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Investor Group on Climate Change

IMPACTS ON ELECTRICITY MARKETS OF DELAYING AN EMISSIONS TRADING SCHEME

- June 2011

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Abstract

When an emission trading scheme should commence has been a key debating point, with many commentators arguing for a delay in the start until other countries adopt similar measures and others arguing that delaying would only increase uncertainty faced by investors. In this study, we examined the implications of delaying the start. The analysis found that a 4 year delay led to additional generation costs of around $1 billion ($500 million to 2030), with this cost due mainly to suboptimal investment decisions in new generation. Although generation costs were lower in the period prior to the delayed commencement of emission trading, the suboptimal investment in new generation (reflecting investor decisions to invest in low risk plant) increased generation costs over the longer term. Emissions are also higher with a delayed start leading to about $3 billion ($2 billion to 2030) in economic costs due either to additional permits being purchased or in higher social costs. The additional cost manifested in higher electricity prices when emission trading commenced. Given that reducing emissions is the ultimate goal, an early start is beneficial in preventing the lock in of suboptimal investments in new generation.

Executive Summary

SKM MMA has been engaged by the Investor Group on Climate Change to determine the electricity market impacts of a delay to an emissions trading scheme (ETS) on the assumption that eventual action will be taken to achieve a given 2020 target. This was carried out by comparing electricity market outcomes under two scenarios:

- emissions trading commencing in July 2012;
- delayed action with emissions trading commencing in July 2016;

The two scenarios are identical, apart from the different commencement date for the emissions trading scheme.

Differences between 2012 start and delayed start scenarios

Victorian brown coal plant begins to retire in both scenarios as the carbon price is introduced. Under the 2012 start scenario the retirement time frame for the most emissions intensive capacity spans from 2014 until 2018 and is mostly replaced by combined cycle gas turbines (CCGTs) and some open cycle gas turbines (OCGTs). In contrast, the same amount of brown coal capacity is retired between 2017 and 2018 under the delayed start scenario because the price of carbon is just as high as the 2012 start case. Due to the lack of investor certainty in this case, all retiring brown coal capacity is replaced by OCGT plant, which is significantly more expensive to run than CCGT plant but quicker to build. As a result wholesale prices are higher than the 2012 start scenario and retail prices averaged across all customer classes are some 3% higher by 2030.

The sub-optimal investment in replacement thermal generation capacity for the delayed start case results in higher resource costs[1], which are 1% higher than the 2012 start case by 2030 on an NPV basis. Costs of running gas turbines (both open cycle and combined cycle) are higher under the delayed start case, but the high build of OCGT capacity in this scenario also means that incumbent gas steam plant, which is quite old and inefficient, also runs harder. In contrast, these plants are partly displaced by CCGT capacity in the 2012 start case and therefore incur less cost. The delayed start case also sees the release of 2% more emissions than the 2012 start scenario by 2030. Coal plants generate approximately 1% more energy under the delayed start case, whereas generated energy from natural gas and liquid fuels falls by 1% relative to the 2012 start case.

Finally, there are lower emissions under the 2012 start scenario relative to the 2016 start. Most of the emissions savings occur in the first ten years from 2012 amounting to about 90 Mt relative to the delayed start. These represent emissions savings of 2% by 2030.

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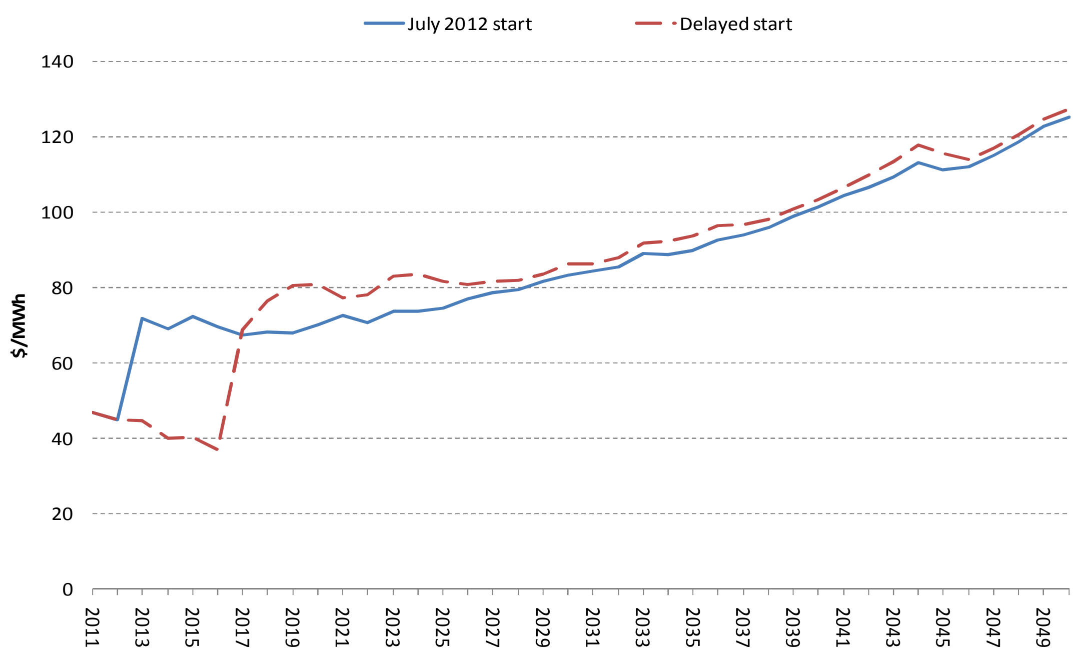
[1] Resource costs are comprised of fuel costs and operating costs

■ **Exec Table - 1: Impacts of delaying the start of emission trading relative to 2012 start**

Parameter	2011-16	2017-2021	2022-2030
Wholesale price, $/MWh	-20	8	5
Wholesale price, %	-32%	11%	7%
Retail price, average, $/MWh	-22	9	7
Retail price, %	-17%	6%	4%
Savings in generation costs, $M	-929	1,128	358
Proportion of total generation costs, %	-2%	3%	2%
Additional emissions, Mt CO_2e	37	26	26
Proportion of total emissions, %	3%	3%	2%
Cost of additional emissions, $M	789	536	499

Note: All $/MWh data are averages across the periods, all $M data are present values calculated using a 5% discount rate.

■ **Exec Figure -1: Impact on wholesale prices of delaying the start of emission trading**



Economic benefits

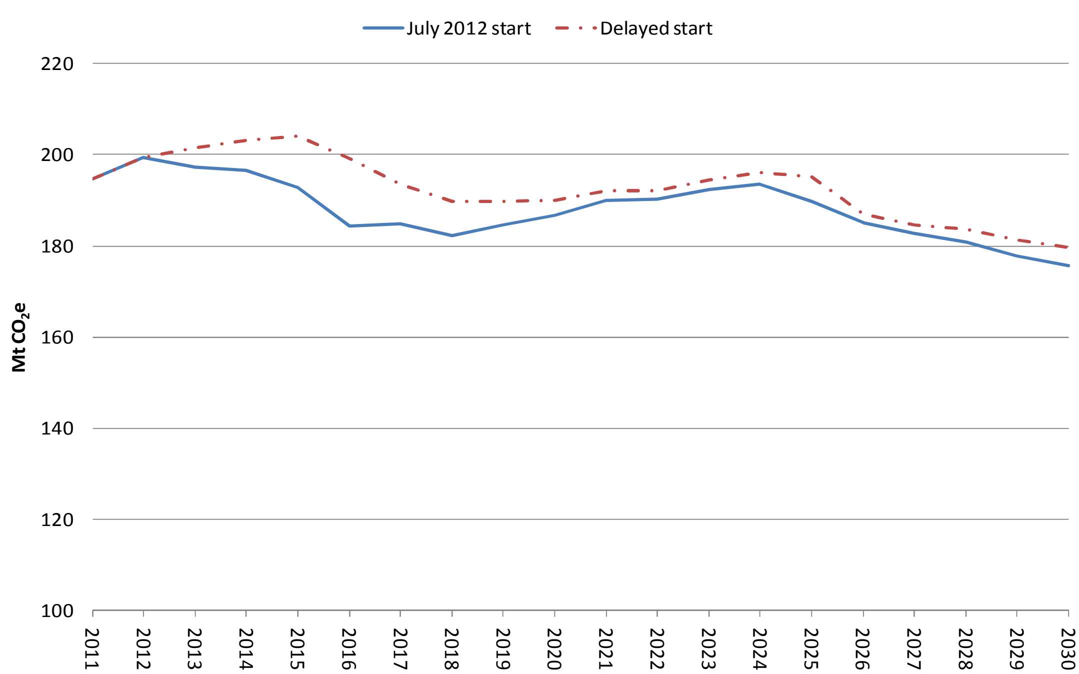
The savings accrue under the 2012 start scenarios due to three main factors:

- Delaying the start of emissions trading results in a different mix of generating plant before 2016, which affects the choice of plant from 2016. The key assumption is that the timing of commencement in the delayed case is uncertain and this leads to the change in choice of plant.

OCGTs are the preferred investment strategy with a delay due to their low capital costs. Investments in coal-fired plant are not encouraged by the delay due to the prospect that carbon prices will be introduced[2]. CCGTs have high capital costs and wholesale prices prior to emission trading are not high enough for early entry of this plant. Thus, any new plant required to meet load growth and to ensure reliable supply tend to be OCGTs.

