support of the demand distribution G(d), then there does not exist an equilibrium in pure strategies.*

This result follows directly from Proposition 1. Since the range of possible demand distributions exceeds the capacity of the largest generator, it follows that for any strategy combination there is a positive probability that sets of either generator will be the marginal operating unit. We can then apply the result of proposition 1; there cannot exist pure-strategy equilibria for which more than one generator has a positive probability of determining the system marginal price.

Characterisation of mixed-strategy equilibria in the general model is cumbersome, and in the remainder of this section we consider a simple example. In this example one can demonstrate that there exists a unique mixed-strategy equilibrium, and derive the explicit form of the two players' strategies. In particular, the lowest price in the support of the players' strategies is strictly greater than the marginal cost of the least efficient generator, and this lowest price is an increasing function both of the highest possible price $\bar{p}$, the probability that both generators will be operating (i.e. demand), and the marginal cost of the least efficient generator.

In the example, it is assumed that each generator owns only one set with capacity normalised to 1, and can submit only one offer price for the whole of this capacity. Demand is discrete

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[43] It is easy to see that in the oligopoly case we get a corresponding result: Whenever demand is such that the highest-bidding generator determines the system marginal price with probability 1, any vector of offer prices such that the highest-pricing generator submits the maximum admissible price, while the rest bid sufficiently below this, will be an equilibrium

[44] This is different in the Scandinavian pool, in which different price bids may be submitted for each of the 24 hourly periods that the market is open. The variable demand case is consequently of less relevance for this market.

and distributed on {1,2} with probabilities $\Pr(d=1) = \pi$ and $\Pr(d=2) = 1-\pi$, $\pi > 0$. We can prove the following:[45]

Proposition 5*: There exists a unique mixed-strategy Nash equilibrium in which player i's strategy is to play $p \varepsilon [p^m, \bar{p}]$ according to the probability distribution $F_i(p)$, $i = 1,2$, where $p^m > c_2$ and $F_1(p) \geq F_2(p)$.*

In equilibrium, players strike a balance between two opposing effects. On the one hand a high bid results in a high system marginal price - and hence payoff - in the event that the generator is marginal. On the other hand, bidding high reduces the probability of being despatched. The latter effect is less important the smaller is π, since then it is very likely that both generators will be despatched. Conversely, when the probability that both generators will be operating is low (i.e. π is large), less probability mass is placed on higher prices. To say this another way, the incentive to raise one's bid is checked by the likelihood of ending up as the higher pricing generator and not being called into operation: when π is small, there is a substantial probability that a generator will be operating even if it offers to supply only at a very high price. Thus, for small π both generators will tend to submit high bids and visa versa. Indeed, the following is easily demonstrated:

$$\lim_{\pi \to 1} p^m = c_2 \,, \tag{5}$$

$$\lim_{\pi \to 0} p^m = \bar{p}. \tag{6}$$

Note that the limit in (5) corresponds to the case discussed in the 'low demand periods' subsection, while the limit in (6) corresponds to the 'high demand' case.

The high-cost generator's strategy profile first-order stochastically dominates the strategy profile of the low-cost generator (i.e. $F_2(p) \leq F_1(p)$). Thus in expected terms, the high-cost generator will submit higher bids than the low-cost generator. A lower bound for the probability that the high-cost generator submits a bid *below* that of the low-cost generator can be established by considering the probability that $p_2 < p_1 - c_2$. When $\pi = ½$, this reduces to

$$\mathrm{Prob}(p_2 < p_1 - c_2) = \frac{1}{2}[1 - \ln(1 + \frac{e}{\alpha - 1})]^2 \tag{7}$$

where $\alpha \equiv \bar{p}/c_2$. If $\alpha = 5$ (10), i.e. $\bar{p}$ is 5 (10) times the marginal cost of the high-cost generator, this probability equals 12% (27%). Thus, although the typical outcome is that the high-cost generator prices above the low-cost generator, there is a potentially significant positive probability that the high-cost generator submits the lowest price offer and thus becomes the only operating generator. Therefore we may conclude that, as in the high-demand periods case discussed above, the regulatory rule, as it is modelled here, is not ex-post efficient (in Section 5 we discuss how the rule may be adjusted to ensure efficient despatch).

In von der Fehr and Harbord (1993) this model was used to consider the question of how an increase in the number of independent generators will effect (average) pool prices, by extending the analysis to the case of oligopoly. Since the question of interest is how the number of suppliers in the market will affect the price structure we considered the situation in which the existing generators are split up into smaller units, i.e. a given total capacity divided between a larger number of generators. This approach seems the most natural if the question of primary interest is the organisation of the deregulated structure of an existing industry.

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[45] See von der Fehr and Harbord (1992) for a derivation and the explicit solutions.

When for a given level of demand and total capacity more players are introduced into the game, there is a pro-competitive effect, i.e. prices will tend to be lower in the more fragmented industry. The intuition for this may be explained as follows: The probability of any generator setting system marginal price decreases as the number of generators increases. Hence the incentive to bid high in order to raise market price decreases. The overall effect is to reduce the probability of any generator submitting a high bid, and hence of a high system marginal price.

This intuition also suggests that in the more general model with multi-unit generators, prices will tend to be higher than in the model in which these same units act independently. As indicated above, raising the bid of one unit will have an external effect on other units in that it increases the expected system marginal price. A generator which controls many units will internalise part of this externality and will thus have an additional incentive to increase its offer prices. In particular, this 'co-ordination incentive' is stronger the more units an owner controls. It therefore seems reasonable to conclude that for a given number of generating sets in the industry, the system marginal price will be a decreasing function of the number of owners, or generators controlling the sets, i.e. the industry concentration ratio.

3.4.2 Discussion

von der Fehr and Harbord (1992) (1993) modelled price competition in the deregulated wholesale market for electricity in England and Wales as a first-price, sealed-bid, multiple unit auction. Green and Newbery (1992) is the only other model specifically designed to study the bidding behaviour of the generators under the new UK system.[46] While the conclusions from the two models concur in many respects, von der Fehr and Harbord's results cast some doubt upon the type of equilibrium analysis employed by Green and Newbery, i.e. Klemperer and Meyer's (1989) 'supply function equilibrium' model. This is because the equilibria found under the assumption that firms submit smooth, i.e. continuously differentiable, supply functions do not appear to generalise to the case where supply functions must be discrete 'step functions', even when the 'step-length' can be made very small. Indeed, they found that for a wide range of demand distributions, pure strategy (i.e. supply function) equilibria will not exist in this case.[47]

While the analysis presented in von der Fehr and Harbord (1993) would appear to be useful in providing a framework for studying pricing behaviour in the deregulated UK electricity industry (for its application to empirical studies, see Section 4 below), the importance of its conclusions is limited by the extent to which it does not take into account opportunities for collusive behaviour between the generators, nor the effects of long-term contracts between suppliers and purchasers (or third parties). These problems still call for further research.

