Final Report to

Electricity Reform Implementation Group

Evaluation of Economic Benefits of Reform

8 January 2007

McLennan Magasanik Associates

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Project Team

Ross Gawler

Lionel Chin

Paul Nidras

Liisa Parisot

Russell Farmer

Antoine Nsair

Sonja Ott

Melbourne Office
242 Ferrars Street
South Melbourne Vic 3205
Tel: +61 3 9699 3977
Fax: +61 3 9690 9881

Brisbane Office
GPO Box 2421
Brisbane Qld 4001
Tel: +61 7 3100 8064
Fax: +61 7 3100 8067

Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

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VERSION

Version	Date	Comment	Approved
Draft 0.1	7 September 2006	Initial working draft as a record of preliminary approaches to the analysis	Ross Gawler
Draft 0.2	15 September 2006	Updated as a result of discussion with Chris Short 11 Sep 06. Updated costs for interconnections and included initial draft of analysis of productivity..	Ross Gawler
Draft 0.3	21 September 2006	Updated analysis on the productivity trends and added some preliminary information on the expansion scenarios.	Ross Gawler
Draft 0.4	6 October 2006	Added comment on the development of ED. Extracted discussion of productivity to a separate report. Added scenario results.	Ross Gawler
Draft 0.5	19 October 2006	Added an Executive Summary. Updated the results for the BAU, TABAU, ED and TAED scenarios after improving the consistency of analysis.	Ross Gawler
Draft 0.6	20 October 2006	Appendices were updated for plant timing.	Ross Gawler
Draft 0.7	23 November 2006	Removed reference to scenarios no longer required and to some preliminary results than were later amended.	Ross Gawler
Draft 0.8	7 December 2006	Corrected expansion table in Table A- 3 for ED. Added comment about the relative benefits for NSW from efficient development. Added preliminary discussion on benefit segmentation studies	Ross Gawler
Draft 0.9	11 December 2006	Amended TAED results.	Ross Gawler
Draft 1.0	12 December 2006	Amended levelised price results and updated the discussion of those results.	Ross Gawler
Final 1.1	8 January 2007	Convert draft 1.0 to Final version by removing marked changes and amending title	Ross Gawler

ABBREVIATIONS

The following abbreviations are used in this report.

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
ANTS	NEMMCO's Annual National Transmission Statement
BAU	Business as Usual
CCGT	Combined Cycle Gas Turbines
ED	Efficient Development
ETEF	NSW Electricity Tariff Equalisation Fund
ERIG	Electricity Reform Implementation Group
ESAA	Energy Supply Association of Australia
FR	Final Recommendations
FTRs	Financial Transmission Rights
GEC	Queensland Gas Electricity Certificates
GMLG	Gas Market Leaders Group
IRSR	Inter-regional Settlement Residue
LEP	Queensland Long-term Energy Procurement Deed
LRMC	Long Run Marginal Cost
MRET	The Commonwealth Government's Mandatory Renewable Energy Target of 9,500 GWh by 2010.
NEMMCO	National Electricity Market Management Company
NEM	National Electricity Market
NGAC	NSW Greenhouse Gas Abatement Certificates
NPV	Net Present Value
OCGT	Open Cycle Gas Turbines
PLEXOS	Simulation model developed by Drayton Analytics
POE	Probability of Exceedance

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PROVIEW	A module to optimise expansion plan in Strategist NEM model
PV	Present Value
QNI	Queensland – NSW Interconnection
SBC	Snowy Boundary Change
SC (Black Coal)	Supercritical black coal (high thermal efficiency)
SOO	NEMMCO's Statement of Opportunities
SRA	Settlement Residue Auction
SRMC	Short-run Marginal Cost
Strategist	Probabilistic NEM Model Developed by New Energy Associates
TABAU	Transmission Augmentation – Business as Usual
TAED	Transmission Augmentation - Efficient Development
UET	Uniform Emissions Trading
WACC	Weighted Average Cost of Capital used for annualising capital costs.

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EXECUTIVE SUMMARY

McLennan Magasanik Associates (MMA) has been engaged by the Energy Reform Implementation Group (ERIG) to develop economic models of the National Electricity market (NEM) that may be used to evaluate the economic benefits of prospective changes to the NEM. Such changes could relate to:

- the ownership structure and vertical integration in the market and its consequential level of competition
- the extent of further inter-regional transmission development
- the impact of the reliability standard and NEMMCO as Reserve Trader
- the incentives for demand side response to extreme peak demands and associated price volatility
- arrangements in financial markets that influence contract cover and spot prices.

Accordingly MMA has developed two models of the NEM which used jointly provide the opportunity to estimate the value of potential changes in the NEM.

Scenarios

In this final report, MMA presents four scenarios that have been developed to provide reference cases for this analysis. The four scenarios are:

- **Business as Usual (BAU)** which represents the market developing in accordance with recent and currents trends for pricing and investment. This scenario provides a reference case with which to value changes from current practices.
- **Transmission Augmentation under Business as Usual (TABAU)** which includes upgrade of QNI, the Heywood Interconnection and Snowy to Melbourne in July 2008 under BAU conditions. This scenario was intended to estimate the economic value of removing some major inter-regional constraints assuming that no other changes take place in the NEM.
- **Efficient Development (ED) in** which the market delivers the lowest potential cost of electricity with pricing based upon short-run marginal costs and perfect foresight for investment to meet medium growth conditions. This scenario represents the maximum potential for cost savings.
- **Transmission Augmentation with Efficient Development (TAED)** in which the early network augmentation is commissioned where the market is already operating efficiently. This scenario provides an estimate of the excess costs associated with early inter-regional network development.

The scenarios based upon Efficient Development were optimised using the PROVIEW module of Strategist to 2018. This module conducts a least cost expansion analysis using dynamic programming. This is a very demanding calculation and requires some simplification to achieve meaningful results within a practical time frame. This was achieved by limiting the number of options considered and applying constraints to their sequencing to guide the solution. The expansion plan was extended to 2025 to meet basic reliability requirements and with some further refinement to minimise cost.

The Business as Usual scenarios were formulated using generator bids that were formulated using the gaming features of PLEXOS. Forty existing generator units were selected on the basis that they are often used by their owners to support market prices. A PLEXOS solution was benchmarked to 2005 price duration curves and then the spot prices were estimated to 2015 for BAU and to 2016 for TABAU. The bid prices from PLEXOS were converted to equivalent peak and off-peak bid prices on a monthly basis and then applied to the Strategist model. The PROVIEW module of Strategist was then used to set up the expansion plan on a least cost basis. The least cost analysis in response to these bids is not fully optimised as the time available was insufficient to completely confirm the least cost analysis. The expansion plan does however approximate a least cost plan that meets the reliability and reserve criteria and stability in costs between iterations has been achieved to within 0.2%.

All four scenarios included 631 MW of interruptible load to represent existing demand side response. This was priced at $3,000/MWh based on the bid profile for these resources that is published by NEMMCO.

Other differences between BAU and ED scenarios were as follows:

BAU/TABAU do not include any new demand side resources apart from some energy efficiency programs that are in common with ED/TAED to meet emission abatement programs in NSW. This view is consistent with very slow development of this aspect of the NEM since its establishment in 1998.

ED/TAED include new demand side resources for extreme peak demand management priced at $25/kW/year fixed cost and $2,000/MWh activation cost. This is much cheaper than using open cycle gas turbines for this purpose. The volume of demand side response versus generating plant was achieved in PROVIEW by applying a maximum loss of load hours for generating reliability of about 30 hours per year and then using the demand side response in a second run to constrain the unserved energy and the interruptible load to an economic level.

ED/TAED costing also includes the fixed cost for additional demand side response for the difference between the 50% POE peak demand and the 10% POE peak demand. This duty is provided by the supply side in the BAU/TABAU scenarios by means of the imposed reserve margin.

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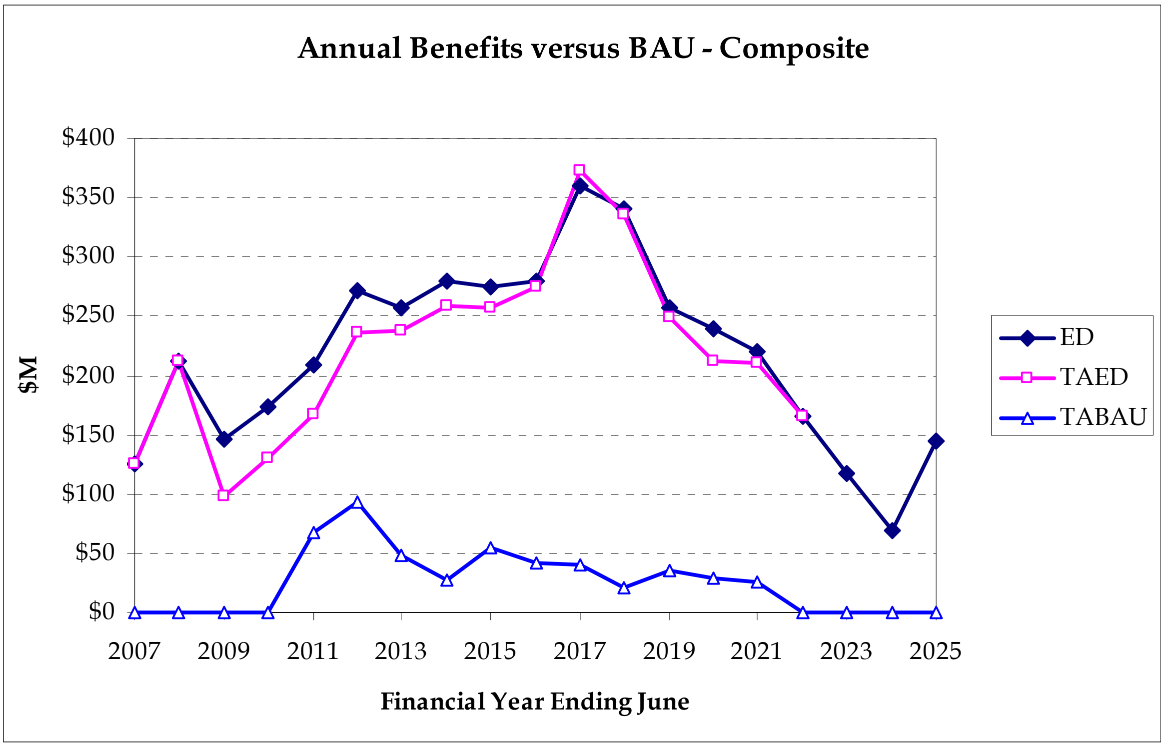
Benefits of Efficient Development

The economic analysis has shown that a fully efficient market would have total costs of about $200 M per annum lower than the current market structure based on a comparison of cost between the BAU scenario and the ED scenario. Figure 1 shows the annual

Figure 1 Annual benefits of alternative market developments



benefits of Efficient Development and Business as usual with early transmission augmentation relative to Business as Usual. Efficient Development creates initial benefits of about $200 M pa which rise to about $300 M pa for a short period and then decline as the market is expected to become more competitive over time. If the new power plants are only developed by incumbents then we would expect that the gap between Business as Usual and Efficient Development would continue to increase up to $300 M pa by 2025. These results have been developed using TABAU to represent BAU from 2022. Similarly ED has replaced the higher cost TAED from 2022 as these scenarios had the same network state by that time. The modest differences between the base scenarios reflected slightly different approaches to adjusting emission abatement allocations between plants in the later years as it was a manual iterative adjustment process in which Queensland plants were switched between GEC and NGAC assignment for their emission abatement revenue.

Table 1 shows the structure of the additional costs and offsetting benefits that would be the consequence of a more efficient market. In the short term cost savings are achieved from lower gas usage and some reduced capital investment in generating plant which is partially offset by demand side response costs. In the longer term the capital savings from new generating plant grow considerably and the fuel mix allows more coal fired development and reduced savings in gas fired generation. The increased contribution from demand side resources provides a substantial saving in fixed costs for new generating plant.

Table 1 Structure of cost saving with Efficient Development

Cost Component	Early to 2013	2014 - 2018	Later from 2019
Variable O&M	$9	-$11	-$18
Coal Cost	-$55	-$129	-$272
Gas Cost	$203	$201	$29
Fixed capital and O&M	$75	$453	$675
Demand side response	-$36	-$200	-$234
Total	$195	$313	$179

Impact of Early Transmission Augmentation

As observed in Figure 1, early transmission augmentation offers no economic advantage with Efficient Development. Under Business as usual there are some modest economic benefits in the period from 2011 to about 2021 of about $38 M pa on average. These benefits arise from more efficient dispatch and a higher level of competition between regions. By 2020 we would expect that the main interconnectors would be upgraded under Business as Usual conditions.

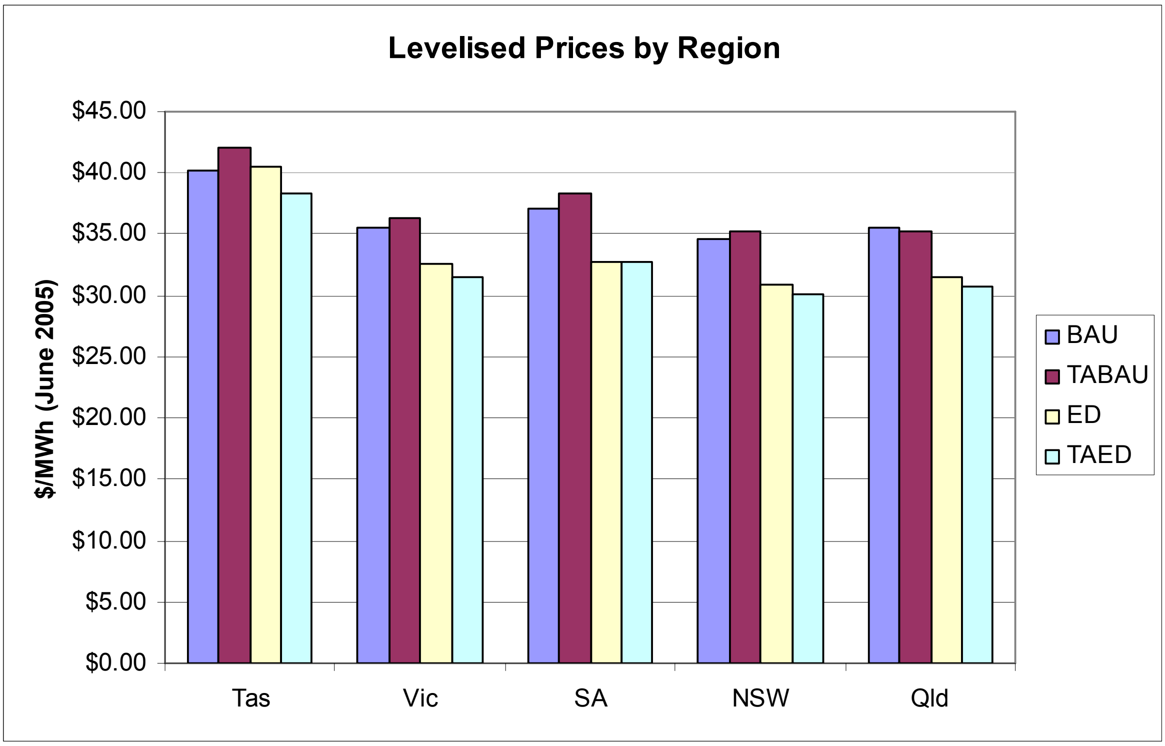
Price Impacts

The analysis of the scenarios has also considered the impacts of alternative developments on the long-term average cost of electricity to customers based upon the spot market prices and the costs of the additional transmission developments. Figure 2 provides an estimate of the impact on base load power costs by region. It is concluded that early transmission augmentation with 300 MW capacity between Victoria and South Australia, 600 MW capacity between Snowy and Melbourne and a 400 MW upgrade of QNI is unlikely to lower prices to consumers under Business as Usual because the reduction in spot prices would not be sufficient to compensate for the additional networks costs. This is because the major portfolios would still be able to support prices in importing regions by adjusting bids and deferring new investment. Prices would be higher in exporting regions due to the increased generation requirements in the short-term until new generating capacity is built. Queensland is the only region likely to benefit from early transmission augmentation. Early transmission augmentation would lower prices under Efficient Development in all regions except South Australia but at the expense of generators and the economy as a whole.

Comparing BAU and ED, the price chart may give the impression that NSW is not as far from an efficient price outcome relative to Queensland and Victoria as might be expected.

These results should not be relied upon to make such assessments because of the difficulty of predicting the evolution of market power in the future under business as usual conditions. The business

Figure 2 Levelised time weighted prices by region for composite scenarios



Note: Prices include the impact of the additional interconnection transmission costs when applicable.

as usual scenario has quite modest prices for NSW at the lower end of the likely range and therefore the assessment in Figure 2 is near the more favourable end of the range when considered as part of a price efficiency assessment.

An assessment of the relative contributions of generation/transmission co-ordination, competitive bidding and demand side response to the $200 - $300 M pa savings from reform has shown that:

- about 80% of the potential benefits of market reform would be achieved from more competitive bidding
- about 13% could be achieved from improved demand side response, and
- the remaining 7% could be achieved from timely augmentation of interconnections.

1 INTRODUCTION

The purpose of the study is to provide evidence that changing the structure of the National Electricity Market (NEM) or its regulations will produce economic benefits in terms of productive and allocative efficiency.

Two reports have been prepared by McLennan Magasanik Associates (MMA). This report simulates the development of the NEM to provide a basis for estimating the economic benefits of various mechanisms for reform. The other report entitled "Analysis of Productivity Factors in Transmission and Generation for the National Electricity Market" examines published data on the transmission and generation sectors in NEM.

1.1 Efficiency objectives

Productive efficiency is realised by using the least amount of resources to produce a give amount of goods or services. In terms of the electricity market this means that:

- Generation and demand side resources are dispatched to meet the load in order, from lowest cost to highest short-run marginal cost, or shadow value as appropriate. This is the normal basis for ordering the dispatch by means of bid prices but to be certain of productive efficiency it is necessary that competition is sufficient to provide incentive for generators to bid close to their short-run marginal costs or at the least in the order of their costs.
- Resources are employed and maintained using the most efficient use of inputs. Such matters relate primarily to on-going operational and maintenance activities, such as the effect of staffing levels and use of in-house services versus external contracting.

Allocative efficiency occurs when firms produce those goods and services most valued by society. This means scarce resources are allocated to the production of the goods and services so that consumer wants and needs are met in the best way possible. If a market is allocative efficient then any reallocation of resources to make some customers better off will make other customers worse off. Put in another way marginal cost must equal marginal benefit.

Where appropriate, competitive pricing (price equal to marginal cost) is the best mechanism for ensuring allocative efficiency. In an electricity system, the dispatch process must match the supply to the demand on a nearly continuous basis. Ideally, the social marginal cost should equal the marginal customer benefit such that the level of producer and consumer surplus generated is maximised.

Questions to be answered in this part of the study are:

- Are the most suitable generation technologies likely to be selected as the basis for minimising the long-run cost of power production in the future?

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- Are new proposed transmission developments likely to maximise the economic utilisation of generating plants across the NEM to serve customers?

In this study, we consider:

- productive efficiency simulated by representing bid price based dispatch of generation resources. This ensures productive efficiency to the extent that bid prices are efficient, that is related to short-run marginal costs or shadow values for energy limited resources. Whether or not this is true is dependent on the level of competition and the ability of producers to forecast accurately so that limited resources are dispatched optimally over time.
- a second important productivity efficiency matter which affects the choice between generation and transmission development and relates to the type of power plant built. If the nature of the market places undue risks on one type of plant relative to other types, such as capital intensive coal fired plant, then an inefficient capital structure may be built into the market for many years ahead. This happened in the early 1980s in NSW when ten 660 MW coal fired units were ordered in rapid succession because it was considered that missing out on the projected minerals processing boom would be a lost opportunity for NSW relative to other states. A more recent consideration is that the risks of building coal fired plant to private investors is such that in the southern states, all the major new projects in the development pipeline are based upon low capital cost, and low emission gas turbine technology.
- allocative efficiency to be relevant to the extent that energy services are met from the production of electricity, the installation of energy saving devices or the cessation of the energy consuming activity. This can best be achieved when market prices reflect marginal costs or marginal values arising from the demand side when supply is approaching a capacity constraint. The latter state relates to whether the market clears at the marginal value of unserved energy and to the economic efficiency of the reliability standard. The level of the reliability standard is under review by the Reliability Panel and will not be explicitly assessed in this study except to make distinctions between the current reliability standard of 0.002% and what might be more efficient having regard to the cost of reserve capacity and the value of unserved energy.

1.2 Efficiency Measures

The measures of efficiency will be taken as related to costs assessed from the market simulations. The approach to costing is as follows:

1. Since the simulations are taken over a period less than the life cycle of new assets, it is necessary to annualise the recovery of capital costs by some means to represent an allocation of a portion of the capital investment to the study period. This is done using a real weighted average cost of capital (WACC) for the project to convert the capital cost into an annual cost. Where the future cost of such plant is expected to rise or fall with CPI the effective WACC is adjusted for the purpose of calculating the first year

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cost which subsequently varies according to the CPI trend. The sculpting of the cost recovery is then matched to the new entry capital cost trends so that once built a new plant recovers its costs in line with subsequent changes. This assumes perfect foresight. New entry capital costs are estimated to be declining at CPI-1% in real terms.

2. Fixed operating costs are assumed to increase with CPI with increasing labour costs offset by increasing productivity of labour resources. The same applies to variable operating costs.

3. Fuel costs are formulated based on the particular fuels concerned. Coal costs have been declining in real terms over the last two decades and it is expected that they will now stay constant in real terms.

4. City gate gas prices for high load factor gas fired generation are determined on a long term contractual basis and converted to equivalent annual prices for the purposes of estimating new entry costs. The MMA-GAS model is used for the purpose of aligning gas prices to gas demand for power generation and other purposes. This will enable gas costs to be assessed in terms of the input costs to power stations and/or the underlying costs back at the source. This provides some flexibility about where the cost boundary is defined and allows some assessment of how changes in the electricity industry might affect the gas industry.

Using these cost components:

- The changes in the costs of new entry including annualised capital and operating costs can be used to represent the change in productive efficiency in relation to costs that are substantially fixed after an investment decision is committed.
- The changes in the costs of operation of the existing plants can be used to represent the change in productive efficiency arising from changes in the variable costs of electricity production from alternative sources that are available to operate.
- Change in prices to wholesale market participants, both in the short-term (due to either altered dispatch or bidding behaviour) and the long-term (by changing the timing and pattern of entry of new supply options) can be used to assess the share of the benefits between producers and customers.
- Improvements in reliability, as defined by such measures as energy not served reflects benefits to customers. The average unserved energy was costed at $30/kWh based upon an average market value that has been assessed in previous analyses by Monash University and Charles River Associates[1].

There is interaction between the new entry mix and the operations of the existing resources and to that extent the costs of the existing plants depend on the new entry mix. For example, a new base load coal plant with high capital and low operating costs would

[1] Assessment of the Value of Customer Reliability (VCR),, Charles River Associates, December 2002.

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increase the productive efficiency of older plants by reducing the utilisation of high cost energy resources such as peaking gas or oil. The impact of market development on new entry costs and the operating costs for existing plants is identified in the studies. The least cost analysis maximise total efficiency of the new and existing plant combined as well as the associated demand side response where applicable. We have identified the changes in system costs with reference to fuel consumption and power plant fixed costs to highlight the sources of cost and benefit.

We do not necessarily have accurate fixed operating costs for existing plants. Such costs are common to all studies and therefore have no impact on comparisons between scenarios unless existing plants are mothballed and recommissioned on different timetables in which case fixed operating costs may be varied. Particular attention was paid to fixed operating costs assumptions when retirement or mothballing was considered as likely to be economic.

1.3 Issues

To what extent is the current market operation and development close to an efficient outcome? Consideration of this question will require a characterisation of the nature of inefficiencies in the current NEM which are perceived to include:

- Insufficient or delayed investment in inter-regional transmission capacity which leads to inefficient congestion costs.
- Pre-emptive investment by state–owned corporations which are consistent with managing state level risks rather than clearly defined commercial opportunities in the broader National Electricity Market.
- Vertical integration by retailers into construction of peaking plant to manage their purchase risk especially during times of high summer peak demand.
- An uneconomic reliability standard which provides a disincentive for private investment because the probability of achieving a commercial return is too low, especially on base load and high intermediate plant[2] unless fuel costs are very low (such as at Kogan Creek and Condamine).

A number of further issues will be identified during ERIG deliberations which may require modelling to identify specific economic benefits and costs.

1.4 Scenarios

The corresponding issues relate to a number of scenarios which were evaluated. The market scenarios and their key features are summarised in Table 1-1. The key scenarios were related as follows:

[2] Assuming 60%-70% load factor

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- **Business as Usual (BAU)** provides a business as usual view of the world with continuing state-based emission n abatement schemes and supply-side development dominated by reliability criteria based around a 0.002% unserved energy standard and derived reserve margins guiding investment timing.
- **Efficient Development (ED)** represents least cost total resource cost expansion plan including supply and demand side resources with merit order dispatch. This represents a theoretical optimal outcome with a high level of competition and perfect foresight
- **Transmission Augmentation with Efficient Development (TAED)** represents the impact of an early commitment to augment existing interconnections in July 2008 and with further development of the market on the same basis as ED.
- **Transmission Augmentation with Business as Usual (TABAU)** represents the potential impact of increasing the capacity of existing interconnections but with no other changes to the market arrangements.

