LONG RUN MARGINAL COST OF ELECTRICITY

Cover note for the report on the long run marginal cost of electricity prepared by IES '*The long run marginal cost of electricity generation in NSW*'

Prepared by members of the IPART Secretariat

Background on the IES paper

The Tribunal intends to use the IES paper to inform its decision on the appropriate value of wholesale electricity costs for NSW standard electricity retailers and to invite discussion amongst roundtable participants on the topic.

The Tribunal currently incorporates wholesale electricity purchase costs into retail electricity prices based on the long run marginal cost (LRMC) of electricity generation. Within the range determined by the Tribunal, individual retailers have received different cost allowances as a result of applying each retailer's actual load profile for customers on regulated tariffs.

There are other methods that could be used to estimate the wholesale electricity cost for regulated retailers (for example, the current market price) and it is likely that the final estimate based on such approaches would be different from the LRMC.

The Terms of Reference for the current review require the Tribunal to determine the allowance for electricity purchase costs based on an assessment of the LRMC of electricity generation, given the characteristics of the demand of customers remaining on regulated tariffs.

Issues for discussion at roundtable – 4 March 2004

Is the methodology used by IES appropriate for determining the LRMC of electricity over the regulatory period in question? If not, is there a more suitable way of obtaining a benchmark range?

Has the methodology been applied appropriately? If not, what specific problems with IES's approach can be identified?

Is the range recommended in the IES report reasonable?

IES has recommended a range of costs including a peak, shoulder and off-peak LRMC and a value for each retailer depending on its individual load profile. Should the LRMC allowance be retailer specific (based on load profile) or would it be more desirable to calculate a single value to be applied to all retailers based on a 'typical' load profile?

If a single benchmark value is considered preferable, what would a typical load profile look like and what are the implications of this for retailers' incentives (for example, relationship with demand management issues)?

THE LONG RUN MARGINAL COST OF ELECTRICITY GENERATION IN NEW SOUTH WALES

A Report to the Independent Pricing and Regulatory Tribunal

February 2004

Intelligent Energy Systems

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Executive Summary

This report presents the approach and results of a study undertaken by Intelligent Energy Systems (IES) for IPART on the Long Run Marginal Cost (LRMC) of electricity in New South Wales. This study was undertaken in the context of a wider review being undertaken by IPART, relating to franchise customer regulated retail tariffs for gas and electricity in New South Wales (NSW) for the period beyond 30 June 2004.

The study began by reviewing the definition of LRMC and the context of the analysis. This led to the use of a LRMC definition that was based on meeting the individual retailer load profiles using an optimal (lowest cost) generator plant program based solely on new entry generation.

With this definition, the study identified potential new entry generator technologies and their respective costs, and developed a linear program approach to the development of optimal generator installation programs.

New Entry Costs

The new entry technologies assumed for the mix of generators to supply the NSW retailer load profiles are:

- Black coal thermal power stations
- Combined cycle gas turbines (CCGT), and
- Open cycle gas turbines (OCGT)

The study identified the significant factors influencing costs and from this it determined the cost characteristic of each generator type under a low, medium and high cost scenario. The factors considered in this development included fixed capital costs, variable operating costs (fuel and operations and maintenance) and the financial structure (discount rate).

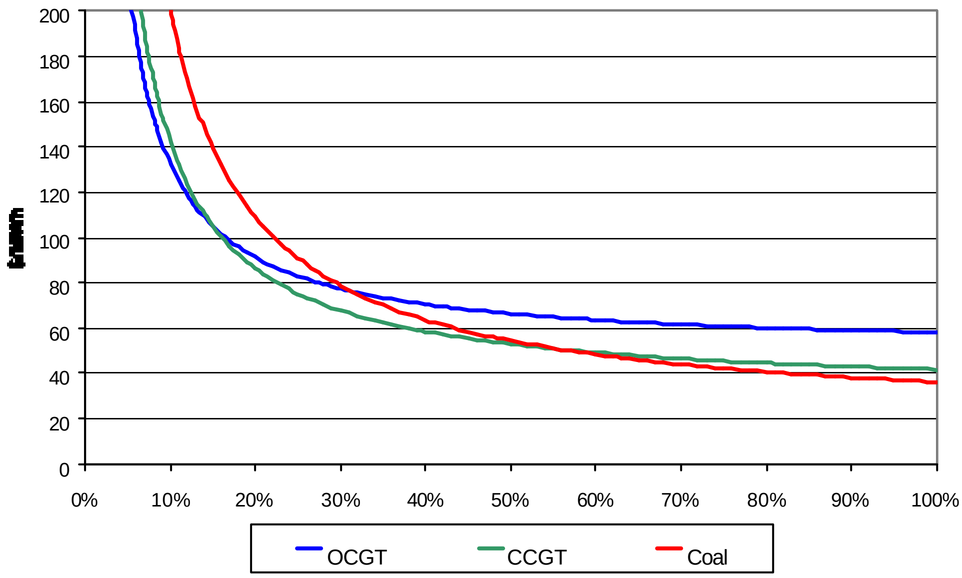
The resulting new entry costs for each generator type are presented below:

- Exhibit 1-1 shows the average cost of production assuming 100% capacity factor;
- Exhibit 1-2 shows the cost versus capacity factor profile.

Exhibit 1-1 New Entry Cost $/MWh

Plant Technology	Low	Medium	High
Thermal Coal	28.02	36.22	45.22
CCGT	34.46	41.77	49.16
OCGT	21.22	58.99	65.54

Exhibit 1-2 Medium New Entry Cost Scenario as a Function of Capacity Factor (Medium Scenario)



The study noted the cross over points in the cost versus capacity factor characteristic. These cross over points represent the capacity factors where one technology becomes more economic than the next. The optimal capacity factors and the corresponding new entry costs for each technology are shown in Exhibit 1-3 below.

Exhibit 1-3 Optimal Capacity Factors and Associated New Entry Cost (Medium Scenario)

	Thermal Coal	CCGT	OCGT
CF	100%	55%	14%
New Entry Cost	$36.2/MWh	$50.9/MWh	$109.0/MWh

Optimal Plant Combination

Using the above new entry costs, optimal plant portfolios were then constructed for each retailer's load profile using the linear programming model developed. The individual retail load profiles were supplied to IES by IPART.

The advantages of the linear programming approach were:

- Assurance that given a NSW load profile, the combination of plant chosen would minimise the total costs (capacity plus operating costs);
- Transparency;
- The automatic production of shadow prices representing the marginal supply costs. The model produced shadow prices for 438 time blocks each of 20 hours duration in the year modelled;

- Revenue neutrality as defined by total revenues matching the total costs (ie. no producer surplus).

Allocation of Costs to Individual Retailers

From the (revenue neutral) marginal costs developed, the average marginal cost for each retailer for the peak, shoulder and offpeak time sectors were determined. This was done by applying the marginal costs produced by the linear programming model to the increment of retailer load in the respective time sectors.

The average LRMC results for each NEW retailer as determined by the model are summarised in Exhibit 1-4 below:

Exhibit 1-4 Average LRMC Results ($/MWh)

	New Entry Cost Scenario		
	High	**Medium**	**Low**
Total NSW Load	51.37	41.47	32.31
Total NSW Franchise Load	58.32	47.38	37.24
Energy Australia Franchise Load			
Integral Energy Franchise Load			
Country Energy Franchise Load			
Australia Inland Franchise Load			

The peak, shoulder and offpeak LRMC based on the medium new entry cost scenario are shown in Exhibit 1-5 below. Definitions for peak, shoulder and offpeak time periods are shown in Exhibit 1-7.

Exhibit 1-5 Medium New Entry Scenario Peak, Shoulder and OffPeak LRMC Results ($/MWh)

	Time Period		
	Peak	**Shoulder**	**OffPeak**
Total NSW Load	89.59	47.25	22.66
Total NSW Franchise Load	123.77	33.99	30.92
Energy Australia Franchise Load			
Integral Energy Franchise Load			
Country Energy Franchise Load			
Australia Inland Franchise Load			

The differences in the results shown above are due to the different load shapes attributable to each customer segment and retailer. The normalised load shapes for each of the loads listed above are shown in Exhibit 1-6. A retailer with a load exhibiting more peakiness will have a larger weighting of high cost generation (OCGT) that one with a more flat load and in turn a higher overall LRMC.

Exhibit 1-6 Normalised Load Shapes

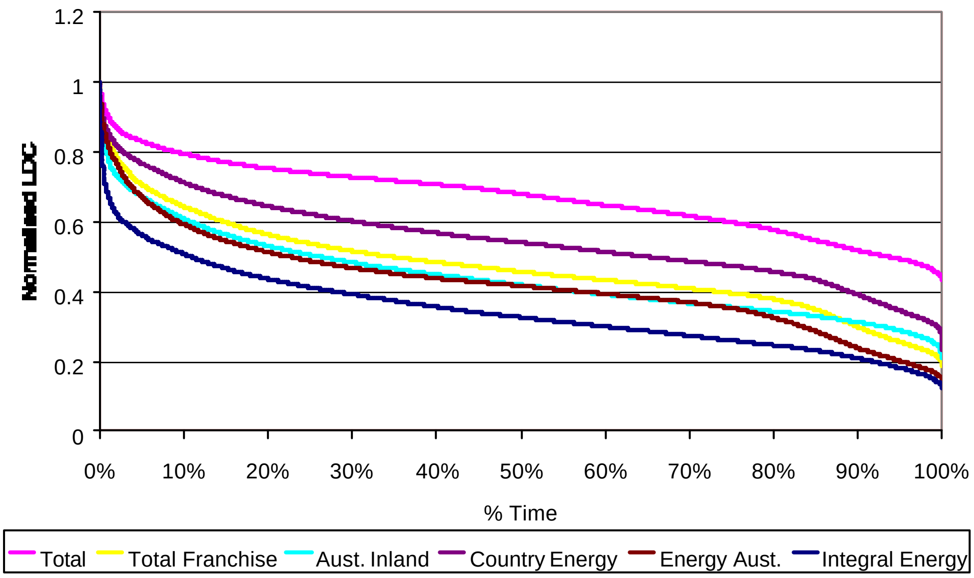


Exhibit 1-7 Peak, Shoulder and OffPeak Definitions

Time Period	Day of Week	Time of Day
Peak	Monday to Friday	7am to 9am
		5pm to 8pm
Shoulder	Monday to Friday	9am to 5pm
		8pm to 10pm
OffPeak	Monday to Friday	Midnight to 7am
		10pm to Midnight
	Saturday, Sunday and Public Holidays	All

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1 Introduction

1.1 Background

IPART is currently conducting a review of the franchise customer regulated retail tariffs for gas and electricity in New South Wales (NSW) for the period beyond 30 June 2004. In relation to electricity, this review requires investigations into the form of regulation to apply, generation costs, retail operating costs, retail margins, and miscellaneous charges.

As part of this review, IPART commissioned Intelligent Energy Systems (IES) to conduct a study to determine the Long Run Marginal Cost (LRMC) of electricity in NSW.

1.2 Scope and Deliverables

The scope of the determination of LRMC of electricity in NSW is as follows.

The consultant should develop a model for calculating the Long Run Marginal Cost (LRMC) of electricity generation. The model

1. *should be forward looking and consider the impact of changing demand on the cost of incremental generation capacity*
2. *should include any specific requirements relevant to greenhouse gas*
3. *should emphasise the supply price of new generating capacity.*

The consultant should consider whether it is appropriate for hedging costs to be included in the calculation of energy costs. If the inclusion of a hedging component is reasonable, the consultant should estimate what an appropriate allowance would be.