- Higher fuel costs due to less efficient plant entering the market.
- The higher cost of replacing unprofitable plant after 2016 over a short time period. Around 2,000 MW of plant are required to be replaced in the period from 2016 to 2020 in the delayed case, resulting in higher engineering and material costs than would have occurred if the same amount of capacity was closed over a longer time period.
- The cost of additional emissions is $2bn to 2030. This includes the externality cost of emissions in the period from 2012 to 2016 when there is no explicit price for carbon emissions and secondly, the cost of additional emissions reduction permits from 2017, where it was more cost effective to buy additional permits than invest in plant that could reduce emissions.

- **Exec Figure - 2: Projected emissions**



2 This is reflected in the modelling as a higher risk premium on the returns to capital required of around 5 percentage points. Note that we did not take into account higher debt premiums on debt rollovers of existing assets that would occur in the delayed scenario. See P. Simshauser and T. Nelson (2011), "Carbon taxes, toxic debt and second-round effects of zero compensation: the power generation meltdown scenario" AGL *Applied Economic and Policy Research Working Paper No.26*, April

1. Introduction

SKM MMA has been engaged by the Investor Group on Climate Change to determine the electricity market impacts of a delay to an emissions trading scheme on the assumption that eventual action will be taken to achieve a given 2020 target. This was carried out by comparing electricity market outcomes under three scenarios with different combinations of start date for emission trading and other interim actions to curb emissions.

This report outlines the key assumptions and the modelling methodology employed for this study. The results are then presented in terms of direct electricity market impacts due to a delay in emissions trading, and this is followed by an analysis of the economic costs caused by such a delay.

Monetary values presented in this report are in mid 2010 dollars, and stated years refer to financial years ending June.

2. Issues

There is an extensive literature on the relative merits for early versus delayed action to curb emissions of greenhouse gases.

Arguments for delay are based on the following arguments:

- Because future costs and benefits are discounted, delaying abatement action can allow Governments to increase mitigation efforts in the future to achieve the same cumulative abatement at the same net present costs.
- Delaying emission reduction efforts will allow larger cumulative amounts of greenhouse gases in the atmosphere, and allow less abatement to be required due to the natural absorption of carbon dioxide through biosequestration.
- Delaying mitigation action has the advantage that abatement could be achieved through cheaper abatement options that become available in the future. This benefit can only be realised if effort is expended to develop these options through research, development and demonstration.

Realising these benefits may be difficult. One issue with delaying action is that there can never be a guarantee that action will be taken. The nature of mitigation policy is that the costs are borne upfront, whereas the benefits of reduced emissions may take 100 years or more to be fully recognised. At each point of time, a decision maker may continue to delay action until such time as the costs of mitigation action are only minor. By then detrimental climate change may already be locked in. Cheaper options may not become available unless concerted effort is made to invest in research and development and deployment of new technologies. Although emission trading may not optimise research and development of new technologies, it provides a driver (market pull) that could at least guide development in new low emission technologies.

Early action can bring other benefits. First, early action can help to minimise technological lock-in. Investments in generation have long lives and continuing entry of high emitting plant could lock in emissions from those plants. Investor foresight may reduce lock –in to the extent that investors are confident that some form of carbon mitigation policy will be adopted. Second, delaying action may slow down innovation in low emission technologies and defer cost reductions through learning by doing. Third, delaying action could require a rapid turnover of the existing stock of capital (e.g. high emission generation), which could increase costs and endanger security of supply.

Finally, uncertainty over when emission trading or carbon pricing may commence can also lead to higher costs both before and after carbon pricing is eventually introduced. A recent study[3] found

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[3] T. Nelson, S. Kelly, F. Orton and P. Simshauser (2010), "Delayed Carbon Policy Certainty and Electricity Prices in Australia", *Economic Papers*, Volume 29 (4), pp 446-465

that "the additional cost to electricity users associated with the sub-optimal introduction ...... to be significant; under a business-as-usual electricity demand growth scenario, prices in 2020 would be about $8.60/MWh higher than necessary". They also found that "costs to consumers are lower where complementary policies are introduced to encourage energy efficiency and renewable energy". A review of this study determined that the actual impact of uncertainty on costs was an empirical question, with the magnitude depending on the outlook for the market and the interaction with other Government policies. Using a simulation model of the electricity market and plausible assumption on the entry of new plant, the conclusion was that the added cost was only $3.40/MWh in NSW[4]. The lower estimate was due to the fact that investment in generation in the period to 2020 is dominated by new renewable energy generation, which received financial incentives independent of carbon pricing.

[4] Frontier Economics (2010), *What's the Cost of Carbon Uncertainty? The Impact of Delayed Investment in the Power Sector*, Melbourne, November

3. Methodology and assumptions overview

3.1. Overview

The impacts on electricity markets of a delay to an ETS were determined by modelling the major Australian electricity grids using Strategist, an electricity market modelling software package. The grids that were considered in the study are as follows:

- NEM (National electricity market);
- Mt Isa in northwest Queensland;
- SWIS (South-west interconnected system);
- DKIS (Darwin-Katherine interconnected system);
- NWIS (North-west interconnected system); and
- the remote mining regions of the Pilbara in Western Australia.

The costs from delay are likely to arise from:

- Less than optimal timing of entry of new generation plant (particularly of low emission plant).
- Increased uncertainty for investors in new high emission and low emission plant, increasing the risk premium on new investments and hence the cost of new generation[5].
- Less than optimal sequence and selection of new generation technologies. Despite the uncertainty more coal plant could enter the market on the back of usurping existing coal plant should action be eventually taken and on the anticipation of receiving some "compensation". Because of investment and technological lock in, the delay could impact on the optimal investment patterns both before and after 2020.
- Increased cost of replacing high emission plant to meet a 2020 target. If the target is the same and if the carbon price faced by the electricity sector is the same under an early and delayed start, then the same retirement would be required for both cases by 2020. With a 2012 start, this retirement could occur over a longer time period leading to an orderly replacement program. With a delayed start, the replacement is compressed in shorter time period leading to higher cost of replacement (due to shortages of labour and materials)
- Suboptimal investment in transmission capacity, such as gearing investment in transmission to serve current areas of generation instead of reallocating this investment to building transmission capacity to areas with low emission sources. Because of current of current

[5] In this study, we did not take into account higher debt premiums on debt rollovers of existing assets that would occur in the delayed scenario. See P. Simshauser and T. Nelson (2011), "Carbon taxes, toxic debt and second-round effects of zero compensation: the power generation meltdown scenario" AGL *Applied Economic and Policy Research Working Paper No.26*, April

revenue setting arrangements for network, this suboptimal investment could be locked into the revenue base for future network price reviews.

- Suboptimal investment in renewable energy under the RET scheme, as prices for electricity received by renewable energy generators would differ by location under different time paths for action on carbon emissions.
- Delay in the development of new technologies and deferring any learning by doing that might occur.

These additional costs would likely lead to higher electricity prices than would occur if early rather than delayed action was taken. Furthermore, they would lead to less efficient use resources in electricity supply, potentially leading to further economic costs on the rest of the economy.

3.2. Strategist software platform

Strategist is a multi-area probabilistic dispatch algorithm that accounts for the economic relationships between generating plants in the system. Dispatch of each power station is based on the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system.

The modelling algorithm incorporates:

- chronological hourly loads representing a typical week in each month of the year;
- chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro plant is assumed to shadow bid to maximise revenue at times of peak demand);
- where an auction market exists, a range of bidding options for thermal plant (fixed prices, shadow bidding, average price bidding);
- chronological dispatch of demand side programs, including interruptible loads and energy efficiency programs;
- estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions;
- scheduled and forced outage characteristics of thermal plant; and
- demand side management and interruptible loads as a dispatchable resource.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. For multi-region grids, such as the NEM, prices are solved having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns.

Bids are generally formulated as multiples of marginal cost and are varied above unity ratio to represent the impact of contract positions and the price support provided by dominant market participants. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model.

For a detailed description of the Strategist NEM and SWIS databases see Appendix A.

3.3. Scenario assumptions

Two scenarios were considered in the modelling:

- Emissions trading commencing in July 2012.
- Delayed action with emissions trading commencing in July 2016.

The two scenarios are identical, apart from the different ETS commencement date.

3.4. Base assumptions

The dispatch model is structured to produce half-hourly price and dispatch forecasts for the entire year. There are a large number of uncertainties that make these projections difficult.

The base assumptions are common to all three scenarios and reflect the most probable market outcomes given the current state of knowledge of the market. The assumed growth in energy has been taken from published forecasts. Peak demand has been derived from the energy projection by using AEMO's[6] relationship between the two.

Key features of the base assumptions include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- The demand growth projections are accompanied by annual demand shapes consistent with the relative growth in summer and winter peak demand.
- A 5% emissions reduction target relative to 2000 emissions levels is set for 2020, and the Federal Treasury's CPRS-5% carbon price path has been assumed. This results in a carbon price of \$51/t CO_2e in 2030 and \$122/t CO_2e in 2050.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market. This includes the retirement of various coal-fired power stations due to the escalating carbon price.

[6] The IMO's relationship is used for the SWIS.