1.4.1 Standard Features of the Scenarios

Standard features of the scenario were:

- Operating and maintenance costs remain constant in real terms
- New entry capital costs decline at CPI-1%
- Plant performance of thermal plant and hydro yield based on historical performance

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Table 1-1 Distinguishing features of scenarios

Scenario ▶ **Feature ▼**	**Business as Usual (BAU)**	**Efficient Development (ED)**	**Transmission Augmentation-ED (TAED)**	**Transmission Augmentation-BAU (TABAU)**	**Final Recommendations (FR)**
Purpose	To provide a basis for estimating the benefits of change from current market structure and policies.	To provide an efficient benchmark from which the costs and benefits of other alternative policies can be estimated.	To establish the costs of bringing forward investment in interconnections to remove most constraints and to indicate what competition benefits would be needed to justify that investment. TAED shows the value with efficient development.	To show the costs of bringing forward investment in interconnections to remove most constraints and to indicate what competition benefits would be needed to justify the investment. TABAU shows the value with BAU development.	*To simulate the combined effect of all recommendations*

Scenario ► Feature ▼	Business as Usual (BAU)	Efficient Development (ED)	Transmission Augmentation-ED (TAED)	Transmission Augmentation-BAU (TABAU)	Final Recommendations (FR)
The prime development concept	To model future behaviour based on current and recent market behaviour assuming no further changes occur. Model parameters were set with the intention to replicate market behaviour as observed since NEM stage 3 commenced in 1998.	Minimises the long-run cost of electricity using generation and inter-regional transmission options. This represents an idealised fully competitive electricity market operating with perfect foresight. A greater role for demand side response was identified in this scenario than for BAU.	That the major upgrades to existing interconnections for QNI, Snowy to Victoria and Heywood for SA would proceed by summer 2008/09 as a way to increase competition in the generation sector. This scenario shows the inherent economic net costs or benefits of such a proposal.	The additional costs would show the competition benefits that would be required. This scenario was developed in the context of BAU principles.	*Includes the effect of all recommendations*
Market Modelling Factors for the sections below …					

Scenario ▶ **Feature ▼**	**Business as Usual (BAU)**	**Efficient Development (ED)**	**Transmission Augmentation-ED (TAED)**	**Transmission Augmentation-BAU (TABAU)**	**Final Recommendations (FR)**
Price elasticity of demand in NEM models	Not included	Not included	Not included	Not included	*If substantial price changes are expected, it may be considered as part of the economic benefit.*
Generation	Excessive base load in Queensland initially, excess peaking plant in SA/Victoria relative to potential demand side role. Generator bids derived by PLEXOS were used in Strategist	Based on a least PV cost expansion plan with perfect foresight a 7% real discount rate. Sequence was optimised to 2018.	Based on a least PV cost expansion plan with perfect foresight a 7% real discount rate. Sequence was optimised to 2018.	Based on a least PV cost expansion plan with perfect foresight but with Generator bids derived by PLEXOS.	*To be determined.*
Transmission	Interconnection developments based upon PLEXOS bids and least cost analysis.	Timed to minimise total system costs	Based upon PLEXOS bids and least cost expansion analysis.	As for BAU except for interconnection advancement.	*Timed to minimise total system costs*

Scenario ► Feature ▼	Business as Usual (BAU)	Efficient Development (ED)	Transmission Augmentation-ED (TAED)	Transmission Augmentation-BAU (TABAU)	Final Recommendations (FR)
Demand response	631 MW of existing committed and uncommitted interruptible load priced at $3,000/MWh	Based on $2,000/MWh bid price and $25/kW/year total fixed cost as an indicative cost profile. Existing committed and prospective demand side response amounts to 631 MW. This resource is treated as last resort "interruptible load" in the modelling and is priced at $3,000/MWh which is the load weighted bid in accordance with NEMMCO modelling of demand side response in the ANTS studies.			*To be determined.*
Gas market	Use MMA-Gas model to estimate delivered gas prices for new power generation. This model allows some gaming of gas price above LRMC production cost.	Use the BAU gas prices in the model due to time constraint	Use BAU gas prices due to time constraint.	Use BAU gas prices due to time constraint.	Use MMA-Gas model to estimate delivered gas prices for new power generation. This model allows some gaming of gas price above LRMC production cost. May use BAU gas prices due to time constraint.
Spot price gaming	Derived from a PLEXOS analysis for the first five years	Short-run marginal cost bidding	Short-run marginal cost bidding	Derived from a PLEXOS analysis for the first five years	*Derived from a PLEXOS analysis for the first five years*

Scenario ▶ Feature ▼	Business as Usual (BAU)	Efficient Development (ED)	Transmission Augmentation-ED (TAED)	Transmission Augmentation-BAU (TABAU)	Final Recommendations (FR)
Level of Greenhouse Response	Continuation of NGAC, GEC and MRET Schemes to 2020 and beyond.	Continuation of NGAC, GEC and MRET Schemes to 2020 and beyond. Existing resources including for MRET continue to serve the market.	As for ED	As for BAU	*To be determined*
Reliability standard	0.002% continues	Determined by the model using a value of unserved energy by region at up to $45/kWh plus the demand and supply side options included for peaking duty. Marginal unserved energy costs are varied by region.	As for ED	As for BAU	*As for ED*

Scenario ▶ Feature ▼	Business as Usual (BAU)	Efficient Development (ED)	Transmission Augmentation-ED (TAED)	Transmission Augmentation-BAU (TABAU)	Final Recommendations (FR)
Expansion Modelling Methodology	Use Strategist to develop an initial expansion plan and then use this plan in PLEXOS to estimate distortionary bidding based on the current market structure. Derive equivalent bids for Strategist and then run an expansion plan in PROVIEW which is compared to the efficient plan to confirm the nature of distortion due to gaming.	Use PROVIEW in Strategist to screen options to develop an optimal expansion plan that minimises present value cost. In one run, maximum loss of load hours would be based upon the breakeven level between open cycle gas turbines and the demand side response (about 30 hours). This would show the economic limit for open cycle generating capacity with full demand side response. A second run would then apply the reliability target (0.004%/0.001%) and determine how much demand side response would be	As for ED The TA version with efficient expansion (TAED) uses the same methodology as ED.	Use the BAU expansion plan Strategist with PLEXOS to estimate distortionary bidding based on the revised regional structure. Use the distortionary bidding to review the expansion plan.	*To be determined.*

Scenario ▶ Feature ▼	Business as Usual (BAU)	Efficient Development (ED)	Transmission Augmentation-ED (TAED)	Transmission Augmentation-BAU (TABAU)	Final Recommendations (FR)
PLEXOS	Used to estimate extent of bidding above short-run marginal cost	**Not used.** It is assumed that all bidding is at short-run marginal cost.	Not used for TAED version.	Used to estimate how the temporary removal of the transmission constraints could affect bidding, prices and production across the NEM.	*Used to assess the impact of final recommendations on bidding across the NEM.*
Strategist	Used to estimate the least cost expansion plan using generic new entrants or specific projects where they have been identified in the Statement of Opportunities (SOO).				
Market Design Issues are considered in the sections below …					
Inter-regional development	Include as options based on moderate cost regulated upgrades to QNI, Snowy to Victoria and Heywood interconnections.				
Application of Firm SRA	Not applicable	Not applicable	Not applicable	Not applicable	*As recommended*
Snowy Boundary	Current boundary				*As recommended*

Scenario ▶ Feature ▼	**Business as Usual (BAU)**	**Efficient Development (ED)**	**Transmission Augmentation-ED (TAED)**	**Transmission Augmentation-BAU (TABAU)**	**Final Recommendations (FR)**
Gaming of SRAs across inter-regional boundaries	Not included as PLEXOS does not provide suitable gaming methodologies in its current form.	Not included	Not included	Not included	*To be determined.*
Impact of diffuse emissions trading across the NEM	Reflected already in BAU	As for BAU	As for BAU	As for BAU	*As recommended.*

- Median peak demands in all seasons and regions to estimate expected outcomes.
- A standard development scenario for renewable energy for which the plant already committed is assumed to continue under the Renewable Energy Mandatory Target (MRET) scheme irrespective of future emission abatement policies
- Current portfolios of ownership and vertical integration
- Investments in inter-regional regulated transmission assets are made when the assets would pass the ACCC's Regulatory Test. This was assessed by means of minimising the total present value costs of capital and energy production across generation and transmission over the study period. In addition, an upgrade of Central to North Queensland transmission capacity was included on this basis to represent the addition of a new transmission line.
- Murraylink and Directlink operate as regulated interconnections
- Basslink continues to be bid by Hydro Tasmania
- Renewable generation built for MRET and VRET continues to operate in all scenarios
- Where least cost optimisation was applied, the evaluation of possible combinations was limited to contain processing time by setting limits on reliability parameters and by pre-determining sequences of development from lower cost to higher cost options.

1.4.2 Business-as-Usual (BAU)

In consultation with ERIG, MMA established a 'Business-as-Usual' base case which continues current policies, practices and market participant behaviours. Using the wholesale market model, *Strategist*, MMA determined year-by-year, the investments required in generation (by plant size, location, capacity factor and fuel type), transmission, and where suitable, gas transmission, needed to satisfy expected demand growth to 2025 and the commonly applied reserve margin which is interpreted from the 0.002% reliability target. The Business-as-Usual case begins with a continuation of existing commitments and then is derived as a distortion from the efficient case by advancing the plant development program to meet the reliability constraints. For this reason the efficient case was developed first.

In the BAU:

- There are no new emission abatement policies or programs at state or federal level.
- The existing state-based emission abatement schemes are assumed to continue indefinitely beyond projected termination dates in 2020.
- Whether or not the MRET continues has no effect on the scenario as the plant would be expected to continue to operate because of very low or negative marginal costs relative to energy market prices.
- NGAC target remains unchanged but price is determined to clear the market with NSW population forecast linked to the NSW electricity demand forecast changes. The

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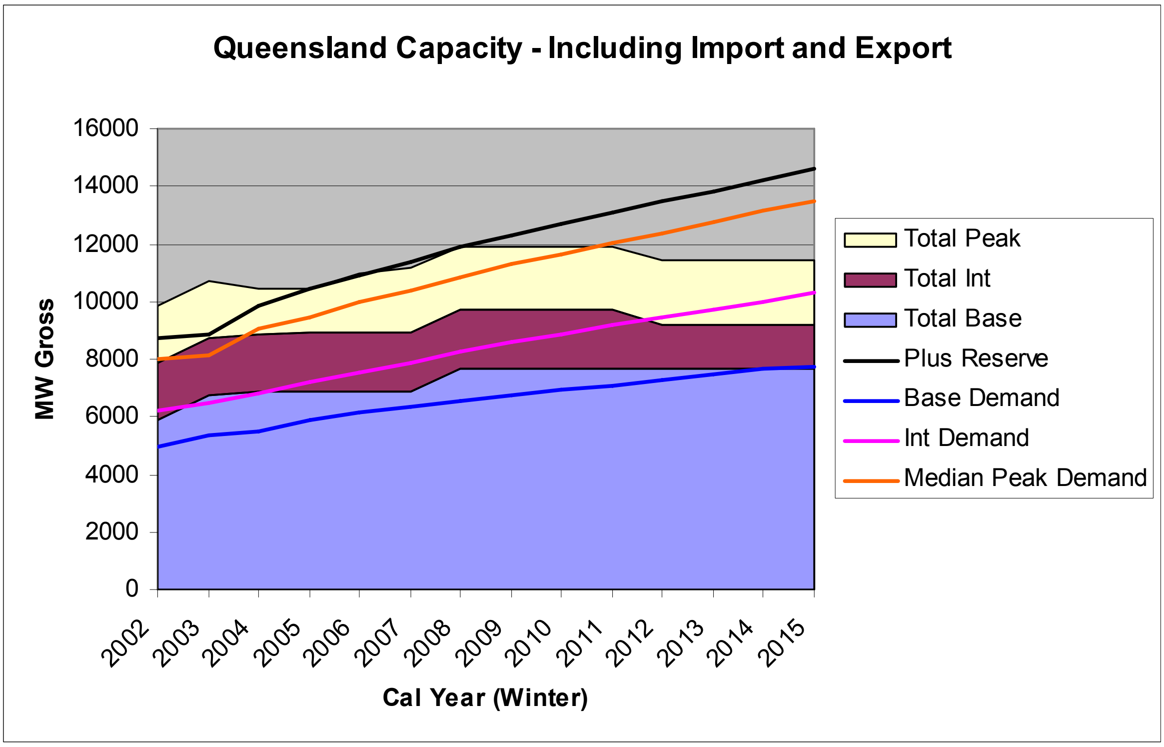
scheme is expected to be modified to overcome the current shortage of NGAC supply by extending the scheme or an equivalent scheme beyond 2012 indefinitely.

In the BAU scenario, investments in generation were made when the new generator would minimise costs in the NEM based upon the dispatch profile derived from the gaming algorithm in PLEXOS as well as meet the reliability criteria for the NEM. It does not necessarily mean that it would be guaranteed to earn a commercial rate of return appropriate for merchant risk in the first year of operation. However the price outcomes that have been obtained would ensure that the base load and intermediate plants would earn satisfactory income when contracting margins are considered.

The BAU scenario is consistent with current inefficiencies in the NEM such as:

- The tendency to pre-emptive new entry of base load coal plant in Queensland based on the historical trend shown in Figure 1-1 - from 2002 to 2008 financial years. The figure shows that the base capacity has exceeded the base demand even after allowing for exports to NSW.) After transferring bids from PLEXOS to Strategist, it was found that high prices in Queensland would encourage new base load coal fired plant earlier in BAU than in the ED scenario. This earlier base load plant was also consistent with lower total system costs.

Figure 1-1 Load segmentation in Queensland



- Excessive development of peaking plant with potential delays in economic base load capacity in Victoria and South Australia because there are no long-term contracts available to finance base load plant and no government support through state-owned utilities. The BAU scenario has mostly gas fired plant in the expansion sequence

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because of the gaming in the bidding of coal fired plant, the emission abatement targets and the initial surplus of base load plant.

- Due to the large economic scale of base load units relative to the level of demand, it is economic that peaking plant should be in excess when base load plant enters service. It is efficient for large scale base load plant to be held back so that when it commences service it displaces an equivalent amount of high marginal cost plant. This displacement value compensates the cost of the surplus capacity that is initially provided due to the large unit size.
- Excessive development of peaking plant due to a shortage of demand side response to meet infrequent extreme peak demands or coincident outages of large power generation units at times of high demand.
- Gaming by the larger coal portfolios to support market prices which slightly reduces coal consumption and increases gas consumption.
- Inefficient reliability standard which supports surplus generating capacity with a virtual absence of economic demand side response.

Four alternative ways were considered for setting up the Business-as-Usual (BAU) case:

1. Modelling the efficient scenario and then manually distorting it by changing new entry timing to reflect simple principles concerning plant mix, delay to transmission investments and other observed market distortions. This method would be easy to do, but may be considered somewhat arbitrary and not an adequate basis for an evidence based enquiry.

2. Setting up an indicative expansion plan, as in the first point, modelling price bids in PLEXOS and then using distorted price bids to develop an expansion plan assuming that costs are still minimised but that dispatch is distorted by gamed bids. This second method is more credible as we have shown that it is feasible to adequately apply the gamed bids derived from *PLEXOS*. However, it has not been possible to fully develop the expansion plan beyond 2016 with bids reflecting the conditions in each year. This method has been adopted for the BAU and TABAU scenarios.

3. Setting up an expansion plan as in the second bullet but treating the distorted bids as if they were costs when optimising the expansion plan, rather than just dispatch factors for pricing purposes. This is likely to result in some additional base load power and earlier development of new entry and may be more credible. This method has yet to be tested. It might better represent what we have observed in the NEM.

4. Adjusting an expansion plan with *PLEXOS* based bids using Strategist but using maximum unit profitability with a reserve margin constraint as the objective function. This fourth method was tested but it failed to yield a result after one simulation to 2013 ran for a whole week without producing any result.

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A back-casting exercise to select the most accurate method would be preferable but time for this approach was not available.

What has been achieved to date is:

- The BAU case has been developed with a preliminary bidding pattern to 2016 but further refinement has been difficult to achieve because run-times were excessive and time to look for practical methods of improvement has not been available. However we consider that we have attained a cost level to within about 0.2% of what might be achieved with further refinement for the given assumptions and methodology.
- Beyond 2016 we have developed an approximate expansion plan that is close to optimal because the dispatch of peaking and combined cycle gas fired resources is consistent with efficient operating bands with open cycle running less than 15% capacity factor and combined cycle running more than 15% capacity factor.
- A run using maximum unit profitability has failed to complete in sufficient time to give any guidance on the usefulness of this method.

A scenario using the second principle was established using preliminary bid analysis from PLEXOS. The applicable marginal cost of unserved energy to be used in the case was derived from the optimal reliability analysis performed by MMA in 2005/06[1]. The values that were obtained previously are in June 2005 dollars and that which were applied in this model as shown in Table 1-2. In each case we have applied some rounding of values for convenience and so as not to imply a high level of precision. Note that in determining dispatch within Strategist the unserved energy was priced at $10/kWh to align with the market cap price. However the unserved energy was costed as shown in Table 1-2.

1.4.2.1 *Gaming the bidding*

The impact of trading rules on behaviour of selected generators was estimated using MMA's *PLEXOS* market simulation model. The model was run across all trading periods to determine the contract and bidding behaviour of key generators in the market, using the gaming model options in *PLEXOS*.

PLEXOS is a chronological dispatch model that determines the dispatch of generating plant required to meet demand in each hour of the year. Wholesale market prices are determined on the basis of hourly dispatch prices, with the contract price determined as the opportunity cost of contracting. The model is designed to simulate the behaviour of participants in the wholesale market. The key behavioural variable is the ability of generators to exercise market power.

[1] "Estimation of the Economically Optimal Reliability Standard for the National Electricity Market", MMA, 16 June 2006. Report prepared for the Energy Users Association of Australia for submission to the Reliability Panel.

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Table 1-2 Assumptions for the marginal cost of unserved energy at 0.002% reliability level for business as usual ($/kWh)

Region	MMA/EUAA Report June 2006	As applied for BAU costs	Basis
Queensland North	N/A	$45	High value loads
Queensland Central	N/A	$10	Industrial base
Queensland South	$46.84	$45	High value loads
Queensland South-West	N/A	$10	Use lower value for over-supplied region
NSW	$7.69	$8	Industrial base. Rounded up
Victoria	$4.65	$5	Industrial base. Rounded up
South Australia	$25.67	$25	Rounded
Tasmania	N/A	$5	Industrial base

The basic mechanism underlying the *PLEXOS* simulation model is a bidding algorithm that allows generators to adjust their price offered in an attempt to achieve a revenue target. Evidence of the exercise of market power is provided when the optimal dispatch solution chosen by the simulation model involves some generators bidding above marginal costs in the NEM. This provides evidence that generators have the incentive under the proposed market rules to exercise market power.

In the medium term model, optimisation of bidding strategies was formulated on a portfolio basis. Attempting to optimise each plant separately in a company will not necessarily optimise the company's profits because each station would then be competing with one another. Moreover, there are other benefits from having a diverse range of stations in a portfolio that are not necessarily shown if each station is considered individually. Each company attempts to reach its revenue target by increasing its offer prices. This process is constrained by the willingness of each portfolio to lose market share in their attempt to bid up prices, thus placing an effective cap on the market price. Bidding strategies are sensitive to the assumptions made on ownership of the power plants, the assumed level of contracting of each portfolio, the structure of the wholesale market and regulations affecting the exercise of market power.

Companies with a large portfolio will also have more of an ability to influence the bidding than the small independent power companies. In PLEXOS this is represented in BAU by

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the larger portfolios marking up their price bids as opportunities arise, which generally correspond to times of high demand and low capacity reserve. This method has been calibrated for the 2006/07 simulation year to recent market behaviour by achieving price duration curves for each NEM region with similar characteristics to recent history. The 2006/07 PLEXOS gaming parameters were then carried forward to subsequent years and were not further adjusted unless excessive market power, evidenced by high market prices that would ordinarily precipitate new entry, was observed.

These bidding strategies observed in PLEXOS were then summarised for peak and off-peak trading periods on a monthly basis and were then imposed on our wholesale market model, *Strategist* to determine the efficiency implications for the proposed trading arrangements for the period to 2025. This process was designed to check what distortions would occur in dynamic efficiency if the current bidding regime continued and for comparison with the distortions identified above in the previous section.

The work to date has been limited to assessing PLEXOS bids from 2007 to 2011 for the business as usual scenario and from 2007 to 2013 for the business as usual scenario with early transmission augmentation.

1.4.3 Efficient Market Development

In the Efficient Market Development scenario (ED), the timing of new entry and the volume of demand side response were determined so as to minimise total system costs. Since new investments in generation or transmission would only be accepted if they reduced system costs over all, it is apparent that they would be able to earn a commercial rate of return appropriate for merchant risk in the first year of operation either through marginal cost trading or through long term contracts that reflected the higher costs of alternative resources.

The analysis was conducted using the PROVIEW module of Strategist which conducts a least cost dynamic programming analysis of expansion options. It was not practicable to do a full analysis because of the time required. Rather an initial expansion plan was developed based on a production cost screening diagram to determine a suitable sequence of base, intermediate and peaking options and then PROVIEW was run by making one year adjustments to timing in several runs within the time available. Chapter 3 shows the convergence achieved was acceptable, although scope for further refinement is apparent. However, our purpose is to show the potential magnitude of benefits from changed policies rather than to obtain an exact assessment and to that end the results are considered useful for that purpose.

Reliability standards were assumed to be economic, so only the value of unserved energy at up to $45/kWh was used to determine reliability levels. This assumes that reliability levels are based on economic criteria. In this scenario, generator bidding patterns followed short-run marginal costs.

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The Efficient Development scenario was formulated in two stages:

- In the first stage only supply side resources were considered assuming that all unserved energy could be avoided through demand side response priced at $25/kW/year and $2,000/MWh not supplied at the wholesale level.
- In the second stage the existing demand side response of 631 MW was added at an average price of $3,000/MWh and the amount of new demand side response was determined based upon the breakeven loss of load hours versus the remaining cost of unserved energy.

The marginal cost of unserved energy was based upon the results of the MMA analysis of optimal reliability for the NEM. The previously assessed values were rounded and adjusted for various sub-regions in the modelling shown in the Table 1-3. Lower values were used where there are known to be industrial loads available that could reduce the exposure to load shedding for high value loads.

Table 1-3 Assumptions for the marginal cost of unserved energy at optimal reliability level for efficient development ($/kWh)

Region	MMA/EUAA Report June 2006	As applied in the report	Basis
Queensland North	N/A	$40	High value loads
Queensland Central	N/A	$15	Industrial base
Queensland South	$41.91	$40	High value loads
Queensland South-West	N/A	$15	Use lower value for over-supplied region
New South Wales	$9.79	$10	Industrial base. Rounded up
Victoria	$13.70	$15	Industrial base. Rounded up
South Australia	$44.10	$45	Rounded up
Tasmania	N/A	$10	Industrial base

The applicable break-even levels of loss of load hours by region for the ED scenario for each region are summarised in Table 1-4 and Figure 1-2. The target loss of load hours changes over time because we have assumed that the cost of demand side response remains constant in real terms whereas the fixed cost of peak generation equipment is expected to decline in real terms.

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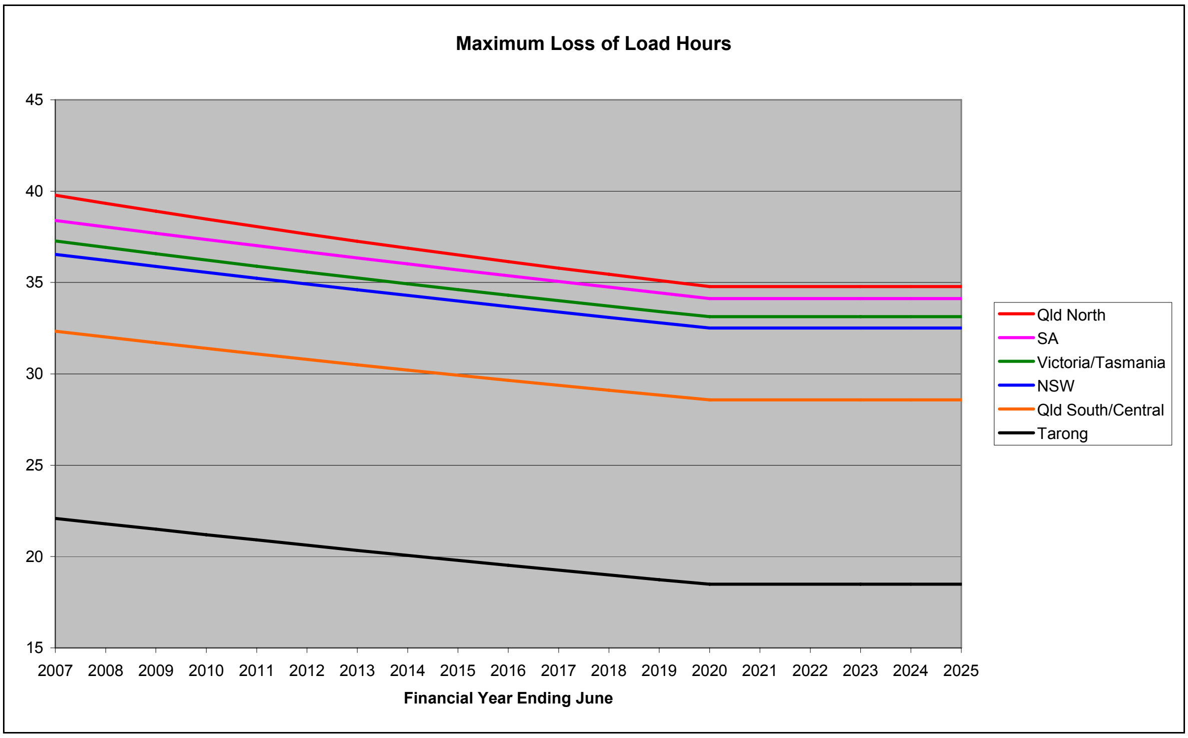
Table 1-4 Loss of load hours for Efficient Development scenario

Region	Stage 1 for Capacity Planning (Versus Demand Side Response)	Stage 2 for Demand Side Planning (Versus Unserved Energy)
Queensland	18.5 – 22.1	0.58
NSW/Snowy	32.5 – 36.5	3.13
Victoria	33.1 – 37.3	3.13
South Australia	34.1 – 38.4	1.09
Tasmania	33.1 – 37.3	3.13

Figure 1-2 Trend for maximum loss of load hours for supply-side capacity planning



1.4.4 Transmission Augmentation Scenarios

For the two Transmission Augmentation scenarios TAED and TABAU, the concept applied was that three developments of existing interconnections would be applied by July 2008. These involved:

- Enhancing QNI by 400 MW.
- Augmenting Heywood Interconnection by 300 MW.
- Upgrading the Snowy to Melbourne link by 600 MW in two stages of 180 MW and 420 MW respectively.

The timing of the Tarong limit upgrade and from Central to North Queensland were treated as intra-regional developments that were allowed to be jointly timed by means of the optimisation process with the choice of generation options. The subsequent timing of these options has been explored but is not fully optimised. However, MMA considers that a reasonable indication of appropriate timing and cost impact has been assessed.

The TAED scenario examines the transmission augmentation in the context of Efficient Development (ED) and apart from these earlier network developments it was developed on the same principles as scenario ED. The purpose of this analysis was to show when such an early development would create net economic benefits.

The TABAU scenario examined the transmission augmentation in the context of Business as usual (BAU). The purpose was to assess what additional costs would be imposed that would need to be matched by competition benefits if customers were to be better off overall.

