Assessing The Potential For Market Power In The National Electricity Market

STAFF INFORMATION PAPER

December 1996

ISBN 0 642 26444 9

The views expressed in this paper do not necessarily reflect those of the Industry Commission.

Inquiries

Industry Commission
Locked Bag 2
Collins Street East Post Office
Melbourne Vic 8003

Phone: (03)9653 2244

An appropriate citation for this paper is:

IC (Industry Commission) 1996, *Assessing the Potential for Maket Power in the National Electricity Market,* Staff Information Paper, Industry Commission, Melbourne.

Forming the Productivity Commission

The Industry Commission, the former Bureau of Industry Economics and the Economic Planning Advisory Commission have amalgamated on an administrative basis to prepare for the foramtion of the Producivity Commission. Legislation formally establishing the new Commission is before Parliament

Acknowledgments

This paper was researched and written by Dr John Salerian, John Robinson, Kate Pearson, Anne Cole and Chris Chan.

We are grateful for comments provided by Professor Gordon MacAulay at the University of Sydney. However, all errors and omissions are the responsibility of the authors.

December 1996

Contents

SECTIONS

BOXES

TABLES

FIGURES

Abbreviations

ABARE	Australian Bureau of Agricultural and Resource Economics
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CUBE	Canadian Utilities Power and Boral Energy cogeneration project
ETSA	Electricity Trust of South Australia
GWh	Gigawatt–hour
IC	Industry Commission
IOA	Interconnection Operating Agreement
KWh	Kilowatt–hour
MSG	Minimum stable generation
MW	Megawatt
MWh	Megawatt–hour
NGMC	National Grid Management Council
NPS	Northern power station
NSW	New South Wales
SA	South Australia
SMP	System marginal price
TIPS	Torrens Island power station

Assessing the potential for market power in the national electricity market

The existence of transmission costs, transmission losses, limited transmission capacity, and the small number of power stations in some regions may mean the introduction of the national electricity market in south eastern Australia results in spatial oligopolistic markets, in the short to medium term. This paper applies spatial-intertemporal equilibrium theory, using non linear programming, to analyse the incentives that exist for ETSA Generation to exert its market power in the South Australian region of the national market. Specifically, imperfect competition and detailed electricity production and consumption activities are incorporated into the spatial-intertemporal equilibrium models pioneered by Takayama and Judge (1971). The results indicate that in the short-term, there is an incentive for ETSA Generation to exert market power. Further, that splitting ETSA Generation into separate businesses would not significantly reduce this incentive. The model is also used to explore the use of vesting contracts to reduce market power in the short run, and the impact of new entry of regional generators in the long run.

1 INTRODUCTION

The Industry Commission (IC) recently undertook a review of the structure of the South Australian electricity industry (IC 1996). It was undertaken to assist the South Australian Government to determine the structure that will best suit South Australia in preparing for the introduction of the national electricity market. The terms of reference requested the Commission to take into account the extent of competition likely and the potential for market power to be exercised in the South Australian region given existing interstate transmission capacity and alternative generators.

To assist in evaluating these issues, the Commission undertook some modelling. The results of the analysis were included in the report. However, the short amount of time available to produce the report did not allow documentation of the work. This paper documents the full analysis undertaken. However, data supplied by ETSA for the IC (1996) report was confidential. In the work here, the confidential data has been replaced by publicly available data. Therefore the results here are slightly different to those in the IC (1996) report, but the findings are the same.

2 ELECTRICITY SUPPLY IN SOUTH AUSTRALIA

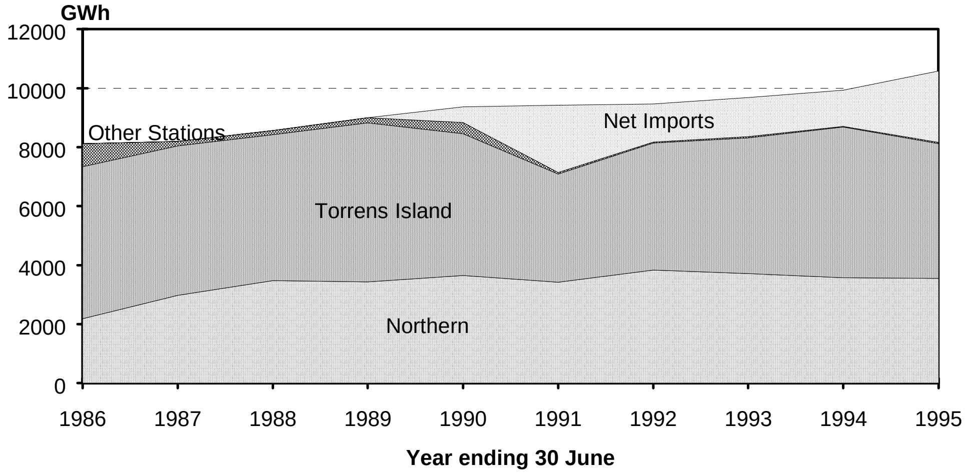
There are three sources of electricity supply in South Australia (SA):

- electricity generated by ETSA Generation;
- imports of electricity from the eastern states; and
- private producers.

In 1994–95, electricity generated by ETSA represented 75 per cent of total supply, imports made up 24 per cent and private producers supplied about 1 per cent (figure 1). As ETSA currently controls imports from the eastern states, in effect it controls 99 per cent of SA's electricity supply. It will also control disposal of the output from the Canadian Utilities Power and Boral Energy (CUBE) cogeneration project.

In 1990, the transmission interconnection between SA and Victoria was completed, enabling interstate trade in electricity between SA and Victoria and NSW. The interconnection has a capacity of 500 MW for imports into SA, and a capacity of 250 MW for exports from SA. ETSA considers that

Figure 1: Imports by SA and output of main SA power stations, 1985–86 to 1994–95

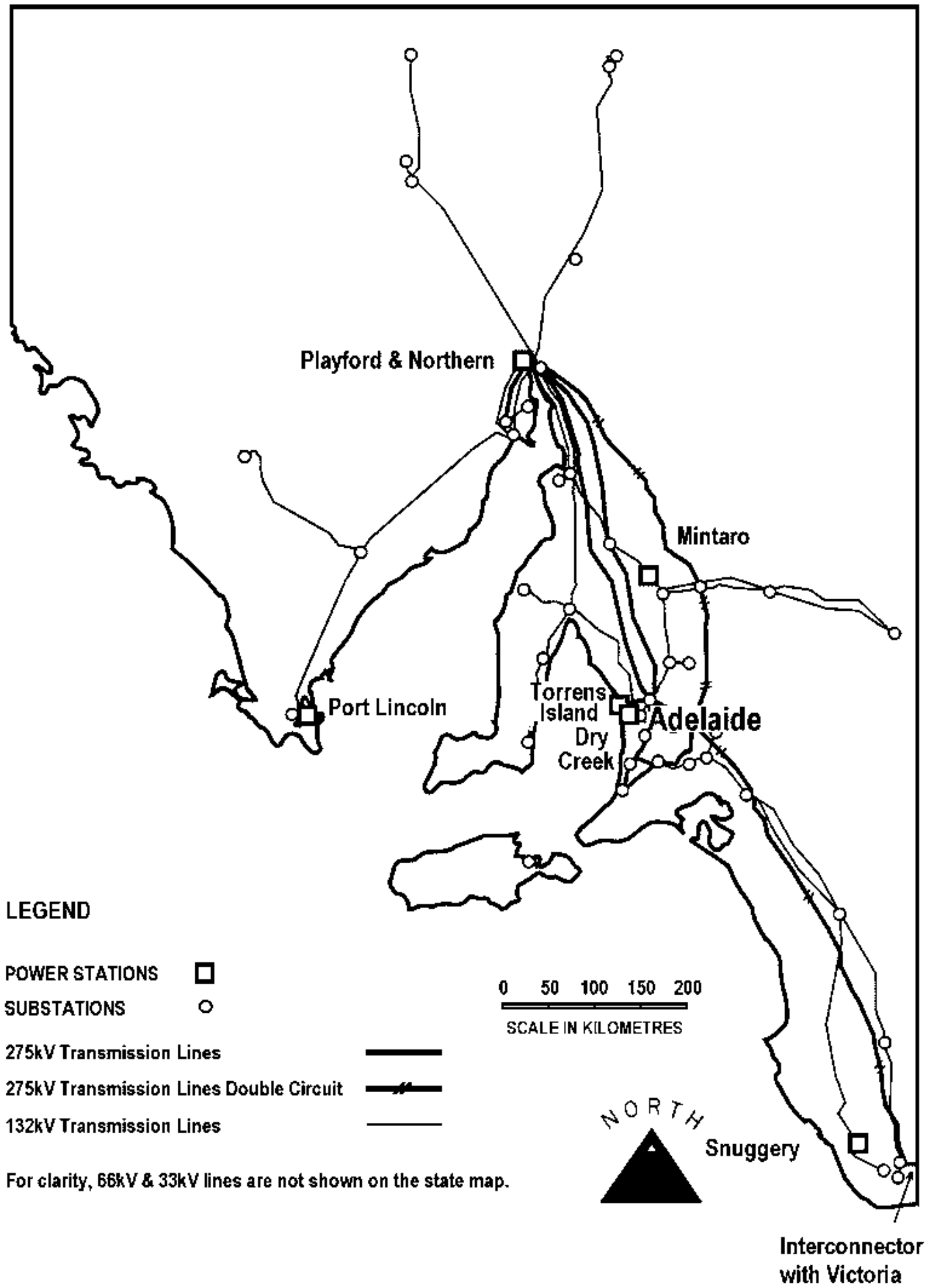


Source: ETSA Corporation (1995, p. 74).

imports could provide up to 35 per cent of SA (source) demand, given the existing interconnection capacity.

Figure 2 provides a simple representation of the SA electricity supply system. ETSA has seven power stations (table 1), with a total capacity of around 2200 MW. However, two power stations — Northern (NPS) and Torrens Island (TIPS) — account for 99 per cent of electricity generated by ETSA. ETSA's power stations have been designed to complement, not compete with each other. Northern (thermal coal) provides base load power throughout the day, the small stations only generate in the peak, and Torrens Island (thermal gas) handles the intermediate load and most of the peak.

Figure 2: South Australia's electricity supply system



Source: Adapted from ETSA Corporation (1995, pp. 65–66).

Table 1: ETSA's power stations, 1994–95[a]

Name	*Capacity (MW)*	*Output (GWh)*	*Plant type*	*Role*	*Age (years)*	*Value[b] ($ million)*
Northern	500	3 555	steam, brown coal	base load	11	307
Torrens Island A	480	4 566[c]	steam, gas	peaking	19	288[d]
Torrens Island B	800		steam, gas	Intermediate	19	
Dry Creek	156	4	gas turbine	peaking	23	8
Playford	120	10	steam, brown coal	peaking	32	0
Mintaro	90	0	gas turbine	peaking	12	24
Snuggery	63	3	gas turbine	peaking	18	12

a Osborne and Port Lincoln power stations have been excluded. In recent years, these power stations have produced negligible output.
b Value is after revaluation and depreciation.
c Combined annual output of Torrens Island A and B stations.
d Combined value of Torrens Island A and B stations.
Source: ETSA Corporation (1995 p. 52, 74), ETSA Corporation (1996), NGMC (1994 p. 29).

Current demand forecasts by ETSA indicate that SA will need to augment capacity or increase imports shortly after the year 2000. In an efficient market, whether future electricity requirements are met through new generation capacity installed in SA or through higher imports will depend on the cost of new SA capacity and gas prices, compared to the cost of importing power and expanding the transmission link to the eastern States.

3 MARKET POWER

Market power in the generation sector is a potential problem during the transition to a competitive market. In part, it reflects the change in the objectives given by the shareholder (government) to directors appointed to manage generation assets. In the past, managers of public generation assets were mainly charged with minimising the cost of supplying a particular grade of service. The design (size, location and technology) of the existing assets was chosen to meet the previous objectives. Now managers are being instructed to maximise shareholder value.

The national electricity market is designed to promote competition between generators and between retailers and generators. Providing competition develops, it will keep profits to competitive levels and encourage generators to be as efficient as possible. Without effective competition, actions taken to maximise shareholder value will not result in efficient market outcomes.

Effective competition does not necessarily mean actual competition. As long as the market is contestable, the threat of competition means that the incumbent firms will set prices so as to realise only competitive returns.

Gas is currently only a substitute for limited amounts of electricity. In 44 per cent of its market, electricity faces no competition from gas, for example, in lighting and water pumping. Gas represents the strongest competition for electricity in some industrial applications, space heating and water heating. These sectors have quite long appliance cycles and it is expected that, in the short run, consumers have little incentive to substitute between the two energy sources. If electricity prices are increased relative to gas prices for sustained periods of time, consumers would be expected to switch from electrical appliances to gas ones, over a period of years.

Transmission losses, transmission costs and transmission capacity constraints create a set of spatial markets linked by the Australian transmission network. In the national electricity market, generators' bids for dispatch do not include inter-regional transmission losses, and the cost of dispatching a generator in one region to meet a load in another region is adjusted to account for them. It is this adjusted bid that determines the merit order. The combination of transmission losses and strict capacity constraints on transmission led Hinchy and Low (1993) to argue that the competitive structure of the industry within each state would influence the performance of the overall national electricity market. This view is also supported by other studies of deregulation of spatially separated markets linked by networks, for example, Hobbs and Schuler (1985). However, a set of spatially linked markets is not inconsistent with economic efficiency — the costs of transporting electricity from one region to another should be reflected in regional prices. Nonetheless, it suggests that it is appropriate to consider the analysis of market power in both the regional and national contexts.

The most distinctive features of the SA market are:

- an import capability of up to 35 per cent of current system maximum demand under normal conditions[1];

----

1 The capacity of the interconnect is nominally 500 MW. However, this is dependent on system stability and the flows between NSW and Victoria. At full Victorian export capacity to NSW, the SA interconnect has a maximum capacity of 300 MW. The firm rating of the interconnect is 250 MW (NGMC 1993).

