Sustainability Victoria

GREENHOUSE GAS ABATEMENT FROM WIND AND SOLAR IN THE VICTORIAN REGION OF THE NEM

- 21 October 2010

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Abbreviations

AEMO	Australian Energy Market Operator
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CES	(Queensland) Cleaner Energy Strategy
CPRS	Carbon Pollution Reduction Scheme
CSG	Coal seam gas
DSM	Demand side management
ESOO	Electricity Statement of Opportunities 2009
FCAS	Frequency control ancillary services
GECs	(Queensland) Gas Electricity Certificates
GGAS	(NSW) Greenhouse Gas Abatement Scheme
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
NGACs	NSW Greenhouse Abatement Certificates
NRET	NSW Renewable Energy Target
POE	Probability of exceedance
PV	Photovoltaic generation
RECs	Renewable Energy Certificates
SKM	Sinclair Knight Merz
SRES	Small Renewable Energy Scheme
SWIS	South West Interconnected System
VRET	Victorian Renewable Energy Target

Executive Summary

This report is prepared for Sustainability Victoria as the basis for market modelling to determine the emissions abatement impact of wind farms and solar PV systems located in Victoria. The assessment was effected through seven market scenarios, including a baseline scenario, where all additional wind capacity was removed from Victoria. Scenarios 2 to 5 had 1,000 MW, 2,000 MW, 3,000 MW and 4,000 MW of additional wind capacity respectively. Scenarios 6 and 7 had 2,000 MW of additional wind capacity and 250 MW and 500 MW of additional PV capacity respectively.

The key assumptions underlying the modelling were as follows:

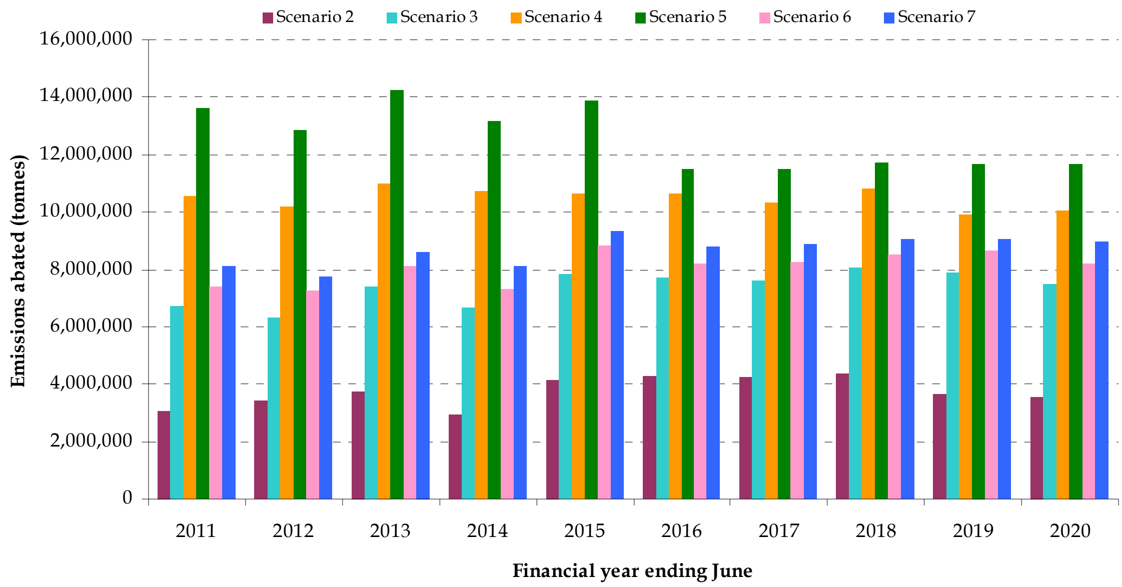
- Demand forecast based on medium economic growth with the peak demand governed by 50% POE weather conditions.
- The LRET and SRES schemes have superseded the expanded MRET scheme. The LRET target as legislated is for 41,000 GWh of renewable generation by 2020 from large-scale renewable generation projects however, both schemes in total are expected to deliver more than 45,000 GWh of additional renewable energy by 2020.
- CPRS commencing in July 2014 with a 5% emissions reduction target by 2020.

Exec Figure- 1-1 shows the emissions abated by Victorian wind farms over the simulation horizon. It shows that the emissions abated by the CPRS are maintained or enhanced in all cases except for Scenario 5 (4,000 MW of additional wind). This occurs as a result of the modelling methodology, which effectively has the last 1,500 MW of Victorian wind capacity in Scenario 5 displacing wind capacity from other regions.

Exec Figure- 1-2 shows the abatement intensity of the four pure wind cases (Scenarios 2 to 5). Pre 2015, the abatement intensity varies from 0.9 t CO_2e/MWh to 1.2 t CO_2e/MWh, although there is no clear correlation between additional wind farm capacity and abatement intensity. The lower end of the abatement intensity spectrum reflects the emissions intensity of NSW black coal plant, which is typically from 0.9 to 1.0 t CO_2e/MWh. The upper end of the spectrum reflects the emissions intensity of the Victorian brown coal plant, whose emissions intensity ranges from just over 1.2 t CO_2e/MWh to 1.6 t CO_2e/MWh. This suggests that wind capacity pre CPRS predominantly displaces a combination of NSW black coal generation and some Victorian brown coal generation.

Post CPRS, the emerging pattern is that the average abatement intensity decreases as the additional wind farm capacity increases. Moreover, in Scenarios 2 and 3, the post CPRS abatement intensity is higher than the pre CPRS abatement intensity. This reflects the fact that the first 2,000 MW of wind capacity displaces more brown coal post CPRS rather than black coal in these scenarios. The abatement intensity for Scenario 4 is similar before and after the introduction of the CPRS, although it seems to be decreasing over time, which is consistent with an increasing carbon price. For Scenario 5 the abatement intensity of wind is lower than the pre-CPRS abatement intensity, which once again reflects the assumption that 1500 MW of wind in Victoria displaces wind in other states.

- **Exec Figure- 1-1 Emissions abated in the NEM for Scenarios 2 to 7**



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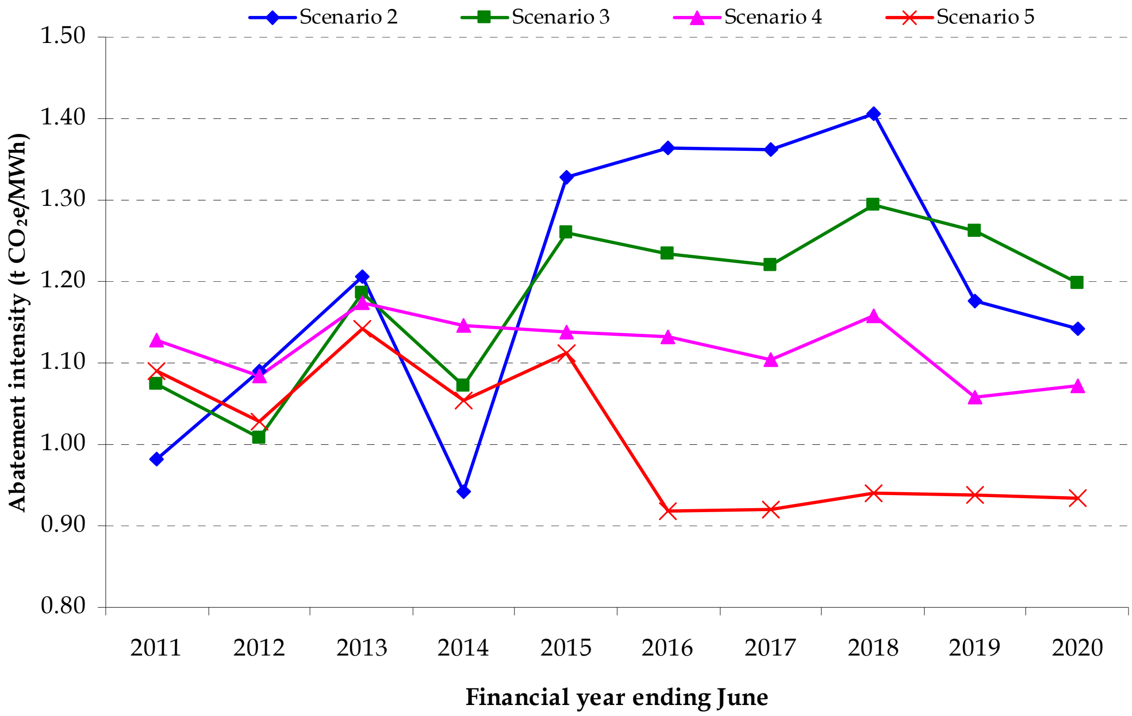
- **Exec Figure- 1-2 Average abatement intensity for the pure wind scenarios**



Exec Figure- 1-3 shows the same output as Exec Figure- 1-2, but for the two scenarios with large scale PV capacity (Scenario 6 and 7), and with the comparable wind-only scenario (Scenario 3). Pre CPRS the large scale PV scenarios tend to have higher abatement intensities than the corresponding wind scenario. This is mainly due to the emissions savings made by PV capacity at weekends when it tends to displace brown coal plant during the day[1]. This occurs because brown coal is the marginal Victorian plant only during off-peak periods, which occur overnight or over the weekend, when industrial and commercial demand is reduced. Post CPRS all three scenarios exhibit similar behaviour, although it is not possible to conclusively determine what effect the additional PV capacity has on the average abatement intensity.

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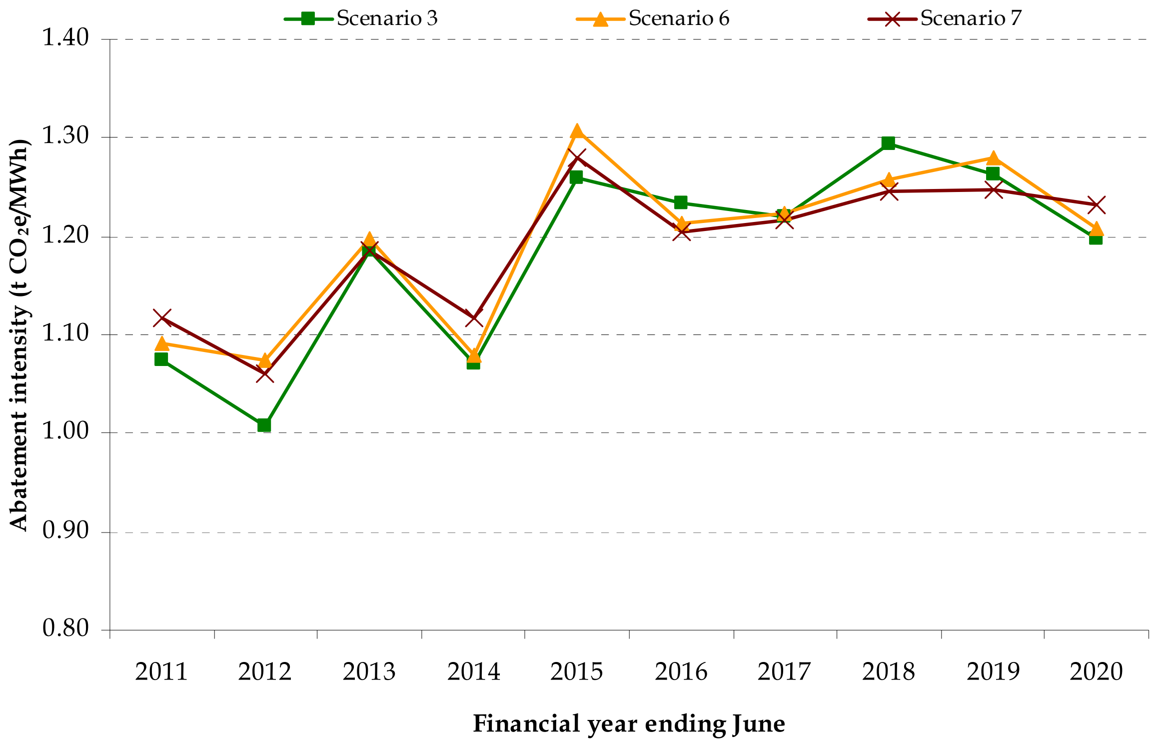
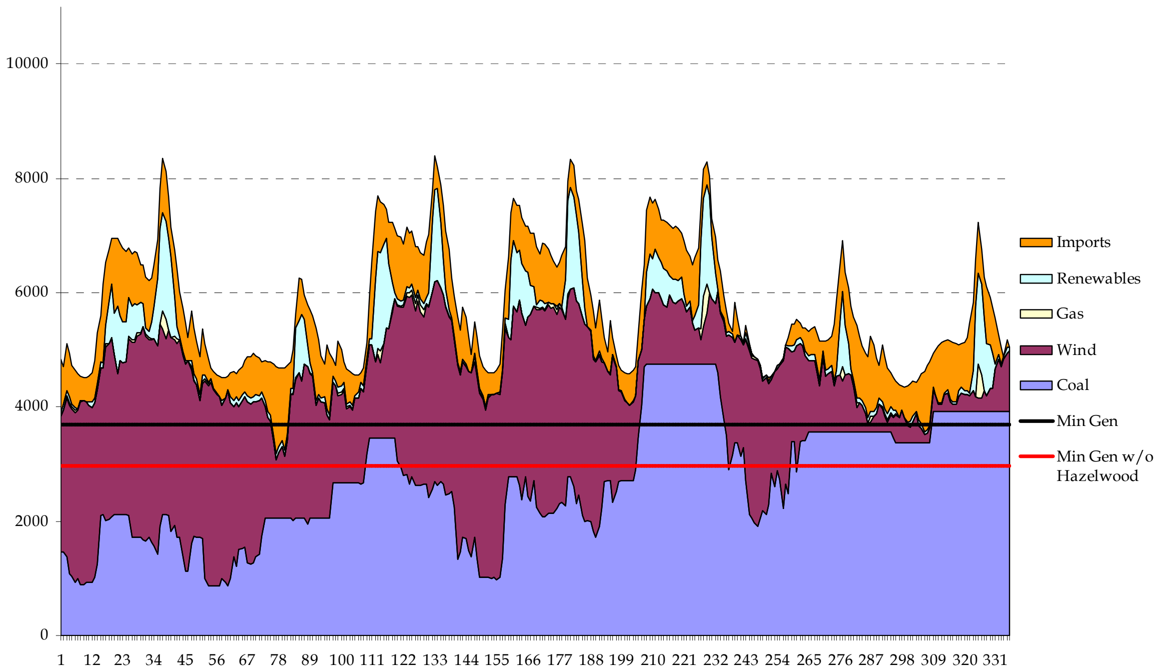
[1] PV displacement of brown coal at weekends could lead to low or even negative spot prices, which might in turn encourage greater demand.

▪ **Exec Figure- 1-3 Average abatement intensity for Scenarios 3, 6 and 7**

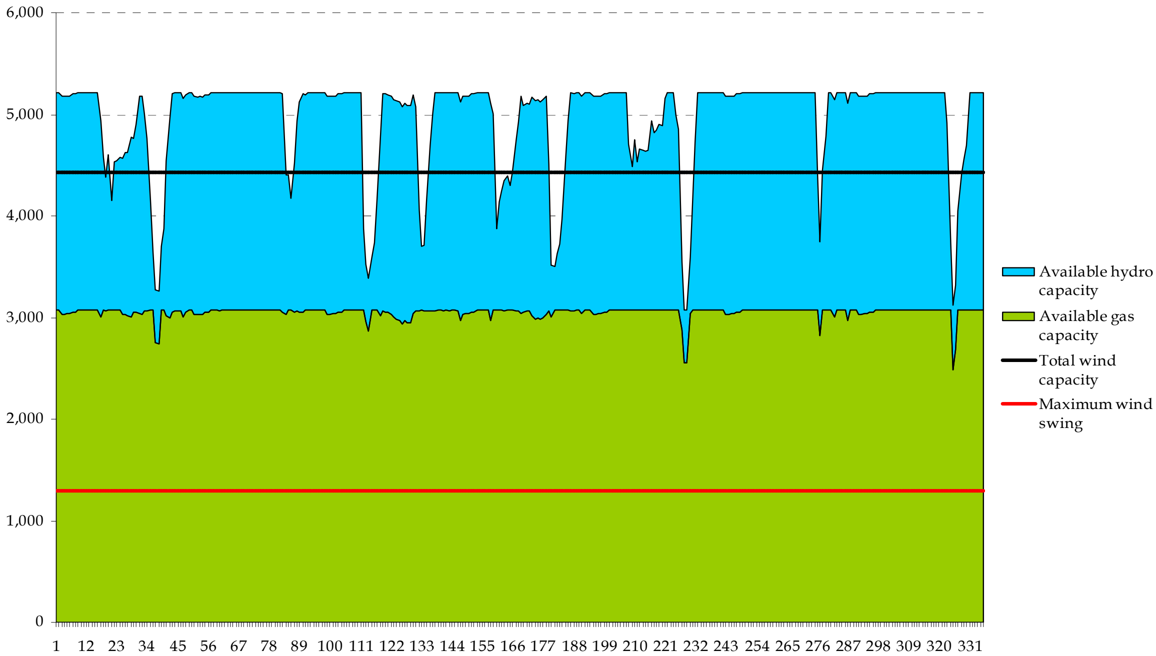


For Scenarios 3 and 5, the Victorian plant dispatch for a typical week for all seasons was investigated to check the extent to which brown coal generation was crowded out by wind generation. In the cases where total coal generation was forced below its minimum generation level, we also checked the availability of fast-start hydro and gas generation in those periods to verify that there was enough flexible capacity in the system to avoid unserved energy. Exec Figure- 1-4 shows the most extreme example of wind generation crowding out brown coal generation, which predictably occurs under Scenario 5 in Autumn 2020. In the first half of the week in particular both Hazelwood and Yallourn have been crowded out, as well as some units of Loy Yang A. However, Exec Figure- 1-5 shows that there is ample fast-start capacity in the system to handle any extreme swings of wind power output when the brown coal plant would not be able to come online fast enough.

▪ **Exec Figure- 1-4 Victorian weekly generation profile for Autumn 2019/20, Scenario 5**



▪ **Exec Figure- 1-5 Unused gas and hydro capacity for Autumn 2019/20, Scenario 5**



1. Introduction

This report is prepared for Sustainability Victoria for the purpose of estimating the emissions abatement impact of wind farms and solar PV systems located in Victoria.

The report includes an outline of the market assumptions and the methodology used to estimate the impact of Victorian based wind farms and solar PV systems in the National Electricity Market (NEM). The modelling was developed for a medium economic growth scenario, with a 50% probability of exceedance (POE) as presented in the 2009 AEMO Electricity Statement of Opportunities (ESOO).

The discussion includes the assumptions leading to market outcomes including details on:

- new generators by regions
- inter-connector capacities and timing
- treatment of the operation and development of greenhouse gas abatement schemes
- the Carbon Pollution Reduction Scheme
- fuel costs
- new entry timing and costs.

The results of the study are also presented, along with an analysis of some of the key issues associated with a large penetration of wind technology into a power system. The wind farm and solar impacts are developed for the period from 1 July 2010 to 30 June 2020.

2. Expected evolution of Renewable Energy Target

2.1. Design of the Expanded Renewable Energy Target (RET)

The Australian Government intends for the equivalent of at least 20% or 60,000 GWh of Australia's electricity supply to be generated from renewable sources by 2020. To enable this it has been legislated that the existing Mandatory Renewable Energy Target (MRET) will be increased to 45,000 GWh to ensure that, together with the approximately 15,000 GWh of existing renewable capacity, this target will be met. The scheme was split into two parts under recent legislation into the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The 2020 target for the LRET scheme is now 41,000 GWh, applicable for large-scale renewable generation only. However, it is expected that the combined LRET and SRES schemes will deliver more additional renewable energy than the original 45,000 GWh target[2]. Existing renewable generators are eligible to create Renewable Energy Certificates (RECs) provided they can demonstrate renewable electricity production above a specified baseline. The previous national MRET and existing state based targets have been merged into a single national scheme where only renewable energy counts toward the target. The target will remain constant from 2020 to 2030 as emission trading matures and prices become sufficient to ensure a RET is no longer required. Projects which have been approved under existing state based schemes will remain eligible under the expanded RET and will be able to earn certificates until 2030. Additional provision has been made for existing power production from waste mine gas to earn certificates as the NSW Greenhouse Gas Abatement Scheme will no longer provide support when the CPRS is commenced. This provision has not affected the impact on renewable energy resources.

The market for renewable energy is guaranteed to suppliers via legislative obligation for retailers and large users to purchase an increasing proportion of their energy from renewable sources. Liable parties either demonstrate their compliance by acquiring and surrendering RECs or pay a shortfall charge of $65/MWh.

2.1.1. Banking of RECs

The new scheme includes unlimited banking; i.e. RECs remain valid until the end of the scheme or until they are surrendered. This banking period has strong implications for providing sufficient capacity early enough to meet the target, and can also affect the liquidity of the REC market as well

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[2] This is due to the SRES scheme, where an uncapped amount of Small-Scale Technology Certificates (STCs) will be offered at a fixed nominal price of $40/MWh . It is expected that the resulting small-scale renewable technology uptake will exceed 4,000 GWhs per annum, and hence more than 45,000 GWh per annum of renewable energy is expected to result from the combination of the SRES and LRET schemes.

as the costs of the scheme and the technology mix put in place. Banking of certificates helps to ensure there are sufficient certificates to meet the target and that the long-term costs and benefits are taken into consideration when new entrants decide to invest in renewable generation. Renewable generation in early years can therefore be greater than the target during these years and possibly less than the target in later years.

2.1.2. Project eligibility periods

The project eligibility period is the number of years during which a renewable based power station that is accredited under a scheme is entitled to create RECs. RECs created during this period can be sold to supplement revenue from the sale of the electricity generated. The RET scheme allows all accredited power stations to create RECs for the duration of the scheme. The previous expectation that existing MRET generators (i.e. pre-December 2007 generators) may be excluded beyond 2020 to avoid windfall gains has not eventuated since existing generators will be eligible to participate until the end of the scheme.

2.1.3. Duration of the expanded RET scheme

The purpose of the expanded RET scheme is effectively to provide early incentives for renewable generation. The expanded target will have a significant upward impact on the REC price relative to the original scheme, and this will flow into the revenue stream available to a new entrant in the renewable supply sector. Such an incentive is essential for renewable generation to compete with thermal sources of generation, particularly when investment in renewable generation typically requires at least 10 years of a secure revenue stream.

It is expected in the longer term and when emissions trading is implemented, that renewable generation will become competitive and viable without the need for an expanded RET scheme. During this period electricity prices could rise to a sufficient level to support renewable generation without the price support provided by the expanded RET scheme. When renewable energy can compete with carbon priced thermal energy the value of RECs would drop to zero and the scheme would become redundant. The timing of this end stage depends on the evolution of carbon price and the future cost of renewable energy technologies compared to thermal technologies.

3. Measuring Emissions Abatement from Wind Farms

A number of issues need to be considered in attempting to estimate the actual level of emissions abated from wind farms. These can be summarised under three points:

- What is the generation mix that is displaced by wind generation?
- What is the level of emissions abated by wind farms over their life cycle?
- To what extent does the variability of wind reduce its emissions abatement benefit?

All three questions are specific to the characteristics of the electricity system that is the subject of the study, and must therefore be considered in that specific context.

3.1. Generation mix displaced by wind

In the NEM, generation from wind output is generally bid into the pool at zero dollars or less because wind farm owners can access a REC income stream once eligible electrical energy has been generated. Thus wind will be located deep in the bid stack (usually just after the must-run generation segments, which are bid in at negative prices) and will usually be fully dispatched except at very low load conditions or when affected by transmission constraints. The net effect of this is that wind reduces demand for electricity from other sources, which are typically bid in at or above their marginal cost of generation. In other words, wind displaces generation from the top of the bid stack (the marginal generator), and if this generation source would have used fossil fuel to produce electricity, then the use of wind would have reduced emissions from the electricity supply sector.

In the Victorian context, the primary fuel source for electricity generation has been and still is brown coal, although gas is playing an ever-increasing role, whereas hydro generation still plays an important peaking role. Other sources of electricity generation are imports from NSW, Tasmania and South Australia, although these tend to service peak loads since Victoria is usually an exporting region due to its cheap brown coal resources. The major Victorian brown coal plants tend to be price takers since they are at the bottom of the bid stack. We would therefore expect to see wind and solar generation in Victoria initially displacing gas-fired generation or interstate coal-fired generation ahead of brown coal plant, thus somewhat mitigating the emissions abatement impact of these renewable technologies. However, post CPRS, wind and solar should more effectively displace brown coal generation, since the introduction of a carbon price would probably make some of these plants marginal. Also, if in the future there are a large number of wind farms and high wind speeds at night, one or more brown coal generators may shut down to avoid having to run below their safe minimum operating level.

It is unlikely that wind would ever displace hydro generation for two key reasons. Firstly, hydro generation is a storable, energy-constrained resource. Thus, if it were hypothetically being displaced by wind at a particular point in time, it could be stored in a dam (unless it was already full) and released at another time when the wind was not blowing. This would not substantially[3] alter the total amount of energy generated from the stored water. Secondly, hydro is often a price-taker in the market, meaning that it is often bid into the pool at zero dollars, just as wind is. The upshot of these two points is that, unless very large numbers of wind farms are installed, we expect wind in Victoria to be almost exclusively displacing fossil fuel from interstate coal-fired generators, Victorian coal-fired generators or gas-fired generators.

3.2. Level of emissions abated by wind

There are two factors that need to be considered in answering this question. Firstly, how much emissions are abated from the electricity output of the wind farm due to the displacement of fossil fuel generation. Secondly, how many emissions were produced in the manufacture, construction and operation of the wind farm itself.

The first point was discussed in the previous section, where it was established that, in the Victorian context, almost all wind generation would displace fossil fuel generation, although some of this generation may be gas-fired, rather than coal-fired. This is affirmed in MMA's previous study on the present topic for Sustainability Victoria[4], which found that the abatement intensity from wind generation depended on the level of installed wind capacity, and also tended to decrease over time. The abatement intensity projected from 2007 to 2015 averaged to 0.93 t CO_2e/MWh for 100 MW of installed wind capacity and 1.08 t CO_2e/MWh for 1000 MW of installed wind capacity. These abatement intensities are well below the average emission intensity of generation in Victoria, which was roughly 1.3 t CO_2e/MWh at the time. This implies that wind generation displaces a mix of both gas-fired and coal-fired generation.

The emissions resulting from the manufacture, construction and operation of wind farms are quite low relative to those associated with the manufacture, construction and operation of large fossil fuel plants. The evidence suggests for a wind farm of average output that it takes about 14 kg CO_2e/MWh to manufacture, build and operate a 50 MW wind farm[5,6]. This represents less than

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3 There may be a very minor amount of hydro energy lost in storage due to evaporation.

4 MMA, *Assessment of Greenhouse Gas Abatement from Wind Farms in Victoria*, Sustainability Victoria, July 2006. See http://www.sustainability.vic.gov.au/resources/documents/Greenhouse_abatement_from_wind_report.pdf.

5 International Energy Agency, *Hydropower and the Environment: Present Context and Guidelines for Future Action*, IEA Technical Report, 2000.

6 URS, *Environmental Impact Statement – Woodlawn Wind Farm*, Woodlawn WindEnergy Joint Venture, 2004.

two percent of the typical emissions reduction that such a wind farm would achieve from displacing fossil fuel generation.

3.3. Impact of wind's variability on emissions abatement

In this section, we consider the direct impact that wind power's variability has on its ability to abate emissions, as well as one of the best ways to mitigate the deleterious effects of its inherent variability, which is through accurate forecasting of wind power output.

The minute-to-minute variability in wind farm output, which arises from varying wind speed and direction, and is therefore only controllable downwards, is managed in the NEM via frequency control ancillary services (FCAS). FCAS is used to keep the frequency of the power system within acceptable limits, by raising or lowering online generation supply to match demand. FCAS includes raise and lower services operating within 6 second, 60 second and 5 minute timeframes. These primarily deal with the sudden loss of either a generating unit (raise service) or a load (lower service). In addition, there are the regulation raise and regulation lower services, which are used to govern minor deviations in the balance of supply and demand within the NEM's 5-minute dispatch cycle. It is these regulation reserve services that would primarily deal with the variability associated with wind generating units.

There is no evidence in the NEM of a significant increase in the use of FCAS to deal with wind variability. However, it is likely that the need for FCAS will increase at some point as more wind is installed in the NEM[7]. This will have the effect of increasing emissions since the use of FCAS means that any fossil fuel generators providing additional FCAS would be operating at levels below their maximum capacity, which is sub-optimal in terms of thermal efficiency and therefore results in an increased incremental emissions coefficient. Variability in itself is not much of a problem with respect to increasing emissions, but rather it is whether additional thermal units must be on line due to the variability of wind. If this is the case, then there would be an increase in standing thermal losses, particularly from the furnace/boilers of steam cycle plant. Much will depend on the accuracy of wind forecasting and the evolution of the resource mix.

However, any increase is likely to be very small, and in the words of the UK's Sustainable Development Commission

7 The Australia Institute, *Wind farms: The facts and the fallacies*, 2006, p.17.

> [w]hen wind produces 20% of total output, it is estimated that the emissions savings from wind will be reduced by a little over 1%, meaning that 99% of the emissions from the displaced fuel will be saved[8].

Thus, it is likely that the emissions savings from displaced fossil fuel far outweigh any additional emissions arising from the need for additional FCAS.

Variability of wind within a power system is dealt with in the same way as variability arising from other supply or demand sources. However, there is a view that the variability of wind requires 100% backup by gas plant operating at minimum load (which is very inefficient fuel-wise) in order to provide the necessary spinning reserve to deal with wind power's variability. This view argues that the emissions produced by the wasteful use of gas needed to operate the gas plant at minimum load to provide the necessary level of spinning reserve, substantially offset the emissions savings achieved by the wind turbines. This view does not necessarily acknowledge the existence of the rest of the power system, which already has the methods and the capacity to deal with variability from both the supply side and the demand side.

3.3.1. Wind power forecasting

At large penetration levels, the value of wind power can potentially be eroded by the need to keep large quantities of spinning reserve on hand in order to deal with wind's variability. Wind power's variability can also present significant issues for the operation and security of the transmission grid, especially since wind farms are often (or expected to be) located in remote locations, where the grid may not be as robust. In cases where wind power displaces slow-starting generation assets, as is potentially the case in Victoria, knowledge of wind's future generation within the time frame needed to start the thermal generators is critical in enabling optimal commitment of these units. These problems can be mitigated through the ability to accurately forecast wind power output at various time scales. In order to bring this issue into context, it is important to understand wind's variability at the various time scales. At the one second time frame, the standard deviation of a wind farm's variability is typically about 0.1% of its rated capacity. At the ten minute time frame the standard deviation is about 3% of rated capacity, and at the one hour time frame the standard deviation is about 10% of rated capacity[9].

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8 Sustainable Development Commission UK, *Wind Power in the UK: A guide to the key issues surrounding onshore wind power development in the UK,* Government of the UK, 2006, p.26.

9 J. C. Smith and B. Parsons, *What does 20% look like,* IEEE Power and Energy, Vol. 5 No. 6, (2007), p.29.

There are three basic steps in producing a wind power forecast:

- numerical weather prediction
- wind power output forecast
- regional upscaling

Numerical weather prediction usually starts with a coarse, computationally expensive global model, whose inputs are meteorological measurements from weather stations, satellites, etc. The resulting forecast is then input into a local area model, which models part of the Earth at much higher resolution, also taking into account terrain effects.

Most of the innovation in wind power forecasting has occurred in Europe, where countries such as Denmark, Germany and Spain already have significant penetrations of wind power to contend with. There have been a number of studies in recent years which show that improved forecast accuracy can be achieved by combining the results of several different types of weather models together. The idea is that each type of weather model has its own strengths and weaknesses in modelling different weather conditions. As an example, one ISET study found that the root mean square error (RMSE) for a combined weather model of Germany was 4.7%, whereas the individual component models had RMSEs between 5.8% and 6.1%[10].

There are three basic approaches of turning a weather forecast into a wind power output forecast.

- the physical approach, which models the physics of turning wind into wind power
- the statistical approach, which uses time series analysis to statistically relate wind speed and direction to wind power output; and
- the learning approach, which uses artificial intelligence methods to learn how wind speed and direction translate into wind power output.

Research has demonstrated that more accurate forecasts can be achieved by using a combination of the above three approaches. The efforts of such research have seen continual improvements in the accuracy of wind power forecasts. For example, the wind power management system in Germany has achieved continual improvement since its implementation in 2001. The RMSE of the operational wind power forecast was approximately 10% of installed capacity in 2001, and this had improved to 6.5% in 2006[11].

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10 B. Ernst et. al.,*Predicting the Wind,* IEEE Power and Energy, Vol. 5 No. 6, (2007), p.85.

11 Ibid., p.84.

Finally, regional upscaling is used for regions with many wind farms. In this case wind power output forecasts are performed for representative wind farms only and then scaled to the rest of the capacity. This results in only a slight increase in forecast error, since neighbouring wind farms have similar unit output, but minimises the effort in producing the forecast.

Recognising the increasing importance of wind's role in the NEM, AEMO commissioned the Australian Wind Energy Forecasting System (AWEFS). The project was delivered by a European consortium of 6 partners, and the resulting forecasting system is an advanced system by world standards. It uses the physical and statistical approaches described above in formulating its wind power forecast, and it also avoids the introduction of additional error from regional upscaling since a forecast is provided for each individual wind farm. The system will produce NEM wind farm forecasts for each NEM forecast timescale, ranging from 5-minutes ahead for the dispatch timescale to 2 years ahead at daily resolution for the MT PASA[12].

[12] MT PASA is AEMO's Medium Term Projected Assessment of System Adequacy, which is a forecast of reserve levels.

4. Methodology and Assumptions Overview

The emissions abatement impact that wind farms and large scale solar plant will have in Victoria is driven in part by the future generation mix, which is in turn driven by electricity demand, the carbon price and the expected level of renewable energy projects. The carbon price is a critical component in this equation as it drives the abatement of emissions, primarily through the retirement and/or winding down of coal plant production. The critical factors for the uptake of renewable energy projects are:

- The magnitude of the renewable energy target
- The new renewable energy supply curve which will determine the new entry cost for renewable energy
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if REC prices are lower due to high energy prices elsewhere, such as in Western Australia[13].

4.1. Factors Considered

The market forecasts developed for Sustainability Victoria take into account the following parameters:

- regional and temporal demand forecasts
- generating plant performance
- timing of new generation including embedded generation
- existing interconnection limits
- potential for interconnection development

The following sections summarise the major market assumptions and methods utilised in the forecasts. A more detailed exposition of the methodology and assumptions can be found in Appendix C.

13 Note that the South West Interconnected System (SWIS) in WA is small compared to the NEM and can only accept a relatively small amount of renewable energy capacity, particularly wind farms. Therefore, lower REC prices due to opportunities for higher electricity sales income in the SWIS would only prevail until the limit was reached for technically acceptable and/or commercially viable wind farms in the SWIS.

4.2. PLEXOS Software platform

The wholesale market price forecasts will be developed utilising SKM MMA's Monte Carlo NEM database. This database uses PLEXOS, a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

4.2.1. Key PLEXOS settings

For the present assignment, we have chosen to run with marginal cost bidding since prices were not a critical output. The market was modelled with the full annual chronology in 30 minute time steps, and ramping restrictions of power stations were also modelled within this time frame in order to capture the effect that a sudden drop in wind may have on the dispatch, and in particular, the fuel mix.

Unit commitment was only optimised for brown coal generators, since previous modelling has shown that black coal generators are able to economically operate continuously whenever available, as they do at present[14], until at least 2020. Brown coal units are assumed to self-commit during weekdays in the peak months of July, August, January and February. Otherwise, PLEXOS optimises brown coal unit commitment by minimising system costs, also taking into account start costs, using a one-day look ahead with perfect foresight.

4.3. Scenario assumptions

The present study consists of seven scenarios, each with different levels of wind and large scale PV penetration in Victoria. The first scenario is the baseline scenario, in which no new wind or large scale PV capacity enters Victoria. The second through to the fifth scenarios model additional Victorian wind penetrations of 1000 MW, 2000 MW, 3000 MW and 4000 MW respectively, with no additional large scale PV capacity. These levels of wind penetration represent plausible market outcomes over the life of the expanded RET scheme. The sixth and seventh scenarios model 2000 MW of additional Victorian wind capacity, together with 250 MW and 500 MW respectively of additional large scale solar PV capacity. A description of how large scale solar PV capacity is modelled in PLEXOS can be found in section C.9.5 of Appendix C. The definition for the seven scenarios are summarised below for easy reference in Table 4-1.