1.5 PLEXOS and Strategist

MMA has a comprehensive database of the electricity systems in the NEM. Forecasting spot market prices or pool prices requires the use of a model of the interconnected Australian electricity systems. The model needs to account for the economic relationships between stations in the system. In particular, the model needs to calculate production at each power station given the availability of other stations and the costs of production for each station. The model also needs to account for price bids by each station under various bidding strategies to determine expected spot market prices. MMA has developed the database for two different models of the NEM in east and south-east Australia. The models are based on two commercially available software products, *Strategist* from New Energy Associates[2] and *PLEXOS* from Drayton Analytics[3].

Strategist provides a fast probabilistic model of fuel sources, hydro and thermal power stations and emissions and can be used with a dynamic programming capability to assess optimal expansions of supply and demand based energy services. *PLEXOS* offers Monte Carlo capability with features which allow optimal bidding for generation portfolios and unregulated interconnectors. *PLEXOS* assesses price chronology and price volatility in more detail.

1.5.1 Modelling Approaches

We used our probabilistic market model *Strategist* to formulate the long-term supply/demand base case scenario in the NEM. This is more readily done using *Strategist* because of the speed of processing and the ability to assess demand side programs, emissions based dispatching and long-run trading of abatement certificates.

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[2] www.NewEnergyAssoc.com/products/strategist/

[3] www.DraytonAnalytics.com/plexos_home.asp

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The advantage of using *Strategist* is that it provides a convenient basis to track the effects of emissions abatement in NSW and Queensland and determine its impact on new plant timing. Because of the complexity of the whole NEM, the emission abatement prices for GECs and NGACs were fixed at initial values in the expansion analysis. They were then adjusted after the expansion plans were finalised so that total costs would take into account relationships with emission abatement.

This work did not fully explore the volatility of revenue. We obtained an indicative estimate of average revenue and its relationship to market prices.

The scenarios were based on medium economic growth with an expected contribution from renewable energy and those additional resources needed to meet Greenhouse emissions abatement in Queensland and NSW and the renewable energy target for Victoria.

We used *PLEXOS* to simulate selected trading periods (for peak and off-peak periods) and determined the contract and bidding behaviour of generators in the market.

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2 INPUT ASSUMPTIONS FOR MARKET MODELLING

This chapter summarises the key input assumptions that were key drivers to the analysis.

2.1 New entry costs

Table 2-1 summarises the projects that were considered in the new entry analysis. The list is rather extensive because there are a large number of options for development in the NEM including:

- Addition of capacity to existing units by replacement of boiler and turbine components (eg Loy Yang and the 660 MW coal fired units in NSW)
- Addition of new plant at existing sites (eg Hallett, Mintaro, Snuggery, Millmerran, Tarong North, Kogan Creek, Swanbank F)
- New Greenfield developments (Mortlake, Spring Gully, Condamine)
- Enhancements to existing inter-regional links (QNI, Snowy to Melbourne, Heywood interconnection)
- Intra-regional developments that affect inter-regional trade (Latrobe Valley to Melbourne, Tarong to Brisbane, Central to North Queensland
- New interconnections (NSW to South Australia, Central Queensland to Mt Isa).

The projects are grouped by the region when the generation plant is located. The transmission projects were included in the region that is expected to be the primary beneficiary. The projects are also included in approximate order from most beneficial to least beneficial with similar technologies grouped according to energy production role.

Some of these options have been excluded from the study (refer Appendix A) because they are unlikely to be economic in the time frame of the study in the context of the defined scenarios. We have also over-looked some options or simplified them to achieve useful results with the available time and resources.

Some options are quite specific such as Braemar extension and Kogan Creek B whereas others are generic open and combined cycle gas fired options that may be needed after the lower cost options have been exploited.

2.2 Additional risk of coal fired development

There is perceived, under current market arrangements, an additional risk of building new coal fired plant that relates to the uncertainty of future emission abatement imperatives. This risk represents a potential loss of revenue of up to \$15/MWh based on carbon abatement costs up to \$15/t CO_2 higher than current emission abatement policies and consistent with the subsidy to renewable energy through MRET. In this study the risk premium has been assumed to be equivalent to \$5/t CO_2 which is equivalent to about \$5/MWh penalty cost. For a coal plant costing \$1,500/kW, this is equivalent to a loss of

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Table 2-1 Summary of new entry options

Region	Name	Size (MWso)	Technology	Role	Available	First Unit BAU	First Unit ED
Qld North	QN OCGT	130	Open cycle GT	Peaking capacity for North Qld	Nov-08	Nov-14	Nov-15
	QN CCGT	380	Combined cycle	Intermediate load for North Qld	Nov-09	Nov-17	N/A
Qld Central	QC BLCL	450	SC Black Coal	Base load power for Queensland central and northern regions	Nov-10	N/A	N/A[1]
Qld South	Wambo Sth OCGT	145.5	Open cycle GT	Peaking capacity for southern Queensland	Nov-08	Nov-10	Nov-12
	QS CCGT	385	Combined cycle	Intermediate load for Southern Qld	Nov-09	Nov-10[2]	Nov-15
Qld S-West	Braemar	150	Open cycle GT	Peaking capacity for southern Queensland	Nov-08	N/A	N/A[3]
	Kogan Creek B	705	Black coal	Base load power for NSW and South Qld	Nov-11	Nov-16	Nov-22
	Millmerran 3-4	420	Black coal	Base load power for NSW and South Qld	Nov-12	Nov-22	N/A
	Tarong-Brisbane	1000	Transmission	Convey power from South-west Queensland and QNI to Brisbane load centre	Nov-09	Jul-15	Jul-12
	QT CCGT	388	Combined cycle	Intermediate load for Southern Qld	Nov-09	N/A	N/A[4]
NSW	Tomago OCGT	250	Open cycle GT	Peaking capacity for NSW	Nov-08	Nov-09	Nov-17

[1] Combinations of Central Queensland coal fired genenration with upgrades to South and North Queensland were not considered in the study.
[2] The Queensland CCGT was advanced in BAU to respond to high prcies that would otherwise occur in South Queensland.
[3] Peaking plants were installed in the Queensland South region rather than the South-west so as to avoid the cost of additional transmission to the Brisbane area.
[4] The development of gas fired combined cycle plant in South-west Queensland was not fully explored. The Origin Energy Spring Gully project would be a suitable candidate. Electricity transmisison costs to the load centres may be a significant cost. Combned cycle plant was added in the South-east region instead.

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Region	Name	Size (MWso)	Technology	Role	Available	First Unit BAU	First Unit ED
	Tomago CCGT (by conversion of OCGT)	400	Combined cycle GT	Intermediate load for NSW	Nov-09	Nov-11	Nov-20
	Munmorah OCGT (4 units)	150	Open cycle	Peaking capacity at existing power station site	Nov-08	Nov-16	Nov-21
	Bayswater (4 units)	697.5	Black coal	Unit uprating for base load and intermediate power for NSW	Nov-09 – Nov-12	Nov-10 – Nov-12	Nov-17 – Nov-18
	Eraring (4 units)	697.5	Black coal	Unit uprating for base load and intermediate power for NSW	Nov-09 - Nov-12	Nov-14 – Nov-15	Nov-22 – Nov-24
	Mt Piper (2 units)	697.5	Black coal	Unit uprating for base load and intermediate power for NSW	Nov-09 – Nov-10	Nov-13	Nov-18 – Nov-21
	Port Kembla Cogen	194	Cogeneration	Base load power using waste gas and natural gas	Nov-10	Nov-15	Nov-18
	N OCGT	200	Open cycle GT	Peaking capacity for NSW	Nov-08	Nov-10	Nov-15
	N CCGT	400	Combined cycle	Intermediate load for Vic and SA	Nov-09	Nov-16	Nov-21
Snowy	Wagga [5]OCGT	150	Open cycle GT	Peaking capacity for southern NSW and Victoria	Nov-08	N/A	N/A
Vic	NewVic1	180	Transmission	To provide additional peaking capacity to Victoria and South Australia	Nov-08	Jul-13	Jul-17
	NewVic2	420	Transmission	To provide additional peaking capacity to Victoria and South Australia		Jul-16	Ju-20

[5] Note that Wambo Wagga open cycle plant is modelled in the Snowy region in the MMA model to recognse that it will be constrained by the transmission capacity between Snowy and Sydney. The impact of this option was not explored in the modelling to limit the number of choices studied.

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Region	Name	Size (MWso)	Technology	Role	Available	First Unit BAU	First Unit ED
	Maryvale	150	Cogeneration	Base load power in association with steam for pulp and paper mill	Nov-09	Nov-13	Nov-16
	Western CCGT	500	Combined cycle	Base load for Vic and SA	Nov-09	Nov-15	Nov-18
	Latrobe Valley CCGT	372.5	Combined cycle	Intermediate load for Vic and SA	Nov-09	Nov-24	Nov-23
	Latrobe Valley Brown Coal	440	Advanced Brown coal	Base load for Vic and SA	Nov-12	Nov-20	Nov-18[6]
	V OCGT	160	Open cycle GT	Peaking capacity for Vic and SA	Nov-08	Nov-12	Nov-20
	V CCGT	385	Combined cycle	Intermediate load for Vic and SA	Nov-09	N/A	N/A[7]
Tas	Tas GT	120	OCGT	Peaking and energy reserve	May-08	Nov-18	Jul-18
	Tas CCGT	200	CCGT	Intermediate energy production	May-09	N/A	N/A

[6] The timing of new brown coal plant in Victoria could be further refined in the scenarios. There is no obvious reason why it should be earlier for ED than BAU.
[7] Generic CCGT was not used. Western Victoran and Latrobe Valley versions of combined cycle plant were used.

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return on capital of about 2.4%[1]. In the Efficient Development scenario, no new coal fired plant was required prior to 2019. The coal plant development was based upon upgrading the NSW coal fired plants plus one new base load unit in Victoria and Queensland.

In optimising the expansion analysis of the market we have added 2.4% to the WACC for coal fired resources when determining the costs of development of such plant. However, when the present value economic costs were assessed, we applied a 7% real discount rate to all costs. The annual costs of coal plant were assessed at the higher WACC level. Thus made coal plant unfavourable in the efficient development scenarios and it was not included in any of the refined expansion plan analysis. Despite this disadvantage for new coal plant the carbon emissions were higher for Efficient Development than for Business as Usual because a more efficient merit order favoured the existing coal plants.

2.3 Intra-Regional Transmission Costs

The scenarios were developed assuming that intra-regional transmission costs are unaffected by the particular plant mix in each region. The Strategist model includes four zones within Queensland and it was possible in principle to consider what transmission costs might be imposed on the main central to north, central to south and west to east links within Queensland. The primary focus was on Tarong to Brisbane (west to south) and central to north. Tarong to Brisbane is important because it is needed in association with developments in south-west Queensland. Central to North Queensland is important because it is an alternative to developing new capacity in North Queensland.

Where intra-regional transmission is associated with particular generation developments, such as Latrobe Valley to Melbourne, associated costs were incorporated into the scenario for major transmission reinforcement (e.g. a 5th 500kV line may be needed according to generation capacity in the Latrobe Valley).

2.4 Inter-Regional Transmission Costs

The modelling has taken the major upgrades to the interconnections that have been identified in the Annual Transmission Reviews and considered when these would be economic. The main upgrades were considered as follows. In each case the additional capacity was assumed to apply in both directions. This is consistent with the way that Strategist models interconnection link upgrades. It may not be correct for all the links modelled. For example the 600 MW upgrade of Snowy to Victoria would not be expected to be fully realised in the reverse direction.

2.4.1 Tarong Limit

The Strategist model has four zones representing Queensland: South-west (Tarong), South, Central and North. To limit the number of alternatives we have assumed that the central

[1] Cost ratio 2.4% = 5 * 8760 * 0.9 / 1500 / 1.1. The 90% is the available capacity factor and the 1.1 is the ratio to include interest during construction.

to south and central to north capacity remains static over the review period unless developments are associated with specific reliability requirements. However, for the limit between Tarong and Brisbane we have made provision for 1,000 MW enhancements should they be needed in association with expansion at Millmerran, Kogan Creek, Braemar or the development of Spring Gully. We allowed PROVIEW to schedule the upgrade when needed on an economic basis.

2.4.2 QNI Upgrades

A 400 MW upgrade to QNI[2] which would create benefits from the surplus low cost plant in Queensland and the seasonal and weekly peak load diversity between NSW and Queensland. It has been estimated that such an upgrade would cost between $100 - $120 M to provide line series compensation and voltage support. The annual cost of this transmission capacity is $30/kW per year at a 10% discount rate. Assuming that this capacity is used to supply the NSW base load at 90% capacity factor, the cost of transmission would add approximately $3.80/MWh to the Queensland average cost of energy. Assuming a base load energy price of around $32/MWh in Queensland, base load power transmission to NSW would cost around $37.80/MWh after including losses of 6%. This upgrade is thus economically viable with the avoided cost of base load energy in NSW estimated to be around $40/MWh.

Two other options have also been suggested involving either the installation of a back-to-back high voltage DC link or a new line development. The HVDC link would add up to 500 MW at a cost of around $350M while the new line development would add up to 1,000 MW costing around $700M. In both instances the cost of this capacity would amount to around $700/kW or $8.90/MWh on base load operations. This implies that the base load power transmission to NSW from Queensland would cost around $43/MWh after including losses of 6%. These options are thus marginal for base load operations. Alternatively, the additional capacity could be considered for peaking operations. Peaking operations will result in higher losses as the system is under greater stress at high loads. Adding losses at 8% to the cost of capacity of $700/kW gives a capacity costs around $760/kW. This is marginal as gas turbines installed in NSW would cost around $700/kW.

These considerations suggest that a further upgrade to QNI could be economic providing that generation costs in Queensland remain substantially below the equivalent costs in NSW. NEMMCO also indicated that these upgrades would be expected to pass the regulatory test for market benefits[3].

[2] TransGrid, *NSW Annual Planning Report 2006*, pg 47

[3] Assessment of the 2005 ANTS conceptual augmentations: Verification Studies, IRPC, 8th February 2006, page 2.

2.4.3 Snowy to Melbourne

A 600 MW upgrade to the Snowy to Victoria interconnection for $161M[4] ($268/kW) which would create benefits from the peak load diversity between NSW and Victoria and the surplus capacity in NSW at Liddell and Munmorah. This includes $61M for works in Victoria and $100M in NSW. This upgrade would divert some Snowy power away from NSW at the time of the Victorian peak demand as NSW generators increase their output in response to the higher NSW price. The on-going benefits would depend on continuing peak load diversity which is sustained by the regional weather patterns which make it extremely unlikely that NSW would not have spare capacity at the time of the Victorian peak. The limit on the economic level of capacity from Snowy to Victoria would be determined by the lesser of:

- The Snowy generating capacity during summer **plus** the NSW export limit to Snowy – which represents the maximum power flow that could be transmitted to Victoria. This value is typically about 4,000 MW.
- The load diversity as measured by the difference between the NSW peak demand and the NSW load at the time of Victorian peak demand less any committed maintenance at such times **plus** any spare capacity in NSW – normally scheduled NSW maintenance would be very low at the time of the Victorian peak because both regions have peak demands in the summer season. This value is currently about 15% of the NSW peak load plus 700 MW spare capacity at Liddell and Munmorah which would give a total of 2,800 MW, decreasing to 2,100 MW as the NSW capacity surplus is eroded over the next several years. The diversity will then increase again as NSW demand increases.

The published information suggests that the Snowy to Melbourne upgrade could be accomplished in two parts, a first stage of 180 MW and a second stage of 400 MW. The first stage is more expensive on a per MW basis, being $65.5M for 180 MW at $65.5M. The average and incremental costs of these stages are shown in Table 2-2.

Table 2-2 Snowy to Melbourne development stages

Stage	Capacity MW	Capital Cost $M	Incremental Cost $/kW
1	180	$65.5	$364
2	420	$95.5	$227
Both	600	$161	$268

These costs are well below the costs of open cycle gas turbine plant and there will be sufficient diversity between peak load in NSW and Victoria to indicate that such

[4] VENCorp 2006 Annual Planning Report, page 94 shows the transmisison works necessary in Victoria to incraese import from Snowy by 600 MW. There may be some additional works in NSW to supprt such power transfers. The 2005 ANTS stated the cost at $75 M in 2005/06 dollars for a 180 MW capacity increase with an estimated economic timing of 2009/10.

augmentation should be the most economic next capacity addition to Victoria, apart from some possible plant capacity enhancements which may be of lower cost. These two stages were included in the economic analysis. As a result of this analysis the initial development sequence commenced with these projects.

2.4.4 Heywood Interconnection

A 270 MW upgrade to Heywood interconnection at a cost of $135M[5] ($500/kW) which would take advantage of lower cost power in Victoria relative to resources available in South Australia, particularly after the coal resource at Leigh Creek is depleted. There is very little load diversity between Victoria and South Australia at times of extreme peak demand, so most of the benefits would need to come from energy flow from NSW/Victoria to South Australia. There is some diversity for peak winter demands and for 50% POE summer peak demands, so there is some reliability benefit most of the time. This option was included in the expansion analysis. There is an additional potential to increase the upgrade capacity to 300 MW by the expenditure of an additional $22M for the installation of a 200 MVAr SVC at Heywood. By itself, this expenditure is unlikely to be economic but there are additional benefits in supporting an increased load at Portland. Accordingly, the cost of the SVC would be discounted by the value of these additional benefits and the unit cost of $500/kW is unlikely to be significantly different with its inclusion. For this purpose, we have represented 300 MW to be available at a cost of $500/kW. Preliminary results show that this option is not viable in one step prior to 2018 in the Efficient Development scenario. It was included in Nov 2018 but it may be more efficient at a later date which would require additional analysis.

2.4.5 Central to North Queensland

The expansion of capacity from Central to North Queensland is material to the market analysis because of the potential competition between generating capacity in North Queensland and import from Central Queensland. The network performance issues are quite complex because of:

- The load supply points all along the transmission network.
- The dynamic performance which requires a minimum impedance between the two zones to support dynamic stability.
- The potential for use of flexible AC technology to enhance stability of the network.

We have represented a 315 MW expansion of transfer capacity at a cost of $271M to represent the construction of a new 275kV line at $0.33M/km for approximately 700 km plus $40M for termination equipment. This gives a unit cost of $860/kW. This is more

[5] VENCorp 2006 Annual Planning Report, page 93 shows three projects necessary for this enhanceent including a third Heywood transformer, a third 275kV line from Heywood to South-East Substation and some reactive power plant for a total capital cost of $73 M. Tne 2005 ANTs quoted $125-135 M also including an additional South East Tungkillo 275kV line in South Australia. In addition the VENCorp 2006 Annual Planning Report provides for an additional $22m for the SVC at Heywood.

expensive than open cycle gas turbine capacity but may be cost effective versus a combined cycle plant if sufficient low cost energy is available from the south.

2.4.6 South Australia – NSW Interconnection

In 1998 TransGrid proposed to develop an AC interconnection from Darlington Point via Buronga to Adelaide called SNI for South Australia – NSW Interconnection. The original proposal was eventually abandoned as it was overtaken by a number of power developments in SA, including the development of Pelican Point, the refurbishment of Playford Power Station and the development of Murraylink. The subsequent review process showed that the total project as formulated by TransGrid would no longer maximise market benefits. One significant limitation was that the incremental capacity that could be provided in addition to that contributed by Murraylink would be about 160 MW even though the transmission link from Buronga would be able to carry 250 MW, apart from constraints arising in the Victorian network. Various later assessments indicated that the whole project would not pass the regulatory test but that some components that would enhance Victorian import capacity would maximise market benefits. Accordingly, the 400 MW upgrade of the Snowy to Victorian import capacity proceeded in 2002.

2.5 NSW/Snowy to South Australia Connection

There remains the possibility of augmenting the network between Snowy/NSW and South Australia, but the costs remain uncertain but significant. A paper published in April 2004 by IPA suggested a cost of $110M, which today would be about $120M. Some additional costs would be incurred to achieve a full 250 MW capacity, perhaps another $20M. This would give an average cost of at least $140M at $560/kW which is more expensive than upgrading through Heywood. On this basis, we have omitted further consideration of SNI.

2.5.1 Summary of Interconnection Projects

Table 2-3 shows the interconnection options that were considered in the analysis. The equivalent weighted average cost of capital for the annualising of their costs was 7% real pre-tax based on debt/equity of 75% and equity return of 12% real. Operating costs were assumed to be 1% of capital cost.

Table 2-3 Summary of interconnection options

Project	Capacity MW	Capital Cost $M	Incremental Cost $/kW
Tarong Limit	1000	$102	$100
QNI Upgrade	400	$120	$300
NewVic 1	180	$65.5	$364
NewVic 2	420	$95.5	$227
Heywood	300	$150	$500
Qld Central to North	315	$271	$860

3 MARKET ANALYSIS RESULTS

3.1 Efficient Development Scenario

The Efficient Development (ED) scenario was formulated based on short-run marginal cost (SRMC) bidding and an analysis of total costs for capital, operating and maintenance and fuel. Capital costs were annualised for each option and then inserted as a fixed cost. The annualising method accounted for WACC as well as the expected future trend in capital costs. Emission revenues arising to generators from GECs and NGACs were recognised in formulating SRMC and the total costs of the NGAC and GEC sales at the assumed or estimated prices (as appropriate) were added to represent the total costs to consumers and producers.

To contain the expansion planning analysis to practical dimensions some additional reliability criteria were applied as follows.

- A minimum reserve margin of zero relative to the 50% POE peak demand was applied on the basis that stakeholders may not accept a role for demand side response that covers median peak demand on a firm basis. This criterion was an essential feature of Strategist and a value above zero had to be applied. Using the lowest possible value assists in finding the optimal role for demand side response.
- A maximum unserved energy level which corresponds to the magnitude of remaining demand side response was set at 0.02% for each region. This level is ten times the current reliability standard. It represents a level above which it is regarded as difficult to gain acceptance of an increased role for demand side response.
- A maximum unserved energy level for the system as a whole was set at a lower level of 0.01% to represent concerns that widespread reliance on demand side response across all regions at high levels would be regarded as difficult to accept by market participants.

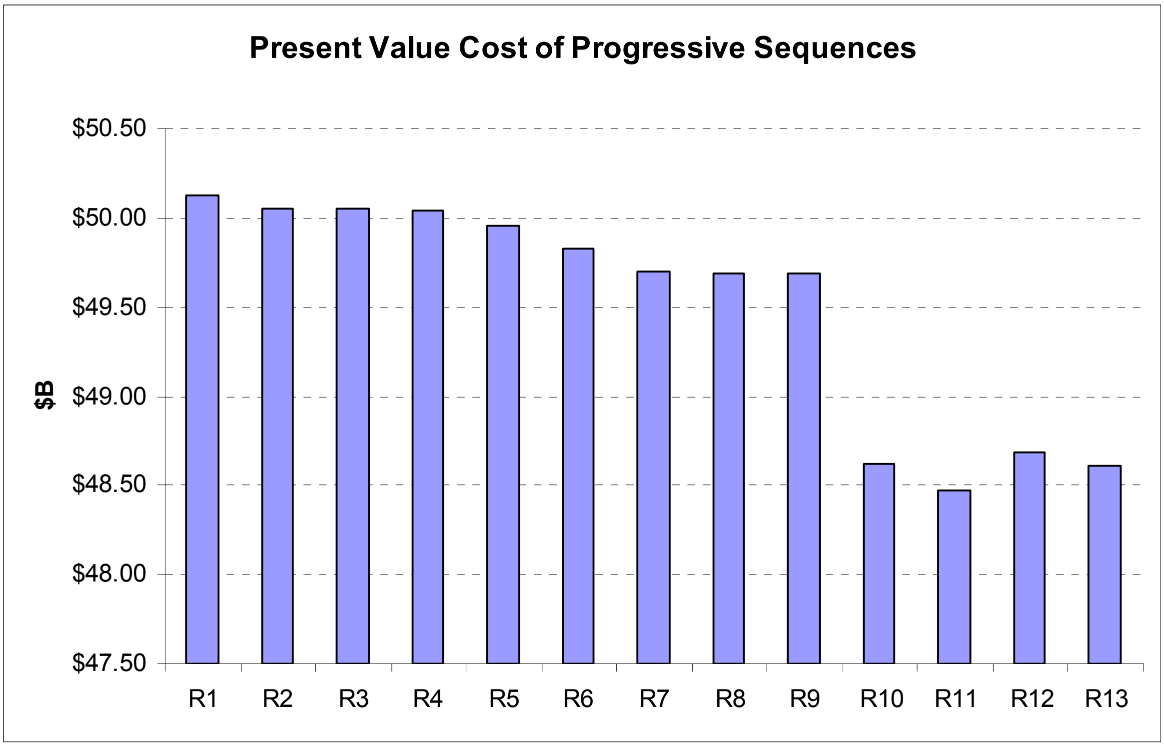
3.2 Expansion Plans

The components of the Expansion plans for the ED and TA scenarios were progressively developed by:

- Firstly, estimating a candidate expansion plan by choosing lowest cost resources initially.
- Checking the dispatch of the resources to ensure that peaking and intermediate plants operate at efficient levels.
- Performing several runs of PROVIEW to test alternative sequences in an attempt to find a lower cost solution.
- Reviewing the later years of the expansion plan where the sequence had not been fully optimised to remove excess plant not required to meet reliability and reserve criteria.

The progressive reduction in NPV levelised cost at 7% real discount rate for the Efficient Development scenario is shown in Figure 3-1. The slight step down at the R10 stage was when the period from 2019 to 2025 was optimised by deferring new capacity as much possible to match target reserve margins whilst keeping unserved energy (for 50% POE peak demand) within 0.001%. R10 was selected as the least cost expansion for the first draft report. Further analysis after R10 involved adding NGAC factors for new entrants which had not been adequately established in the first round of analysis. This resulted in revision 13 being accepted as the basis for the ED scenario. The relatively small variations in the levelised system cost for the subsequent iterations as shown in Figure 3-1 demonstrates the extent to which the overall cost assessment has stabilised. This shows that the costs were reduced by about 3% in the course of the analysis and that final variation was about 10c/MWh out of $48.50/MWh. This suggests that the accuracy achieved for the stated assumptions was about 0.2%.

Figure 3-1 Evolution of the cost of the ED scenario.