- a low projected rate of demand growth of 2 per cent per annum;
- an import capability of up to 63 per cent of the current system minimum demand;
- supply and demand balance which is tight compared to NSW and Victoria, and an expansion of capacity will probably be required in the next few years[2];
- a small number of power stations supplying a high proportion of base and intermediate load; and
- the dominance of two main generation plants, NPS and TIPS, which supply 99 per cent of electricity generated in SA.

Current interstate transmission capacity is 500 MW and base load demand in SA rarely falls below 800 MW. Therefore, irrespective of the pricing of local generation or imports, some ETSA generation capacity is always dispatched during off-peak and would set the SA regional price. Given merit order dispatch based on current operating and transmission costs, interstate transmission would probably not be at capacity during off-peak periods. However, if ETSA Generation raises its prices sufficiently, and interstate transmission capacity is fully used, the SA marginal generator will face a residual demand of over 300 MW.[3] ETSA Generation could then set the SA price in off-peak periods to maximise profits across this residual demand. If ETSA bid low to maximise the amount of its plant dispatched, the level of imports will then be determined by the relative prices bid by generators in Victoria and NSW.

As demand increases over a day, the flow through interstate transmission will vary as new generators are dispatched. For example, an ETSA generator could be dispatched in SA, lowering the import of electricity. The price in Victoria and SA would then be determined by the marginal

---

2 It is estimated that SA has sufficient existing capacity including imports to provide supply reliability until 1998. Additional capacity is being installed, which will then meet demand until the year 2000.

3 A merit order based on current Victorian pool prices rather than the operating costs of Victorian generators may result in different flows across the interconnector.

generator that may have been dispatched in either SA or Victoria,[4] depending upon the bidding behaviour of the participants.

There is a trade-off between high prices and residual demand, but bidding behaviour determines the merit order of dispatch of generation plant and this will also influence a generator's bidding strategy.

4 ANALYSIS OF MARKET BEHAVIOUR BY GENERATORS IN SA

In electricity markets, costs and demand conditions vary by time and from place to place. For example, electricity demand in SA can be met by generation from a range of technologies (gas and coal), a range of plant sizes or imported via transmission lines from interstate. Therefore, spatial-temporal models, which include elements of networks, are particularly useful to capture this heterogeneity.

In terms of modelling oligopolistic behaviour, there is not general agreement on how generators expect rivals to respond to output or price changes. Therefore, this analysis attempts to provide insights into the potential incentives for market power in SA rather than specify a particular behaviour.

Since ETSA is the dominant supplier of electricity in SA, this study uses a dominant firm model,[5] with imports and new generators effectively forming a competitive 'fringe'. Because imports come from the Victorian pool they are assumed to be competitively supplied.

ETSA's residual (or effective) demand is determined by subtracting the amount supplied by imports and new generators from the total quantity demanded, at any given price. Because capacity constraints (on the interstate transmission link) mean that imports are less than the current system's minimum demand, ETSA will always have a level of residual demand in which it is a monopoly supplier.

---

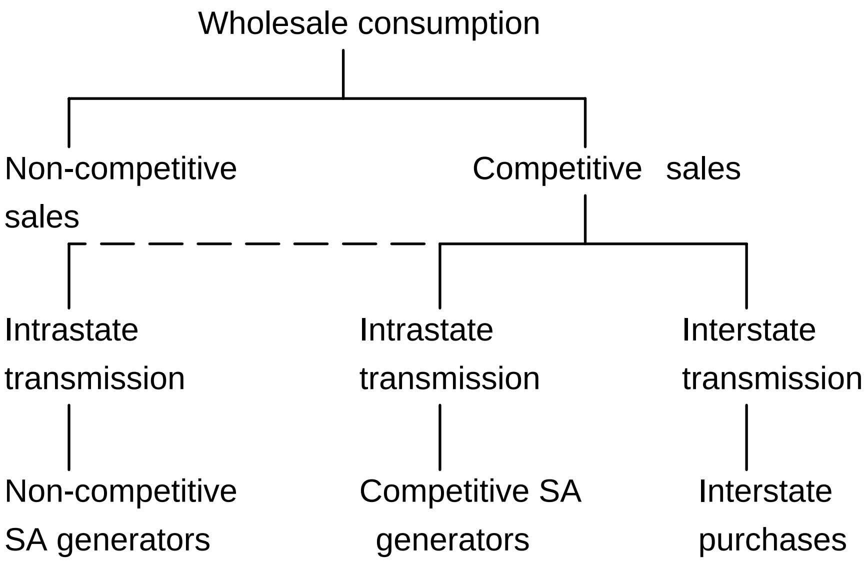
[4] An exception to this rule is when the marginal generator is running at minimum stable generation (MSG). The National Grid Management Council rules do not permit a generator running at MSG to set the system marginal price (SMP).

[5] The model used here corresponds to Forchheimer's dominant firm model (see Scherer and Ross 1990).

This study compares a range of behaviours by ETSA generators combined with competition at the ‘fringe’ from new entrants in SA or imports from Victoria via the interstate transmission link. See section 11 for a description of the different scenarios modelled.

To enable the inclusion of different behaviour in the modelling technique adopted, the flow of electricity is set up as shown in figure 3. The possible extremes are monopoly and competitive markets and the dashed line indicates the bridge connecting this extreme. In the competitive case, all electricity goes through the right hand side. When the dominant firm is acting as a monopoly, the majority of electricity goes through the left hand side, with competitive sales from imports and new producers. The other scenarios (vesting or splitting up the dominant firm) involve a combination of both sides.

Figure 3: Treatment of electricity flows[a]



a Dashed line indicates alternative paths to provide a range of possible scenarios.

5 MATHEMATICAL PROGRAMMING METHODOLOGY

Samuelson (1952) showed that it was possible to construct a maximisation problem that guarantees fulfilment of the conditions of perfectly competitive equilibria among spatially separated markets. This provided the opportunity to use mathematical programming to simulate market behaviour. Later, Takayama and Judge (1971) significantly extended the applicability of the technique by showing that the competitive and monopoly models could be formulated as quadratic programming models.

They also showed that two alternative formulations, the quantity formulation (primal) and the price formulation (the purified dual of the primal) could be used. Takayama and Woodland (1970) proved the equivalence between the two formulations. Takayama and Judge (1971) also showed that the quantity and price formulations could be combined to form another maximisation problem where both quantity and price are explicit variables in the model. This is the 'general' formulation referred to by MacAulay (1992) and is sometimes referred to as the 'self-dual' and 'primal-dual' formulations. Takayama and Judge (1971) also refer to it as the net social revenue formulation.

The general formulation has wider applicability. For example, it applies where interdependent demand functions do not satisfy the integrability condition (that is there is no unique solution to their integration) or where policy requires constraints on both prices and quantities.

MacAulay (1992) presents oligopolistic models of economic behaviour using the general formulation. This was the formulation initially used in this study. However, it was discovered upon examining the first order conditions, that oligopolistic models can also be solved using the quantity formulation, as shown by Hashimoto (1985). This is the method presented here.

In this particular study and those that may usefully follow, the quantity formulation has advantages over the general formulation. First, it reduces the number of variables and equations, which is important when dealing with large scale models. Second, it is easier to explain the technique and develop and implement the model using the model generating software, GAMS.[6] This is important, when the time to complete the study is short.

By approximating continuous non linear variables with expanded sets of linear variables, it would be possible to convert the non linear programming problem into a linear programming one by replacing non linear functions

----

6 For more information on the GAMS computer software package see: Brooke, Kendrick and Meeraus (1992); Meeraus (1983); and Bisschop and Meeraus (1982).

with piece-wise linear segments. This, in turn, means that the model could be set up as a mixed integer problem, allowing for greater realism by including discrete transmission and power station options, as well as minimum stable generation from power stations and even fuel purchasing constraints, such as for gas.

Theoretical developments and application of this methodology to study pricing and deregulation in spatial energy markets increased during the 1980s. Some examples include Salerian (1992), Kolstad (1989), Provenzano (1989), Uri (1989), Hobbs and Schuler (1985), Sohl (1985) and Uri (1983).

In the mathematical programming model developed here, the supply of electricity is represented by detailed linear programming models of power stations and transmission, rather than as supply functions. Mathematical programming has been widely applied to electricity supply, primarily to evaluate the least cost options to meet demand. Examples include Scherer (1977) and Turvey and Anderson (1977). Two Australian applications of note are ABARE's version of the MENSA model (Dalziell, Noble and Ofei-Mensah 1993) and CSIRO's earlier version of the MENSA model (Stocks and Musgrove 1984).

The inclusion of oligopolistic behaviour in this framework is achieved by the use of conjectural variations (see section 6 for the formal statement of the model). Although the use of conjectural variations to characterise strategic behaviour has been debated, the claim that competition amongst small numbers of firms leads to a set of equilibria between the competitive and monopoly solutions has not (Tirole 1988). Other studies which have attempted to model specific strategic behaviour in electricity markets include Bolle (1992), Green and Newbery (1992), Armstrong, Cowan and Vickers (1994), von der Fehr and Harbord (1993), and more recently, London Economics (1996).

There is disagreement as to what types of behaviour lead to sustainable equilibria in a spot pool for electricity (von der Fehr and Harbord 1993). However, it is agreed that there are incentives to raise prices above marginal cost. Armstrong *et al.* characterise the electricity pool as price competition with capacity constraints. Their results are prompted by the observation that, when one firm cannot supply the entire market at the competitive price, there is an incentive to raise prices above marginal cost.

The model developed in this paper does not attempt to model a specific strategic behaviour. Conjectural variations are used as a convenient instrument to generate solutions with varying degrees of market power — Shapiro (1989) discusses this issue. The profitabilities resulting are then used to assess whether there exists incentives for strategic behaviour and informal collusion.

6 BASIC MATHEMATICAL MODEL

As well as formally describing the model in this study, this section briefly outlines some of the theory involved in modelling oligopolistic behaviour in spatial-temporal models. The model presented is the basic model which can be used to simulate market equilibrium for competitive and oligopolistic cases where ETSA operates a portfolio of generators. To model the case where ETSA generators are not part of a single portfolio, but act independently in an oligopolistic fashion, a variation is required. This is discussed in the section below on modelling oligopolistic behaviour.

The model used for this study has a non linear objective function and linear constraints. Non linear constraints for transmission losses have been linearised, as discussed below.

6.1 NOTATION

The notation used to present the model is divided into sets, parameters and variables.

Sets

b	=	set of time periods (load blocks)
L	=	set of piece-wise linear segments used to replace non linear transmission constraints with linear constraints
m	=	set of generators belonging to ETSA's portfolio
n	=	set of new SA generators, independent of ETSA, which behave competitively (fringe competitors)

Parameters

A_b	=	intercept value of the inverse linear demand function in each time period

w_b = slope coefficient of the inverse linear demand function in each time period

Z = aggregate conjectural variation for ETSA, which behaves as an oligopolist

C_{bm} = intra-state unit transmission cost for ETSA generators in each time period

C_{bn} = intra-state unit transmission cost for competitive (fringe) generators in each time period

d_{bl} = total cost of transmission for interstate imports at a given transmission load in each time period

$F_{b'm}$ = fuel cost of ETSA generators for incremental output in each time period

$F_{b'n}$ = fuel cost of competitive generators for incremental output in each time period

E_m = average annual fixed cost of capacity for ETSA generators

E_n = average annual fixed cost of capacity cost for competitive generators

g_b = interstate purchase price of imported electricity in each time period

J_{bm} = intra-state transmission coefficient (1-loss factor) for competitive generators in each period

J_{bn} = intra-state transmission coefficient (1-loss factor) for competitive generators in each period

K_{bl} = interstate transmission coefficient of imports for given transmission load in each time period

$R_{b'}$ = scale factors converting MW to GWh for generators in each time period

X = scale factor representing peak reserve requirement in each time period

T_{bm} = scale factors representing availability of ETSA generators in each time period

T_{bn} = scale factors representing availability of competitive generators in each time period

h = amount of existing interstate transmission capacity

u_m = scale factor representing availability of ETSA generators

u_n = scale factor representing availability of competitive generators

I_m = upper bound on existing or potential capacity for ETSA generators

I_n = upper bound on existing or potential capacity for competitive generators

v_{bl} = scale factor converting units of transmission load to GWh for each level of interstate transmission load in each time period

Variables

XE_b	=	quantity of demand in each time period (GWh)
$XSATD_b$	=	amount of demand supplied by ETSA generators (GWh) in each time period
$XISTD_b$	=	quantity of demand supplied by competitive generators and interstate (GWh) in each time period
$XSAT_{bm}$	=	intra-state transmission of electricity supplied by each of ETSA's generators in each period (GWh)
$XSAT_{bn}$	=	intra-state transmission of electricity supplied by each competitive generator in each time period (GWh)
$XISTL_{bl}$	=	the proportion of the interstate transmission capacity represented by this variable that is being used
$XO_{b'm}$	=	incremental output by each of ETSA's generators in each time period (MW)
$XO_{b'n}$	=	incremental output by each competitive generator in each period (MW)
XC_m	=	operating capacity of each of ETSA's generators (MW)
XC_n	=	operating capacity of each competitive generator (MW)
$XISE_b$	=	quantity of electricity purchased from interstate markets (Victoria) in each time period (GWh)
$\lambda_{1,*}$ to $\lambda_{12,*}$	=	sets of Lagrangean variables associated with the constraints in the model

6.2 EQUATIONS

Objective function ($m)

(1) Maximise NSW

$$= \sum_b \left(a_b XE_b + \tfrac{1}{2} w_b XE_b^{\,2} \right) + \sum_b \tfrac{1}{2} w_b (1+z) XSATD_b^{\,2}$$
$$- \sum_b \sum_m c_{bm} XSAT_{bm} - \sum_b \sum_n c_{bn} XSAT_{bn} - \sum_b \sum_l d_{bl} XISTL_{bl}$$
$$- \sum_b \sum_{b'} \sum_m f_{b'm} XO_{b'm} - \sum_b \sum_{b'} \sum_n f_{b'n} XO_{b'n}$$
$$- \sum_m e_m XC_m - \sum_n e_n XC_n - \sum_b g_b XISE_b$$

The objective function maximises NSW, a mixture of social welfare (measured as consumer plus producer surplus — the area under the demand curve minus the sum of the variable costs) and profit (discussed further in the next section). The first term of equation (1) is the area under the demand curve (integral of the demand curve). The second term is the oligopolists' or monopolists' margin (see MacAulay 1992; Scherer and Ross 1990; Kolstad and Burris 1986; Hashimoto 1985). Here, ETSA is acting as an oligopolist in control of a portfolio of power stations. There is no oligopolist margin for sales from competitive sources ($XISTD_b$) because by assumption they equate price to marginal cost. The third, fourth and fifth terms represent the cost of transmission by oligopolistic and competitive generators and imports from interstate. The sixth and seventh terms are the variable operating costs of the power stations. The eighth and ninth terms are the average annual fixed costs of power stations, which are very low for existing plants because their costs are considered sunk. The last term is the cost of purchasing electricity in interstate markets (Victoria).