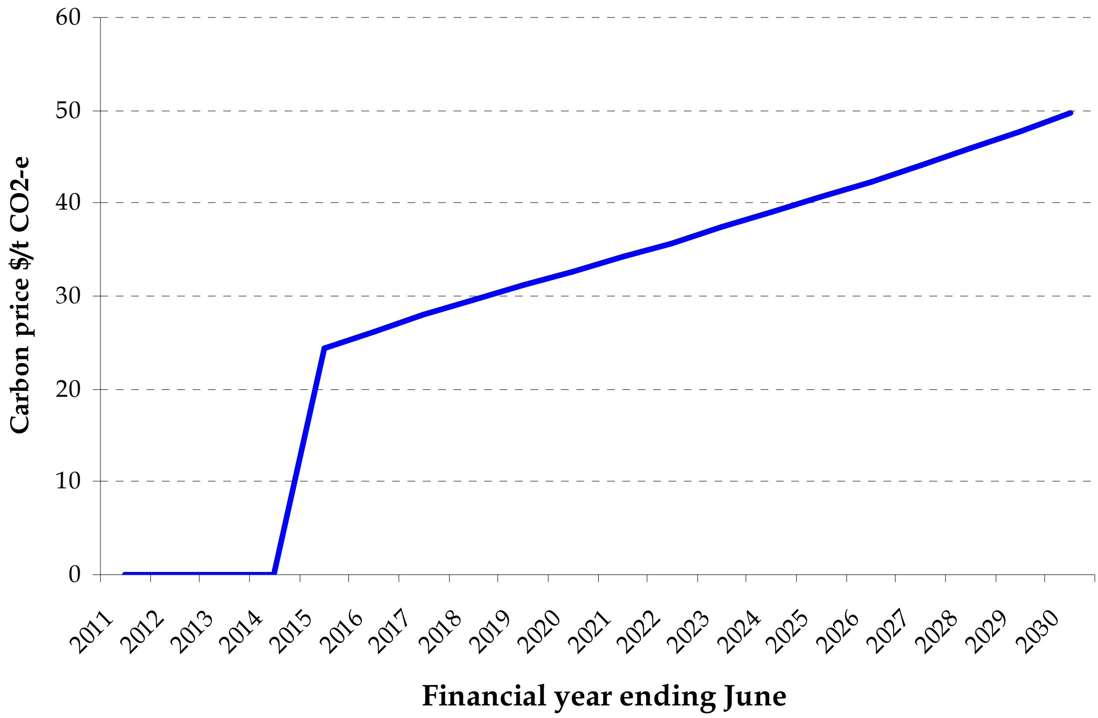
[14] We do however, include the dispatch modifications described in section C.10.2 of Appendix C.

All scenarios assume that the 5% emission reduction target for 2020 is adopted by the Government, although its implementation is delayed until July 2014. The carbon price path is shown in Figure 4-1, and is adapted from the CPRS-5% price path employed in the Federal Treasury modelling.

Table 4-1 Definition of scenarios

Scenario	Additional VIC wind capacity	Additional VIC large scale solar PV capacity
1	0 MW	0 MW
2	1000 MW	0 MW
3	2000 MW	0 MW
4	3000 MW	0 MW
5	4000 MW	0 MW
6	2000 MW	250 MW
7	2000 MW	500 MW

Figure 4-1 Carbon Price Path – delayed CPRS-5%



4.3.1. Scenario methodology

Here we describe the methodology underlying the formulation of the scenarios. The first step is to run a base expansion plan with optimal least-cost new entry for thermal plant and optimal timing of retirement of uneconomic capacity, which simultaneously satisfies the Large-scale Renewable Energy Target (LRET) constraint, also in a least cost way. All wind and PV capacity is then removed from Victoria, with the scenario specific wind and PV capacity added in its place, and any necessary thermal capacity in also installed at least cost in order to satisfy system adequacy and reliability constraints.

The optimised retirement of capacity was only considered for the Baseline scenario, and was kept identical in all other scenarios. This is summarised below in Table 4-2. In addition to these optimised retirements, we also included retirement of capacity already announced to the market, such as that of Swanbank B (progressively from 2010 to 2012) and Munmorah (in 2014).

Table 4-2 Assumed retirement of capacity for all scenarios

Retirement date	Capacity (MW)
July 2014	200
July 2015	200

A summary of the cumulative new capacity installed by region by scenario is presented below in Table 4-3 to Table 4-6.

In running the initial base expansion plan, we found that about 2,500 MW of wind was the optimal renewable generation mix for Victoria. However, this meant that for Scenarios 4 and 5, we would have to remove renewable generation capacity from other regions to avoid over subscribing the LRET target, at least for the latter years[15]. The wind capacity was removed from the other states on a proportional basis, but there was some lumpiness in the capacity removed (especially around 2015, which is when wind capacity began ramping up in sufficient volume). Removing the "excess" wind capacity from the other NEM states meant that this capacity in Victoria effectively displaced wind capacity, and so this underestimates the abatement intensity of this "excess" wind capacity block. Table 4-7 to Table 4-9 show the cumulative wind capacity by scenario, including incumbent capacity, for all regions except for Victoria.

[15] Over subscribing the LRET target in the early years was unavoidable, especially for the high wind capacity cases.

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4.3.2. 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 seven scenarios and reflect the most probable market outcomes given the current state of knowledge of the market. They include medium energy growth as well as median peak demands, as provided in AEMO's 2009 ESOO. The demand forecasts have been amended slightly to take account of differences in assumptions related to carbon prices in formulating the forecast, although the adjustment is quite minor at less than 0.3% after 2022.

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 medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market.
- The LRET and SRES schemes have superseded the expanded MRET scheme. 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 the existing scheme 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 $10/tCO2e carbon price, there is enough gas fired generation to meet 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.
- Carbon capture and storage is not available until 2025/26 and thus lies outside the scope of this study. However, the long term modelling for the Federal Treasury revealed that the threat of (relatively) low cost carbon capture and storage in the face of high carbon prices made problematic the entry of conventional CCGT plant in the medium term as a transitional base load technology. CCGTs would therefore only be commissioned sparingly, and only if prices are high enough to support a relatively rapid recovery of their fixed costs.
- Geothermal generation becomes commercially viable in 2017.

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Table 4-3 Cumulative thermal capacity expansion (MW), Scenarios 1 and 2

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW CCGT	0	0	0	0	0	0	0	0	0	0
NSW GT	0	250	830	830	830	1160	1335	1685	1685	1685
QLD CCGT	0	0	0	0	0	0	0	500	1000	1000
QLD GT	0	0	0	0	173	519	865	865	865	865
SA CCGT	0	0	0	0	0	0	0	0	0	0
SA GT	0	0	130	130	130	130	260	260	260	260
VIC IGCC	0	0	0	0	0	0	0	0	0	0
VIC CCGT	0	0	0	0	0	0	0	0	0	0
VIC GT	0	0	161	161	482	642	803	803	1125	1125
TAS CCGT	0	0	0	0	0	0	0	0	0	0
TAS GT	0	0	0	0	0	0	0	0	0	0

Table 4-4 Cumulative thermal capacity expansion (MW), Scenarios 3, 4 and 5

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW CCGT	0	0	0	0	0	0	0	0	0	0
NSW GT	0	250	830	830	830	1160	1335	1685	1685	1685
QLD CCGT	0	0	0	0	0	0	0	500	1000	1000
QLD GT	0	0	0	0	173	519	865	865	865	865
SA CCGT	0	0	0	0	0	0	0	0	0	0
SA GT	0	0	130	130	130	130	260	260	260	260
VIC IGCC	0	0	0	0	0	0	0	0	440	440
VIC CCGT	0	0	0	0	0	0	0	0	0	0
VIC GT	0	0	161	161	322	482	643	643	965	965
TAS CCGT	0	0	0	0	0	0	0	0	0	0
TAS GT	0	0	0	0	0	0	0	0	0	0

- **Table 4-5 Cumulative thermal capacity expansion (MW), Scenario 6**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW CCGT	0	0	0	0	0	0	0	0	0	0
NSW GT	0	250	830	830	830	1160	1335	1685	1685	1685
QLD CCGT	0	0	0	0	0	0	0	500	1000	1000
QLD GT	0	0	0	0	173	519	865	865	865	865
SA CCGT	0	0	0	0	0	0	0	0	0	0
SA GT	0	0	130	130	130	130	260	260	260	260
VIC IGCC	0	0	0	0	0	0	0	0	440	440
VIC CCGT	0	0	0	0	0	0	0	0	0	0
VIC GT	0	0	0	0	161	322	482	482	804	804
TAS CCGT	0	0	0	0	0	0	0	0	0	0
TAS GT	0	0	0	0	0	0	0	0	0	0

- **Table 4-6 Cumulative thermal capacity expansion (MW), Scenario 7**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW CCGT	0	0	0	0	0	0	0	0	0	0
NSW GT	0	250	830	830	830	1160	1335	1685	1685	1685
QLD CCGT	0	0	0	0	0	0	0	500	1000	1000
QLD GT	0	0	0	0	173	519	865	865	865	865
SA CCGT	0	0	0	0	0	0	0	0	0	0
SA GT	0	0	130	130	130	130	260	260	260	260
VIC IGCC	0	0	0	0	0	0	0	0	440	440
VIC CCGT	0	0	0	0	0	0	0	0	0	0
VIC GT	0	0	0	0	161	322	482	482	804	804
TAS CCGT	0	0	0	0	0	0	0	0	0	0
TAS GT	0	0	0	0	0	0	0	0	0	0

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Table 4-7 Cumulative wind capacity by region for Scenarios 1-3, 6 and 7

FY ending	NSW	QLD	SA	TAS
2010	212	0	1039	140
2011	212	0	1156	140
2012	212	0	1156	140
2013	247	0	1156	140
2014	247	500	1156	140
2015	693	500	1420	140
2016	2292	500	1420	805
2017	2441	500	1420	805
2018	2441	500	1420	805
2019	2441	500	1561	805
2020	2441	500	1681	805

Table 4-8 Cumulative wind capacity by region for Scenario 4

FY ending	NSW	QLD	SA	TAS
2010	189	0	1039	140
2011	189	0	1156	140
2012	189	0	1156	140
2013	189	0	1156	140
2014	189	425	1156	140
2015	462	425	1345	140
2016	2017	425	1345	730
2017	2166	425	1345	730
2018	2166	425	1345	730
2019	2166	425	1486	730
2020	2166	425	1606	730

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- **Table 4-9 Cumulative wind capacity by region for Scenario 5**

FY ending	NSW	QLD	SA	TAS
2010	189	0	1039	140
2011	189	0	1156	140
2012	189	0	1156	140
2013	189	0	1156	140
2014	189	275	1156	140
2015	397	275	1196	140
2016	1467	275	1196	580
2017	1616	275	1196	580
2018	1616	275	1196	580
2019	1616	275	1337	580
2020	1616	275	1457	580

5. New Renewable Energy and Emission Abatement

Modelling the NEM is no longer simply an exercise in determining the centrally coordinated dispatch of generation to meet demand at least cost. There are a number of greenhouse gas abatement measures that have been implemented by Federal and State governments in the past four to five years that impact on the dispatch of generation. Some schemes, such as the RET, facilitate renewable energy projects which displace thermal generation. Other schemes, such as the New South Wales Greenhouse Gas Abatement Scheme (GGAS) and the Queensland Cleaner Energy Strategy (CES), provide subsidies to gas-fired generation or other low-emission technologies and consequently lower the net marginal costs of these generators.

The major impact of these schemes has been to suppress wholesale electricity prices by prolonging the supply surplus through additional demand side management, renewable energy generation and advancement of gas fired generation. New entry prices are lower than in the absence of these schemes because gas fired plants have been able to obtain a subsidy of between $3 and $12/MWh depending on the supply/demand in these niche markets.

Of course the major development with respect to renewable energy generation has been the expansion of the RET scheme, initially to a target of 45,000 GWh by 2020, and now to a 2020 target of 41,000 GWh for large scale renewable generating plant, under what is now known as the LRET scheme. The scheme is legislated, and its design has not changed substantially from the prior MRET scheme, in that unlimited banking of RECs is allowed, and there are no restrictions on project eligibility periods. The LRET is likely to bring on significant wind and biomass capacity over the next decade, which will meet a large proportion of the underlying demand growth. Substantial penetration of wind may require additional open cycle gas turbine plants to provide reserve capacity for when the wind is not blowing. In principle, these plants may displace to some degree combined cycle and new coal fired options that would become less economic with wind eroding the base load role.

The Federal Government has now delayed the implementation of its emissions trading scheme, known as the CPRS, thus adding to the uncertainty surrounding emission trading. Even though there is less uncertainty about the emissions targets and their scope, carbon prices are still difficult to predict given the scheme's dependence on the outcome of international negotiations.

For the purpose of this study, SKM MMA has utilised the carbon prices that emerged from the Federal Treasury modelling for the CPRS-5% scenario (reference), although the scheme's implementation has been delayed until July 2014.

With the introduction of the CPRS, wholesale electricity prices will no longer be suppressed through subsidies provided to gas-fired generation or other low-emission technologies. On the contrary, the carbon price will be an additional cost to generators that they will want to pass through to end-users via the wholesale market.

5.1. Renewable energy scheme

5.1.1. LRET scheme

The Commonwealth Government's new policy is to achieve 20% additional renewable energy by 2020. It has been legislated as a 41,000 GWh target for large-scale renewable generation plant with a maximum penalty for non-performance of $65/MWh. This penalty is not indexed to CPI. The penalty is also not tax deductible, meaning that under current company tax rates a liable party would be indifferent between paying the penalty or purchasing certificates at a price of $93/MWh.

To model the LRET scheme, it has been assumed that the current scheme for MRET would continue to operate with an increased target from 2010 onwards, and with an increase in the penalty price for non-compliance. The targets are shown in Table 5-1. The 41,000 GWh target continues until 2030.

For the purpose of PLEXOS modelling, it is important to note that this is a national renewable energy target rather than a NEM-wide target. Moreover, not all eligible renewable energy sources are modelled explicitly in PLEXOS. Therefore, it was necessary to derive a NEM equivalent renewable energy target taking account of the expected contribution from other sources including:

- Renewable energy sources from Western Australia and the Northern Territory.
- Eligible existing and committed biomass and small hydro generation.
- Greenpower sales, which effectively increase the total renewable energy requirements.
- Additional renewable energy demand created by the promise that desalination plants in Victoria, NSW and South Australia would source their energy from renewable sources.

Where renewable sources contribute towards the NEM native demand[16], load was modified based on the assumed levels of generation from these sources. Up to 3,500 GWh of electricity demand is assumed to be displaced by solar water heaters annually.

The annual renewable energy targets included in SKM MMA's NEM database take these considerations into account, but also include baseline hydro generation from existing hydro schemes.

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[16] For example, solar water heater uptake under the small scale renewable energy scheme.

- **Table 5-1 Required GWh from renewable energy sources to meet LRET**

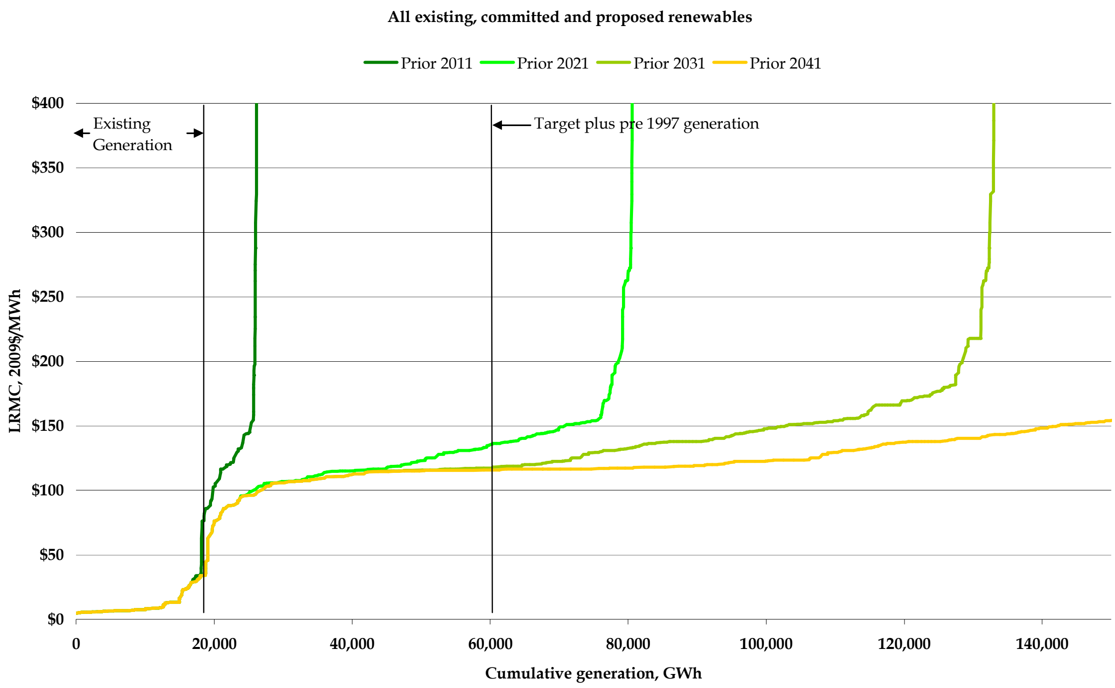
Calendar Year	Target (GWh)
2009	8,678
2010	12,500
2011	10,400
2012	12,300
2013	14,200
2014	16,100
2015	18,000
2016	22,600
2017	27,200
2018	31,800
2019	36,400
2020 - 2030	41,000
2031	0

5.1.2. Renewable energy supply curve

For the purposes of forecasting renewable energy prices, a critical requirement is the database of potential renewable energy projects. SKM MMA has developed a database which includes existing, committed, and prospective projects including some allowance for generic projects based on projections by industry organisations. With the current tightening of the global financial system, we have assumed project financing costs based on a debt level to 60%, and have also added on a 1% premium to return on debt, reflecting the increased scarcity of capital funding, bringing to it 7.3% in real terms. Under these assumptions the resulting WACC is 11.0%, which is applied from 2010 trending back to the typical past level of 9.3% by 2014.

Figure 5-1 shows the cumulative renewable energy supply curve developed from the database including the existing and committed plants. The supply curve includes all resources expected to be available until 2040. This shows that at 41 TWh, the marginal cost is about $115/MWh. The actual renewable energy cost at 2020 will be higher because some of the resources shown in Figure 5-1 will not be available at this cost until well after 2020.

▪ Figure 5-1 Renewable Energy Supply Curve to 2040



The equivalent curve for only wind farms is shown in Figure 5-2[17]. Most of the available wind projects are in the cost range of $110 to $140/MWh. We expect that the higher cost wind farms will be displaced by the development of other renewable energy technologies.

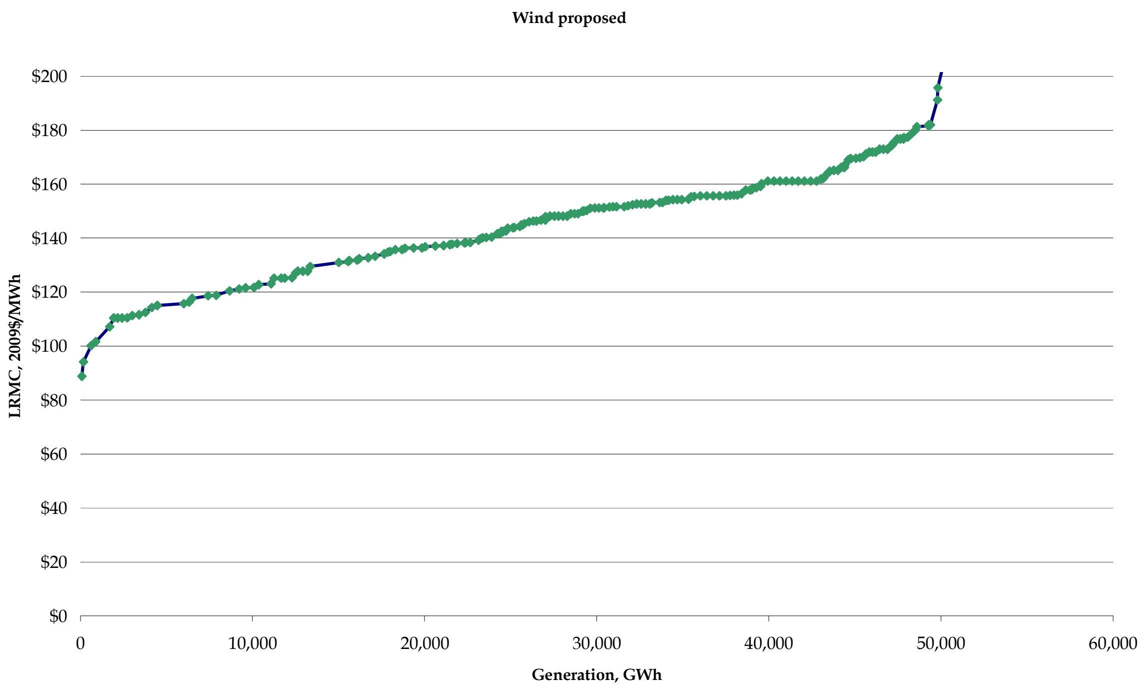
In 2008, wind turbine costs had increased at a significant rate due mainly to demand for wind turbines and the large increase in the cost of steel. However, with the onset of the global financial crisis, these cost pressures have eased because demand has fallen significantly and metal prices have fallen since their peak. The net effect is that capital costs are where they were before the 2008 price spike. Increased global demand for wind turbines could increase again in the future, leading to renewed pressure on wind turbine purchase prices, but competition amongst renewable energy technologies could limit any price increase.

The geothermal supply curve for both scenarios is shown in Figure 5-3. Geothermal is priced at $4,300/kW plus approximately $26/MWh plus up to $750/kW for transmission cost. Real capital cost reductions are set at 0.7% per year.

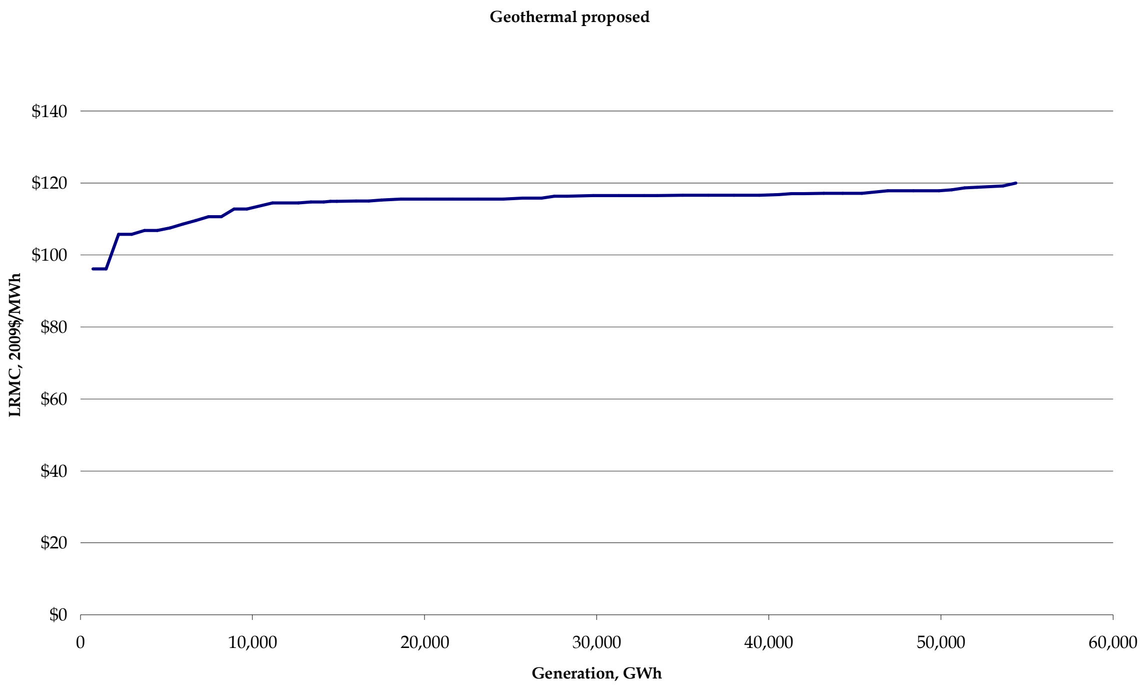
17 Capital costs for wind turbines range from $2000 to $5000/kW (typically $2200 to $3000/kW) plus transmission connection capital costs from $100 to $500/kW. Capital costs trend at CPI-0.4%.

The solar thermal supply is shown in Figure 5-4. These resources are not available until after 2020 and the low cost assumes that production capacity is scaled up to produce about 50 to 75 MW of capacity per year. The current cost is about \$6,000/kW decreasing at CPI-2%. It is expected that economies of scale of production will eventually reduce capital costs. The same supply curve is used for both scenarios.

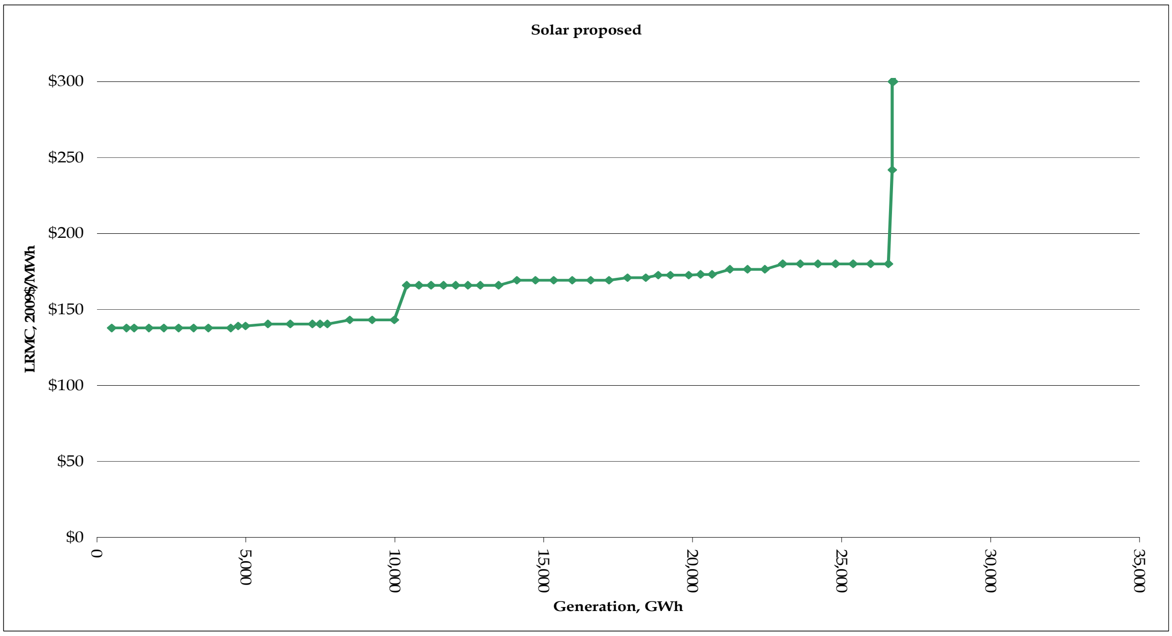
- **Figure 5-2 Wind Energy Supply Curve**



- **Figure 5-3 Geothermal Energy Supply Curve**



- **Figure 5-4 Solar Thermal Energy Supply Curve**



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5.2. NSW Greenhouse Gas Abatement Scheme

The NGGAS scheme is expected to finish just prior to emission trading, and it was previously assumed that the NSW Greenhouse Abatement Certificates (NGACs) traded under the NGGAS would be given full value as emission credits equal to 1 tonne of CO_2. This is now unlikely to happen, and NGAC prices are expected to remain low.

The NSW Government has announced that the scheme will continue to operate until 2025 unless an emissions trading scheme is implemented. The Federal Government is expected to introduce the CPRS after 2013, and the New South Wales Government committed to undertake a 'smooth transition between the two schemes'[18] in order to compensate for revenue losses from NGAC creations.

Given the limited horizon of the NGAC scheme assuming that it is superseded by the CPRS, SKM MMA's NGAC price projection for the present study is based on the NGAC spot price and the forward curve. This is presented below in Table 5-2. The prices were derived from forward prices in March 2010 and adjusted back to June 2009 dollars.

Table 5-2 NGAC prices (\$/t CO_2e) assumed for present study (June 2009 dollars)

Year ending June	NGAC Price
2011	4.30
2012	4.48
2013	4.50
2014	4.50

5.3. Gas Electricity Certificates Scheme in Queensland

In May 2000, the Queensland Government announced the Queensland Energy Policy – A Cleaner Energy Strategy. A key initiative of the Energy Policy is the Queensland Gas Electricity Scheme. This scheme requires electricity retailers and other liable parties to source at least 13% of their electricity from gas-fired generation from 1 January 2005.

The Gas Electricity Scheme is a certificate based scheme consisting of:

- Accredited Parties – generators of eligible gas-fired electricity who can create GECs, which have value and can be traded separately to the electricity to which they relate; and

18 NSW Department of Water and Energy. (2008). *Transitional arrangements for the NSW Greenhouse Gas Reduction Scheme – Consulation paper*. ((http://www.dwe.nsw.gov.au)

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- Liable Parties (largely electricity retailers and others that sell electricity to end users) - parties who are required to surrender GECs to the Regulator to acquit a liability.

Liabilities may be incurred by parties who are connected to, or sell to end users connected to, a major grid. A major grid is defined as a grid with an installed capacity which exceeds 100 MW. There are currently two Queensland grids that fit this description, the National Grid and the Mica Creek Grid, which supplies electricity to the Mount Isa region.

The target was to be modified to 18% by 2020 by the Queensland Government. However, with the more recent commitment to emissions trading, the target is now 15%. Post July 2011, it is expected that there will be a transition to the CPRS and the target with become redundant. It is assumed that the target will be increased linearly toward 18% by 2020.

Given the limited horizon of the GEC scheme assuming that it is superseded by the CPRS, SKM MMA's GEC price projection for the present study is based on the GEC spot price and the forward curve, which is presented below in Table 5-3. The prices are expected to be relatively low as subdued gas prices mean a significant and growing proportion of Queensland generation will be gas-fired.

Table 5-3 GEC prices (June 2009 dollars)

Year ending June	CPRS Jul-11
2011	2.65
2012	2.69
2013	2.74
2014	2.78

6. Results

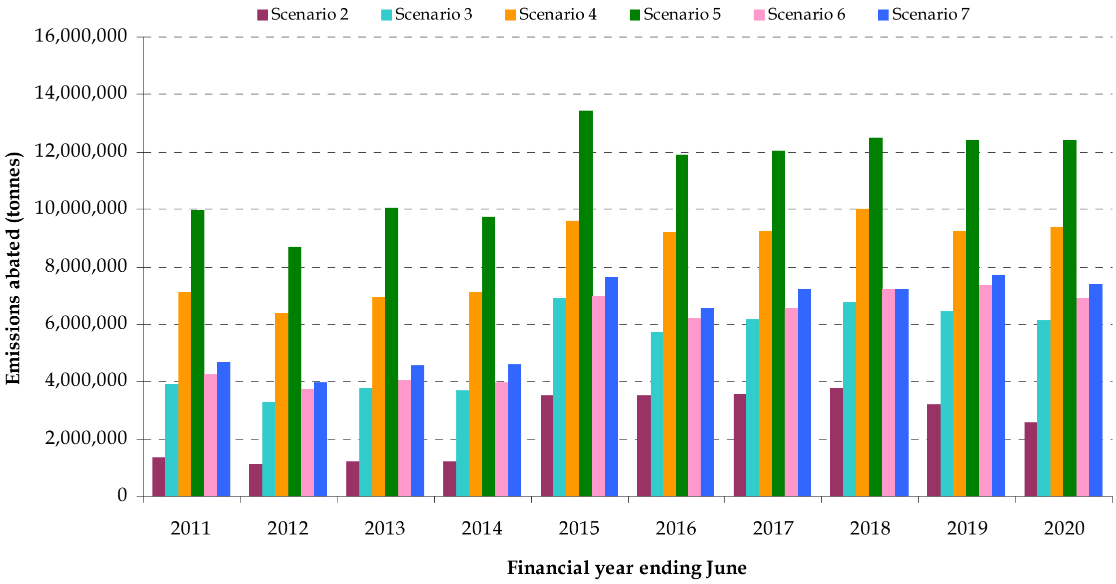
The PLEXOS models were set up in the seven scenarios (see Table 4-1) to run from July 2010 until June 2020. They modelled the market chronologically in 30 minute time steps, and also modelled ramping restrictions of power stations within this time frame in order to capture the effect that a sudden drop in wind may have on the dispatch, and in particular, the fuel mix. Such detailed modelling of these market dynamics meant that only two Monte Carlo simulations could be run within the time frame of the assignment.

6.1. Emissions abated

Figure 6-1 shows the annual amount of emissions abated in Victoria for Scenarios 2 to 7, all relative to the Baseline scenario. It is interesting to note that from 2011 to 2014 fewer emissions are abated in Victoria relative to other NEM regions (specifically NSW). This occurs because wind output displaces the marginal plant, which from 2011 until 2014 is typically NSW black coal. The full abatement effect of Victorian wind is presented in Figure 6-2, which shows that the emissions abatement of Victorian wind farms is maintained or enhanced by the CPRS in all cases except for Scenario 5 (4000 MW of additional wind). This is discussed in more detail below.

In all six wind and PV scenarios, Figure 6-1 shows that there is a notable increase in Victorian abatement levels from 2015 onwards, which coincides with the introduction of the CPRS. This occurs because once a carbon price is introduced, some brown coal plant become the marginal plant and the majority of wind output directly displaces brown coal generation or imported black coal generation.

- **Figure 6-1 Emissions abated in Victoria for Scenarios 2 to 7**



- **Figure 6-2 Emissions abated in the NEM for Scenarios 2 to 7**

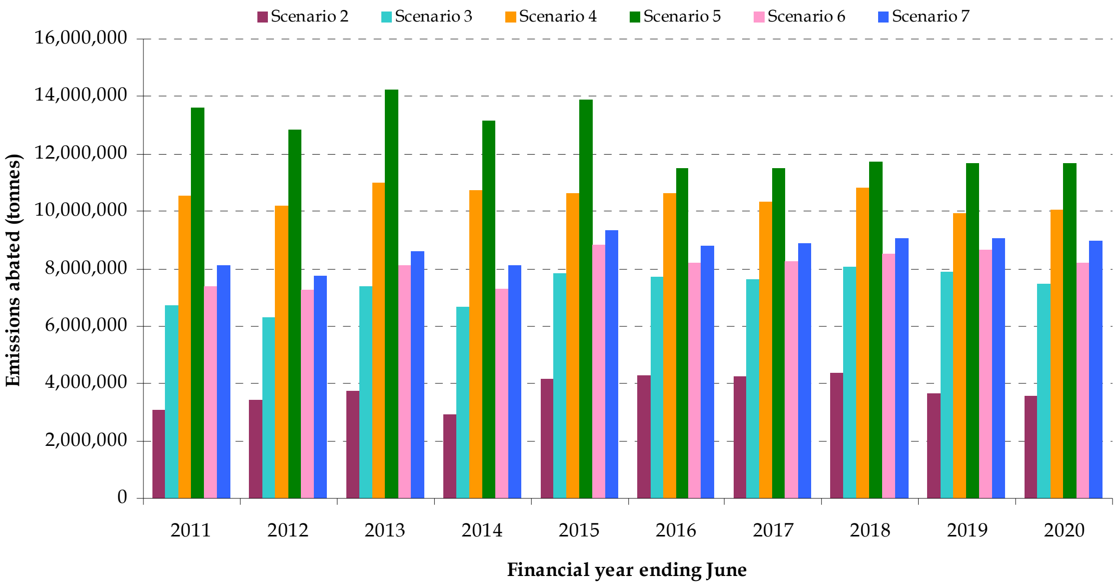


Figure 6-3 shows the abatement intensity of the four pure wind cases (Scenarios 2 to 5). Pre 2015, the abatement intensity varies from 0.9 t CO_2e/MWh to 1.2 t CO_2e/MWh, although there is no clear correlation between additional wind farm capacity and abatement intensity. The lower end of the abatement intensity spectrum reflects the emissions intensity of NSW black coal plant, which is typically from 0.9 to 1.0 t CO_2e/MWh. The upper end of the spectrum reflects the emissions

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intensity of the Victorian brown coal plant, whose emissions intensity ranges from just over 1.2 t CO_2e/MWh to 1.6 t CO_2e/MWh. This suggests that wind capacity pre CPRS predominantly displaces a combination of NSW black coal generation and Victorian brown coal generation.

Post CPRS, the emerging pattern is that the average abatement intensity increases as the additional wind farm capacity decreases. Moreover, in Scenarios 2 and 3, the post CPRS abatement intensity is higher than the pre CPRS abatement intensity. The abatement intensity for Scenario 4 is similar before and after the introduction of the CPRS, although it seems to be decreasing over time, which is consistent with an increasing carbon price. For Scenario 5, which has 4,000 MW of additional wind capacity, the abatement intensity of wind is lower than the pre-CPRS abatement intensity. These findings align with Figure 6-2, which shows that the CPRS maintains or enhances total emissions abated in all cases except Scenario 5.