3.3 Transmission Augmentation with Efficient Development

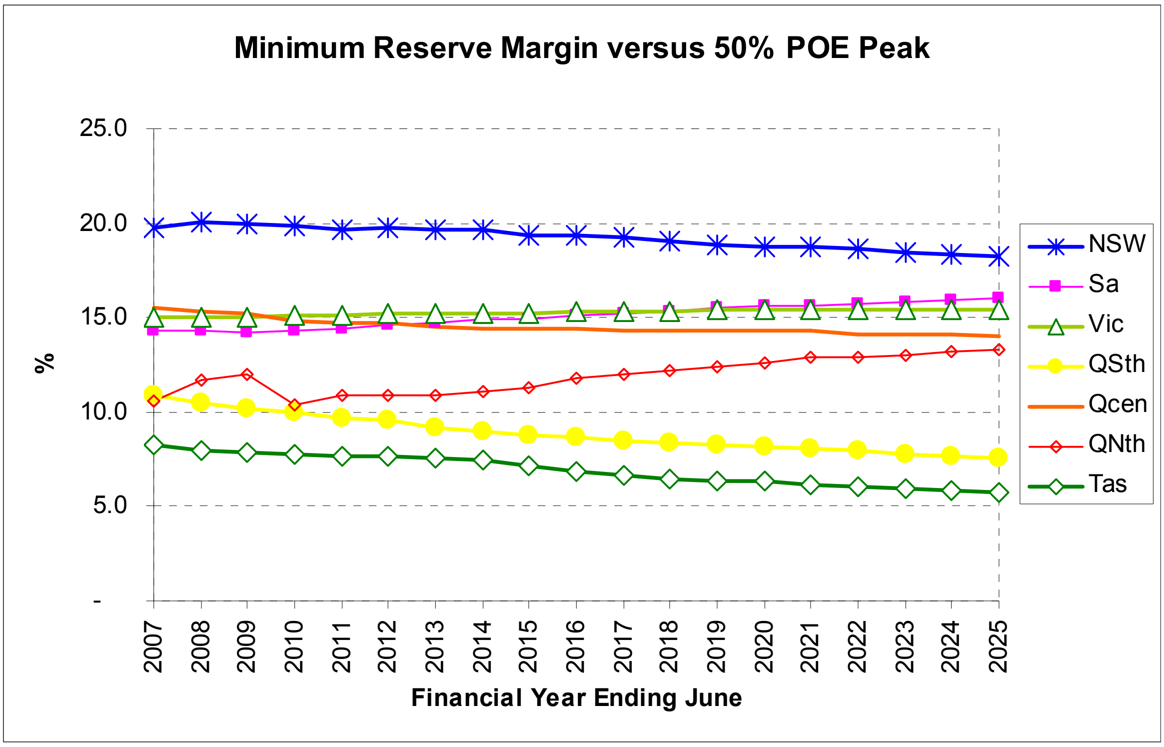
As a first step in developing the Transmission Augmentation Scenario, an efficient expansion plan was developed on the same basis at ED except that the three main interconnection augmentations were added in July 2008. This scenario was designated TAED. By 2019 these two scenarios should have converged because all of the interconnection upgrades were the same by 2019 financial year. However, in the present form, TAED has a Central Queensland to North Queensland upgrade in July 2017 which did not occur in the ED expansion until July 2019. Thus from 2020 the results for the TAED scenario was ignored and the ED scenario results were used to represent an equivalent result. Thus implies that the TAED scenario as currently formulated would benefit from some further refinement to match the ED performance. It may be that the advancement of the interconnectors has an effect on plant mix that would take longer than 2020 to work out. However we do not consider this to be proven by the current analysis.

3.4 Business as Usual Scenario

The BAU scenario was initially developed using some preliminary estimates of bids from PLEXOS together with reliability criteria matched to the current regulatory regime. The following principles were progressively adopted as the BAU case was refined:

- The capacity reserve margin as currently implemented was used as the basis for installing new generating capacity. The reserve margin was calculated relative to the 50% POE peak demand as modelled. The minimum reserve levels for each region were as shown in Figure 3-2. The reserve levels progressively decline in general as the capacity reserve margin becomes smaller relative to peak demand. Where the 10% POE peak demand is growing more quickly than the 50% POE peak demand the reserve ratio is increasing. This reserve margin was maintained on the basis that the role of NEMMCO as Reserve Trader and the interpretation placed on information in the Statement of Opportunities (SOO) tends to encourage supply capacity to meet these targets as a minimum response to reliability requirements.

Figure 3-2 Reserve margin relative to 50% POE peak demand for BAU



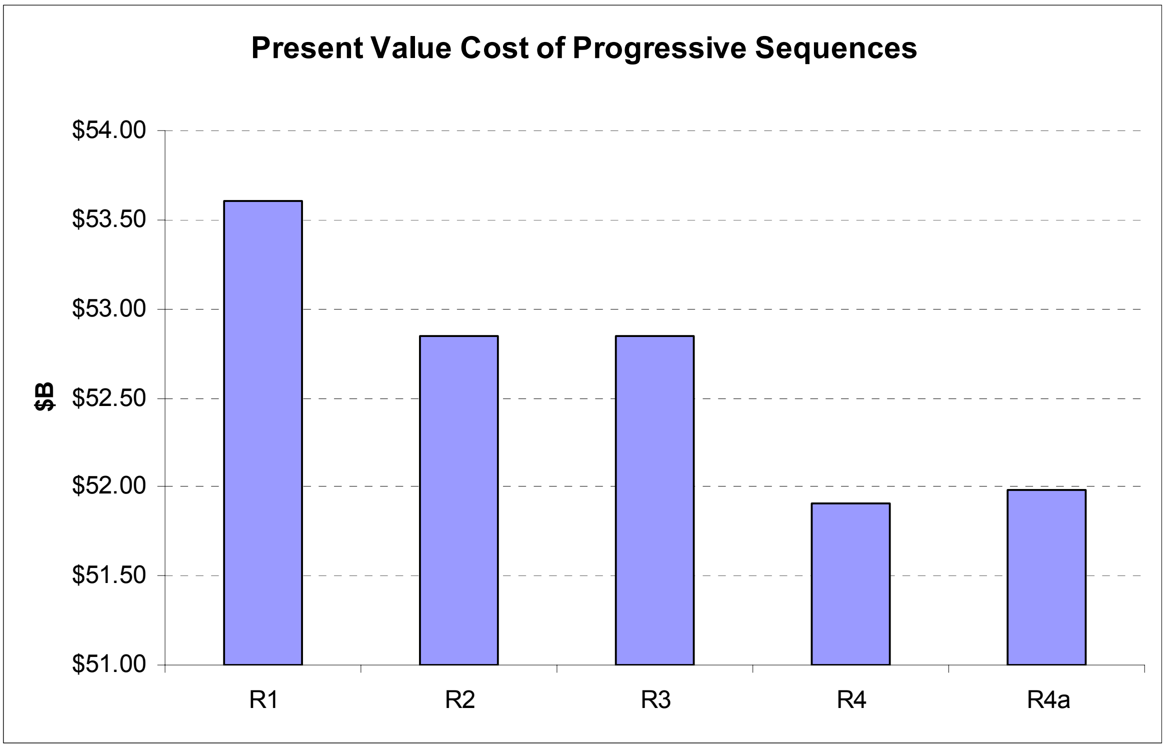
- In addition to the capacity reserve criterion, a reliability target was applied to the 50% POE peak demand for a maximum unserved energy of 0.001%[6]. This was added to help limit unserved energy where the reserve margin might no longer be a sufficiently accurate measure of reliability. This is half the normal standard of 0.002% on the basis that the remaining portion would be applicable to conditions with greater than 50% POE demand. In the northern regions the 50% POE share is much lower than 0.001% based upon Monte Carlo simulations because of the flatter peak load profile. Given the modelling approximations made in Strategist it was considered preferable not to be too conservative in assigning the need for reserve capacity which would have been the result if we had set a more stringent unserved energy criterion for 50% POE peak demand.
- The inter-regional pricing in the BAU case was based upon $10,000/MWh at nominal prices assuming 3% pa CPI as the dispatch cost of unserved energy. The actual cost of unserved energy was evaluated using the marginal value as shown above in Table 1-2. Using the marginal value may slightly overstate the cost of unserved energy. Representing a full unserved energy cost curve could be considered as a refinement but would be unlikely to alter the overall results because the cost of unserved energy is abut 0.2% of the total cost in the BAU scenario on average over the study period, about the same as the estimated error level.

The development of the BAU case with PLEXOS bids involved estimating an initial expansion to 2025 that met the minimum reserve criterion and then a progressive refinement of the expansion plan by successive adjustments to lower costs using PROVIEW. Figure 3-3 shows the evolution of the present value BAU cost for the four main iterations which include some adjustments to the PLEXOS bid gaming analysis. The small change in the final result R4a indicates that we are close to a minimum cost for this scenario.

From 2020 the BAU and TABAU scenarios had similar costs as would be expected because they have the same inter-connection arrangements by that time. Therefore, for the purposes of current analysis we have taken the minimum of BAU and TABAU from financial year ending June 2020. With the latest revision, the TABAU scenario has lower costs after 2020.

[6] There is an additional reason why a higher unserved energy target is needed in Strategist than would occur in the market. A higher level is needed because Strategist models the peak load as a one hour period in the peak month. This is equivalent to 4.3 hours of peak demand. Therefore a higher level of unserved energy would be expected in Strategist because of the longer duration of the peak demand than in the actual market.

Figure 3-3 Evolution of BAU cost



3.5 Transmission Augmentation with Business as Usual (TABAU)

The transmission augmentation scenario in the context of business as usual was developed by advancing the transmission developments and then refining the expansion plan to meet the reliability criteria by deferment. A full analysis of least cost using the PLEXOS bids has been completed to 2016. The major focus after that time has been on deferring plant within reliability and reserve margin constraints and applying some bidding above marginal costs for new plants to produce a sustainable price path similar to that which has been observed in recent years. The PLEXOS bids were developed for the final expansion sequence developed in Strategist. Some further analysis could perhaps refine the development sequence but significant change in cost is unlikely because plants are operating in an efficient regime apart from those participating in the market gaming.

Based upon the data provided in Table A- 1 we have concluded that the effect of transmission augmentation under BAU is as follows:

- Plant expansion is substantially unaffected in **North Queensland** because that region is almost self-contained due to the Central to North Queensland constraint. There remains scope to optimise the timing of the Central to North Queensland augmentation in this analysis. The Central to North expansion is two years later in TABAU than BAU and this may be contributing to the lower costs of this scenario.
- Transmission augmentation requires plant to be advanced in **South Queensland** to support exports south.

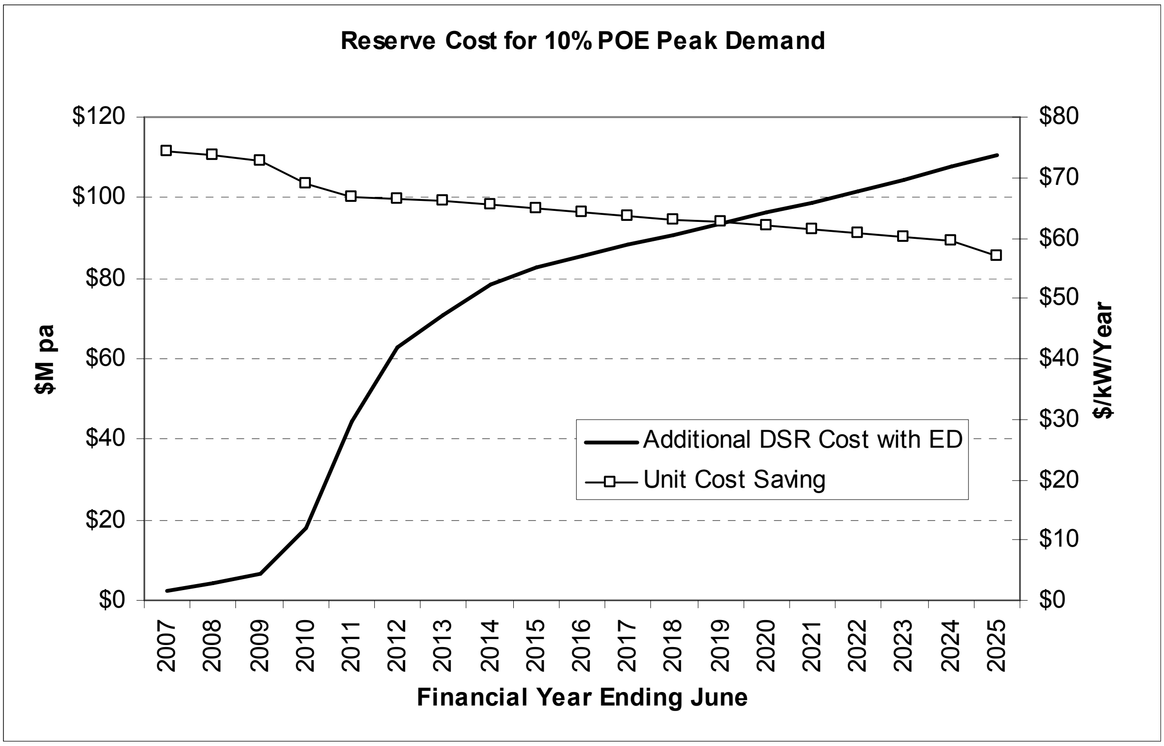
- New plant can be delayed in **NSW** as a result of transmission augmentation. Since power generation costs are generally higher in NSW this yields net benefits.
- New plant in **Victoria** and **South Australia** is delayed in the period to 2015 with transmission augmentation.
- New plant in **Tasmania** is not affected by mainland interconnection developments. The expansion development for Tasmania has not been optimised in this study. Peaking plant should be sufficient to manage variations in hydro yield throughout most of the study period.
- The analysis shows that benefits for transmission augmentation under Business as Usual commence in 2011 financial year and the composite analysis has notionally delayed the transmission augmentation in the composite TABAU analysis from 2009 to 2011.

3.6 Demand side response for extreme years

In comparing the scenarios, it is necessary to recognise the less frequent demand side response associated with years when peak demand exceeds the median (50% POE) forecast. Our modelling has not included the unserved energy associated with peak demand in excess of 50% POE and therefore it would not be consistent to add the cost of this extra demand side response in full unless the unserved energy saving was also recognised. However, it is conservative to add the fixed costs associated with the extra demand side response where this is not already provided through existing surplus capacity or new capacity included on the basis of reserve margin targets.

Specifically, in Efficient Development, we have not included the cost of additional demand side response for the gap between 50% POE and 10% POE peak demands. However, in BAU we have included the capacity to meet this additional service requirement because the BAU reserve margins require the capacity to be provided. Therefore to refine the analysis, we add to the ED and TAED scenarios the fixed cost of the additional demand side response that would need to be provided to meet the 10% POE peak demand. In Figure 3-4 we show the cost of this additional reserve based on usage of the existing spare capacity and existing demand side response where feasible. This cost has been added to the costs for ED and TAED where the reserve margin to cover 10% POE peak demand has not been included otherwise. The chart also shows the effective unit cost saving between the fixed cost of demand side response and an open cycle gas turbine.

Figure 3-4 Additional costs in ED/TAED for demand side response to meet 10% POE peak



3.7 Relative Costs

Figure 3-5 shows the relative annual cost benefits of selected scenarios in their raw form with the additional fixed costs for 10% POE demand side response for the ED/TAED scenarios. The results show the similarity of ED and TAED throughout the study period. This shows that transmission augmentation has no economic benefit if the market is otherwise efficient. It is considered that by 2022 these two scenarios should be equivalent on an annual basis. Therefore the minimum of ED and TAED from 2022 is taken as the composite scenario for efficient development. This results in ED values being used for the current iteration. Modified results which resolve these inconsistencies are shown in Figure 3-6. Further analysis uses this composite of the four cases as a better basis for making meaningful comparisons.

In the formulation of TABAU after the expansion analysis, it was found that TABAU had a sustained benefit relative to BAU after 2022. This fact was taken as evidence that BAU and TABAU are not fully optimised and consistent. Further study of TABAU showed high prices in Queensland North from 2017 and in Queensland South from 2022. Some peaking and combined cycle plant was advanced to capture the value of these high prices in TABAU and this reduced the apparent long-term benefit for transmission augmentation. From 2022 the lower cost from the BAU and TABAU scenarios was taken as an appropriate estimate for BAU.

Figure 3-5 Comparison of annual cost differences between scenarios relative to BAU

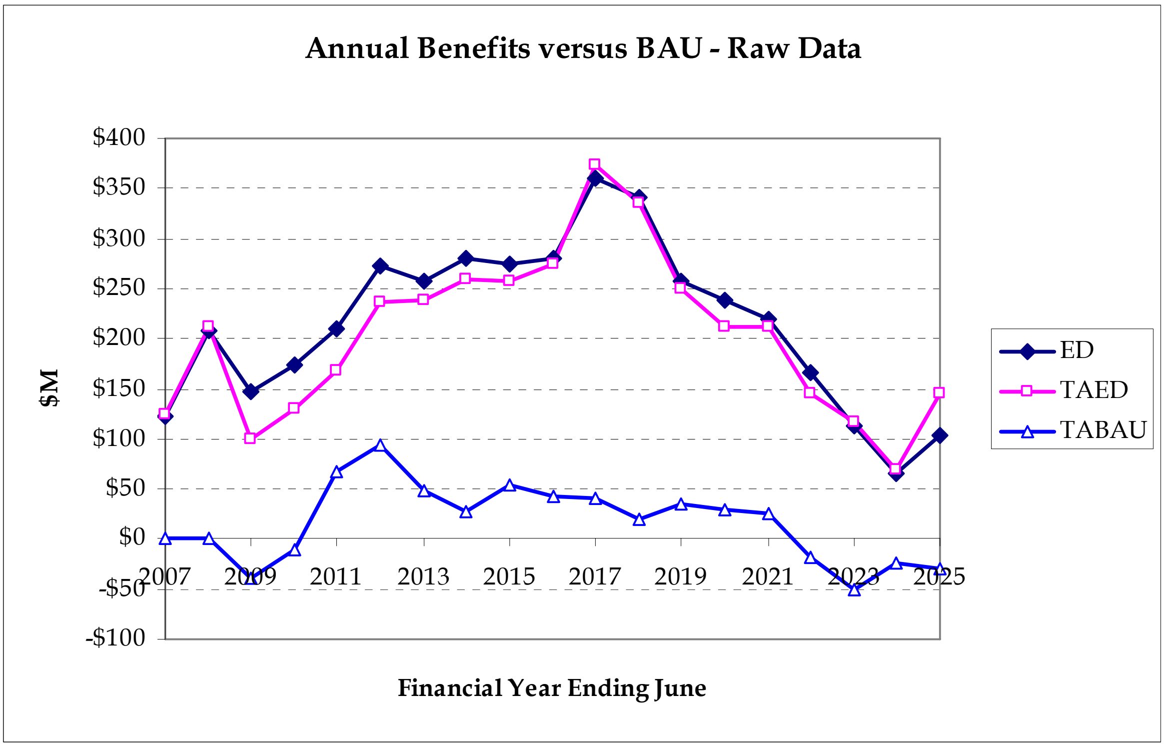
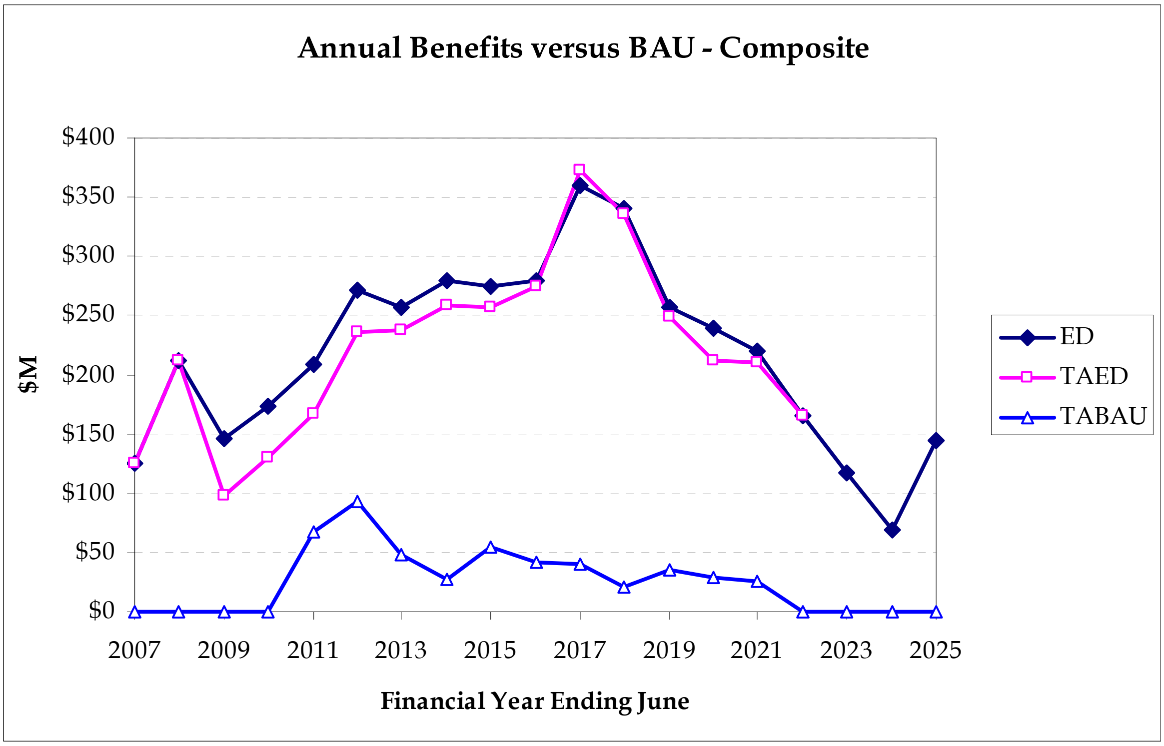


Figure 3-6 Comparison of annual cost differences between scenarios relative to BAU after merging scenarios from 2020



Merging ED/TAED and BAU/TABAU from 2022 reduces the risk of over-stating benefits with respect to transmission augmentation. Figure 3-6 shows the comparison of scenarios after merging the scenario definition from 2022.

The key points of this comparison are that:

- The efficient development scenario ED shows the substantial potential value in further reform of initially $150M per annum, rising to $250 M by 2012 and then declining after 2020 as the market becomes more competitive. This favourable trend at the back end is based on the modelling assumption that new entry is introduced by new parties who take the market prices and do not game the market under BAU conditions. If the new plant is built by incumbents and they continue to support market prices through gaming, then we would expect the benefits of ED relative to BAU to continue to grow to some $300 M by 2025 instead, on the basis of extrapolating the trend from 2007 to 2017.
- The optimum time for major transmission augmentation with Efficient Development is about 2013 when the ED and TAED net benefits converge toward each other as observed in Figure 3-5 and Figure 3-6.
- Early transmission augmentation with Business as Usual does not offer significant net benefits compared to efficient development on its own and not until 2011.
- Under a business as usual scenario, transmission augmentation offers modest net economic benefits from 2011 to 2021 of about $38 M per annum on a levelised basis. This is about 15% of the potential benefits that could be achieved with efficient development over this period.

The analysis to date confirms that advancing efficient transmission augmentation could create net economic benefits if other mechanisms were difficult to implement.

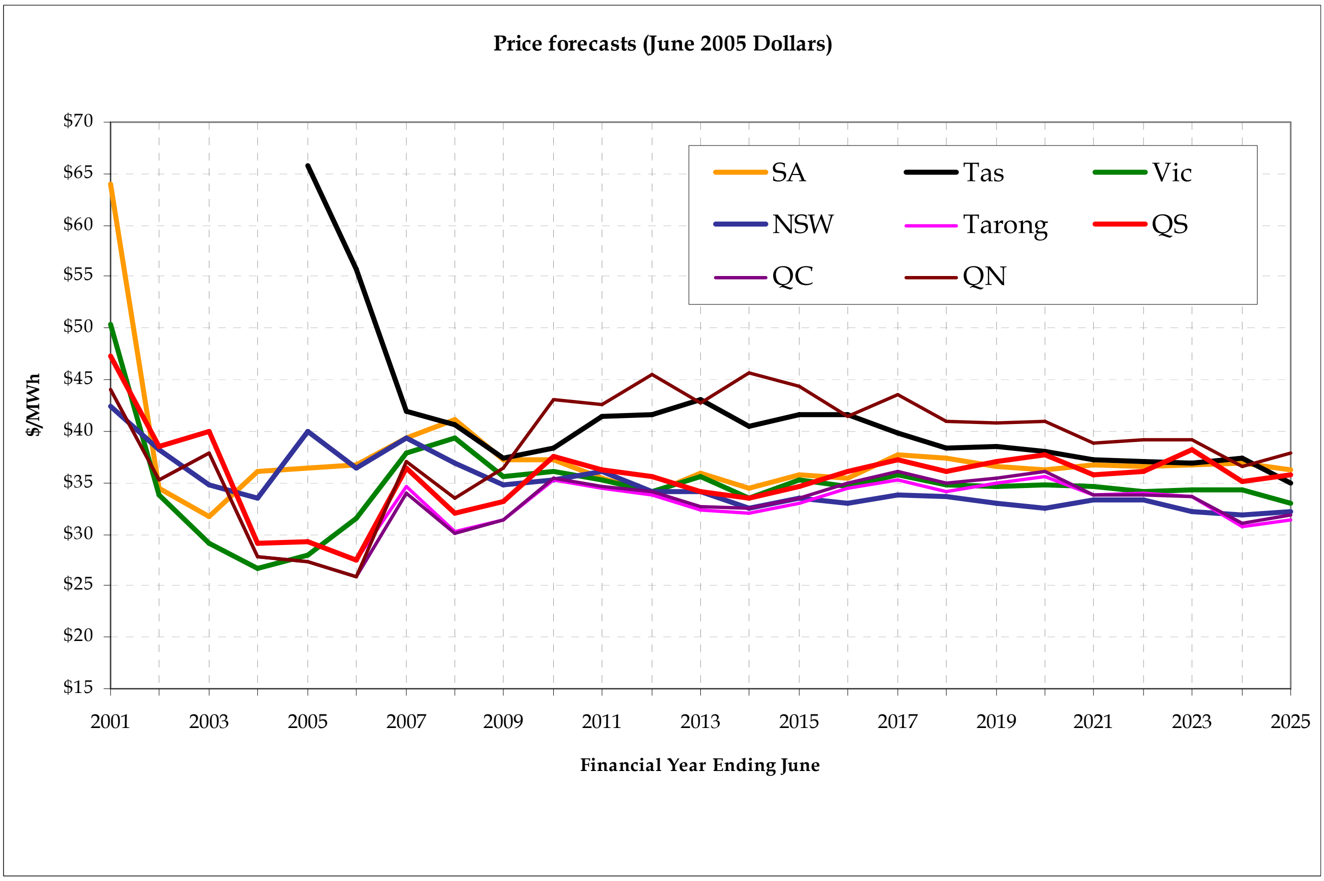
3.8 Price Outcomes

Market price outcomes have been assessed for the scenarios using the average system marginal price as evaluated by Strategist. For BAU and TABAU a market cap price of $10,000/MWh nominal was represented. For ED and TAED there was no market cap with maximum prices determined by the marginal cost of unserved energy as detailed in Table 1-3.