The required outputs from the consultancy are:

4. *participation in discussions with IPART's analysts on the various issues related to the review*
5. *preparation of, or provide assistance in the preparation of, briefings for the Tribunal to consider the various issues*
6. *attendance at Tribunal meetings, as required, to discuss the issues addressed in the Tribunal Briefing papers*
7. *attendance at, and participation in, public forums (eg presenting specific issues at round table discussions).*

Although not specifically specified in the scope, the LRMC of electricity in NSW is to be determined for each NSW retailer for the peak, shoulder and offpeak periods.

2 Methodology Development

The first task of the consultancy was to develop an appropriate methodology for the determination of the LRMC of electricity supply in NSW.

Accordingly, the methodology developed needed to account for the requirements as outlined in the Terms of Reference, the context in which it would be used, and the economic definitions of LRMC of supply.

2.1 Guiding Principles

The Terms of Reference specified a number of desirable requirements in relation to the determination of the LRMC of electricity supply in NSW.

Firstly the determination should be forward looking and consider the impact of changing demand on the cost of incremental generation capacity. This implies that the load shape, and more specifically the varying load shapes of the franchise customers of the different retailers, should be explicitly accounted for. In particular, this means that the peakiness of the load shape and how this develops over the review period should be properly accounted for in the modelling undertaken.

Secondly, it was thought that the determination should include any specific requirements relevant to greenhouse gas emissions. In the context of NSW retailers, the green energy schemes that place added costs onto retailers are the Mandatory Renewable Energy Target (MRET), Green Power and the NSW Greenhouse Gas Abatement schemes. However, the fixed targets associated with MRET and Green Power result in no additional marginal cost and have been excluded from the LRMC calculation. Furthermore, the target associated with the NSW Greenhouse Gas Abatement scheme may be met by a number of non generation sources (such as demand side management and carbon sequestration in trees), therefore the source of credits and marginal cost attributable to this scheme is uncertain. These schemes are discussed in more detail in section 2.3.5 below.

Thirdly, the determination should emphasise the supply price of new generating capacity. As is discussed below, there are various methodological choices in relation to the supply side options used to satisfy a marginal increase in demand, and the reference here is for that option to be based solely on new generation capacity, as opposed to the inclusion of existing installed capacity (that may be able to be used at lower cost).

In the Terms of Reference for this study, IPART asked to consider whether it is appropriate for hedging costs to be included in the calculation of energy costs. In recent reviews of regulated electricity retail tariffs undertaken by the South Australian and Victorian regulators, the retail tariff determinations were based on the wholesale energy purchase costs that a retailer would be required to pay in the market to supply its retail customers. Thus, for these reviews hedging costs were explicitly included in the determination of energy costs. However, in the context of this study, the issues of competition, pricing and risk were not seen as determinants of the long run marginal costs of physically supplying an increase in demand. Contributing factors to prevailing discount rates are the market risks and level of competition specific to the market in which generators operate, as markets where generators are able to exert some market power will ultimately result in increased returns. Therefore aspects of risk, competition etc. were expected to be implicitly incorporated into the calculation of the LRMC via the discount rates used.

As a consequence, the issues of hedging costs and contracting strategies within a market context were not seen to be relevant to the calculation of LRMC. This approach was discussed and agreed with IPART.

2.2 LRMC Definition

Noting the guiding principles discussed above, the starting point was a review of the definition of LRMC of supply.

A classic definition of LRMC of generation is defined as the levelised cost of meeting an increase in demand over an extended period of time. It is calculated by determining the difference in the NPV of two optimal generation development (installation) programs over an extended period (say 30 years). Each of the optimal generation programs utilises existing generation plant, committed developments and the most efficient new generation entry. Sunk costs are not included in the analysis. The first generation installation is done under the current load forecast and the second under a load forecast that has a defined increment of load added. The LRMC is the change in NPV of costs divided by the change in NPV of load. This is a long run marginal cost basis as it determines the marginal increase in costs associated with meeting a marginal increase in demand with all factors of production variable.

An important aspect of this definition is that it determines the marginal cost of supply based on utilising existing and new generating capacity. Consequently, this definition can yield very different LRMC results depending on the current demand/supply balance and the amount of committed new generation. When excess capacity exists, additional energy can be supplied at close to short run marginal cost, as there is sufficient capacity to supply the additional demand. When there is no excess capacity the marginal cost of producing additional energy includes the full costs of capacity and operations.

Within the NSW context, there is excess capacity in the form of partially utilised coal units and support from interstate. This excess capacity would have the marginal costs of supplying an increase in demand relatively low compared to the full costs of generation for quite a few years.

However, this definition is not consistent with the guiding principles provided, or with the issues paper released in October 2003 “Review of Gas and Electricity

Regulated Retail Tariffs Issue Paper (October 2003)". This paper provides the context in which the assessment is being made and in particular how it relates to the issues of protection and competition:

"If default tariffs are set too low, they may hamper the development of competition because new retailers will find it difficult to offer a more attractive service to customers. If the tariffs are set too high, they may encourage customers to switch retailers. However, if default tariffs are set at cost reflective levels, they should operate in a 'neutral manner' and strengthen the incentives on retailers to operate efficiently."

This leads to a modified definition to that outlined above, where each generation development program is based solely on meeting the load profile with the lowest combination of new entry generation. This definition is somewhat akin to an optimised deprival value, but marginal since it is the cost of providing an increment of additional demand that is being determined. This approach clearly satisfied all the methodological and contextual criteria.

In using this approach, multi-year analysis only becomes applicable in the event that the load patterns of the total NSW load and of the individual retailer franchise loads change.

2.3 Specific Issues

Given the basic definition of the LRMC of electricity in NSW, there are a number of issues that require clear specification. These issues relate to:

- The generation plant that is assumed available to satisfy NSW demand;
- The optimal plant combination;
- The determination of the marginal cost profile;
- Revenue neutrality (ie. no producer surplus);
- The consistency of total NSW marginal costs to the marginal costs determined for each NSW retailer (ie. allocation of costs to individual retailers).

2.3.1 Generation Plant and Optimal Plant Combination

Fuel availability in NSW determines the assumed availability of generation plant.

This is considered reasonable, as a review of fuel cost differences between States would show that when transmission costs are considered, the lowest cost options to supply NSW load would be generation plant developed within NSW.

The generator technologies assumed available are:

- Black coal thermal power stations
- Combined cycle gas turbines (CCGT), and
- Open cycle gas turbines (OCGT)

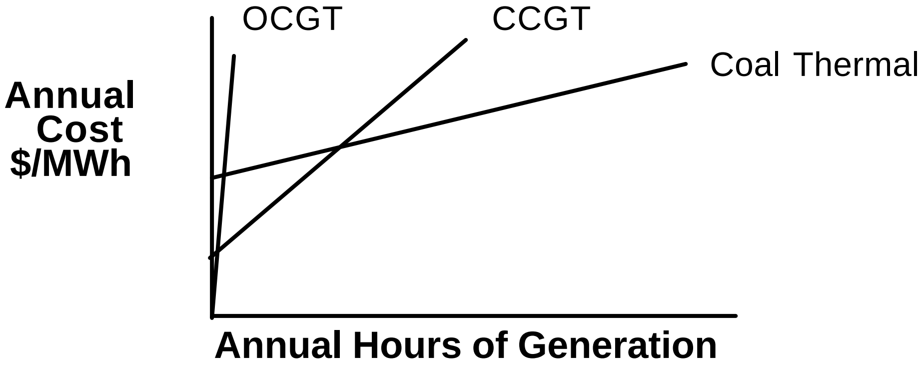
It is assumed that Snowy hydro resources would not be further developed due to the environmental restrictions and costs.

Using this generating plant, an optimal plant portfolio can be constructed using a linear programming model. Such an approach ensures that given the NSW load profile, the combination of plant chosen would minimise the total costs (capacity plus operating costs) of meeting the demand. In order to determine long run marginal costs the linear program assumes the capacity of all of the classes of plant (black coal, OCGT and CCGT) is variable. With this assumption, the linear programming approach can automatically generate the shadow prices of meeting additional load for each hour of the modelled period or each segment in a load duration curve. These shadow prices are the marginal costs of supplying an additional unit of load at that time or at that point in the load duration curve. The issues of marginal cost are discussed in the next section.

2.3.2 Optimal Plant Mix

For a generator to be economic, the average price for energy produced needs to match its average cost of producing this energy (both capital and fuel). In the choice of a generation portfolio there is a trade-off between capital costs and operating costs. The lower capital cost plant tends to have higher fuel costs and hence higher operating costs. For each of the classes of plant we have identified, black coal, CCGT and OCGT there is an operating cycle for which they are the least cost source of supply. This is illustrated in Exhibit 2-1 below.

Exhibit 2-1 Theoretical Market Plant Mix and Spot Prices



The top graph in the figure shows the total cost of production for three generator types as a function of their hours of operation. For each of the cost curves shown, the intercept with the y-axis represents the capital cost and the slope is the variable cost. The roles and features of the three generator types shown in the graph are as follows:

- The coal generator is a base load plant that runs all the time. It has a cost structure of high capital costs and low fuel costs.

- The CCGT is an intermediate generator. Compared to the base load generator it has lower capital costs but higher fuel costs.
- The OCGT is a peaking generator that is optimum for low capacity factor usage.

An optimum mix of generators is one that has the lowest cost. From the graph, this is established by having the various generator types operating for that percentage of time when its cost curve is the lowest on the graph.

2.3.3 Principles of Marginal Cost

There are a number of issues associated with the determination of the long run marginal cost as an hourly profile over the modelled period. These issues are best illustrated by example.

Example

The following example presents a very simplified power system consisting of three generator technologies used to optimally satisfy a load profile. Assuming that the capital and variable costs for the three generator types are as specified in Exhibit 2-2, the economics of new entry generation are such that:

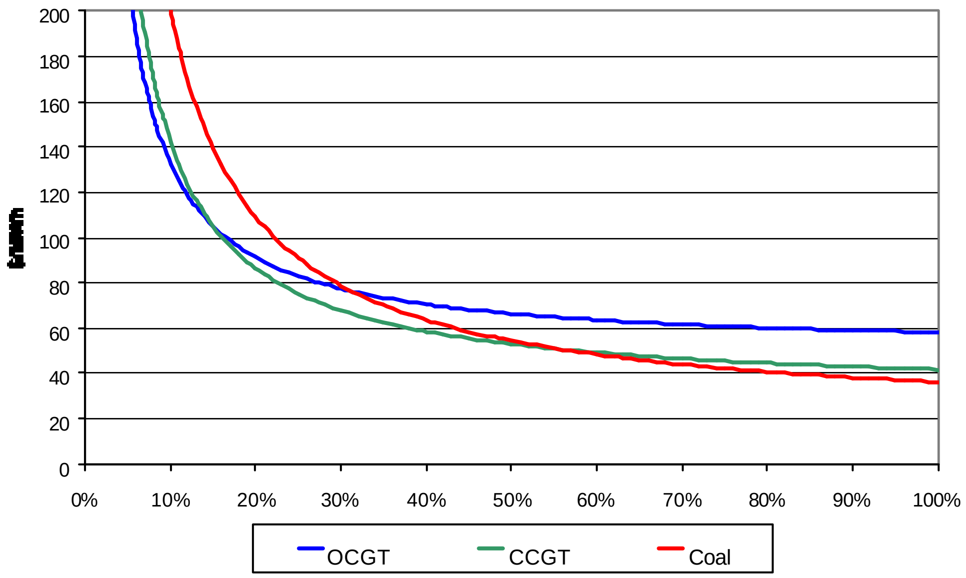
- OCGT has the lowest average cost at operating capacity factors of less than 14%;
- CCGT the lowest average cost for operating capacity factors between 14% and 55%;
- Coal plant the lowest average cost at operating capacity factors greater than 55%.