3.5 Concluding Comments

In this section we have described various attempts to analyse pricing and bidding behavior in electricity pools. A major theme has been that while standard oligopoly models can be suggestive, if used carefully, such as in the discussion of Armstrong, Cowan and Vickers (1994), a realistic understanding of generator bidding behavior in electricity pools requires an

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[46] While the model of Bolle (1990) is very close that of Green and Newbery (1991) in many respects, its purpose is somewhat more general.

[47] Newbery (1996) suggests that a reconciliation of the two modelling approaches is possible.

explicit modeling of optimal bidding strategies, given the actual pool pricing mechanism and characteristics of electricity supply.

Two essentially complementary models of generator bidding behavior in pools which do this have been discussed: Green and Newbery (1992) and von der Fehr and Harbord (1993). Both models found that the duopoly generators in the England and Wales pool should bid into the pool at prices well above marginal costs, and hence arrive at similar predictions concerning the outcome of strategic bidding behavior. The differences between the two models have to do with the assumptions made concerning the bidding strategies available to the generators and their cost functions. Green and Newbery (1992) model bidding strategies as ‘smooth’ supply functions, whilst von der Fehr and Harbord (1993) model strategies as discrete step supply functions. Both models also predict that with a larger number of independent generators, the England and Wales pool would be significantly more competitive. Hence these conclusions would appear to be robust to alternative modeling approaches.

All of the models described above abstract from the interaction of the contracts markets with competition in the pool, which may be potentially important for the analysis of pool competition. With reference to the pool in England and Wales, this topic has been discussed in Helm and Powell (1992), Powell (1993) and von der Fehr and Harbord (1994) (see also Armstrong, Cowan and Vickers, 1994, Ch. 9).

4. Empirical Evidence and Electricity Market Simulations

While the theoretical analyses presented in Section 3 may provide insights into the qualitative workings of electricity pools, empirical work is necessary to evaluate the quantitative importance of the various effects involved. There have been attempts to simulate strategic behaviour in pools using both very simple and more complex models of electricity markets. In Section 4.2 below we describe two attempts at simulating the UK pool, based respectively on the supply function and the multi-unit auction approaches discussed above. Section 4.3 then describes a large simulation study which was undertaken by the authors as part of the reform process of the Australian electricity supply industry.

Before turning to the simulation studies however we first present some empirical evidence on competition in electricity markets. Empirical studies of market power issues in electricity pools have been largely focused upon the England and Wales pool,[48] and here two types of evidence concerning pool prices and generator bidding behaviour in are available. The regulator Offer has produced numerous reports on pool prices which ultimately led to the temporary price capping of pool prices and an agreement on capacity divestiture.[49] In addition most attempts to model bidding behaviour in the pool have been accompanied by empirical work designed to exploit - or test - the theory (or both). This evidence is discussed immediately below.

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[48] An exception is Sørgard (1993) who discusses the possible abuse of market power in the Norwegian pool. Empirical studies of market power issues in the Norwegian electricity market have generally concentrated on price discrimination in retailing.

[49] On the former see Offer in the references, and Armstrong, Cowan and Vickers (1994), Ch. 9. See Green (1996) on the latter.

4.1 Empirical Evidence

A number of recent empirical analyses of competition in the England and Wales pool have been undertaken: in particular by von der Fehr and Harbord (1993), Wolak and Patrick (1996) and Wolfram (1996). This subsection discusses these analyses in turn.

von der Fehr and Harbord (1993)

von der Fehr and Harbord examined empirical evidence concerning generator costs and bidding behavior from May 1990 to April 1991, using actual bid data and cost estimates derived from published thermal efficiencies and fuel prices. This evidence shows that for the first 7-9 months of the new system, the two privatised generators appeared to bid very close to their (estimated) costs. By early 1991, however, bidding behaviour had changed and both generators were bidding above their estimated costs. They also provide evidence that suggests (i) experimentation and abrupt changes in pricing strategies and (ii) for at least certain types of units (i.e., large coal sets), asymmetric ‘high-low’ bidding patterns were emerging (with PowerGen as the high-price bidder), as suggested by their theory. Figure 4.1 below depicts average bids on large coal units for National Power and PowerGen from 1 May 1990 to 30 April 1991. It can be seen that around early December 1990 both generators altered their bidding behaviour on these units, and in opposite directions. National Power’s bids drop dramatically (from approx. £14 per MWh to less than £10 per MWh) in almost all weeks. PowerGen’s bids, on the other hand, increased its bids by an average amount of £1 per MWh. This pattern of bids remained stable from December 1990 until the end of April 1991.

[INSERT Figures 4.1]

One explanation for the changes in bidding behavior observed by von der Fehr and Harbord is that for the first year of operation of the new system contract coverage for each generator was approximately 85% of their capacities, and contract strike prices put downward pressure on spot prices. Subsequently contract coverage was reduced, allowing the generators greater freedom to exert market power in the pool. A second explanation is suggested in von der Fehr and Harbord (1993) which relates the empirical evidence to the results of their theoretical model. Recent support for this has come from the empirical work of Wolak and Patrick (1996), which is discussed immediately below.

Wolak and Patrick (1996)

Wolak and Patrick (1996) provide an extensive empirical analysis of prices in the England and Wales pool from 1 April 1991 to 31 March 1995, with a view to assessing whether or not the market has performed competitively, and in particular, *“...to determine the impact of the rules governing the market price determination process on the time series properties of market prices and the ability of generators supplying the E&W electricity market to maintain prices significantly above the short-run marginal cost and average total cost of production.*” They also provide commentary on, and some empirical analysis of, the theoretical models of competition in pools described immediately above.

Wolak and Patrick (1996) first characterise the times series properties of the average daily wholesale price of electricity and the vector of 48 half-hourly daily prices, because, *“...any story of how the generators use the market rules and market structure to maintain prices above average cost must be consistent with these time series properties of the wholesale* *prices*." They find that deterministic changes in the mean of the average daily wholesale price depend upon the day of the week, month and year in which a specific daily average price occurs. Stochastic fluctuations around the deterministic mean are modelled as a low-order autoregressive process in which the state dependence in the price process dies out after a week. They argue that this time series behaviour of wholesale prices can be explained by the major generators using their market power over price bids and capacity declarations to obtain very high prices for short periods of time e.g. for two or three half hour periods within a day. They also find that days in which high prices occur tend to follow each other in the same week.[50]

Wolak and Patrick (1996) also provide figures on the mean and standard deviation of SMP for the four year period they study, in which each year's pricing data is divided into four demand 'regimes.' They suggest that these regimes correspond roughly to those described in von der Fehr and Harbord (1993). Table 4.1 below is taken from Wolak and Patrick (1996), Table 3.