3.8.1 Business as Usual

Figure 3-7 shows average spot price forecast for BAU to 2025. Prices up to 2006 are actual prices in June 2005 dollars. Equivalent prices for North, Central and South-west Queensland are shown as if they were priced as separate nodes for explanatory purposes. Under current arrangements all prices in Queensland are referenced to South Pine which is shown as QS in the following charts.

Figure 3-7 Spot Price Forecast price forecast for BAU



The BAU price path shows relative stability in prices from year to year which is a feature of the assumptions of 50% POE peak demand in each year and the exercise of market power to support prices. In reality prices will vary more on a year-to-year basis due to other natural variations related to plant performance at times of high demand and the extent of weather related peak demands. Interconnection reliability may also have some influence over short periods.

In the current solution the prices to 2015 were based upon PLEXOS bids established for each year. After 2015 the bid factors from 2015 were applied. Generating plant in South Queensland was advanced in the years 2011 to 2013 in response to the gamed prices that were obtained in the R4 expansion plan. This increases the costs of BAU by $79 M in present value.

3.8.2 Transmission Augmentation with Business as Usual

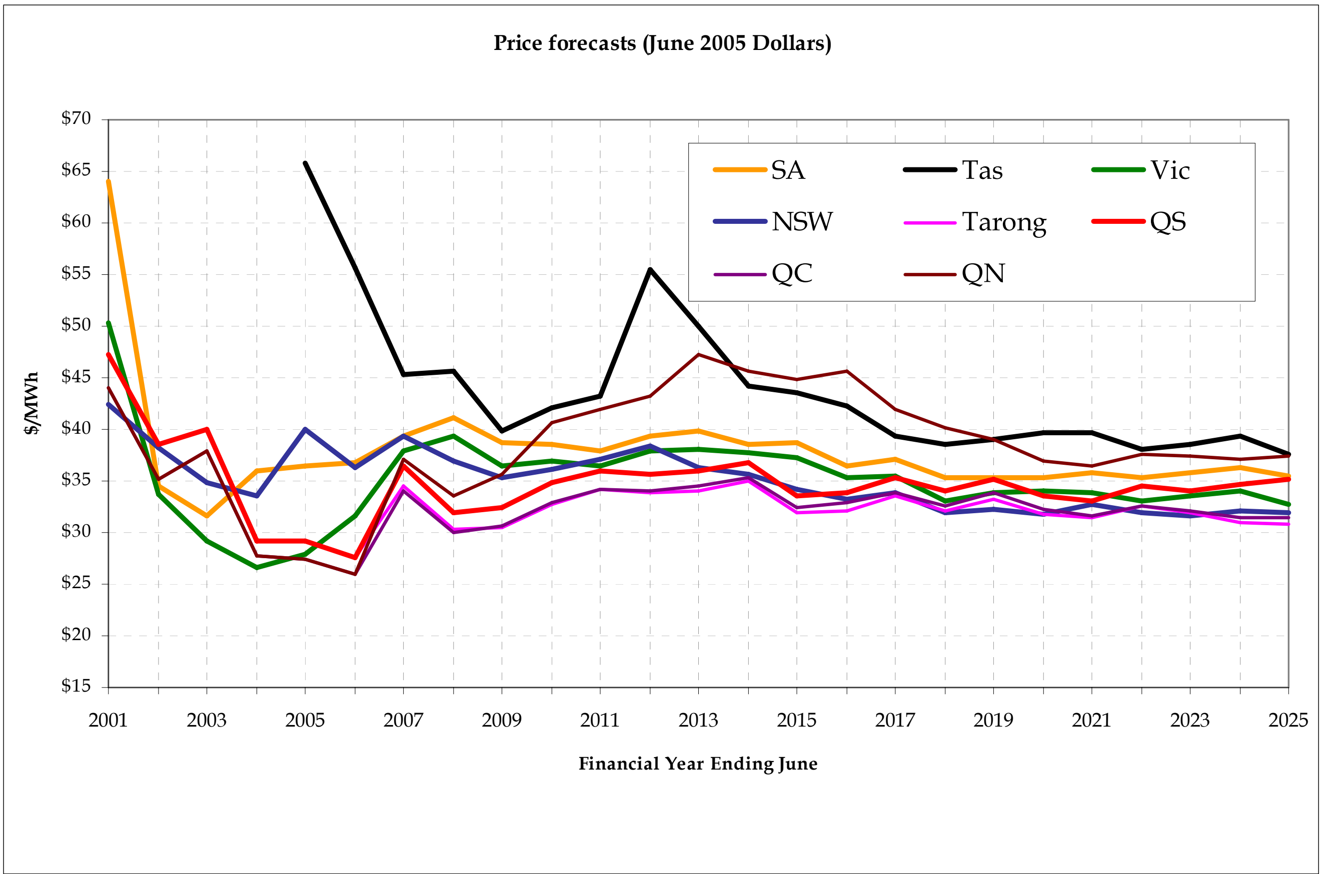
Figure 3-8 shows average spot price forecast for transmission augmentation with BAU to 2025 on the same basis as for Figure 3-7. The market prices are:

- Initially lower due to the immediate impact of the transmission upgrades increasing competition;

- Subsequently higher as new entry of generating plant is deferred in Victoria and South Australia with prices maintained in NSW with exercise of market power facilitated by the higher utilisation of generating plant at times of high demand; and then
- Falling back to similar levels when the interconnections would have been upgraded under BAU conditions.

Kogan Creek was installed in November 2015, two years earlier than for BAU to take advantage of the early QNI upgrade. This advancement of Kogan Creek corresponds to the period when TABAU offers reduced net benefits relative

Figure 3-8 Spot price forecast for TABAU - Transmission Augmentation with BAU



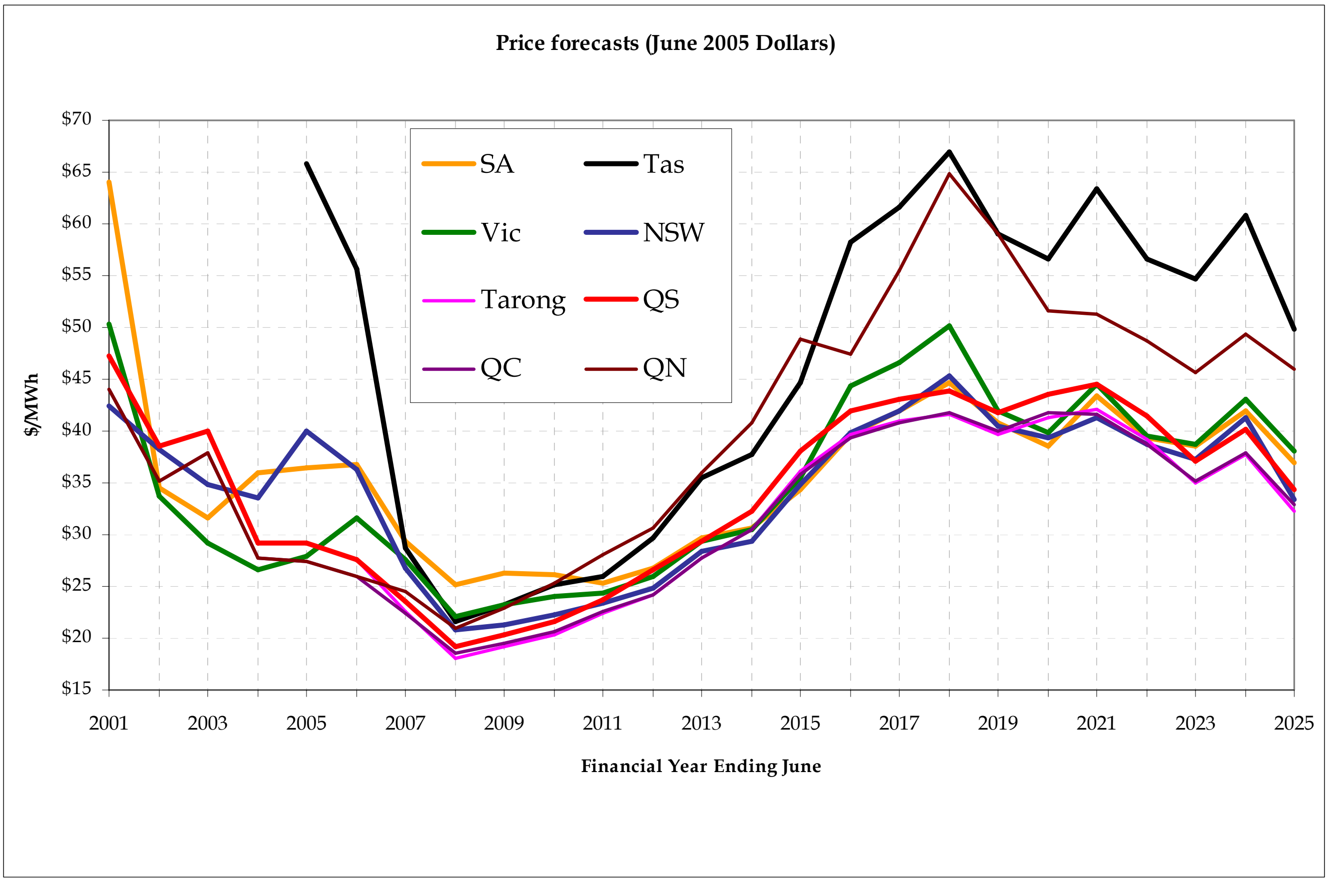
to BAU. This means that the advancement of the interconnections and Kogan Creek in that period is similar in value to the alternative.

The Queensland prices prior to Kogan Creek B service are higher than BAU due to the delayed new entry in response to the extra inter-regional transmission capacity. This is an example of where inter-regional capacity can reduce the incentive for pre-emptive new entry, at least based on rational behaviour if not in practice when foresight may be limited.

3.8.3 Efficient Development

Figure 3-9 shows the price forecast for Efficient Development. The price path is quite different from that for BAU and accords with the basic principles for a fully efficient market.

Figure 3-9 Spot price forecast for ED – efficient development



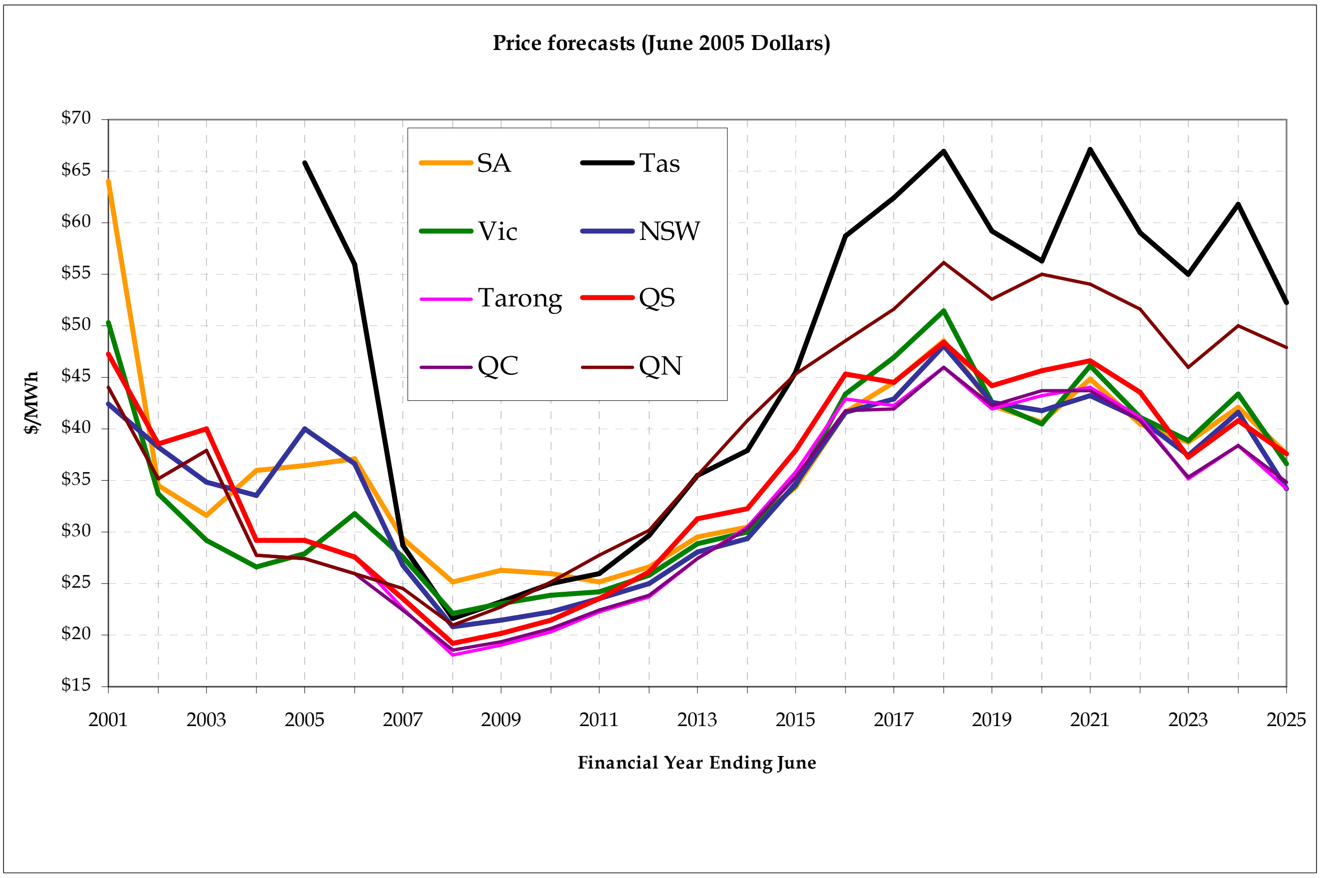
- All bid prices are at marginal cost which results in a price collapse immediately as all current price gaming is curtailed.
- There is no longer any price support in NSW which results in less price separation between the NEM regions in the early years.
- The marginal prices progressively increase as the demand side picks up the growth in peak demand and power plant utilisation increases with gas plant becoming marginal more frequently.
- Market prices approach new entry costs from 2013 for the lower cost resources and new entry commences.
- Prices peak in 2018 just before new coal plant is commissioned and prices settle to above the long-run marginal costs attributable to those resources, at about $40/MWh. This shows the impact of large efficient units which if timed efficiently will be delayed until they can enter the market WITHOUT depressing prices below their long-run

marginal cost. As the system continues to expand this size premium gradually reduces.

3.8.4 Transmission Augmentation with Efficient Development

Figure 3-10 shows the price forecast for transmission augmentation with efficient development. The price path is very similar to ED which shows that this level of transmission augmentation is not sufficient to markedly alter marginal costs and prices across the NEM regions.

Figure 3-10 Spot price forecast for TAED –transmission augmentation with Efficient Development



This reflects the following features of the NEM and argument:

- The distances between regions are large and marginal transmission losses are up to 20% at peak power transfers which means that price separation would occur even if there were no constraints.
- There are large gas and coal reserves in the eastern states which means that underlying short-run marginal supply costs are comparable in Queensland, NSW and Victoria and commensurate with the inter-regional transmission losses using existing transmission technology.

- It is therefore impossible for a major augmentation of inter-regional transmission capacity to have a major impact on NEM prices if the market is already operating efficiently.
- The existing state of inter-regional transmission development reflects relative resource costs and inter-regional load diversity as a result of some key project developments –
  - The development of the Snowy Mountains Scheme which resulted on a co-ordinated effort to connect NSW and Victoria at lowest cost. The changing patterns of summer demand has provided additional benefits from upgrading these links to make better use of the Snowy peak generating capacity
  - The development of 500kV line to the Portland smelter in Western Victoria enabled the extension to South Australia at 275kV to become economic.
  - The surplus generating capacity that developed in NSW during the early 1990s after Mt Piper was completed provided an economic basis for the Queensland – NSW Interconnection to be developed. Unfortunately, due to parochial attitudes and poor investment decisions the benefits of QNI have not been maximised and it has been used to export surplus low cost base load energy from Queensland.
  - The increasing summer demand growth in Queensland and NSW increases the economic benefit of further augmenting the capacity of QNI by about 2013 under business as usual conditions and efficient development.

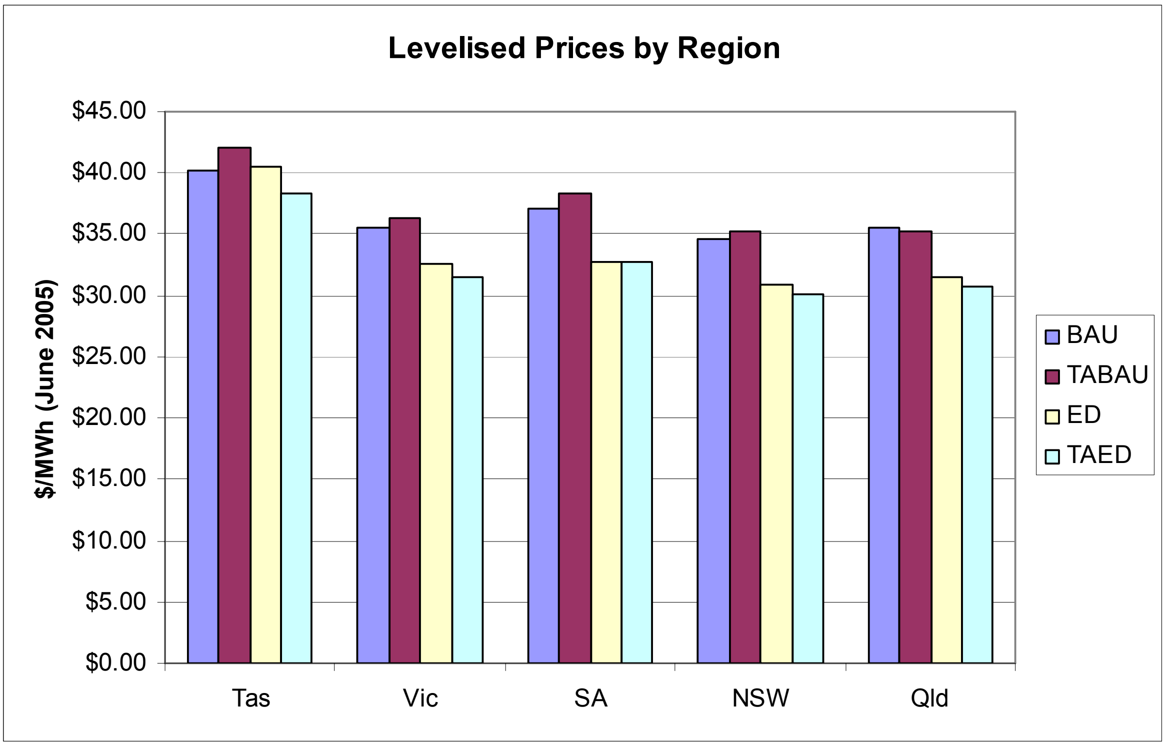
3.8.5 Impact on Levelised Time Weighted Prices

If we take the composite scenarios formulated as shown in Figure 3-6 and calculate the levelised time weighted spot price for the four scenarios by region as shown in Figure 3-11 then we may appreciate the potential customer impacts taking into account the cost of the transmission augmentations in the scenarios. We have estimated the annual interconnection transmission costs and added them to the generation and demand side costs and divided the total cost by the annual energy supplied at the wholesale sent-out level in each region to determine an estimated average levelised wholesale cost. The network costs were arbitrarily allocated to each region according to the Table 3-1. This is an estimated allocation of benefits arising from the network projects. It is not based upon a detailed assessment of the project beneficiaries and is only indicative for the purposes of this illustration. In any case the average cost of the transmission development is no more than 80c/MWh in South Australia and it does not significantly affect the price comparison.

The levelised prices in Figure 3-11 provide the following information:

- Long-term electricity prices on a levelised basis over time would be lower with efficient development with or without early transmission augmentation, except perhaps in Tasmania. The benefits of efficient development to customers are less marked as you move from south to north, in part because long-run marginal costs of base load power are lowest in Queensland and highest in South Australia and Tasmania.

Figure 3-11 Levelised time weighted prices by region for composite scenarios



Note: Prices include the impact of the additional interconnection transmission costs when applicable.

Table 3-1 Indicative allocation of network project costs to regions

	QNI	SnoVic 1	QC-QN	Tarong	SnoVic 2	Heywood
Tas		10%			10%	10%
Vic		65%			65%	25%
SA		25%			25%	65%
NSW	50%					
Qld	50%		100%	100%		

- Under Business as Usual conditions the network projects do not necessarily reduce costs to customers except perhaps in Queensland where we observed the impact on prices before the next base load coal fired station which was modelled as Kogan Creek B. This suggests that under current arrangements the benefits of interconnection upgrades will accrue to suppliers rather than to consumers, which is not widely anticipated. It is possible that even greater investment might have a more favourable impact on wholesale prices to customers, but that would be offset by even higher network charges. There is no evidence of substantial benefits to customers from premature transmission development under Business as Usual.
- Under Efficient Development conditions the transmission augmentation produced lower prices except in South Australia where there was virtually no change On a

regional basis there could be winners and perhaps some losers from a customer viewpoint depending on their load factor.

- The clear lesson from this analysis is that the economic benefits of early transmission development under Business as Usual are significant but that customers would not necessarily benefit. This reflects the market power of incumbents to support market prices.

A note of caution is needed at this point. To the extent that real world behaviour is subject to imperfect foresight and that there will always be some price gaming, it is reasonable to conclude at this point that there is no guarantee that a major reinforcement of the transmission system would provide huge benefits to customers. It is more likely that the benefits would accrue to suppliers, especially under BAU and to a lesser extent under an approximation to the ideal ED conditions. Since the benefits to suppliers would benefit the economy as a whole, then customers may benefit indirectly, rather than primarily through lower electricity prices.

It has also been noted in correspondence with ERIG based upon an earlier draft of this report that the improvement of prices in NSW from BAU to ED is not as great as might be expected if the NSW region pricing is as inefficient has some would propose. The results of this analysis were subsequently corrected when a calculation error was found. The new results show a greater gap between ED and BAU prices for NSW which is proportionately larger than for Victoria. However a still bigger gap might be expected.

There are two components affecting the assessment of relative levelised prices. One relates to variable fuel costs and affects the early period of the analysis and determines how much prices can fall in a strongly competitive environment. The second factor relates to the modelling of gaming post 2016 and the extent to which prices match or exceed new entry costs.

With respect to variable fuel costs, there is less potential for ED to produce benefits in SA and NSW relative to BAU because these regions have substantially higher variable fuel costs than Victoria and Queensland. Much of the benefits of ED occur in the early years as the inefficient plant mix is exposed and prices fall to lower levels. There is less potential for the benefit of ED in NSW and SA because the higher fuel costs make up a larger proportion of the total cost of generation.

In relation to the long term price effects when SRMC has less impact, the ED price results among the regions are quite consistent among the regions. However the BAU results are necessarily more speculative because of the need to project less competitive market behaviour over a long time into the future with changing plant mix and potentially changing market structure and market power.

Under the BAU scenario the NSW price path is quite benign and some \$3 - \$5/MWh below the new entry cost line toward the back end of the study period. MMA was unable in the time available to evaluate the longer-term bidding impacts of market power with PLEXOS and therefore the 2016 bidding profiles were continued beyond 2016. For the

NSW new entrants, it was necessary to apply some strategic bidding to achieve the barely sustainable price path. In the other regions it was sufficient for the new entrants to bid SRMC for a sustainable price path. Typically NSW peakers were bid at 5 times SRMC, NSW intermediate plants at 1.2 times SRMC, new NSW coal at SRMC, and the uprated Bayswater, Eraring and Mt Piper at 1.2 to 2 times SRMC to maintain similar levels of price supporting NSW. Detailed modelling of the gaming behaviour of these new entrants and uprated plants may show that higher prices are prospective in NSW under BAU. It is very unlikely that NSW prices would be any lower than shown under BAU. Therefore, more detailed analysis is likely to slightly increase the levelised price gap between ED and BAU in NSW.

Therefore we may regard the NSW comparison as the most favourable under BAU that we could achieve with the methodology we have developed. The results would not be accurate enough or sufficient to prove that the NSW region is less efficient under BAU with 10.8% price improvement than say Victoria which shows a lesser 8.3% price improvement under ED.

3.9 The Structure of Economic Benefits

To further explore the structure of the economic benefits of transmission augmentation and efficient market development, we have segmented the total market costs in the components shown in Table 3-2. Where the cells of the Table are blank, the costs are ignored or treated as unchanged among the scenarios. There were some small changes to fixed costs of incumbents where plants are re-powered, retired or refurbished. The emission costs for GECs and NGACs are a zero sum because the revenue to generators is a cost to customers. However the balance of revenues between incumbents and new entrants is of potential interest.

3.9.1 Demand side response for median peak demand

The median level of demand side response for median peak demand is shown for the modelled scenarios in Figure 3-12. It represents the summation of

- 631 MW of existing and uncommitted demand side response as reported by NEMMCO, which is treated in the modelling as “interruptible load”
- the explicit new demand side response which was represented in the ED related scenarios for median peak demand
- the component of demand side response for managing the volatility between 50% POE and 10% POE peak demand not covered by existing resources.

Table 3-2 Segmentation of costs and benefits

	Generation	Transmission	Demand Side	Customers

			Response	
INCUMBENTS				
Fixed Costs	Assumed mostly fixed			
Variable O&M	*		Unserved energy cost	
Variable Fuel Costs	*			
Emissions	GECs/NGACs			GECs/NGACs
NEW ENTRANTS				
Fixed Costs	Capital and O&M	Capital and O&M	DSR fixed costs	
Variable O&M	*		Bid costs for DSR	
Variable Fuel Costs	*			
Emission	GECs/NGACs			GECs/NGACs

The chart shows the capacity utilised but excludes the capacity associated with the remaining unserved energy which is indeterminate. The results show that efficient development would be expected to yield about 2200 MW of additional demand side response in a typical median year plus another 4000 MW of demand side response to manage the extreme peak conditions by 2025. Based on a fixed cost of $25/kW/year versus about $80/kW/year for equivalent gas turbine capacity, the resulting savings would be $330M per annum relative to gas turbine capacity by 2025. This benefit would be offset by the higher dispatch cost for this demand side response.