The abatement intensity for Scenario 5 is reduced markedly from 2016 onwards[19], and this is mostly an artefact of the modelling methodology. The problem is that, as described in section 4.3.1, the Victorian wind capacity in Scenarios 4 and 5 exceeds the optimal Victorian wind capacity, which is about 2,500 MW. Therefore every MW of wind capacity exceeding this level for these scenarios (500 MW for Scenario 4 and 1,500 MW for Scenario 5) directly displaced wind capacity from the other NEM regions — otherwise the LRET scheme would be over-subscribed. Setting up the scenarios in this way means that this last block of wind capacity has inherently less abatement potential than the first 2,500 MW of wind since it displaces other wind resources, rather than black or brown coal plant. However, the modelling results do show that the last 1,500 MW of wind for Scenario 5 still has a positive abatement intensity which ranges from 0.35 t CO_2e/MWh to about 0.45 t CO_2e/MWh[20]. This positive abatement intensity reflects the fact that Victorian brown coal generation is more emissions intensive than the technology mix[21] that would have otherwise been displaced by wind capacity located in the other NEM regions[22].

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19 The effect is also present in Scenario 4, but is not as dramatic.

20 This assumes that the first 2,500 MW of wind capacity has an average abatement intensity of 1.25 tCO_2e/MWh, as is indicated by the abatement intensities of Scenario 2 and 3 in the post CPRS time frame. If the abatement intensity of the last 1,500 MW of wind capacity under Scenario 5 was zero, then the overall abatemernt intensity of the Victorian wind would be approximately 0.8 tCO_2e/MWh.

21 The mix would presumably have been predominantly black coal plant and some gas-fired plant.

22 The specific thermal capacity displaced by wind resources depends on where they are located in the NEM for two reasons. Firstly, as was mentioned previously, wind displaces the marginal plant, and this is more likely to be located in the same region because plants from other regions are penalised by the interregional loss factor, which in the NEM typically ranges from 10% to 20%. Secondly, in any given dispatch period, wind capacity can only displace a limited amount of thermal capacity in a neighbouring region. This would be the difference between the export limit and export level that would have been achieved in the absence of the wind capacity.

- **Figure 6-3 Average abatement intensity for the pure wind scenarios**

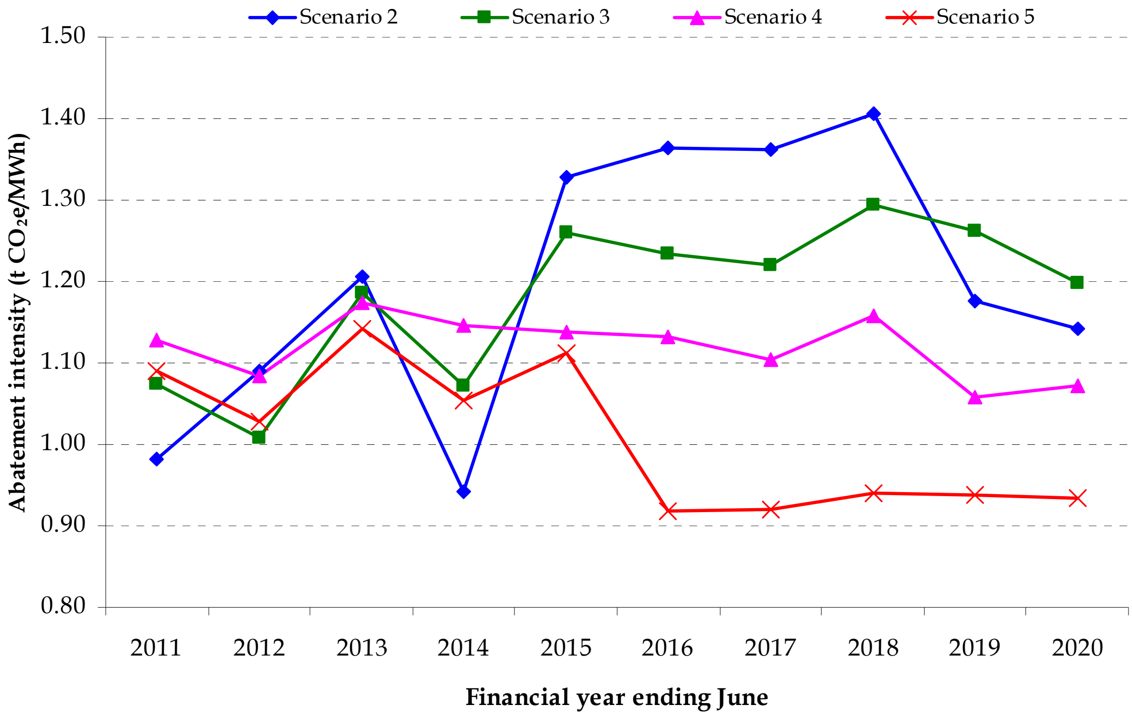

Figure 6-4 shows the same output as Figure 6-3, but for the two scenarios with large scale PV capacity (Scenario 6 and 7), and with the comparable wind scenario (Scenario 3). Pre CPRS the large scale PV scenarios tend to have higher abatement intensities than the corresponding wind scenario. This is mainly due to the emissions savings made by PV capacity over the weekend when it tends to displace brown coal plant during the day. This occurs because brown coal is the marginal Victorian plant only during off-peak periods, which occur overnight or over the weekend, when industrial and commercial demand is reduced. Post CPRS all three scenarios exhibit similar behaviour, although it is not possible to conclusively determine what effect the additional PV capacity has on the average abatement intensity.

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- **Figure 6-4 Average abatement intensity for Scenarios 3, 6 and 7**

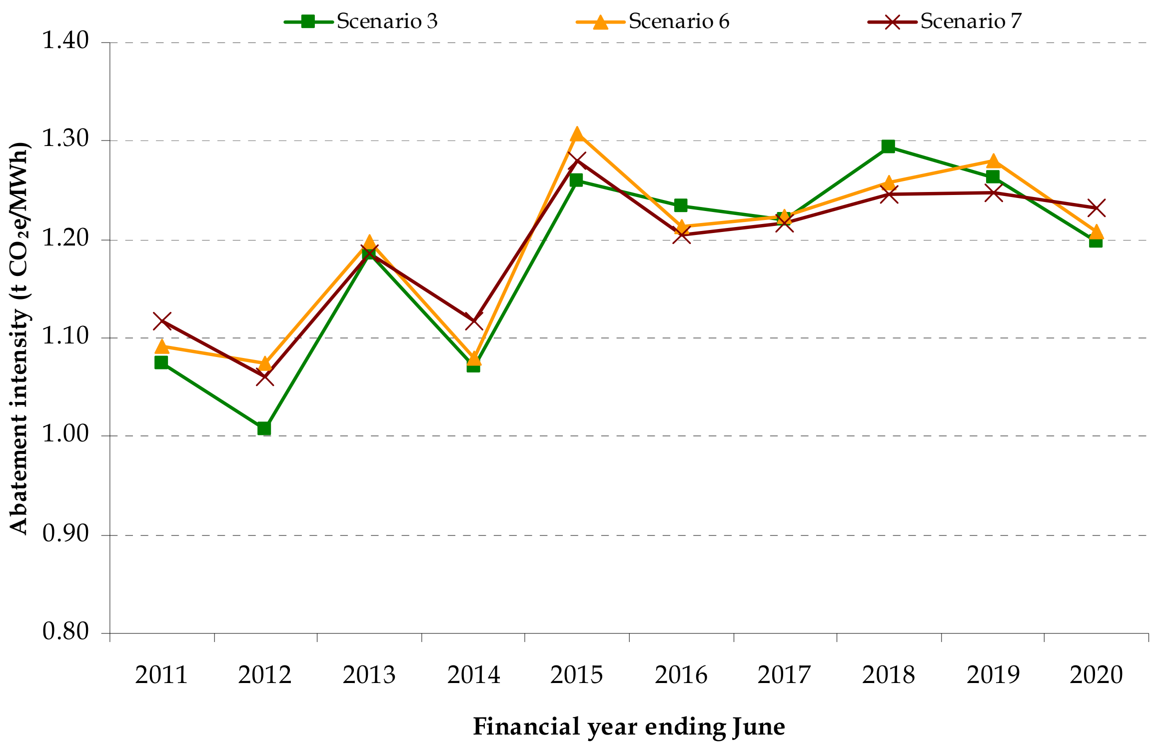

Figure 6-5 shows the abatement intensity of the additional PV capacity in Scenarios 6 and 7. The abatement intensities were derived by using emissions from Scenario 3 as the baseline. The range of abatement intensities is quite wide, varying from just over 0.8 t CO_2e/MWh to almost 1.6 t CO_2e/MWh. It should be noted that these derived emissions intensities for the additional PV capacity are noisier than those derived for wind capacity because of the smaller increments of PV capacity modelled[23] (250 MW and 500 MW respectively). Otherwise, the abatement intensities closer to 1.6 tCO_2e/MWh imply that the PV capacity only displaces generation from the Hazelwood power station[24], which is highly unlikely, especially pre CPRS when Hazelwood is not penalised for emissions. Figure 6-5 clearly shows that pre CPRS, PV capacity has a greater abatement intensity than wind capacity. However, post CPRS it is not possible to conclusively determine whether PV's abatement intensity is greater or less than the abatement intensity of wind due to the noisiness of the data.

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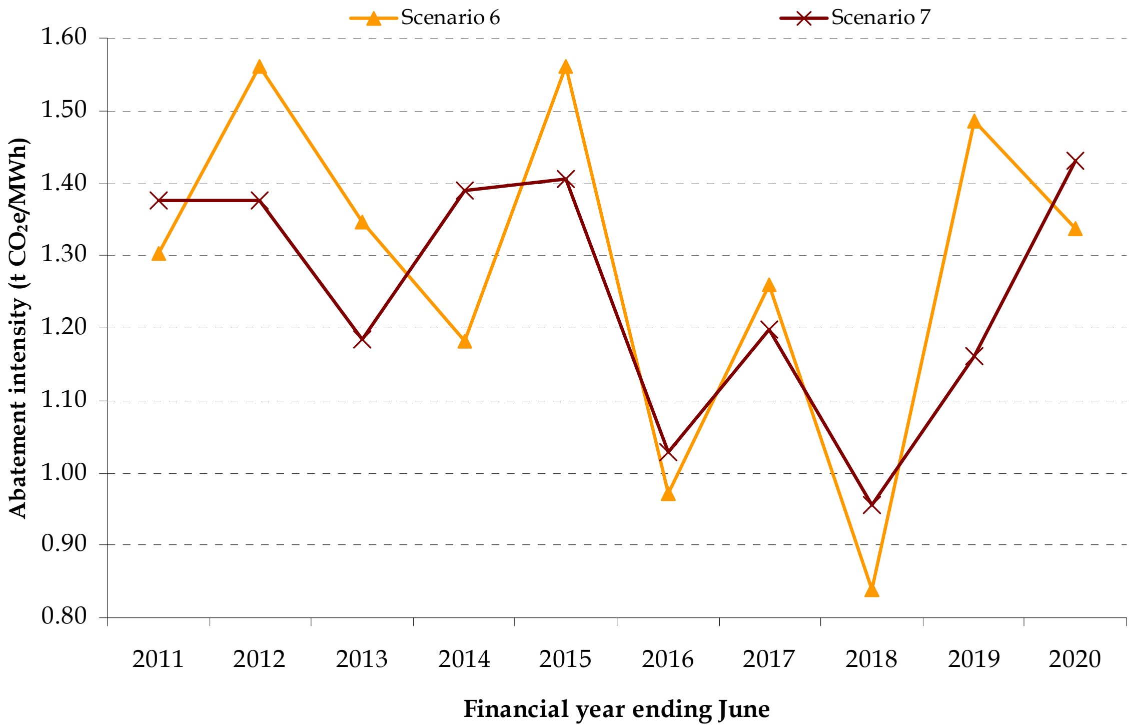
23 The results are noisier because the variation in emissions from random factors in the Monte Carlo simulation, such as reduced or increased outages of coal plant, are larger in percentage terms to emissions abated by smaller increments of capacity.

24 Hazelwood is the only large scale power station in the NEM with this level of emissions intensity.

- **Figure 6-5 Average abatement intensity of additional PV capacity in Scenarios 6 and 7**



The emissions savings profile of an average week by year is presented in Figure 6-6 for the pure wind scenarios (Scenarios 2 to 5), and for the large scale PV scenarios (Scenarios 3, 6 and 7) in Figure 6-7. The first day of the average week as it is presented is a Monday. The emissions savings profile is subject to other factors such as random noise resulting from different forced outage patterns across the scenarios. This is particularly an issue because of the small sample size, and it explains why the emissions savings occasionally cross over between the scenarios.

Figure 6-6 shows that pre CPRS, the emissions savings profiles for the cases with at least 2000 MW of additional wind exhibit a weekly cycle with distinct daily peaks and generally increased savings over the weekend[25]. The pattern is somewhat present in the 1000 MW wind case, but it is distorted by noise from the different forced outages patterns that are present in the modelling. The weekday peak emissions savings lie somewhere between 10pm and 6am, and the daily troughs coincide with the middle of the day. The daily peak pattern during the weekend typically disappears since the emissions savings profile tends to flatten out. This seemingly odd behaviour in fact confirms our explanation for Figure 6-1 since the most emissions savings occur when brown coal is marginal, which only occurs in off-peak demand periods — i.e. overnight or during the weekend. On the other hand, emissions savings are lowest during the daily peak demand cycle because that is when the wind displaces black coal generation, which is less emissions intensive. Once the CPRS commences from 2015 the emissions savings profile becomes flatter and the previously observed daily cycle either disappears or becomes quite distorted. This occurs because brown coal is now the marginal plant over all time periods, and so wind output mostly displaces brown coal generation. Another noticeable feature of Figure 6-6 is that the difference in emissions savings between Scenario 4 and 5 is much less from 2016 onwards. The same explanation given for the sharp post 2015 drop in the abatement intensity of Scenario 5, evident in Figure 6-3, also applies here.

Figure 6-7 shows the emissions savings impact on an average weekly profile of large scale PV. Given the PV profile, we would expect to see more emissions savings in the PV scenarios (Scenario 6 and 7) relative to the pure wind scenario (Scenario 3) during the middle of the day. This pattern is only present in patches because it has otherwise been drowned out by the noise of the sampling and the small PV capacities modelled relative to the wind capacity. A more consistent pattern that is evident pre CPRS is the tendency for more PV-created emissions savings during the middle of the day over the weekend period, when brown coal is often the marginal plant. Post CPRS the emissions savings created by large scale PV are much more apparent, especially for the 500 MW case (Scenario 7), and clearly occur in the middle of the day when a brown coal unit is almost always marginal.

6.2. Trends in Victorian emissions intensity from power generation

Figure 6-8 shows the Victorian emissions intensity factor by scenario. It clearly demonstrates that the average emissions intensity of power generation decreases over the modelling time frame. The effect of the introduction of the CPRS in FY 2015 is clearly apparent for all seven scenarios since in all cases there is a significant step down in the emissions intensity. This step down is due to a combination of the brown coal plant being off-loaded due to the carbon price and the retirement of

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[25] The fact that brown coal plant may be de-committed over the weekend has been taken into account in the modelling.

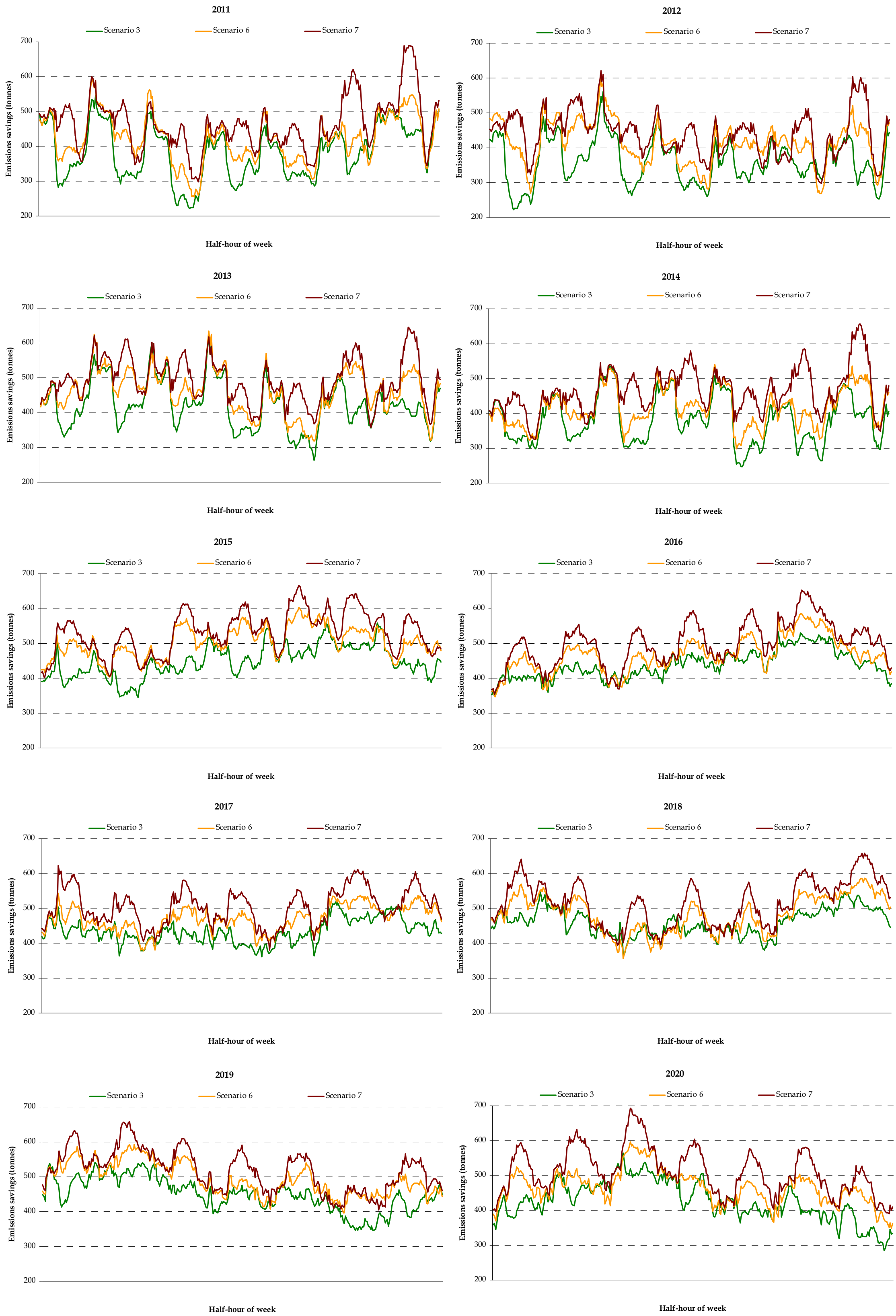
one of the older units. The retirement of one more coal fired unit in FY 2016 results in another, albeit smaller decrease in emissions intensity for all seven scenarios. Even though the trend in emissions intensity continues to be negative for all seven cases beyond 2016, it flattens out somewhat mainly because there are no more brown coal retirements other than the two coal fired units in FY 2015 and 2016.

The major factors driving the general reduction in emissions intensity are: (i) increased dispatch of lower emissions gas plants, such as Newport, the Latrobe Valley GTs, Laverton North, Somerton and Bairnsdale; (ii) the commissioning of new low emission gas turbine power stations[26]; and (iii) increased penetration of renewable generation sources. These points are illustrated in Figure 6-9, which shows that both gas-fired and renewable generation are growing at a faster rate than coal-fired generation, which is actually decreasing. Figure 6-10 also demonstrates the same point since it clearly shows the market share of coal-fired generation initially decreasing, and that of gas-fired and renewable generation initially increasing. The increase in the market share of coal-fired generation in FY 2019 and 2020 is due to the commissioning of the HRL IGCC plant, which has much lower emissions than conventional brown coal plant.

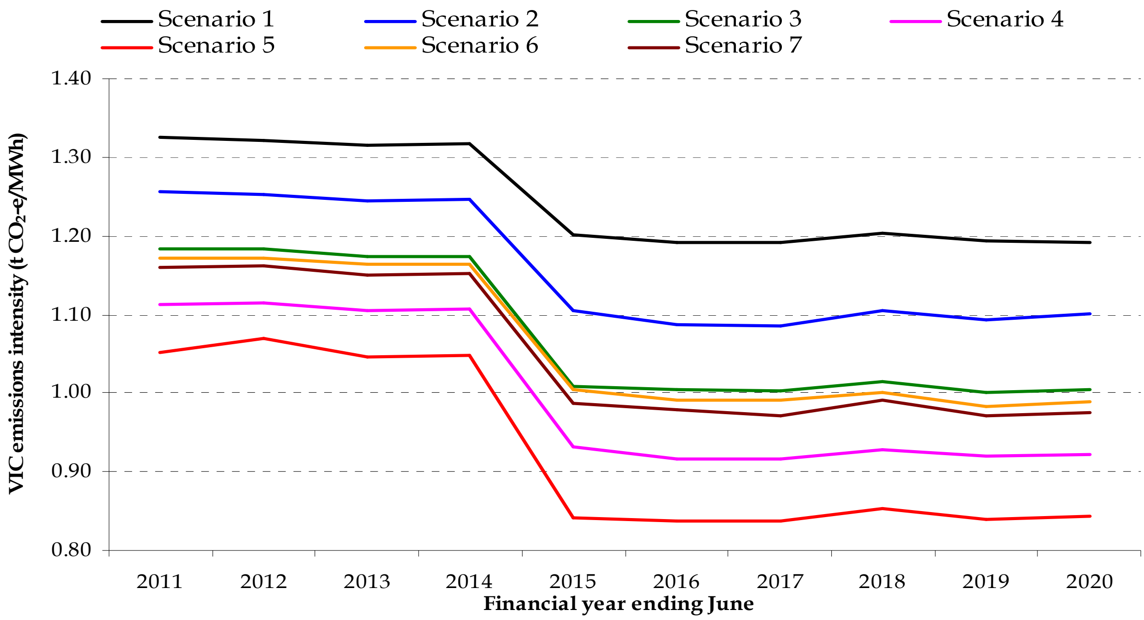
[26] Up to seven 160 MW gas turbines are commissioned by 2020.

▪ Figure 6-6 Emissions savings profile of average week by year for Scenarios 2 to 5

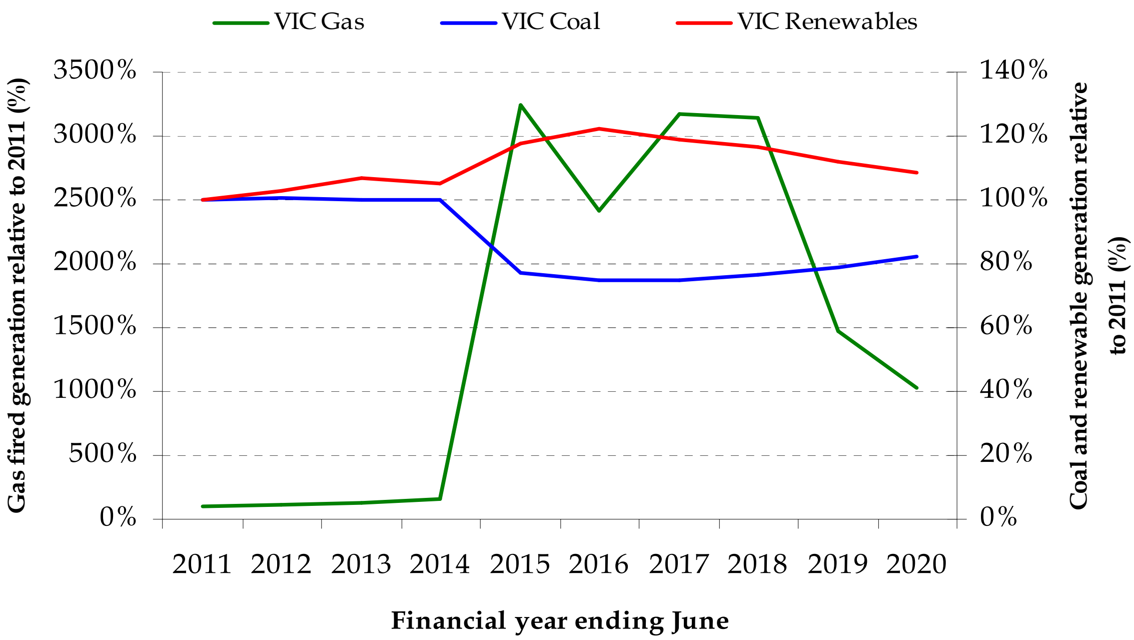
- **Figure 6-7 Emissions savings profile of average week by year for Scenarios 3, 6 and 7**



▪ **Figure 6-8 Victorian emissions intensity by scenario**



▪ **Figure 6-9 Growth in Victorian generation categories relative to 2011, Scenario 1**



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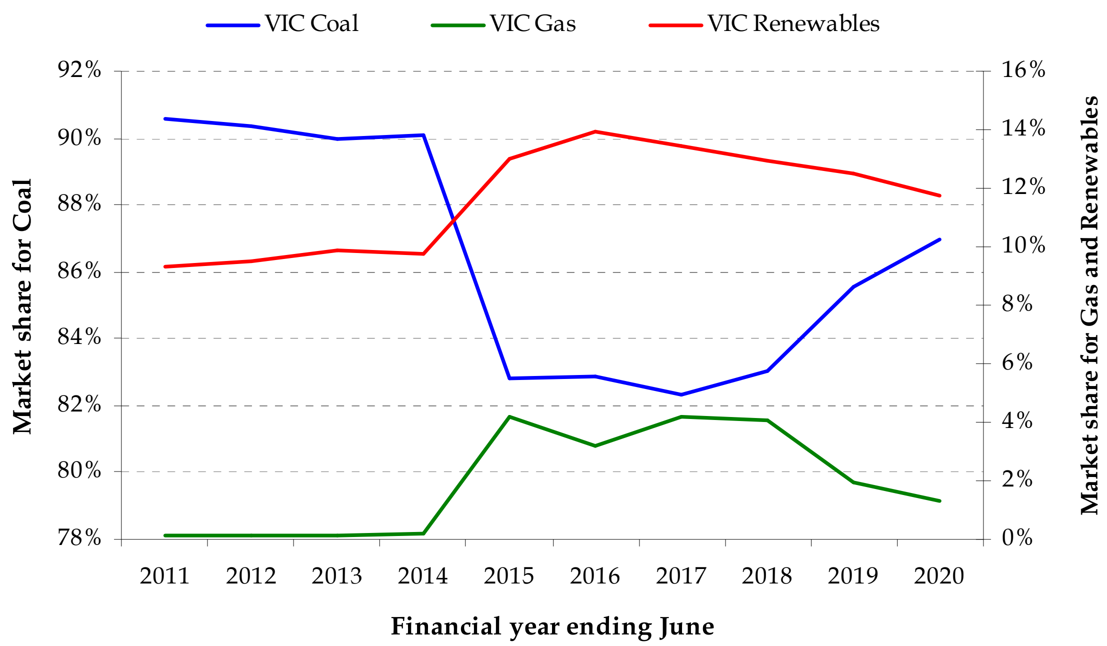
▪ **Figure 6-10 Victorian power generation market shares by fuel type, Scenario 1**



6.3. Victorian weekly generation profiles

Figure 6-11 to Figure 6-42 show typical Victorian weekly generation profiles for each season of the year in 2014/15 and 2019/20 for Scenarios 1, 3 and 5. They also display the aggregate minimum generation level of all the Victorian brown coal power stations both with and without the Hazelwood power station. Hazelwood's minimum generation level is most relevant here because it could be the first brown coal power station expected to retire in Victoria due to the introduction of a carbon price, but it is also expected to cycle its units on and off, especially in the low demand seasons of autumn and spring.

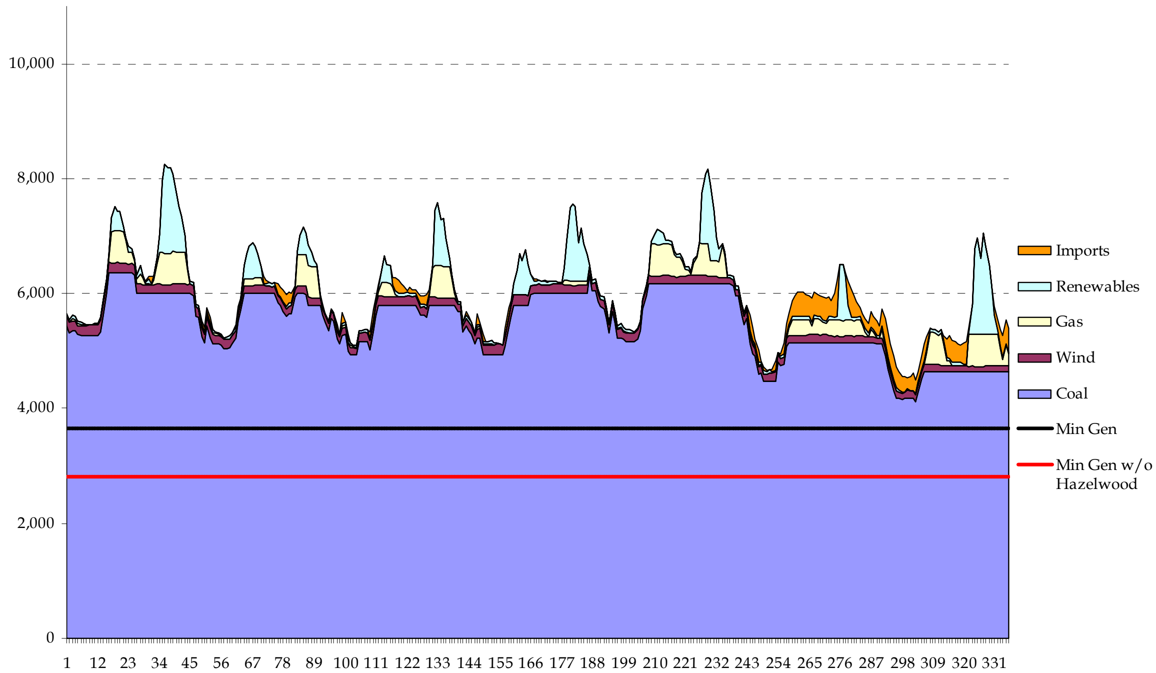
In the cases where aggregate coal generation falls beneath the aggregate minimum coal generation level, we have also included a graph of unused gas and hydro capacity (e.g. Figure 6-21 and Figure 6-24) directly following the generation profile graph. All of these graphs show that there are sufficient levels of unused fast-start gas[27] and hydro capacity in Victoria to cover the maximum half-hourly swing in wind generation if coal generation is crowded out of the market by wind.

Under Scenario 3, the graphs show that the additional wind capacity would crowd out Hazelwood during spring and autumn in both 2014/15 and 2019/20, since the level of coal generation

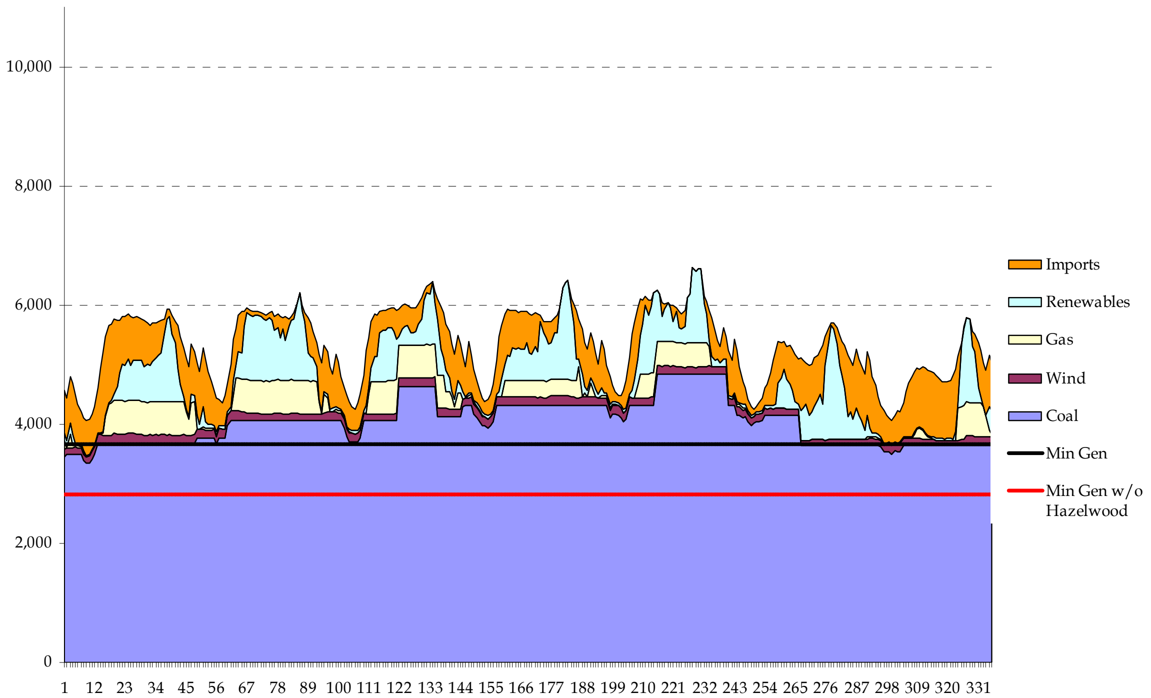
27 Only fast-staring gas turbine capacity is factored into this calculation. In other words, the capacity of Newport power station is not included.

frequently dips below the aggregate Victorian minimum generation level. This effect is even more severe under Scenario 5, where brown coal generation can also dip below the aggregate minimum generation level excluding the Hazelwood power station in spring and autumn of both years.