- The LRET and SRES schemes have superseded the expanded MRET scheme and take effect from 1 January 2011. The LRET target as legislated is for 41,000 GWh of renewable generation by 2020 from large-scale renewable generation projects however, both schemes in total are expected to deliver more than 45,000 GWh of additional renewable energy by 2020. The LRET scheme remains similar to its predecessor in terms of issues such as banking and project eligibility periods.
- It was assumed that the increase in the Queensland gas fired generation target to 18% by 2020 will be eventually replaced by the CPRS. In the meantime the target is increased from 15% at 0.5% per year from 2010. Even with a \$10/tCO2e carbon price, there is enough gas fired generation to meet and exceed the Queensland gas fired generation target and so the Gas Electricity Certificate (GEC) price would go to zero.
- The assessed demand side management (DSM) for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.
- Large-scale carbon capture and storage technology is not available until at least 2025/26.
- Geothermal generation becomes commercially viable in 2017.
- Nuclear generation technology is not considered as an option in the modelling.

3.5. Modelling methodology

Future trends in wholesale electricity prices are driven by the supply and demand balance, with long-term prices being effectively capped near the cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Consequently price drivers include carbon prices under an ETS, fuel costs, unit efficiencies and capital costs of new plant. Year to year prices will deviate from the new entry cost level based on the timing of entry of new plant. In periods when new plants are not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power. The market price projections developed in this study have taken into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

For renewable energy projects, the carbon price has a lesser impact while it is of insufficient level to sustain new renewable projects without additional certificate revenue. Any increase in carbon price raises electricity prices and consequently reduces the required revenue stream from certificates in new projects. The critical factors for renewable energy projects during this period are the magnitude of the renewable energy target, the new renewable energy supply curve which will determine the new entry cost for renewable energy, and the extent to which renewable resources are developed in areas of higher energy costs relative to other locations.

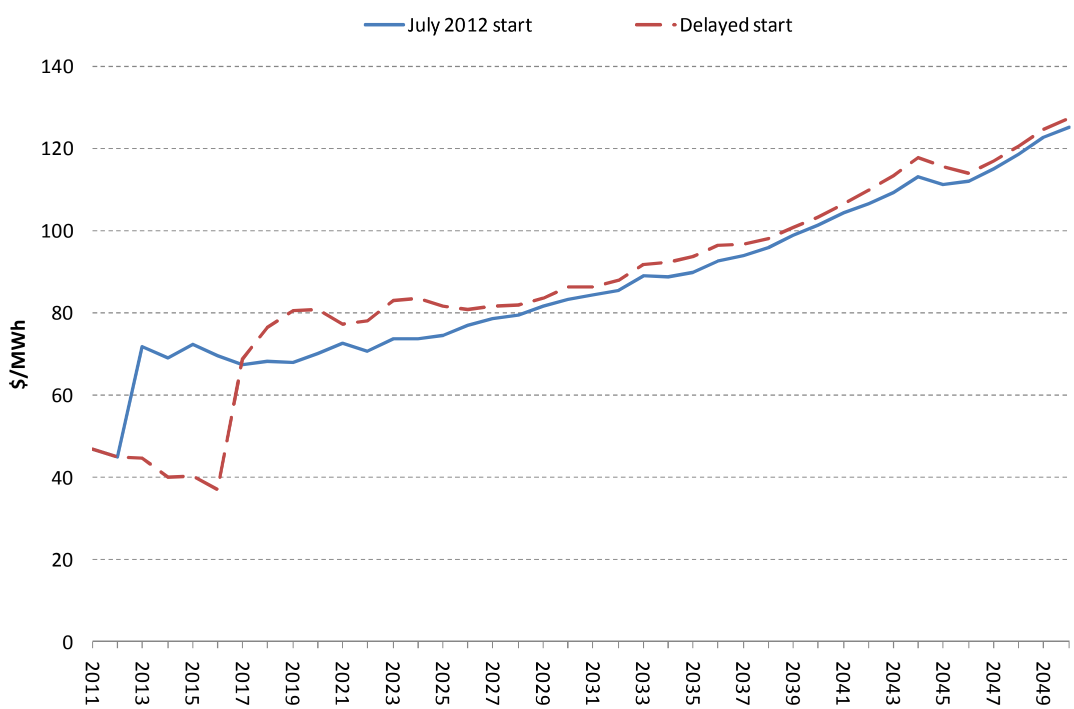
Timing of new generation was determined from development of a generation expansion plan. SKM MMA used the PROVIEW module of Strategist to assist with this task and have developed a plan that minimises total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations of the Strategist package, it is not feasible to complete in one analysis the establishment of an optimal expansion plan that is completely consistent with external scheme outcomes (e.g. level of renewable generation afforded by the RET scheme) and with review of individual generator's contract positions and opportunities to game spot market prices. SKM MMA therefore conducted a number of iterations of PROVIEW to develop a workable expansion plan based upon an initial estimate of renewable generation and then refined the expansion plan to achieve a sustainable price path applying market power where it is apparent and to obtain a consistent set of renewable and thermal new entry plant mix. The final expansion plan meets reserve constraints applied in each region. Generators must behave rationally with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. Infrequently used peaking resources were bid near Value of Lost Load (VoLL) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

4. Electricity market impacts

4.1. Wholesale prices

Figure 4-1 shows the time weighted average electricity wholesale market price in the NEM for the three scenarios. Impacts on price are moderate for the delayed start scenario, with an initial price differential of around -$27/MWh relative to the 2012 start scenario in the period to 2016 due to the delay in carbon pricing, followed by higher prices, peaking at $13/MWh in 2019 but averaging around $6/MWh to 2030.

- **Figure 4-1 Average NEM wholesale price by scenario**



4.2. Retail prices and REC price

Changes in retail prices reflect changes in wholesale prices. The delayed scenario has lower retail costs on average to 2020 because this only reflects four years of carbon pricing. By 2030 retail prices for the delayed start scenario are 3% above the 2012 start case, and they remain about 2% higher across the modelling horizon.

Figure 4-2 shows the REC price for each of the scenarios. The REC price tends to move in the opposite direction to the wholesale energy price because it represents the amount of subsidy needed to make renewable energy competitive in the wholesale energy market. Thus, whilst the average wholesale energy price in Figure 4-1 tends to increase, the REC price tends to decrease over the same time horizon. There is a sharp decrease in the 2012 start REC price from 2013 to 2014, which is a result of the introduction of the carbon price in 2014. A similar drop happens in the delayed scenario from 2016 to 2017. The average REC price over the time horizon is highest for the 2012 start scenario, which reflects the lower average wholesale energy price for that case. The REC price for the delayed start case is much lower, being on average 23% lower relative to the 2012 start case.

4.3. Generation profile

Table 4-1 shows the change in the generation profile for the various fuel classes relative to the 2012 start scenario. The largest change occurs in the years between 2014 and 2020, since this includes the years where a carbon price is not present in the delayed scenario. On average there is around 5% more coal-fired generation under the delayed start scenario in the early years. However, there is about 15% less natural gas and liquid fuels used under the delayed start case.

The large initial differences between the delayed scenario and the 2012 start scenario are dampened from 2021-30, although there is still a consistent pattern of slightly higher coal use in the delayed scenario and less use of gas and liquid fuels.

- **Figure 4-2 REC price by scenario**

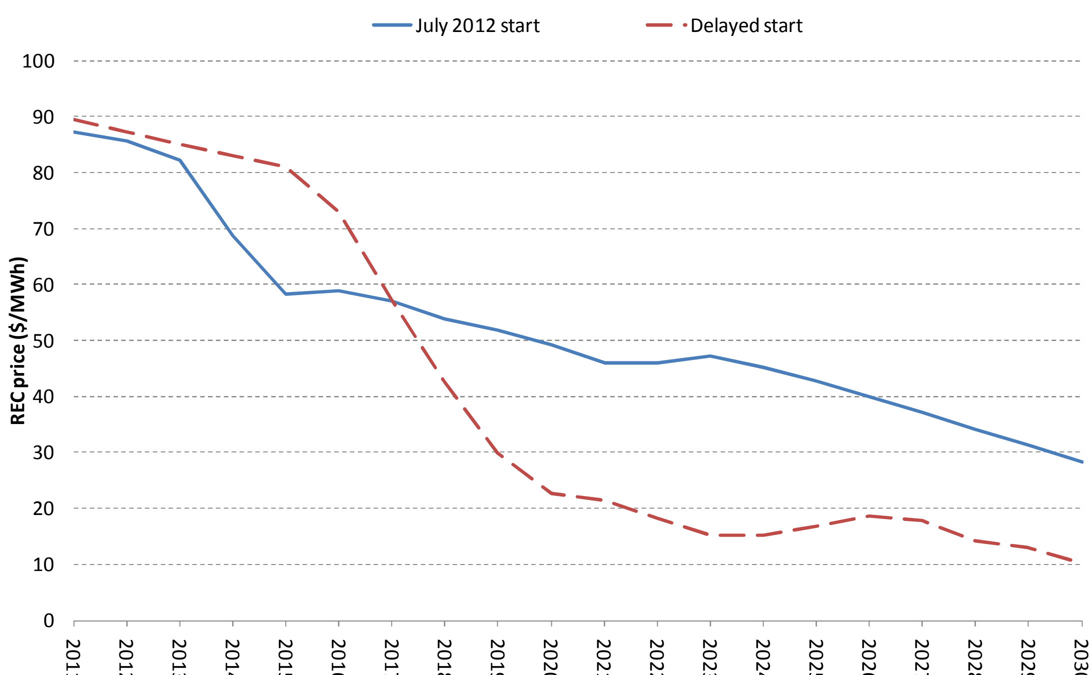


Table 4-1 Change in generation by fuel type relative to the 2012 start scenario

	2014 to 2020	2021to 2030
Change in generation, GWh		
Coal	8,689	4,346
Natural gas/Liquid fuels	-9,721	-5,686
Renewable energy	452	341
% change of generation by fuel type		
Coal	5%	3%
Natural gas/Liquid fuels	-17%	-7%
Renewable energy	1%	1%

4.4. Investment in new generation

Figure 4-3 shows the new thermal generation capacity entering all of the major Australian grids by scenario. The earliest significant investment in high load factor capacity is made under the 2012 start scenario. In contrast, no significant thermal capacity with high load factors is brought online for the delayed start scenario until the introduction of the carbon price in July 2016. In the delayed scenario, new investment to 2016 mainly comprises renewable generation (which occurs under all scenarios as a result of the LRET scheme) and opens cycle gas turbines (OCGTs).