Table 4.1 Mean and standard deviation of SMP by load period regimes, 1991-1995

	Year	Mean	Std Dev	Std Dev/Mean (%)
FTSL < 20GW	1	15.75	1.35	8.75%
20GW < FTSL < 35GW	1	18.81	3.73	19.82%
35GW < FTSL < 45GW	1	21.88	4.03	18.41%
45GW < FTSL	1	30.71	4.36	14.20%
FTSL < 20GW	2	18.43	1.47	7.96%
20GW < FTSL < 35GW	2	22.01	4.13	18.76%
35GW < FTSL < 45GW	2	25.05	3.55	14.18%
45GW < FTSL	2	31.54	3.03	9.61%
FTSL < 20GW	3	23.30	7.80	33.49%
20GW < FTSL < 35GW	3	23.72	6.65	28.05%
35GW < FTSL < 45GW	3	25.27	6.38	25.25%
45GW < FTSL	3	37.66	3.85	10.21%
FTSL < 20GW	4	9.64	0.45	4.63%
20GW < FTSL < 35GW	4	18.69	9.43	50.44%
35GW < FTSL < 45GW	4	30.54	14.28	46.76%
45GW < FTSL	4	68.36	20.97	30.68%

[50] By contrast total system demand is much less volatile and is predictable over longer periods.

For each of the four years being studied, load periods were divided into those depicted in the figure. FTSL ≤ 20GW is interpreted as a von der Fehr and Harbord (1993) 'low demand period'; the next two types of load period are intended to be 'intermediate demand periods'; and FTSL ≥ 45GW defines 'high demand periods' (see Wolak and Patrick, 1996, pp. 34-35 for an explanation of why periods were defined in this way). The lowest mean value of SMP occurs in the low demand period, as would be expected. Mean values increase moving from the first to the fourth 'regime', with the greatest 'price volatility', as measured by the ratio of the standard deviation to the mean, occurring in the two 'intermediate demand periods.' Hence the data is broadly consistent with the hypotheses that:

(i) In low and high demand periods pure strategy equilibria occur, with price being determined by marginal cost bidding in low demand periods, and by at least one generator bidding high prices in high demand periods; and

(ii) In intermediate demand periods only mixed strategy equilibria occur.

Wolak and Patrick thus argue that the evidence on the mean and standard deviations of SMP as depicted in Table 4.1 broadly suggests the types of generator bidding behaviour described by von der Fehr and Harbord (1993). They conclude: "*While these results cannot confirm the validity of the von der Fehr and Harbord (1993) view of the operation of the market, we do feel their model provides a useful theoretical lens through which to view the behaviour of SMP*."

Wolak and Patrick (1996) consider further empirical evidence on bidding behaviour and prices in the pool for the period considered, not all of which we will attempt to describe in detail here. In particular they estimate marginal cost curves for National Power and PowerGen and compare them to bids on selected days in 1995. These comparisons mirror fairly closely those estimated by von der Fehr and Harbord (1993).

The theme of Wolak and Patrick 's paper is that the duopoly generators in the England and Wales pool have two instruments available for influencing pool price: (1) price bids and (2) capacity availability declarations. They argue that the latter is potentially more significant, and are used to periodically raise pool prices well above marginal and average costs of supply. In particular they suggest that capacity bids are a more 'high-powered' instrument than price bids for manipulating pool prices because:

- price bids are fixed for 48 hours, whilst capacity bids can be changed practically continuously;
- capacity availability more difficult to monitor than price bids versus costs; and
- the LOLP function is non-linear and extremely convex at low reserve margins, allowing for large effects on the capacity payment from relatively small changes in capacity bids.

Wolak and Patrick (1996) conclude:

> "*...The evidence presented makes it hard to believe that PowerGen and National Power do not strategically set their supply functions and available capacity to obtain PPPs and PSPs that are temporarily significantly above average production costs for those load periods. Summing over all load periods within the year, this strategy results in revenues significantly above total production costs. ....We suggested a mechanism that the two largest participants in this market use the market structure and rules of the market to strategically set capacity and prices to result in the temporary exercise of market power within a day in a manner that is also consistent*

with the time series behaviour of prices. The major result is that market power is a periodic and transitory phenomenon requiring a confluence of factors...”

Wolfram (1996)

Wolfram (1996) applies techniques from empirical industrial organisation theory to the measurement of market power in the England and Wales electricity spot market. Like von der Fehr and Harbord (1993), Wolfram calculates short run marginal cost functions for the generators based on assumed fuel prices and operating efficiencies for the portfolio of plant for each generator. She then computes the price cost margin using these marginal cost functions and actual market PPPs and quantities. Wolfram also uses three NEIO (‘new empirical industrial organisation’) approaches to measuring market power. The results of all of these approaches are broadly similar. She finds price costs mark-ups in the neighbourhood of 20%, but also that the generators are not exercising their market power to the extent deemed possible by some theoretical models. This is explained first by contracts, and later by the imposition of a price cap on pool prices. Wolfram (1996) also hypothesises that the threat of entry may be constraining pool prices, following Green and Newbery (1992) and Newbery (1995), (see below).

4.2 Simulation Studies of the England and Wales Pool

Simulations of competition in the England and Wales pool have been carried out using the ‘supply function’ and ‘auction’ approaches described above, by Green and Newbery (1992) and Lucas and Taylor (1993) respectively.

Green and Newbery (1992)

Green and Newbery calibrated their model to the circumstances of the E&W industry using demand and output data from 1988/89 to create a stylised ‘year’, and thermal efficiency data from the *CEGB Statistical Yearbook* to create cost curves using values for relative fuel prices quoted in various sources. Their assumed cost functions took the form:

$C' = 18.5 + .1Q,$ for $Q \leq 30$

$C' = 21.5 + .06(Q\text{-}30)^2,$ for $30 \leq Q \leq 48$

adjusted for plant availabilities. Their ‘marginal cost pricing’ reported in the table below was calculated on the basis of assuming these cost functions for the thermal duopoly generators. A linear time-dependent demand curve was assumed, and alternative values for the slope of the demand curve were tried (see Table 4.2 below).