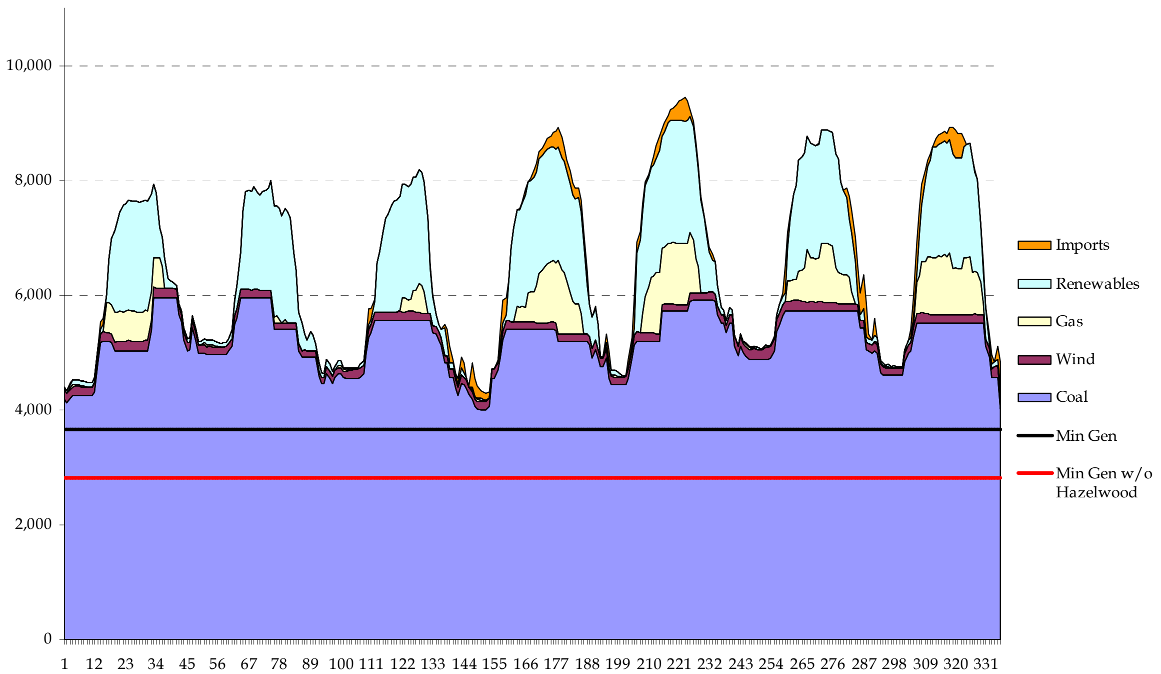
■ **Figure 6-11 Victorian weekly generation profile for Winter 2014/15, Scenario 1**



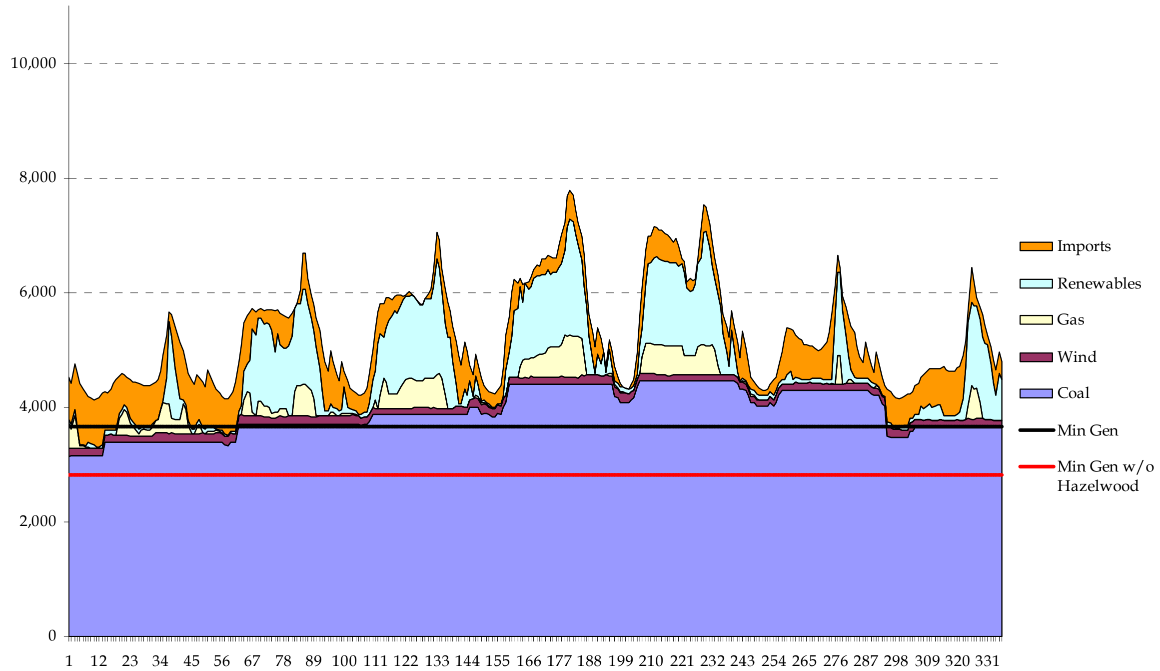
▪ **Figure 6-12 Victorian weekly generation profile for Spring 2014/15, Scenario 1**



▪ **Figure 6-13 Victorian weekly generation profile for Summer 2014/15, Scenario 1**



- **Figure 6-14 Victorian weekly generation profile for Autumn 2014/15, Scenario 1**



- **Figure 6-15 Victorian weekly generation profile for Winter 2019/20, Scenario 1**

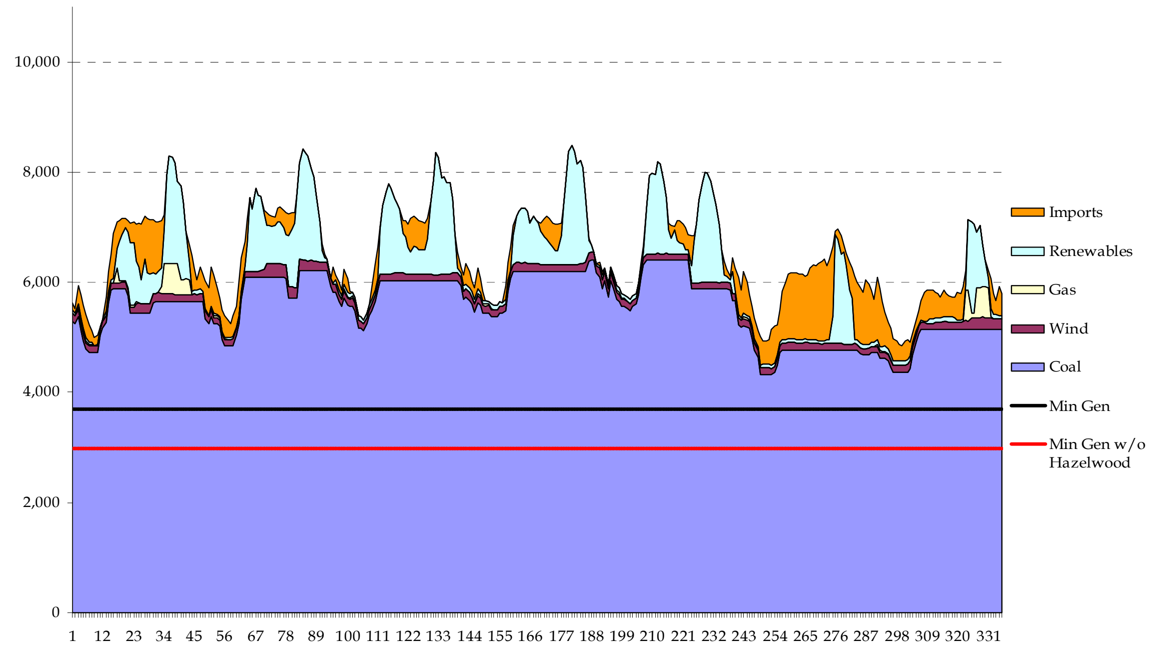


Figure 6-16 Victorian weekly generation profile for Spring 2019/20, Scenario 1

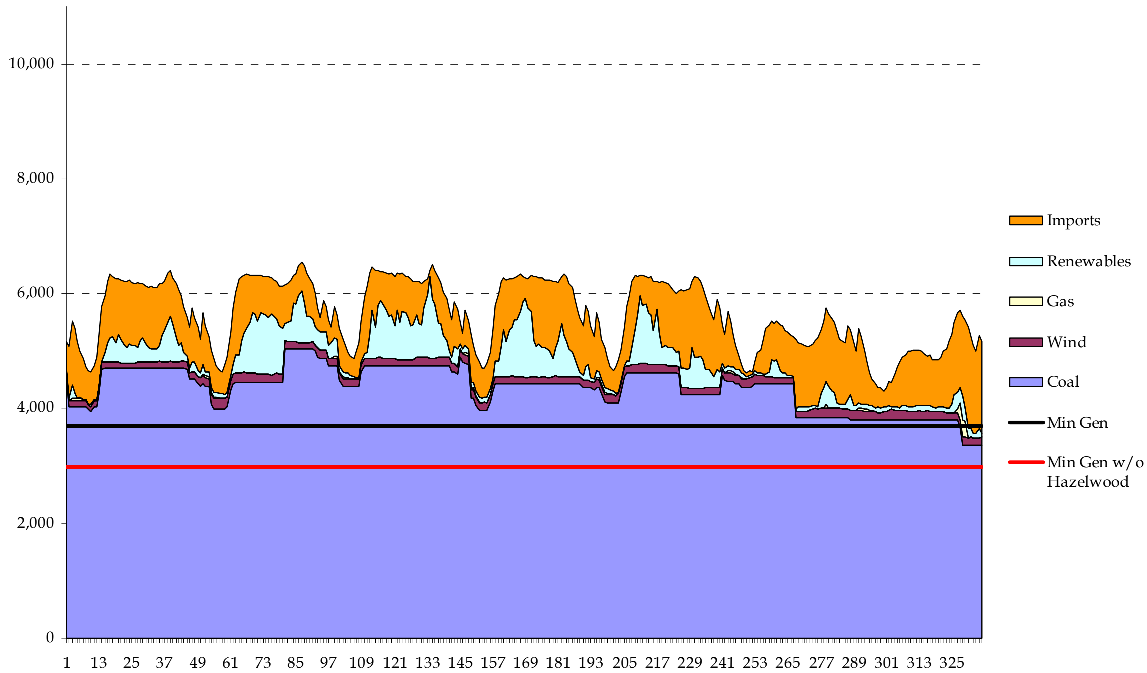
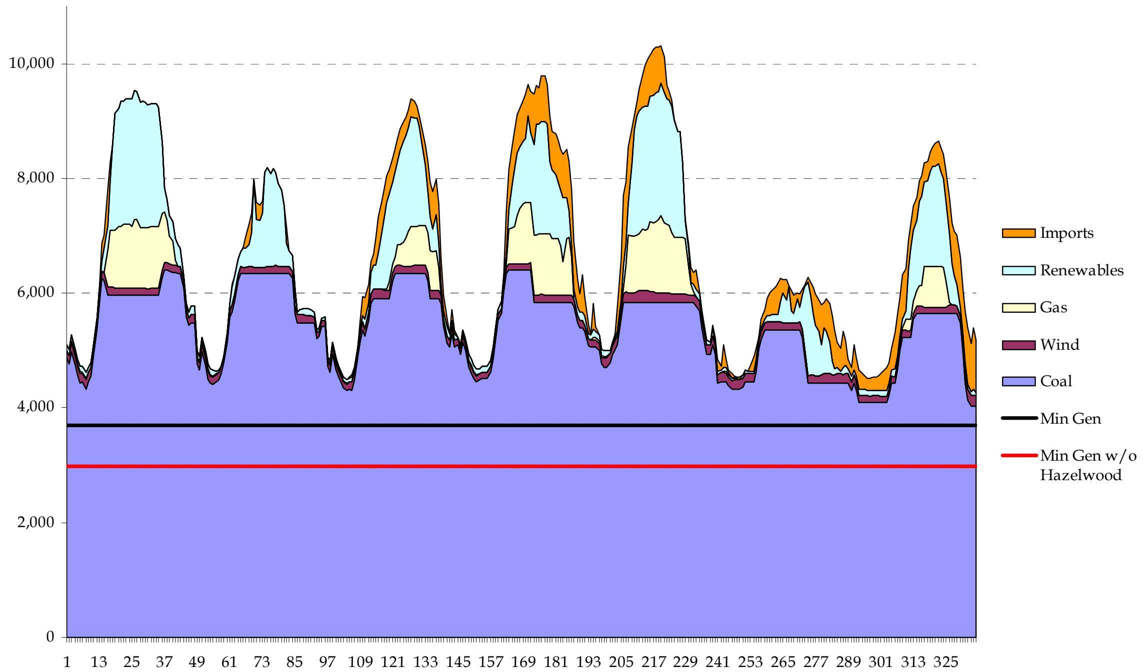


Figure 6-17 Victorian weekly generation profile for Summer 2019/20, Scenario 1



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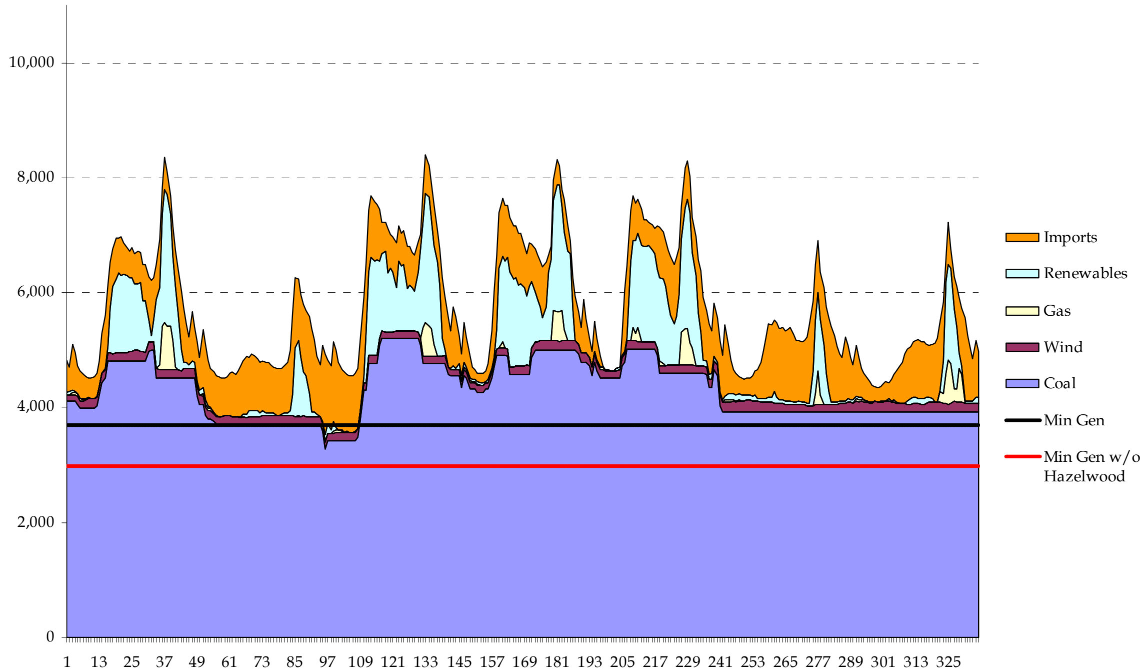
- **Figure 6-18 Victorian weekly generation profile for Autumn 2019/20, Scenario 1**



- **Figure 6-19 Victorian weekly generation profile for Winter 2014/15, Scenario 3**

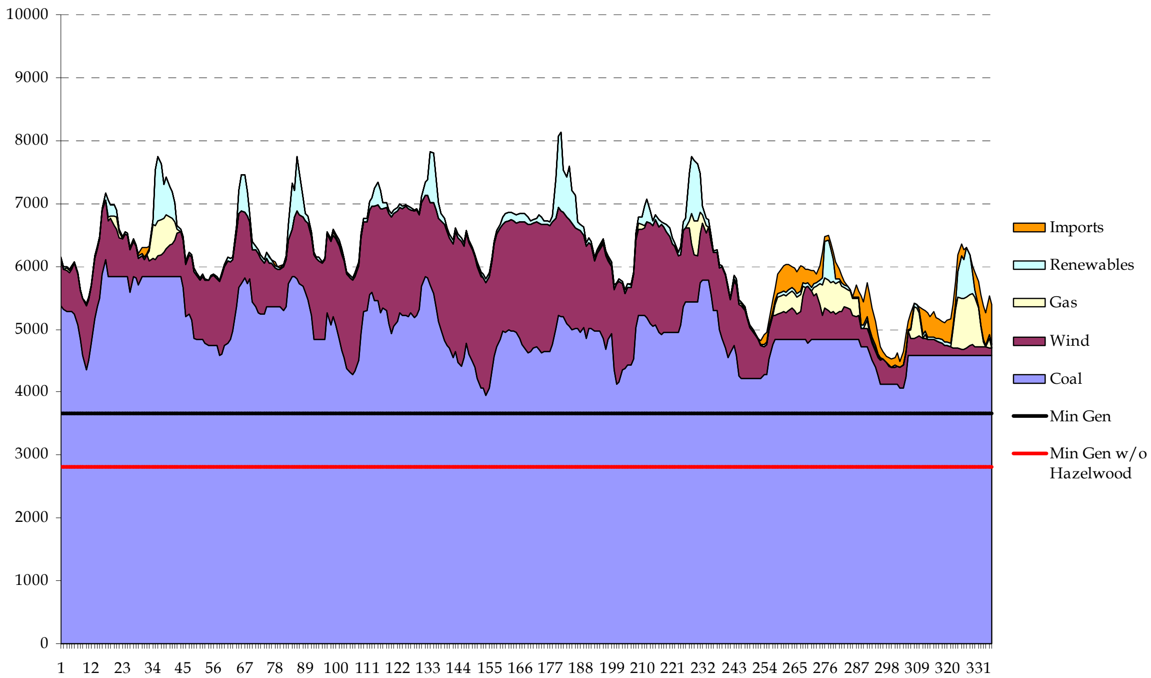


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Figure 6-20 Victorian weekly generation profile for Spring 2014/15, Scenario 3

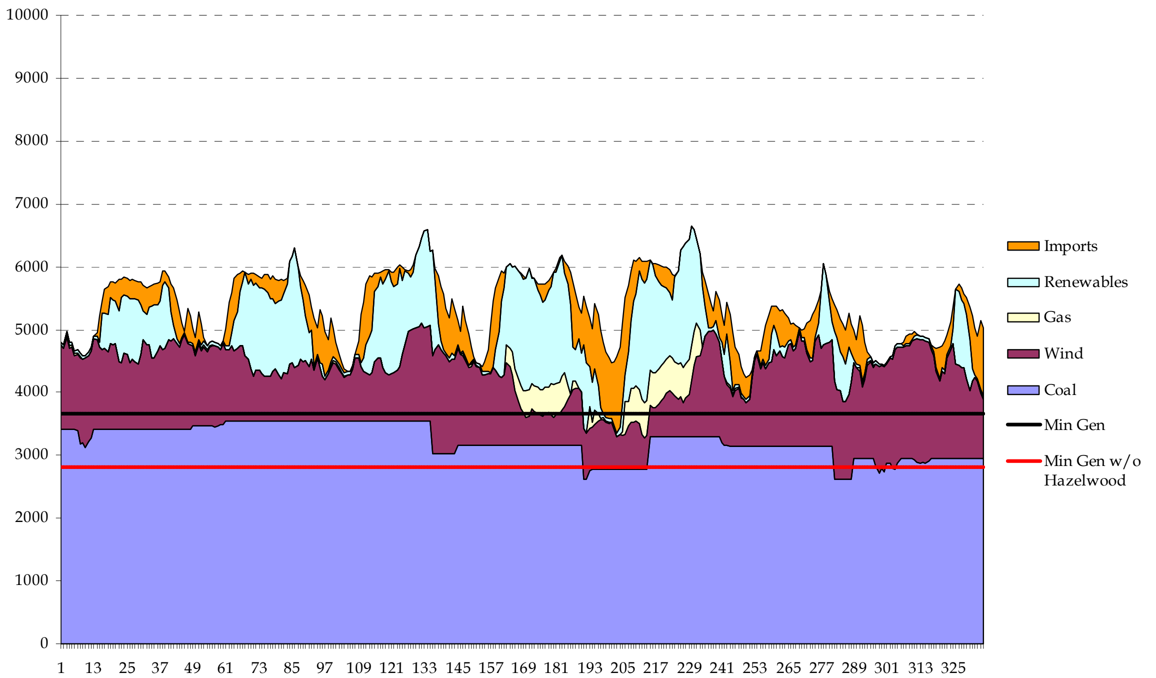
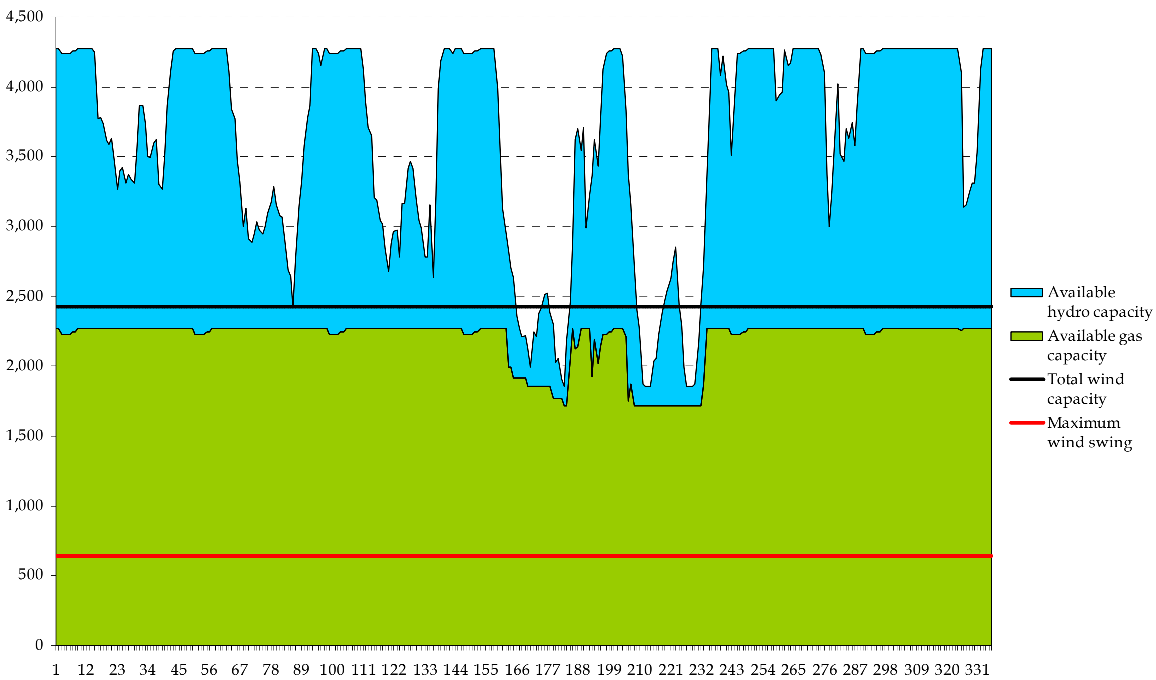


Figure 6-21 Unused gas and hydro capacity for Spring 2014/15, Scenario 3



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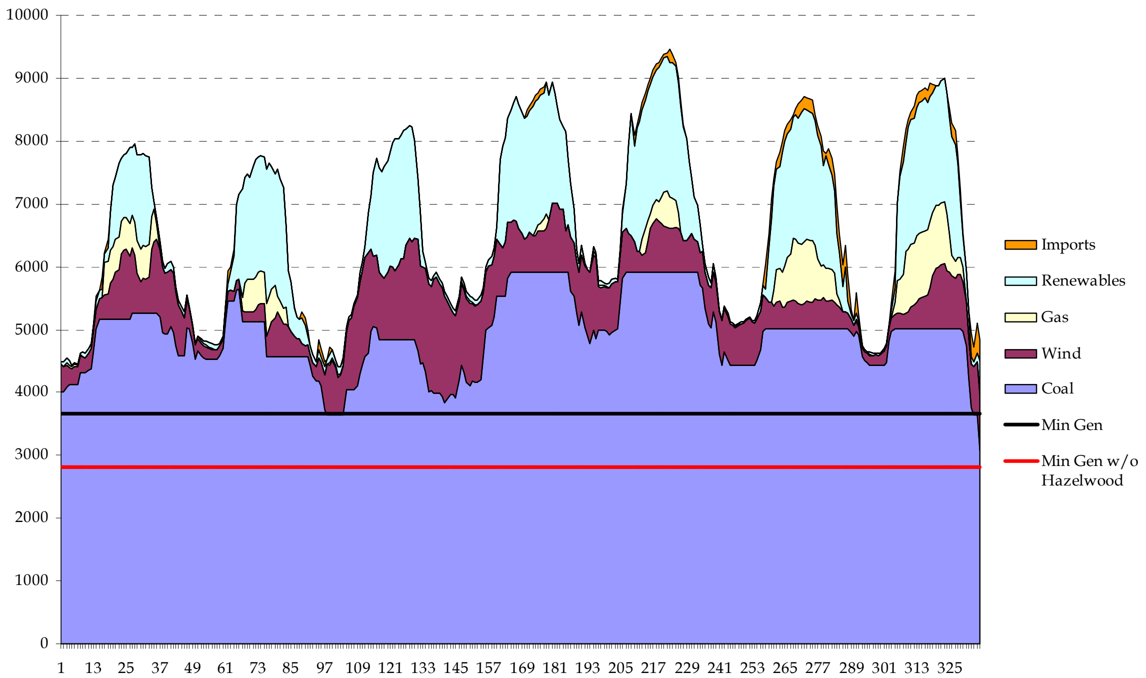
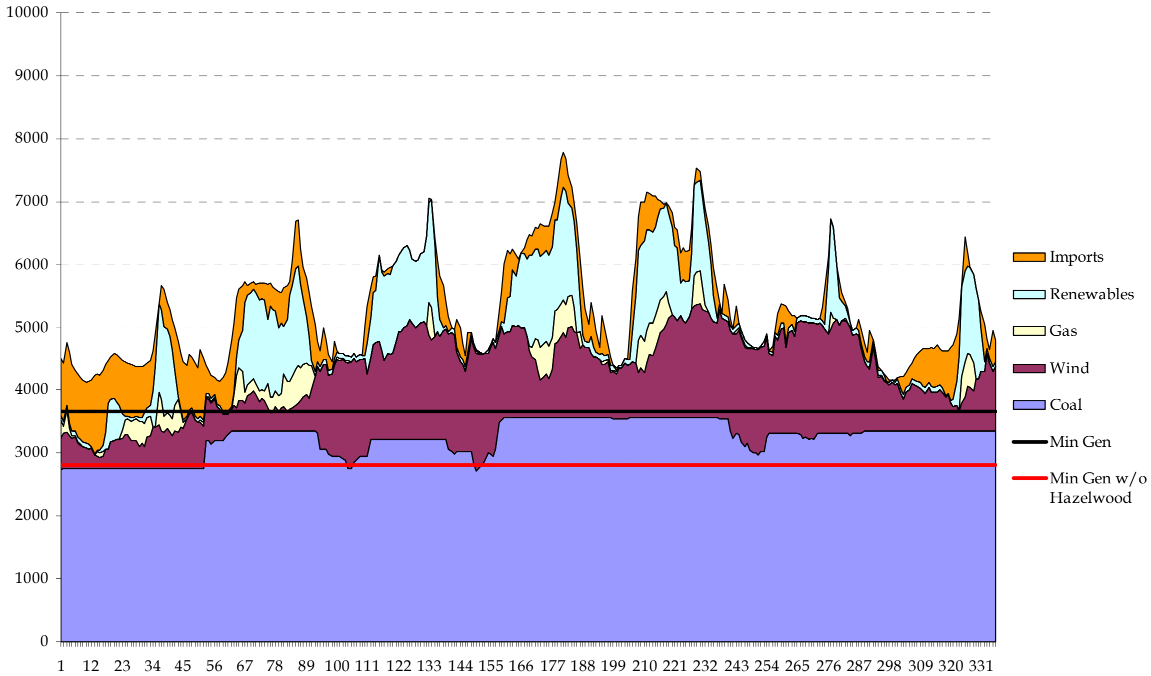
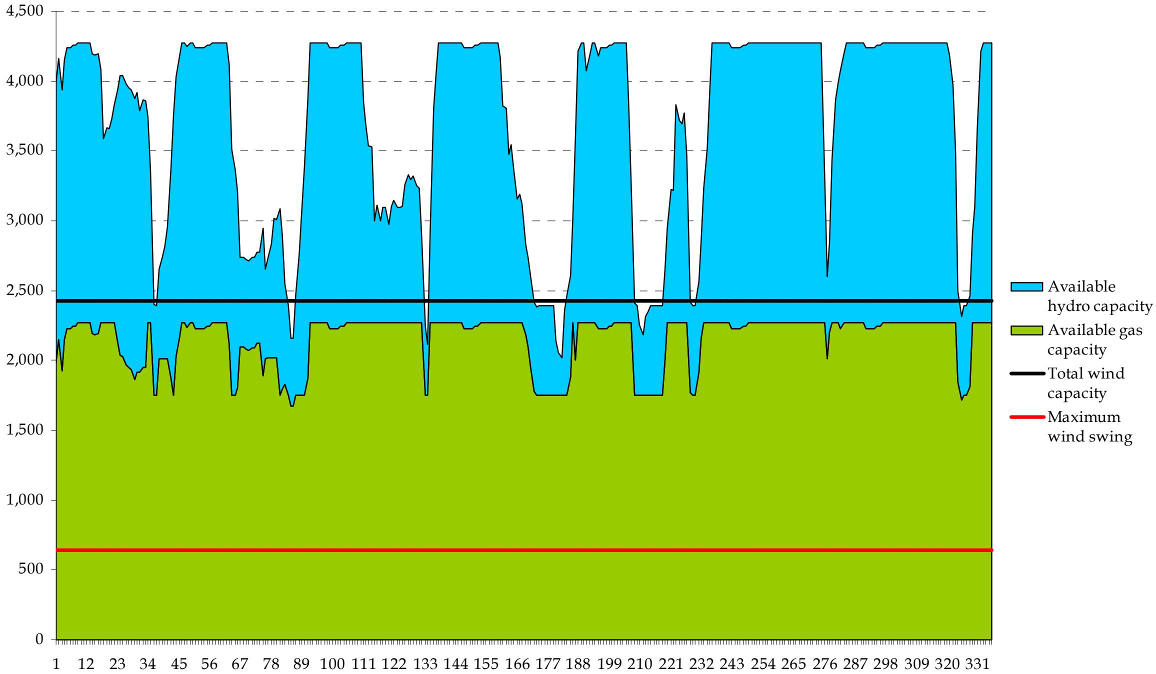
- **Figure 6-22 Victorian weekly generation profile for Summer 2014/15, Scenario 3**



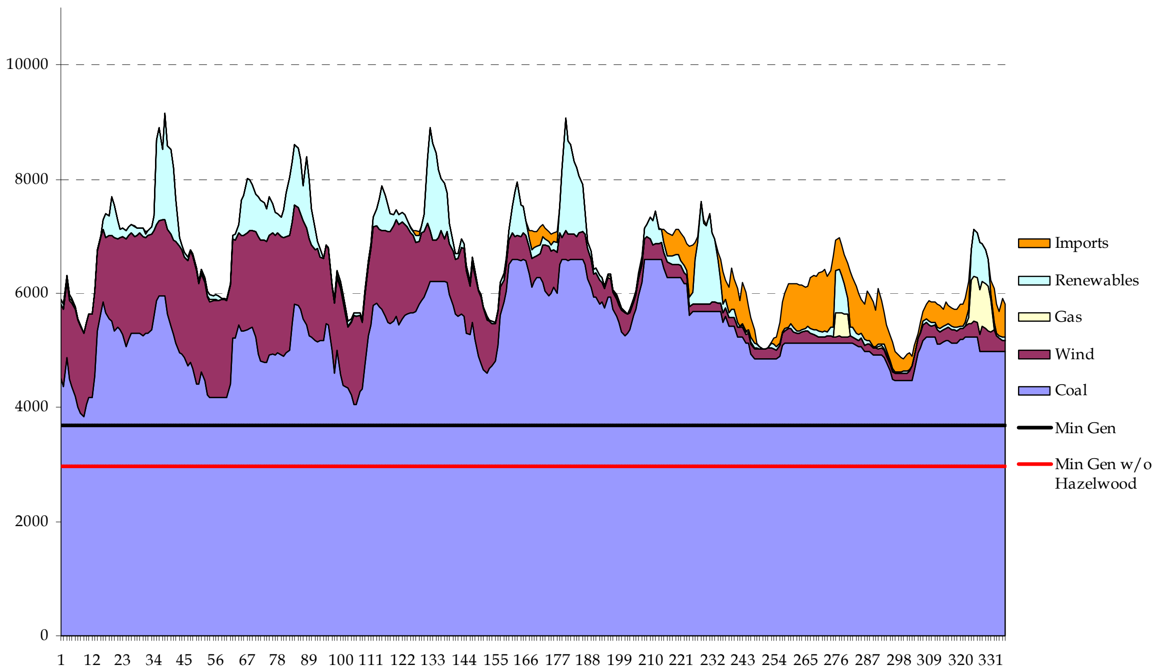
- **Figure 6-23 Victorian weekly generation profile for Autumn 2014/15, Scenario 3**



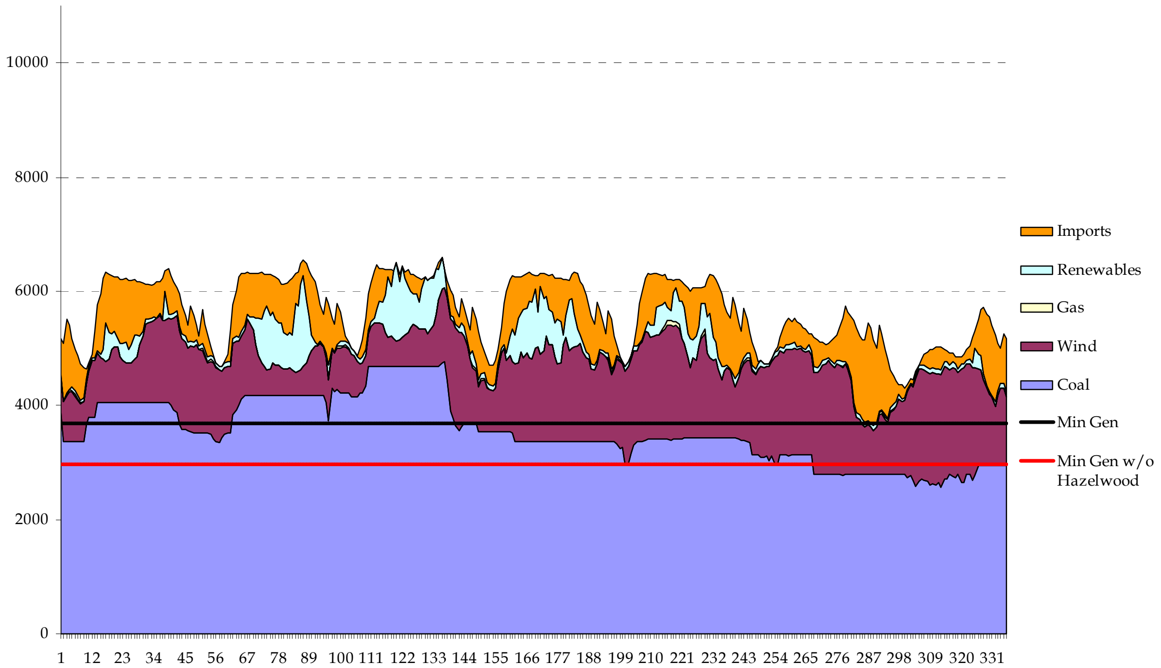
- **Figure 6-24 Unused gas and hydro capacity for Autumn 2014/15, Scenario 3**



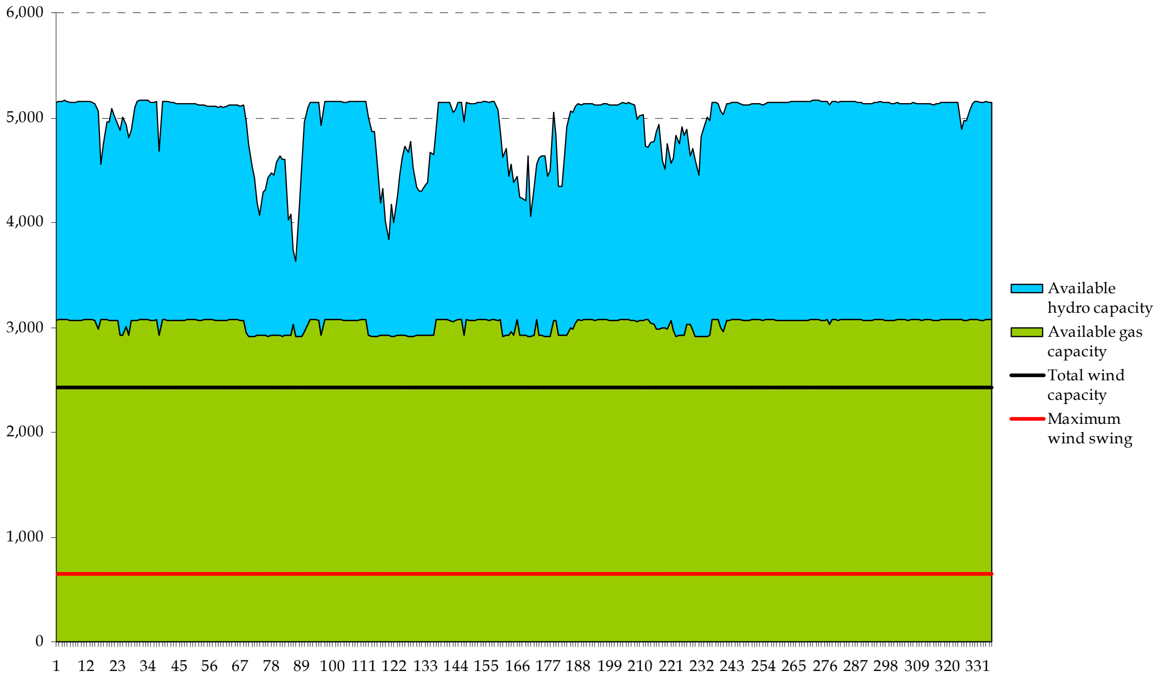
- **Figure 6-25 Victorian weekly generation profile for Winter 2019/20, Scenario 3**



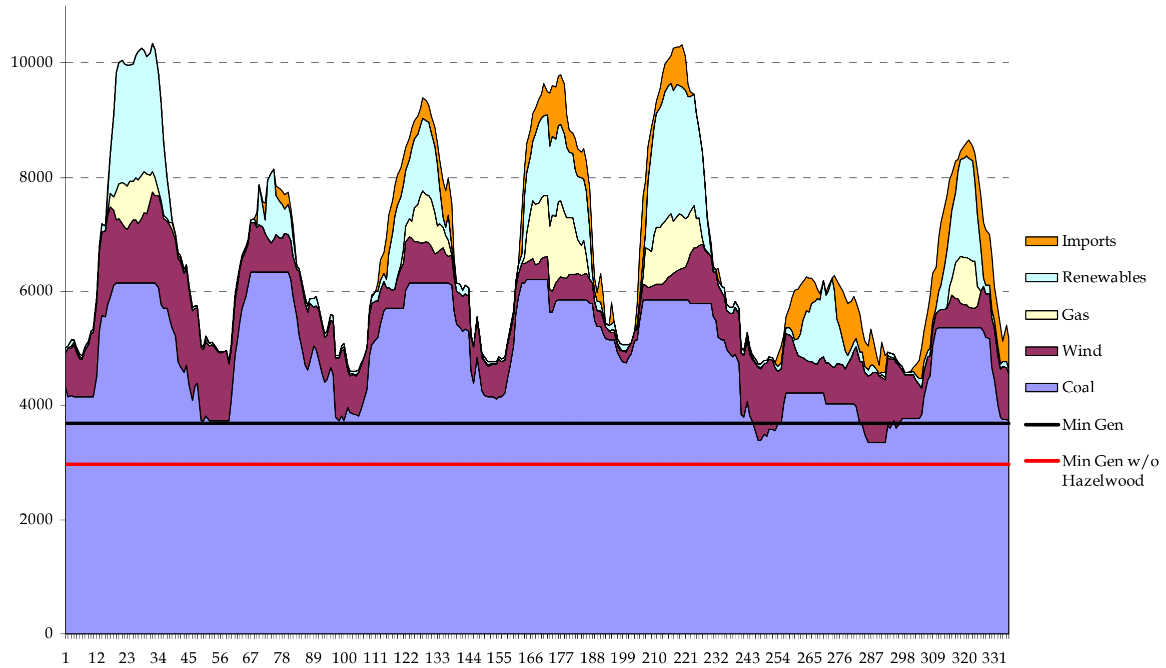
- **Figure 6-26 Victorian weekly generation profile for Spring 2019/20, Scenario 3**