A clearer picture emerges in examining the differences between the scenarios in the type of capacity that is built, especially early on. This is shown in Table 4-2, which shows the difference in capacity by thermal technology relative to the 2012 start scenario. The delayed start case has more OCGT plant relative to the 2012 start case until 2030, but over 1,000 MW less CCGT capacity. CCGTs are built earlier in the 2012 start case primarily because of the early retirement of brown coal capacity in Victoria, which initially occurs over a four year period. In contrast, a large amount of OCGT capacity is needed in the delayed start case to handle the large amount of brown coal plant retirement, which is now compressed into a two year timeframe. It would not be viable in this case to replace the retiring capacity with CCGT plant because of the lead time required.

Figure 4-3 New thermal generation capacity by scenario

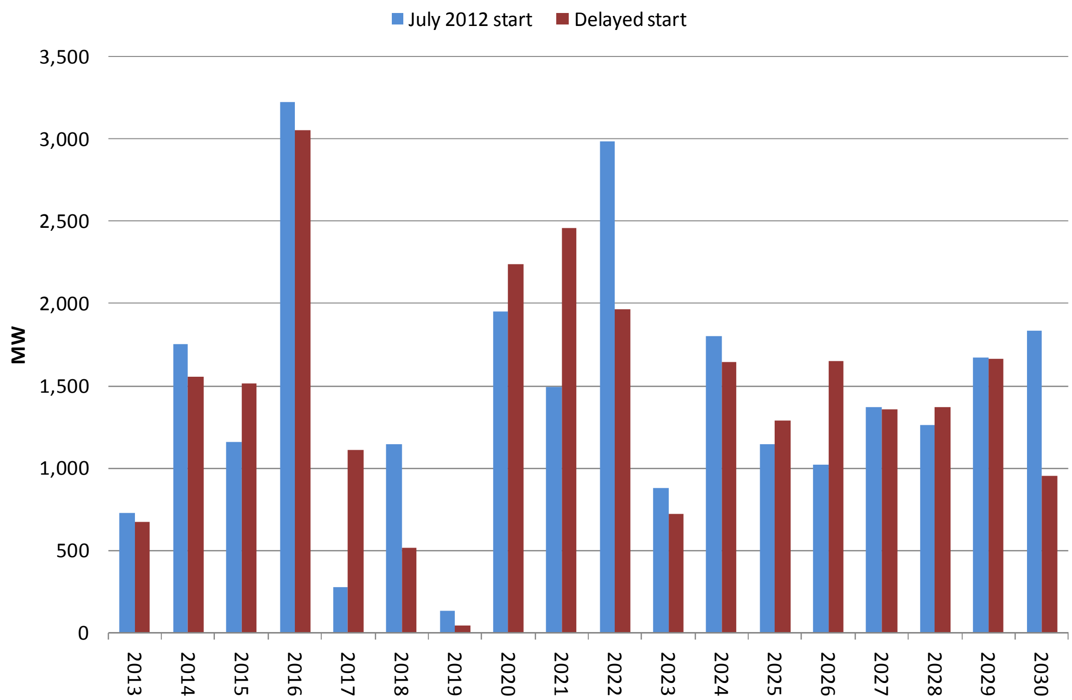


Table 4-2 Cumulative difference in capacity by technology type relative to 2012 start scenario (MW)

Technology type	2015	2020	2025	2030
OCGT	334	2,004	1,044	685
CCGT	-1,110	-1,960	-1,705	-980
Coal with CCS	0	0	0	-380

5. Economic cost of delay

5.1. Change in investment costs

Table 5-1 shows the difference in investment costs for the delayed start scenario relative to the 2012 start scenario. The pattern is similar to that of the installed capacity data (Table 4-2) in that more OCGT investment occurs in the delayed start scenario and less investment in CCGT plant. By 2030 there is almost $1.7 billion less investment in the delayed start case relative to the 2012 start case.

- **Table 5-1 Cumulative difference in investment cost by technology type relative to 2012 start scenario ($M, $2010)**

Technology type	2015	2020	2025	2030
OCGT	299	2,077	1,218	1,348
CCGT	-1,317	-2,449	-1,565	-1,426
Coal with CCS	0	0	0	-2,596
Total	-1,017	-371	-348	-2,675

5.2. Change in resource costs

Figure 5-1 shows the annual savings in resource costs due to a 2012 start in the ETS, where positive numbers denote savings due to the 2012 start. Savings are negative from 2014 until 2016 reflecting the carbon impost in the 2012 start scenario, and the cheapest scenario in this period is the delayed start case. However, savings in the 2012 start scenario begin to accrue from 2018 onwards for the delayed start case. The largest savings occur from 2019 until 2021 relative to the delayed start scenario. A breakdown of the costs into generator categories shows that the main differences occur in the OCGT and CCGT categories, but also in the cost of running incumbent gas steam plant. Thus the main contributions to the cost differences over these three years between the two scenarios are the increased OCGT costs under the delayed start scenario, and the fact that the additional CCGTs in the 2012 start scenario displace the more expensive gas steam plant.

The savings accrue due to three main factors:

- Delaying the start of emissions trading results in a different mix of generating plant before 2016, which affects the choice of plant from 2016. The key assumption is that the timing of commencement in the delayed case is uncertain and this leads to the change in choice of plant. OCGTs are the preferred investment strategy with a delay due to their low capital costs. Investments in coal-fired plant are not encouraged by the delay due to the prospect that carbon prices will be introduced[7]. CCGTs have high capital costs and wholesale prices prior to emission trading are not high enough for early entry of this plant except under regulatory fiat. Thus, any new plant required to meet load growth and to ensure reliable supply tend to be OCGTs.

- Higher fuel costs due to less efficient plant entering the market.
- The higher cost of replacing unprofitable plant after 2016 over a short time period. Around 2,000 MW of plant are required to be replaced in the period from 2016 to 2020 in the delayed case, resulting in higher engineering and material costs than would have occurred compared with if the same amount of capacity was closed over a shorter time period.

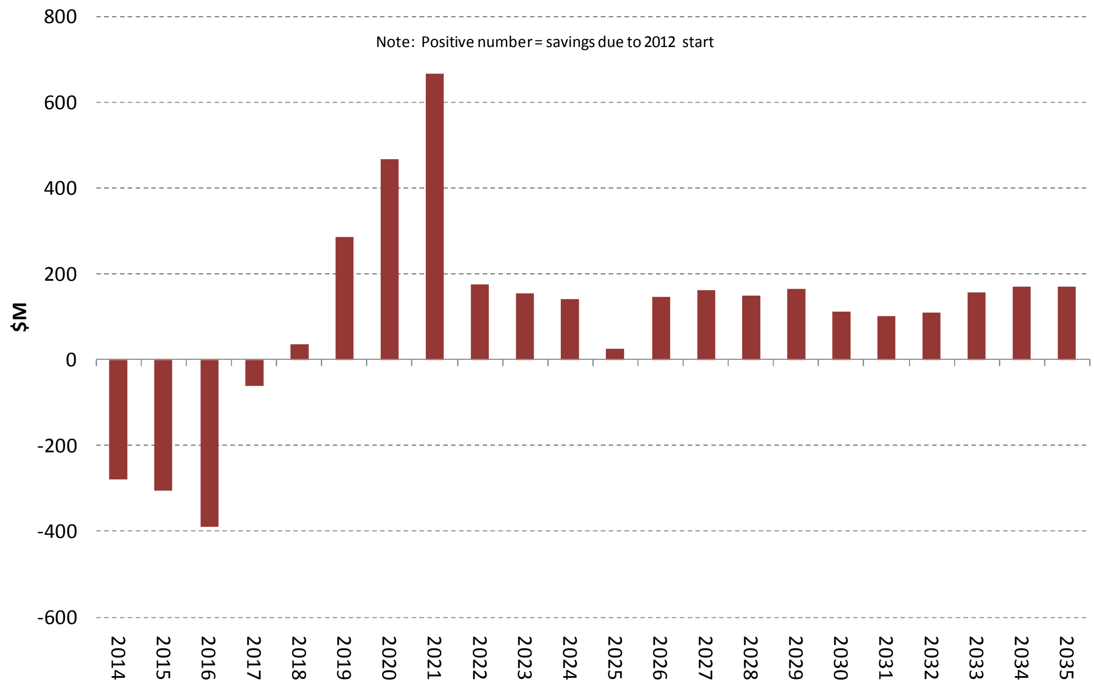
Much of the savings are due to lower CCGT operating costs in the 2012 start scenario. However, in the early years part of the cost savings are also attributable to lower brown coal operating costs, whereas in the later years there are also significant savings from lower OCGT operating costs.