Wholesale electricity balance (GWh)

$$(2) \quad XE_b - XSATD_b - XISTD_b \leq 0 \text{ for b}$$

Equation (2) states that the quantity of electricity consumed in the wholesale market must be less than or equal to that supplied by the generators belonging to ETSA's oligopoly and the competitive suppliers (generators and imports).

Oligopolistic supply balance (GWh)

$$(3) \quad XSATD_b - \sum_m j_{bm} XSAT_{bm} \leq 0 \text{ for b}$$

Equation (3) states that the wholesale quantity supplied by generators belonging to ETSA's oligopoly generators in each time period cannot exceed that transmitted by these generators, after adjustment for intra-state transmission losses.

Competitive supply balance (GWh)

$$(4) \quad XISTD_b - \sum_n j_{bn} XSAT_{bn} - \sum_l k_{bl} XISTL_{bl} \leq 0 \text{ for b}$$

Equation (4) states that the wholesale quantity supplied by competitive suppliers in each time period cannot exceed that transmitted intra-state by competitive generators plus that transmitted from interstate (imported).

Oligopolistic transmission-generation balance (GWh)

(5) $XSAT_{bm} - \sum_{b'=b} r_{b'} XO_{b'm} \leq 0$ for b and m

Equation (5) states that the quantity of electricity transmitted by each generator belonging to ETSA's portfolio must not exceed the output of the generator.

Competitive transmission-generation balance (GWh)

(6) $XSAT_{bn} - \sum_{b'=b} r_{b'} XO_{b'n} \leq 0$ for b and n

Equation (6) states that the quantity of electricity transmitted by each competitive generator must not exceed its output.

Peak reserve requirement (MW)

(7) $xXE_b - \sum_m t_{bm} XC_m - \sum_n t_{bn} XC_n \leq h$ for b

Equation (7) is a peak reserve requirement that requires total capacity (after adjusting for availability) exceed demand by a specified amount. The parameter h refers the existing level of interstate transmission capacity. Because demand is endogenous, the peak reserve requirement is applied to all periods because it is unknown, before optimisation, in how many periods this constraint will be binding.

Oligopolistic generation balance (MW)

(8) $\sum_b \sum_{b'=b} XO_{b'm} - u_m XC_m \leq 0$ for m

Equation (8) states that the sum of the incremental output levels by each of ETSA's generators must not exceed their output capacity, adjusted for availability of power stations.

Competitive generation balance (MW)

(9) $$\sum_{b}\sum_{b'=b} XO_{b'n} - u_n XC_n \le 0 \text{ for n}$$

Equation (9) states the sum of the incremental output levels by each of the competitive generators must not exceed output capacity, adjusted for availability.

Limit on ETSA generator capacity (MW)

(10) $$XC_m \le i_m \text{ for m}$$

Equation (10) states that the capacity of each of ETSA's generators cannot exceed an upper bound. This equation is usually binding for existing power stations, which are generally preferred because of sunk capital cost.

Limit on competitive generator capacity (MW)

(11) $$XC_n \le i_n \text{ for n}$$

Equation (11) states that the capacity of each of the competitive generators must not exceed an upper bound. The equation is usually binding for existing power stations, which are generally preferred because of sunk capital cost.

Transmission convexity constraint

(12) $$\sum_{l} XISTL_{bl} \le 1 \text{ for b}$$

Equation (12) is a constraint which ensures that the linear combination of interstate transmission loads is less than or equal to one. It is a typical convexity constraint used in association with piece-wise linear approximations to non linear functions.

Interstate transmission-purchase balance (GWh)

(13) $$\sum_{l} v_{bl} XISTL_{bl} - XISE_b \le 0 \text{ for b}$$

Equation (13) states that the quantity of electricity sent out over the interstate transmission line must not exceed the quantity purchased interstate (Victoria).

Non negativity of variables

(14) $XE_b, XSATD_b, XISTD_b, XSAT_{bm}, XSAT_{bn}, XISTL_{bl}, XO_{bm}, XO_{bn}, XC_{bm}, XC_{bn}, XISE_b \geq 0$

Equation (14) is the non negativity constraint on variables.

Stylised Tableau

A stylised version of the model is presented in tableau format in table 2. The stylised model has two time periods (b=1 and 2), two power stations in ETSA's imperfectly competitive portfolio (m=1 and 2), two independent competitive generators (n=3 and 4), and three load levels for interstate transmission during each time period (l=1, 2 and 3).

The actual model description in the GAMS programming software is in Appendix A. This model has 849 variables and 482 equations.

Table 2: Stylised tableau of the model

	XE1	XE2	XSATD1	XSATD2	XISTD1	XISTD2	XSAT11	XSAT12	XSAT21	XSAT22	XSAT13	XSAT14	XSAT23	XSAT24	XISTL11	XISTL12	XISTL13	XISTL21	XISTL22	XISTL23	XO11	XO12	XO21	XO22	XO13	XO14	XO23	XO24	XC1	XC2	XC3	XC4	XISE1	XISE2		
EQN1	F_1	F_2	G_1	G_2			$-c_{11}$	$-c_{12}$	$-c_{21}$	$-c_{22}$	$-c_{13}$	$-c_{14}$	$-c_{23}$	$-c_{24}$	$-d_{11}$	$-d_{12}$	$-d_{13}$	$-d_{21}$	$-d_{22}$	$-d_{23}$	$-f_{11}$	$-f_{12}$	$-f_{21}$	$-f_{22}$	$-f_{13}$	$-f_{14}$	$-f_{23}$	$-f_{24}$	$-e_1$	$-e_2$	$-e_3$	$-e_4$	$-g_1$	$-g_2$		
EQN2$_1$	1		-1		-1																														≤	
EQN2$_2$		1		-1		-1																													≤	
EQN3$_1$			1				$-j_{11}$	$-j_{12}$																											<	
EQN3$_2$				1					$-j_{21}$	$-j_{22}$																									<	
EQN4$_1$					1						$-j_{13}$	$-j_{14}$			$-k_{11}$	$-k_{12}$	$-k_{13}$																		<	
EQN4$_2$						1							$-j_{23}$	$-j_{24}$				$-k_{21}$	$-k_{22}$	$-k_{23}$															<	
EQN5$_{11}$							1														$-r_1$	$-r_2$													<	
EQN5$_{12}$								1															$-r_1$	$-r_2$											<	
EQN5$_{21}$									1													$-r_2$													<	
EQN5$_{22}$										1														$-r_2$											<	
EQN6$_{13}$											1														$-r_1$	$-r_2$									<	
EQN6$_{14}$												1															$-r_1$	$-r_2$							<	
EQN6$_{23}$													1													$-r_2$									<	
EQN6$_{24}$														1														$-r_2$							<	
EQN7$_1$	x																												$-t_{11}$	$-t_{12}$	$-t_{13}$	t_{14}			<	h
EQN7$_2$		x																											$-t_{21}$	$-t_{22}$	$-t_{23}$	t_{24}			≤	h
EQN8$_1$																					1	1							$-u_1$						<	
EQN8$_2$																							1	1						$-u_2$					<	
EQN9$_3$																									1	1					$-u_3$				<	
EQN9$_4$																											1	1				$-u_4$			<	
EQN10$_1$																													1						<	i_1
EQN10$_2$																														1					<	i_2
EQN11$_3$																															1				<	i_3
EQN11$_4$																																1			<	i_4
EQN12$_1$															1	1	1																		<	1
EQN12$_2$																		1	1	1															<	1
EQN13$_1$															v_{11}	v_{12}	v_{13}																-1		<	
EQN13$_2$																		v_{21}	v_{22}	v_{23}														-1	<	

Notes: $F_1 = a_1 XE_1 + \frac{1}{2} w_1 XE_1^{\,2}$ $F_2 = a_2 XE_2 + \frac{1}{2} w_2 XE_2^{\,2}$ $G_1 = \frac{1}{2} w_1 (1+z) XSATD_1^{\,2}$ $G_2 = \frac{1}{2} w_2 (1+z) XSATD_2^{\,2}$

The stylised model has 2 demand periods, 2 power stations (1 and 2) in the oligopolistic portfolio, 2 competitive power stations (3 and 4), and 3 piece-wise linear segments forinterstate transmission losses

6.3 MODELLING OLIGOPOLISTIC BEHAVIOUR

Oligopolistic behaviour is incorporated in spatial-temporal allocation models by maximising a mixture of social welfare and profit (Shapiro 1989; Bergstrom and Varian 1985). The profit element relates to the oligopolist's margin (box 1), which also incorporates the aggregate conjectural variation parameter. To see how this generates oligopolistic equilibria, the first order conditions for an optimum are examined. To assist with this, the model is expressed in its Lagrangean form using the method of Lagrange multipliers (see Lambert 1993; Intriligator 1971), given by equations (15) and (16).

(15) Maximise L

$$
\begin{aligned}
&= \sum_b \left(a_b XE_b + \tfrac{1}{2} w_b XE_b{}^2\right) + \sum_b \tfrac{1}{2} w_b (1+z) XSATD_b{}^2 \\
&- \sum_b \sum_m c_{bm} XSAT_{bm} - \sum_b \sum_n c_{bn} XSAT_{bn} - \sum_b \sum_l d_{bl} XISTL_{bl} - \sum_b \sum_{b'} \sum_m f_{b'm} XO_{b'm} \\
&- \sum_b \sum_{b'} \sum_n f_{b'n} XO_{b'n} - \sum_m e_m XC_m - \sum_n e_n XC_n - \sum_b g_b XISE_b \\
&+ \sum_b \lambda_{1b} \left(XSATD_b + XISTD_b - XE_b\right) \\
&+ \sum_b \lambda_{2b} \left(\sum_m j_{bm} XSAT_{bm} - XSATD_b \right) \\
&+ \sum_b \lambda_{3b} \left(\sum_n j_{bn} XSAT_{bn} + \sum_l k_{bl} XISTL_{bl} - XISTD_b \right) \\
&+ \sum_b \sum_m \lambda_{4bm} \left(\sum_{b'=b} r_{b'} XO_{b'm} - XSAT_{bm} \right) \\
&+ \sum_b \sum_n \lambda_{5bn} \left(\sum_{b'=b} r_{b'} XO_{b'n} - XSAT_{bn} \right) \\
&+ \sum_b \lambda_{6b} \left(h + \sum_m t_{bm} XC_m + \sum_n t_{bn} XC_n - xXE_b \right) \\
&+ \sum_m \lambda_{7m} \left(u_m XC_m - \sum_b \sum_{b'=b} XO_{b'm} \right) + \sum_n \lambda_{8n} \left(u_n XC_n - \sum_b \sum_{b'=b} XO_{b'n} \right) \\
&+ \sum_m \lambda_{9m} \left(i_m - XC_m\right) + \sum_n \lambda_{10n} \left(i_n - XC_n\right) \\
&+ \sum_b \lambda_{11b} \left(1 - \sum_l XISTL_{bl} \right) + \sum_b \lambda_{12b} \left(XISE_b - \sum_l v_{bl} XISTL_{bl} \right)
\end{aligned}
$$

$$(16)\quad XE_b, XSATD_b, XISTD_b, XSAT_{bm}, XSAT_{bn}, XISTL_{bl}, XO_{bm}, XO_{bn}, XC_{bm}, XC_{bn}, XISE_b, \lambda_{1b}, \lambda_{2b}, \lambda_{3b}, \lambda_{4bm}, \lambda_{5bn}, \lambda_{6b}, \lambda_{7m}, \lambda_{8n}, \lambda_{9m}, \lambda_{10n}, \lambda_{11b}, \lambda_{12b} \geq 0$$

The first order necessary conditions for an optimum in the presence of inequality constraints in the original problem are given by the Kuhn-Tucker conditions (Lambert 1993; Intriligator 1971). The only conditions directly relevant to understanding oligopolistic behaviour relate to the first three variables, XE_b, $XSATD_b$, and $XISTD_b$. Therefore, for the sake of brevity, only the first three first order conditions are presented.

$$(17)\quad \frac{\partial L}{\partial XE_b} = a_b + w_b XE_b - \lambda_{1b} - x\lambda_{6b} \leq 0 \text{ for } b$$

$$\frac{\partial L}{\partial XE_b} XE_b = \left(a_b + w_b XE_b - \lambda_{1b} - x\lambda_{6b}\right) XE_b = 0 \text{ for b}$$

Equation (17) states that, providing the quantity demanded is greater than zero and the peak reserve constraint is not binding, the wholesale price of electricity in each period, $a_b + w_b XE_b$, is equated to the shadow price of electricity delivered, λ_{1b}, that is, the price of electricity is equated to short run variable costs.