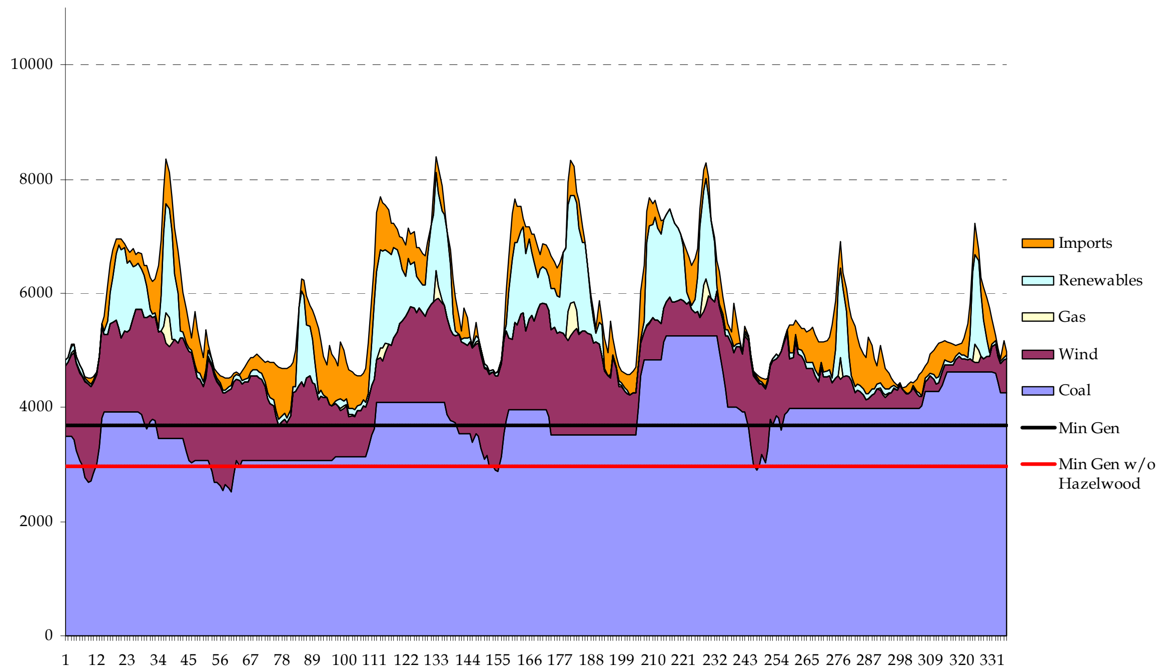
- **Figure 6-27 Unused gas and hydro capacity for Spring 2019/20, Scenario 3**



- **Figure 6-28 Victorian weekly generation profile for Summer 2019/20, Scenario 3**



- **Figure 6-29 Victorian weekly generation profile for Autumn 2019/20, Scenario 3**



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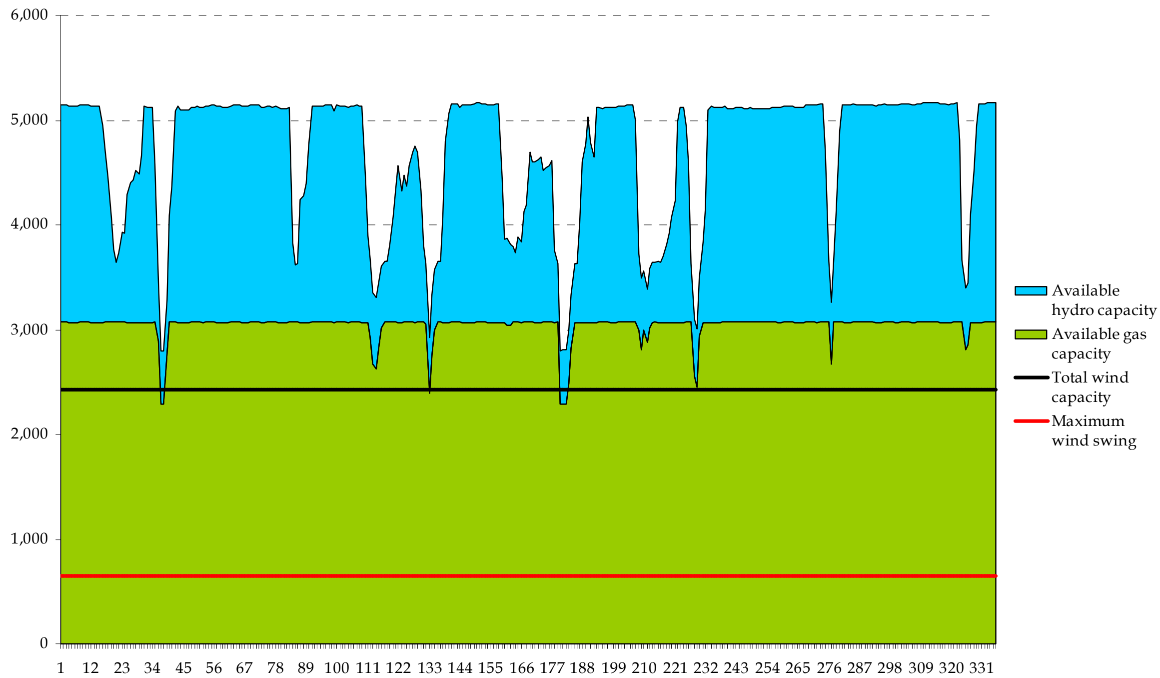
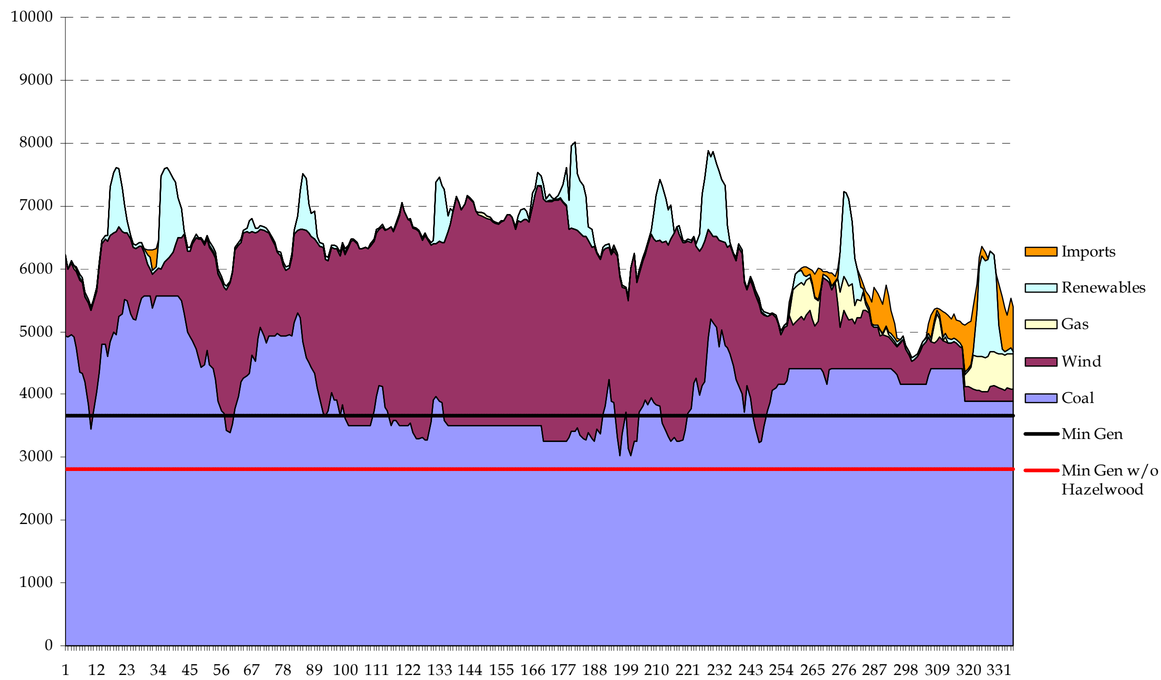
- **Figure 6-30 Unused gas and hydro capacity for Autumn 2019/20, Scenario 3**



- **Figure 6-31 Victorian weekly generation profile for Winter 2014/15, Scenario 5**



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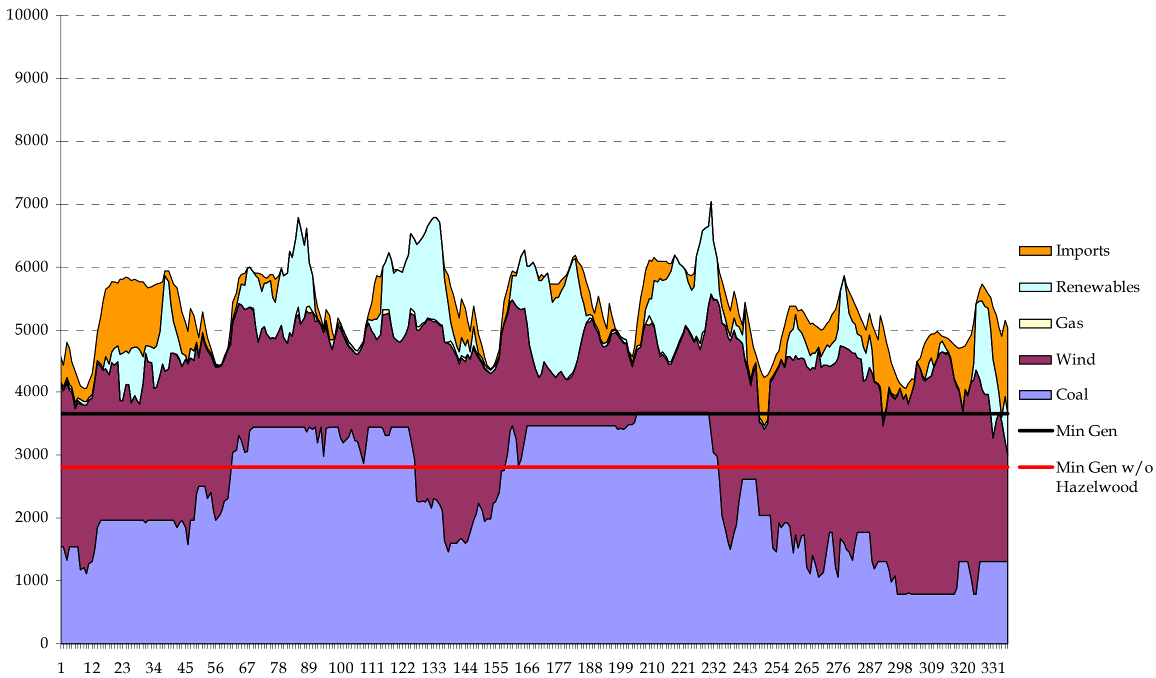
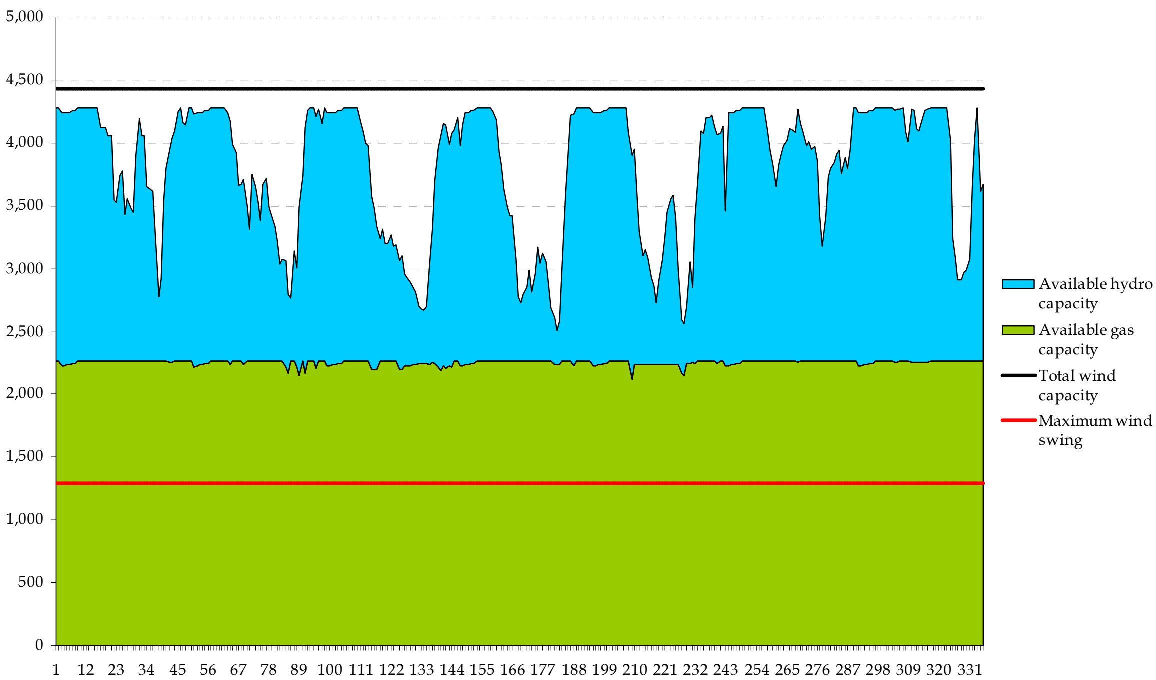
- **Figure 6-32 Victorian weekly generation profile for Spring 2014/15, Scenario 5**



- **Figure 6-33 Unused gas and hydro capacity for Spring 2014/15, Scenario 5**



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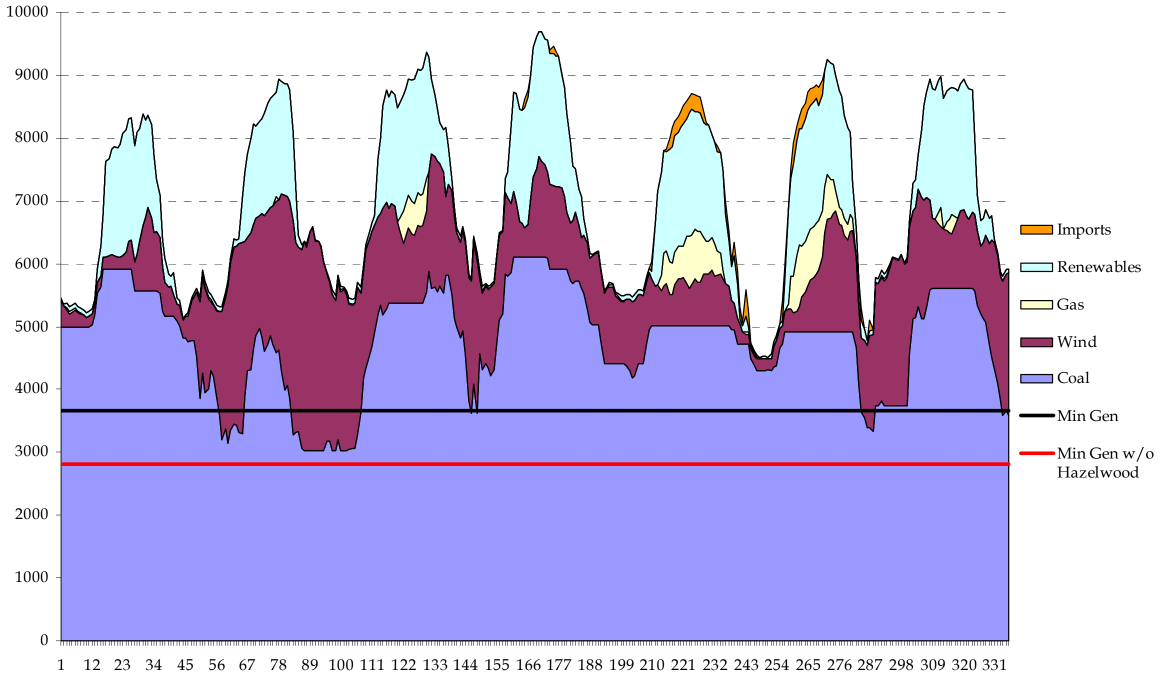
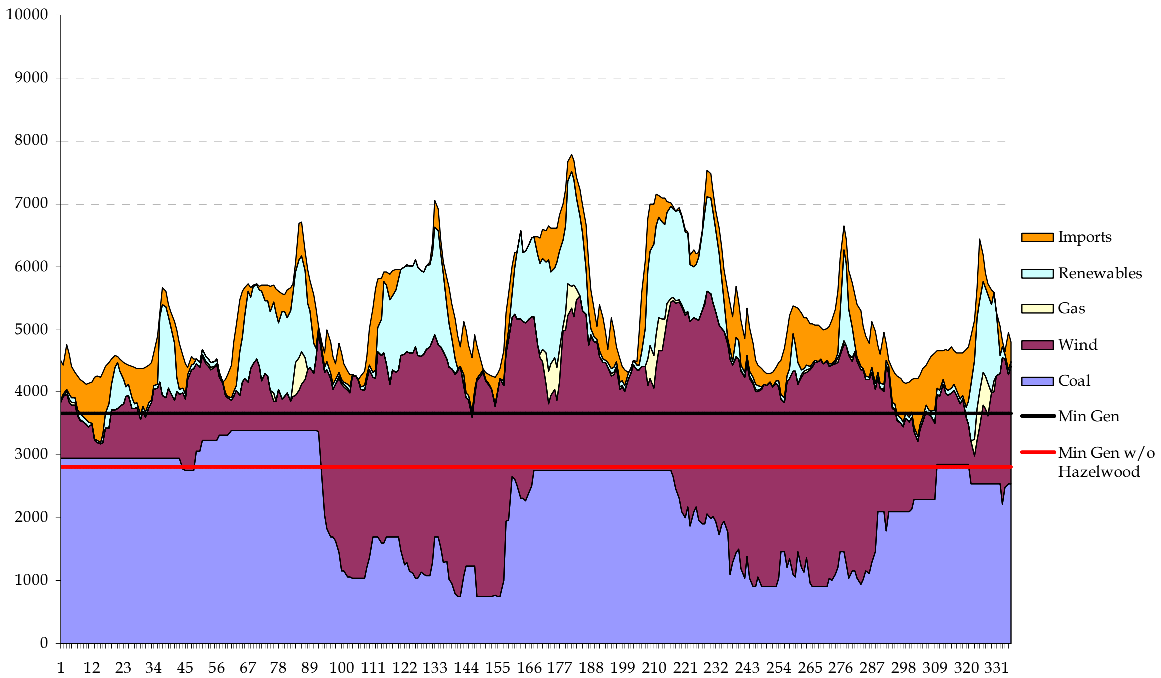
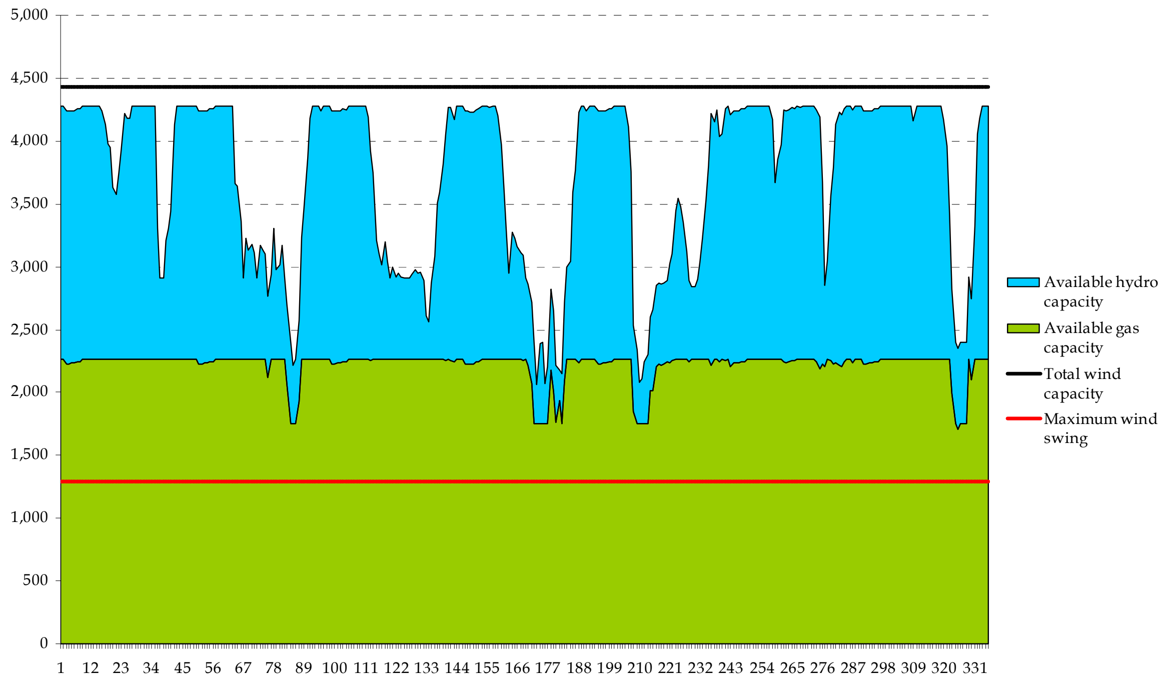
▪ **Figure 6-34 Victorian weekly generation profile for Summer 2014/15, Scenario 5**



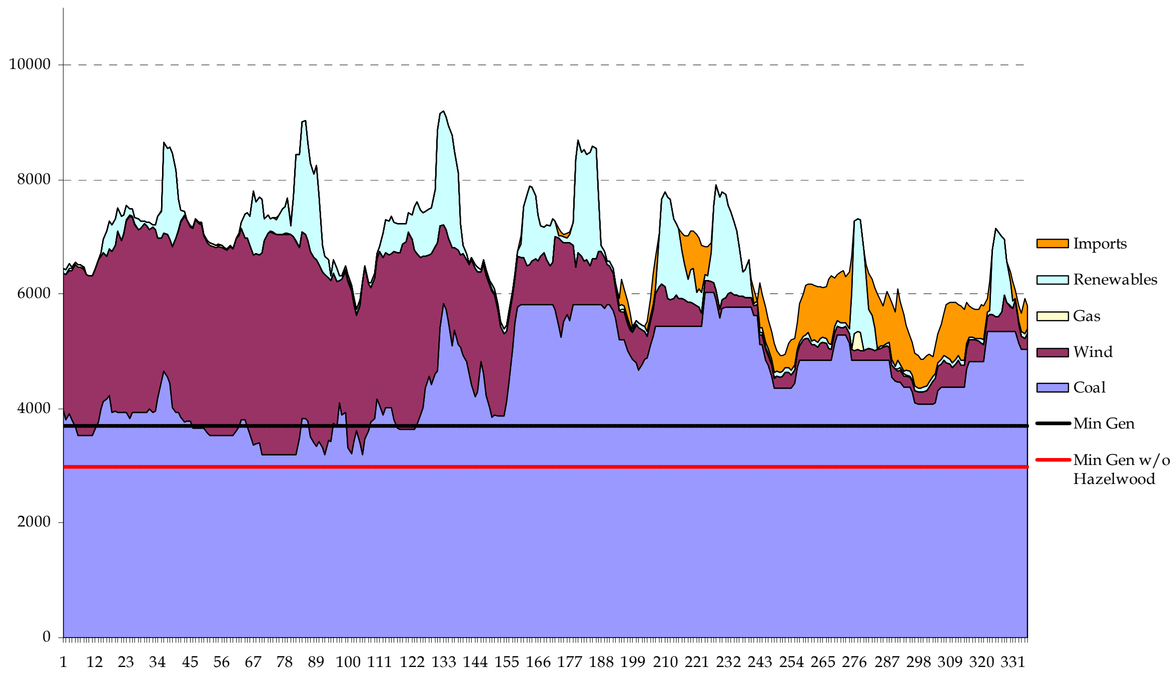
▪ **Figure 6-35 Victorian weekly generation profile for Autumn 2014/15, Scenario 5**



▪ **Figure 6-36 Unused gas and hydro capacity for Autumn 2014/15, Scenario 5**



▪ **Figure 6-37 Victorian weekly generation profile for Winter 2019/20, Scenario 5**



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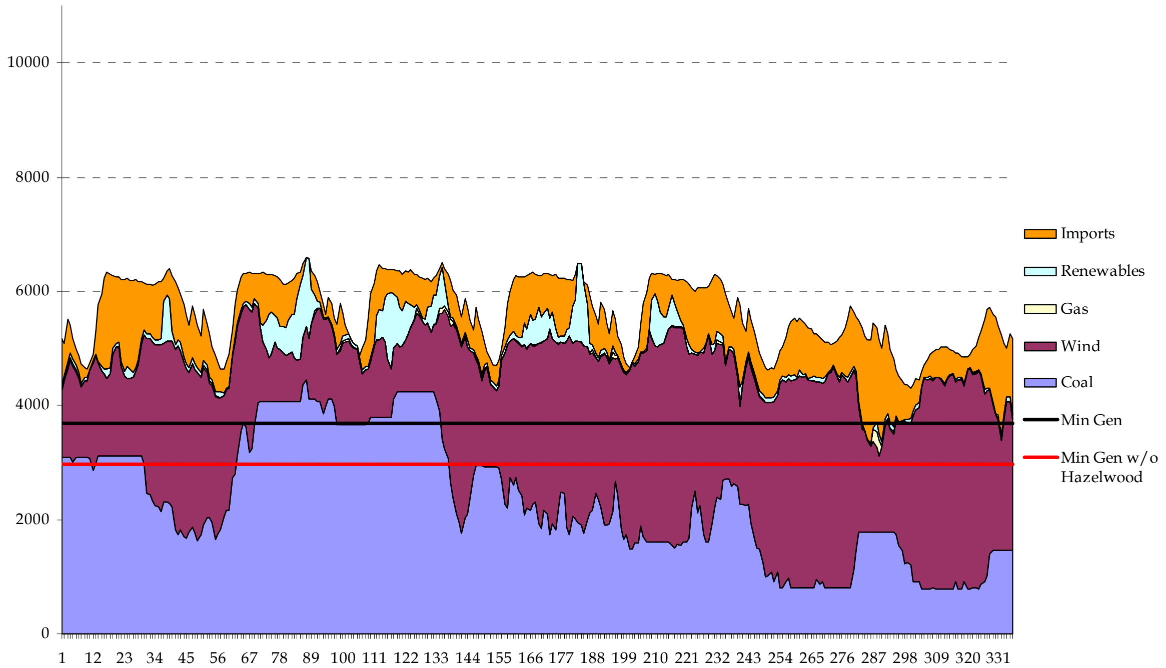
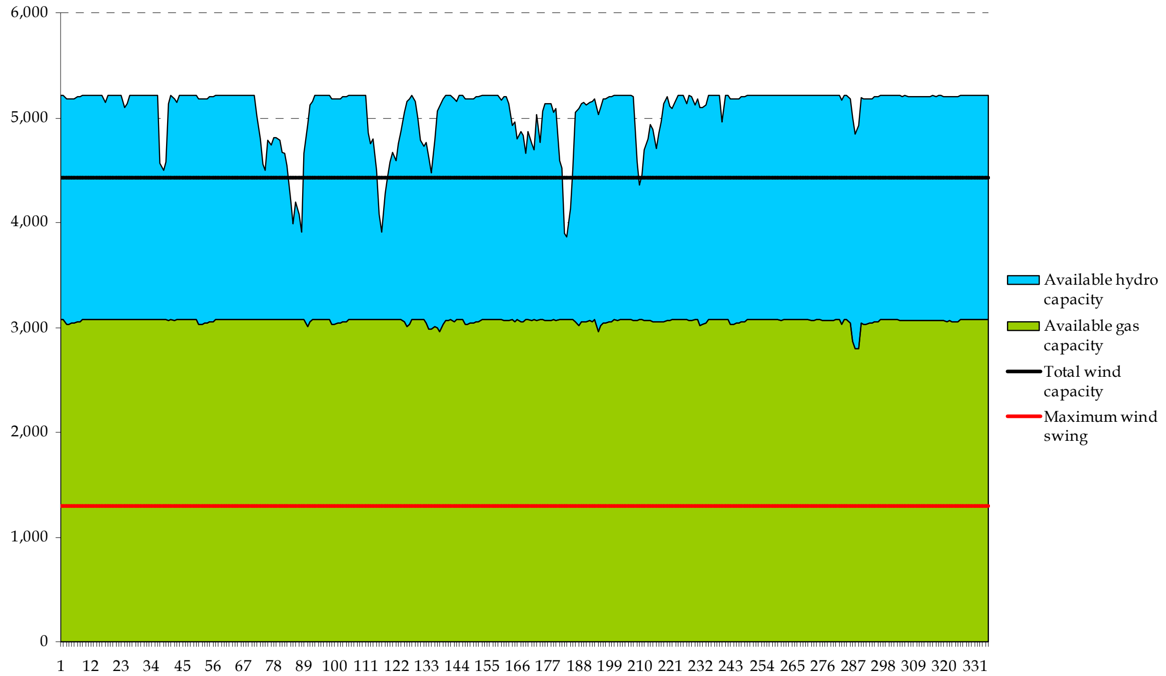
- **Figure 6-38 Victorian weekly generation profile for Spring 2019/20, Scenario 5**



- **Figure 6-39 Unused gas and hydro capacity for Spring 2019/20, Scenario 5**



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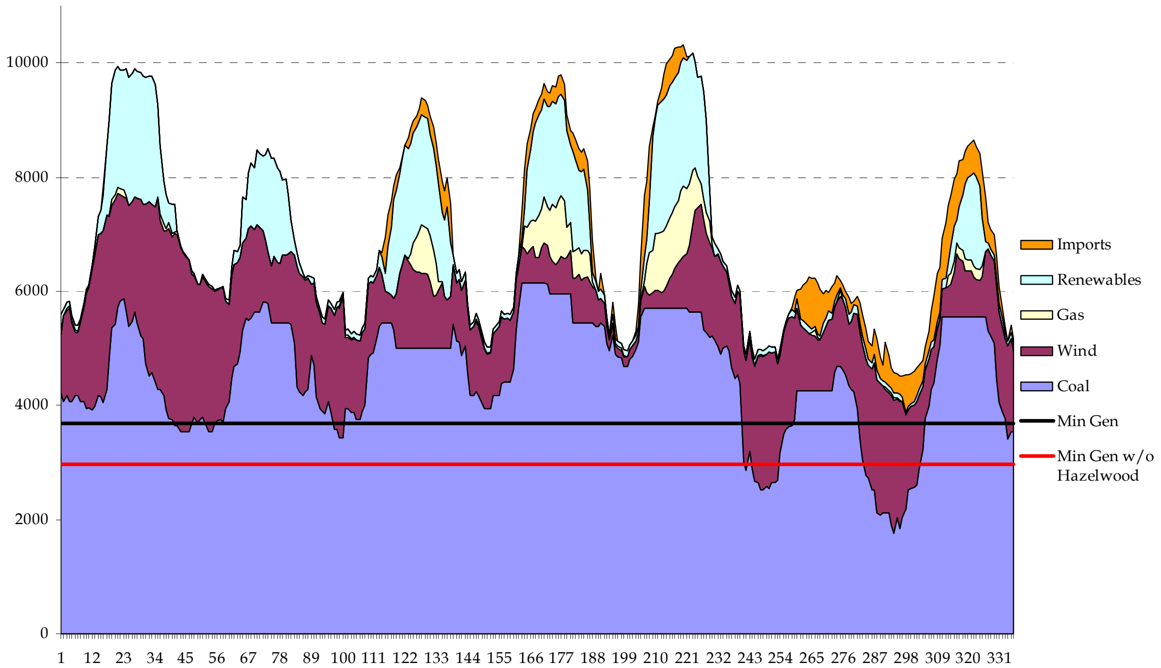
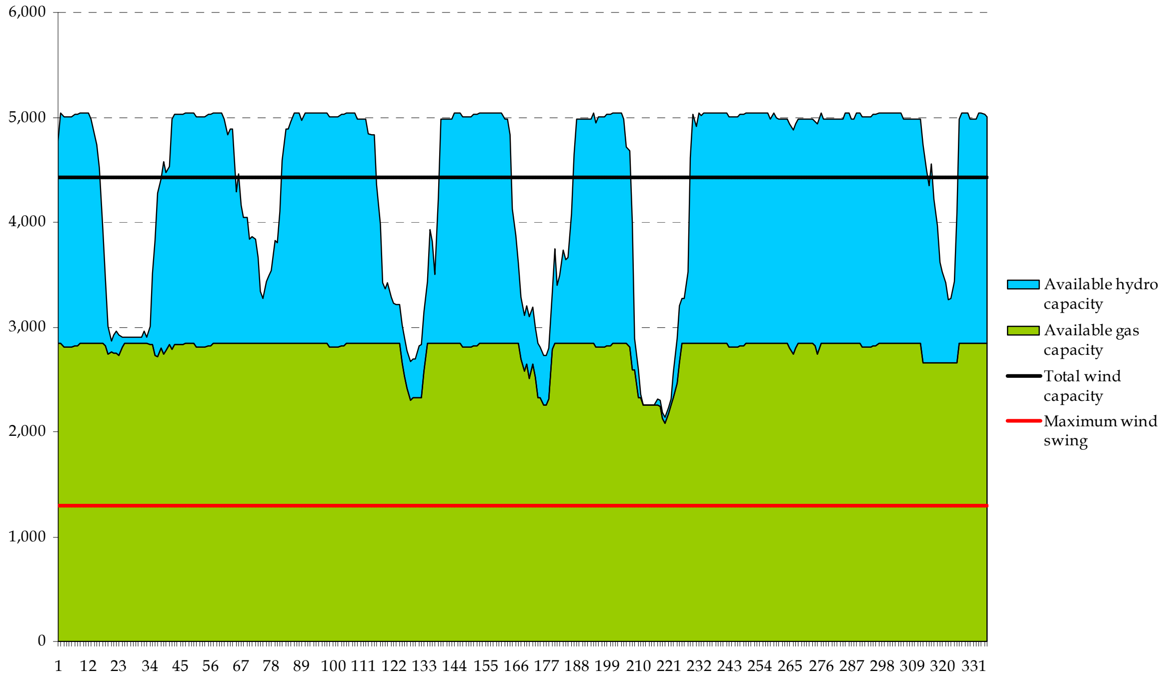
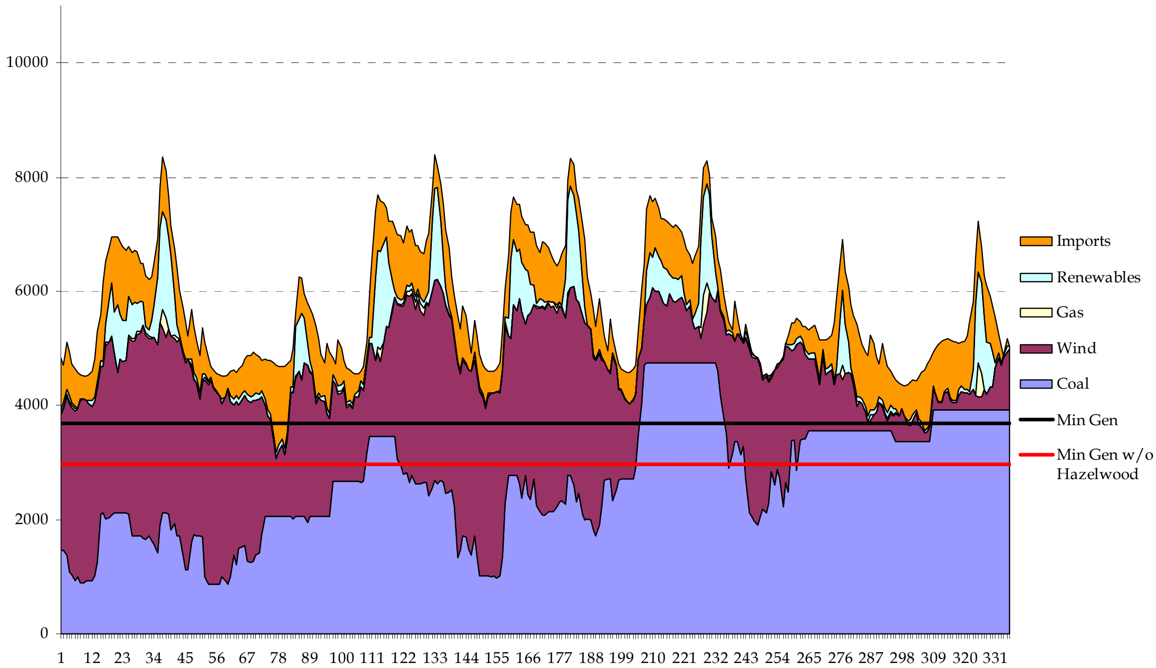
- **Figure 6-40 Victorian weekly generation profile for Summer 2019/20, Scenario 5**



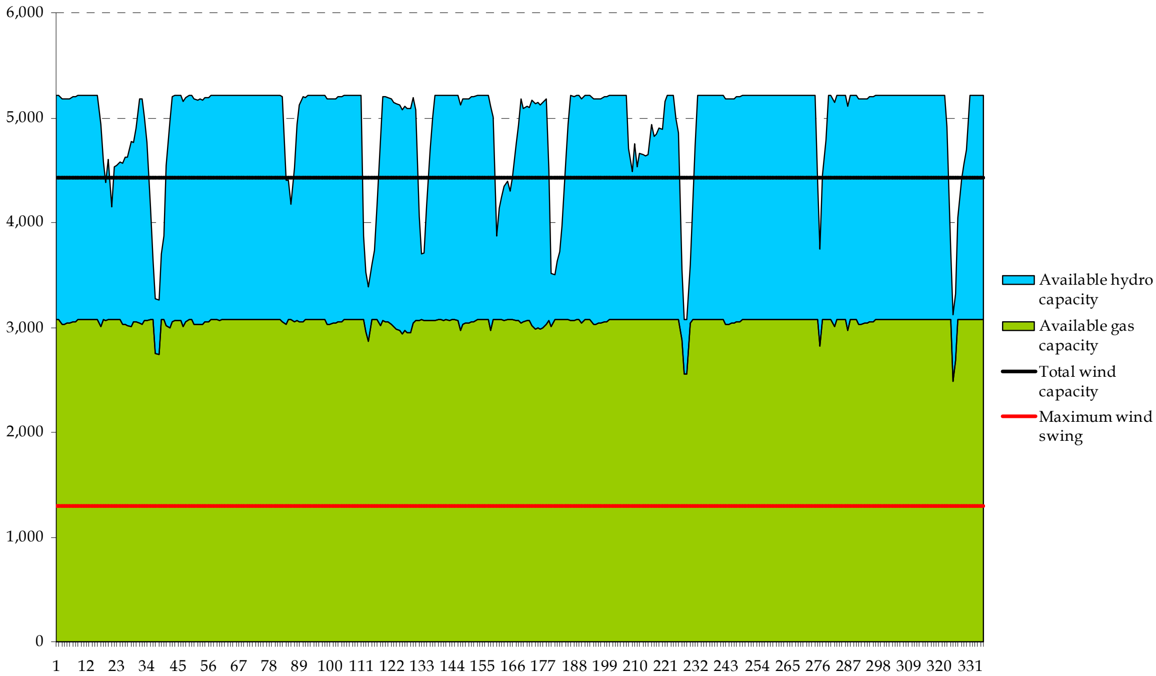
- **Figure 6-41 Unused gas and hydro capacity for Summer 2019/20, Scenario 5**



- **Figure 6-42 Victorian weekly generation profile for Autumn 2019/20, Scenario 5**



- **Figure 6-43 Unused gas and hydro capacity for Autumn 2019/20, Scenario 5**



6.4. Large swings in wind generation

Figure 6-44 to Figure 6-51 show the largest half-hourly drop and gain in wind generation in 2014/15 and 2019/20 for Scenarios 3 and 5. Note that positive demand in this graph represents demand reduction. It is important to note that the largest half-hourly swings in wind generation are about one third of the total installed wind capacity in Victoria. This arises because of the geographic diversity of the wind assets[28], which tends to smooth out sudden changes in wind speed and/or direction. Of particular interest are the largest drops in wind generation, which are handled differently according to the level of installed wind capacity. At 2,000 MW of additional wind capacity, it is clear that these drops are handled by a combination of ramping up of other renewable generation (mainly the Murray generating units) and increased imports into Victoria. However, under the 4,000 MW wind scenario, brown coal tends to play the primary role in responding to large swings, whereas other renewable energy and imports are used to a lesser degree. It is significant that virtually no ramping by gas-fired generation is called upon to handle these swings in wind generation, even at 4,000 MW of installed capacity. This implies that there is ample thermal capacity in Victoria[29] to adequately deal with the swings in generation output associated with large amounts of wind capacity.