The NPV of savings for the 2012 start scenario relative to the delayed scenario are modest in magnitude, being just over $500 million[8] to 2030, $700 million to 2035 and $950 million to 2050. The additional costs represent 0.5% of the total resource costs of the major Australian electricity grids.

7 This is reflected in the modelling as a higher risk premium on the returns to capital required of around 5 percentage points.

8 Present value calculated from 2012 using a discount rate of 5% real.

▪ Figure 5-1 Savings in resource costs due to 2012 start



5.3. Cost of emissions

Figure 5-2 shows the emissions profile for each of the scenarios. Most of the emissions savings under the 2012 start scenario occur in the first ten years relative to the delayed start case. Emissions savings to 2030 under the 2012 start scenario amount to 90 Mt relative to the delayed start. These represent emissions savings of 2% by 2030.

If the value of additional emissions are included in the benefit cost analysis (due to the externality cost of additional emissions in the period to 2017 on the assumption that the cost of emissions must be borne elsewhere in the economy, and the value of purchasing additional permits from 2017), the total net cost of delayed action rises by $2.0 billion for delayed action by 2030.

Figure 5-2 Emissions profile by scenario

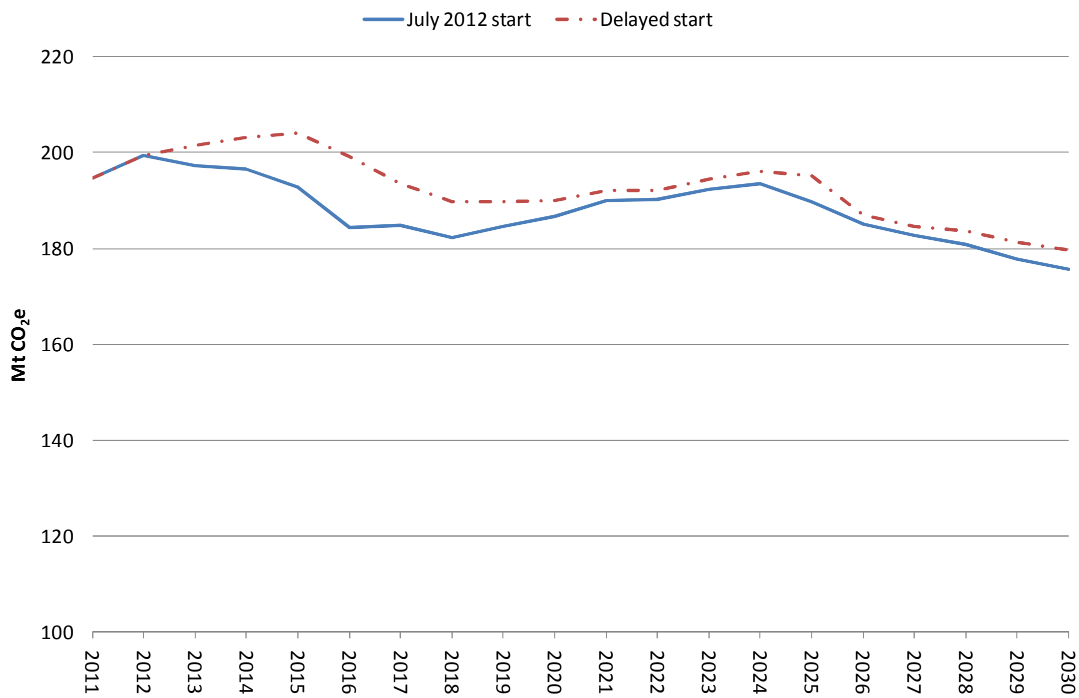
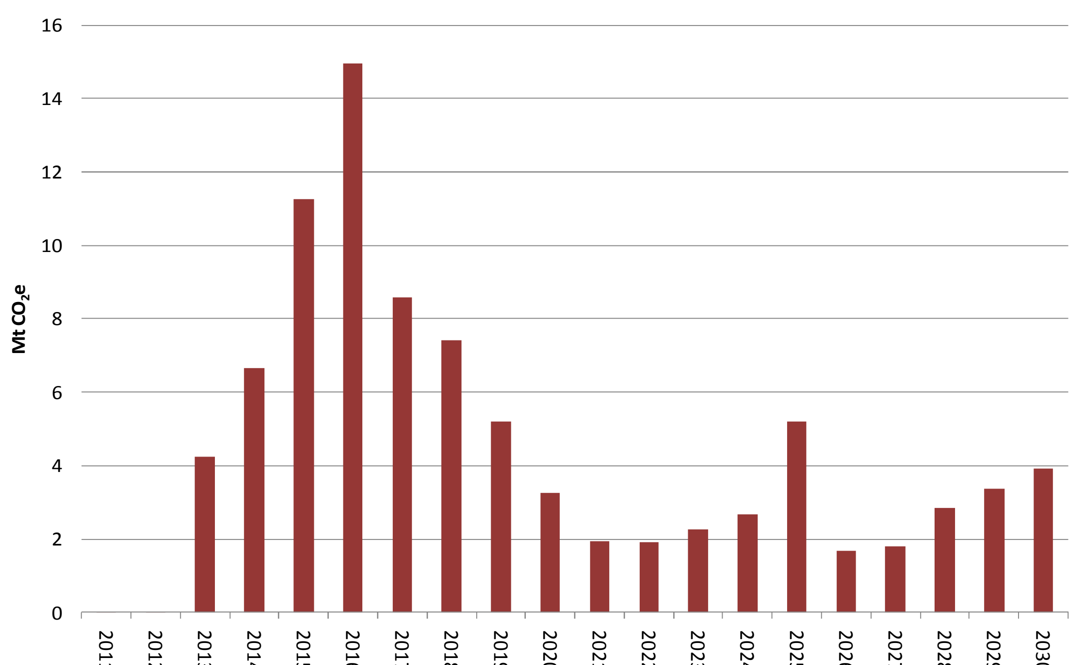


Figure 5-3 Additional emissions due to delayed action



6. Conclusion and limitations

The conclusions of this study are conservative in that the study did not into account impacts such as an increased risk premium on new investments and on rollover of debt funding under a delayed start due to the additional uncertainty, or the deferment in the development of new technologies under the delayed start cases due to a delay in the "learning by doing" process.

Other limitations of the study include:

- Based on modelling assumptions, there is only a limited delay in replacing uneconomic plant in the delayed start scenarios. The modelling procedure tends to put in OCGTs to make up the shortfall, with these OCGTs then deferring the need for other new low emission plant. Another possibility is that the coal plants stay in operation for a longer period to allow for CCGTs to be built to replace them. This would lead to higher emissions and higher electricity prices in the period to 2020, but could lead to outcomes closer to the 2012 start scenario after 2020.
- Other options may be adopted to manage the shortfall of capacity to cover retirement of high emission capacity after the delayed introduction. For example, investors may invest in OCGTs initially but then convert them into CCGTs later on. There would be small penalty in terms of fuel efficiency as the CCGTs are not as efficient generally as single shaft systems.
- The impact of uncertainty of future carbon prices on the choice of plant has not been modelled.

Despite these limitations, this study has demonstrated that delaying the start of an ETS does incur economic costs in a number of ways including higher wholesale and retail prices, higher resources costs, less investment in generation assets and greater release of emissions. Wholesale prices are overall higher under a delayed start mainly because of the rapid retirement time frame required for the brown coal plant in Victoria (from 2017 to 2018), which is primarily handled by the construction of higher cost OCGT capacity. In contrast, the Victorian brown coal plant is mainly replaced by CCGT capacity in the 2012 start scenario because of the foresight afforded by the 2012 start, and this cheaper plant helps keep wholesale prices and retail prices in check. The difference in new plant build also explains the higher resource cost in the delayed start scenario, which amounts to an additional 0.5% by 2030, with most of this due to higher fuel costs. Costs of running gas turbines (both open cycle and combined cycle) are higher under the delayed start case, but the high build of OCGT capacity in this scenario also means that incumbent gas steam plant, which is quite old and inefficient, also runs harder. In contrast, these plants are partly displaced by CCGT capacity in the 2012 start case and therefore incur less cost. Finally, the delayed start case also sees the additional release of emissions of around 3% to 2020 and 2% to 2030 relative to the 2012 start scenario.

The costs of a delayed ETS start are real and are fully avoidable if an early ETS start date is adopted. In particular, a 2012 start would allow the orderly retirement and replacement of capacity with high emissions intensities, much of which is concentrated in Victoria. A delayed ETS start has the potential to cause volatile market outcomes, especially if there are unexpected delays in commissioning replacement capacity due to shortages of skilled labour or other unforeseen circumstances.