If the peak reserve constraint is binding, the wholesale price of electricity is equated to the shadow price of electricity delivered, λ_{1b}, plus the shadow price of capacity, $x\lambda_{6b}$.

This condition is the typical peak load pricing rule. When capacity is not binding, price is equal to short run costs of electricity production. When capacity is binding, the price is equal to the short run cost of production plus the long run marginal cost of capacity or the imputed value of capacity if it cannot increased.

$$(18)\quad \frac{\partial L}{\partial XSATD_b} = w_b(1+z)XSATD_b + \lambda_{1b} - \lambda_{2b} \leq 0 \text{ for } b$$

$$\frac{\partial L}{\partial XSATD_b} XSATD_b = \left(w_b(1+z)XSATD_b + \lambda_{1b} - \lambda_{2b}\right)$$

$$XSATD_b = 0 \text{ for b}$$

$$(19)\quad \frac{\partial L}{\partial XISTD_b} = \lambda_{1b} - \lambda_{3b} \leq 0 \text{ for } b$$

$$\frac{\partial L}{\partial XISTD_b} XISTD_b = \left(\lambda_{1b} - \lambda_{3b}\right) XISTD_b = 0 \text{ for b}$$

Box 1: Modelling oligopolistic behaviour in spatial equilibrium models

The case of 'competition among the few' is examined in Intriligator (1971, pp. 205–213). In the case of imperfect competition between two firms, the aim of one firm, say firm 1, is to maximise profits. An adapted version of the maximisation is:

$$\max \Pi^1 = p\left(q^1, q^2\right)q^1 - f^1\left(q^1\right)$$

Where Π^1 is firm 1's profit, p is the output price, q^1 is firm 1's output, q^2 is firm 2's output, f^1 is firm 1's cost function.

The first order conditions are:

$$\frac{\partial \Pi^1}{\partial q^1} = p\left(q^1, q^2\right) + q^1 \frac{\partial p}{\partial q^1} + q^1 \frac{\partial p}{\partial q^2}\frac{\partial q^2}{\partial q^1} - \frac{\partial f^1\left(q^1\right)}{\partial q^1} = 0$$

If we assume that each firm knows the slope of the market demand curve, then:

$\frac{\partial p}{\partial q^1} = \frac{\partial p}{\partial q^2} = \frac{\partial p}{\partial Q} =$ slope of the demand curve, where $Q = q^1 + q^2$. Note that $\frac{\partial q^2}{\partial q^1}$ is the conjecture that firm 1 has about how the rival firm 2 responds to a change in output by firm 1.

The first order conditions then collapse to:

$$p + q^1 \frac{\partial p}{\partial Q}\left(1 + \frac{\partial q^2}{\partial q^1}\right) = \frac{\partial f^1\left(q^1\right)}{\partial q^1} \qquad \text{(a)}$$

Firm 1 equates marginal revenue with marginal cost, where marginal revenue depends upon its perception of the output response by firm 2.

The spatial equilibrium model also generates the same first order conditions. The objective function for this study (equation 1 in text), expressed in the same notation as above, with a linear demand curve ($p=a+wQ$) is:

$$\begin{aligned}\max \quad NSW = {} & aQ + \tfrac{1}{2}w(Q)^2 + \tfrac{1}{2}w\left(1+z^1\right)\left(q^1\right)^2 \\ & + \tfrac{1}{2}w\left(1+z^2\right)\left(q^2\right)^2 - f^1\left(q^1\right) - f^2\left(q^2\right)\end{aligned}$$

Assuming firm 2 has a conjectural variation (z^2) of –1, that is, behaving competitively by assuming its rival will exactly offset any output change, and expanding Q $\left(Q = q^1 + q^2\right)$, gives:

$$\max \quad NSW = a\left(q^1 + q^2\right) + \tfrac{1}{2}w\left(q^1 + q^2\right)^2 + \tfrac{1}{2}w(1+z)\left(q^1\right)^2 - f^1\left(q^1\right) - f^2\left(q^2\right)$$

Box 1 (continued)

The first order conditions with respect to firm 1 are:

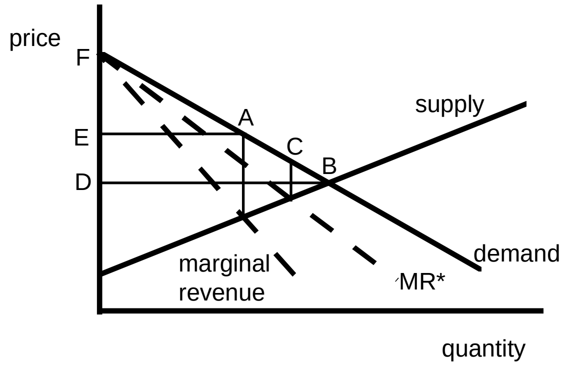
$$\frac{\partial\,\mathrm{NSW}}{\partial q^1} = a + wq^1 + wq^2 + w(1+z)q^1 - \frac{\partial f^1(q^1)}{\partial q^1} = 0$$

$$\Rightarrow p + q^1 w(1+z) = \frac{\partial f^1(q^1)}{\partial q^1}$$

Substituting $z = \frac{\partial q^2}{\partial q^1}$ and $w = \frac{\partial p}{\partial Q}$ gives $\Rightarrow p + q^1 \frac{\partial p}{\partial Q}\left(1 + \frac{\partial q^2}{\partial q^1}\right) = \frac{\partial f^1(q^1)}{\partial q^1}$

This is the same first order conditions as derived above in equation (a).

A simple illustration of the different solutions is in the figure below, with the simplification that there is only one firm. The objective function can be thought of as maximising the area under the demand curve $\left(aQ + \frac{1}{2}w(Q)^2\right)$ minus a weight (1+z) times the level of consumer surplus $\left(\frac{1}{2}w(Q)^2\right)$, and then minus total variable costs (area under the supply curve).



When z = –1 the maximisation is the area under the demand curve $aQ + \frac{1}{2}w(Q)^2$ (welfare) minus costs (consumer plus producer surplus), so a competitive solution is reached at point B.

When z = 0 the maximisation collapses to total revenue, $aQ + w(Q)^2$, minus costs (total profit), giving the monopolist's solution at point A, because welfare minus consumer surplus equals total revenue.

When –1 < z < 0, we can think of the firm involved as deciding (for some reason) not to fully exploit its monopoly power, and equating a marginal revenue line MR* with marginal cost, generating a solution C, between A and B.

To examine the pricing behaviour of the oligopolistic supplier — ETSA — (represented by $XSATD_b$), eliminate λ_{1b} from equation (18) using the definition of λ_{1b} from equation (17). The result is shown in equation (20).

$$(20) \quad a_b + w_b XE_b + w_b (1+z) XSATD_b - \lambda_{2b} - x\lambda_{6b} \leq 0$$

w_b is the slope of the demand curve ($\partial P_b / \partial XE_b$) and z is the aggregate conjectural variation for ETSA ($\partial XISTD_b / \partial XSATD_b$). The aggregate conjectural variation represents what ETSA (the oligopolist operating a portfolio of power stations) considers the aggregate response of its competitors to it changing the quantity of electricity it supplies in that period. For a more detailed discussion see Scherer and Ross (1990), Kolstad and Burris (1986) and Intriligator (1971).

The aggregate conjectural variation takes on a value in the range from 0 to –1. The term (1+z) is also thought of as the degree of market power. When the aggregate conjectural variation (z) is equal to –1, then ETSA expects that any change in its supply will be exactly offset by a change in its competitors supply. In this case, the change in $XSATD_b$ will be offset by $XISTD_b$. Therefore, the aggregate supply XE_b is unchanged and the marginal revenue to ETSA is therefore equal to the price. This solution corresponds to the competitive situation.

If the aggregate conjectural variation (z) is zero, then ETSA believes that its rivals will not respond at all. In this case, ETSA behaves as a monopolist on the residual demand, with price greater than marginal cost. Values of z between 0 and –1 give a continuum of market power between the monopolist and perfect competition.

By computing equilibrium for a range of values of z between 0 and –1, it is possible to estimate the value of z which maximises profit (payoff) to ETSA. This provides an estimate of the degree of market power likely to be exercised by ETSA.

To model the case where ETSA generators are disaggregated into independent generators — but act in an oligopolistic fashion (see Forchheimer's dominant firm model in Scherer and Ross 1990), the variable $XSATD_b$ is disaggregated into the source from each power station. That is, $XSATD_b$ is redefined as $XSATB_{bm}$. In this case, there is an oligopolist margin in the objective function for each power station rather than for ETSA as a whole. Similarly, there is a conjectural variation term for each power station, which defines the way in which each of these oligopolistic power stations expects the aggregate response of its competitors to be.

7 DEMAND

The electricity system must constantly balance demand and supply because electricity cannot be economically stored in large quantities. Demand for electricity is a derived demand. That is, it is used to provide an energy service, such as light, air conditioning, refrigeration and water heating. Its demand for use depends upon the price of alternative energy forms and the cost of equipment that uses the alternative energy sources, including electricity. Even if no substitution occurs, changes in the price of electricity are likely to affect the level of consumption of electricity. Therefore, the amount of electricity purchased from a wholesale market varies with price. In this study, the price of electricity only is endogenous. All other prices are assumed exogenous and implicit in the constant term of the demand function.

In this model, 27 demand periods are defined by dividing the load duration curve into 50 MW blocks. The load duration curve is obtained by arranging the half-hour demands during the year into descending order (Turvey and Anderson 1977; Scherer 1977). The load duration curve represented by the 27 periods is shown in figure 4.

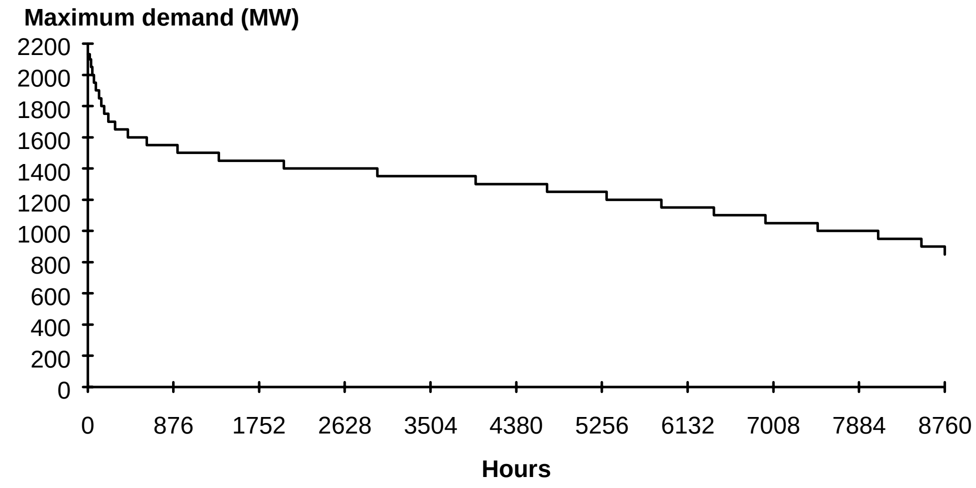
Each of the 27 segments of the load duration curve is assumed to have an independent demand function. It is possible to include interdependent demand functions (see Salerian 1992), but due to a lack of information they are not used here.

In this study, no econometric estimation of the demand function was undertaken due to the lack of a suitable data set, particularly in the absence of volatile electricity prices in the past. Instead the parameters of each demand function are estimated using price, quantity and an assumed own-price elasticity of demand based on a review of literature.

Equation 21 shows the demand function using the quantity formulation, with a_b and w_b being the parameters. Price is in \$m per GWh and quantity is in GWh.

$$\text{PRICE}_b = a_b + w_b \text{QUANTITY}_b \qquad (21)$$

Figure 4: SA annual load duration curve, 1994–95



Source: ETSA Corporation.

The own-price elasticity of demand, ε, is the responsiveness of demand to electricity price and is given by equation (22):

(22) $$\varepsilon_b = \frac{\partial \; \text{QUANTITY}_b}{\partial \; \text{PRICE}_b} \frac{\text{PRICE}_b}{\text{QUANTITY}_b} = \frac{1}{w_b} \frac{\text{PRICE}_b}{\text{QUANTITY}_b}$$

Taking price, quantity and the own-price elasticity of demand as given allows the parameters to be derived as shown in equation (23).

(23) $$a_b = \text{PRICE}_b \left(1 - \frac{1}{\varepsilon_b}\right) \text{and} \, w_b = \frac{1}{\varepsilon_b} \frac{\text{PRICE}_b}{\text{QUANTITY}_b}$$

Assuming an average wholesale price (the price including transmission costs) of 6 cents per kilowatt hour (kWh), an own-price elasticity of demand, and the quantity purchased in each period, 27 demand curves at the wholesale level are derived. As shown below, the model is used to simulate market outcomes in both the short and long run.

In the short run, demand is assumed to have an own-price elasticity of –0.1 at a wholesale price of 6 cents per kWh. In the long run, customers have the opportunity to switch appliances and industry has the opportunity to change production processes in response to sustained changes in electricity prices. The price-elasticity of demand is assumed to be –0.5 in the long run.

8 TRANSMISSION

Transmitting electricity along wires connecting the source of generation and consumption results in the loss of some electricity and incurs a cost for construction and maintenance of the transmission system.

The National Grid Management Council (NGMC) has developed a draft Code of Conduct for the proposed national electricity market. It includes specific methods of dealing with the transmission losses within and between regions of the market.

The Code also contains a network pricing component that sets out a framework for cost-reflective pricing for the use of the transmission network. This is a separate charge for market participants. In the model, the transmission cost is in millions of dollars per GWh delivered.