Exhibit 2-2 New Entry Capital and Variable Costs (Example only)

	Gas OCGT	Gas CCGT	Coal Thermal
Capital Cost ($/kW)	700	925	1400
Variable Cost ($/MWh)	50	30	18

The optimal generation mix outlined above is illustrated in Exhibit 2-3 below. Reading off the graph we have the cost of OCGT at 14% capacity factor at about $109/MWh, CCGT at 55% capacity factor at $51/MWh and coal at 100% capacity factor at $42/MWh. These are the average energy costs that each plant requires to cover its capital and operating costs when operating at the respective capacity factors.

Exhibit 2-3 Average Generation Costs as a function of Capacity Factor (Example only)

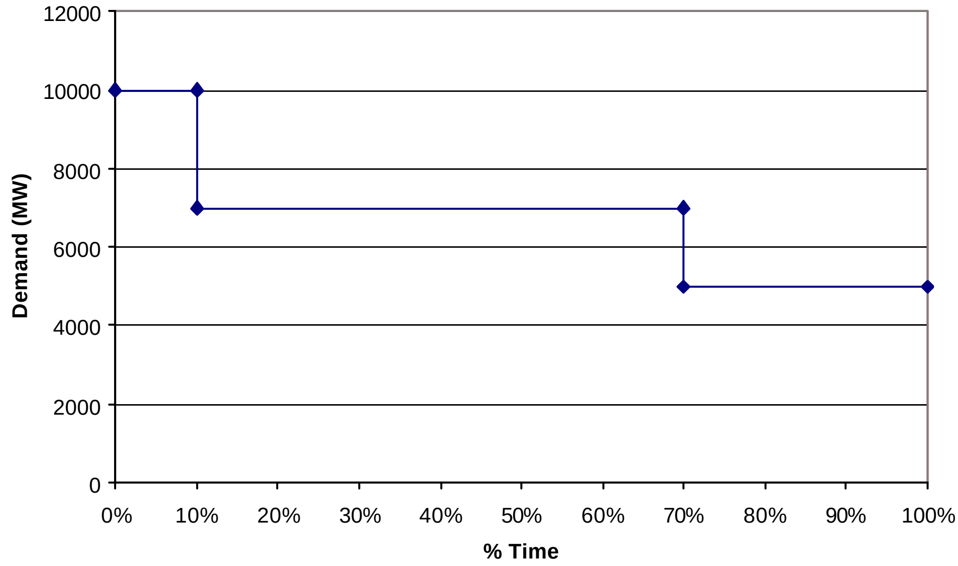


Now assume that the load to be supplied has the following profile:

- 10,000 MW for 10% of the time;
- 7,000 MW for 60% of the time; and
- 5,000 MW for 30% of the time.

The above load profile is illustrated in the form of a load duration curve in Exhibit 2-4 below.

Exhibit 2-4 Load Duration Curve (Example)



The lowest combination of generation would then be:

- 5,000 MW of coal plant (operating at 100% capacity factor)
- 2,000 MW of CCGT plant (operating at 55% capacity factor)
- 3,000 MW of OCGT plant (operating at 14% capacity factor)

The combination of generation and costs required to meet the specified load are summarised in the Exhibit 2-5 below. This table shows the load segments, the optimum plant and the total costs required by each plant (to be economic), and finally the revenue paid by the load based on the marginal generation costs shown for each load segment.

Exhibit 2-5 Generator Costs and Incorrect Cost Over-recovery Approach

Average Load MW	Time segment % of Time	Generator Type	Average Generation Cost Required $/MWh	Generator Capacity MW	Annual Cost Required by Generators $M	Annual Cost Recovered (Based on Marginal Generation Costs) $M
10000	14%	OCGT	109	3000	401	1337
7000	55%	CCGT	51	2000	491	1282
5000	100%	Coal	42	5000	1840	828
				Total	**2732**	**3447**

Of particular note is that there is over-recovery of generation costs (producer surplus) when the load pays costs based on marginal generation costs in each time segment, when the marginal cost calculation is based only on the average cost that each generator requires to satisfy its total costs. The reason for the over-recovery is that the marginal cost calculation has not accounted for the contribution to capital cost that has occurred when each generator type is intramarginal.

In the above example, the price of $109/MWh is that required to cover the fixed and variable costs of the OCGT plant that operates for 14% of the time. This price is also seen by both the CCGT plant and coal plant for 14% of their operating hours, providing a significant contribution to capital. The marginal cost of each technology when the unit is marginal on the system should account for the capital contribution made when the unit was intramarginal.

In the example above, the revenues obtained for each of the three generators when intramarginal and when marginal are shown in the table below. The following are noted in relation to the marginal cost (or shadow cost) for each time segment:

- As the OCGT plant is never intramarginal (being the highest in the merit order), the marginal cost includes full capital cost recovery plus operating costs;

- The CCGT plant obtains about 50% capital recovery when intramarginal to the OCGT plant. The marginal cost of $31.2/MWh when the CCGT plant is marginal reflects the costs needed during this period accounting for the intramarginal revenue received;
- Likewise, the coal plant obtains about 67% capital recovery when intramarginal to both the OCGT and CCGT plants. The marginal cost of $31/MWh when the coal plant is marginal reflects the costs needed during this period accounting for the intramarginal revenue received.

Exhibit 2-6 Generator Costs and Correct Cost Recovery Approach

Plant Type	Intramarginal Revenue $M	Revenue when Marginal $M	Marginal Cost $/MWh	Load MW	% of Time	Total Cost $M
OCGT	0	401	109	10000	14%	1337
CCGT	267	224	31	7000	55%	784
Coal	1229	611	31	5000	100%	611
						2732

Although not part of the above example, in the case where there are multiple units of the same technology operating at different capacity factors (due to merit order differences), say two OCGT generators, full capital recovery occurs for both units during the hours the highest merit order unit operates. The marginal cost during this period incorporates both capital and operating costs. For the period of time the unit with the higher capacity factor operates and the other is not needed, the marginal cost is simply the variable cost of CCGT generation. The marginal cost does not reflect any capital costs as capital costs have already been recovered in the higher demand period.

2.3.4 Reserve Plant

Generating reserves are required to cover the planned and forced outages of generator units. In NSW, NEMMCO currently requires that there is sufficient access to the installed capacity to provide 660 MW of reserve above the 10% Probability of Exceedence[1] (POE) Maximum Demand. This amount remains fixed as load grows into the future.

In terms of cost allocation, the full costs of the 660 MW of reserve would be allocated to the time of maximum demand, as this is the time it is needed. Given this allocation, there are no reserve costs required at other times.

However, on a marginal cost basis, given that the required reserve level remains fixed at 660 MW as load increases, reserve costs cancel out in the calculation of marginal cost.

[1] The 10% POE maximum demand is the level of maximum demand that would be expected once every 10 years.

2.3.5 Green Energy Schemes

The green energy schemes do place increased costs on retailers. As mentioned previously, the MRET and Green Power schemes have fixed targets associated with them and therefore on a marginal cost basis the costs associated with green energy schemes to the aggregate NSW energy demand cancel out in the calculation of marginal cost. Having said this, the MRET obligation for individual retailers (as determined the ORER) is represented as a percentage (RPP) of their total annual energy usage and it could be argued that a marginal increase in energy for a retailer would have some additional MRET costs attributable to it. Increased energy usage by a retailer may be due to either growth in energy usage over the whole market (ie. retailers maintain market share) or an increase in market share. In the case of increased retailer usage due to market growth, the RPP's determined by the ORER would be adjusted down to meet the fixed overall system target and there would be no increase in the MRET cost attributable to individual retailers. However, an increased energy usage by a retailer (due to an increased market share for instance) would result in a higher RPP determination by ORER for the retailer exhibiting growth and a lower RPP determination by the ORER for the retailer exhibiting contraction. As a determination of future market share for individual retailers is outside the scope of this study we have not considered increased MRET costs attributable to a marginal load increase due to increased market share.

Under the NSW Greenhouse Gas Abatement scheme, the total emissions from electricity generation is capped by the Electricity Sector Benchmark (measured in tonnes of CO2-e). On the surface it appears that this scheme may affect the type of generation that may come on stream in the future (to meet increased demand) as additional high CO2-e generation such as coal plant might violate the benchmark. However, the benchmark may be met by a number of non-generation sources (such as demand side management and carbon sequestration in trees) and therefore the source of credits and marginal cost attributable to this scheme is uncertain.

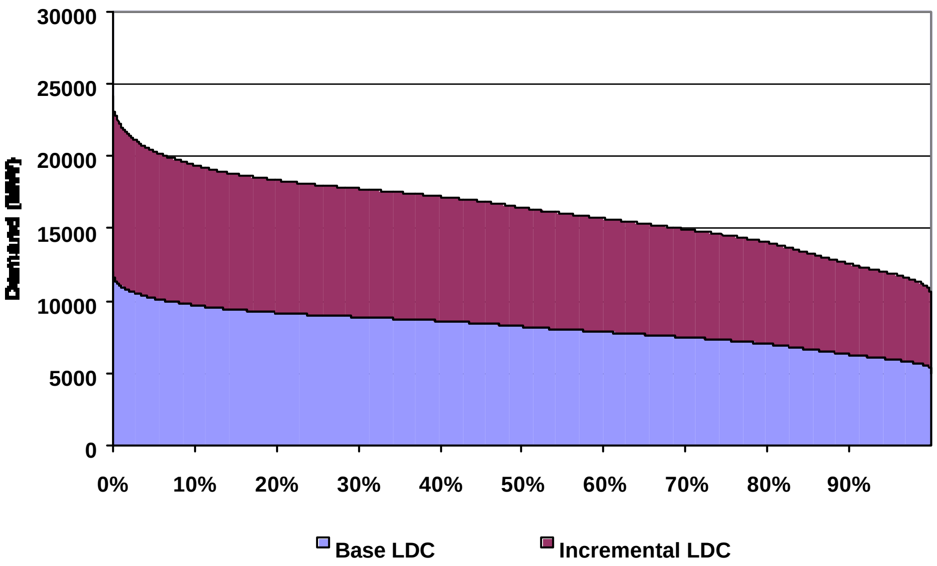
For the reasons outlined above we have excluded green energy schemes from the LRMC presented here.

2.3.6 Allocation of Marginal Costs to Defined Time Sectors and Retail Load Components

The shadow prices produced are the marginal cost of supplying an increment of load during that particular hour.

To determine the marginal cost associated with supplying an increment of load across a particular time period, say franchise load over a particular year or other time segment (eg. peak period), the underlying load shape must be taken into account. In order to do this, a constant factor needs to be applied to the load profile being considered to create the incremental load. **Error! Reference source not found.** below shows a base and incremental load where the incremental load equals the base load.