Table 4.2 reproduces the Green and Newbery (1992) results in the no entry case. They find that in their base case (using a demand slope parameter of 0.25), in the highest-price, static, symmetric, duopoly supply-function equilibrium, the energy price is approximately 80% higher than the ‘perfectly competitive’ price level, i.e., the level implied by marginal cost bidding (£41 per MWh versus £23 per MWh), and output is 10% lower (214 TWh versus 248 TWh). When a more ‘vertical’ demand curve is assumed, the average pool price is significantly higher (£66.7 per MWh), but output remains roughly constant. With five equally sized generators however, they find that the equilibrium average price would have been £27 per MWh, much closer to the competitive outcome, and output 241 TWh. Hence the welfare losses from duopoly would appear to be much higher than they would have been under quintopoly, at least in this sort of equilibrium.

Green and Newbery also analysed their model for the case of asymmetric duopoly, with one larger and one smaller generator, and found that the differences at the industry level between the symmetric and asymmetric equilibria were small. In the asymmetric case however, the larger generator (‘National Power’) stands to gain relatively more from keeping prices high and so submits a steeper price schedule. As a result - and unlike their symmetric case - there is productive as well as allocative inefficiency, i.e., overall industry supply costs are not minimised because the merit order is distorted, with some cheaper ‘National Power ‘plant being bid in at higher prices than more expensive 'PowerGen' plant.

Table 4.2 Green and Newbery results for the no entry case[51]

	Actual 1988/89	Marginal Cost Pricing	Quintopoly	Duopoly (4)	(5)	(6)
Slope of demand curve, b			.25	.10	.25	.50
Elasticity at equilibrium			.24	.25	.40	.64
Price strategy of incumbents			high	high	high	high
Production (TWh):						
System	248	248	241	215	214	213
Oligopoly Output	189	189	182	156	155	154
Average pool price	20.8	23.0	27.0	66.7	41.1	32.3
Deadweight Losses		0	20	761	340	190
Duopoly profits		816	1,567	7,798	3,664	2,247

Finally, Green and Newbery considered the entry by new generators into the market, assuming that entrants all built CCGTs. They assumed that entry would occur until the average pool price equaled the entrants’ average energy costs (approx. £30 per MWh). On these assumptions their base case predicted an additional 8 GW of capacity being added to the

[51] Partial reproduction of Table 1 in Green and Newbery (1992), p. 945.

market, lowering average pool prices but resulting in a good deal of excess capacity, and hence adding to welfare losses. Table 4.3 summarises their results.

Table 4.3 Green and Newbery results for entry case[52]

	Marginal Cost Pricing	Quintopoly	Duopoly (3)	(4)	(5)	(6)
Slope of demand curve, b		.25	.25	.10	.25	.50
Price strategy of incumbents		high	high	low	low	low
Entry (GW)		0	13.5	11.2	8.0	2.5
Production (TWh)	273	264	258	267	258	243
Average pool price	21.7	26.7	30.1	29.9	29.8	29.7
Deadweight Losses	0	-54	412	268	208	108

Green and Newbery's 'base case' prediction of 8 GW of additional CCGT capacity was remarkably close to actual events - see Section 2 above - despite the lack of realism in their assumptions. In particular, as we have already noted, the assumed demand elasticities seem too high, and lower demand elasticities appear to result in much more entry[53]. Offsetting this however, is the assumption that entry will occur until average pool price is equal to CCGT average costs. This treats new entrants as 'price takers,' and ignores any reaction to entry by incumbents. Taking these into account would presumably reduce the amount of entry in each of the cases considered. In fact entry incentives in the England and Wales market are much more complex than described here, and have arguably been distorted by the regulatory regime. Hence the predictions of any simple model are unlikely to have very much empirical validity.

Lucas and Taylor (1993)

Lucas and Taylor (1993) simulated bidding behaviour in the England and Wales electricity pool by considering an extremely simplified version of the von der Fehr and Harbord (1993) model. They found examples of the equilibria identified in von der Fehr and Harbord (1993) for 'high-demand' and 'low-demand' periods, in both symmetric and asymmetric cases. They also solve for the mixed strategy equilibria of a simple two-strategy example in the high-demand case for symmetric generators.[54]

Table 4.4 below depicts one of the normal form games studied by Lucas and Taylor (1993). They considered a model in which there were two equally-sized generators with 10 plants or

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52 Partial reproduction of Table 2 in Green and Newbery (1992), p. 951.

53 Although only 8.8 GW of CCGT capacity has been added since vesting; 5.6 GW is currently under construction, to be commissioned in 1996/97, and 4 GW more is in the planning stage. Against this however, approximately 12 GW of (older coal) plant has been retired, so that from 1990 to 1996 there has been a overall reduction in total capacity of 3GW.

54 Lucas and Taylor suggest that pure strategy 'high-low' bid equilibria are less plausible than mixed strategy equilibria, on a priori grounds.

generating units, each with marginal costs varying from 16/MWh to 20.50/MWh. Each plant was assumed to have a capacity of 1000 MW. Generators were constrained to bid in all of their plant at the same multiple of marginal costs, ranging from 1 to 2. Each cell in the table contains the payoffs (i.e. profits) for each generator from the specified bidding behaviour. Generator A's profits are given first followed by Generator B's.

Table 4.4 The 'high-low' bidding game

	Generator B's Bids					
Generator A's Bids	**1.0 MC**	**1.2 MC**	**1.4 MC**	**1.6 MC**	**1.8 MC**	**2.0 MC**
1.0 MC	11, 11	28, 17	63, 31	98, 45	133, 59	168, 73
1.2 MC	17, 28	37, 37	64, 31	98, 45	133, 59	168, 73
1.4 MC	31, 63	31, 64	64, 64	105, 48	133, 59	168, 73
1.6 MC	45, 98	45, 98	48, 105	91, 91	130, 77	168, 73
1.8 MC	59, 133	59, 133	59, 133	77, 130	117, 117	162, 95
2.0 MC	73, 168	73, 168	73, 168	73, 168	95, 162	144, 144

When total demand is taken to be 14,000 MW - i.e. a 'high demand period' of the von der Fehr and Harbord (1993) model - as predicted by the theory, two types of pure strategy Nash equilibria exist. Equilibria (interchangeable) in which the first generator bids at 2 times marginal cost while the second generator bids low; and equilibria in which the second generator bids high (2 times marginal cost) whilst the first generator bids low. Lucas and Taylor (1993) also calculate a symmetric mixed strategy equilibrium for this example.