Appendix A Strategist modelling assumptions

A.1 NEM

A.1.1 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table A-1. SKM MMA also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

▪ **Table A-1 Indicative average variable costs for existing thermal plant ($June 2010)**

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$7 - $11	Brown Coal – SA	$23 - $29
Gas – Victoria	$45 - $65	Black Coal – NSW	$21 - $24
Gas – SA	$38 - $183	Black Coal - Qld	$8 - $23
Oil – SA	$268 - $330	Gas - Queensland	$26 - $103
Gas Peak – SA	$103 - $185	Oil – Queensland	$258

A.1.2 Plant performance and production costs

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%.

A.1.3 Bidding behaviour

We assume the current market structure continues under the following arrangements:

- Victorian generators are not further aggregated.
- NSW generators remain under the current structure in public ownership.
- The generators' ownership structure in Queensland remains as public ownership.
- The SA assets continue under the current portfolio groupings.

This market arrangement provides the following features:

- NSW generators dominate the price making in Victoria and NSW due to their higher variable costs than the brown coal businesses and the coal fired surplus which leaves the Victorian gas fired business with little dispatch or market influence initially in Victoria.
- Victorian brown coal generators are assumed to maintain a price-taking role which is strengthened as demand grows in Victoria and the brown coal plants become fully loaded. Southern Hydro is also assumed to be a price taker in Victoria.
- Victorian brown coal generators may contribute to price making at times of very high peak demands when supply conditions permit.
- Since the commissioning of QNI and Millmerran, NSW generators also influence prices in Queensland.

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed[9] for operational reasons or bid at marginal cost to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out.

In Strategist, contracts are not explicitly modelled. Rather we typically have half to three quarters of the capacity of base load and intermediate plants bid at marginal cost to represent the contracted level. If this produces very low pool prices bid prices are represented at a level higher than marginal cost to represent periods of price support that would be necessary to support the spot and contract market from time to time.

SKM MMA formulates future NEM development ensuring that the reserve requirements are met in each region at least cost. The minimum reserve levels assumed for each state are based on values specified in the 2009 ESOO and are summarised in Table A-2 below. The minimum reserve level for VIC and SA combined is 615 MW of which -50 MW has been allocated to SA by AEMO in an attempt to minimise the local reserve requirement in SA. This means that Victoria must carry 665 MW when South Australia is fully relying on Victoria. Post Kogan Creek the size of the largest unit in QLD increases by 300 MW, however this only translates to an 80 MW increase in minimum reserve levels for the region.

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[9] "Self-committed" means that the generator specifies the timing and level of dispatch rather than NEMMCO and this is taken as a zero bid when setting pool prices. If generators are required to off-load below their self-commitment level, a negative pool price will be declared for generators and customers.

- **Table A-2 Minimum reserve levels assumed for each state**

Region	Qld	NSQ	Vic	SA	Tas
Reserve Level 2006/07	480 MW	-1490 MW	665 MW	-50 MW	144 MW
Reserve Level 2007/08 – 2009/10	560 MW	-1430 MW	665 MW	-50 MW	144 MW

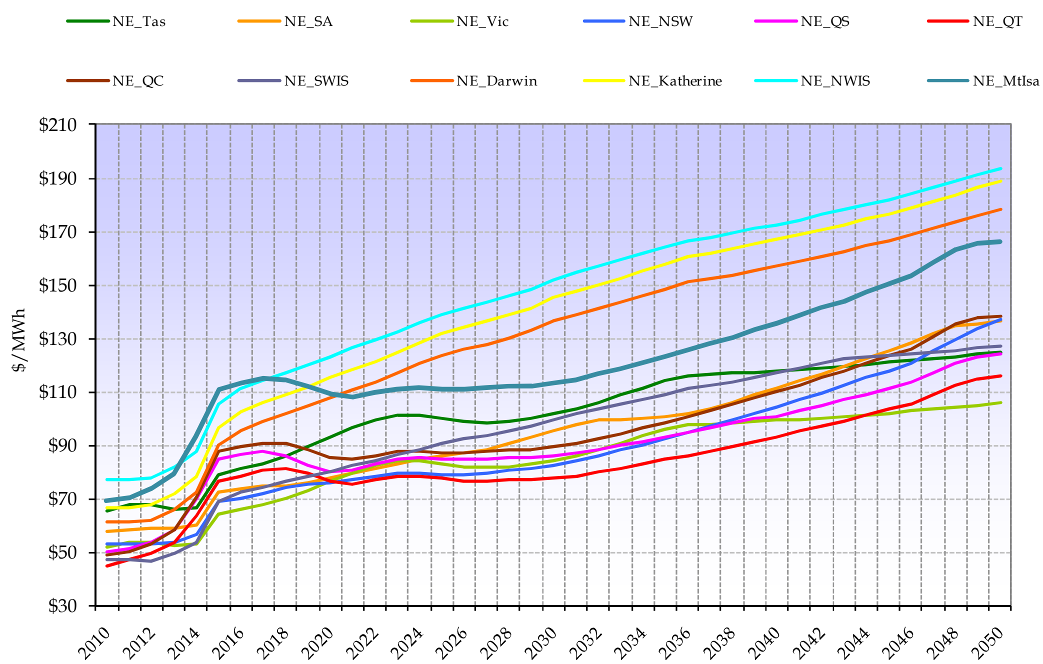
After selecting new entry to meet AEMO's minimum reserve criteria, SKM MMA's pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. We assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest.
- Infrequently used peaking resources are bid near VoLL or removed from the simulation to represent strategic bidding of such resources.

The 2012 start scenario new entry prices, including the effect of the ETS are shown in Figure A-1 in June 2010 dollars. These new entry prices include the impact of emission abatement schemes such as Gas Electricity Certificates (GECs) in Queensland and the NSW Gas Abatement Certificates (NGACs) until the commencement of the ETS. They are also based on gas prices output from SKM MMA's in-house MMAGas model.

Cost and financing assumptions used to develop the long-term new entry prices are provided in Table A-3. The real pre-tax real equity return was 17% and the CPI applied to the nominal interest rate of 9% was 2.5%. The capital costs are generally assumed to escalate at CPI-1% until they reach the long term trend. New technologies have higher initial costs and greater rates of real cost decline up to -1.5% pa for IGCC. The debt /equity proportion is assumed to be 60%/40%. This gives a real pre-tax weighted average cost of capital (WACC) of 10.60 % pa. It is assumed that the higher risks emerging in the electricity generation sector from ETS will require these higher equity returns.

- **Figure A-1 2012 start scenario new entry prices (June 2010 $/MWh)**



The capacity factors in Table A-3 are deliberately high to allow us to approximate a time-weighted new entry price in each state that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market. These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. The unit's true LRMC measured in $/MWh is higher than this level. For example, we would be more likely to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 92% as indicated in Table A-3. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours. However, this would require more detailed analysis and in our experience does not yield any significantly different price path.

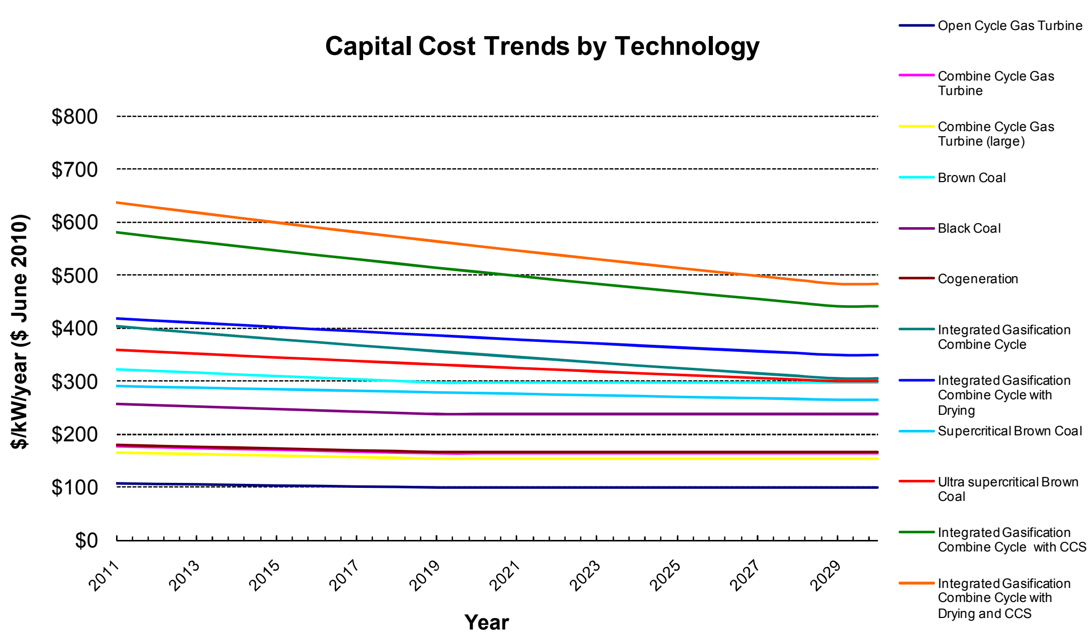
Figure A-2 shows the trend in new entry fixed costs represented in the new entry cost modelling in June 2010 dollars.