Exhibit 2-7 Base and Incremental Load Duration Curves



2.4 Linear Program Approach

As previously mentioned, the basis of the methodology for determining the LRMC of electricity supply in NSW was a linear programming (LP) approach. The advantages of this approach are as follows:

- Given the load to be met, as well as the cost characteristics of the various generator technologies and other costs such as green energy schemes, an optimal plant program is developed;
- Shadow prices are automatically produced each hour (or selected time division) that represent the marginal cost of supply in that hour (or selected time division or load duration segment). These prices have the property of providing no producer surplus or deficit. The prices effectively account for the intramarginal effects.

The following section presents a technical discussion of this approach and the properties inherent in the formulation used. This section is included for interested readers and also to provide increased transparency on the LP approach used.

2.4.1 LP Approach and Revenue Neutrality

The linear programming approach breaks up the load duration curve into a number of segments. Each of these segments is approximated by an average load in the segment and the proportion of time that the loads are in the segment. For instance, the load duration curve could be broken into 100 equally probable segments with the average demand being determined for each segment. For each of these segments the load will be met in the most cost effective way given the available capacities of the various types of plant. This boils down to minimizing the short run marginal costs (fuel costs) of meeting each of the segment loads. As well as minimizing the operating costs the linear program minimizes the capital costs assuming that the investment in plant is infinitely divisible.

The formulation of the linear program is roughly as follows.

Minimise Annual fuel costs + annualized capital costs

Subject to:

Total supply = demand for each segment in the load duration curve

Plant capacity – plant dispatch >= 0

In an algebraic form the problem looks like:

Minimise $$\sum_{i \in segment,\, j \in plant} c_j x_{ij} + \sum_{j \in plant} C_j X_j$$

where c_j is the short run marginal cost of plant j

x_{ij} is the dispatch of plant j in segment i

C_j is the annualised costs of plant j

X_j is the capacity determined for plant type j

Subject to:

$$\sum_{j \in plant} x_{ij} = b_i$$ = demand for all segments i

$$X_j - x_{ij} \geq 0$$ for all plant types j and segments i

The marginal costs of meeting the demands in each segment can be determined from the shadow prices of the constraints. The shadow prices are the optimised variables from the dual problem. They reflect the marginal costs in terms of both fuel and plant capacity in meeting the segment demands.

Now one property of a linear program is, that at its optimum the objective function of the primal problem equals the objective function of the dual at its optimum. In this case the objective function of the primal problem is annual fuel costs + annualized capital costs. For the dual, the objective function is the shadow prices of the constraints x the constraint limits. For the dual problem the capacity constraints have zero limits (zero right hand sides) and hence do not contribute to the objective function. Thus the objective function for the dual is just

$$objective\ function = \sum_{i \in segment} b_i y_i$$

This is just the segment marginal prices multiplied by the demands. Thus the total revenues match the total costs. There is no surplus. Further, the linear programming approach ensures that each type of plant at least covers its costs. Consequently, since there is no surplus and each type of plant at least covers its costs, although each plant may make an accounting profit no producer surplus occurs in the modelling.

2.4.2 Overview of Approach

Having described the LP approach in some detail, this section presents an overview of the total process undertaken in this study:

1. The new entry generation cost characteristics were developed from publicly available information and IES data sources;
2. The profiles of total NSW and individual retailer franchise loads were obtained and reviewed;
3. A linear program model was developed that incorporated all the relevant costs associated with supplying demand;
4. The linear programming model was used to produce an optimal generation plant program in NSW and the shadow prices, each hour of the modelled year;
5. The shadow prices were applied to the individual retailer franchise load shapes to obtain the annual marginal costs for each retailer's franchise load;
6. The marginal costs for the hours that correspond to peak, shoulder and offpeak periods for each retailer were selected to obtain time sector marginal costs.

The steps outlined above are explained in more detail in section 3.

3 New Entry Costs

This section provides a detailed description of the new entry costs used in this study. As previously mentioned, the technologies assumed for this study are:

- Black coal thermal power stations,
- Combined cycle gas turbines (CCGT), and
- Open cycle gas turbines (OCGT).

New entry costs can be categorised into fixed capital costs and variable operating costs (fuel and operations and maintenance). The fixed and variable cost assumptions used to calculate the new entry costs are presented below.

3.1.1 Capital Costs

The capital cost of new generation is influenced by many factors that can be grouped into the three cost classes below.

1. Plant Supply and Installation – these include the costs associated with the following:
    - Gas turbine genset;
    - Heat recovery boiler;
    - Fuel handling, water treatment and makeup system;
    - Steam turbine genset;
    - Condenser;
    - Cooling tower;
    - Installation of main mechanical plant;
    - Miscellaneous auxillaries;
    - Mechanical and electrical hardware;
    - Controls and instrumentation;
    - Transformers, interconnect and switchgear;
    - Site preparation and buildings;
    - Engineering;
    - Contractor's contingency and margin;
    - Fixed operations and maintenance.
2. Indirect costs such as owner's engineering, owner's contingency, spares, start-ups and insurance;
3. Financial costs – these include things such as due diligence, legal expenses, financial instruments etc;

Based on information from a number of sources, IES has determined high, medium, and low capital costs as shown in Exhibit 3-1 for each of the thermal, OCGT, and OCGT plant types.

Exhibit 3-1 Capital Costs $/kW

	Low	Medium	High
Thermal	1380	1610	1840
CCGT	884	962	1040
OCGT	663	714	765

3.1.2 Variable Costs

The variable costs associated with running a power station need to be taken into account when assessing the new entry cost. Variable costs include:

- Plant operations and maintenance;
- Fuel; and
- Fuel transport.

Based on information from a number of sources, IES has determined high, medium, and low variable costs broken down into the three classes described above. Exhibit 3-2 shows the variable cost breakdown for each of the thermal, OCGT, and OCGT plant types.

Exhibit 3-2 Variable Costs $/MWh

Plant	Cost	Low	Medium	High
Thermal	Operations and Maintenance	4.5	5	5.5
	Fuel*	9	12	15
	Total	***14.5***	***18.0***	***21.5***
CCGT	Operations and Maintenance	3.5	4	4.5
	Fuel*	21.5	25	28.5
	Total	***25.5***	***30.6***	***35.5***
OCGT	Operations and Maintenance	2.5	3	3.5
	Fuel*	41.5	45	48.5
	Total	***44.5***	***49.8***	***55.5***

*Includes transport. Efficiency rates assumed as per Exhibit 3-4.

3.1.3 Financial Assumptions

The financial structure of a new generation asset also has a bearing on its new entry cost. Factors underpinning the financial structure include:

- Debt and equity (gearing) structure;
- Tax;
- Dividend Imputation; and
- Inflation.

For the purpose of this study we have not considered the impact of each of these factors individually but have nominated a high, medium, and low real rate of return. These rates are shown in Exhibit 3-3 below.

Exhibit 3-3 Financial Assumptions

	Low	Medium	High
Real discount rate	7%	9.5%	11%

3.1.4 Other Assumptions

In order to calculate the new entry cost a number of other assumptions need to be specified. These are:

- Asset life (years);
- Fixed operations cost (expressed as a percentage of the annual fixed cost for capital); and
- Thermal efficiency (GJ/MWh).

For this study the above factors are assumed to be constant (as shown in Exhibit 3-4) for each of the high, medium, and low scenarios.

Exhibit 3-4 Other Assumptions

	Thermal	CCGT	OCGT
Asset Life	35 years	30 years	30 years
Fixed Operations Cost	15%	4%	2%
Thermal Efficiency	36%	57%	37%

3.2 New Entry Expressed as an Energy Cost

Using the above assumptions low, medium, and high new entry costs have been determined for coal, CCGT, and OCGT technologies. Exhibit 3-5 shows these new entry costs expressed in terms of $/MWh based on 100% capacity factor.

Exhibit 3-5 New Entry Cost $/MWh

Plant Technology	Low	Medium	High
Thermal Coal	28.02	36.22	45.22
CCGT	34.46	41.77	49.16
OCGT	21.22	58.99	65.54

It is unlikely that any plant will run at 100% capacity factor. In reality we would expect new OCGT to operate at around 2% to 5% capacity factor, CCGT to operate at between 50% and 80% capacity factor and coal to operate at between 80% to 95% capacity factor. The low, medium, and high new entry cost scenarios derived from the set of assumptions presented previously are shown as a function of capacity factor in Exhibit 3-6, Exhibit 3-7 and Exhibit 3-8 below.