[28] Our modelling is conservative in this respect since it is based on wind traces from only three sites, two of which are within 50 kilometers of each other. We would expect to see even greater diversity if 2,000 MW or 4,000 MW of wind was actually installed in Victoria.

[29] There is almost 3,500 MW of gas-fired generation capacity in Victoria by 2020, including over 1100 MW of new GTs, not including Mortlake.

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Figure 6-44 Largest half-hourly drop in wind generation 2014/15, Scenario 3

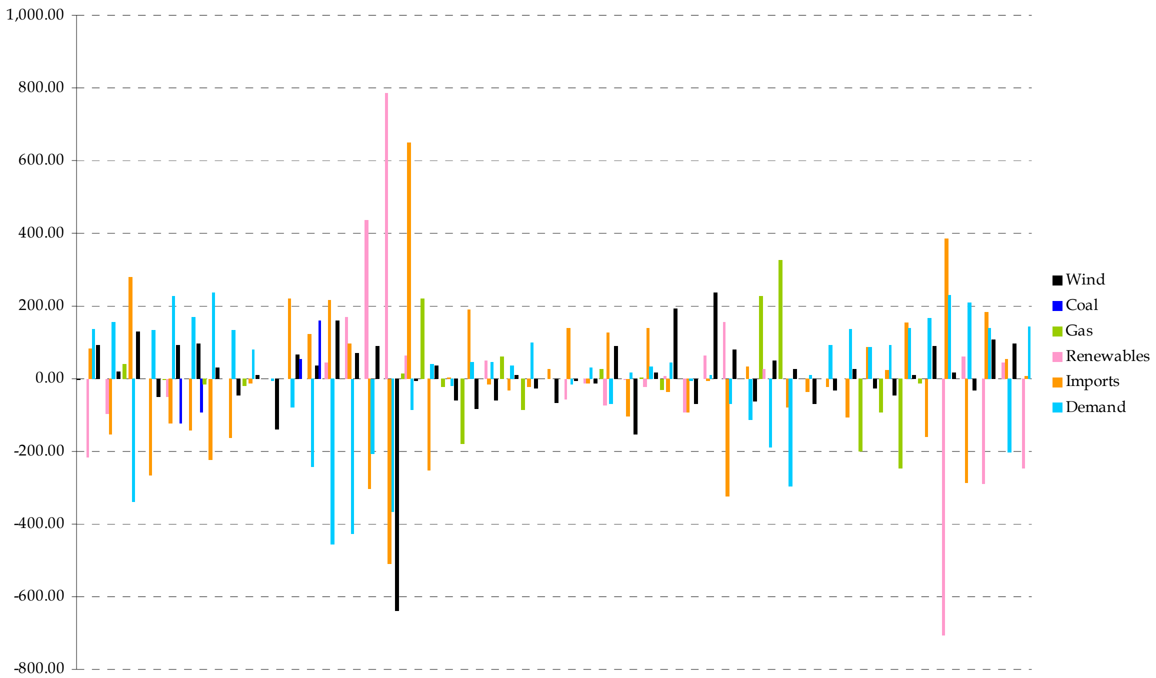
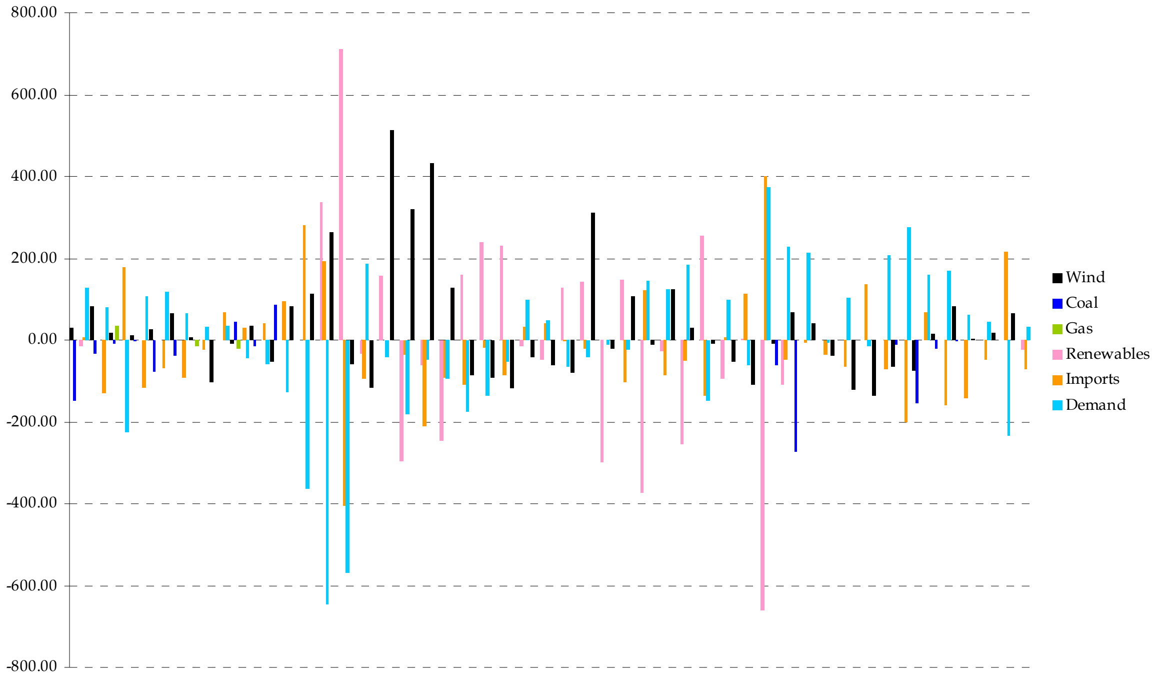


Figure 6-45 Largest half-hourly gain in wind generation 2014/15, Scenario 3



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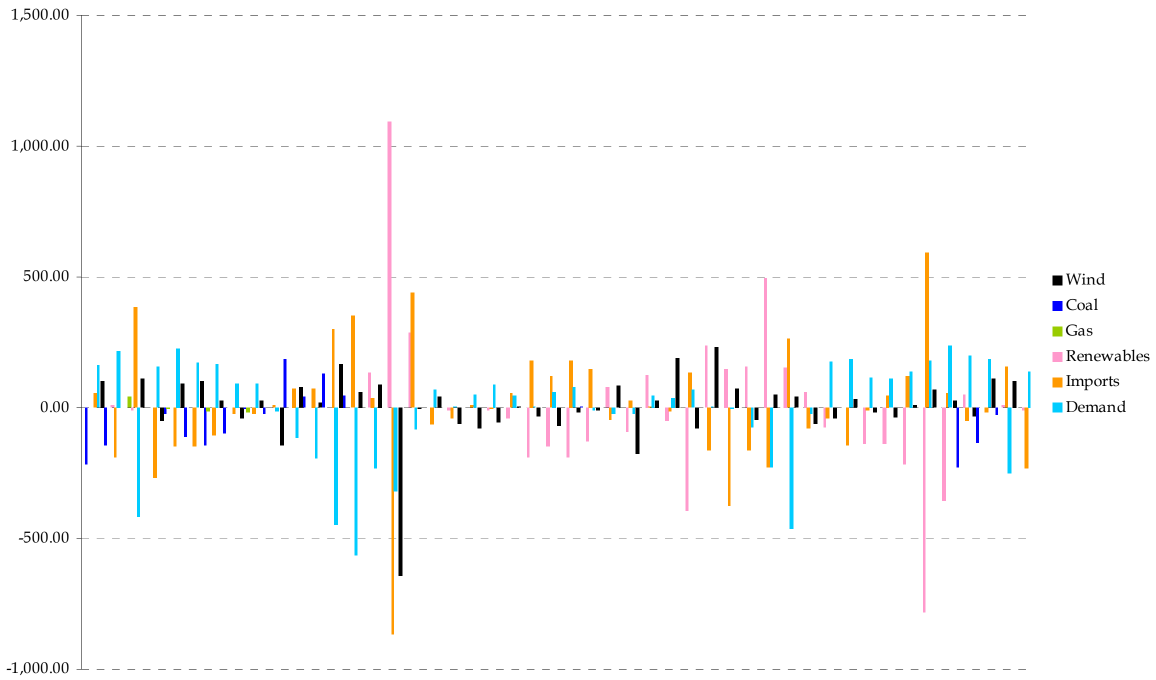
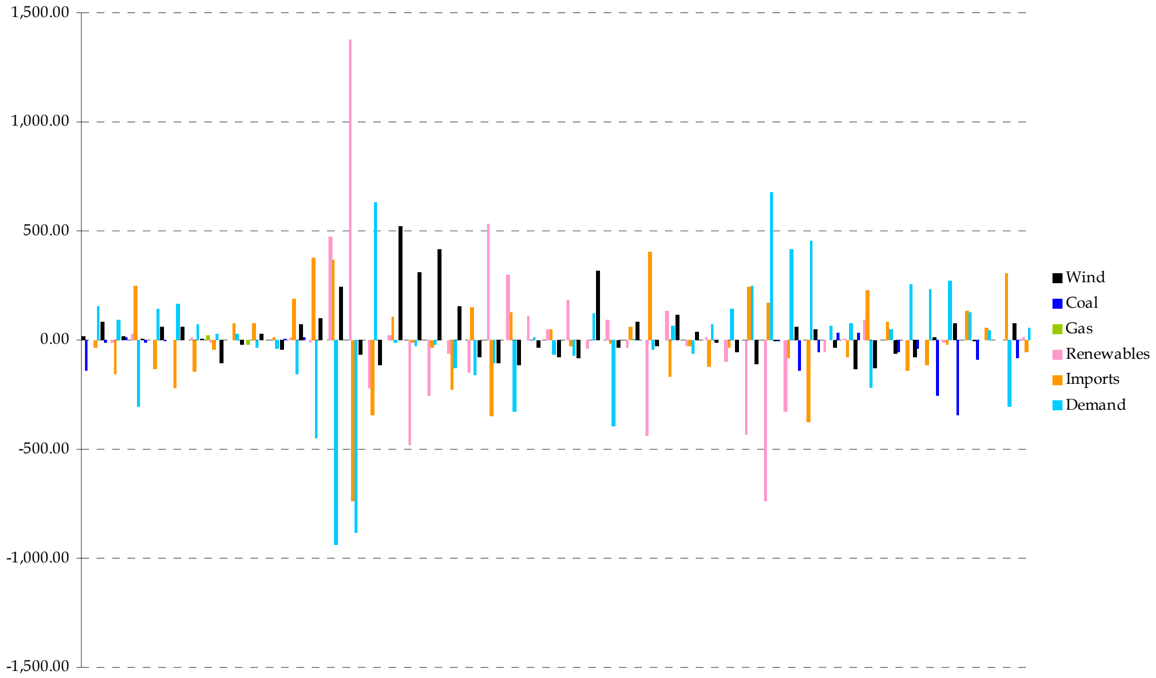
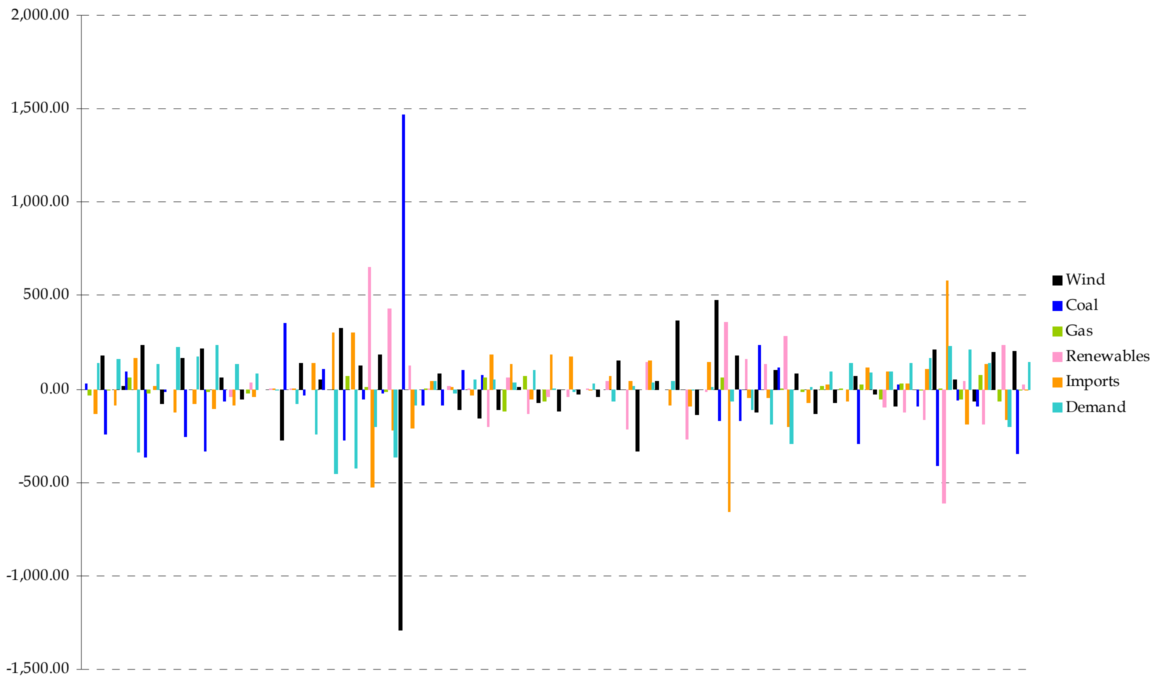
- **Figure 6-46 Largest half-hourly drop in wind generation 2019/20, Scenario 3**



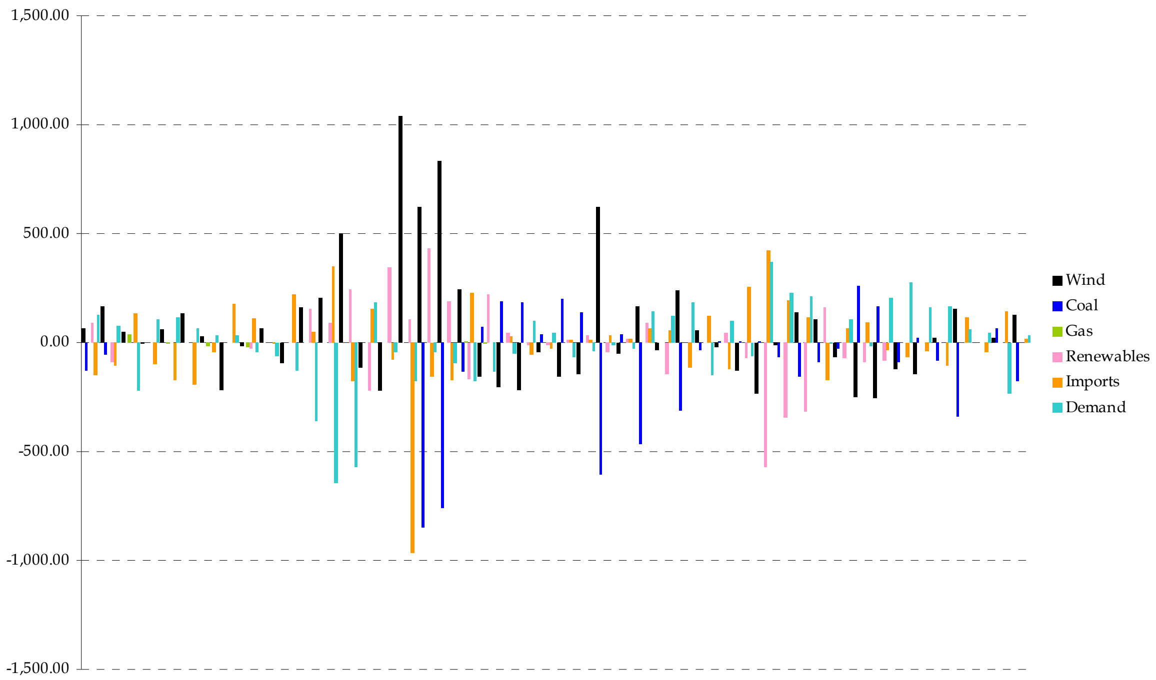
- **Figure 6-47 Largest half-hourly gain in wind generation 2019/20, Scenario 3**



■ **Figure 6-48 Largest half-hourly drop in wind generation 2014/15, Scenario 5**



■ **Figure 6-49 Largest half-hourly gain in wind generation 2014/15, Scenario 5**



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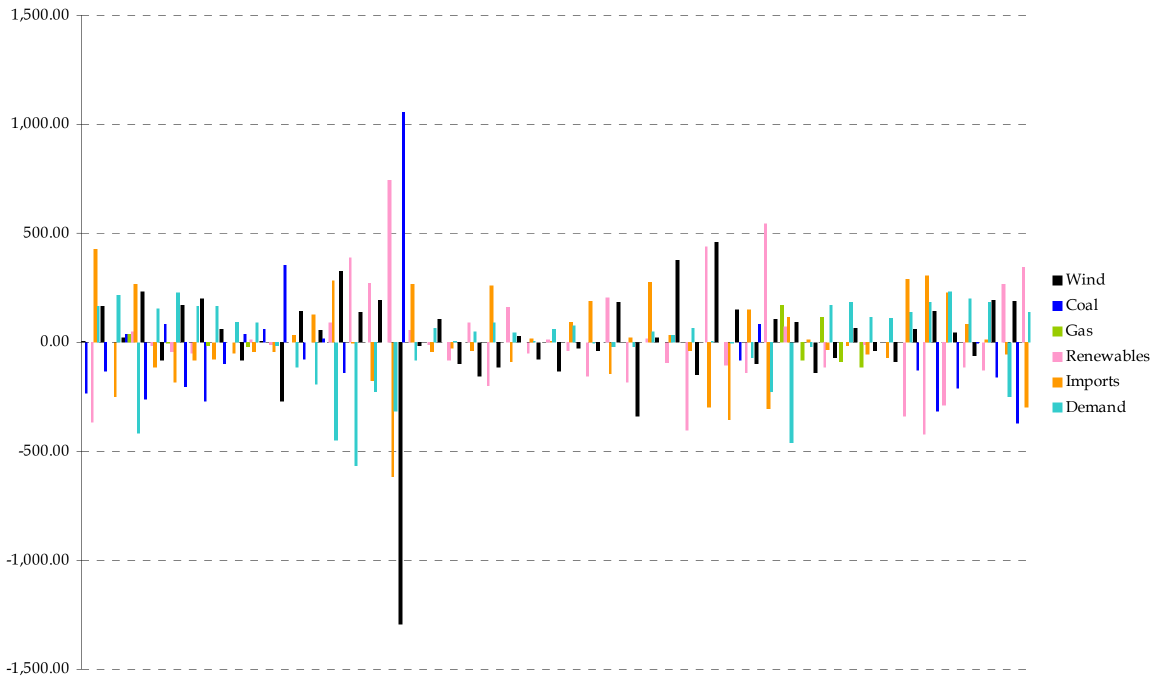
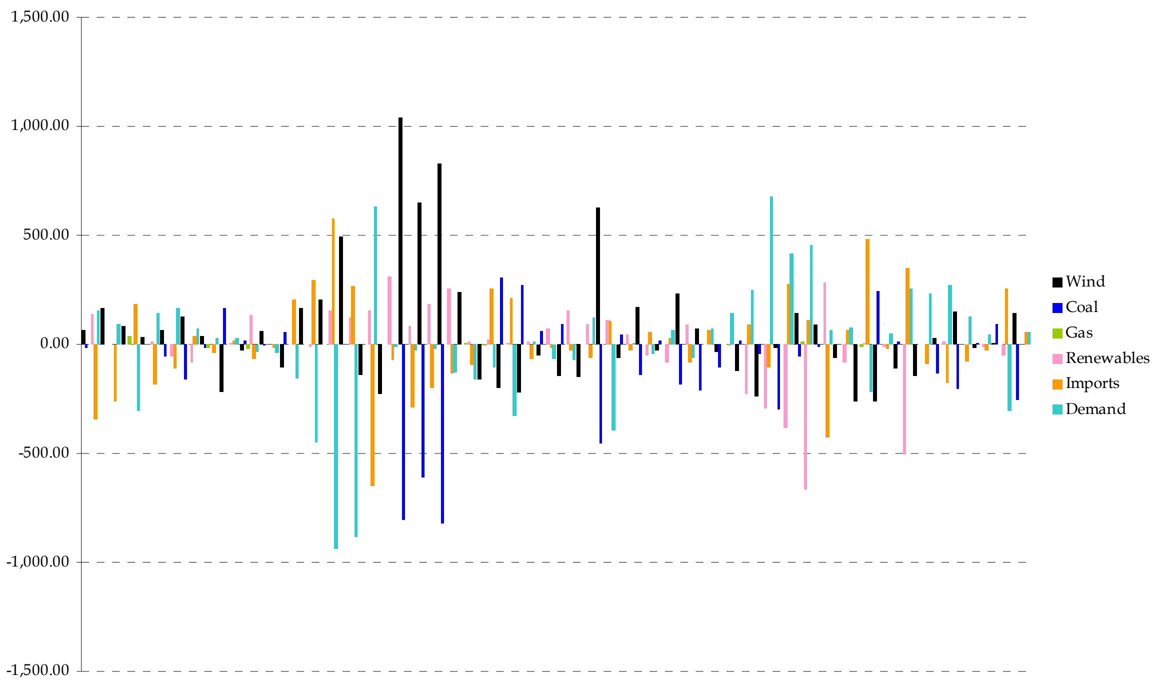
▪ Figure 6-50 Largest half-hourly drop in wind generation 2019/20, Scenario 5



▪ Figure 6-51 Largest half-hourly gain in wind generation 2019/20, Scenario 5



7. Conclusion

This study has demonstrated that any future large-scale wind and PV capacity located in Victoria would offer excellent emissions abatement, primarily displacing NSW black coal generation prior to the introduction of a carbon price, although Victorian brown coal would also be displaced in off-peak periods. The expected abatement intensity factor would lie somewhere between 0.9 and 1.2 t CO_2e/MWh prior to the introduction of a carbon price.

Once a carbon price is introduced, a combination of Victorian brown coal and NSW black coal would be displaced, with the average abatement intensity decreasing as more renewable capacity is added into Victoria. However, the first 2000 MW of additional wind and/or PV capacity would raise the average abatement intensity with the introduction of a carbon price, as brown coal plant becomes marginal. It is not possible to assess how quickly the average abatement intensity would fall with increasing wind capacity beyond the 3000 MW level since the methodology employed in this study does not fully capture this. However, up to 3000 MW wind capacity, the expected abatement intensity factor would lie somewhere between 1.1 and 1.4 t CO_2e/MWh after the introduction of a carbon price. The level of abatement intensity would however decrease in the long term as the increasing carbon price forces the most emissions intensive generators to retire due to a lack of profitability.

One of the major challenges facing the Victorian power system with the introduction of large amounts of wind power would be managing the scheduling of the large, slow-starting brown coal plants which at high penetrations of wind capacity would be crowded out by wind generation from time to time and therefore forced to switch off. We were able to verify that in such cases, there was enough fast-start hydro and gas-fired capacity in the Victorian system to manage the swings in wind power in the event that brown coal capacity could not come online quickly enough. We also tracked the largest inter-dispatch swings in wind capacity and found that the largest drops in wind power output were handled by a combination of increased hydro generation, increased imports into Victoria and also increased production from brown coal plant. The fact that very little gas-fired plant was called upon to bridge the gap suggests that there is ample capacity in the system to deal with the swings in output brought about by large penetrations of wind capacity.

Appendix A Costs and Performance of Thermal Plants

The following table shows the parameters for power plants used in the PLEXOS model. Costs are reported in June 2009 dollars. The variable costs exclude the effect of the CPRS. The MW assumptions are generator terminal assumptions.

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
NEW SOUTH WALES										
Bayswater	4	2760	2.5	2.0	93.3	9.8	2.08	1.41	15.88	0.905
Colongra	4	668	2.5	3.5	91.9	10.9	9.27	10.13	119.26	0.680
Eraring	4	2760	2.5	3.6	91.8	9.7	2.18	1.58	17.48	0.889
Eraring GT	1	40	2.5	3.5	91.9	23.5	9.27	22.46	537.16	1.732
Hunter Valley GT	1	51	4.0	3.5	89.1	24.2	9.27	22.46	552.26	1.783
Liddell	4	2100	2.5	3.1	92.3	11.1	2.30	1.41	17.94	1.007
Mt Piper	2	1400	1.0	0.9	97.1	9.7	2.36	1.48	16.74	0.875
Munmorah	2	600	43.1	9.6	15.6	10.9	1.80	1.48	18.00	0.994
Redbank	1	150	2.0	2.3	93.9	11.9	2.68	0.33	6.64	1.066
Smithfield	4	160	3.0	3.0	91.4	13.0	5.11	4.43	62.71	0.810
Tallawarra	1	435	2.5	3.0	92.3	7.1	3.41	4.80	37.27	0.443

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
Uranquinty	4	664	2.5	2.0	93.3	11.2	3.24	10.13	116.19	0.698
Vales Point	2	1320	3.8	4.1	88.9	9.9	1.35	1.53	16.46	0.898
Wallerawang	2	1000	4.8	7.6	83.9	10.2	1.80	1.53	17.48	0.896
QUEENSLAND										
Barcaldine	1	49	3.0	3.0	91.4	8.1	4.03	3.27	30.49	0.500
Braemar1	3	504	2.0	2.0	94.2	10.6	3.38	1.40	18.20	0.586
Braemar2	3	519	2.0	2.0	94.2	11.6	3.38	1.40	19.64	0.642
Callide A	1	30	2.0	3.0	93.3	10.0	1.93	1.55	17.38	0.975
Callide B	2	700	2.0	3.0	93.3	10.5	1.53	1.15	13.55	1.024
Callide C	2	900	1.2	6.0	91.9	10.0	1.35	1.41	15.36	0.975
Collinsville	5	187	3.0	5.0	89.5	10.9	2.68	1.92	23.60	0.984
Condamine	3	135	2.0	2.2	94.1	7.6	3.38	0.93	10.45	0.421
Darling Downs	4	630	2.0	1.0	95.2	7.8	3.34	1.05	11.55	0.432
Gladstone	6	1680	2.4	4.6	91.1	10.8	1.18	1.81	20.85	1.005
Kogan Creek	1	744	3.0	3.0	91.4	9.9	0.81	0.73	8.07	0.867
Mackay GT	1	32	2.0	2.0	94.2	14.3	10.75	22.46	331.49	1.054

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
Millmerran	2	852	3.0	8.2	86.5	10.5	1.21	0.80	9.65	0.920
Moranbah	1	45	4.8	4.0	87.1	9.0	2.68	0.00	2.68	0.000
Mt Stuart GT 3	2	288	2.0	2.0	94.2	11.8	5.38	22.46	270.82	0.870
Mt Stuart GT	1	127	2.0	2.0	94.2	11.8	5.38	22.46	270.43	0.870
Oakey GT	2	332	2.0	2.0	94.2	11.6	5.38	6.90	85.10	0.716
QAL Cogen	1	153	2.5	1.0	94.2	7.0	3.37	0.00	3.37	0.432
Roma	2	68	4.0	5.0	87.7	13.5	5.38	3.27	49.49	0.833
Stanwell	4	1470	1.8	0.9	95.6	10.7	1.07	1.42	16.24	0.981
Swanbank B	4	480	3.0	10.0	84.8	13.3	2.68	1.71	25.38	1.163
Swanbank E	1	370	2.0	2.0	94.2	8.1	2.68	3.27	29.21	0.500
Tarong	4	1400	2.2	1.6	94.2	10.0	1.59	1.15	13.01	0.904
Tarong North	1	443	2.4	1.6	93.9	9.5	1.11	1.15	11.96	0.859
Yabulu CCGT	2	256	3.0	2.0	92.3	9.4	2.68	3.16	32.51	0.586
Yarwun Cogen	1	167	2.0	2.0	94.2	10.9	3.38	3.27	38.94	0.673
SOUTH AUSTRALIA										
Angaston	30	50	0.5	7.5	91.6	11.1	11.54	22.46	261.11	0.818

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
Dry Creek	3	148	4.0	3.5	89.1	14.1	8.06	8.77	131.74	0.871
Hallett	1	187	4.0	0.0	92.3	15.4	9.20	8.77	144.55	0.951
Ladbroke Grove	2	86	3.0	2.3	92.1	10.0	6.72	2.70	33.73	0.617
Mintaro	1	90	4.0	4.6	88.0	16.3	8.06	8.77	150.65	1.006
Northern	2	546	2.8	2.1	92.6	11.4	0.70	1.42	16.90	1.107
Osborne	1	192	2.0	2.3	93.9	10.4	2.61	4.16	45.82	0.642
Pelican Point	1	474	3.0	1.0	93.3	7.2	2.68	3.91	30.80	0.445
Playford	1	240	6.0	5.0	84.0	17.2	1.92	1.42	26.25	1.670
Port Lincoln	3	75	3.0	3.0	91.4	10.7	8.06	22.46	249.02	0.788
Quarantine	4	92	4.0	3.5	89.1	10.4	8.42	8.77	99.40	0.642
Quarantine 5	1	128	4.0	3.5	89.1	10.3	9.81	4.58	56.94	0.636
Snuggery	3	66	4.0	4.6	88.0	15.0	8.06	22.46	344.51	1.105
Torrens Island A	4	504	4.0	5.0	87.7	10.8	8.06	4.58	57.49	0.673
Torrens Island B	4	820	4.0	5.0	87.7	10.5	2.01	4.58	50.09	0.655
TASMANIA										
BBThree	3	120	3.0	1.0	93.3	11.6	4.03	8.76	105.64	0.728

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
Tamar Valley CCGT	1	203	1.9	3.0	93.5	9.5	2.68	4.35	44.05	0.596
Tamar Valley GT	1	58	3.0	1.0	93.3	11.6	4.03	9.81	117.96	0.728
VICTORIA										
Anglesea	1	159	1.0	1.5	96.6	15.3	1.35	0.14	3.46	1.415
Bairnsdale	2	92	3.0	1.0	93.3	10.5	4.03	4.38	50.23	0.650
Energy Brix	5	164	5.0	4.0	86.8	18.4	2.68	0.91	19.41	1.693
Hazelwood	8	1600	4.0	9.0	84.0	16.1	2.68	0.62	12.65	1.481
HRL IGCC	1	440	3.0	0.0	94.2	7.2	3.24	1.00	10.50	0.681
Jeeralang A	4	232	2.1	1.0	95.0	13.8	8.06	3.73	59.34	0.849
Jeeralang B	3	255	2.1	1.0	95.0	12.9	8.06	3.73	55.99	0.794
Laverton North	2	340	2.0	2.3	93.9	11.6	4.03	4.99	61.90	0.714
Loy Yang A	4	2270	2.5	3.5	91.9	13.2	1.07	0.47	7.26	1.248
Loy Yang B	2	1050	2.5	3.0	92.3	13.1	1.07	0.47	7.24	1.239
Mortlake GT	2	553	2.5	4.0	91.4	10.8	3.67	2.66	32.46	0.668
NewPort	1	510	2.2	3.0	93.0	9.4	2.68	3.83	38.72	0.578
Somerton	1	160	4.0	5.0	87.7	13.5	2.68	3.83	54.39	0.831

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)	Full Load emissions intensity (t CO_2e / MWh)
Valley Power	6	336	2.1	1.0	95.0	13.8	8.06	3.73	59.34	0.849
Yallourn W	4	1487	3.0	6.0	88.6	14.9	1.35	0.48	8.53	1.445

* A very low marginal cost has been assumed for Anglesea to reflect the contractual arrangements for supply to the Pt Henry Smelter which encourages full output from Anglesea irrespective of pool prices.

** Redbank has also been assigned a low marginal cost consistent with its observed base load operation and its use of coal washery waste which otherwise has no value.