Lucas and Taylor (1993) also consider (i) the same game in which demand is 7,000 MW (a 'low demand period') and find the unique equilibrium to be 'Bertrand-like;' and (ii) the same game with two asymmetrically-sized generators. In the latter they find that in 'high demand periods' there are more (interchangeable, i.e. payoff-equivalent) equilibria in which the larger generator bids high and maintains system marginal price.[55]

4.3 The Australian Market Power Study

A larger scale simulation of generator bidding behaviour based on the auction approach of von der Fehr and Harbord (1993) was undertaken for the Australian National Electricity Market (see Section 2 above for a description). The simulations were performed in a study for the Industry Commission of Australia by London Economics (Aust) Pty and D. Harbord and Associates (1995). The study made use of an actual model of the Australian system - including the pool price setting mechanism, generator capacity and cost data, and transmission

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[55] They also consider examples in which the generators are endowed with contracts for differences.

and interconnector constraints - to assess the effects on generator bidding behaviour and prices of different market structures of generation.

The purpose of the study was to analyse likely bidding behaviour by generators in the interconnected state electricity markets under different assumptions concerning the horizontal structure of generation. At issue was whether Pacific Power - New South Wale's monopoly, and Australia's largest, generator - should be left intact as a single generating entity, or split up into two or more separate companies. In order to do so a computer model of the Australian electricity market was employed to evaluate payoffs to generators for different bidding strategy combinations, and this model was amongst the most comprehensive, detailed and realistic available anywhere. Therefore the effects of different types of bidding behaviour on generator payoffs could be evaluated in a reasonably realistic setting.

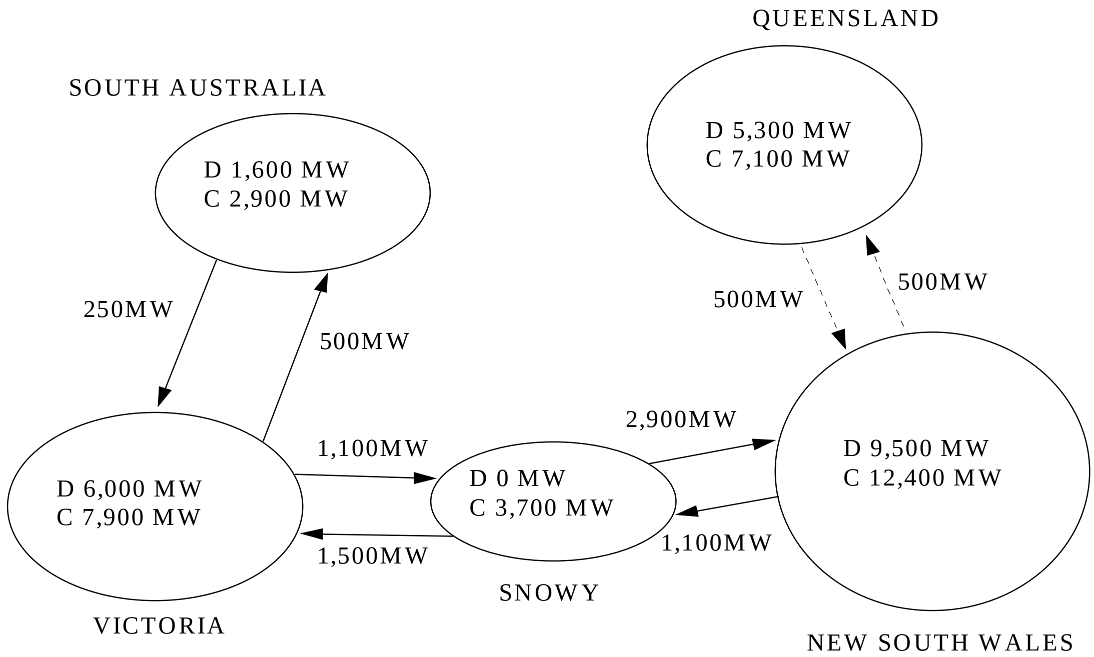
Despite the greater realism of this simulation exercise however, like the simpler examples studied by Lucas and Taylor (1993), only a very small number of strategies were permitted each generator (i.e. bids were allowed to vary by only 3 or 4 multiples of marginal cost), and the effects of contracts was ignored. Nevertheless the results corresponded remarkably well to the equilibria identified in the model of von der Fehr and Harbord (1993), despite the considerable added complexity of the empirical model. Thus this simulation evidence suggests that these equilibria are potentially robust to more realistic modelling approaches.

A detailed description of the Industry Commission study is available in London Economics and D. Harbord & Associates (1985), which we only briefly discuss here. We limit ourselves to describing the basic market structure of the Australian market in 1995, and a number of the key results, using Tables 4.5 to 4.8 below.

Figure 4.6 describes the basic market structure of the Australian electricity industry in July 1995. In New South Wales peak demand of 9500 MW was met by 12,400 MW of capacity controlled by Pacific Power, the state monopoly utility. Victoria had an peak demand of 6000 MW and capacity of 7,900 MW. In South Australia the corresponding figures were 1600 and 2900 respectively. In addition the Snowy Mountain Hydro Authority had a capacity of 3700 MW, which was sent via interconnects to both Victoria and NSW.

The capacities of the interstate interconnectors are also shown in Figure 4.6. As is evident, interconnector capacities were small relative to the within-state generation capacities. This is particularly so for South Australia, where imports and exports capacities amount to, respectively, 18% and 9% of total generation capacity. The import capacity to New South Wales was approximately 23% of the states generation capacity.

Figure 4.6 The Australian National Electricity Market, 1995



In 1995 Pacific Power's generating capacity was provided by seven coal-fired thermal power stations (ranging in size from 600MW to 2640MW), and within the interconnected south east region of Australia, Pacific Power had 48% of the total system capacity. In contrast, Victoria had separated its generation sector into five entities, two of which have recently been privatised, and the largest of which had a generating capacity of 2000MW, which represented 8% of total interconnected system capacity. The South Australian utility had 9% of interconnected system operating capacity.

The study for the Industry Commission addressed the issue of the likely competitiveness of generator bidding behaviour in the National Electricity Market under two basic options for generation structure:

(i) Pacific Power as a single entity, and

(ii) Pacific Power broken up into two or three (more or less) equally-sized, independent companies.

Thus simulations of equilibrium bidding behaviour were carried out for these scenarios.