Exhibit 3-6 Low New Entry Cost Scenario as a Function of Capacity Factor

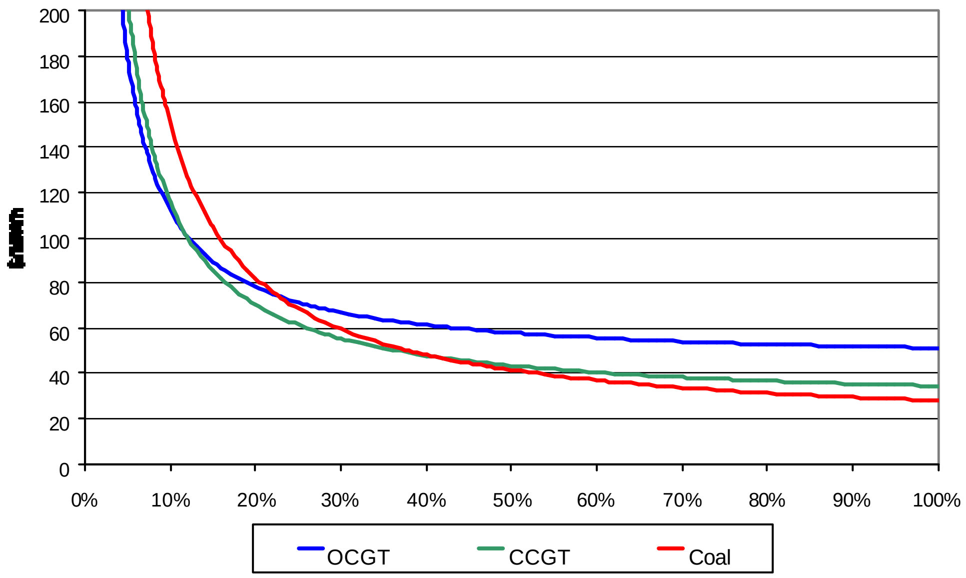


Exhibit 3-7 Medium New Entry Cost Scenario as a Function of Capacity Factor

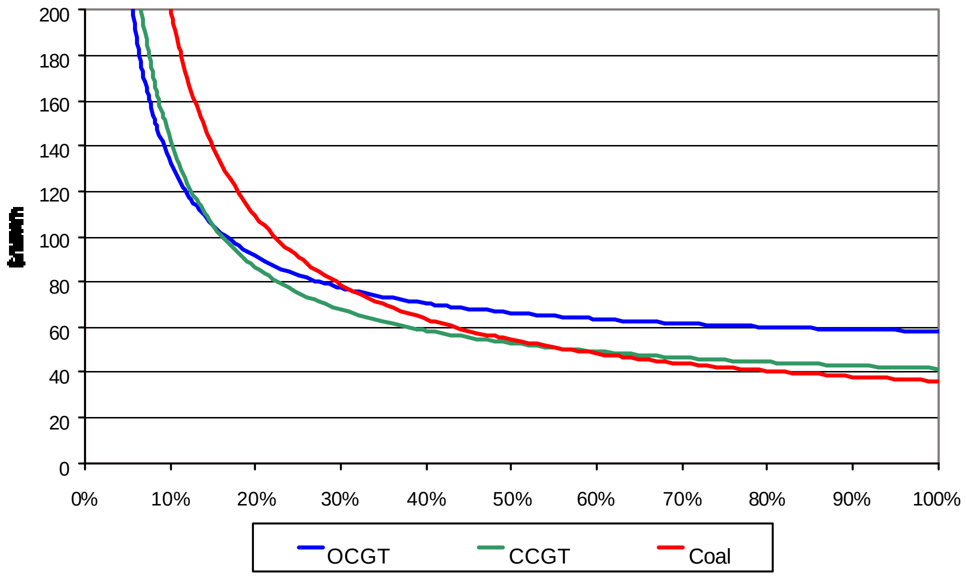
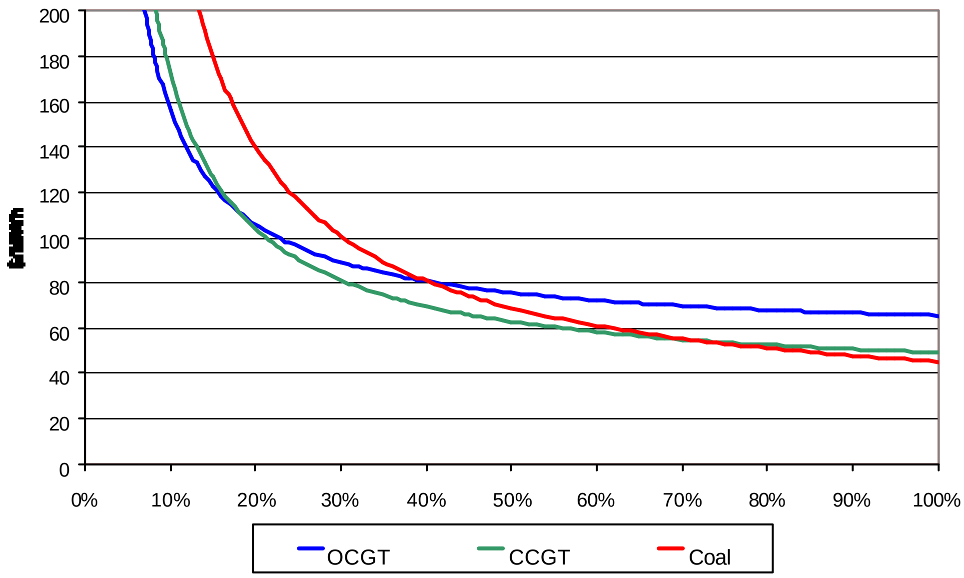


Exhibit 3-8 High New Entry Cost Scenario as a Function of Capacity Factor



In section 2.3.2 it was noted that an optimum mix of generators is one that has the lowest cost and that this mix is established by having a particular generator type operating for that percentage of time when its cost curve is the lowest. Using the above cost curves, the optimal mix of generators and their associated costs has been determined for the low, medium, and high new entry cost assumptions presented previously. These are shown in Exhibit 3-9 below.

Exhibit 3-9 Optimal Capacity Factors and Associated New Entry Cost

		Thermal Coal	CCGT	OCGT
Low	**CF**	100%	41%	11%
	New Entry Cost	$28.0/MWh	$47.4/MWh	$105.6/MWh
Medium	**CF**	100%	55%	14%
	New Entry Cost	$36.2/MWh	$50.9/MWh	$109.0/MWh
High	**CF**	100%	71%	18%
	New Entry Cost	$45.2/MWh	$54.7/MWh	$111.3/MWh

4 Modelling Approach

This section provides a detailed description of the approach used and the inputs required to determine a range of prices for the LRMC for electricity generation in NSW.

The 2002 NSW load is used as an example to describe the approach, however the approach taken is independent of the load source and may be applied to any region or customer segment.

4.1 New Entry Costs

The fundamental input into the linear program used for this study is the new entry costs associated with the assumed generation types. Please refer to Section 3 for a detailed description of the new entry costs associated with the assumed gas (OCGT and CCGT) and coal generator types. The assessed new entry capital costs are shown in Exhibit 4-1 and the variable costs associated with new generation (comprising fuel, transport and operation costs) are shown in Exhibit 4-2.

Exhibit 4-1 Capital Costs $/kW

Plant Technology	Low	Mid Range	High
OCGT	586	663	739
CCGT	728	832	936
Coal	1150	1380	1610

Exhibit 4-2 Variable Costs $/MWh

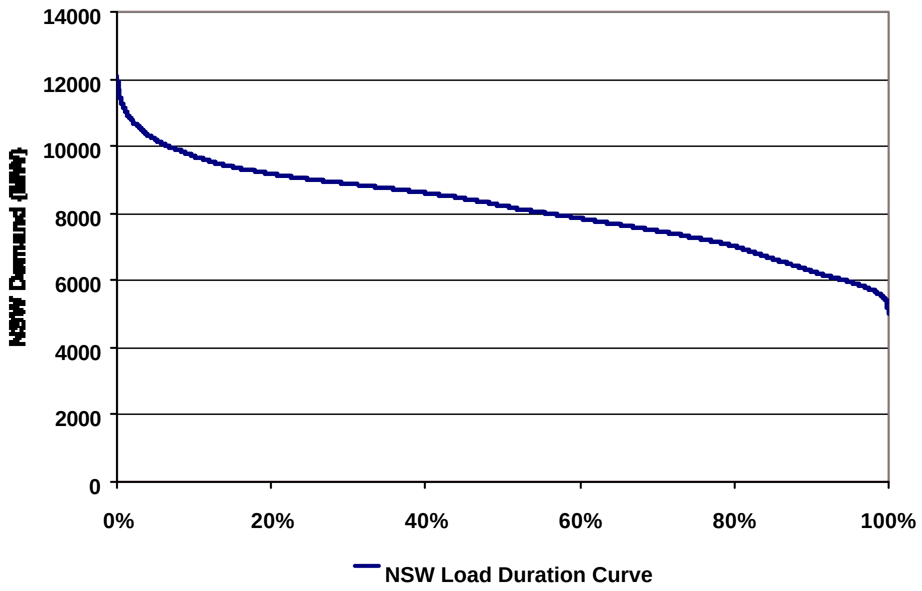
Plant Technology	Low	Mid Range	High
OCGT	44	48	52
CCGT	25	28.5	33
Coal	12.5	15	19.5

Given the above cost assumptions the new entry cost has been calculated for each of the generation types as a function of capacity factor. The low, medium and high new entry cost scenarios derived from the capital costs, variable costs and other assumptions presented in Section 3 are shown as a function of capacity factor in Exhibit 3-6, Exhibit 3-7 and Exhibit 3-8.

4.2 Load Profiles

The next input required by the model is the load for which the LRMC is being calculated. The load is implemented in the form of a load duration curve (LDC). Given a half hourly load trace over a period, a LDC can be created by ordering the half hourly demands from highest to lowest and plotting against percentage of time. Exhibit 4-3 shows the LDC for 2002 NSW demand.

Exhibit 4-3 Load Duration Curve (2002 NSW)



The LRMC needs to be assessed for an increment of load. One approach to developing the incremental load would be to add a constant amount to the base LDC, however this approach does not take into account the shape of the base LDC. To account for the shape of the base LDC, the incremental load is developed by applying a constant factor to the base LDC. When the factor is equal to one, the incremental LDC is identical to the base LDC as shown in Exhibit 4-4 below.

A half hourly LDC comprises 17,520 data points. This amount of data is prohibitively large for the linear program developed for this project; therefore the LDC has been modified to contain 438 data points. The 438 points have been determined by splitting the half hourly LDC into 438 equal segments and averaging the 40 points contained in each segment. The average and half hourly LDC's are shown in Exhibit 4-5 for small section (the top 1.6%) of a sample LDC.

It is important that the date and time associated with each of the 40 points in each load segment is known for the purpose of determining the LRMC for peak, shoulder, and off-peak time periods. This issue is address in detail in section 4.5 below.

Exhibit 4-4 Base and Incremental LDCs

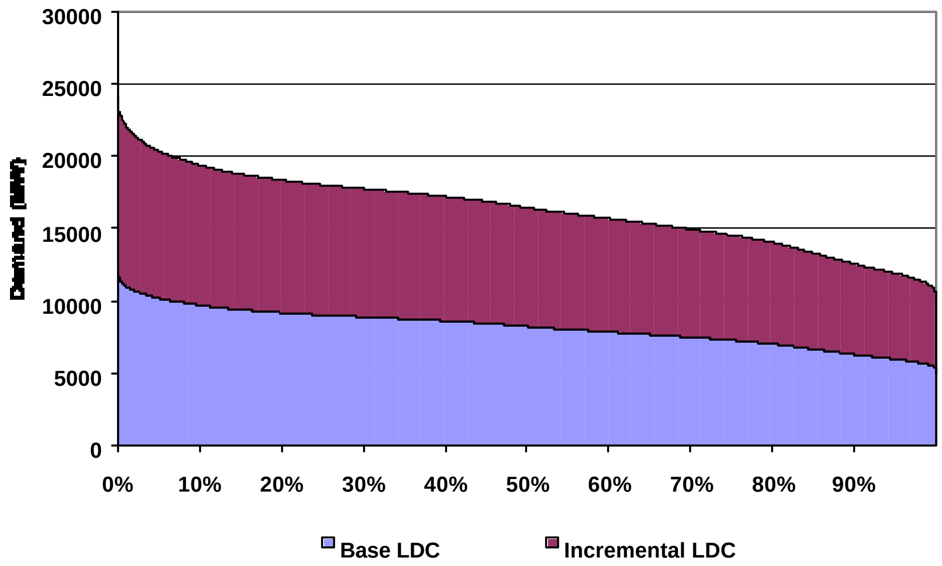
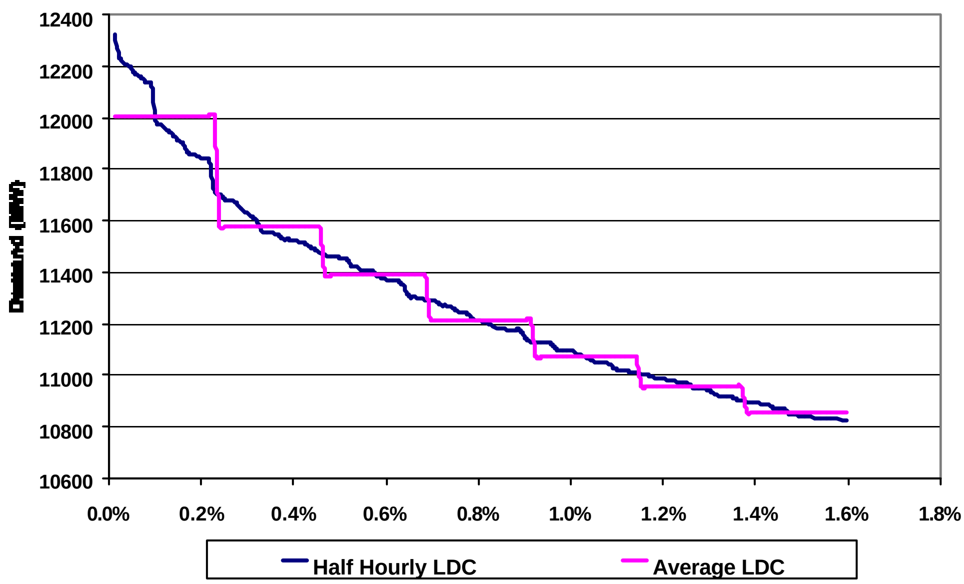


Exhibit 4-5 Half Hourly and Average LDCs



4.3 Population of Linear Program

The linear program model can then be populated with the new entry cost and average load duration curve data. Exhibit 4-6 shows the linear program model. The inputs are highlighted in yellow and comprise:

- Discount rate;
- Plant life (years) for each of coal, CCGT and OCGT;
- Capital cost ($/kW) for each of coal, CCGT and OCGT;

- Operating cost ($/MWh) for each of coal, CCGT and OCGT;
- The average demand for each of the 438 segments in the average LDC.