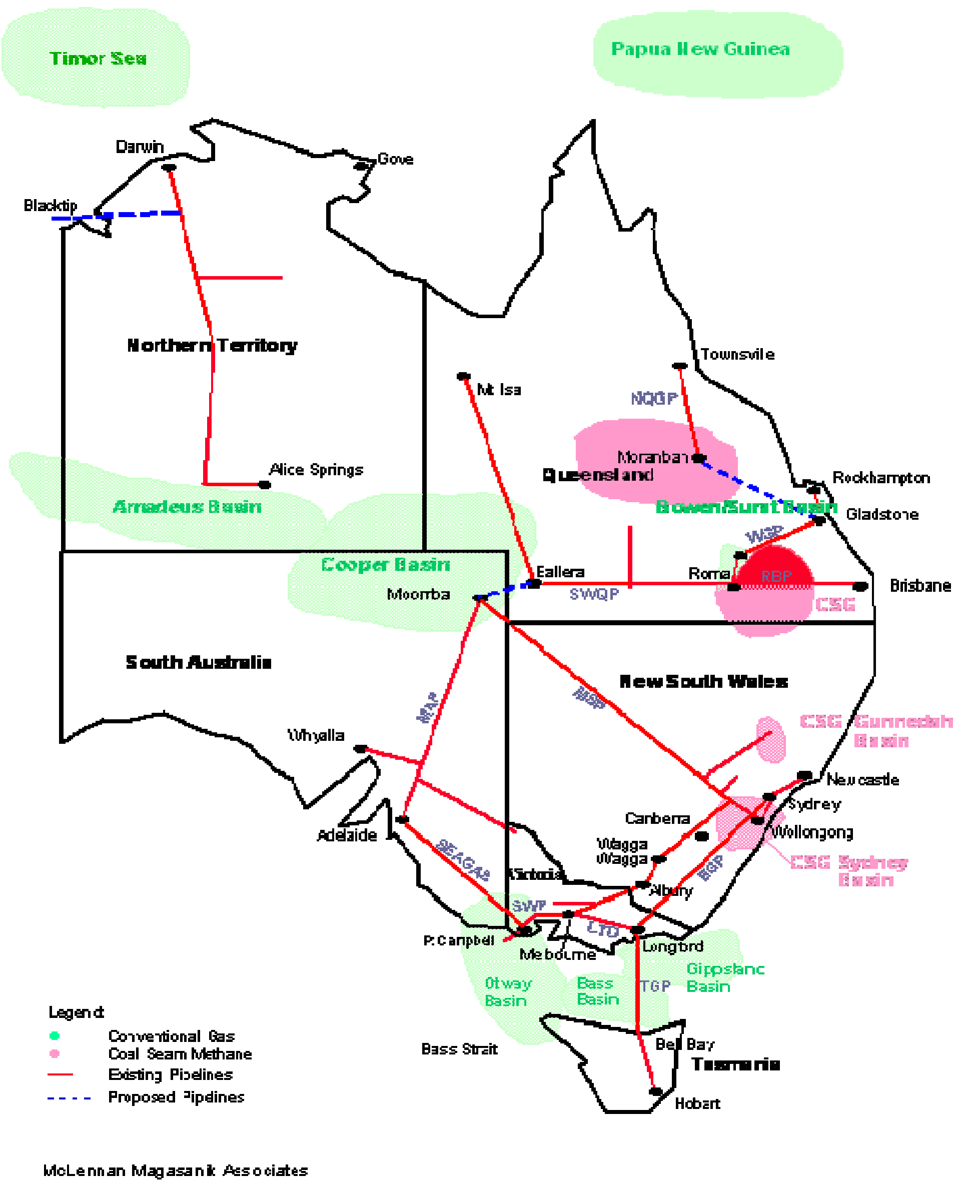
Appendix B Twenty Year Gas Price Forecast for the NEM

B.1 Overview

SKM MMA prepares gas price forecasts based on projected demand-supply balance in Eastern Australia. The gas resources and delivery infrastructure in this region are illustrated in

Figure B-1. This chapter presents in detail SKM MMA's gas price forecasts, along with the assumptions underlying them.

▪ **Figure B-1 Gas resources and infrastructure, Eastern Australia**



Section B.3 describes the Standard Liquefied Natural Gas (LNG) scenario, which is the basis of the gas prices assumed for the electricity market modelling work. Section B.4 describes the baseline scenario, which assumes that LNG exports from Gladstone do not ultimately proceed. This scenario is not used in the electricity price modelling, but is presented as a reference case, and moreover it served as the foundation for the formulation of the Standard LNG scenario.

The gas prices reported in this chapter are reported in June 2008 dollars. For the purposes of modelling they have been escalated by CPI to June 2009 equivalents using Australian capital city weighted CPI.

B.2 The Eastern Australian gas market

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has a growing domestic market, estimated at 589 PJ in 2006 and 667 PJ in 2007, supported by ample conventional and CSG reserves. Demand and supply patterns in this market have operated in isolation from other gas markets in Australia and overseas because to date there have been no gas exports from or imports to the region. The LNG exports that are the focus of this study are the first such exports contemplated and have the potential to considerably change the market, both in terms of the demand-supply dynamics and the nature of the participants.

While the prospect of exports suggests an excess of gas supply over local demand, historically the opposite, an excess of demand over local supply, has concerned the market and energy policy makers. Consequently there is a considerable history of projects to import gas from the North West Shelf in Western Australia, Papua New Guinea and the Timor Sea, all of which have been deferred because of unforeseen growth in Eastern Australian gas reserves and supply, most recently the CSG resources being developed in Queensland.

Significant new resources of gas have been developed since the introduction of third party access to transmission and distribution pipelines in 1997. Production in the Otway and Bass Basins in Victoria and the Bowen-Surat Basin in Queensland (refer to Figure B-1) has provided competition to the formerly dominant production centres in the Gippsland and Cooper Basins and new pipelines have been constructed (EGP, TGP, SEAGas and NQGP) to bring competing gas to market.

The majority of Eastern States sub-markets are now served by multiple basins and/or pipelines, the key exception being Townsville. Planning for a pipeline between Moranbah and Gladstone, which would link Townsville to other supplies, is well advanced but construction appears to be contingent upon LNG development in Gladstone using gas from the Moranbah area. Operation of QSN Link between Ballera and Moomba, scheduled for early 2009, will directly link Queensland to the southern states – to date Queensland CSG has been supplied to southern states only via swap arrangements.

The dominant transactions in the Eastern Australian gas market are long-term gas sales agreements (GSAs) between gas producers and buyers such as retailers, large industrial users and generators. There is a spot market in Victoria but the gas injected comes largely from buyer-controlled GSAs rather than directly from producers and it is anticipated that the short-term trading markets being established in other regions under the auspices of the Ministerial Council on Energy will be similar in this respect. Wholesale gas prices are therefore mainly determined by the prices set in the GSAs, though the Victorian spot market does provide considerable additional price transparency.

The level of gas producer competition has until now been sufficient to maintain price levels for new GSAs in the south-east and to reduce prices in some Queensland sub-markets. During 2007 there was upward pressure on short-term gas prices during peak demand periods in the Victorian market and elsewhere, because of unanticipated demand for gas fired power generation owing to the drought constraining coal units, but this pressure has now abated.

B.3 Standard LNG scenario

B.3.1 Modelling the impact of LNG on the domestic market

Introduction

The prospect of LNG exports from Gladstone has already impacted the market for new gas supply agreements in Queensland and the rest of Eastern Australia. In the analysis of the Baseline Scenario (section B.4) it is noted that CSG reserves that may previously have been available for domestic contracts are being retained for LNG projects with a consequent reduction in competition and upward price pressure on long term contract prices in the domestic market. In interviews with market participants SKM MMA has found a consistent expectation that gas prices will increase substantially once LNG exports from Queensland begin and that this expectation is accompanied by considerable uncertainty about the level of the increase.

In an LNG scenario the retention of CSG reserves for LNG will be far more prolonged than in the Baseline scenario, where LNG projects are assumed to be abandoned during 2011. The price pressures will also therefore be more prolonged. The price levels reached in the domestic market are likely to be influenced by a number of factors:

1) Gas scarcity – those involved in LNG projects may not be willing to enter new domestic contracts until their reserve commitments to LNG projects are met.
2) Attractiveness of LNG prices – higher prices will attract increased sales of LNG from existing projects, to the extent that they are not at full capacity, and will see more projects constructed, resulting in further reserves pressure.
3) Development cost pressures – the scale of LNG developments may absorb resources, crowding out or increasing the cost of development of CSG for domestic sale.

In regard to development cost pressures, the progressive build up of LNG capacity envisaged in the 28 Mtpa case is built around the concept of spreading resource use over a long period, consistent with minimising the cost pressures. The cost pressures that have built up over the last year are limited and have been more than offset by increases in CSG productivity and we are unable to provide any reliable quantification of the longer-term cost pressures at present.

The impact of the gas scarcity and LNG price factors will depend upon how much Eastern States gas has access to the LNG market, how much that market will absorb and how much gas is effectively confined to the domestic market. Most of the current LNG project proposals are being developed by partnerships between a CSG producer and an LNG market participant but with shared ownership of the upstream and downstream components. Combined with low marginal costs of CSG production, this means that the LNG plants have very little incentive to purchase and process non-related producers' gas, other than to deal with imbalance issues. Consequently the gas resources of the CSG producers in the partnerships will have preferential access to the export market through the LNG plants, compared to other CSG producers and conventional gas producers in other states, who are also disadvantaged by their distance from Gladstone.

Comparing export and domestic gas prices

Estimating the impact of LNG prices on the domestic market is not straightforward for two reasons:

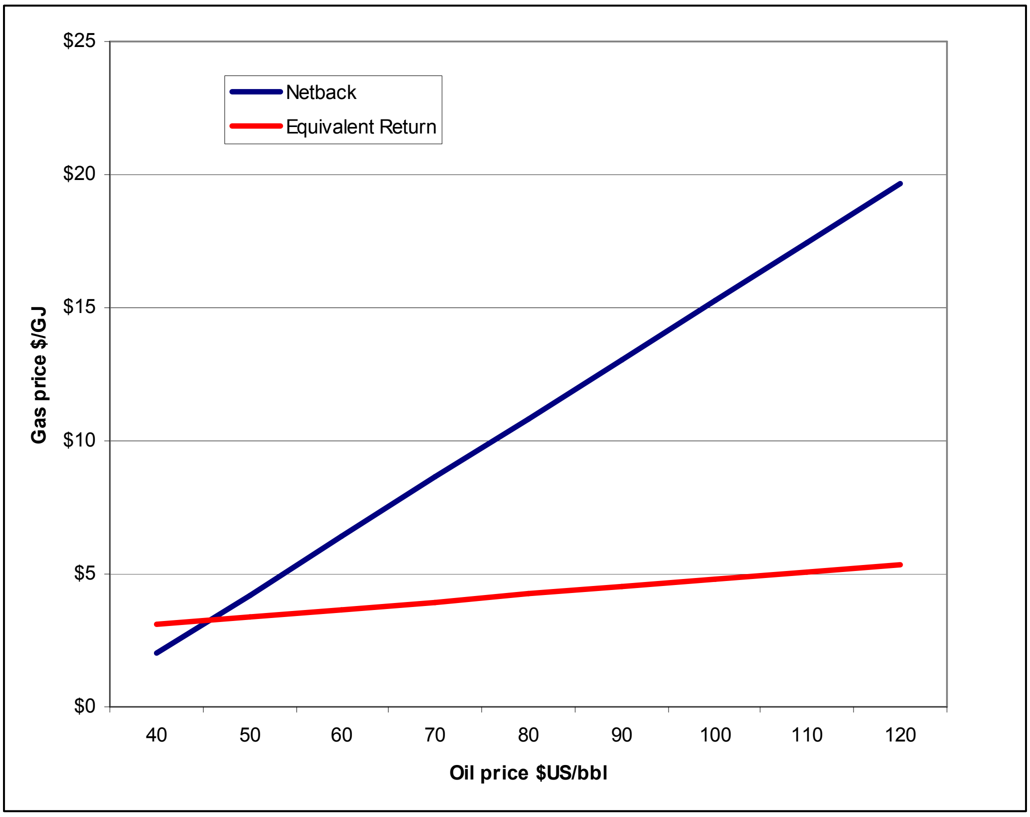
- There is no definitive basis for comparing export and domestic prices
- Domestic prices are currently set through long-term contracts with very limited volatility, whereas LNG delivered prices track highly volatile spot oil prices

The most commonly used basis for comparing export and domestic prices is the LNG netback price, defined as the LNG delivered price less the costs of transportation, liquefaction and shipping, i.e. the value of the exports at the wellhead. In practice, in itself this does not provide a single figure for the value of exports, because of the differences in LNG prices (variations in oil-LNG price linkages), and differences in the costs incurred by different participants. However a greater difficulty with the netback concept is that it assumes that the costs of transportation, liquefaction and shipping are in some sense fixed and that all the export value above breakeven can be ascribed to the production sector, even though it typically represents only 35% of the LNG supply chain costs in the case of Gladstone LNG projects and perhaps a slightly higher percentage where offshore gas production is involved, as in WA and NT LNG projects.

If production and liquefaction were under separate ownership, it seems highly unlikely that the liquefaction owners would agree to the above outcome, given their control over producers' access to the export market. Moreover, from a gas producer's perspective, in deciding between investment in an LNG project and investment to support domestic supply, the relevant comparison would be the project returns on investment or IRRs. Other things being equal, LNG and domestic projects with the same IRRs should be equally attractive since they would generate equivalent returns on shareholders' capital. The domestic price necessary to produce an LNG project equivalent return is referred to as the equivalent return price.

Figure B-2 illustrates that there is a large gap between netback prices, calculated using a WACC of 12% real, and equivalent return prices at high oil prices, at which LNG project returns are much higher than the benchmark WACC of 12%. The crossover point is at the LNG project breakeven oil price of $US43/bbl. SKM MMA expects that gas producers will continue to highlight the higher netback prices while being prepared to supply new domestic contracts at something closer to the equivalent return price.

- **Figure B-2 Netback and equivalent return prices as a function of oil prices**



The way that LNG prices are actually reflected in new gas contracts could take two paths: the contract prices could continue to be fixed in real terms but at higher levels, with periodic repricing, or the contract prices could be indexed to LNG or oil prices. Gas users would be expected to favour the former since they would at least be able to estimate in advance how their viability would be affected by higher gas prices. Recently, gas producers appear to have favoured moving to indexed price contracts[30], probably in the belief that oil prices will rise inexorably. For users whose alternatives are liquid fuels this may be reasonable, however those for whom coal is an alternative or is used by a competitor are less likely to find it workable. A move to indexation may also need to be accompanied by other contract changes, such as reduction in take-or-pay levels, to reduce user risk exposure, and this will certainly be less attractive to producers.

The domestic price uncertainty associated with LNG exports seems likely to result in shorter-term gas contracts, with both producers and users hoping for conditions to change in their favour.

Modelling

The interaction of the domestic and export markets can be modelled in a number of different ways, ranging from full integration in a world gas trade model to the addition of an export zone in a domestic gas market model.

1. World gas trade model. World gas trade models, such as that of the Baker Institute[31], endeavour to model the demand for natural gas by region and its supply from domestic sources and imports by pipeline and LNG tanker. Prices are determined in each market by the interaction of supply and demand. In view of its comprehensiveness such a model would be viewed as ideal. However in addition to the obvious drawback of enormous information and modelling resource requirements, this approach would also involve estimating within the model the level and timing of Gladstone LNG exports in the context of world LNG demand and competition from other country suppliers. This would be an interesting exercise but may not be consistent with the general approach to this study, which has been to estimate the level and timing of Gladstone LNG exports based on the current project proposals.
2. Domestic model plus LNG. In this approach LNG demand is added as a new zone in a model of the Eastern Australian market. LNG demand is specified exogenously and the domestic producers compete to supply the combined domestic and LNG demand. This LNG demand is not open to competition from other country suppliers. To reflect the barriers to LNG market access discussed above, some producers are barred from the LNG market by assuming very high access costs. This approach results in consistent aggregate volumes of LNG being modelled but the volumes exported by each producer may not be consistent with owning multiples of 3.5 Mtpa LNG trains, because each producer's exports are determined within the model on the basis of their gas resources and resource costs. This cannot be avoided by

[30] Santos recently entered such a contract with Moly Metals in WA. The proportion of the price that is indexed is unkown .

[31] The Baker Institute World Gas Model, Peter Hartley and Kenneth B Medlock, March 2005. In "Geopolitics of Natual Gas Supply".

allocating LNG to individual producers, because the allocation would eliminate any competition for the allocation which is what produces the price impact.

SKM MMA has followed the second approach, adding an LNG export zone to the MMAGas model (described in section B.4.3). The value of gas in the zone is set at the delivered price ($18.09/GJ at the medium oil price projection) and the costs of transmission, liquefaction and shipping are used instead of just the transmission costs used in the domestic zones. The model calculates a demand-supply balance to maximise producers' profits across all zones, subject to competition from one another.

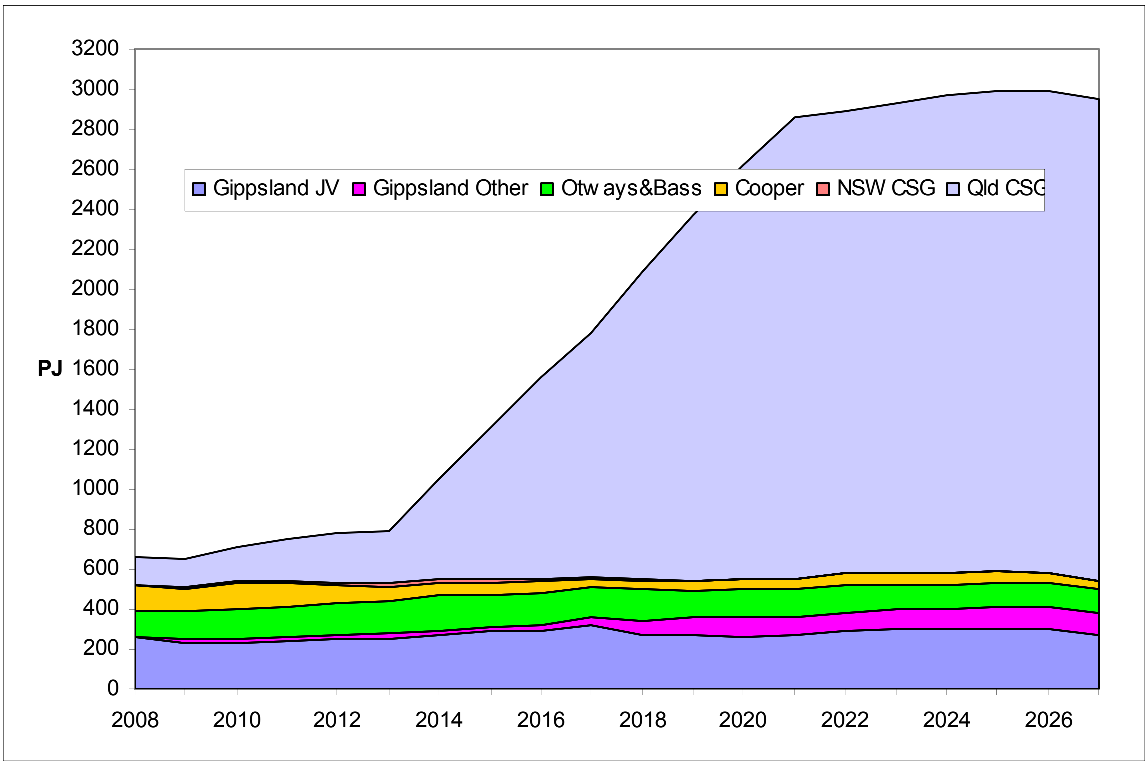
B.3.2 Gas market outcomes

Standard LNG scenario

Gas supply projections

The projected aggregate gas supply pattern for Eastern Australia that matches gas demand with 28 Mtpa of LNG is depicted in Figure B-3. Differences in producer output between the Baseline and LNG scenarios are shown in Table B-1. All regions increase supply, CSG because of the LNG project and the others by substituting for CSG supplied in the Baseline scenario, in the South Eastern Australian zones and Queensland West. Most of the additional Cooper Basin gas is supplied to Queensland West zone. Short term 'ramp-up gas' is not modelled.

■ **Figure B-3 Standard LNG scenario projected gas supply, Eastern Australia**

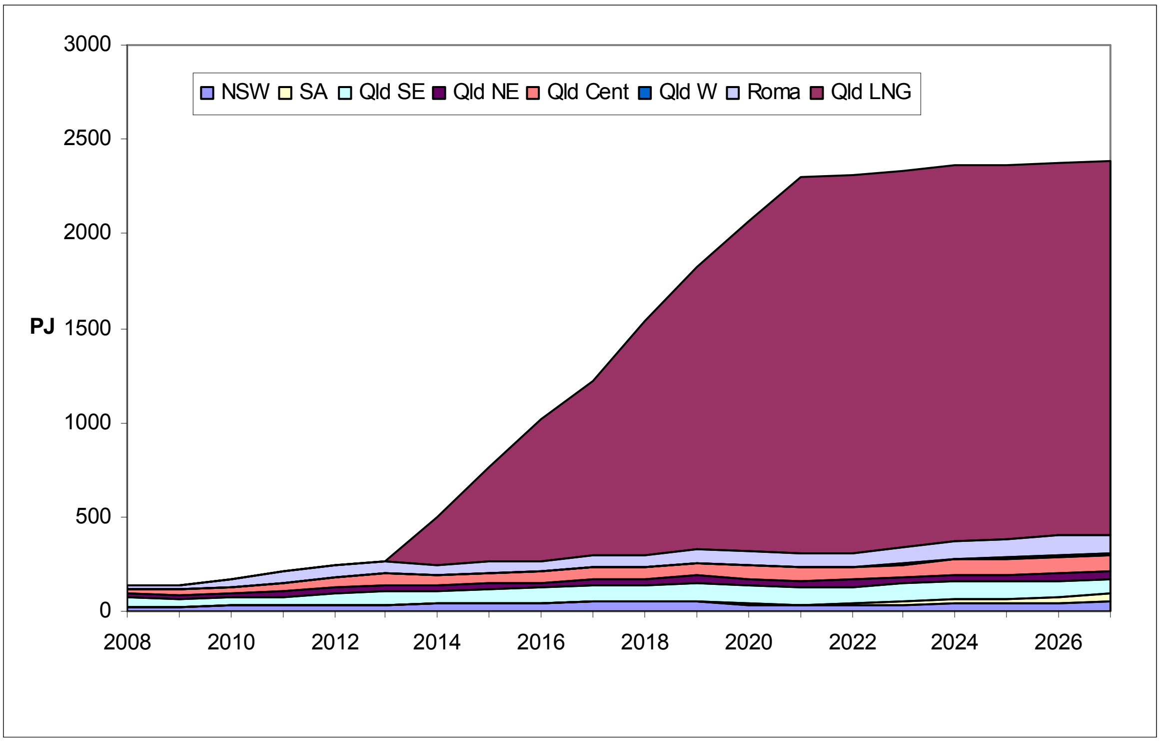


■ **Table B-1 Differences in producer output, Baseline and LNG scenarios, 2025-7 average (PJ)**

Producer	Baseline	LNG	Increase
Gippsland JV	262	292	30
Gippsland Other	90	105	15
Otways & Bass	117	122	5
Cooper	37	48	11
Queensland CSG	671	2409	1738

SKM MMA

▪ Figure B-4 Standard LNG scenario projected supply of Queensland CSG, by market



Gas price projections

Gas price impacts in the standard LNG scenario are presented in the following section. As with the Baseline scenario, all prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real $2008 terms. For each zone or aggregate region two prices are discussed:

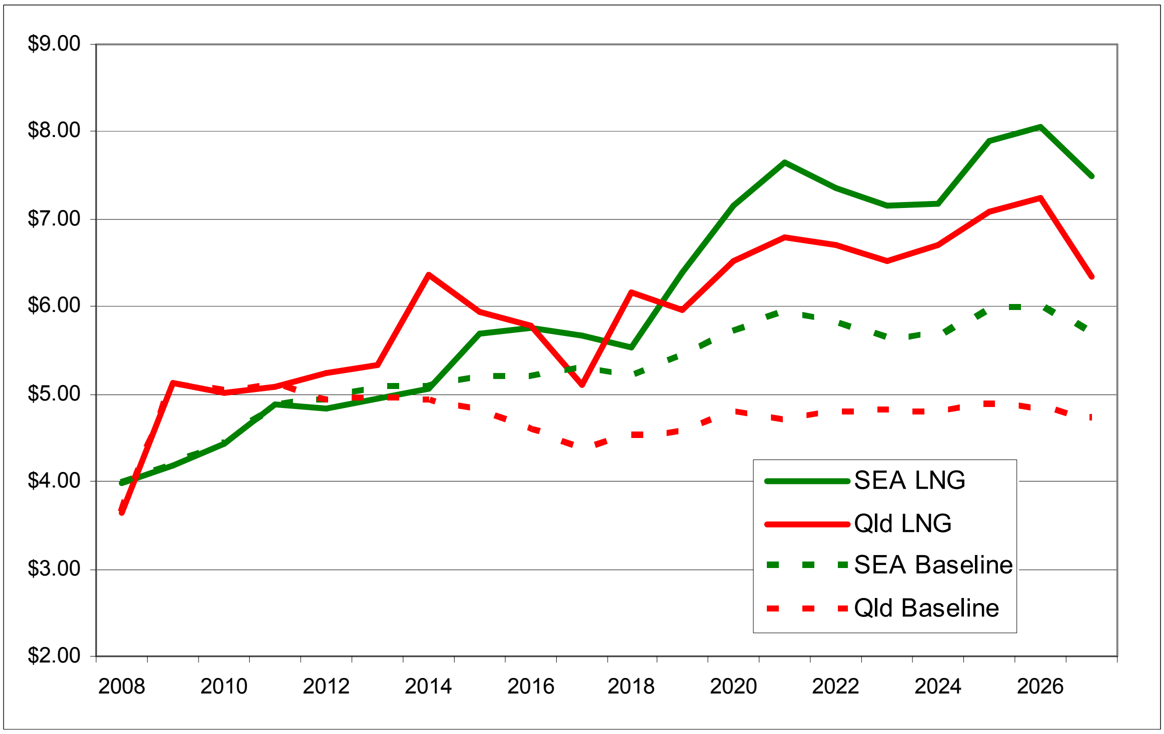
- The estimated average price over all gas contracts delivering gas in any year (labelled "Ave" in each figure)
- The estimated price of new gas contracts starting in a particular year (labelled "New" in each figure).

The estimated impact of the 28Mtpa LNG industry on new contract gas prices in South Eastern Australia (SEA) and Queensland is illustrated in Figure B-5. This shows two distinct phases:

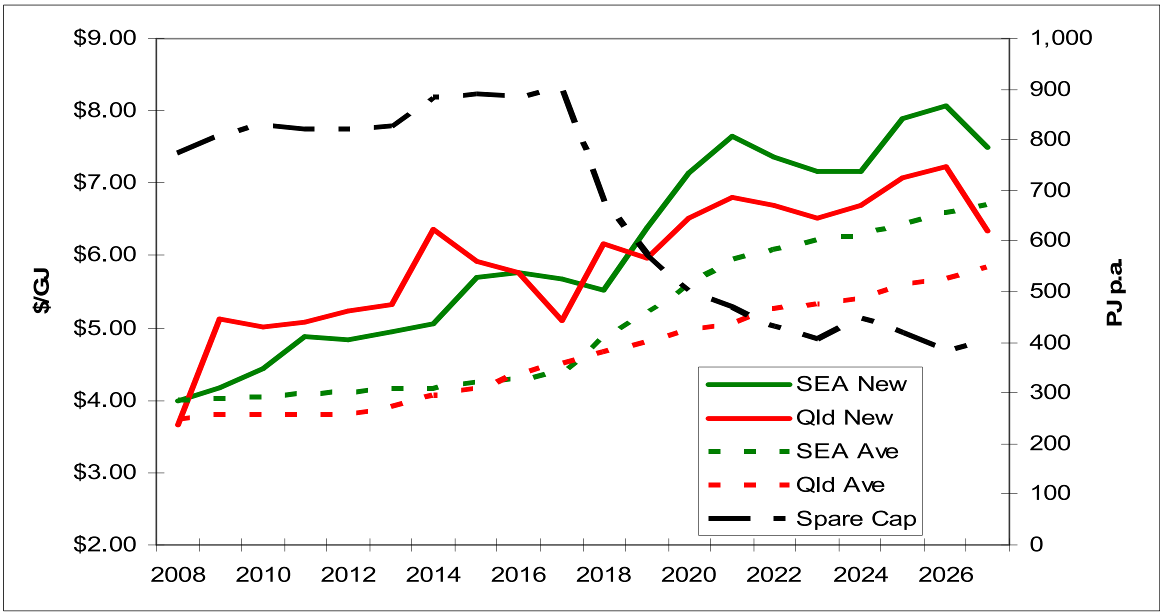
- An initial increase in new gas prices from 2014 of approximately $1/GJ in Queensland and $0.50/GJ in South Eastern Australia, relative to the Baseline scenario.
- Further relative increases in prices after 2018 to about $2/GJ in Queensland and $1.50-$1.75/GJ in South Eastern Australia, due to the increasing scale of LNG production and the progressive depletion of South Eastern reserves following significant recontracting in 2018.

The flow-on of new contract price increases to average prices in the LNG scenario is shown in Figure B-6. Average prices increase gradually towards the new contract prices as older, lower priced contracts expire. Detailed zonal new contract and average prices are shown in Figure B-7 and Figure B-8. These show strong new contract price correlations between all zones except the western zone (Mt Isa), which are more remote in terms of transmission distance.

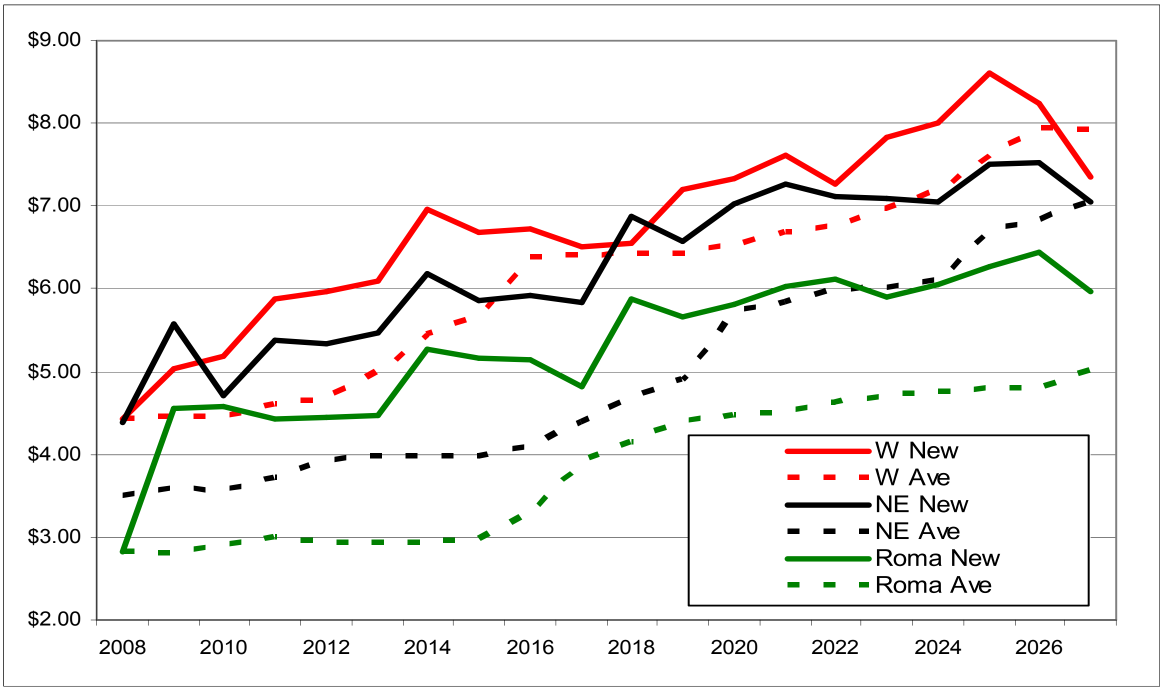
- **Figure B-5 Comparison of New gas contract prices, standard LNG scenario and Baseline scenario South Eastern Australia and Queensland ($/GJ, $2008 real)**



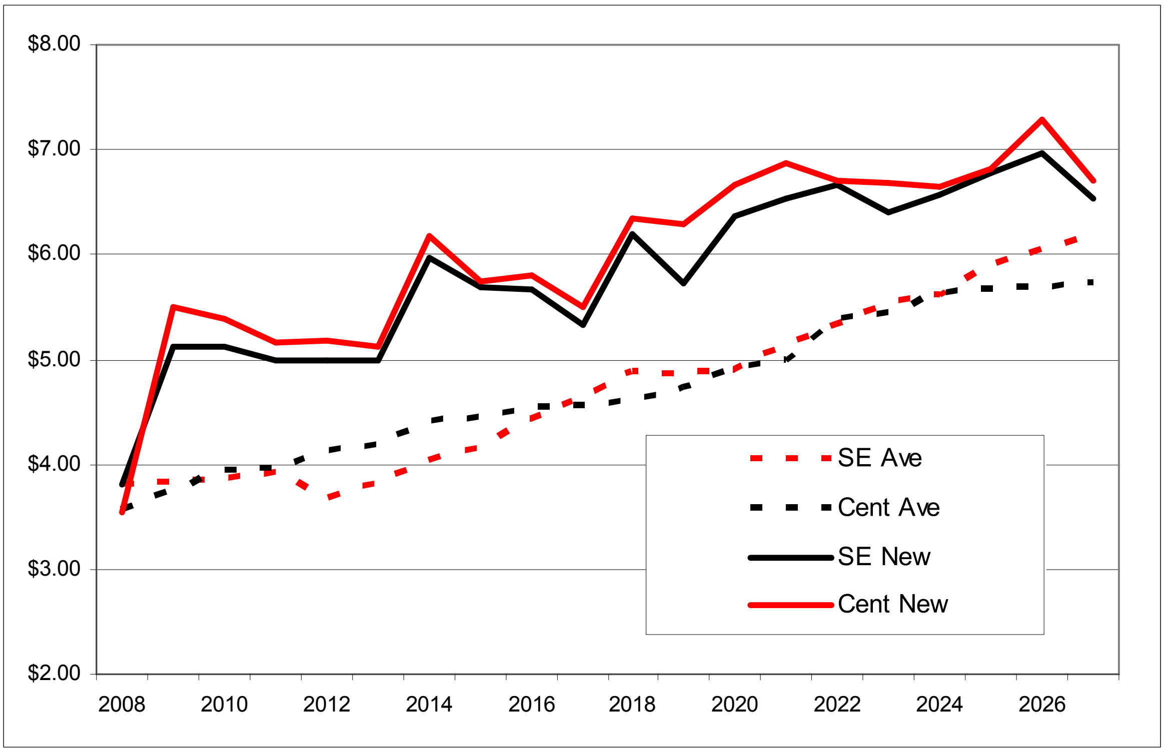
- **Figure B-6 Standard LNG scenario new contract and average contract prices, South Eastern Australia and Queensland ($/GJ, $2008 real)**



- **Figure B-7 Delivered gas price projections, average and new contracts, Queensland NE, W and Roma Zones ($/GJ, real $2008)**



- **Figure B-8 Delivered gas price projections, average and new contracts, Queensland SE and Central Zones ($/GJ, real $2008)**



- **Table B-2 Standard LNG scenario Queensland zonal average gas prices ($/GJ, Real $2008)**

	SE	Cent	NE	W	Roma
2008	$3.81	$3.56	$3.49	$4.44	$2.83
2027	$6.18	$5.73	$7.05	$7.92	$5.02
Increase	$2.36	$2.16	$3.55	$3.48	$2.19

Clearly, the modelling suggests that the standard LNG scenario will lead to significant gas price increases in Queensland and to an only slightly lesser extent across the rest of Eastern Australia. Wellhead prices, represented by the Roma zonal price, increase to approximately $6/GJ, higher than the equivalent return price but lower than the netback price.

B.4 Baseline scenario

The Baseline scenario is presented here only as a reference case, and it assumes that the proposed LNG exports from Gladstone do not proceed for one or more reasons. The scenario nevertheless recognises that activities undertaken in anticipation of LNG exports will impact Baseline gas supply and gas demand.

As export contracts need to be backed up by proved gas reserves, CSG producers have already proved up reserves beyond those required to meet incremental domestic GSAs and will continue to do so over the next two to three years. When it becomes clear that LNG exports are not going to proceed under this scenario, reserve proving activity will fall to significantly lower levels as there will be significant uncontracted reserves available to meet incremental domestic contracts. Until then however the reserves needed for LNG will not be available for new domestic GSAs and this could lead to increases in new GSA prices.

It is noted that many projects, and particularly LNG projects in other jurisdictions, are never formally terminated. Instead their final investment decision (FID) dates under this scenario are continually deferred as the participants try to overcome the barriers to proceeding, such as high costs, funding problems, regulatory barriers and absence of buyers willing to commit. The major Gladstone LNG projects have planned FID dates in 2009 and 2010 for their first trains and allowing for normal slippage it is therefore likely to be at least 2011 before their viability will be publicly doubted and 2012 before some of the reserves held back for LNG are sold into the domestic market, to generate some cashflow. The release of reserves may be partial and spread over time but for the purpose of defining a clear-cut Baseline scenario it is assumed that all projects are terminated in 2012 and all the CSG reserves built up until then become available for new domestic GSAs. The quantities involved are described in section B.4.2.