4.3.1 Simulation Results

The model used solved for system marginal price (SMP) in each regional market, output and operating profits for each generating unit, and power flows (including those over the interconnectors) for any given set of strategies assumed for the generators. Due to the complexity of the model, designed to be a realistic representation of the Australian electricity supply industry, and the number of simulations required to solve the model for all possible strategy combinations,[56] it was necessary to limit both the number of strategic players and the number of available bidding strategies. Hence in the simulations, the number of 'strategic'

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[56] Equal to S^N, where S is the number of strategies in a player's strategy set and N is the number of players.

players never exceeded four, while the number of available strategies was typically restricted to three. In each game modeled, strategic players were allowed a choice between three different step supply function bidding strategies - marginal cost bidding, twice marginal cost bidding, and three times marginal cost bidding.[57] Simulations were undertaken for six different day types. In many cases however, the qualitative feature of the results did not differ significantly between types of day.

The restrictions on the strategy sets means that equilibria in these numerical games may not correspond to equilibria in more general games in which strategies are less restricted, and care is therefore required in interpreting the results. Nevertheless, taken together with results from the theoretical model of von der Fehr and Harbord (1993), the numerical simulations appeared to give some useful insights into the likely functioning of the Australian electricity market under alternative assumptions about market structure.

Pacific Power As a Single Entity

Table 4.5 illustrates a payoff matrix for a cold business day (i.e. medium demand day) in which the two strategic players are Pacific Power as a single entity, and the South Australian generator.[58] The typical result in all simulations with a single New South Wales generator was that Pacific Power had a dominant strategy to bid at the highest multiple of marginal cost permitted (three times marginal cost in this example). This result was very robust to changes in modeling assumptions and day types, and also survived both increasing the size of the interconnect links between states, and allowing for a significant amount of IPP ('independent power producers') entry (see further below). The reason for this was evidently that its share of New South Wales and south east Australian generation capacity meant that Pacific Power was the residual monopolist in all scenarios, and priced its capacity units accordingly.[59]

Table 4.5 PP versus SA: Dominant Strategy Equilibrium

Cold Business Day $'000's	PP = MC	PP = MC*3
SA = MC	$269	$4,258
	$57	$364
SA = MC*3	$430	$4,375
	$784	$784

57 Earlier simulation which were not reported allowed for more multiples of marginal cost, however it was felt that these led to unrealistically high pool prices in many instances.

58 For the simulations reported here, the five Victorian generators were assumed to bid at marginal cost, however the robustness of this assumption was checked.

59 Under this market structure for generation the von der Fehr and Harbord (1993) model would predict a high-low bidding equilibrium outcome, with Pacific Power as the high bidder. Since, by assumption, in these simulations the Victorian generators bid at marginal costs, this is exactly the type of outcome that is found here.

Three-Part Pacific Power

All other simulations carried out assumed Pacific Power broken up into two or three entities. The former resulted in little improvement in the outcomes however, and is not reported here. Table 4.6 shows the allocation of capacity (including average costs for each station) for the three-part Pacific Power.

Table 4.6 Pacific Power in three generation groups

Station	Capacity	Operating costs (per MWh)
Pacific Power 1 (PP1) total	**3,451MW**	
Mount Piper	1,251MW	\$12.2
Vales Point B	1,251MW	\$14.8
Wallerlang	948MW	\$14.8
Pacific Power 2 (PP2) total	**4,399MW**	
Bayswater	2,503MW	\$13.1
Liddell	1,896MW	\$14.7
Pacific Power 3 (PP3) total	**3,128MW**	
Eraring	2,503MW	\$14.3
Munmorah	626MW	\$14.3

Tables 4.7 and 4.8 illustrate the simulation results for the three-part Pacific Power for a 'mild non-business' (i.e. low demand) day and a 'hot business' (i.e. high) demand day respectively. In the first case, each Pacific Power generating entity bids at marginal cost in equilibrium, and thus very competitive outcomes emerge. In the second case there were multiple equilibria in each of which one of the Pacific Power generators bid high (i.e. at the maximum multiple of marginal cost) whilst the other two bid low (i.e. at marginal cost). Hence although the bidding strategies now reflected strategic considerations, high priced outcomes still resulted in some of the simulations (i.e. on some day types). In fact competitive outcomes occurred on only two out of six day types. Nevertheless average market outcomes were significantly improved by the break-up of Pacific Power into three parts, and average annual pool prices fell by more than 15%. [60]

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[60] Given the size of each of the three Pacific Power generators relative to the within-day variation in demand in New South Wales, the von der Fehr and Harbord model would predict that no pure strategy equilibrium exist in this game (Proposition 1, Section 3 above). Consequently, the only equilibrium in the simulation game is not an equilibrium in a game with unrestricted strategy sets. For obvious reasons, it is an unmanageable task to characterise mixed-strategy equilibria in the simulation model.

Table 4.7 Three Part Pacific Power: Marginal Cost Bidding

Mild non-business day	**Payoff = $'000'**	PP3 MC		PP3 MC*3	
		PP1 MC	PP1 MC*3	PP1 MC	PP1 MC*3
	PP1	$104	$0	$165	$622
PP2	PP2	$217	$1,063	$240	$2,463
MC	PP3	$89	$628	$0	$79
	SA	$582	$583	$582	$582
	PP1	$896	$391	$2,149	$799
PP2	PP2	$0	$989	$643	$1,724
MC*3	PP3	$597	$1,354	$0	$595
	SA	$582	$582	$582	$582

Table 4.8 Three part Pacific Power: High-Low Bidding

Hot business day	**Payoff = $'000'**	PP3 MC		PP3 MC*3	
		PP1 MC	PP1 MC*3	PP1 MC	PP1 MC*3
	PP1	$92	$121	$1,497	$394
PP2	PP2	$217	$1,897	$2,397	$2,439
MC	PP3	$107	$1,263	$142	$927
	SA	$708	$708	$708	$708
	PP1	$1,361	$446	$1,653	$485
PP2	PP2	$484	$1,588	$1,522	$1,999
MC*3	PP3	$1,530	$1,815	$527	$1,375
	SA	$780	$708	$708	$708

Easing transmission constraints

Two alternatives for increasing the size of interstate links were considered. The first assumed strengthening of the existing interconnector links by 30%. The second assumed that the interconnector to Queensland had been constructed. Increasing existing interconnection capacities by 30% had little effect on system marginal prices under any scenario. While resulting in reduced outputs and profits from the exercise of market power in the importing regions, the relative sizes of payoffs from following the alternative strategies were unaffected. Consequently (given that Victoria generators bid at marginal cost), it remained a dominant strategy for both Pacific Power and South Australia to bid at the highest allowed multiple of marginal cost.