The demand side response as measured by the energy displaced including unserved energy is shown in Figure 3-13 for median peak demand. The energy associated with 10% POE peak demand has not been quantified. The chart shows that substantial new demand side response is not required until 2012 financial year which provides time to develop the technologies and deliver them to the market customers. In the medium term

Figure 3-12 Demand side capacity provided response by scenario

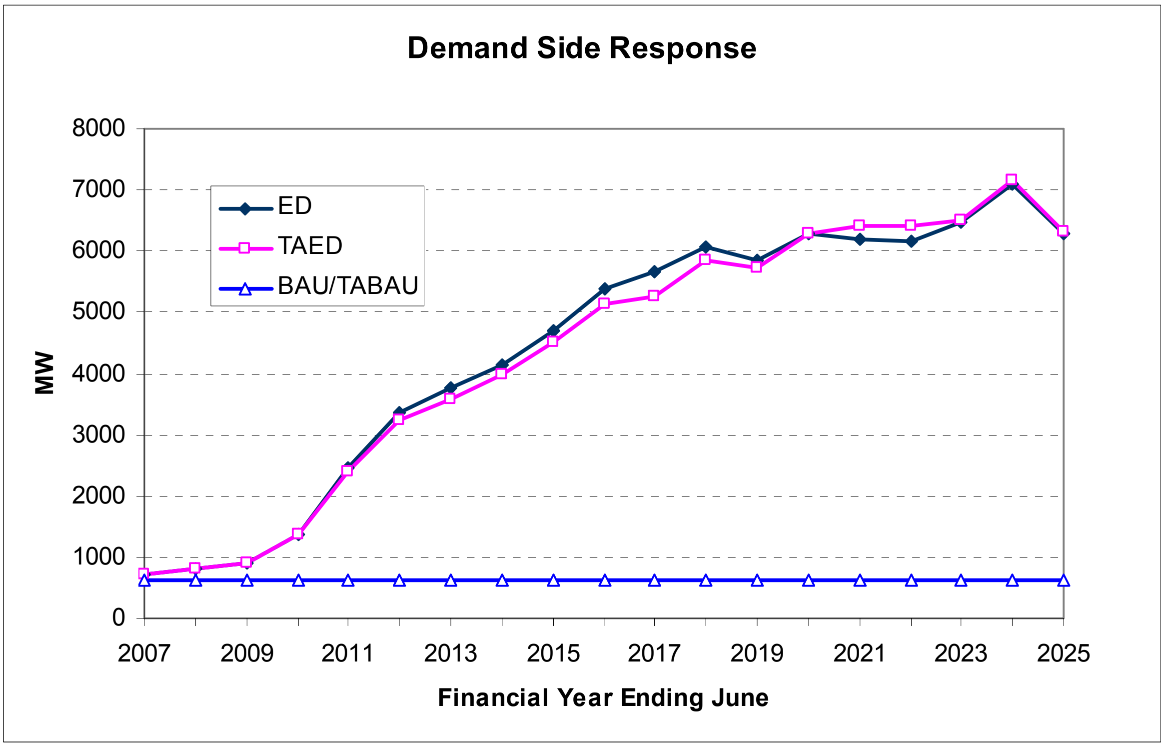
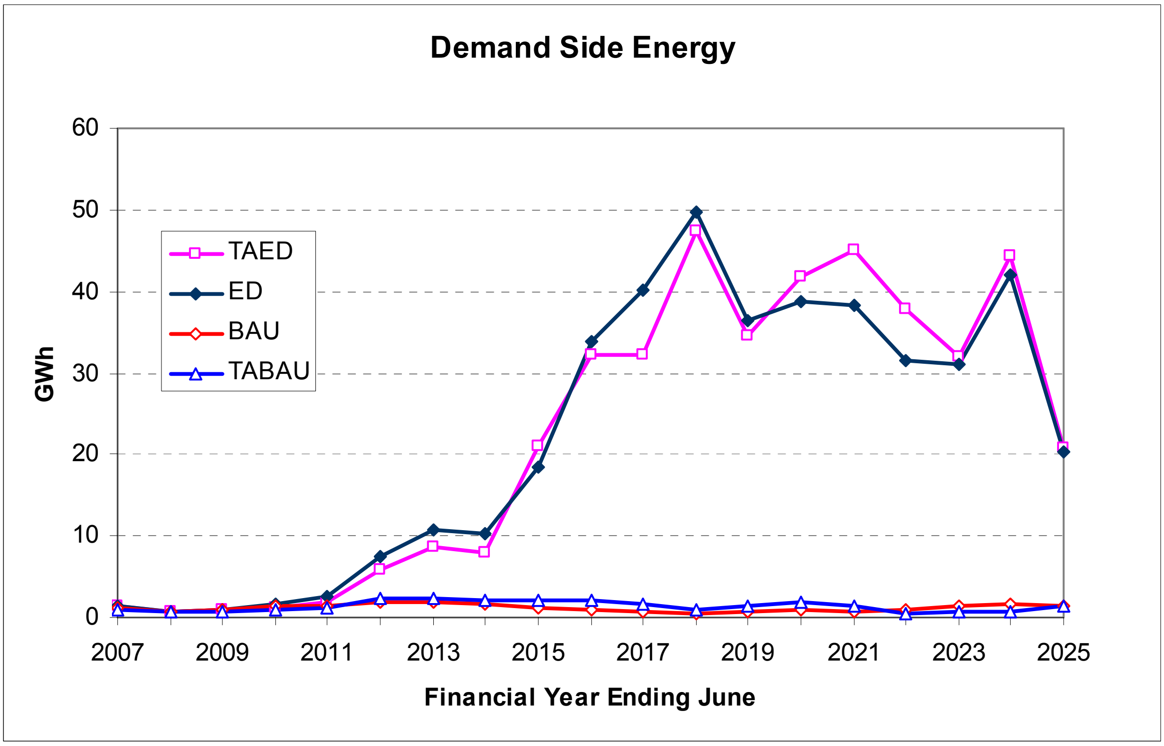


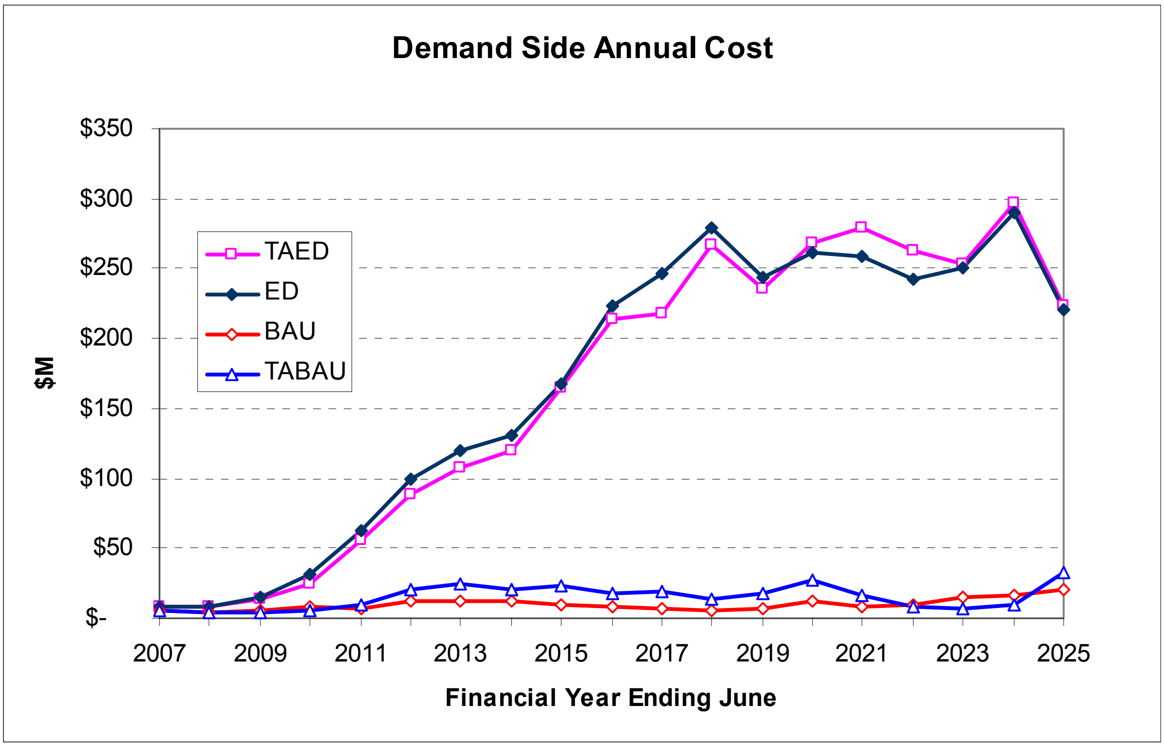
Figure 3-13 Demand side energy response by scenario



the TAED case has reduced demand side response over ED. This is a result of the increased network capacity reducing the requirement for demand side response to meet local peak demand. From 2020 to 2023 the ED case has reduced demand side response as the new generators have an impact. Generally, transmission augmentation permits less generating capacity where there is inter-regional load diversity and the peaking generating capacity is utilised more frequently which is an indicator of improved efficiency. The reduced reliance on demand side response is an indicator of this efficiency improvement. From 2024, ED and TAED are equivalent.

Figure 3-14 illustrates the total cost of demand side response including the cost of interruptible energy based upon its average marginal cost. It appears that with and without transmission augmentation does not greatly affect the total cost of demand side response. The reduction in cost towards the end of TABAU reflects the advancement of generating plant in South Queensland in response to high prices. Overall, the lower capacity is offset by the higher utilisation almost exactly. Under Business as Usual conditions, the transmission augmentation does significantly reduce the cost of demand side response until the timing of new generation can be adjusted at which time they converge again in 2013. The variations after 2020 for BAU/TABAU are due to changes in the plant mix.

Figure 3-14 Demand side response annual cost by scenario



3.10 Cost analysis

In order to gain an understanding of the value drivers in the scenarios, we have also analysed the fixed and variable costs for the incumbents and new entrants.

3.10.1 Fixed cost analysis

Figure 3-15 shows a summary of the fixed costs of incumbents, new entrants and total fixed costs for the four scenarios. The fixed costs for incumbents include the projected costs of committed plants such as Braemar, Kogan Creek and Tallawarra. That is why it initially increases. It later decreases following the uprating of the large 660 MW units in NSW and the repowering of the Quarantine open cycle gas turbines. The costs of the existing plants are replaced in the model by the cost of the up-rated generator. The up-rating of the NSW generators occurs earlier in BAU than TABAU and hence the fixed costs of incumbents decreases earlier in BAU than TABAU.

These fixed costs include the allowance for annual network charges for the transmission augmentation projects. They do not include the fixed costs associated with demand side resources.

The results show that:

- Transmission augmentation enables deferment of the uprating of units in NSW
- Fixed costs of new entrants including transmission augmentation are reduced with transmission augmentation.
- Total fixed costs for BAU are slightly reduced with transmission augmentation up to 2013.

3.10.2 Network Cost analysis

A component of the scenarios that is of interest is the annual cost of the new network upgrades. This provides an indication of the rate at which new network development occurs and when the commensurate benefits should begin to appear. Figure 3-16 shows the annual network costs for the new links included in the modelling for the four scenarios. The network timing for TAED and TABAU was the same and therefore these appear initially together as TAED in the chart, with the exception that the Tarong-Brisbane interconnect appears in 2013 for TABAU. The ED scenario shows two phases of network development. The first phase is associated with QNI upgrade and extension of capacity through to Brisbane. The second phase is the Snowy-Victoria-South Australia augmentation.

3.10.3 Variable cost analysis

The scenario variable O&M costs are shown in Figure 3-17 on the same basis as discussed for fixed costs above in section 3.10.1. The total variable O&M costs are not greatly influenced by transmission augmentation or the efficiency of the market. Subtle changes occur due to changes in plant mix and utilisation. The delayed commitment to new plant is apparent in the total variable cost for new entry when comparing business as usual and efficient development. Transmission augmentation initially reduces these costs by improving low cost plant utilisation across the NEM. It also has the effect of utilising the incumbents more and therefore postpones new entry, as expected.

Figure 3-15 Scenario fixed costs

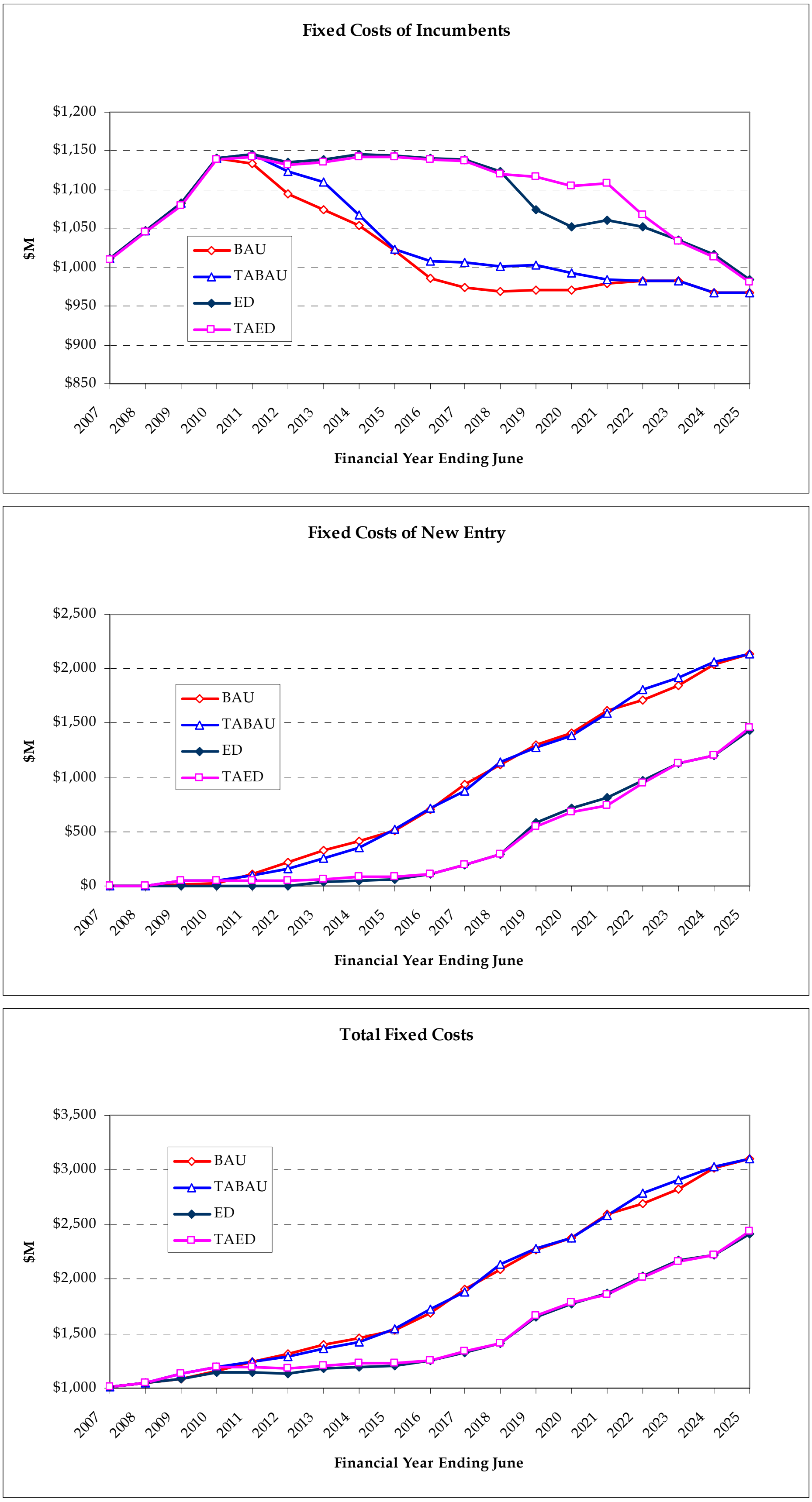
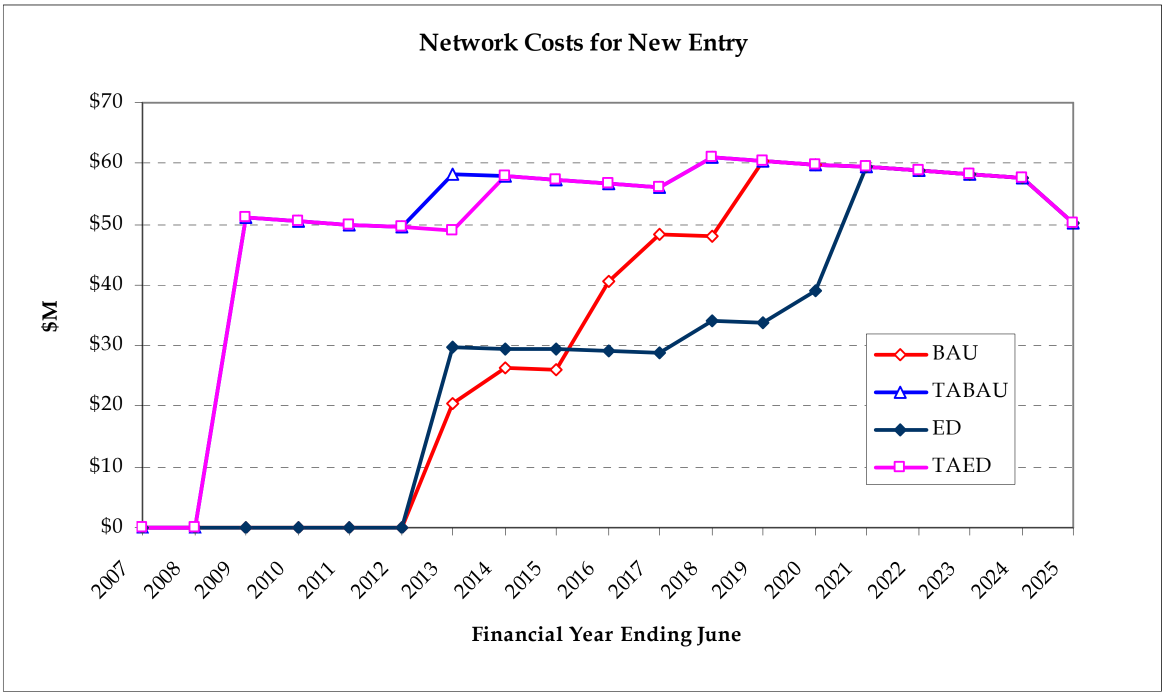


Figure 3-16 Annual costs for new network developments



3.10.4 Scenario fuel costs

The scenario fuel costs for new entrants and incumbents are shown in Figure 3-20. In the early period Efficient Development enforces a more efficient dispatch order and fuel costs are reduced by about $130 M per annum. The chart shows that under Efficient Development, fuel costs in later periods are higher as the operating benefits of new efficient plant are delayed and existing plant is more highly utilised which leads to higher fuel costs by about $230 M per annum. These higher fuel costs are offset by the lower fixed costs from the new capacity deferment. BAU has more new efficient gas fired plant than does Efficient Development. This increases the fuel costs for new entry but reduces fuel costs overall.

3.11 Emission abatement

A comparison of the carbon dioxide emission performance of the scenarios is presented in Figure 3-18 for the composite scenarios. It confirms what is expected in that efficient development would result in higher carbon emissions due to merit order dispatch of coal and gas fired plants at all times which tends to maximise coal fired plant dispatch. The impact of transmission augmentation is better observed from the differences among the scenarios as shown in Figure 3-19. The chart shows that transmission augmentation has little impact under Efficient Development with some slight improvement. Under Business as Usual, with emissions being slightly worse due to increased utilisation of existing coal plant.

Figure 3-17 Scenario variable O&M costs

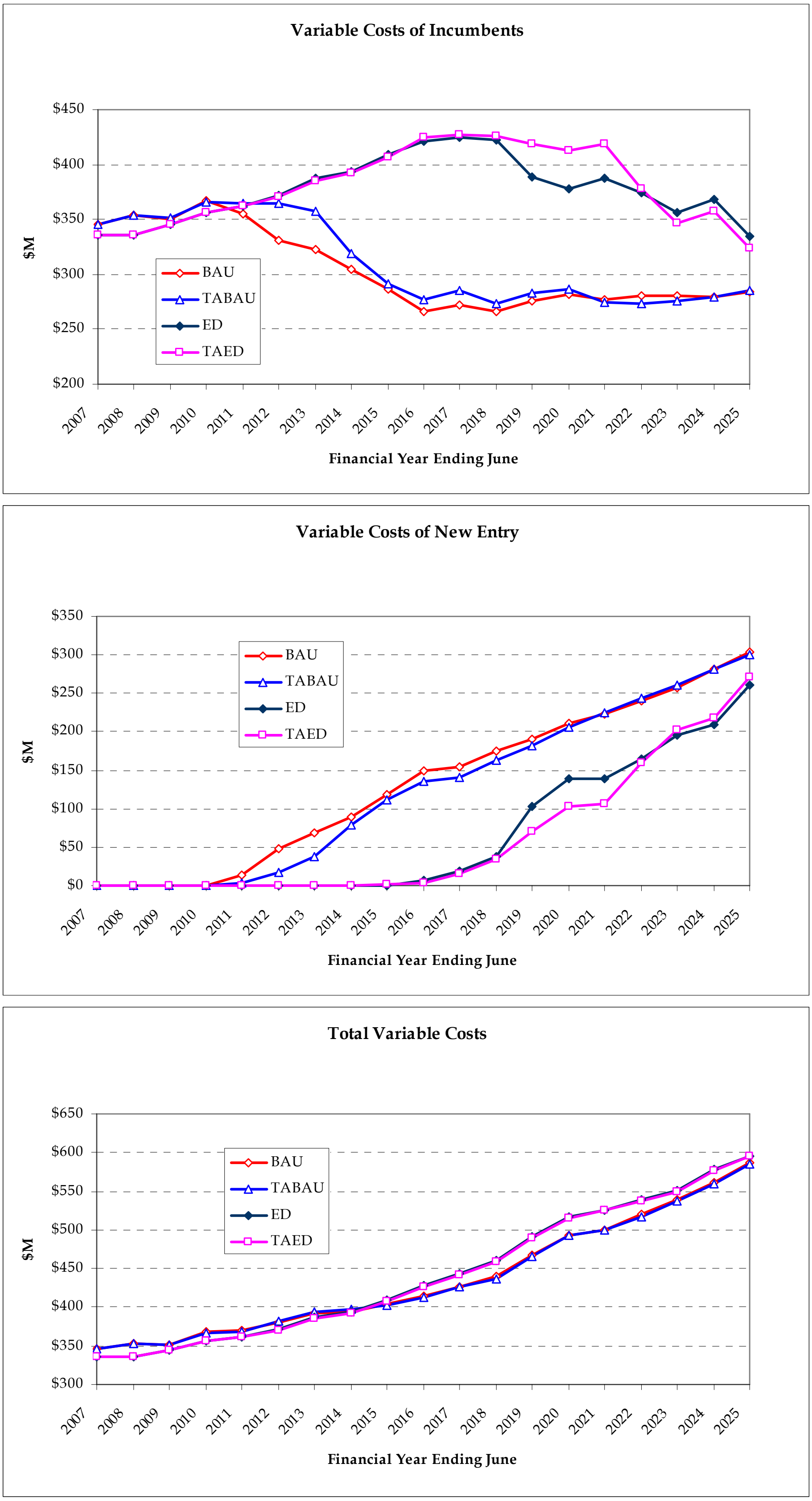


Figure 3-18 Carbon dioxide emission performance of scenarios (composite)

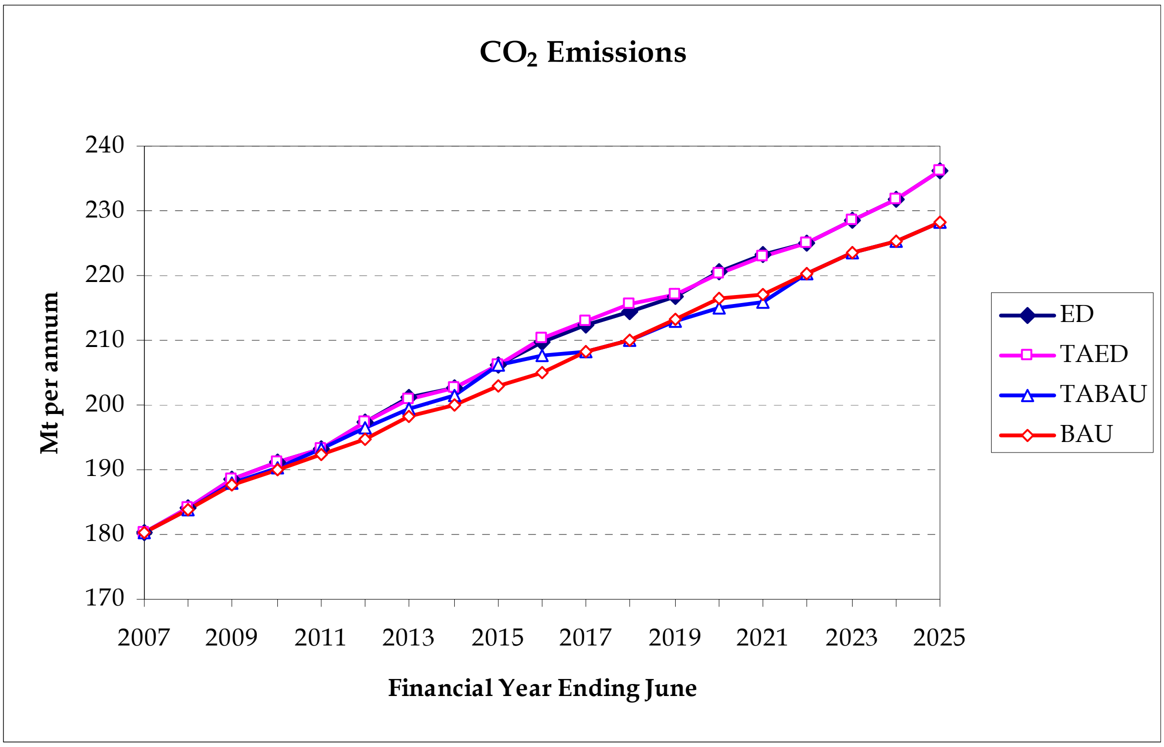


Figure 3-19 Differential carbon dioxide emission performance of scenarios (composite)