8.1 STATIC TRANSMISSION LOSSES

Simulation modelling of transmission losses *within* a regional network (such as that within SA) have shown that losses are a constant proportion of the amount transmitted. The NGMC has developed a relatively simple method of making participants pay for these losses. The Code assigns a particular loss factor to each market participant that indicates the rate of loss for each unit of electricity bought or sold into the market at the central reference point in their region. The loss factor does not vary with the amount transmitted.

In the model, the amount actually delivered by a SA generator to the SA market is the sum of the output of each ETSA generator, less transmission losses in each period. The loss is assumed to be two per cent of electricity generated by SA generators.

8.2 DYNAMIC TRANSMISSION LOSSES

Presently there are limited links between state transmission networks. The NGMC found that the relationship of losses and delivered energy *between* regions is not linear. There is a single connection between the SA and Victorian regions with a maximum capacity of 500 MW. Average losses along this transmission line are about 18 per cent at 500 MW. At lower levels of transmission, the average percentage loss is lower. The NGMC has developed an algorithm for calculating these losses that depends on interregional flows.

Average loss factors are represented by:

$$\text{(24)} \quad \text{LOSS FACTOR} = \tfrac{0.18}{500}\,\text{SENT OUT LOAD}$$

The total amount of electricity delivered is the output of power stations less transmission losses as given below:

$$\begin{aligned}\text{(25)} \quad \text{DELIVERED LOAD}_b &= \left(1 - \text{LOSS FACTOR}_b\right)\text{SENT OUT LOAD}_b \\ &= \text{SENT OUT LOAD}_b - \tfrac{0.18}{500}\left(\text{SENT OUT LOAD}_b\right)^2\end{aligned}$$

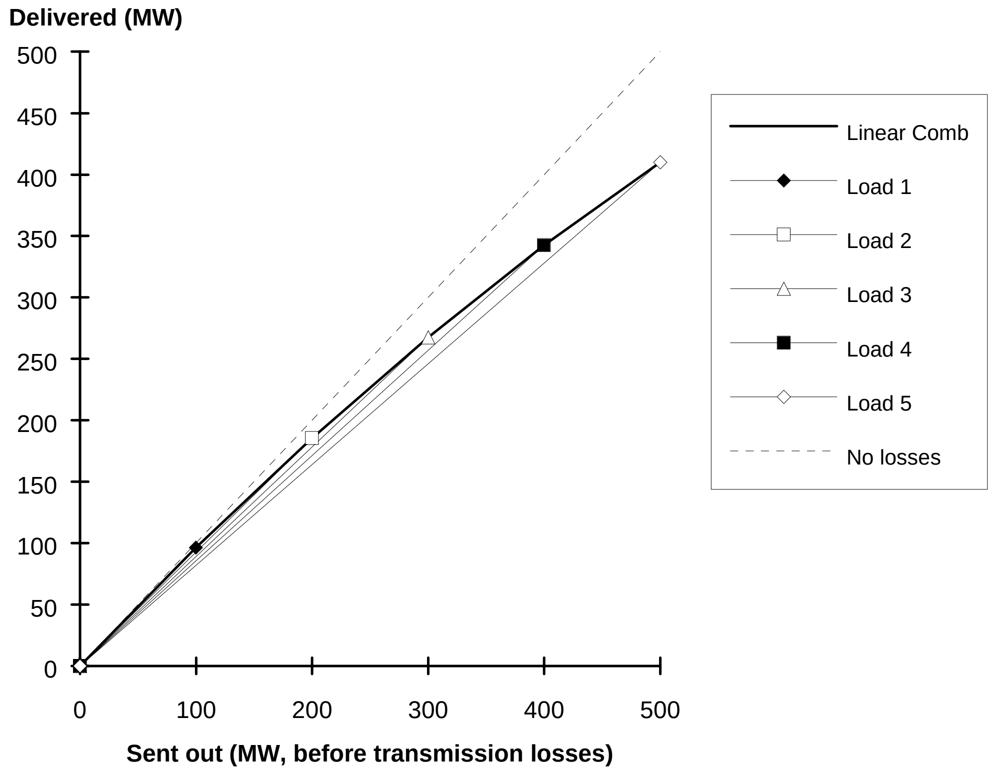
The non-linearity of inter-regional transmission losses can be directly modelled using non-linear constraints — but this increases the computational difficulty. This is particularly important when using the general formulation, which has twice as many equations and variables as the quantity formulation used in this analysis. In this study, the non-linear function is approximated using linear segments (see Scherer 1977, pp. 79–80). This increases the number of linear variables, but replaces non linear constraints with linear constraints. The accuracy of the approach can be improved by increasing the number of linear segments that the non-linear function is divided into (see Shapiro 1984).

For this purpose the load is segmented into 100 MW loads. As transmission losses are concave in pre-transmission load, the first load (0 MW to 100 MW) delivers the greatest amount of electricity, followed by the second load (100 MW to 200 MW) and so on. The concavity also means that the amount of electricity delivered when 150 MW is transmitted, for example, would be a linear combination of that delivered at 100 MW and that delivered at 200 MW.

This relationship between electricity sent out from power stations and delivered is illustrated in figure 5.

In any given period, the five levels of dynamic transmission losses can be incorporated into the model by five extra constraints — one for each of the different load levels (see Shapiro 1984). However for computational ease, we reduced the number of equations required to one (see Hazell and Norton 1986, p. 74).

Figure 5: Dynamic transmission losses



As mentioned above, any amount of electricity delivered can be represented as a linear combination of the segmented load blocks. By setting the transformation that:

$$\text{(26)} \quad \text{the amount of electricity delivered} = \sum_{l} XISTL_{bl}(100 \times l)\text{MW for } l$$

and constraining the segmented load blocks ($XISTL_{bl}$ for each l=1 to 5) to lie between 0 and 1, allows the use of a convexity constraint equation, equation (12), which ensures that the linear combination applies. The corresponding parameters in part transform these loads back into their MW values, which appear in the equations (1), (4) and (13), incorporating equation (26).[7]

[7] The parameters in equations (1), (4) and (13) also perform other tranformations, for example v_{bl} in (13) converts $XISTL_{bl}$ to GWh.

For example, the amount of electricity delivered at 150 MW is a linear combination of that delivered at 100 MW and that delivered at 200 MW. The solution is where $XISTL_{b1}$, $XISTL_{b2}$ = 0.5 and $XISTL_{b3}$, $XISTL_{b4}$, $XISTL_{b5}$ = 0.

The amount delivered is:

$$
\begin{aligned}
&= 0.5_{b1}(100\times1) + 0.5_{b2}(100\times2))\mathrm{MW} \\
&= ((0.5\times96.4) + (0.5\times185.6))\mathrm{MW} = 141\mathrm{MW}
\end{aligned}
$$

An advantage of this formulation over a more straightforward segmentation, is that the function can be approximated as closely as desired without requiring additional linear constraints in the program.

9 PRODUCTION MODEL

The principles of electricity production models are discussed in Munasinghe (1990). These principles are readily applied in mathematical programming models. The model used in this study is based on that of Turvey and Anderson (1977) and is similar to others, such as ABARE’s MENSA model (Dalziell, Noble and Ofei-Mensah 1993).

A characteristic of plant operated in a cost-minimising manner (merit order) is that a plant that is operated in off-peak periods will definitely be operated in a peak period (subject to availability). In contrast, some plants only supply peak demand. This principle can be directly used in the construction of mathematical programming models to reduce the number of constraints by specifying output of power stations in terms of incremental output in each load block rather than total output. Turvey and Anderson (1977, p. 251) discusses this.

In this model, the amount of electricity sent out by each generator in each period must be less than the cumulative sum of incremental output (output in the current lower load blocks in the merit) by the generator. For example, in the peak period, total output of Northern power station equals output in the off-peak plus the incremental output in the peak.

The sum of incremental peak and off-peak output is constrained to be less than or equal to the capacity of each plant. The total output of electricity in SA is limited by the capacity of plants in SA. The constraint on new plants is set at an arbitrarily large size and is thus not binding.

The output of each plant must not be greater than the available capacity of that plant. With maintenance and other outages, the output is usually less than the available capacity. However, in this case availability is assumed to be 100 per cent.

The model here is deterministic. However, in practice, the demand in each period has a stochastic element. This is particularly important for the peak load blocks. There is also a probability that plants will incur unplanned outages during the peak. To account for this, a peak reserve constraint is included whereby capacity must exceed demand by a margin, which can be thought of as the reserve plant margin. Because this model has price-responsive demand functions, it is likely that this type of constraint will be binding in more than one load block. This arises because if the price is raised, demand falls and results in two load blocks having the same load.

The characteristics of individual and potential power stations influence the equilibrium outcome. Power station characteristics are presented in table 3.

Table 3: Plant data

Power station	*Avail-ability*	*Variable op. cost*[a]	*Annual fixed operating cost*	*Capital cost*[b]	*Life*	*Maximum allowable capacity*
		$m-GWh	*$m-MW-year*	*$m-MW*	*Years*	*MW*
Northern	1.0	0.0132	0	0.000	30	500
Torrens Island B	1.0	0.0180	0	0.000	30	800
Torrens Island A	1.0	0.0190	0	0.000	30	480
Mintaro	1.0	0.0277	0	0.000	30	90
Dry Creek	1.0	0.0268	0	0.000	30	156
Snuggery	1.0	0.0800	0	0.000	30	63
CUBE	1.0	0.0150	0.0150	0.000	30	180
New coal	1.0	0.0150	0.0268	1.340	30	9000
New gas open cycle	1.0	0.0185	0.0150	0.500	30	9000
New gas combined cycle	1.0	0.0120	0.0120	0.800	25	9000
New distillate	1.0	0.1500	0.0010	0.300	30	9000

a For the SA electricity report (IC 1996), we used confidential data supplied by ETSA Corp for variable and fixed operating costs. However, in this publication, variable operating cost for existing plants is based on London Economics and David Harbord and Associates (1995). It includes all non-capital costs. New plant data are based on Hinchy and Low (1993).

b Annualised capital cost is derived by converting this value using the life of the plant and a real discount rate of 8 per cent. Existing plants are considered 'sunk' and have zero value.

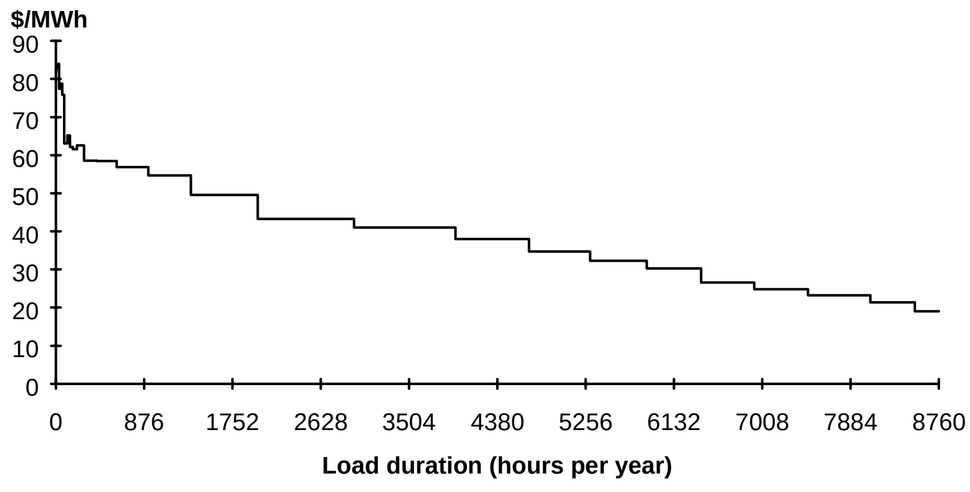
10 INTERSTATE PURCHASES OF ELECTRICITY

Interstate trade between NSW, Victoria and SA is currently governed by the Interconnection Operating Agreement (IOA). ETSA has a contract concluded under the IOA with the SECV to purchase electricity at prices significantly lower than observed in the Victorian market. Consequently SA imports around 24 per cent of its electricity requirements. This contract expires in April 1997.

With the advent of the national electricity market, it is unlikely that any new contract would contain such favourable prices for ETSA. Therefore it is assumed that the price of imports is that existing in the Victorian market. Because the price is higher, the model chooses a lower level of imports than ETSA currently purchases.

Victoria has collected system marginal prices (SMP) for the half hour periods for 1994–95. This means it is possible to obtain the mean SMP of electricity in the Victorian pool corresponding to the chronological hours in each of the 27 load blocks. The resulting Victorian price over the SA load duration curve is shown in figure 6.

Figure 6: Average price of electricity in the Victorian pool for each time period in South Australia



Source: IC estimates based on unpublished data from the Victorian Power Exchange.

11 SCENARIOS MODELLED

There are a range of factors that can influence the assessment of whether ETSA has the potential to exert market power and what policy options might be effective in dealing with it.

To explore these, a number of scenarios were modelled. Each scenario involves developing a variation of the model described earlier. The formal description of each scenario is not presented here, but the GAMS code used is available upon request.

Four main scenarios were modelled — three short run and one long run. These are described below. Rather than making assumptions of the way that ETSA will behave (through the level of market power), ten different variations are examined for each of these scenarios. As defined earlier, market power is the term (1+z). The ten variations modelled are market power = 0 (perfect competition), 0.01, 0.02, 0.03, 0.04, 0.05, 0.06, 0.07, 0.08 (minor levels of market power) and 1 (a monopolist).[8]

In the short run it is assumed that no new investment is possible. Thus, in the short run scenarios, electricity can only be sourced from ETSA's current generators in SA and imports over the transmission line from Victoria. A spot pool operates in Victoria and it is assumed in all scenarios that Victorian generators behave competitively.

Scenario 1 — Short run: maintain ETSA

The first scenario is primarily used as the reference for comparison, modelling ETSA as a single firm, for the ten different levels of market power.