When Queensland was interconnected with New South Wales via the (planned) 500MW Eastlink, again bidding the highest permitted prices remained a dominant strategy for both Pacific Power and South Australia (the Queensland generator now had the same dominant strategy). The conclusion was therefore that increasing interconnection capacities, or the construction of Eastlink, did not appear to reduce Pacific Power's market power.

Entry by IPPs

An alternative way of bringing more supply capacity, and hence competition, into the New South Wales market is by the entry of new, independent generators. This was simulated in two experiments in which 800MW and 2800MW of independent generation capacity were added respectively to the New South Wales market.[61] This IPP capacity was assumed to have marginal costs of $25/MWh to $26/MWh, and to bid at this level. Again the effect was that Pacific Power's output and profits fell by approximately 40%, but that average pool prices remained almost identical to the no entry case. Therefore from the consumers point of view, new IPP entry on this scale had almost no significant effects. Indeed, constructing costly, new capacity was highly inefficient since it increased the amount of excess capacity in the market, without significantly affecting either total output or market prices.

4.3.2 Concluding Comments

The Australian public policy debate concerning whether Pacific Power should be left intact to operate as a single entity in the national electricity market, or broken up into a number of competing units, was unique, not least because it has attempted to address directly issues of market structure and competition which have been largely neglected in electricity market reforms which have occurred elsewhere. The debate focused on the potential for the emergence of effective competition in the interconnected, inter-state market, under various alternative scenarios for the horizontal market structure of generation. In doing so it was able to draw upon international experience with previous (not entirely successful) reforms, a burgeoning theoretical and empirical literature on competition in electricity pools, and empirical techniques and models which have been unavailable to study these issues hitherto. It should therefore stand as a model of the type of debate which public policy issues of this importance should receive, and from which there is much to be learned.

The above discussion has focused upon a single simulation study carried out by the consulting economists which, as events turned out, was an important determinant of government policy.

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[61] The latter case increased New South Wales capacity by over 20%.

However opposition to its conclusions - led by Pacific Power's chairman, Fred Hilmer - was vigorous.[62] Nevertheless, in August 1995 the government-appointed New South Wales Generation Reform Working Group recommended the break-up of Pacific Power, and this became government policy.[63] The current structure of generation in New South Wales is depicted in Table 2.8 above.

5. The Design of Electricity Auctions

The creation of a electricity pool raises a number of fundamental questions concerning industry market structure, the role of regulation, and the design of the electricity auction itself (see Introduction). Should electricity auctions be 'one-shot' or iterative? Should there be a uniform market-clearing price, or should prices be determined by individual transactions i.e. as in a dynamic 'bid-ask' market? Should a first-price or second-price auction be used? Should there be a single market, or separate markets for energy and supply security? Should prices be determined in advance, or in 'real time'? Should generator bids include elements of fixed costs, or be for energy only? What constraints on generator bidding behaviour should be imposed? And so on.

We will not attempt to treat all of these questions in this section. Rather we limit ourselves to brief discussions of two key issues: the use of second-price versus first-price mechanisms and the design of iterative electricity auctions. Binmore and Harbord (1997) contains comments upon the other issues raised, many of which deserve further study and consideration.

In the theoretical models of the electricity pool described in Section 3 above, generators typically submit offer prices which exceed their marginal costs of supply for at least some capacity units. Furthermore, more expensive capacity units may submit lower offer prices than less expensive units. This leads to two types of inefficiency: (i) system marginal price tends to exceed the marginal costs of any operating unit, resulting in allocatively inefficient consumer prices, and (ii) despatch will often be suboptimal, and hence total system generation costs will not be minimised. An important question is therefore whether a pricing rule (or mechanism) can be devised which induces truthful revelation of costs and, as a result, efficient despatch. A related question is whether there exist pricing rules - or auction forms - which result in lower payments to generators and, consequently, lower consumer prices.

Designing pool pricing mechanisms which perform better - in some well-defined sense - than existing pool pricing rules can be viewed as a topic in *mechanism design*, on which there is a large theoretical literature (see Myerson, 1987 for a useful introduction and references; also Binmore and Harbord, 1997). In von der Fehr and Harbord (1993) we showed - by extending an insight on optimal auctions due to Vickrey (1961) - that a modification of the existing pool price mechanism was possible which resulted in efficient despatch and, on average, lower payments to generators. Other pricing rules or mechanisms for the England and Wales pool have also

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62 Professor Fred Hilmer is widely known as the author of Australia's recent competition policy reforms (the "Hilmer report," Australian Government, 1993). In addition to being the chairman of Pacific Power at the time of the above-discussed debate, he also, somewhat ironically, chaired the New South Wales Generation Reform Working Group. Despite his opposition to the restructuring policy ultimately adopted, by virtue of his chairmanship of the Working Group, Professor Hilmer is now widely cited as the architect of the New South Wales electricity market reforms.

63 The Working Group's key recommendation was that Pacific Power be broken up into two units, for reasons of 'financial viability.' However for reasons well outside the domain of the current discussion, the ultimate result was that three new independent generators were created.

recently been suggested.[64] And in California, the design of the trading rules for the new power exchange (PX) auction is currently an important topic (see WEPEX, 1996 and the recent reports by Wilson, 1997a, 1997b, 1997c). The remainder of this section discusses first, the second-price auction mechanism described in von der Fehr and Harbord (1992)(1993), and subsequently the auction design problems currently being addressed in setting up the California PX.

5.1 Second-Price Electricity Auctions

All competitive electricity pools which have been created to date are *first-price auctions.* That is, the price paid to each successful seller is determined by the bid price of the highest priced supplying unit. Much recent work in auction design by economists however focuses on *second-price auctions*. These are auctions in which the price paid to (or by) a successful seller (or buyer) is determined independently of the sellers' (or buyers') own bids. This type of auction has the important property that each supplier has an incentive to bid prices which reflect their true costs - i.e. players reveal all of their private information. This means that such auctions always result in units being sold by the lowest-cost suppliers first, and hence productive efficiency is achieved.

The generator bidding game analysed above may, as noted, be interpreted as a first-price, sealed-bid, multiple-unit auction with a random number of units. In particular, the system marginal price is determined by the offer price of the *marginal operating unit*, and thus a generator's bids will determine the price received by *all* of its units whenever one of its generating units is marginal. The fundamental insight of Vickrey (1961) was that by making the price received by a player independent of its own offer price, marginal cost bidding can be induced as a dominant strategy for each player. In von der Fehr and Harbord (1992)(1993) we considered a generalised form of a 'Vickrey auction' in which generator i is paid a price for each unit sold determined by the intersection of demand with the 'residual' supply curve obtained by subtracting the higher-priced units of generator i.[65] In such a set-up a generator can only influence its own payoff only to the extent that its' bids affect the probability of being despatched. A generator will prefer to be operating for all realisations of demand such that its payoff is positive, and will prefer not to operate whenever its payoff is negative. Therefore, offering to supply at a price equal to marginal cost becomes a dominant strategy because it maximises the probability of being called into operation whenever the generator's payoff is expected to be non-negative.