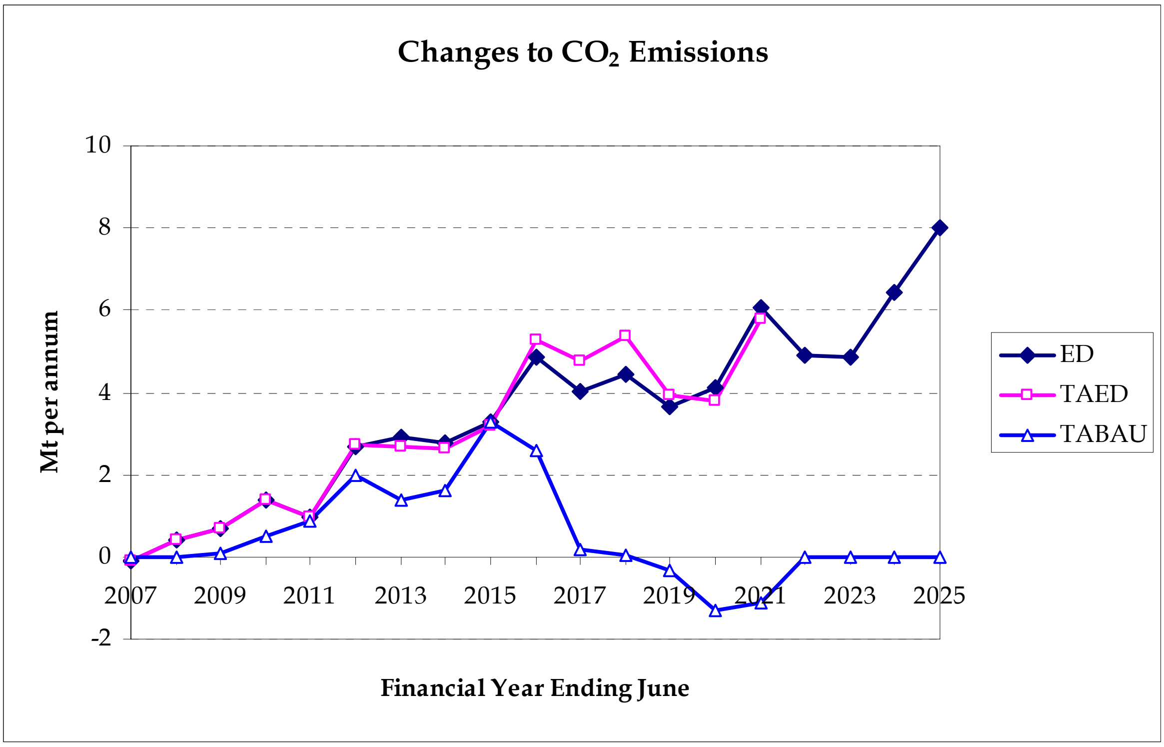
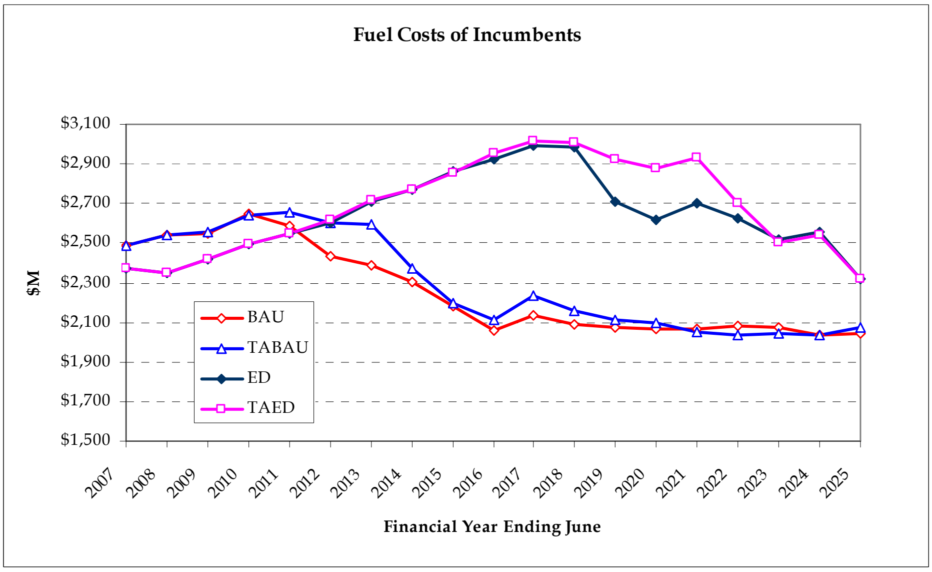
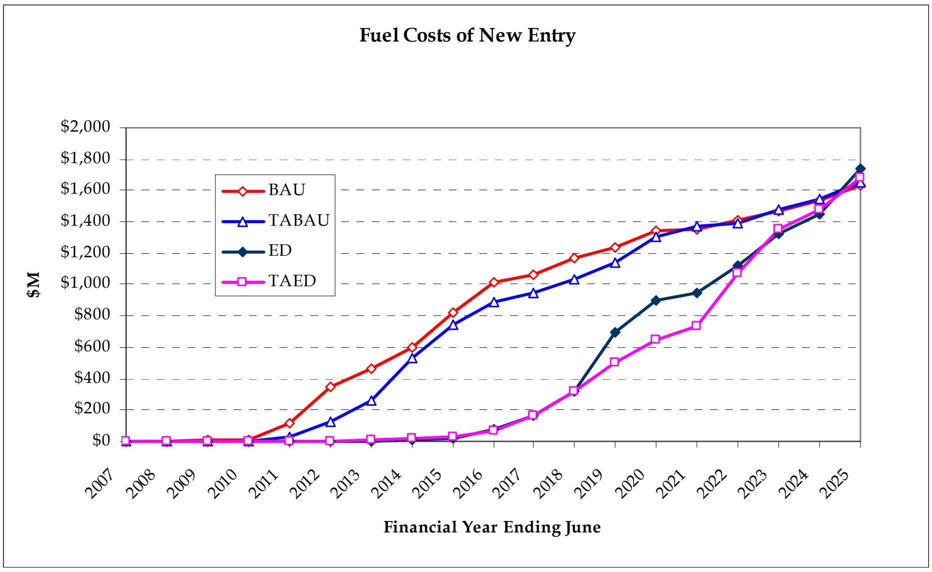


Figure 3-20 Scenario fuel costs





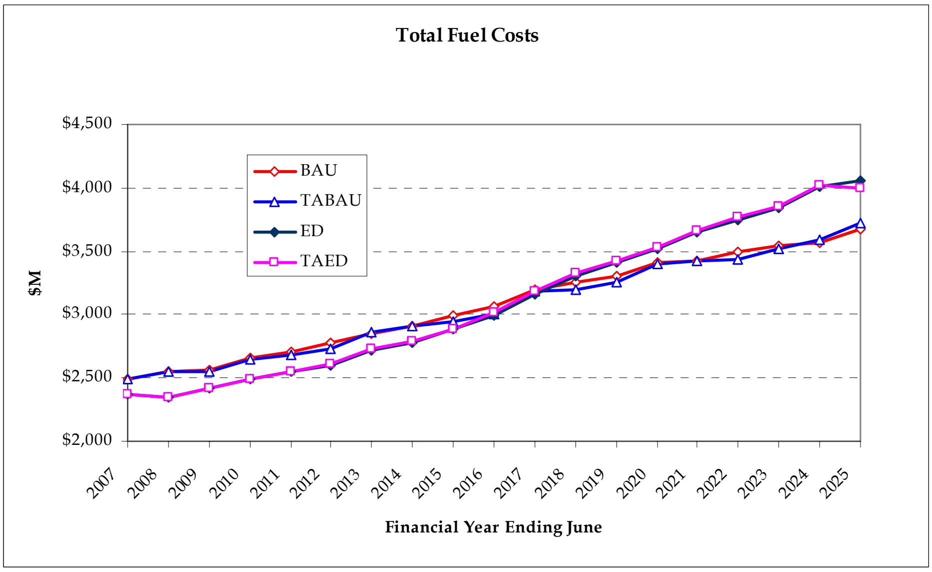
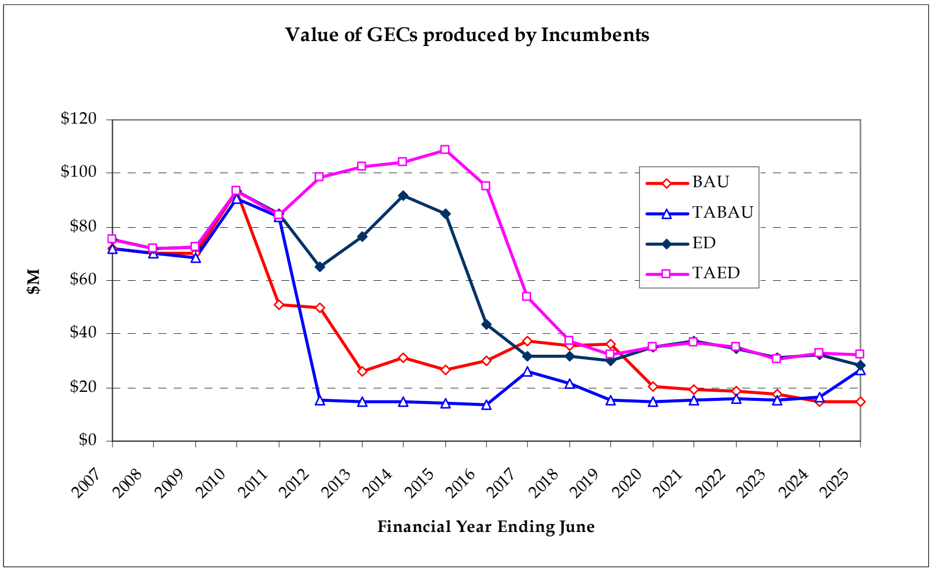
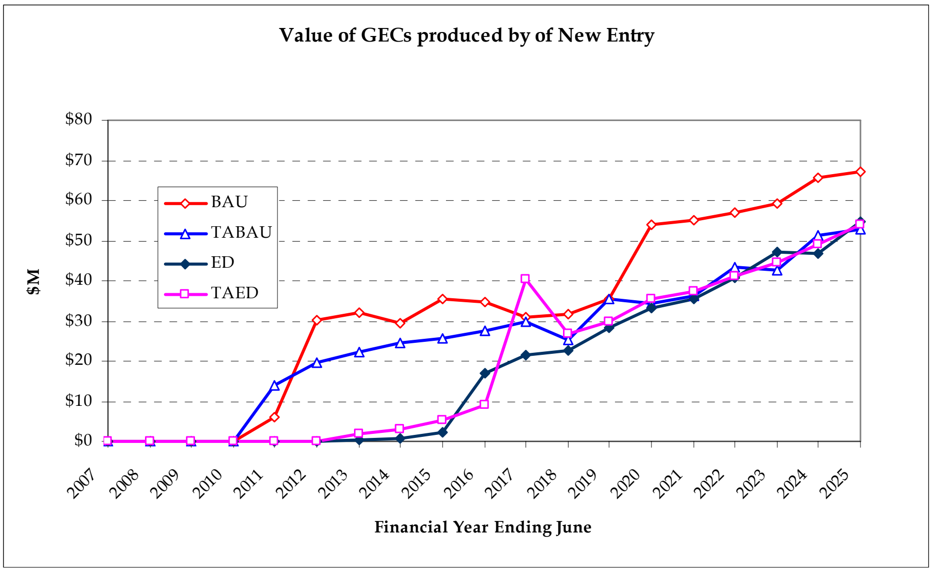


Figure 3-21 shows the annual GEC production by scenario by incumbents and new entrants. It is observed that the GEC are increasingly produced by new entrants and that the contribution from the less efficient incumbents is eroded over time.

The NGAC value shown in Figure 3-22 has the same features as the GEC production value of Figure 3-21. The excess production post 2020 was considered viable because the NGAC market was in deficit for most of the previous 10 years. Whether or not the catch up NGACs would be needed would depend on whether the penalties would be refunded when NGACs are finally available. In any case the value of GECs and NGACs is a transfer within the market and not an economic cost. The underlying economic cost comes from the additional consumption of gas which is needed to meet the abatement target. This cost is reflected in the fuel costs.

Figure 3-21 GEC production by scenarios





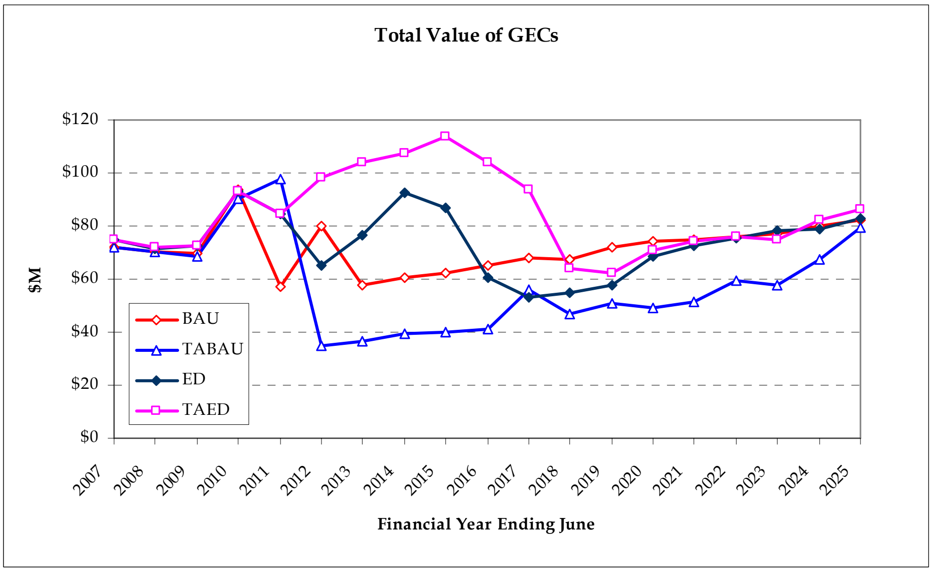
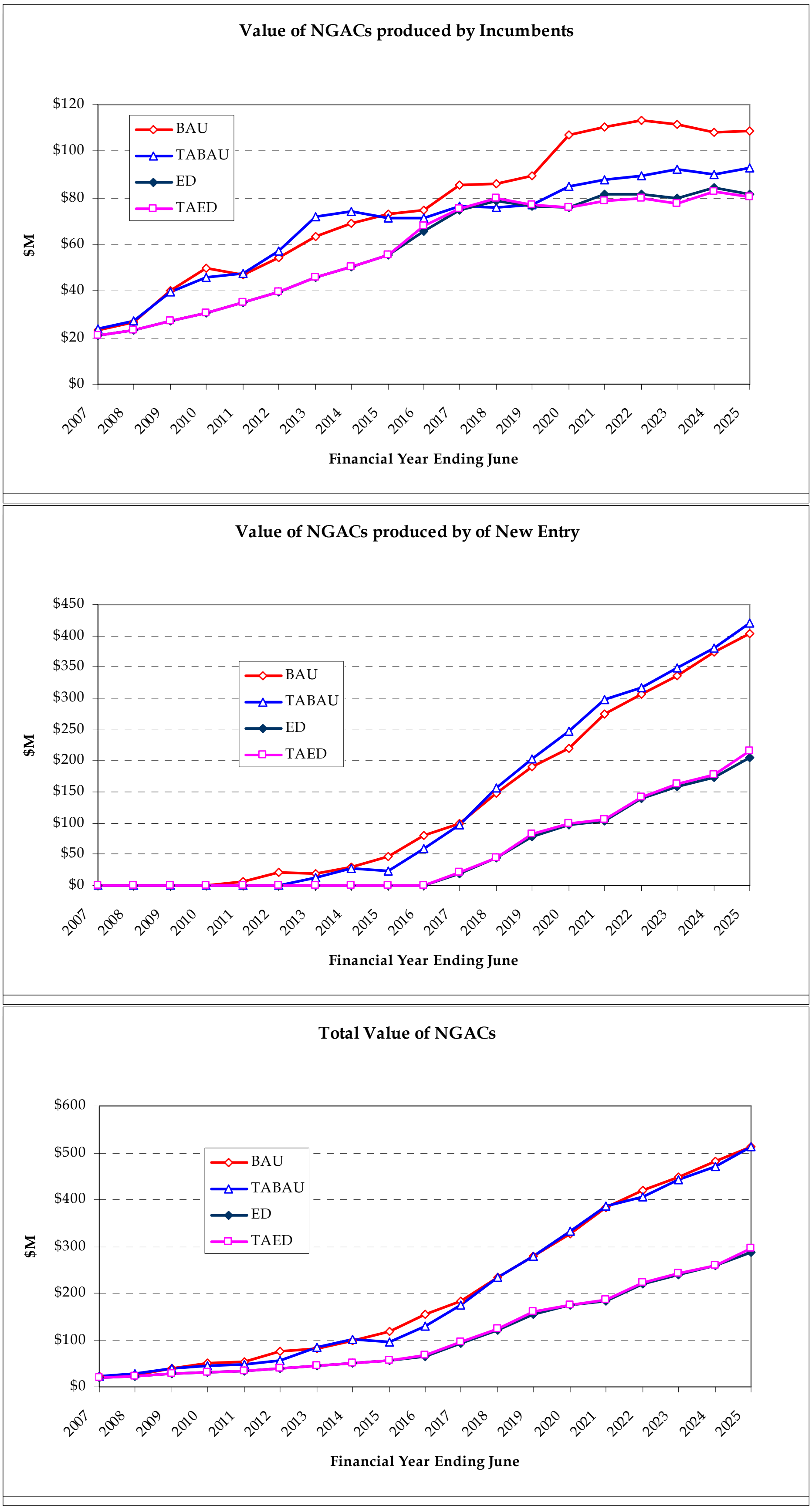


Figure 3-22 NGAC production by scenarios



4 SENSITIVITY STUDIES

4.1 Analysis of Benefits

The ERIG asked if MMA could provide further information on the relative magnitude of three sources of potential benefit:

1. The benefit arising from a more efficient generation / transmission mix
2. The benefit from more competitive bidding
3. The benefit from a more efficient mix of demand side response and gas turbine plant.

This is a different construction of the benefit than described above in Chapter 3. These benefits were assessed by comparing the following cases.

4.2 Generation / Transmission Cases

The benefit arising from a more efficient generation / transmission mix was assessed by comparing two cases EDBT and BAUET.

- EDBT was the efficient development scenario but with the transmission plan the same as for BAU. By comparing the costs of this case with ED we can assess the potential additional costs that arise from an inefficient transmission expansion caused by market distortions.
- BAUET was the Business as Usual scenario with the transmission expansion plan taken from the ED scenario. By comparing the costs of this scenario with BAU we may observe what improvements could be achieved from ED but without changing the transmission development.

In both of these cases we re-optimised the capacity expansion plan in response to the altered transmission plan. This represents generator new entrants adjusting to the changed market as a result of the interconnections. New entry is advanced in exporting regions with lower costs and delayed in importing regions with higher costs. Due to some new solutions at the tail end of the period, we also adjusted the ED and BAU cases where it was possible to further reduce costs in those scenarios so as to provide an equivalent comparison. The primary adjustment involved a change in the timing of the sequence. There was no change in the overall plant mix by 2025.

4.3 Competitive bidding cases

The benefit from competitive bidding was assessed by running the BAU case with short-run marginal cost bidding to represent a fully competitive dispatch and by running the ED case with the bids derived for the BAU case. There was no change in the timing of new entry or transmission upgrades.

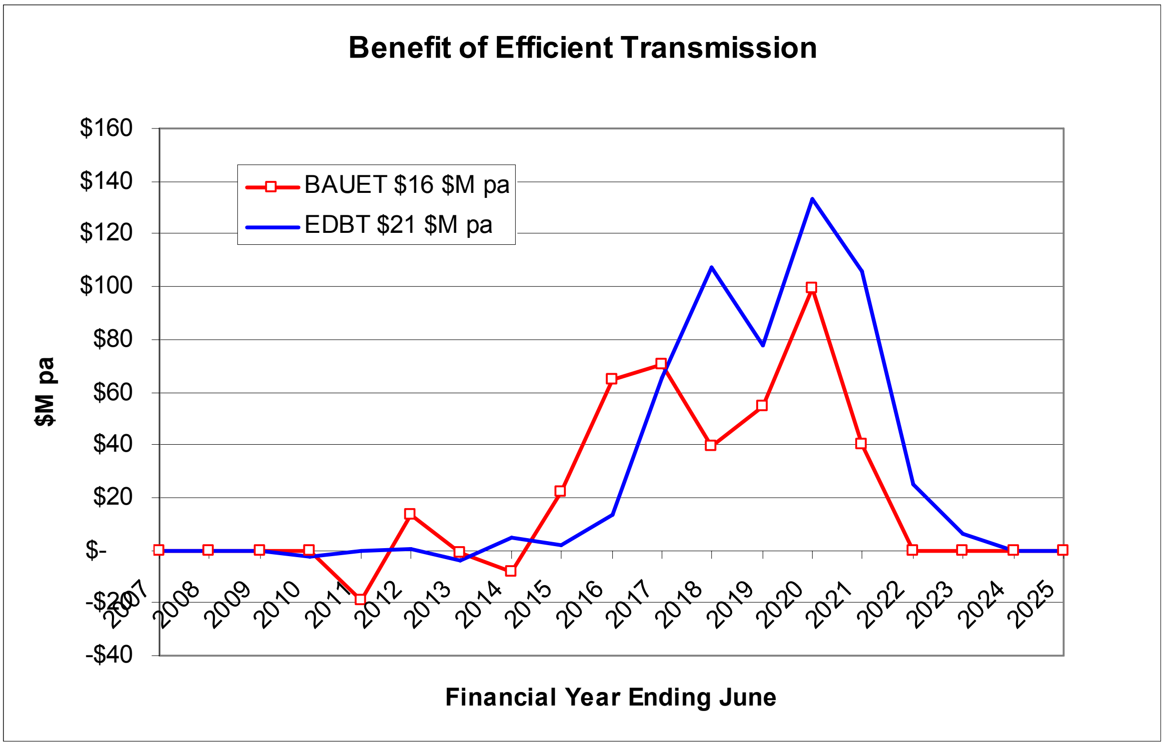
4.4 Demand side response cases

The impact of the switch from open cycle gas turbine plant to efficient demand side peaking was evaluated by replacing the demand side response with open cycle gas turbines in the ED case and adjusting the timing of interconnections where economic. We also adjusted the BAU case by adding in the demand side response and then delaying the open cycle plant and the Tomago combined cycle conversion to produce a sustainable price path. Both of these studies required a change to the expansion plan.

4.5 Impact of efficient generation/transmission mix

The BAU case with variation in transmission timing was identical in terms of plant mix and generation by 2022, although there was some small variation arising in the estimation of emission abatement. Similarly the amended ED case was the same by 2024. For the purposes of this comparison we have set the differences between the cases to zero when they were the same. The net value of refining the transmission expansion assessed by this means is shown in Figure 4-1.

Figure 4-1 Value of efficient generation/transmission mix

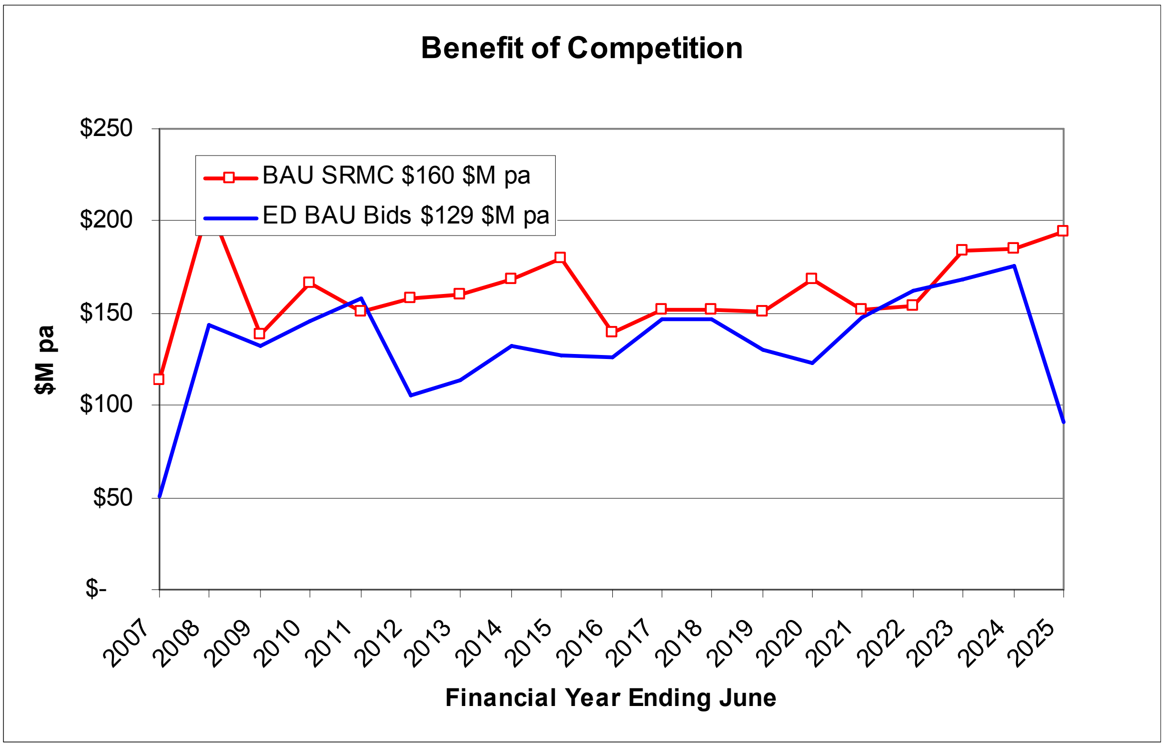


The impact of transmission distortion for the selected interconnection upgrades is only about $16 to $21 M per annum which is at most 10% of the potential value of further reform.