Table A-3 New entry cost and financial assumptions ($ June 2010) for 2009/10

	Type of Plant	Capital Cost	Available Capacity Factor	Fuel Cost *	Weighted Cost of Capital	Interest Rate	Debt Level	LRMC $/MWh (d)
		$/kW		$/GJ	% real	% nominal		
SA	CCGT (a)	$1,162	92%	$5.50	10.60%	9%	60%	$62.46
Vic	CCGT (a)	$1,145	92%	$4.81	10.60%	9%	60%	$57.22
NSW	CCGT (c)	$1,389	92%	$5.50	10.60%	9%	60%	$66.29
NSW	Black Coal (b)	$2,252	92%	$1.66	10.60%	9%	60%	$52.92
Qld	CCGT (c)	$1,392	92%	$5.39	10.60%	9%	60%	$68.20
Qld	Black Coal (Tarong) (b)	$2,255	92%	$0.75	10.60%	9%	60%	$48.71
Qld	Black Coal (Central) (b)	$2,252	92%	$1.61	10.60%	9%	60%	$54.81

- Note: fuel cost shown as indicative only. Gas prices vary according to the city gate prices.
- (a) extension to existing site
- (b) not regarded as a viable option due to carbon emission risk
- (c) at a greenfield site
- (d) excluding abatement costs or revenues

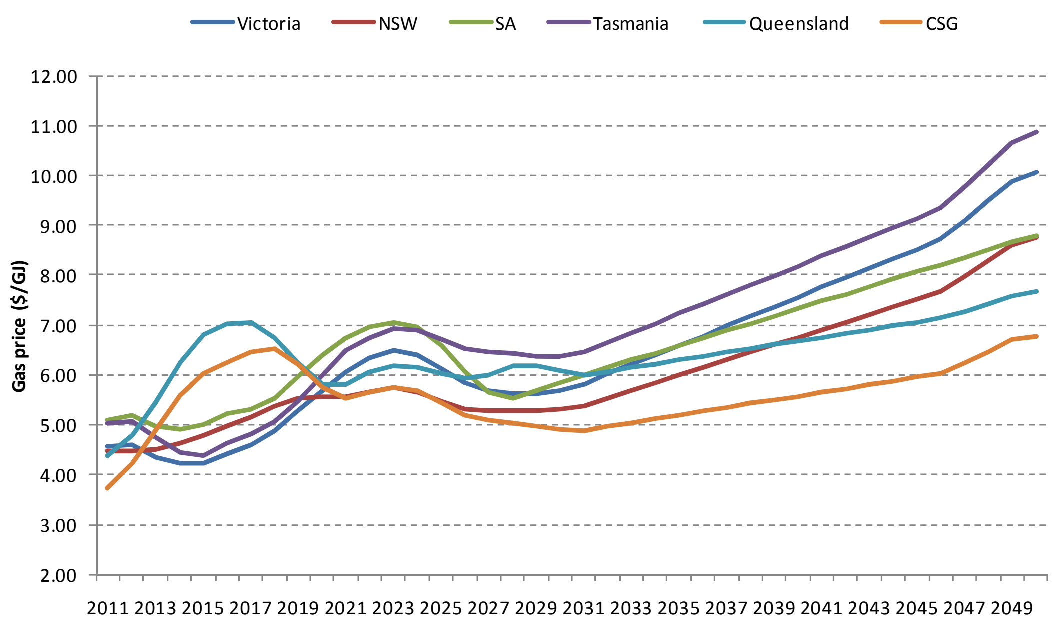
Figure A-2 Trend in New Entry Capital Recovery Costs ($/kW/year June 2010 dollars)



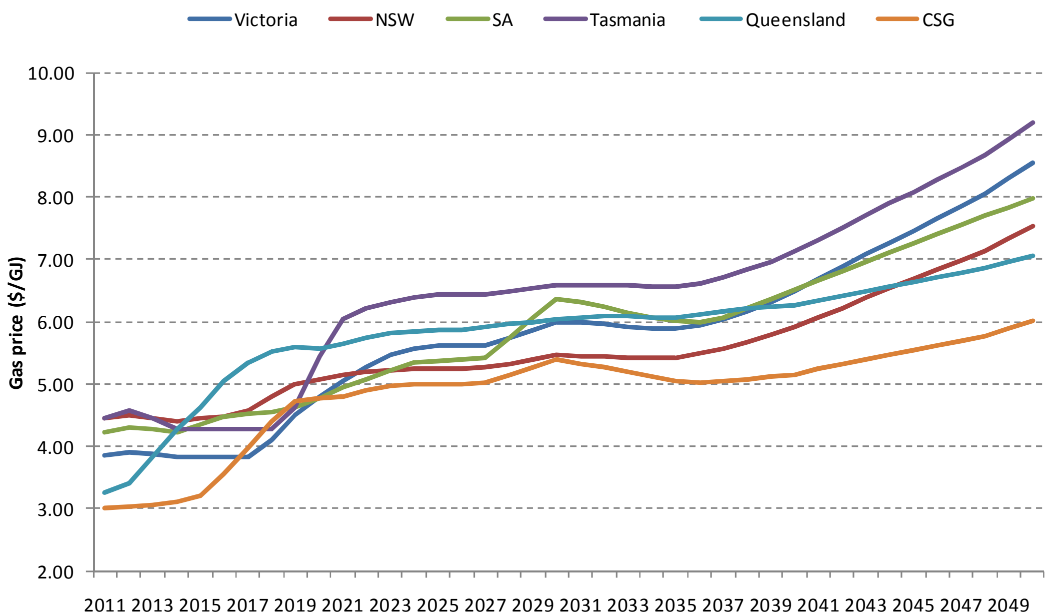
A.1.4 Fuel prices

The gas prices for the Standard LNG scenario derived from the MMAGas model input into Strategist by NEM region and are presented in the charts below. Figure A-3 shows indicative gas costs for new entry plant throughout the forecast period. Similarly, Figure A-4 shows the indicative average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period.

- **Figure A-3 Indicative New Contract Gas Prices for the Eastern States, $June 2010**



▪ **Figure A-4 Indicative Average Contract Gas Prices for the Eastern States, $June 2010**



A.2 SWIS

A.2.1 Key Assumptions

This section details the assumptions underlying the scenarios for this study. The key assumptions for the scenarios are outlined in Table A-4.

▪ **Table A-4 Key Assumptions**

Feature	Base
Load Growth	Published forecasts
Gas Prices	Assumed 1.7% average growth rate
New Entry Capital Costs	40% initial increase to base costs, declining at CPI-3% until they reach a CPI-1% long term trend in real capital costs

The current high new entry costs is not expected to be sustained indefinitely. We expect prices to decline back at about CPI-3% which means about constant in nominal terms until they fall back to the long-term trend of CPI-1%.

In this section, the key assumptions underpinning SKM MMA's market model of the SWIS are outlined.

A.2.2 Trading arrangements

The wholesale market for electricity in the SWIS is structured into:

- An energy trading market, which is an extension of the existing bilateral contract arrangements.
- An ancillary services market to trade spinning reserve and other services to ensure supply reliability and quality.

The SWIS is relatively small, and a large proportion of the electricity demand is from mining and industrial use, which is supplied under long-term contracts. Considering these features, the bilateral contracts market continues to underpin trading in the SWIS, with a residual day ahead trading market (called the STEM) supporting bilateral trades. This residual trading market allows contract participants to trade out any imbalances, and also allows small generators to compete where they would otherwise not be able to due to their inability to secure contracts.

Market participants will have the option of either entering into bilateral contracts or trade in the STEM.

The ancillary services market is the responsibility of system management (WA IMO). The WA IMO is required to determine the least cost supplies to satisfy the system security requirements. Both independent generators and Verve Energy could be ancillary reserve providers, but at least initially it is envisioned that Verve will need to provide all spinning reserve under contract with system management.

All market participants pay for the ancillary services. In SKM MMA's SWIS model, it is assumed that there is a market for trading spinning reserve. Providers receive revenue for this service, and the cost is allocated to all generators above 115MW with the largest cost disproportionately allocated to the largest unit.

In the SKM MMA model of the SWIS, we ignore bilateral contracts and allow all generation to be traded in the market. The reasoning behind this is that the contract quantities and prices will be very similar to the market dispatch – otherwise one or other party would not be willing to enter the contract. Admittedly, contracts provide benefits from hedging that will not be reflected in the trading market. However, in the long run, the differences between contracts and the trading market will be minimal.

A.2.3 Structure of generation

The State Generator, Verve Energy, has been disaggregated vertically from the rest of Western Power but not horizontally.

To encourage competition, Verve Energy will not be automatically allowed to build new plant to replace its old or inefficient plant. The assumption for the analysis is to allow Verve Energy to bid for new entry generation as long as its overall generation capacity does not exceed 3,400 MW, in line with Government regulations.

A.2.4 Demand assumptions

Three key demand parameters are used in the model:

- Peak demand at busbar.
- Energy requirements.
- Load profiles.

The annual compound growth rate for total electricity demand in the SWIS is around 2.0%, which includes the impact of the carbon price on demand.

Projections of the summer and winter peak demand at generator busbar are derived from the relativities of the forecasts of sent out peak demand provided by the IMO, and the implied load factor in the IMO forecasts.

Peak demand for each month is calculated based on the forecast summer peak demand and historical load profiles.