Scenario 2 — Short run: vesting

One way to address short run market power is for a regulator to supervise the vesting of ETSA Generation with contracts to supply some part of its capacity for several years. Vesting contracts remove the incentive to bid prices above cost. Therefore we assume the plant behave competitively for the quantity of capacity vested (conjectural variation of –1).

----

[8] The corresponding conjectural variation values are –1, –0.99, –0.98, –0.97, –0.96, –0.95, –0.94, –0.93, –0.92 and 0.

In this analysis, the output of half of Northern power station, half of Torrens Island B and all of Mintaro power station are assumed to be vested (about 500 MW, or just over half of SA's base load requirement). Thus, these vested plants are assumed to behave competitively (conjectural variation equals –1) and the remaining ETSA plants are assumed to behave with the varying degrees of market power. In the model, this is achieved by splitting ETSA power station variables into two components. The quantity of vested capacity is treated as though it is a competitive power station. The remainder is part of ETSA's portfolio behaving as an oligopolist.

Scenario 3 — Short run: horizontal separation

An alternative to vesting to reduce market power is to divide ETSA Generation into two generation businesses, Northern and Torrens Island (which also includes the other minor power stations). This is modelled by disaggregating the $XSATD_b$ variable into the amount of electricity supplied by each group of power stations ($XSATD_{bm}$). Then each power station group has an oligopolistic margin term in the objective function and requires an aggregate conjectural variation coefficient.

Scenario 4 — Long run

Over a longer period, investment in new plant or transmission lines is possible (although new transmission capacity is not modelled here). The production costs for various generating technologies are specified in the model, and the new entry is endogenous to the model. An additional 180 MW capacity is expected to be available from the Canadian Utilities-Boral Energy (CUBE) project in 1998, but is treated as part of ETSA's portfolio. The long run scenario also considers the various levels of market power for ETSA as outlined above.

12 RESULTS AND POLICY DISCUSSION

The Commission estimated the annual average prices and quantities of electricity, and the payoffs to ETSA under each of the different scenarios (figure 7). These were modelled for each of the different levels of market power. Not surprisingly, regardless of the scenario, as ETSA's level of market power increases, the average annual price increases (and conversely, quantity of electricity supplied decreases).

The first scenario (short run: maintain ETSA) experiences the greatest price rises as market power increases. While both short run options to reduce ETSA's market power are effective, vesting appears the more powerful, producing the lower prices, regardless of market power, by comparison with horizontal separation.

Under scenario 3, ETSA is separated into two generating businesses. While the increased competition does reduce prices, it does nothing to discourage the firms from exerting market power. Even two competing businesses will receive increasing payoffs by exerting market power (illustrated by the lines 'HS: portfolio 1' and 'HS: portfolio 2' in the payoff chart in figure 7).

The payoff to ETSA under the long run scenario peaks at a market power of around 0.02. The reason the payoff doesn't continue its upward path like the short run scenarios, is the higher payoffs make investment in the industry more attractive, and new entry occurs.

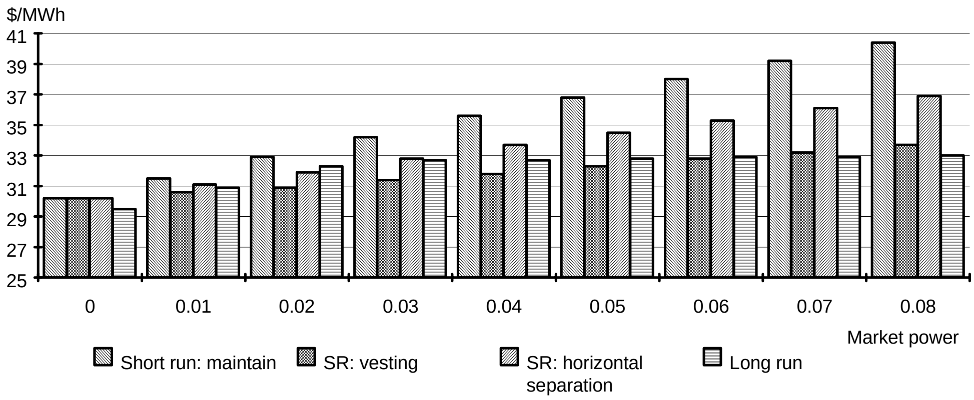
As discussed earlier, the results generated by the model do not make any explicit assumptions about specific behaviour. However it illustrates the incentives faced by ETSA. In the short run, regardless of which scenario is used, exerting market power will increase the price and payoff that ETSA receives. This suggests that faced with the three different scenarios, ETSA will tend to exert its market power.

The long run scenario is different, due to the prospect of new entry. However the incentive is still there to increase market power, but only up to a certain point.

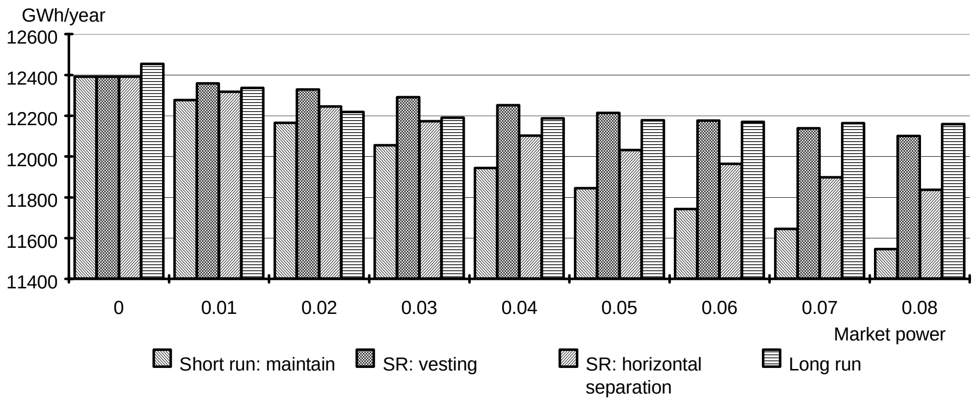
The impact on price of the different levels of market power for each of the four scenarios is similar (figure 8). In general, the higher the market power, the higher the price. The exception is the long term scenario — if ETSA acts as a monopolist, new entry occurs and prices are lower.

Figure 7: Average prices, quantities and payoffs for ETSA under different scenarios[a]

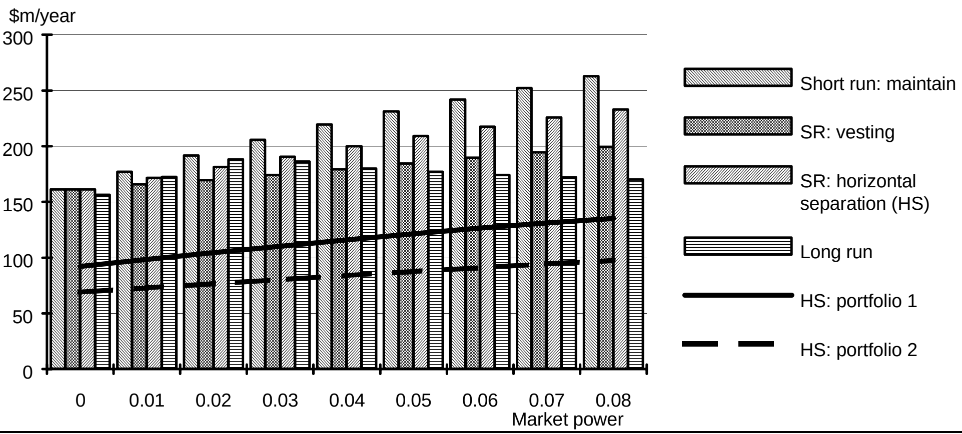
Annual average price



Quantity



Payoff



a Note that market power in these figures ranges from 0 to 0.08. The 'monopolist' (market power = 1) results are not shown here as they overshadow the other results. Figure 8 provides an idea of the mark up of the prices involved.

Vesting stands out as producing the lowest prices in the short run when ETSA behaves as a monopolist. Predictably, if ETSA exerts no market power (behaves competitively) there is no difference in the price level between scenarios.

The modelling also provides the merit order for the dispatch of generators under the different scenarios. That is, which power stations are providing the electricity at that particular time (figure 9). Results are presented for all four scenarios with market power assumed to be 0.08, and the competitive solutions in the short and long run.

If ETSA is behaving competitively, in the short or long run, all of SA's electricity is supplied by ETSA. However in two cases where ETSA exerts market power, imports are used from Victoria.[9]

Power stations are usually dispatched in the order of marginal cost (that is, least cost to high cost). In SA this means Northern is dispatched first, followed by Torrens B, Torrens A, Dry Creek and Mintaro (illustrated in the first diagram in figure 9). The entry of imports depends upon the relative prices.

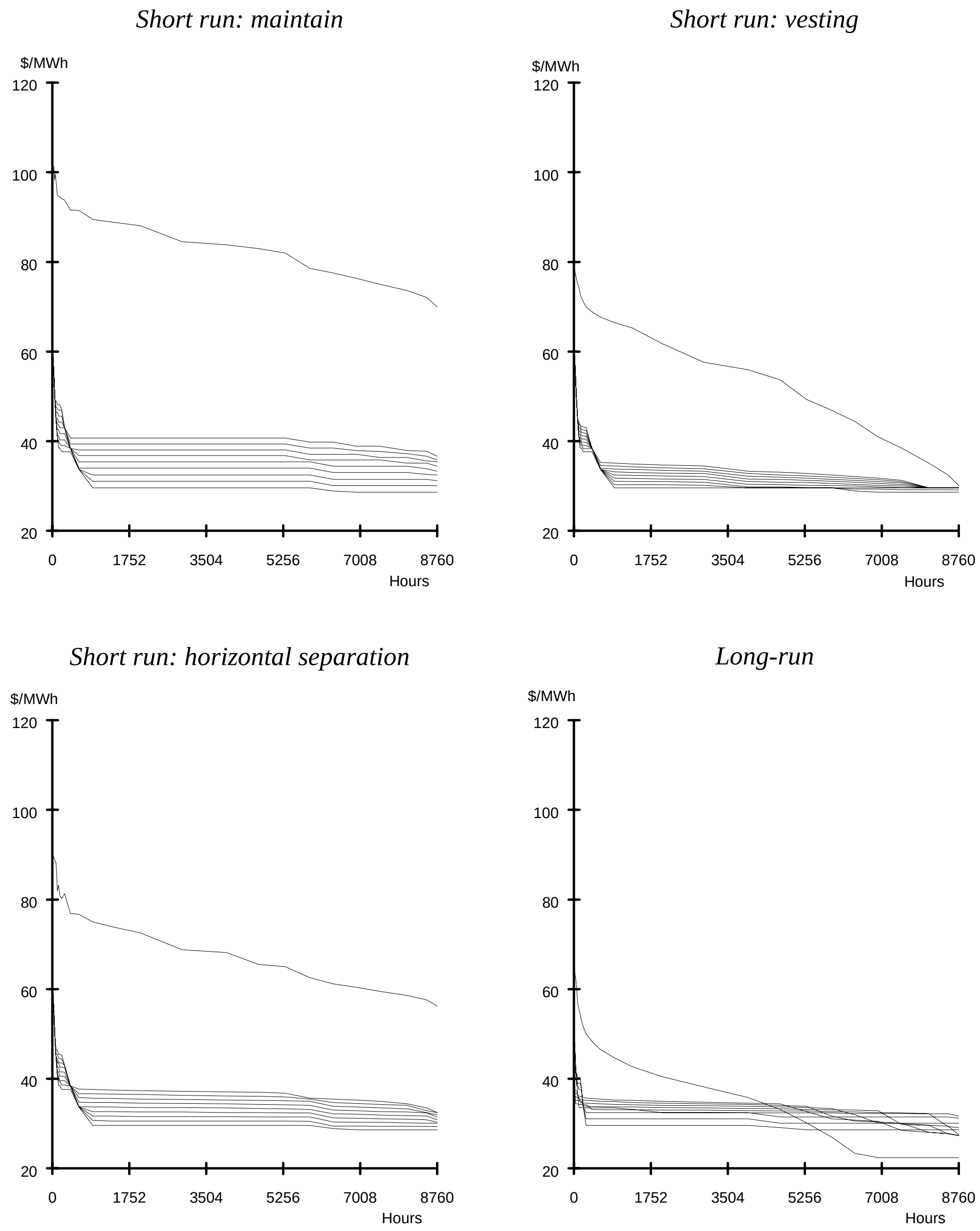
Yet in the short run scenario with vesting, with assumed market power of 0.08, the usual order of dispatch is disrupted. Torrens A 'vesting' output is dispatched before Torrens B output. This distortion is because the vesting contracts bind the suppliers to a more competitive price — the Torrens A 'vesting' (or competitive) price must be lower than the Torrens B 'market power' price, even though it is more expensive to produce.

In the long run ETSA exerting some market power and increasing prices results in the entry of a new gas combined cycle plant. The new plant would replace Northern as the base load plant, and Northern would be pushed up the merit order.