4.6 Impact of competitive bidding

Figure 4-2 shows the annual benefit of competitive bidding relative to the ED and BAU cases. The levelised benefit was $160 M pa for the BAU case and $129 M pa for the ED

Figure 4-2 Value of competitive bidding



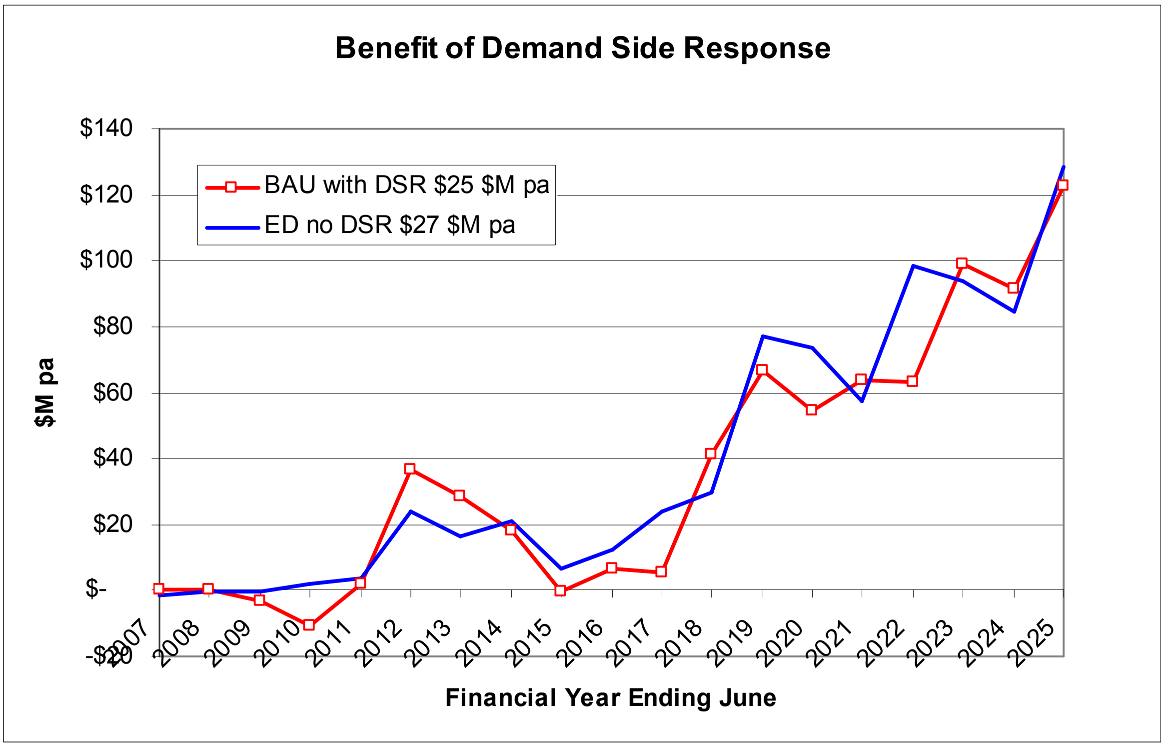
case. These values indicate the substantial economic benefits of more efficient bidding and dispatch and the greater importance from the BAU position. They represent the major share of the potential benefits of a more competitive market, up to 80% of the potential value of reform.

4.7 Impact of efficient demand side response.

The analysis of the impact of demand side response shows a gradual build-up of value starting from around 2011 as shown in Figure 4-3. The value of demand side response can deliver up to about 13% of the value of reform on a levelised basis. That the value is similar for BAU and ED suggests that the displacement of open cycle gas turbine plant with appropriate demand side resources has a value that is largely independent of other market factors.

There would be additional benefit of demand side response arising from the deferment of local transmission and distribution reinforcement related to meeting extreme peak demands. This benefit would similarly grow over time as new network developments are progressively deferred and replaced by suitable demand side resources. The incremental cost of installing the provision for use of demand side response to manage network constraints on a localised basis would be expected to be minimal if provision is already made for responding to energy market capacity constraints causing price spikes. Assuming that about 5% of peak network capacity could be displaced and allowing for $3,000 M per year DUOS and TUOS charges, we would have a net saving of the order of $150 M per year offset by DSR costs of about $37 M in fixed costs and about $15 M per

Figure 4-3 Value of demand side response



annum of variable costs. In round terms this suggests that eventually there could be another $100 M per year network benefit from demand side response.

4.8 Indicated Priority of action

These value characteristics suggest the following priority of action:

- Firstly identify measures to encourage more competitive bidding which may include further disaggregation of the larger generation portfolios or the imposition of contracting rules that would increase the level of contract cover held by generators. These benefits are available immediately through improved dispatch of resources.
- Secondly make provision to increase the role of demand side response in the NEM by 2011. This would require technical infrastructure to automatically control loads in response to prices and commercial contracting arrangements that reward parties which allow their loads to be controlled.
- Thirdly address the processes that influence inter-regional planning to ensure timely investment in transmission augmentation on an economic basis.

5 SUMMARY ANALYSIS

The work to date has shown that a more efficient National Electricity Market would have total costs of about $200 M per annum lower than the current market structure based on a comparison of cost between the BAU scenario and the ED scenario. Efficient Development creates initial benefits of about $200 M pa which rise to about $300 M pa and then decline as the market is expected to become more competitive over time. If the new power plants are only developed by incumbents then we would expect that the gap between Business as Usual and Efficient Development would continue to increase up to $300 M pa by 2025.

An indicative breakdown of the long-term benefits is estimated to be as summarised in Table 5-1 for the early period to 2013, the middle period to 2018 and for the later period from 2019. The analysis is based on the composite scenarios with TABAU representing BAU in the later period.

Table 5-1 Annual benefits of Efficient Development with optimal transmission augmentation ($M June 2005 Dollars)

Cost Component	Early to 2013	2014 - 2018	Later from 2019
Variable O&M	$9	-$11	-$18
Coal Cost	-$55	-$129	-$272
Gas Cost	$203	$201	$29
Fixed capital and O&M	$75	$453	$675
Demand side response	-$36	-$200	-$234
Total	$195	$313	$179

The data show annual benefits of initially $200 M, rising to $300 M and then declining back to $200 M per anum after 2020 as the benefits of growing competition are realised.

Initially a major proportion of the benefit of Efficient Development would be realised by reduced gas consumption and a greater participation from demand side response in meeting infrequent and extreme peak demands. In the longer term, the main source of benefit is from capital deferment which is offset by the cost of sustained demand side response to cover extreme supply/demand conditions.

The benefits of augmenting the transmission system as soon as possible under Business as Usual would accrue from 2011 as compared to delayed development which was represented in the BAU scenario. Whilst it might be expected that such developments would reduce prices to customers, the work to date suggests that the majority of the benefits would accrue to suppliers rather than customers.

Early major transmission augmentation would be of no benefit if the NEM was highly competitive. Such developments would become economic in the period from 2013 to 2018. Immediate benefits could be realised from development of technologies to deliver demand side response on a regular basis. This would defer the need for peaking plant which under current market arrangements is uneconomic. A substantial proportion of the existing peaking plant currently achieves a reasonable utilisation because of the price gaming by the larger coal fired businesses which use such activity to achieve sustainable revenues by influencing prices in the spot and contract markets.

The impact of a more efficient market would be increased carbon dioxide emissions but these could be readily offset by a modest increased contribution from renewable energy sources of up to 5 Mt per annum by 2020 which is equivalent to 5,000 GWh of additional renewable energy generation.

The vast majority of the potential benefit of reform would be delivered by more efficient bidding and dispatch. Demand side response delivers another 13% or so but the value does not become significant until after 2010 because of the surplus generating capacity already installed. Improvement in the planning and timing of interconnection augmentations could deliver value about half that from demand side response in present value terms. The priority order for action based upon potential value and lead time for when value can be appropriated is indicated to be:

- Firstly identify measures to encourage more competitive bidding which may include further disaggregation of the larger generation portfolios or the imposition of contracting rules that would increase the level of contract cover held by generators.
- Secondly make provision to increase the role of demand side response in the NEM after 2010. This would require technical infrastructure to automatically control loads in response to prices and commercial contracting arrangements that reward parties which allow their loads to be controlled.
- Thirdly address the processes that influence inter-regional planning to ensure timely investment in transmission augmentation on an economic basis.

APPENDIX A EXPANSION PLANS

This appendix summarises the expansion sequences and their evolution during the project. Since the development of an optimal expansion sequence is almost intractable for a market the size of the NEM, the approach was to establish an initial candidate expansion plan in PROVIEW and then allow timing to vary by plus or minus one year the thereby to examine adjustments to timing that could reduce total costs. To indicate the nature of this work, this appendix shows the initial, interim and final expansion plans that were developed for each case.

A.1 Business-as-Usual (BAU)

Table A- 1 shows the progressive analysis of the expansion plan for the business as usual scenario with and without transmission augmentation. The key points that may be gleaned from this information are:

- Plant expansion is substantially unaffected in **North Queensland** because that region is almost self-contained due to the Central to North Queensland constraint. There remains scope to optimise the timing of the Central to North Queensland augmentation in this analysis.
- Transmission augmentation requires plant to be advanced in South Queensland to support exports south.
- New plant can be delayed in NSW as a result of transmission augmentation. Since power generation costs are generally higher in NSW this yields net benefits.
- New plant in Victoria and South Australia is delayed in the period to 2015 with transmission augmentation.
- New plant in Tasmania is not affected by mainland interconnection developments.

A.2 Efficient Development (ED)

Table A- 2 shows the progressive analysis of the expansion plan for the efficient development scenario. The key points that may be gleaned from this information are:

- There is a high rate of growth in North Queensland and optimising the expansion plan for that region is in itself a major task. We have only achieved a simple approximation based on base load imports and local peaking plant.
- Coal plant did not feature in the optimal expansion plan for Queensland as far as 2018.
- The QNI upgrade's optimal timing is about July 2012 with associated augmentation from Tarong to Brisbane.
- Coal fired plant is not needed in Victoria until about 2017.

- The Heywood upgrade could be delayed to 2018 with peaking plants and demand side response maintaining reliability in the meantime.

A.3 Early Transmission Augmentation (TAED)

Table A- 3 shows a comparison of the Efficient Development expansion plan with and without early transmission augmentation.

Table A- 1 Development of Expansion Plans for Business as Usual with and without Transmission Augmentation

Initial Guess to 2011 (R1)		Interim (BAU R4a)	With Transmission Augmentation (TABAU R4)
Based on screening curve analysis and expansion plan to 2011 without PLEXOS bids		After expansion analysis and with PLEXOS bids to 2015	After expansion analysis and with PLEXOS bids to 2016
Queensland North			
Qld Central to North (315)		Jul-15	Jul-17
QN OCGT (100)		Nov-14	Nov-12
QN OCGT (100)		Nov-16	Nov-15
QN CCGT (380)		Nov-17	Nov-16
QN OCGT (100)		Nov-17	Nov-17
QN OCGT (100)		Nov-18	Nov-18
QN OCGT (100)		Nov-20	Nov-20
QN OCGT (100)		Nov-21	Nov-21
QN OCGT (100)		Nov-22	Nov-22
Queensland South/West			
CCGT (385)		Nov-10	Nov-10
Wambo South GT (291)	Nov-10	Nov-10	Nov-13
Wambo South GT (291)		Nov-11	Nov-17
Tarong-Brisbane (1000)		Jul-15	Jul-12
Kogan Creek (705)		Nov-16	Nov-14
Wambo South GT (145.5)		Nov-13	Nov-20
Wambo South GT (145.5)		Nov-14	Nov-21
CCGT (385)		Nov-12	Nov-11

Initial Guess to 2011 (R1)		**Interim (BAU R4a)**	**With Transmission Augmentation (TABAU R4)**
Wambo South GT (145.5)		Nov-14	Nov-21
Wambo South GT (145.5)		Nov-14	Nov-22
CCGT (385)		Nov-20	Nov-17
Wambo South GT (145.5)		Nov-24	Nov-24
CCGT (385)		Nov-23	Nov-21
Millmerran 3 (395.6)		Nov-22	Nov-22
Millmerran 4 (395.6)		Nov-23	Nov-23
NSW			
QNI Upgrade (400)		Jul-12	Jul-08
Tomago OCGT (250)	Nov-09	Nov-09	Nov-10
Bayswater 1 upgrade (648.18 ►697.5)	Nov-10	Nov-10	Nov-11
OCGT (200)	Nov-10	Nov-10	Nov-12
Bayswater 2 upgrade (648.18 ►697.5)		Nov-11	Nov-12
Tomago CCGT conversion (250►400)		Nov-11	Nov-12
Bayswater 3 upgrade (648.18 ►697.5)		Nov-11	Nov-13
Bayswater 4 upgrade (648.18 ►697.5)		Nov-12	Nov-13
OCGT (200)		Nov-16	Nov-18
Tomago OCGT (250)		Nov-14	Nov-14
CCGT (400)		Nov-16	Nov-16
Mt Piper 1 upgrade (620.4 ►697.5)		Nov-13	Nov-13

Initial Guess to 2011 (R1)		**Interim (BAU R4a)**	**With Transmission Augmentation (TABAU R4)**
Mt Piper 2 upgrade (620.4 ►697.5)		Nov-13	Nov-13
Eraring 1 upgrade (620.4 ►697.5)		Nov-14	Nov-14
Eraring 2 upgrade (620.4 ►697.5)		Nov-14	Nov-14
Eraring 3 upgrade (620.4 ►697.5)		Nov-15	Nov-19
Tomago CCGT conversion (250►400)		Nov-16	Nov-16
Port Kembla Cogen (194)		Nov-15	Nov-15
Eraring 4 upgrade (620.4 ►697.5)		Nov-15	Nov-20
NSW Black Coal (705)		Nov-18	Nov-17
Munmorah OCGT (150)		Nov-16	Nov-14
OCGT (200)		Nov-19	Nov-21
CCGT (400)		Nov-19	Nov-19
NSW Black Coal (705)		Nov-22	Nov-21
Munmorah OCGT (150)		Nov-21	Nov-21
Munmorah OCGT (150)		Nov-22	Nov-22
Victoria			
SnoVic 1 (180)		Jul-13	Jul-08
SnoVic 2 (420)		Jul-16	Jul-08
Maryvale Cogen (150)		Nov-13	Nov-15
Vic OCGT (160)		Nov-12	Nov-15
Vic OCGT (160)		Nov-15	Nov-16
Western CCGT (500)		Nov-15	Nov-15
Western CCGT (500)		Nov-17	Nov-17

Initial Guess to 2011 (R1)		Interim (BAU R4a)	With Transmission Augmentation (TABAU R4)
Western CCGT (500)		Nov-20	Nov-20
Victoria Brown Coal (440)		Nov-20	Nov-20
Western CCGT (500)		Nov-23	Nov-23
Latrobe CCGT (372.5)		Nov-24	Nov-24
Vic OCGT (160)		Nov-24	Nov-24
South Australia			
Heywood I/C (300)		Jul-18	Jul-08
Hallett (130)	Nov-10	Nov-08	Nov-12
Hallett (130)		Nov-10	Nov-14
Quarantine CCGT conversion (91.6►164.9)	Nov-10	Nov-10	Nov-16
Dry Creek 4 (38.8)		Nov-18	Nov-14
Mintaro 2 (40)		*Nov-08*	Nov-14
Snuggery 4 (20.9)		Nov-18	*Nov-17*
SA OCGT (130)		Nov-15	Nov-20
SA OCGT (130)		Nov-20	Nov-22
SA CCGT (237)		Nov-18	Nov-18
Tasmania			
OCGT (160)[1] (160)		May-19	May-19
OCGT (160) (160)		May-24	May-24

Table A- 2 Development of Expansion Plans for Efficient Development

Initial Guess (R1)	Interim to 2018 (R9)	Final Solution to 2025 (R13)
Based on screening curve	After adjustment by	After adjustment by PROVIEW

[1] The Tasmanian peaking plant was not included in the PROVIEW analysis. It was added mannually to control unserved energy levels and prices in Tasmania.

Initial Guess (R1)		Interim to 2018 (R9)		Final Solution to 2025 (R13)	
analysis		PROVIEW to 2018		to 2025	
Queensland North					
Qld Central to North (315)	Jul-15	QN OCGT (100)	Nov-15	Qld Central to North (315)	Jul-19
QN OCGT (100)	Nov-15	Qld Central to North (315)	Jul-18	QN OCGT (100)	Nov-15
QN OCGT (100)	Nov-16	QN OCGT (100)	Nov-17	QN OCGT (100)	Nov-17
QN OCGT (100)	Nov-17			QN OCGT (100)	Nov-18
QN OCGT (100)	Nov-18			QN OCGT (100)	Nov-20
QN OCGT (100)	Nov-22			QN OCGT (100)	Nov-20
QN OCGT (100)	Nov-23				
Queensland South/West					
		Tarong-Brisbane (1000)	Jul-12	Tarong-Brisbane (1000)	Jul-12
2 Wambo South GT (291)	Nov-12	Wambo South GT (291)	Nov-12	Wambo South GT (145.5)	Nov-12
2 Wambo South GT (291)	Nov-13	Wambo South GT (291)	Nov-13	Wambo South GT (145.5)	Nov-13
		Wambo South GT (291)	Nov-14	Wambo South GT (145.5)	Nov-14
		Wambo South GT (291)	Nov-15		
CCGT (385)	Nov-14				
Tarong-Brisbane (1000)	Jul-15				
Kogan Creek	Nov-			Wambo South GT	Nov-

Initial Guess (R1)		Interim to 2018 (R9)		Final Solution to 2025 (R13)	
(705)	15			(145.5)	16
Wambo South GT (145.5)	Nov-15	CCGT (385)	Nov-15	CCGT (385)	Nov-15
Wambo South GT (145.5)	Nov-16	CCGT (385)	Nov-16	CCGT (385)	Nov-16
CCGT (385)	Nov-17			CCGT (385)	Nov-17
Wambo South GT (145.5)	Nov-17			Wambo South GT (145.5)	Nov-19
Wambo South GT (145.5)	Nov-19			CCGT (385)	Nov-21
CCGT (385)	Nov-20			Kogan Creek (705)	Nov-22
Wambo South GT (145.5)	Nov-21			Wambo South GT (145.5)	Nov-22
CCGT (385)	Nov-22			Wambo South GT (145.5)	Nov-23
Wambo South GT (145.5)	Nov-22			CCGT (385)	Nov-24
CCGT (385)	Nov-24			CCGT (385)	Nov-24
NSW					
		QNI Upgrade (400)	Jul-12	QNI Upgrade (400)	Jul-12
		NSW OCGT (200)	Nov-15	NSW OCGT (200)	Nov-15
Bayswater 1 upgrade (648.18 ►697.5)	Nov-13	Bayswater 1 upgrade (648.18 ►697.5)	Nov-17	Bayswater 1 upgrade (648.18 ►697.5)	Nov-17
Bayswater 2 upgrade (648.18 ►697.5)	Nov-14	Bayswater 2 upgrade (648.18 ►697.5)	Nov-17		

Initial Guess (R1)		Interim to 2018 (R9)		Final Solution to 2025 (R13)	
Bayswater 3 upgrade (648.18 ►697.5)	Nov-15	Bayswater 3 upgrade (648.18 ►697.5)	Nov-17	Tomago OCGT (250)	Nov-17
Bayswater 4 upgrade (648.18 ►697.5)	Nov-16			Port Kembla Cogen (194)	Nov-18
Tomago OCGT (250)	Nov-16	Tomago OCGT (250)	Nov-17	NSW OCGT (200)	Nov-18
NSW OCGT (200)	Nov-16			Bayswater 2 upgrade (648.18 ►697.5)	Nov-18
Tomago CCGT conversion (250►400)	Nov-17			Bayswater 3 upgrade (648.18 ►697.5)	Nov-18
Eraring 1 upgrade (620.4 ►697.5)	Nov-17			Bayswater 4 upgrade (648.18 ►697.5)	Nov-18
Eraring 2 upgrade (620.4 ►697.5)	Nov-17			Mt Piper 1 upgrade (620.4 ►697.5)	Nov-18
Tomago OCGT (250)	Nov-18			Mt Piper 2 upgrade (620.4 ►697.5)	Nov-21
Eraring 3 upgrade (620.4 ►697.5)	Nov-18			NSW CCGT (400)	Nov-20
NSW CCGT (400)	Nov-19				
Tomago CCGT conversion (250►400)	Nov-19			Eraring 1 upgrade (620.4 ►697.5)	Nov-22
Port Kembla Cogen (194)	Nov-19			Eraring 2 upgrade (620.4 ►697.5)	Nov-24
Eraring 4 upgrade (620.4 ►697.5)	Nov-19			Eraring 3 upgrade (620.4 ►697.5)	Nov-24

Initial Guess (R1)		Interim to 2018 (R9)		Final Solution to 2025 (R13)	
Mt Piper 1 upgrade (620.4 ►697.5)	Nov-19			Eraring 4 upgrade (620.4 ►697.5)	Nov-24
Mt Piper 2 upgrade (620.4 ►697.5)	Nov-20				
NSW Black Coal (705)	Nov-20				
NSW Black Coal (705)	Nov-23			NSW Black Coal (705)	Nov-24
Victoria					
SnoVic 1 (180)	Jul-14			SnoVic 1 (180)	Jul-17
SnoVic 2 (420)	Jul-17			SnoVic 2 (420)	Jul-20
Maryvale Cogen (150)	Nov-17	Maryvale Cogen (150)	Nov-16	Maryvale Cogen (150)	Nov-16
		Vic Brown Coal (440)	Nov-17	Victorian Brown Coal (440)	Nov-18
Western CCGT (500)	Nov-18			Western CCGT (500)	Nov-18
Western CCGT (500)	Nov-20			Western CCGT (500)	Nov-21
Western CCGT (500)	Nov-22			Vic OCGT (160)	Nov-20
Latrobe CCGT (372.5)	Nov-23			Latrobe CCGT (372.5)	Nov-23
Vic OCGT (160)	Nov-24				
South Australia					
Heywood I/C (300)	Jul-12	Heywood I/C (300)	Jul-12	Heywood I/C (300)	Jul-20
Hallett (130)	Nov-	Hallett (130)	Nov-	Hallett (130)	Nov-

Initial Guess (R1)		Interim to 2018 (R9)		Final Solution to 2025 (R13)	
	15		15		19
Hallett (130)	Nov-16	Hallett (130)	Nov-16	Hallett (130)	N/A
Quarantine CCGT conversion (91.6►164.9)	Nov-19			Quarantine CCGT conversion (91.6►164.9)	Nov-21
Dry Creek 4 (38.8)	Nov-20			Dry Creek 4 (38.8)	Nov-24
Mintaro 2 (40)	Nov-20			Mintaro 2 (40)	Nov-24
Snuggery 4 (20.9)	Nov-21			Snuggery 4 (20.9)	Nov-24
SA CCGT (237)	Nov-21				
Tasmania					
OCGT (160)[2] (160)	Jul-23			OCGT (160)[1] (160)	Jul-18
OCGT (160) (160)	Jul-24			OCGT (160) (160)	Jul-24

Table A- 3 Development of Expansion Plans for Efficient Development with and without Transmission Augmentation

Initial Guess to 2011 (R1)	Efficient Development (R13)	With Transmission Augmentation (TAED R10)

[2] The Tasmanian peaking plant was not included in the PROVIEW analysis. It was added mannually to control unserved energy levels.

Initial Guess to 2011 (R1)		Efficient Development (R13)	With Transmission Augmentation (TAED R10)
Queensland North			
Qld Central to North (315)		Jul-19	Jul-17
QN OCGT (100)		Nov-15	Nov-14
QN OCGT (100)		Nov-17	Nov-15
QN OCGT (100)		Nov-18	Nov-20
QN OCGT (100)		Nov-20	Nov-20
QN OCGT (100)		Nov-22	Nov-22
Queensland South/West			
Tarong-Brisbane (1000)		Jul-12	Jul-13
Wambo South GT (145.5)		Nov-12	Nov-12
Wambo South GT (145.5)		Nov-13	Nov-12
Wambo South GT (145.5)		Nov-14	Nov-15
Wambo South GT (145.5)		Nov-16	Nov-16
CCGT (385)		Nov-15	Nov-16
CCGT (385)		Nov-16	Nov-16
CCGT (385)		Nov-17	Nov-18
Wambo South GT (145.5)		Nov-19	Nov-17
CCGT (385)		Nov-21	Nov-21
Kogan Creek (705)		Nov-22	Nov-22
Wambo South GT (145.5)		Nov-22	Nov-22
Wambo South GT (145.5)		Nov-23	Nov-24
Millmerran (395.6)		Nov-24	N/A
CCGT (385)		Nov-24	N/A

Initial Guess to 2011 (R1)	Efficient Development (R13)	With Transmission Augmentation (TAED R10)
NSW		
QNI Upgrade (400)	Jul-12	Jul-08
NSW OCGT (200)	Nov-15	Nov-17
Bayswater 1 upgrade (648.18 ►697.5)	Nov-17	Nov-17
Tomago OCGT (250)	Nov-17	Nov-15
Port Kembla Cogen (194)	Nov-18	Nov-18
NSW OCGT (200)	Nov-18	Nov-19
Bayswater 2 upgrade (648.18 ►697.5)	Nov-18	Nov-19
Bayswater 3 upgrade (648.18 ►697.5)	Nov-18	Nov-21
Bayswater 4 upgrade (648.18 ►697.5)	Nov-18	Nov-21
Mt Piper 1 upgrade (620.4 ►697.5)	Nov-18	Nov-21
Mt Piper 2 upgrade (620.4 ►697.5)	Nov-21	Nov-21
NSW CCGT (400)	Nov-20	Nov-20
Eraring 1 upgrade (620.4 ►697.5)	Nov-22	Nov-22
Eraring 2 upgrade (620.4 ►697.5)	Nov-24	Nov-24
Eraring 3 upgrade (620.4 ►697.5)	Nov-24	Nov-24
Eraring 4 upgrade (620.4 ►697.5)	Nov-24	Nov-24
NSW Black Coal (705)	Nov-24	Nov-24
Victoria		

Initial Guess to 2011 (R1)		Efficient Development (R13)	With Transmission Augmentation (TAED R10)
SnoVic 1 (180)		Jul-17	Jul-08
SnoVic 2 (420)		Jul-20	Jul-08
Maryvale Cogen (150)		Nov-16	Nov-17
Victorian Brown Coal (440)		Nov-18	Nov-18
Western CCGT (500)		Nov-18	Nov-18
Western CCGT (500)		Nov-21	Nov-21
Vic OCGT (160)		Nov-20	Nov-20
Latrobe CCGT (372.5)		Nov-23	Nov-23
Victorian Brown Coal (440)		N/A	Nov-24
South Australia			
Heywood I/C (300)		Jul-20	Jul-08
Hallett (130)		Nov-19	Nov-20
Hallett (130)		N/A	N/A
Quarantine CCGT conversion (91.6►164.9)		Nov-21	Nov-21
Dry Creek 4 (38.8)		Nov-24	Nov-23
Mintaro 2 (40)		Nov-24	N/A
Snuggery 4 (20.9)		Nov-24	N/A
Tasmania			
OCGT (160)[3] (160)		May-19	May-19
OCGT (160) (160)		May-24	May-24

[3] The Tasmanian peaking plant was not included in the PROVIEW analysis. It was added mannually to control unserved energy levels and prices in Tasmania.