Exhibit 4-6 Linear Program Data

Microsoft Excel - LRMC LP costing model v7.xls

discount rate (real) 12%

	Life (years)	Capacity cost ($/kw)	Operating cost ($/MWh)
Coal plant	35	1,400	16
Combined cycle GT	30	760	29
Open cylce GT	30	660	48

Capital cost per MW ($k)	Annual Capacity Cost ($k/MW/a)	Capacity Cost per Segment ($k)	Capacity (MW)	Capacity Cost ($k)
1,400	171	8.562	7,645	65,439
760	93	4.656	2,353	10,953
660	81	4.036	2,012	8,116

Total Cost ($k)	Average Cost ($/MWh)
147,568	40.87

Segment	Demand (MW)	Supply (MW) Coal	CC	OC	Total	Fuel cost ($k) Coal	CC	OC	Total	Shadow Price ($/MWh)	Segment Cost ($k)
1	5440	5440	0	0	5440	87	0	0	87	16.00	87
2	5530	5530	0	0	5530	88	0	0	88	16.00	88
3	5588	5588	0	0	5588	89	0	0	89	16.00	89
4	5641	5641	0	0	5641	90	0	0	90	16.00	90
5	5691	5691	0	0	5691	91	0	0	91	16.00	91
6	5734	5734	0	0	5734	92	0	0	92	16.00	92
7	5768	5768	0	0	5768	92	0	0	92	16.00	92
8	5798	5798	0	0	5798	93	0	0	93	16.00	93
9	5820	5820	0	0	5820	93	0	0	93	16.00	93
10	5840	5840	0	0	5840	93	0	0	93	16.00	93
429	10667	7645	2353	669	10667	122	68	32	223	48.00	512
430	10737	7645	2353	740	10737	122	68	36	226	48.00	515
431	10795	7645	2353	797	10795	122	68	38	229	48.00	518
432	10854	7645	2353	857	10854	122	68	41	232	48.00	521
433	10966	7645	2353	968	10966	122	68	46	237	48.00	526
434	11068	7645	2353	1071	11068	122	68	51	242	48.00	531
435	11215	7645	2353	1217	11215	122	68	58	249	48.00	538
436	11388	7645	2353	1390	11388	122	68	67	257	48.00	547
437	11578	7645	2353	1578	11578	122	68	76	266	48.00	558
438	12009	7645	2353	2012	12009	122	68	97	287	4082.67	49031

LP / 2003 / 2002 / Sensitivity Report 1 / Sensitivity Report 2 / LDC Data / LDC / Avg LDC

Given the new entry cost details, an optimal plant program is constructed using the model. The data highlighted in blue in the model are fields calculated using standard simple Excel arithmetical functions. The calculated fields are:

- Annualised Capital Cost ($k/kW/a) – this is the annualised capital cost (in $1,000's) per kW installed amortised over the plant life assuming the given discount rate. This is given for each plant type;
- Segment Capital Cost ($k/kW/segment period) – this is the capital cost (in $1,000s) per kW installed per segment period (assuming 438 segments the segment period = 8760/438 = 20 hours) amortised over the plant life assuming the given discount rate. This is given for each plant type;
- Capacity Cost ($k) – this is the cost to provide the capacity for the given generator types and is calculated by multiplying the assumed capacity cost by the capacity determined by the model;
- Total Supply (MW) – this is the total supply capacity as determined by the model and equals the sum of the coal, CCGT and OCGT capacities. These capacities have been determined by the model for each load segment and have been optimised to ensure that the cost is minimised;

- Fuel Costs ($k) – the fuel costs for coal, OCGT and CCGT.

4.4 Execution of Linear Program to Determine Shadow Prices

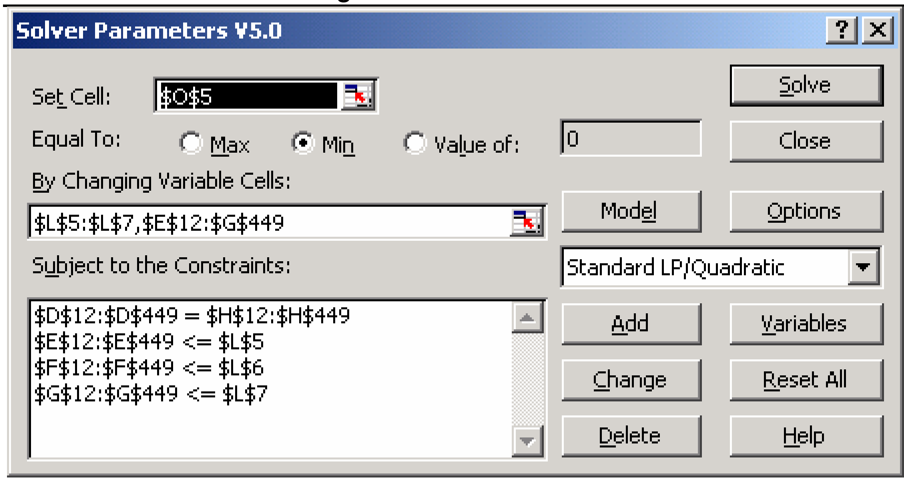
Once the linear program has been populated, it is executed to determine the shadow prices for each load segment.

For each of the 438 segments of the average LDC the model ensures that a combination of plant type generation is chosen such that the total costs are minimised (this is the objective function for this particular linear program). The optimal plant combination for each segment and the overall plant combination are highlighted in pink in the model (see Exhibit 4-6). The linear program generates the shadow prices for each load segment subject to number of constraints. The shadow prices are highlighted in orange in the model. Exhibit 4-7 shows the linear program solver parameters. These solve parameters specify the following:

- The 'Set Cell' and 'Equal To' parameters are set so that the objective is to minimise the total cost (cell Q5 in the spreadsheet);
- The above objective is to be met by changing the coal, CCGT and OCGT plant capacities subject to the following constraints:

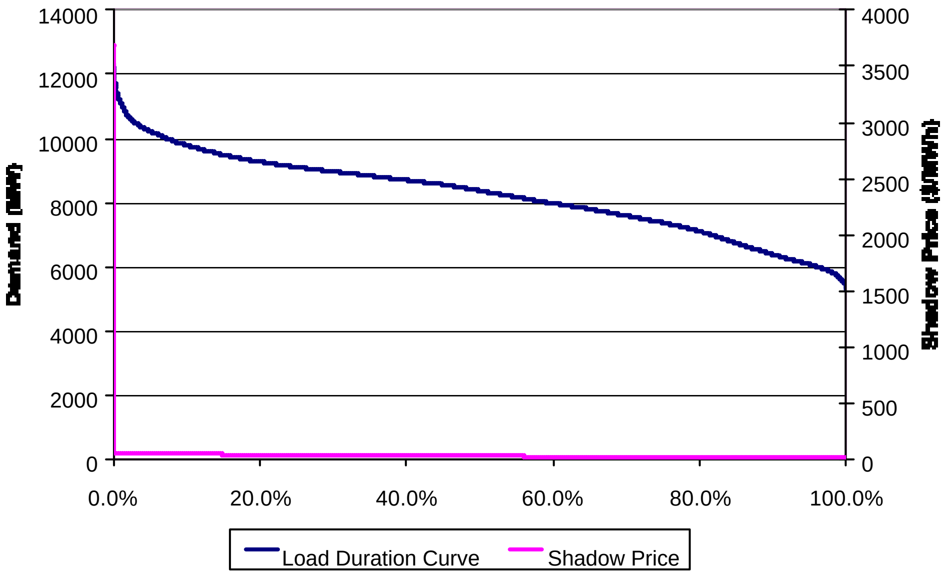
1. For each segment of the average LDC the total supply (generation) must equal the demand;
2. For each segment of the average LDC the coal plant supply must be less than or equal to total coal plant capacity;
3. For each segment of the average LDC the CCGT plant supply must be less than or equal to total CCGT plant capacity; and
4. For each segment of the average LDC the OCGT plant supply must be less than or equal to total OCGT plant capacity.

Exhibit 4-7 Linear Program Solver Parameters



As mentioned, the most important output from the model is the shadow price for each load segment. These shadow prices are the marginal costs of supplying an additional unit of load at that time. Exhibit 4-8 shows an example of the shadow prices determined for a section of an average LDC.

Exhibit 4-8 Example of Shadow Prices



4.5 Determine Annual Average Marginal Cost

At this point it is useful to recap the data that has been established in the previous sections:

- Load duration curve – established using raw load data;
- Average load duration curve – established by segmenting the 'raw' LDC and averaging the loads contained in each segment;
- Optimal (lowest cost) plant generation mix - established for each segment of the average LDC;
- Shadow prices – the marginal costs of supplying an additional unit of load and has been established for each segment of the average LDC

Given the above data, the annual average marginal cost is determined using the following formula:

$$Average\,Maginal\ Cost = Total\ Cost \div Total\ Load = \sum_{i \in segment} L_i SP_i \div \sum_{i \in segment} L_i$$

where L_i is average demand for load segment i

SP_i is shadow price for load segment i

4.6 Determine Annual Average Marginal Cost for Time Sectors

In section 4.2 the importance of recording the date and time for each of the points in each of the 438 load segments was mentioned for purpose of determining the LRMC for peak, shoulder, and offpeak time periods. An example is presented below to illustrate how the raw load data is manipulated and how the linear program model outputs are used to determine the LRMC for specified time classes:

The example uses the load data for one day of the 2003 NSW load data.

1. Develop the LDC keeping the date and time information;
2. Segment the LDC and determine the average demand for each segment.

Exhibit 4-9 shows the following data:

- The raw load data used for this example;
- The resulting LDC; and
- The segmented LDC data.