----

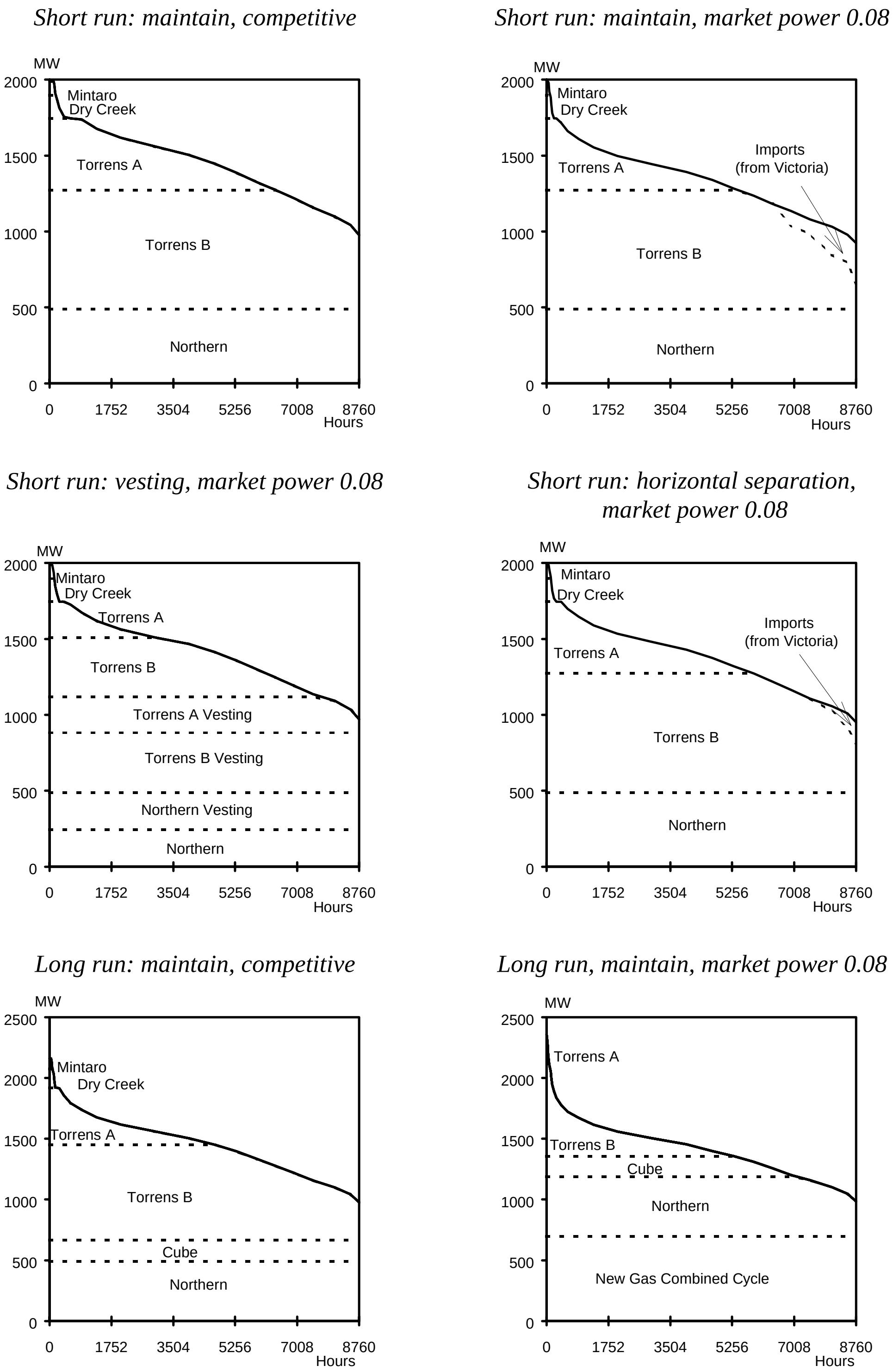
[9] The model assumes that the import price is the existing price in the Victorian market (see section 10), rather than the existing contract price under the IOA.

Figure 8: Impact of market power on prices over the load duration for various scenarios[a]



a The upper price line in each individual chart corresponds with ETSA acting as a short run profit maximising monopolist (market power = 1). The lower groups of lines represent the nine levels of market power: 0.08, 0.07, 0.06, 0.05, 0.04, 0.03, 0.02, 0.01 and 0 (perfect competition) — not surprisingly, the lowest price line corresponds with perfect competition.

Figure 9: Merit order for plant dispatch, various scenarios



13 POSSIBLE EXTENSIONS OF THE TECHNIQUE

Future developments of the technique could include:

- the innovativeness of integer variables to allow for greater realism in generation and transmission by allowing for discrete power stations, minimum stable generation, discrete transmission and fuel supply constraints;
- extension to a multi year model to evaluate long term dynamic effects on the market, such as the timing of transmission augmentation;
- the extension of monopoly behaviour to the transmission system to evaluate market power issues in transmission (see MacAulay 1992 for an example of a transport monopoly); and
- developing Dantzig-Wolfe decomposition or Gauss-Seidel iterative type algorithms and solution procedures that would allow profit maximising generator sub models and a competitive equilibria master models. This is analogous to the methods described by Kutcher (1973) and Hobbs and Schuler (1985). This may provide another avenue to model imperfectly competitive behaviour in the bidding process.

14 CONCLUSIONS

The modelling produced the following conclusions:

- regardless of which scenario is used, the study suggests that in the short term the incentive exists for ETSA to exert its market power;
- a duopoly, formed by splitting NPS and TIPS into separate businesses, is unlikely to result in a significantly greater level of competition in the short run. However new entry would impose competitive pressures at a faster rate on a duopoly than a monopoly;
- forcing ETSA to vest about 500MW (around half of SA's base load requirements) produces the lowest prices (and payoff to ETSA) of the three short term scenarios; and
- in the long run, Torrens Island and NPS are vulnerable to being displaced by entrants utilising newer gas technologies.

The impact of low demand growth in SA is reflected in the Commission's modelling when there is no entry in the year 2000 if ETSA Generation bid at incremental cost. The net expansion of capacity that occurs when CUBE replaces Playford is sufficient to meet SA's needs.[10]

---

[10] The need for additional reserve plant in SA has not been incorporated into the analysis.

Appendix A

GAMS code for the basic long run model

```
$OFFSYMLIST OFFSYMXREF
 OPTIONS DECIMALS = 5 ;
 OPTIONS LIMCOL   = 0 ;
 OPTIONS LIMROW   = 0 ;
 OPTIONS SOLPRINT = OFF ;
 OPTIONS NLP      = MINOS5 ;
 OPTION SYSOUT    = OFF     ;
 OPTIONS ITERLIM  = 20000   ;
 OPTIONS RESLIM   = 8000    ;

SETS
  B  LOAD BLOCKS
    / B1*B27 /
  M  ALL POWER STATIONS
    / N, TB, TA, MIN, DRY, SNUG, CUBE, NEWCOAL, NEWGOC, NEWGCC,
      NEWDIST /
  ME(M)  ETSA POWER STATIONS
    / N, TB, TA, MIN, DRY, SNUG, CUBE /
  MO(M)  INDEPENDENT COMPETITIVE POWER STATIONS
    / NEWCOAL, NEWGOC, NEWGCC, NEWDIST /
  S  SCENARIOS FOR RANGE OF ETSA MARKET POWER EQUILIBRIA
    / SCENE1*SCENE10 /
  L  INTERSTATE TRANSMISSION LOAD (MW)
    / L100, L200, L300, L400, L500 /
  LABELS  NAMES TO IDENTIFY PLANT DATA
    / AVAIL        OPERATIONAL AVAILABILITY OF EACH PLANT
      VOPCOST      VARIABLE OPERATING COSTS ($M PER GWH)
      FOPCOST      FIXED OPERATING COSTS ($M PER YEAR)
      CAPCOST      CAPITAL COSTS ($M)
      LIFE         LIFE OF UNITS (YEARS)
      MAXCAP       MAXIMUM CAPACITY OF EACH PLANT (MW) / ;

ALIAS  (B,BP), (M,MP) ;

PARAMETERS
  MAXLOAD(B)  MAXIMUM LOAD IN EACH BLOCK (MW)
    / B1     2132
      B2     2100
      B3     2050
      B4     2000
      B5     1950
      B6     1900
      B7     1848
      B8     1800
      B9     1750
```

```
    B10    1700
    B11    1650
    B12    1600
    B13    1550
    B14    1500
    B15    1450
    B16    1400
    B17    1350
    B18    1300
    B19    1250
    B20    1200
    B21    1150
    B22    1100
    B23    1050
    B24    1000
    B25     950
    B26     900
    B27     850/

ENERGY(B)  ENERGY IN EACH BLOCK (GWH)
  / B1         6.353
    B2        35.335
    B3        24.324
    B4        30.604
    B5        31.768
    B6        35.602
    B7        60.166
    B8        39.055
    B9        50.858
    B10       71.214
    B11      112.161
    B12      207.650
    B13      293.814
    B14      461.618
    B15      602.203
    B16      912.014
    B17     1264.619
    B18     1283.659
    B19      896.901
    B20      713.453
    B21      630.674
    B22      578.956
    B23      541.480
    B24      520.299
    B25      574.202
    B26      387.212
    B27      196.758 /

HOURS(B)  DURATION OF EACH BLOCK (HOURS)
  / B1         3.0
    B2        17.0
    B3        12.0
    B4        15.5
    B5        16.5
    B6        19.0
    B7        33.0
    B8        22.0
    B9        29.5
```

```
      B10      42.5
      B11      69.0
      B12     132.0
      B13     193.0
      B14     313.0
      B15     423.0
      B16     664.0
      B17     954.5
      B18    1005.5
      B19     731.0
      B20     606.5
      B21     560.5
      B22     538.0
      B23     527.5
      B24     533.0
      B25     620.0
      B26     440.5
      B27     239.0  /

  POOLP(B)  VIC POOL PRICE IN EACH BLOCK ($M PER GWH)
    / B1      0.08190
      B2      0.08286
      B3      0.08392
      B4      0.07740
      B5      0.07873
      B6      0.07585
      B7      0.06308
      B8      0.06519
      B9      0.06214
      B10     0.06155
      B11     0.06257
      B12     0.05851
      B13     0.05846
      B14     0.05687
      B15     0.05473
      B16     0.04954
      B17     0.04330
      B18     0.04099
      B19     0.03798
      B20     0.03473
      B21     0.03230
      B22     0.03024
      B23     0.02654
      B24     0.02482
      B25     0.02320
      B26     0.02136
      B27     0.01903 /;

* SCALE MAXLOAD AND ENERGY TO REFLECT GROWTH IN DEMAND IN THE LONG
  SCENARIO
  ENERGY(B) = ENERGY(B) * 0.94;
  MAXLOAD(B) = MAXLOAD(B) * 1.1;

PARAMETERS
  PRICE(B)  WHOLESALE PRICE IN EACH DEMAND PERIOD (CENT PER KWH)
  BETA(B)  PRICE ELASTICITIES OF DEMANDS
  IBETA(B)  PRICE ELASTICITIES FOR INVERSE DEMAND FUNCTION
  ALPHA(B)  CONSTANTS FOR INVERSE DEMAND FUNCTION ;
```

```
    PRICE(B) = 6.0 ;
    BETA(B) = -0.5 ;
    IBETA(B) = 1/BETA(B)*PRICE(B)/100/ENERGY(B) ;
    ALPHA(B) = PRICE(B)/100-IBETA(B)*ENERGY(B) ;

TABLE  MDATA(M,LABELS)  DATA FOR THERMAL PLANTS
            AVAIL   VOPCOST     FOPCOST   CAPCOST    LIFE   MAXCAP
*                   $M-GWH (?)$M-MW-YR     $M-MW    YEARS       MW
  N        1.0000    0.0132           0     0.000       30      500
  TB       1.0000    0.0180           0     0.000       30      800
  TA       1.0000     0.019           0     0.000       30      480
  MIN      1.0000    0.0277           0     0.000       30       90
  DRY      1.0000    0.0268           0     0.000       30      156
  SNUG     1.0000     0.080           0     0.000       30       63
  CUBE     1.0000   0.01500       0.015     0.000       30      180
  NEWCOAL  1.0000   0.01500      0.0268     1.340       30     9000
  NEWGOC   1.0000   0.01850       0.015     0.500       30     9000
  NEWGCC   1.0000   0.01200       0.012     0.800       25     9000
  NEWDIST  1.0000   0.15000       0.001     0.300       30     9000

SCALARS
  RHO  INTEREST RATE                          / 0.08 /
  PRR  PEAK RESERVE REQUIREMENT               / 0.14 /
  TCAP MAXIMUM INTERSTATE TRANSMISSION CAPACITY (MW) / 500 / ;

PARAMETERS
  PLANTCOST(M)      FIXED ($M PER MW) COSTS
  FUELCOST(M,B)  VARIABLE ($M PER MWH) COSTS
  SATLOSS(M,B)   SA TRANSMISSION LOSSES
  SATCOST(M,B)   SA COST OF TRANSMISSION ($M PER GWH)
  ISTFACT           INTERSTATE TRANSMISSION LOSS FACTOR (PER CENT)
  ISTLOSS(L,B)   INTERSTATE DYNAMIC TRANSMISSION LOSSES
  ISTCOST(L,B)   INTERSTATE COST OF TRANSMISSION ($M PER GWH) ;
    PLANTCOST(M) = (RHO/(1-(1+RHO)**(-MDATA(M,'LIFE'))))
                 *MDATA(M,'CAPCOST') + MDATA(M,'FOPCOST') ;
    FUELCOST(M,B) = MDATA(M,'VOPCOST')/1000*SUM(BP,HOURS(BP)
                    $ (ORD(BP) LE ORD(B))) ;
    SATLOSS(M,B) = 0.02 ;
    SATCOST(M,B) = 0.01 ;
    ISTFACT      = 0.18 ;
    ISTLOSS(L,B) = ISTFACT/TCAP*(ORD(L)*100) ;
    ISTCOST(L,B) = 0.01*ORD(L)*100*HOURS(B)/1000 ;

PARAMETER
  SACV(S)  AGGREGATE CONJECTURAL VARIATION FOR EACH SCENARIO
    / SCENE1   -1.00
      SCENE2   -0.99
      SCENE3   -0.98
      SCENE4   -0.97
      SCENE5   -0.96
      SCENE6   -0.95
      SCENE7   -0.94
      SCENE8   -0.93
      SCENE9   -0.92
      SCENE10   0.00 /

SCALAR
  ACV  AGGREGATE CONJECTURAL VARIATION FOR OLIGOPOLY BEHAVIOUR
```

```
POSITIVE VARIABLES
   XE(B)         SA TIME-OF-USE SALES (GWH)
   XSATD(B)      ETSA GENERATOR SALES(GWH)
   XISTD(B)      INTERSTATE SALES (GWH)
   XSAT(M,B)     SA TRANSMISSION FROM GENERATORS TO CUSTOMERS
   XIST(L,B)     TRANSMISSION FROM INTERSTATE POOL TO CUSTOMERS
                 (NORMALISED MW)
   XO(M,B)       INCREMENTAL OUTPUT LEVEL OF EACH PLANT IN EACH
                 MONTH (MW)
   XC(M)         INDIVIDUAL PLANT CAPACITIES (MW)
   XISE(B)       INTERSTATE ELECTRICITY POOL PURCHASES (GWH)

 FREE VARIABLES
   NSR           NET SOCIAL WELFARE ($M)

 EQUATIONS
   OBJ           NET SOCIAL WELFARE ($M)
   TD(B)         DEMAND BALANCE (GWH)
   SATB(B)       SA TRANSMISSION BALANCE (GWH)
   ISTB(B)       INTERSTATE TRANSMISSION BALANCE (GWH)
   GB(M,B)       PLANT GENERATION BALANCE IN EACH TIME-OF-USE
                 PERIOD (GWH)
   PR(B)         PEAK RESERVE CONSTRAINT (MW)
   CC(M)         CAPACITY CONSTRAINT FOR EACH PLANT IN EACH SEASON
                (MW)
   GCAP(M)       MAXIMUM CAPACITY (MW)
   ISTC(B)       LINEAR COMBINATION OF INTERSTATE TRANSMISSION
                 LOSS VARIABLES
   ISEP(B)       INTERSTATE ELECTRICITY POOL PURCHASES BALANCE;

OBJ..
  NSR =E= SUM((B),ALPHA(B)*XE(B)+0.5*IBETA(B)*SQR(XE(B)))
        + SUM((B),0.5*(1+ACV)*IBETA(B)*SQR(XSATD(B)))
        - SUM((M,B),SATCOST(M,B)*XSAT(M,B))
        - SUM((L,B),ISTCOST(L,B)*XIST(L,B))
        - SUM(M,PLANTCOST(M)*XC(M))
        - SUM((M,B),FUELCOST(M,B)*XO(M,B))
        - SUM((B),POOLP(B)*XISE(B));
TD(B)..
  XE(B) =L= XSATD(B) + XISTD(B) ;
SATB(B)..
  XSATD(B) =L= SUM(M$ME(M),(1-SATLOSS(M,B))*XSAT(M,B)) ;
ISTB(B)..
  XISTD(B) =L= SUM(L,(1-
ISTLOSS(L,B))*HOURS(B)/1000*ORD(L)*100*XIST(L,B))
            + SUM(M$MO(M),(1-SATLOSS(M,B))*XSAT(M,B));
GB(M,B)..
  XSAT(M,B) =L= SUM(BP,HOURS(B)/1000*XO(M,BP)$(ORD(BP) GE ORD(B))) ;
PR(B)..
  XE(B)/HOURS(B)*1000*(1+PRR) =L= SUM(M,(1-
SATLOSS(M,B))*MDATA(M,'AVAIL')*XC(M))
                               + (1-ISTFACT)*TCAP ;
CC(M)..
  SUM(B,XO(M,B)) =L= MDATA(M,'AVAIL')*XC(M) ;
GCAP(M)..
  XC(M) =L= MDATA(M,'MAXCAP') ;
ISTC(B)..
```

```
  SUM(L,XIST(L,B)) =L= 1.0 ;
ISEP(B)..
  SUM(L,HOURS(B)/1000*ORD(L)*100*XIST(L,B)) =L= XISE(B) ;
*INITIAL VALUES
  XE.L(B) = ENERGY(B) ;
  XE.LO(B) = 0.0001 ;

  MODEL  NSR1  / ALL / ;
  NSR1.OPTFILE = 1 ;

PARAMETERS
  PAYOFF(S)       PROFIT
  PRICES(B,S)     MARKET PRICE
  REVENUE(S)      REVENUE
  FIXED(S)        FIXED COSTS
  VC(S)           VARIABLE COSTS
  CAPACITY(M,S)   INSTALLED CAPACITY
  LOAD(B,S)       SA SYSTEM LOAD (BEFORE TRANSMISSION)
  LOADMD(B,S)     DEMAND LOAD (AFTER TRANSMISSION)
  TRNSLOAD(B,S)   INTERSTATE TRANSMISSION LOAD
  PLANLOAD(S,B,M) OUTPUT LEVEL OF EACH PLANT IN EACH TIME BLOCK
  SYSLOAD (S,B,*) SYSTEM LOAD ;

LOOP (S,
  ACV = SACV(S);
  SOLVE NSR1 MAXIMIZING NSR USING NLP ;
  PRICES(B,S)     = ALPHA(B)+IBETA(B)*XE.L(B) ;
  CAPACITY(M,S)   = XC.L(M) ;
  LOAD(B,S)       = SUM((M,BP),XO.L(M,BP)$(ORD(BP) GE ORD(B))) ;
  LOADMD(B,S)     = XE.L(B)/HOURS(B)*1000;
  TRNSLOAD(B,S)   = SUM(L,ORD(L)*100*XIST.L(L,B)) ;
  PLANLOAD(S,B,M) = SUM(BP$(ORD(BP) GE ORD(B)), XO.L(M,BP));
  SYSLOAD(S,B,M)  = XSATD.L(B)/HOURS(B)*1000;
  SYSLOAD(S,B,'VIC') = XISTD.L(B)/HOURS(B)*1000 ;
  PAYOFF(S)       = SUM((M,B)$ME(M),XSAT.L(M,B)*(1-SATLOSS(M,B))*
                    PRICES(B,S)*(1-SATCOST(M,B)))
                  - SUM(M$ME(M), PLANTCOST(M)*XC.L(M))
                  - SUM((M,B)$ME(M),FUELCOST(M,B)*XO.L(M,B)) ;
  REVENUE(S)      = SUM((M,B)$ME(M),XSAT.L(M,B)*(1-SATLOSS(M,B))*
                        PRICES(B,S)*(1-SATCOST(M,B)));
  FIXED(S)        = SUM(M$ME(M), PLANTCOST(M)*XC.L(M)) ;
  VC(S)           = SUM((M,B)$ME(M),FUELCOST(M,B)*XO.L(M,B)) ;
);

DISPLAY
  PRICES, CAPACITY, LOAD, TRNSLOAD, PLANLOAD, PAYOFF, REVENUE,
FIXED,
  VC ;
```