Multi-unit second-price auctions have, to our knowledge, never been implemented in practice, however they have recently become the focus of much theoretical study and experimental work (see Ausubel 1995, 1996 for example). Given that they induce marginal cost bidding, and lower payoffs to generators in general, they clearly deserve serious consideration in the context of designing electricity pools.

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[64] See Electricity Consumers' Committees (1996) for example.

[65] That is, generator i's payment for the rth unit sold is determined by the equilibrium price which would have resulted if generator i had offered to supply only r units. This differs slightly from the payment scheme described in von der Fehr and Harbord (1993). See Vickrey (1961) and Ausubel and Cramton (1996) for further discussions.

5.2 Activity Rules for the California Power Exchange (PX)

The Californian electricity industry is currently in the midst of a process of large-scale change. The structure of the industry is being reorganised, and competition in generation is to operate through a daily, day-ahead, iterative power exchange auction. The PX auction market is to determine a state-wide clearing price for energy for each hour, with a subsequent 'congestion management' phase to determine if separate prices need to be calculated for individual regions. An iterative auction form has been decided upon in order to allow generators to withdraw from the market in the event that their fixed costs of operation are not covered by hourly market clearing prices. This issue arises because it has been decided that each hourly market is to be evaluated independently (i.e. there will be, in effect, 24 separate energy auctions per day), and that generator bids are for energy (i.e. $/MWh) only. This is unlike the pool in England and Wales where generator bids include fixed as well as energy costs, and the fixed costs are averaged over periods of continuous running to determine a generating unit (average) price.

Given the decision to have an iterative or multi-stage auction process for each hourly market, attention has turned to designing appropriate 'activity rules' for the auction. Activity rules are deemed important because in their absence generators could wait until the last iteration of the auction before making any serious price or quantity offers. Indeed, large generators (i.e. generators with market power) will typically have an incentive to do precisely this. Such bidding behaviour would make earlier iteration results poor predictors of the final outcome, and hence the process of 'price discovery,' or orderly convergence to the market clearing prices and quantities, would be impeded. And if early iterations reveal little useful information, the incentive to withhold serious offers until the end of the auction is strengthened. 'Activity' rules therefore set down requirements for participating in the auction which make early, serious offers essential.[66]

The six basic activity rules currently under consideration for the California PX have the following form (see Wilson, 1997c):

1. *Opening Rule*: All participating generators must submit a tender, i.e. a price/quantity bid, for each generating unit (or segment), at the first iteration.
2. *Revision Rule*: In subsequent iterations, tender prices for any unit or segment can only be revised by *improving* the clearing price by a *specified price decrement*.
3. *Exclusion Rule*: Tenders above the clearing price must be revised (i.e. improve the clearing price) at the earliest opportunity, or they are 'idled.' Idled tenders cannot be revised until they are 'reactivated', i.e. until an iteration occurs in which the market clearing price rises above the tendered price.
4. *Withdrawal Rule*: A supplier may withdraw *all* of its offered capacity from the market at any iteration, but having done so the capacity cannot be re-offered (i.e. capacity withdrawals are irrevocable). After the final iteration an accepted tender cannot be withdrawn, and the supplier is financially liable for delivery.

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[66] Recent auctions for radio spectrum in the United States were the first large-scale implementation of iterative, simultaneous, multi-unit auctions and a key feature of their design was the use of activity rules. See Cramton (1995) and Chakravorti, Sharkey Spiegel and Wilkie (1995) for discussions. Robert Wilson, the economist currently responsible for designing the PX activity rules, also played a major role in the design of the radio spectrum auctions.

5. *Closing Rule*: All hourly markets close simultaneously. They close automatically after an iteration in which no tender in any hourly market is revised. Otherwise a final iteration is announced and special closing rules may be applied.
6. *Failsafe Rule:* After the final iteration the PX may accept rejected or withdrawn tenders at the tendered price, whenever this is necessary to ensure 'orderly markets.'

The purpose of these activity rules is to ensure that suppliers' opening tenders are serious (i.e. reveal accurate information about clearing prices and capacity availability) by severely limiting the scope for revisions once the auction has commenced. Additional capacity cannot be offered, so all capacity that is to be despatched must be made available at the opening, and the tendered price for this capacity cannot be increased (Rules 1 and 2). Rule 3 is intended to place pressure on suppliers to improve on clearing prices immediately rather than waiting. Rule 4 allows suppliers to withdraw capacity if average costs are not covered, but in such a way as to minimise opportunities for manipulation, or 'strategic' capacity withdrawals.

Variants of these rules are being considered as well as a number of different auction forms, and these are described in more detail in Wilson (1997a)(1997c). For instance Wilson discusses: (i) discrete and continuous auction forms; (ii) single price/quantity versus 'supply curve' bids for portfolios; (iii) the use of an aggregate revenue requirement mechanism for rejecting tenders, rather than voluntary, iterative, capacity withdrawals; and (iv) various types of strengthened opening rules, such as the use of 'reserve' prices (i.e. prohibiting price tenders above a given $/MWh amount), or rules which penalise generators for submitting initial tenders a specified percentage above the market clearing price. Serious thought is now being given to the consequences of adopting any particular version of these rules, which, unfortunately, are largely non-obvious. Market simulations and experimental methods are therefore being used to test the alternative auction forms.

5.3 Concluding Comments

An important and topical issue in the study of recently deregulated electricity markets is the design of the pool pricing auction or mechanism. In particular it would be useful to devise pool pricing mechanisms which achieve greater performance efficiency in relatively concentrated market structures. Some suggestions for pool pricing mechanisms which may perform better than those currently in use have been made (e.g. von der Fehr and Harbord, 1993; Electricity Consumers' Committees, 1996). However before any alternative pool pricing mechanism is considered for adoption, it should be given careful study. In particular the bidding or pricing incentives of generators must be considered. One way of doing so would be to test them experimentally in an 'economic laboratory' to try to understand how real people (i.e. businessmen) respond to the incentives built into the alternative mechanisms. Another would be theoretical studies or simulations. Since competitive electricity pools are now being created around the world, and encountering similar competition problems, more research in this area would be extremely valuable.

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