Exhibit 4-9 Load Duration Curve and Segments

Raw Load Data		Load Duration Curve			
Datetime	Demand (MW)	Datetime	Demand (MW)	Load Segment	Segment Average (MW)
28/12/2003 1:00	7510.7	28/12/2003 4:00	6209.7	1	6478.029298
28/12/2003 2:00	7003.9	28/12/2003 5:00	6314.5	1	6478.029298
28/12/2003 3:00	6469.3	28/12/2003 3:00	6469.3	1	6478.029298
28/12/2003 4:00	6209.7	28/12/2003 6:00	6981.5	1	6478.029298
28/12/2003 5:00	6314.5	28/12/2003 2:00	7003.9	2	6478.029298
28/12/2003 6:00	6981.5	28/12/2003 1:00	7510.7	2	6478.029298
28/12/2003 7:00	8001.0	29/12/2003 0:00	7925.0	2	6478.029298
28/12/2003 8:00	8653.6	28/12/2003 7:00	8001.0	2	6478.029298
28/12/2003 9:00	8992.5	28/12/2003 23:00	8244.6	3	7631.59761
28/12/2003 10:00	9111.7	28/12/2003 22:00	8316.1	3	7631.59761
28/12/2003 11:00	9055.5	28/12/2003 21:00	8649.9	3	7631.59761
28/12/2003 12:00	8929.2	28/12/2003 8:00	8653.6	3	7631.59761
28/12/2003 13:00	8829.1	28/12/2003 15:00	8688.1	4	7631.59761
28/12/2003 14:00	8746.5	28/12/2003 16:00	8723.9	4	7631.59761
28/12/2003 15:00	8688.1	28/12/2003 14:00	8746.5	4	7631.59761
28/12/2003 16:00	8723.9	28/12/2003 13:00	8829.1	4	7631.59761
28/12/2003 17:00	8894.6	28/12/2003 17:00	8894.6	5	8471.597349
28/12/2003 18:00	9286.0	28/12/2003 12:00	8929.2	5	8471.597349
28/12/2003 19:00	9299.9	28/12/2003 9:00	8992.5	5	8471.597349
28/12/2003 20:00	9055.0	28/12/2003 20:00	9055.0	5	8471.597349
28/12/2003 21:00	8649.9	28/12/2003 11:00	9055.5	6	8471.597349
28/12/2003 22:00	8316.1	28/12/2003 10:00	9111.7	6	8471.597349
28/12/2003 23:00	8244.6	28/12/2003 18:00	9286.0	6	8471.597349
29/12/2003 0:00	7925.0	28/12/2003 19:00	9299.9	6	8471.597349

3. Use the model to determine the shadow price for each segment. The shadow prices determined by the model for this example are shown in Exhibit 4-10;

Exhibit 4-10 Shadow Prices for Example Load Segments

Segment	Segment Average MW	Shadow Price $/MWh
1	6493.7	18.00
2	7610.2	18.00
3	8466.0	22.53
4	8746.9	30.60
5	8967.8	30.60
6	9188.3	97.60

4. Map the shadow price back to the half hourly demands in the 'raw' load duration curve;

5. Reorder the raw load duration curve in ascending time order;

6. Identify the time class (peak, shoulder, or offpeak) that each of the half hourly periods belong to;

Exhibit 4-11 shows the following information for load data in our example:

- Time Period Type – this is one of peak, shoulder, and offpeak;
- The load segment number the demand period belonged to;
- The average load period determined for the load segment; and
- The shadow price determined by model for the load segment.

Exhibit 4-11 Load Duration Curve and Segments

Datetime	Demand (MW)	Time Period Type	Load Segment	Segment Average (MW)	Shadow Price
28/12/2003 1:00	7510.7	Off Peak	2	6478.0	18.0
28/12/2003 2:00	7003.9	Off Peak	3	7631.6	22.5
28/12/2003 3:00	6469.3	Off Peak	3	7631.6	22.5
28/12/2003 4:00	6209.7	Off Peak	3	7631.6	22.5
28/12/2003 5:00	6314.5	Off Peak	5	8471.6	30.6
28/12/2003 6:00	6981.5	Off Peak	6	8471.6	97.6
28/12/2003 7:00	8001.0	Off Peak	6	8471.6	97.6
28/12/2003 8:00	8653.6	Shoulder	5	8471.6	30.6
28/12/2003 9:00	8992.5	Shoulder	4	7631.6	30.6
28/12/2003 10:00	9111.7	Peak	4	7631.6	30.6
28/12/2003 11:00	9055.5	Peak	4	7631.6	30.6
28/12/2003 12:00	8929.2	Peak	4	7631.6	30.6
28/12/2003 13:00	8829.1	Peak	5	8471.6	30.6
28/12/2003 14:00	8746.5	Peak	6	8471.6	97.6
28/12/2003 15:00	8688.1	Peak	6	8471.6	97.6
28/12/2003 16:00	8723.9	Peak	5	8471.6	30.6
28/12/2003 17:00	8894.6	Peak	3	7631.6	22.5
28/12/2003 18:00	9286.0	Shoulder	2	6478.0	18.0
28/12/2003 19:00	9299.9	Shoulder	1	6478.0	18.0
28/12/2003 20:00	9055.0	Shoulder	1	6478.0	18.0
28/12/2003 21:00	8649.9	Off Peak	1	6478.0	18.0
28/12/2003 22:00	8316.1	Off Peak	1	6478.0	18.0
28/12/2003 23:00	8244.6	Off Peak	2	6478.0	18.0
29/12/2003 0:00	7925.0	Off Peak	2	6478.0	18.0

7. Determine the average marginal cost (LRMC) for each time class. To determine the LRMC for each time period, the formula used to determine the annual average LRMC given in section 4.5 above is applied to each time sector. Using the data in Exhibit 4-11, the following LRMC averages were found for the different time periods:

- Peak - $56.55 / MWh;
- Shoulder - $42.88 / MWh;
- Off Peak - $18.58 / MWh.

5 Results

The approach described in Section 4 has been applied to determine the LRMC (average, peak, shoulder and offpeak) applicable to the following:

- 2003 total NSW load;
- 2003 total NSW franchise load;
- 2003 Integral Energy franchise load;
- 2003 Country Energy franchise load;
- 2003 Australian Inland franchise load; and
- 2003 Energy Australia franchise load.

The load data used to calculate these LRMCs is actual 2003 data which was provided to IPART by NSW Treasury. This is the same data that has been used in calculations for the NSW ETEF.

For each of the loads listed above, the following results are presented for the low, medium, and high new entry cost scenarios:

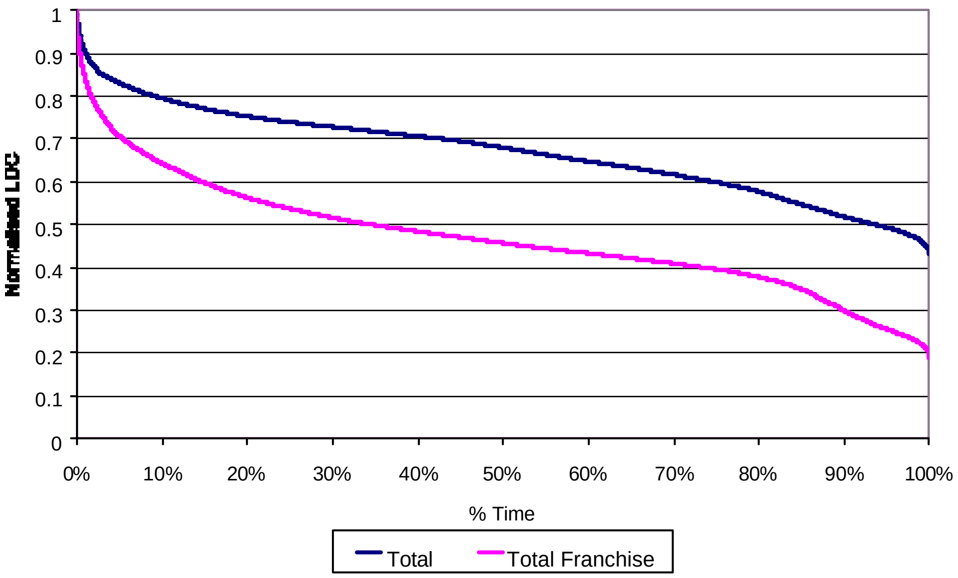
- A chart showing the LDC and resulting shadow price;
- A chart showing the plant mix (stacked generation under LDC); and
- A table showing load statistics and average marginal cost.

5.1 NSW Total and Franchise Load

The total and franchise load duration curve shapes[2] observed in NSW for the calendar year 2003 are shown in Exhibit 5-1. When comparing these two load shapes it is observed that the franchise load exhibits more 'peakiness' than the total load shape. This peakiness is seen at the right hand side of the LDCs where there is a pronounced steep upward rise for approximately the highest 15% of demands in the franchise load shape.

[2] The load duration curve shapes have been developed normalising the load duration curves. The normalisation method used here was to divide the load duration curve data by the maximum demand for the period.

Exhibit 5-1 NSW Total and Franchise Load Shapes for 2003



When the marginal costs for the total and franchise NSW load cases are compared for the medium case the following observations are made:

- A higher overall marginal cost is observed for the franchise load ($47.38/MWh) than for the total load ($41.47/MWh);
- A substantially higher peak marginal cost is observed for the franchise load ($123.77/MWh) than for the total load ($89.59/MWh);
- A higher off peak marginal cost is observed for the franchise load ($30.92/MWh) than for the total load ($22.66/MWh); and
- A lower shoulder marginal cost is observed for the franchise load ($33.99/MWh) than for the total load ($47.25/MWh).

The differences outlined above are due to the different load shapes which result in different relative weightings for the different sectors for the franchise and total loads.

Detailed modelling results for the franchise and total load cases are provided in sections 5.1.2 and 5.1.1 respectively.

5.1.1 Total Load Results

Exhibit 5-2 LDC and Shadow Price (Medium Scenario)

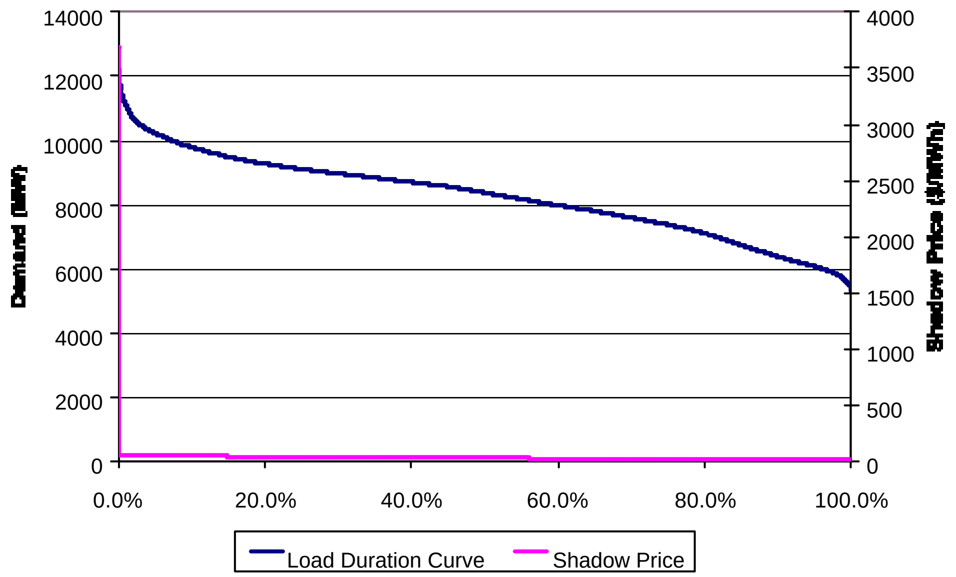


Exhibit 5-3 Plant Mix (Medium Scenario)