References

Armstrong, M., Cowan, S. and Vickers, J. 1994, *Regulatory Reform — Economic Analysis and British Experience*, Oxford University Press, Oxford.

Bergstrom, T. C. and Varian, H. R. 1985, ‘Two Remarks on Cournot Equilibria’, *Economic Letters,* vol. 19, no. 1, pp. 5–8.

Bisschop, J. and Meeraus, A. 1982, ‘On the Development of a General Algebraic Modelling System’ in *A Strategic Planning Environment, Mathematical Programming Study,* vol. 20, pp. 1–29.

Bolle, F. 1992, ‘Supply Function Equilibria and the Danger of Tacit Collusion: The Case of the Spot Markets for Electricity’, *Energy Economics,* April, pp. 94–102.

Brooke, A., Kendrick, D. and Meeraus, A. 1992, *GAMS: A User’s Guide*, Release 2.25, Boyd and Fraser Publishing Company, Denver, Massachusetts.

Dalziell, I., Noble, K. and Ofei-Mensah, A. 1993, *The Economics of Interconnection: Electricity Grids and Gas Pipelines in Australia*, ABARE Research Report 93.12, Canberra.

ETSA Corporation 1995, *ETSA Corporation 1994–95 Annual Report*, ETSA Corporation, Adelaide.

—— 1996, submission to the Industry Commission review of the SA electricity industry (IC 1996).

Green, R. and Newbery D. 1992, ‘Competition in the British Electricity Spot Market’, *Journal of Political Economy*, vol. 100, no. 5, pp. 929–953.

Hashimoto, H. 1985, ‘A Spatial Nash Equilibrium Model’ in Harker, P. T. (ed), *Spatial Price Equilibrium: Advances in Theory, Computation and Application,* Berlin: Springer-Verlag, pp. 20–40.

Hinchy, M. and Low, J. 1993, *Electricity Transmission and Bulk Pricing*, ABARE Research Report 93.14, Australian Bureau of Agricultural and Resource Economics, Canberra.

Hobbs, B. F. and Schuler, R. E. 1985, ‘Evaluation of Electric Power Deregulation using Network Models of Oligopolistic Spatial Markets’, in Harker, T. (ed), *Spatial Price Equilibrium: Advances in Theory, Computation and Application*, Springer-Verlag, pp. 208–254.

IC (Industry Commission) 1996, *The Electricity Industry in South Australia*, research report, Industry Commission, Melbourne.

Intriligator, M. 1971, *Mathematical Optimisation and Economic Theory*, Prentice-Hall Inc, United States.

Kolstad, C. D. 1989, Computing Dynamic Spatial Oligopolistic Equilibria in an Exhaustible Resource Market: in Labys, W. C., Takayama, T. and Uri, N. D. (eds), *Quantitative Methods for Market Oriented Economic Analysis over Space and Time*, Gower Publishing Company Limited, Harts, England.

—— and Burris, A. E. 1986, ‘Imperfectly Competitive Equilibria in International Commodity Markets’, *American Journal of Agricultural Economics*, vol. 68, no. 1, pp. 27–36.

Kutcher, G. 1973, V.2. ‘on Decomposing Price-Endogenous Models’, in Goreux, L. and Manne, A. (eds)’ *Multi-Level Planning: Case Studies in Mexico*, North Holland Publishing Company, Amsterdam.

Lambert, P. J. 1993, *Advanced Mathematics for Economists*, Blackwell Publishers, Oxford, UK.

London Economics 1996, *South Australian electricity generation market structure, competitiveness and scale efficiency*, Draft Report, London Economics, Melbourne.

—— and David Harbord and Associates 1995, *Market power in the Australian electricity market: a Report to the Industry Commission*, August.

MacAulay, T. 1992, ‘Alternative Spatial Equilibrium Formulations: A Synthesis’, in Tinbergen, J. Jorgenson, D. and Laffont, J., *Contributions to Economic Analysis*, North-Holland, Amsterdam.

Meeraus, A. 1983, ‘An Algebraic Approach to Modelling’, *Journal of Economic Dynamics and Control*, vol. 5, pp. 81–108.

Munasinghe, M. 1990, *Electric Power Economics*, Butterworths & Co, England.

NGMC (National Grid Management Council) 1993, *Statement of Opportunities 1993–2005*, May.

—— 1994, *1994 Review of Statement of Opportunities*, May.

Provenzano, G. 1989, 'Alternative National Policies and the Location Patterns of Energy Related Facilities', in Labys, W. C., Takayama, T. and Uri, N. D. (eds), *Quantitative Methods for Market Oriented Economic Analysis over Space and Time*, Gower Publishing Company Limited, Harts, England.

Salerian, J. S. 1992, 'The Application of a Temporal Price Allocation Model to Time-Of-Use Electricity Pricing', *Discussion Paper 92.11*, Department of Economics, University of Western Australia, Nedlands, Western Australia.

Samuelson, P. A. 1952, 'Spatial Price Equilibrium and Linear Programming', *American Economic Review*, vol. 42, pp. 283–303.

Scherer, C. R. 1977, *Estimating Electric Power System Marginal Costs*, Contributions to Economic Analysis v. 107, North-Holland Publishing Company, Amsterdam.

Scherer, F. M and Ross, D. 1990, *Industrial Market Structure and Economic Performance*, Third Edition, Houghton Mifflin Company, Boston.

Shapiro, C. 1989, 'Theories of Oligopoly Behaviour', in Schmalensee, R. and Willig, R. D. (eds), *Handbook of Industrial Organisation*, Volume I, Elsevier Science Publishers B. V.

Shapiro, R. 1984, *Optimisation Models for Planning and Allocation: Text and Cases in Mathematical Programming*, John Wiley and Sons, New York.

Sohl, J. E. 1985, 'An Application of Quadratic Programming to the Deregulation of Natural Gas', in Harker, P. T. (ed), *Spatial Price Equilibrium: Advances in Theory, Computation and Application*, Berlin: Springer-Verlag, pp. 198–207.

Stocks, K. and Musgrove, A. 1984, 'MENSA — Regionalised Version of MARKAL', *The IEA Linear Programming Model for Energy Systems Analysis, Energy Systems and Policy*, vol. 4, no. 8, pp. 313–48.

Takayama, T. and Judge, G. G. 1971, *Spatial and Temporal Price and Allocation Models*, North-Holland Publishing Company, Amsterdam.

—— and Woodland, A. D. 1970, 'Equivalence of Price and Quantity Formulations of Spatial Equilibrium', *Purified Duality in Quadratic and Concave Programming*, *Econometrica*, vol. 38, pp. 899–906.

Tirole, J. 1988, *The Theory of Industrial Organisation*, MIT Press, Cambridge Mass.

Turvey, R. and Anderson, D. 1977, *Electricity Economics, Essays and Case Studies*, The Johns Hopkins University Press, Baltimore.

Uri, N. D. 1983, *New Dimensions in Utility Pricing*, JAI Press Inc., London, England.

—— 1989, 'Linear Complementary Programming: Electrical Energy as a Case Study', in Labys, W. C., Takayama, T. and Uri, N. D. (eds), *Quantitative Methods for Market Oriented Economic Analysis over Space and Time*, Gower Publishing Company Limited, Harts, England.

von der Fehr, N. and Harbord, D. 1993, 'Spot Market Competition in the UK Electricity Industry', *Economic Journal*, vol. 103, May, pp. 531–546.