Using data provided by IMO, SKM MMA derived a SWIS load profile. This data was normalised to the peak value for the 2004/05 and then modified to ensure consistency with energy sales and load factors. The load growth algorithm in the simulation model then used this historical load profile to forecast demand for the entire planning horizon, ensuring consistency with the annual peak and energy sales assumptions for the study period. This implies that the monthly pattern of energy sales and peak demand remains constant during the forecast period.

A.2.5 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS, as shown in Table A-5. The Muja stations operate as base load stations with capacity factors of 70% to 95%. The Kwinana steam plants and the Mungarra gas turbine operate as intermediate plants with capacity factors of about 40%, while the Pinjar gas turbines operate as peaking plant with 10% to 20% capacity factor. Cogeneration plants are assumed to operate as must-run plants due to steam off-take requirements.

The South West Cogeneration Joint Venture is comprised of 50% Origin Energy and 50% Verve Energy. Approximately 30MW of electricity in supplied to the alumina refinery, with the remainder being supplied to domestic customers. Steam from the cogeneration plant is used in the alumina refinery process and also in its own station. There is a 130MW coal-fired plant owned by Worsley Alumina.

The Kwinana C power station is modelled to burn both coal and gas, but this station is assumed to close in 2013.

The physical characteristics and the fixed and variable operating and maintenance costs for each plant are shown in the following tables.

- **Table A-5 Power plant operating assumptions**

Station	Type	Capacity in summer peak, MW sent out	Fuel	Maintenance (%)	Forced outage (%)	Heat rate[2] GJ/MWh
Albany	Wind turbine	12 x 1.8	renew.	-	3	-
Collie A	Steam	304	coal	6	2	10.0
Muja C	Steam	2 x 185.5	coal	4	4	11.0
Muja D	Steam	2 x 200	coal	4	3	10.5
Kwinana C	Steam	2 x 180.5	coal, gas	4	6	10.8
Kwinana GT	Gas turbine	16	gas, dist	2	3	15.5
Pinjar A,B	Gas turbine	6 x 29	gas	6	3	13.5
Pinjar C	Gas turbine	2 x 91.5	gas	6	3	12.5
Pinjar D	Gas turbine	123	gas	6	3	12.5
Mungarra	Gas turbine	3 x 29	gas	6	3	13.5
Geraldton	Gas turbine	16	gas, dist	2	3	15.5
Kalgoorlie	Gas turbine	48	dist	2	3	14.5
Worsley[1]	Cogeneration	70	gas	4	2	8.0
Tiwest	Cogeneration	29	gas	6	3	9.0

1 South West Cogeneration Venture – 120MW nameplate, 50% Western Power owned.

2 Heat rates at maximum capacity. Heat rates are on a sent out basis (that is, GJ of energy delivered per unit of electricity sent-out in MWh). Heat rates are on a higher heating value basis.

Source: Western Power, Annual Report, 2005-06, Perth (and previous issues); estimates of maintenance time, unforeseen outages and heat rates for OCGTs and CCGTs are based on information supplied by General Electric and the IEA.

Table A-6 Fixed and variable operating costs

Station	Unit	Fixed costs ($000s/year)	Variable costs ($/MWh)
Albany	0	0	
Collie	A	10,000	4.00
Muja	C	10,500	5.50
	D	11,000	5.00
Kwinana	C	16,000	7.00
	GT	1,000	9.00
Pinjar	A,B	1,000	4.00
	C	3,000	4.50
	D	3,000	4.50
Mungarra		1,000	4.00
Geraldton		500	5.00
Kalgoorlie		500	5.00
Wellington		0	5.00
Worsley		3,000	4.00
Tiwest		1,000	4.00

Source: Derived by SKM MMA to match operating and maintenance cost data contained in Verve Energy's Annual Reports.

Other generators

Private generating capacity, including major cogeneration, is detailed in Table A-7. The capacity is mostly comprised of gas-fired generation. There had been a large increase in privately-run generating capacity due to substantial falls in gas costs historically and the gradual deregulation of the generation sector. Over the 1996-97 periods, some 324 MW of privately-owned generation capacity was commissioned, at Kwinana and the Goldfields.

The 116 MW BP/Mission Energy cogeneration project commenced operation in 1996. The BP host takes 40 MW of power, with the remaining 74 MW of power being taken by Western Power under a long-term take or pay agreement. About 3 PJ pa of fuel for the 40 MW portion of output will be natural gas purchased directly from the NWSJV, and other inputs will be refinery gas.

Power generation from gas in the Goldfields commenced in 1996. Southern Cross Power generates from 4 x 38 MW LM6000 gas turbine stations for its Mount Keith, Leinster, Kambalda nickel mines and its Kalgoorlie nickel smelter. The stations are expected to use about 14 PJ of gas pa (37 TJ/d), sourced from the East Spar field. Goldfields Power has constructed 110 MW of capacity (3 x LM6000 gas turbines) east of Kalgoorlie to supply the SuperPit, Kaltails and Jubilee gold projects.

Most of the plants are located near major industrial loads. BP/Mission's cogeneration plant at Kwinana supplies electricity to Synergy. This cogeneration plant is treated as a must-run unit. Other units treated this way include Tiwest and Worsley. Both Southern Cross Power and Goldfield Power's plant in Kalgoorlie sell power to other industrial loads within the SWIS.

Table A-7 Generating plants over 10 MW capacity in the SWIS

Company	Fuel	Capacity in summer peak, MW sent out	Maintenance (weeks per year)	Forced outage (%)	Heat rate GJ/MWh
Alcoa	gas	212	3.8	2	12.0
BP/Mission	gas	100	3.8	2	8.0
Southern Cross	gas	120	3.8	4	11.7, 12.7
Goldfields Power	gas	90	3.8	1	9.5
Worsley	gas	27	3.8	2	8.0
NewGen Kwinana	gas	350	3.0	2.0	7.4
Kemerton	gas, liquid fuel	308	1.0	1.5	12.2
Alinta Wagerup	gas	351	3.0	2.0	11.2
Alinta Pinjarra	gas	266	2.0	2.0	6.5
Bluewaters	coal	400	3.0	3.0	9.7

Source: Capacity data from publications published by the WA Office of Energy, SKM MMA analysis based on typical equipment specifications published in Gas Turbine World.

A.2.6 New thermal units

To meet the anticipated growth in demand in the SWIS beyond 2009, additional generation plants will be required. Furthermore, Verve Energy has committed to retiring old and inefficient units – Kwinana B, Kwinana A, and Muja A/B have already been retired – with Kwinana C mooted for retirement in 2013.

The additional capacity required could be met from a number of generation options:

- Open cycle gas turbines (OCGTs), which have low capital costs but require a premium fuel.
- Combined cycle gas turbines (CCGTs), which have lower operating costs than OCGTs, due to their high efficiency.
- Coal-fired plant, which has the highest capital cost but low operating costs due to the competitive price of coal. These are likely to be similar to the two 200 MW units recently commissioned by Griffin Energy (the Bluewater Project).
- Cogeneration, which is efficient like CCGTs but also has an additional benefit from the steam supply.
- New CCGTs at Cockburn owned and operated by Verve Energy.

Table A-8 Assumptions for new thermal generation options

Option	Life	Sent-out Capacity	Capital Cost, 2010	Deescalater	Heat Rate at Maximum Capacity	Variable O&M Cost	Fixed O&M Cost
	Years	MW	$/kW so	% pa	GJ/MWh	$/MWh	$/kW
Black coal							
Supercritical coal	35	230	2,357	0.5	9.1	3	33
IGCC	30	183	3,312	1.5	7.8	2	49
IGCC with CC	30	158	5,160	1.5	10.1	3	56
Natural gas							
CCGT	30	255	1,375	0.5	7.8	3	25
Cogeneration	30	235	1,660	0.5	5.0	3	22
CCGT with CC	30	234	2,399	1.0	8.1	4	45
OCGT	30	130	991	0.5	11.0	6	33

Note: CC = carbon capture. Sources: IEA and SKM MMA database of project capital costs

The wind farms at Walkaway and Emu Downs are assumed to continue to operate past 2030, with a capacity factor of around 35%. Co-firing at Muja at 5% output for one unit is also assumed to continue during the study period.

Additional renewable generation is determined as part of the renewable energy model for Australia as a whole. Additional renewable energy generation in WA competes with options in other States in Australia to secure additional revenue from the REC market or from the emissions trading market.

A.2.7 Fuel assumptions

All assumptions on fuel usage and unit costs are based on the higher heating value (or gross specific energy) for each fuel in line with accepted practices in Australia.

Coal Prices

In the SKM MMA model, coal prices after 2010 are assumed to be $45/t on a delivered basis with an energy content of 19.3 GJ/t. This coal price is SKM MMA data based on market knowledge.

Coal prices are on average assumed to increase by 0.3% per annum in real terms.

Gas prices

SKM MMA assumes that base load gas supply will be priced at $6.50/GJ in 2009 with price escalating at an average rate of 1.7% per annum in real terms.

The transport charge is $1.10/GJ escalating at 75% of CPI.

All stations owned by Goldfields Power and Southern Cross Power are modelled to use gas with a well head price $6.50/GJ in 2009, escalating at an average rate of 1.7% per annum in real terms. The gas transmission charge is assumed to be $3/GJ for gas supplied to the Goldfields region, reflecting the distances gas needs to be transmitted in this region, deflating at 75% of the CPI