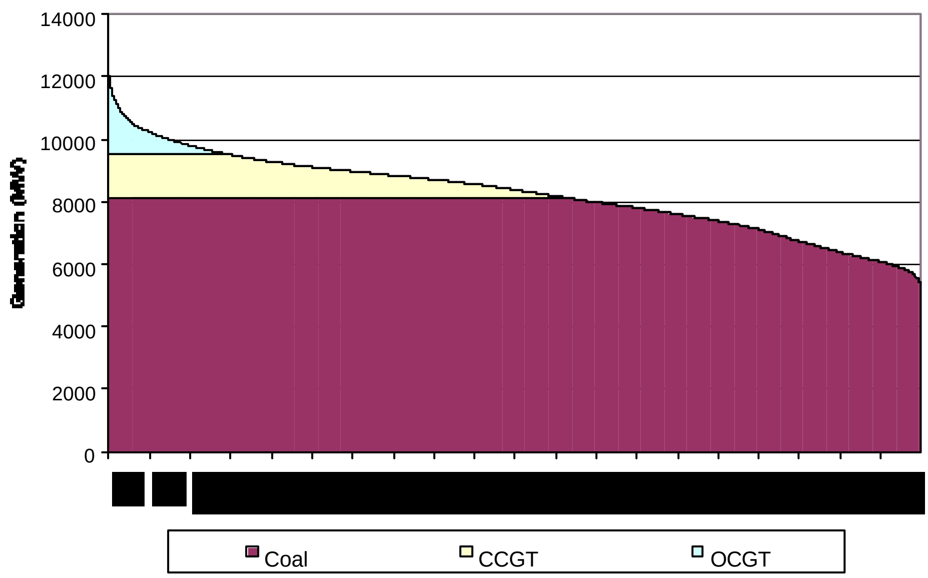


Exhibit 5-4 Average and Marginal Cost Results (Medium Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	3747	846	22.66
Peak	4688	1058	89.59
Shoulder	4586	1092	47.25
Overall	4124	2996	41.47

Exhibit 5-5 Average and Marginal Cost Results (High Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	3747	1136	30.43
Peak	4688	1263	106.93
Shoulder	4586	1312	56.76
Overall	4124	3711	51.37

Exhibit 5-6 Average and Marginal Cost Results (Low Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	3747	611	16.37
Peak	4688	790	66.85
Shoulder	4586	810	35.07
Overall	4124	2211	30.61

5.1.2 NSW Franchise Load Results

Exhibit 5-7 LDC and Shadow Price (Medium Scenario)

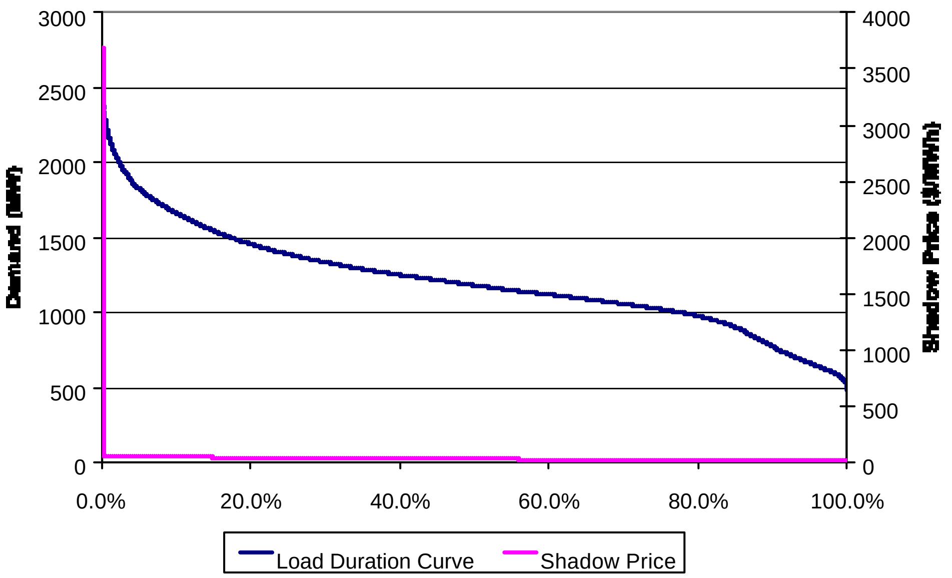


Exhibit 5-8 Plant Mix (Medium Scenario)

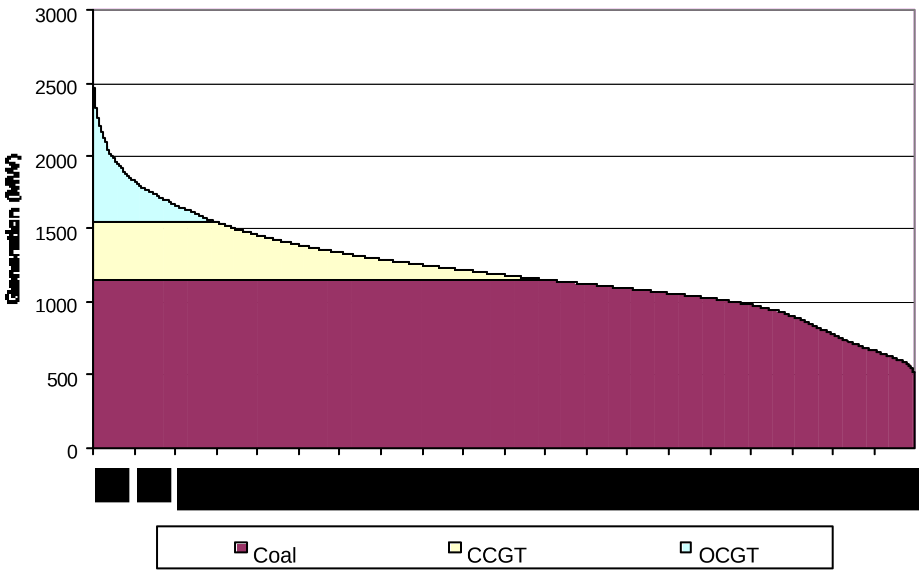


Exhibit 5-9 Average and Marginal Cost Results (Medium Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	571	176	30.92
Peak	707	221	123.77
Shoulder	630	108	33.99
Overall	607	504	47.38

Exhibit 5-10 Average and Marginal Cost Results (High Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	571	216	38.06
Peak	707	267	150.09
Shoulder	630	137	43.10
Overall	607	621	58.32

Exhibit 5-11 Average and Marginal Cost Results (Low Scenario)

	Average Demand (MW)	Total Cost ($M)	Average Marginal Cost ($/MWh)
Off Peak	571	132	23.21
Peak	707	164	92.28
Shoulder	630	78	24.49
Overall	607	374	35.16

5.2 Individual NSW Retailer Franchise Loads

The load duration curve shapes[3] observed for the NSW franchise load as well as the franchise loads belonging to Energy Australia, Country Energy, Integral Energy and Australian Inland for the calendar year 2003 are shown in Exhibit 5-12 below. Comparing these load shapes it is observed that Integral Energy exhibits the most 'peakiness' of any other retailers and that Country Energy exhibits the least peakiness. High, medium, and low average LRMC results are provided in Exhibit 5-13 and detailed results for each retailer are provided in the Exhibits following.

Exhibit 5-12 NSW Individual Retailer Load Shapes for 2003

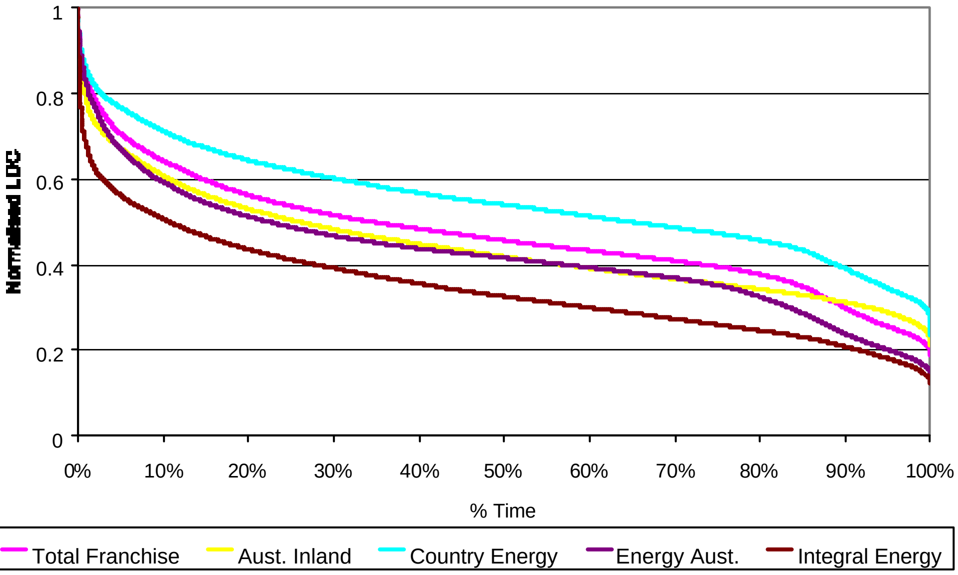


Exhibit 5-13 Average LRMC Results ($/MWh)

	New Entry Cost Scenario		
	High	Medium	Low
Total NSW Load	51.37	41.47	32.31
Total NSW Franchise Load	58.32	47.38	37.24
Energy Australia Franchise Load			
Integral Energy Franchise Load			
Country Energy Franchise Load			
Australia Inland Franchise Load			

[3] The load duration curve shapes have been developed normalising the load duration curves. The normalisation method used here was to divide the load duration curve data by the maximum demand for the period.

5.2.1 Energy Australia Franchise Load Results

Exhibit 5-14 LDC and Shadow Price (Medium Scenario)

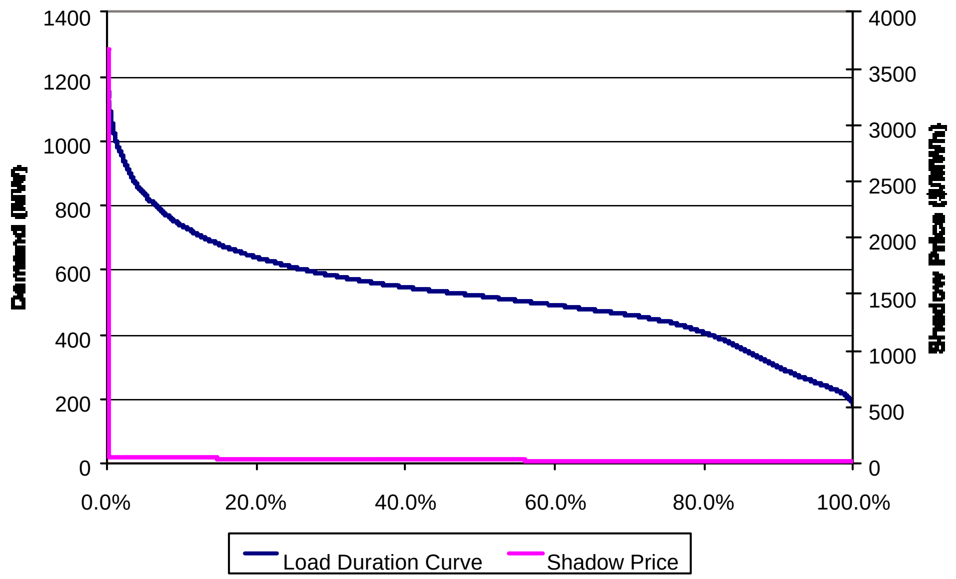


Exhibit 5-15 Plant Mix (Medium Scenario)