B.4.1 Gas demand

Estimated Eastern States gas demand by sector in 2007 is shown in Table B-3. Sector strength varies considerably from state to state: residential and commercial demand is strongest in Victoria; industrial in NSW, Victoria and Queensland; and generation in SA and Queensland. Tasmania has been connected to gas only since 2002 and the reticulation network is incomplete.

Table B-3 Estimated Eastern States gas demand 2007 (PJ)

	NSW	Vic	Qld	SA	Tas	Total
Residential	21	91	3	11	0.3	125
Commercial	13	27	2	3	0.1	45
Industrial	79	90	66	24	5	265
Power Generation	11	42	85	83	11	232
Total	**124**	**250**	**156**	**121**	**17**	**667**

Sources: Non-generation, ABARE and VENCorp; Generation, derived by SKM MMA from AEMO data.

Demand projections

Methodology

SKM MMA bases its gas demand projections on a range of sources:

- Residential and Commercial – projections by ABARE, VENCorp and distribution regulators
- Industrial – projections by ABARE, VENCorp and distribution regulators combined with information on committed and potential large scale industrial and mining projects
- Generation – SKM MMA modeling of the National Electricity Market using public source inputs, including AEMO electricity demand projections, taking into account the schemes in place in each state and the expectation of an carbon pollution reduction scheme (CPRS)

Assumptions

The Baseline scenario demand projections are based on the following:

- Use of base (medium or midpoint) case scenarios as produced by ABARE, VENCorp and distribution regulators
- The assumption that a carbon pollution reduction scheme will be introduced in 2010, which generally has the effect of increasing gas demand for generation compared to scenarios involving later introduction of an emission trading scheme.
- Gas prices consistent with historical prices, uninfluenced by gas' value in any other markets. The forecasts are not consistent with the higher prices that may be expected in the Standard LNG Scenario.

Summary of demand projections

Summaries of Baseline scenario demand projections in the nine domestic demand zones considered in this study are presented in Table B-4 and

Figure B-9. Growth is projected to be strongest in the generation sector generally, with strong industrial growth in Queensland. It is noted that the flat period from 2007 to 2010 has been created by high generation demand for gas during 2007 due to drought induced restrictions on coal fired generators. These restrictions are expected to be removed over the next two years and this element of demand will be eliminated.

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Table B-4 Eastern Australian demand projections (PJ/yr)

					Queensland					
	NSW	Vic	SA	Tas	SE	NE	Cent	W	Roma	Total
2007	124	250	121	17	58	15	24	33	26	667
2008	125	242	108	18	63	20	26	33	15	650
2009	132	234	100	13	61	19	31	33	22	645
2010	143	243	97	13	63	23	40	34	64	719
2011	137	252	97	16	79	29	49	34	80	773
2012	139	274	97	16	82	33	62	36	80	819
2013	143	286	96	17	82	32	69	37	73	834
Growth to 2027	2.1%	3.8%	-0.7%	0.6%	3.8%	7.9%	8.4%	0.7%	13.0%	3.8%

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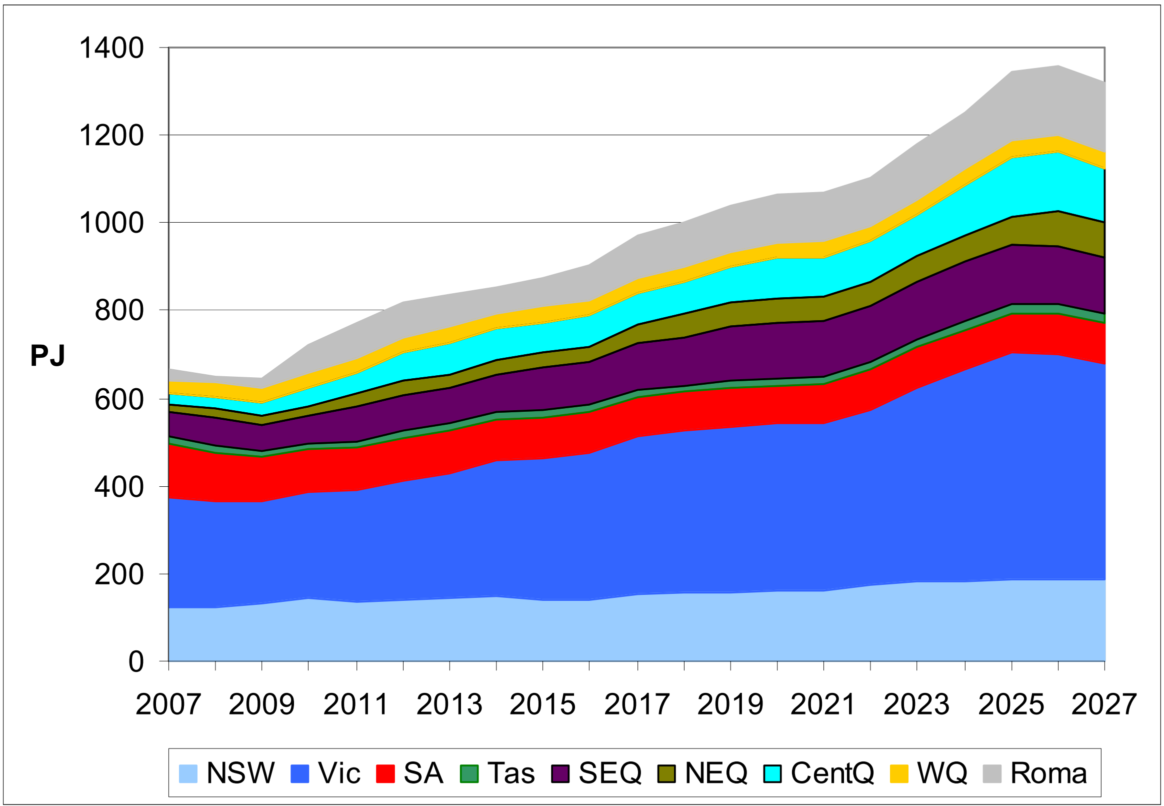
▪ **Figure B-9 Eastern Australian gas demand projections (PJ/yr)**



B.4.2 Gas supply

Gas reserves

Eastern Australian proved gas reserves are spread across ten basins, Clarence-Morton, Gloucester, Gunnedah, Sydney, Bass, Gippsland, Otway, Cooper, Adavale and Surat-Bowen (

Figure B-1). Total 2P reserves remaining as at 30th June 2008, excluding resources that have yet to be proved, are estimated to be approximately 25,000 PJ (Table B-5). 2P reserves are comprised of approximately 12,000 PJ of gas in conventional sandstone reservoirs and 13,000 PJ of CSG in coal seams, which are up from a zero base in 1995.

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▪ **Table B-5 Eastern Australian 2P reserves as at 30th June 2008, operator basis (PJ)**

Basin	Operator	2P Reserves
Clarence-Morton (CSG)	Metgasco	282
Gloucester (CSG)	AJ Lucas	177
Gunnedah (CSG)	Eastern Star Gas	185
Sydney (CSG)	AGL	82
Bass	Origin	572
Gippsland	Exxon-BHPB	6,912
Gippsland	Other operators	1,082
Otway (Minerva/La Bella)	BHP	282
Otway (Thylacine/Geographe)	Woodside	710
Otway (Casino)	Santos	677
Cooper (SA + Qld)	Santos	1,395
Cooper (SA + Qld)	Other operators	100
Surat-Bowen (CSG)	Sunshine Gas	469
Surat-Bowen (CSG)	Arrow	1,519
Surat-Bowen (CSG))	Origin	3,801
Surat-Bowen (CSG)	Anglo Coal	543
Surat-Bowen (CSG)	Santos	2,265
Surat-Bowen (CSG)	Moranbah Gas Project	593
Surat-Bowen (CSG)	Qld Gas Co	2,956
All incl Adavale	Others	247
Total Eastern Australia	**All**	**24,848**

Notes:

1. This table reports reserves on an operator basis i.e. all reserves in a field are attributed to the operator of the field, rather than according to ownership. This is consistent with the reserve definitions used in SKM MMA's modelling
2. The reserve figures for 2P reserves are those meeting the requirements of the Petroleum Resource Management System (PRMS) guidelines of the Society of Petroleum Engineers International
3. Sources: Geoscience Australia, RLMS and industry sources
4. Cooper excludes ethane
5. Santos CSG includes Mosaic which sells some gas to Santos
6. Origin and Santos CSG reserves include small volumes of conventional gas

Future reserve additions

Since the initial conventional gas discoveries in the Cooper, Gippsland and Surat basins in the 1960s, conventional gas reserve growth has been relatively modest in comparison to recent CSG reserve growth. To the extent that exploration has covered a large part of the most prospective conventional gas basins, conventional gas reserves in those basins are well known, with bounded upside potential. In contrast, CSG reserves are likely to have a very significant upside, because well coverage is limited and the inferred resource in place (methane in coal seams) is two orders of magnitude greater than current 2P reserves[32]. It is also noted that CSG reserves are "demand driven" in that producers seem to have had little difficulty proving up reserves once a market has been identified, as exemplified by recent CSG reserve growth in anticipation of LNG exports.

32 300,000-500,000 PJ according to the Australian Gas Association (Gas Supply and Demand Study 1997)

Future reserve additions[33] are by nature difficult to estimate and highly speculative. Gas reserves are clearly ultimately finite but a number of facts support the view that it will be many years before a reliable estimate of this ultimate level can be determined:

- Continued growth in reserves and steady reserve/production levels
- Continuing exploration expenditure
- Significant recent conventional gas discoveries in the Otway basin - Thylacine/Geographe (800PJ) and Casino (300PJ) – in response to the newly available commercial opportunities
- Rapid growth in CSG reserves in response to market opportunities

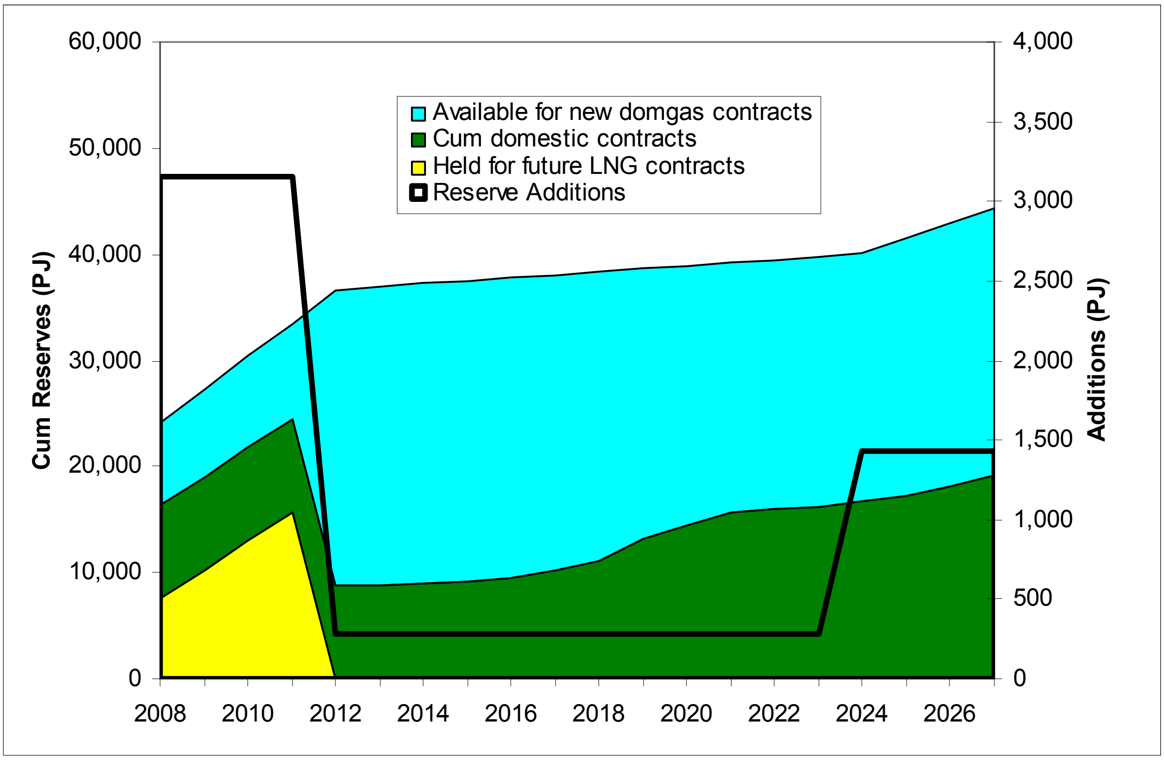
Estimates of future conventional gas reserve additions have been derived from published figures where available, e.g. Geosciences Australia for the Gippsland Basin. The total estimated for conventional gas at the 50% confidence level (that actual additions will exceed this estimate) is 10,150 PJ, approximately 85% of today's 2P reserves. These figures represent discoveries over the next thirty to forty years, assuming exploration expenditure is maintained at current levels, i.e. an average annual discovery rate of 250 to 350 PJ.

For CSG, 2P reserve growth in the year to 31 December 2007 was 2,957 PJ and in the 6 months to 30 June 2008 it was 4,573 PJ. The current 3P (proved, probable and possible) reserve estimates for existing CSG developments are over 30,000 PJ, 17,000 PJ more than 2P reserves and in recent years 3P reserves have been converted to 2P relatively quickly.

For the baseline scenario it has been assumed that CSG reserve development continues apace in anticipation of LNG exports until the end of 2011 (please refer to section B.3). The rate of CSG development is assumed to be 2,870 PJ/yr. Total reserve additions including 282 PJ/yr conventional gas and NSW CSG are 3,152 PJ/yr. From 2012, when the LNG projects are abandoned, Queensland CSG reserve development is assumed to stop altogether in recognition of the excess of reserves built up in relation to the domestic market. Conventional gas and NSW CSG reserve additions continue at 282 PJ/yr and Queensland CSG reserve developments restart when the reserve/production ratio has fallen to a lower level (Figure B-10). In view of the scale of CSG resources the total reserve additions rate of approximately 1,150 PJ/yr necessary to replace gas consumed could continue for a prolonged period after 2027.

[33] We specifically refer to reserve additions rather than gas dicoveries because a significant proportion of reserve growth comes from re-evaluation of reserves in fields already in production.

- **Figure B-10 Baseline scenario - allocation of cumulative gas reserves (PJ)**



It is noted that until 2011 a substantial proportion of reserves are held for future LNG contracts and are not available for new domestic GSAs. After 2011 the reserves available for new domestic contracts expands to over 25,000 PJ and declines only modestly over the study period.

Contracted supply

SKM MMA maintains a data base of Eastern states gas supply contracts, derived largely from information published on buyer/seller websites. While there are likely to be some contracts missing from the data base, either because their existence is not on the public record or because we have failed to find it, SKM MMA believes that 95% of gas volume contracted is accounted for. For many contracts however, only the term and total volume committed are known and annual volumes can only be estimated. The contracts include volumes estimated for related party contracts which can be inferred but have not been publicly revealed, such as between Origin Energy's production and generation divisions, but do not include any LNG related arrangements.

Table B-6 shows the total contracted volumes, compared with 2P reserves as at 30th June 2008. Negative uncontracted reserves imply that some contracts are written against 3P reserves. The volumes of gas already contracted to the domestic market in each year to 2027 are illustrated in Figure B-11. It is noted that estimated uncontracted reserves of CSG are almost 9,500PJ.

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Table B-6 Comparison of 2P reserves and gas contracted (PJ)

Basin	Operator	2P Reserves	Contracted	Uncontracted
Clarence-Morton (CSG)	Metgasco	282	0	282
Gloucester (CSG)	AJ Lucas	177	0	177
Gunnedah (CSG)	Eastern Star Gas	185	5	180
Sydney (CSG)	AGL	82	124	-42
Bass	Origin	572	2,641	4,271
Gippsland	Exxon-BHPB	6,912	242	840
Gippsland	Other operators	1,082	228	344
Otway (Minerva/La Bella)	BHP	282	193	89
Otway (Thylacine/Geographe)	Woodside	710	729	-19
Otway (Casino)	Santos	677	477	200
Cooper (SA + Qld)	Santos	1,395	833	562
Cooper (SA + Qld)	Other operators	100	0	100
Surat-Bowen (CSG)	Sunshine Gas	469	0	469
Surat-Bowen (CSG)	Arrow	1,519	260	1,259
Surat-Bowen (CSG))	Origin	3,801	1,419	2,382
Surat-Bowen (CSG)	Anglo Coal	543	54	489
Surat-Bowen (CSG)	Santos	2,265	301	1,964
Surat-Bowen (CSG)	Moranbah	593	346	247
Surat-Bowen (CSG)	Qld Gas Co	2,956	918	2,038
All incl Adavale	Others	247	0	247
Total Eastern Australia	**All**	**24,848**	**8,770**	**16,079**

Source: SKM MMA estimates of contracted gas

Eastern Australian market requirements for additional contracts are presented in Figure B-11. The market appears to be fully supplied to 2009 and then has a small but growing new contract requirement to 2016 and a larger requirement after 2018.

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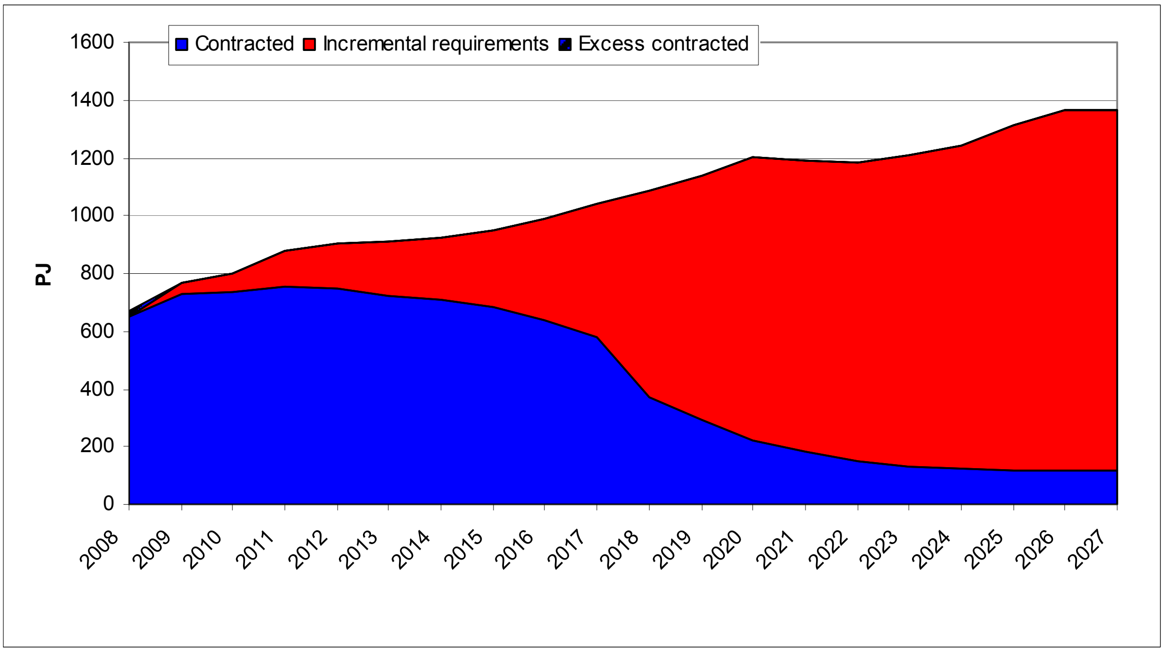
▪ **Figure B-11 Incremental Eastern Australian gas requirements**



B.4.3 Gas demand-supply and price projections

Short-term impact of LNG projects

The prospect of converting CSG into LNG, and earning a higher return or netback price than on domestic sales, has already impacted the market for new GSAs. CSG reserves that may previously have been available for domestic contracts are being retained for LNG projects with a consequent reduction in competition and upward price pressure. However some CSG producers will still be keen to sell gas to generate cashflow prior to LNG sales and some may be keen to sell ramp-up gas.

Earlier in 2008 SKM MMA held informal discussions with a number of potential buyers and sellers to assess the market conditions now and over the next four years. The discussions led to three fundamental "findings" about the expectation of gas pricing over the period of interest:

- Historically, low CSG prices, some less than $2/GJ, were offered to gain market credibility and are unlikely to be found in the future.
- There is considerable uncertainty and divergence of views about current pricing and the direction of pricing in the period between 2008 and the start-up of LNG exports. Some parties looking for gas had encountered difficulty in even getting a quote for prices. Other parties had encountered some producers keen to supply gas at prices around $3 to $3.50/GJ over the next

four or five years, the "ramp-up" period" before LNG exports, but unwilling to commit to any pricing beyond this.

- There is a consistent expectation that gas prices will increase substantially (although not necessarily to LNG export price levels) once LNG exports from Queensland begin, in conjunction with a belief that at least one of the LNG projects planned would eventuate within the next 5–10 years.

These factors are taken into account in the Baseline scenario by replicating the non-availability of reserves, which automatically increases the prices relative to those that will apply after 2012 when it is assumed that the LNG projects are abandoned. Our methodology can accommodate only one contract time frame hence we cannot directly estimate the willingness of gas producers to enter lower priced shorter term contracts.

Methodology

MMAGas, Market Model Australia–Gas, replicates the essential features of the Australian wholesale gas market:

- A limited number of gas producers, with opportunities to exercise market power
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Market growth driven by gas-fired generation and large industrial projects.

MMAGas has been developed to provide realistic assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market. The "gas market" in MMAGas is the market for medium to long-term gas contracts between producers and buyers such as retailers or generators. Competition between producers is represented as a Nash-Cournot game in which each producer seeks to maximise its profit subject to constraints imposed by its competitors. The role of buyers is replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.

One of the most critical assumptions in MMAGas is that negotiations for new contracts take place well before the contracts start, to enable new capacity to supply contracts to be constructed. This is consistent with market behaviour to date, ensures that all uncontracted reserves can be considered for new contracts and thereby leads to the lowest prices consistent with the concentration of reserve ownership. However, reserves being developed to meet anticipated LNG contracts are being withheld from the domestic market and we have therefore added a reserve withholding mechanism to MMAGas to replicate this.

The current implementation of MMAGas represents the eastern states market as up to twenty separate producers competing in nine separate domestic market zones plus one LNG export zone.

Model parameters for this implementation have been estimated so that its outputs replicate recent negotiated contract price and volume outcomes.

Assumptions

Key assumptions in regard to the demand-supply balance and future prices of gas in Eastern Australia are:

- The number of competing gas producers and the gas resources available to them
- Individual producer's gas production costs and production cost escalation
- The costs of transmission faced by the buyers from different producers.

Competing gas producers

The number of producers competing in the Eastern Australian gas market is currently the nineteen joint ventures represented in Table B-5. The assumption that these joint ventures are the competitive entities in the market is a reasonable approximation of reality – in some cases competition between JVs may be restricted by participation of some companies in both JVs but this may be offset by competitive marketing within JVs. It is noted that transmission costs present a barrier to producers competing in all nine zonal markets. To facilitate modelling of some of the policy issues, which require additional production "slots", some of the small JVs have been combined for modelling purposes.

The current uncontracted reserves of the producers are shown in Table B-6 and their projected future reserve additions are discussed in section B.4.2. Changes in these quantities over time, as further gas is contracted and the reserve additions are made, are projected using MMAGas. MMAGas can also accommodate changes in industry structure such as gas reserve additions in new provinces, market entry by new producers and reductions in the number of producers due to mergers or takeovers. However these changes are not calculated within the model but must be input as data – our base case assumption is that the number of producers remains static and only their resources and costs change.

Gas production costs

Gas production cost escalation relative to levels three to four years ago in Eastern Australia is assumed to start at 50% and then decline by 1% p.a. due to technology improvement and innovation.

Gas supply projections

The projected aggregate gas supply pattern for Eastern Australia, which matches the Baseline scenario demand projections presented in section B.4.1, is depicted in Figure B-12. Key aspects are:

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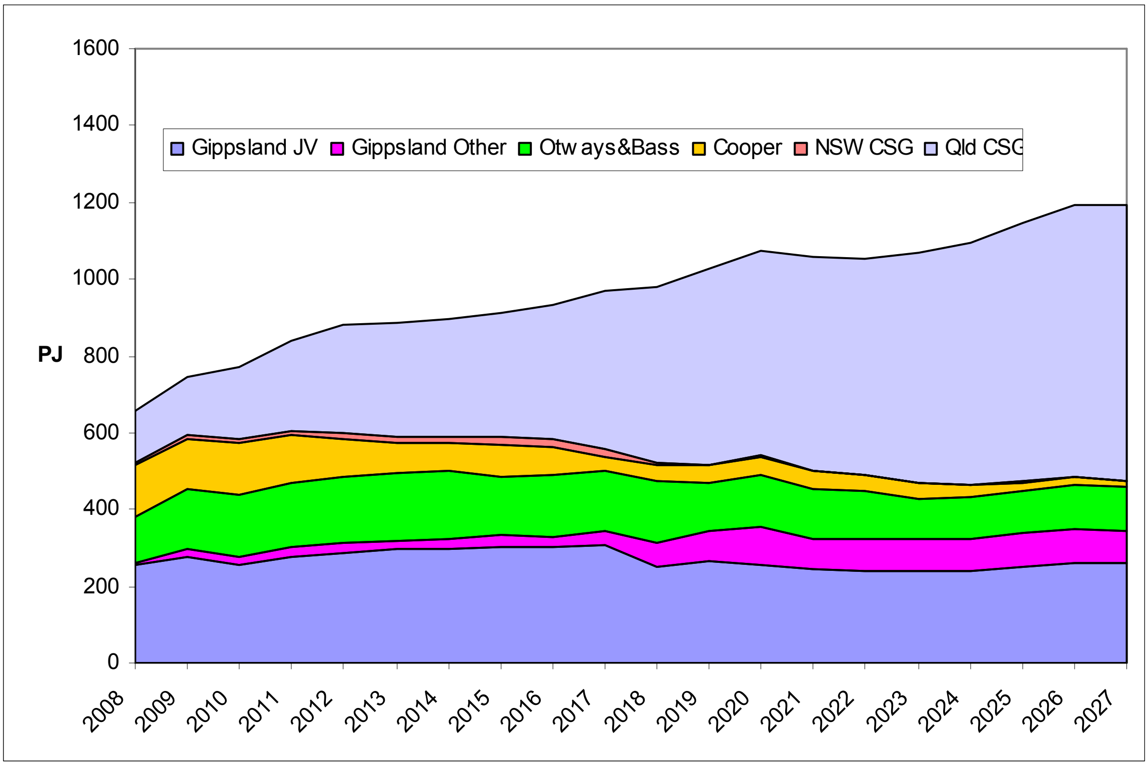
- Significant growth in Queensland CSG production, due to growth in Queensland demand and substitution for Cooper Basin gas
- Initial growth in Otway and Bass Basin production, largely due to substitution for Cooper Basin gas in South Australia and for Gippsland gas in Victoria, followed by a decline.
- Relatively flat production of Gippsland gas, as gains in New South Wales are offset by losses in Victoria.
- Declining Cooper Basin production due to declining reserves.

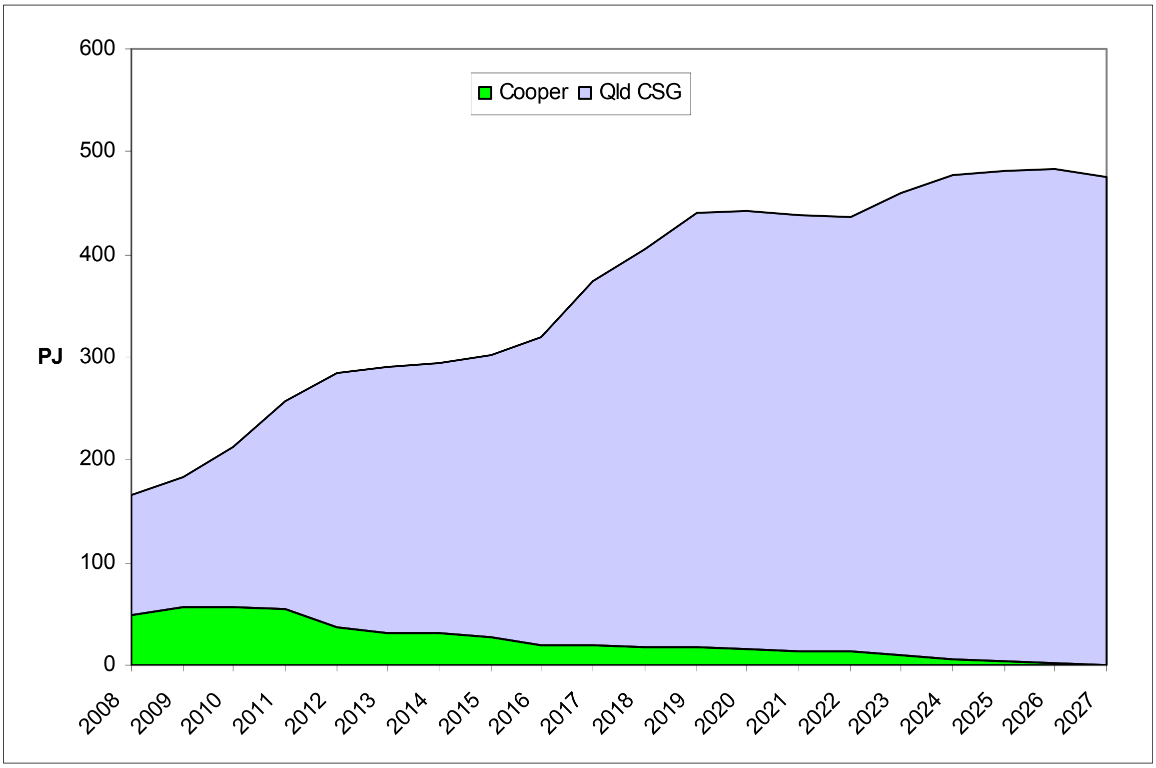
The aggregate supply pattern for Queensland, showing progressive substitution of Cooper Basin gas by CSG as Cooper contracts expire, is depicted in Figure B-13. The only zonal market in which Cooper Basin gas is projected to retain market share is the Western (Mt Isa) market.

Figure B-14 shows that most Queensland CSG is sold in Queensland markets, with limited sales in NSW, Victoria and SA and none projected in Tasmania.

Figure B-12 Projected gas supply, Eastern Australia



- **Figure B-13 Projected gas supply, Queensland**



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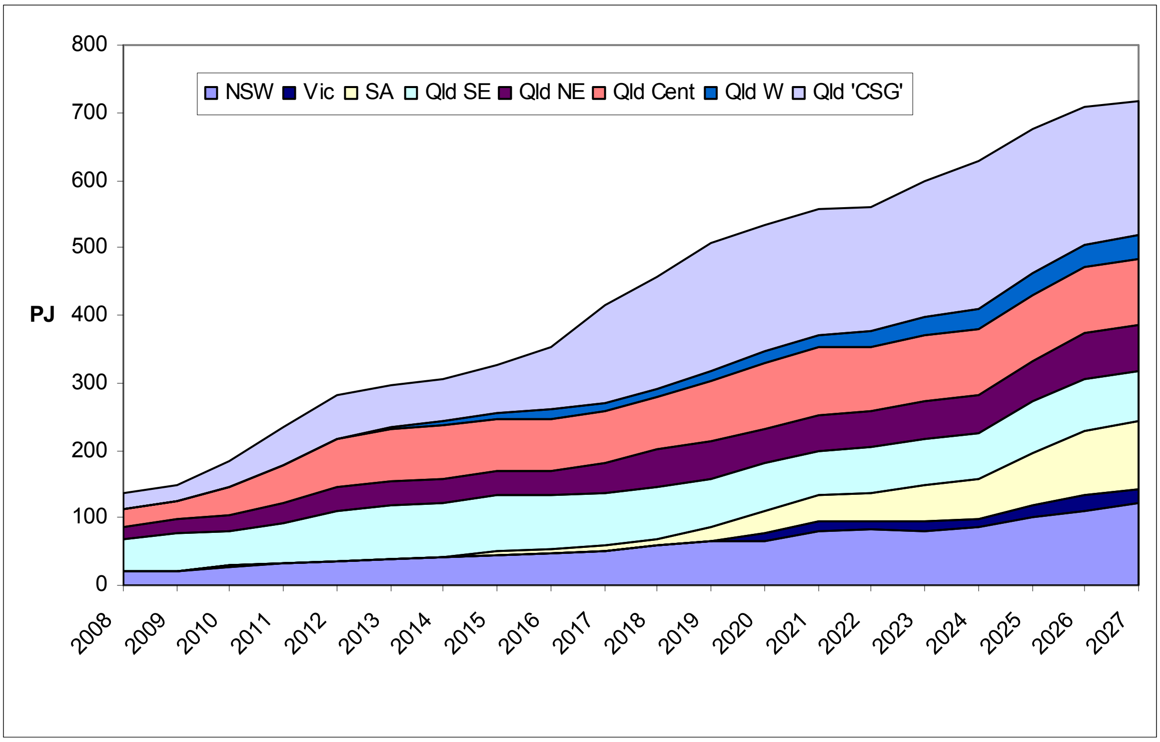
- **Figure B-14 Projected supply of Queensland CSG, by market**



Gas price projections

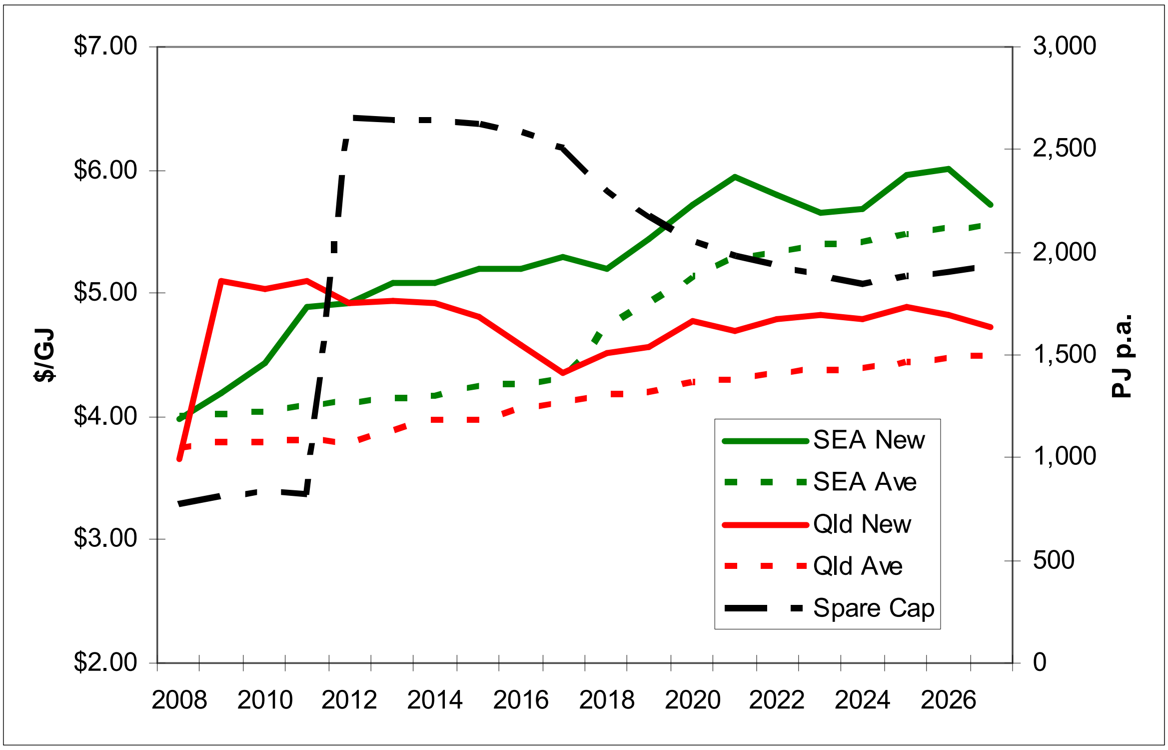
Gas price projections for the Baseline scenario are presented in Figure B-15, Figure B-16 and Figure B-17. All prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real $2008 terms. For each zone or aggregate region two prices are presented:

- The estimated average price over all gas contracts delivering gas in any year (labelled “Ave” in each figure)
- The estimated price of new gas contracts starting in a particular year (labelled “New” in each figure).

Figure B-15 also shows the estimated spare capacity available from uncontracted reserves to meet new contracts – price rises are generally created by falls in spare capacity.

New contract prices are expected to be higher in the short-term, particularly in Queensland, due to the both the withholding of gas for LNG export contracts and the higher cost of production capacity. After 2011 the Queensland new contract price falls but the south eastern states price rises, particularly after 2018 when the local uncontracted gas volume declines and the south eastern states become more dependent on Queensland CSG. The short term spot price effect of ‘ramp-up gas’ is not included in this modelling of long term contracts.

- **Figure B-15 Delivered gas price projections, average and new contracts, and spare capacity South Eastern Australia and Queensland ($/GJ, real $2008)**

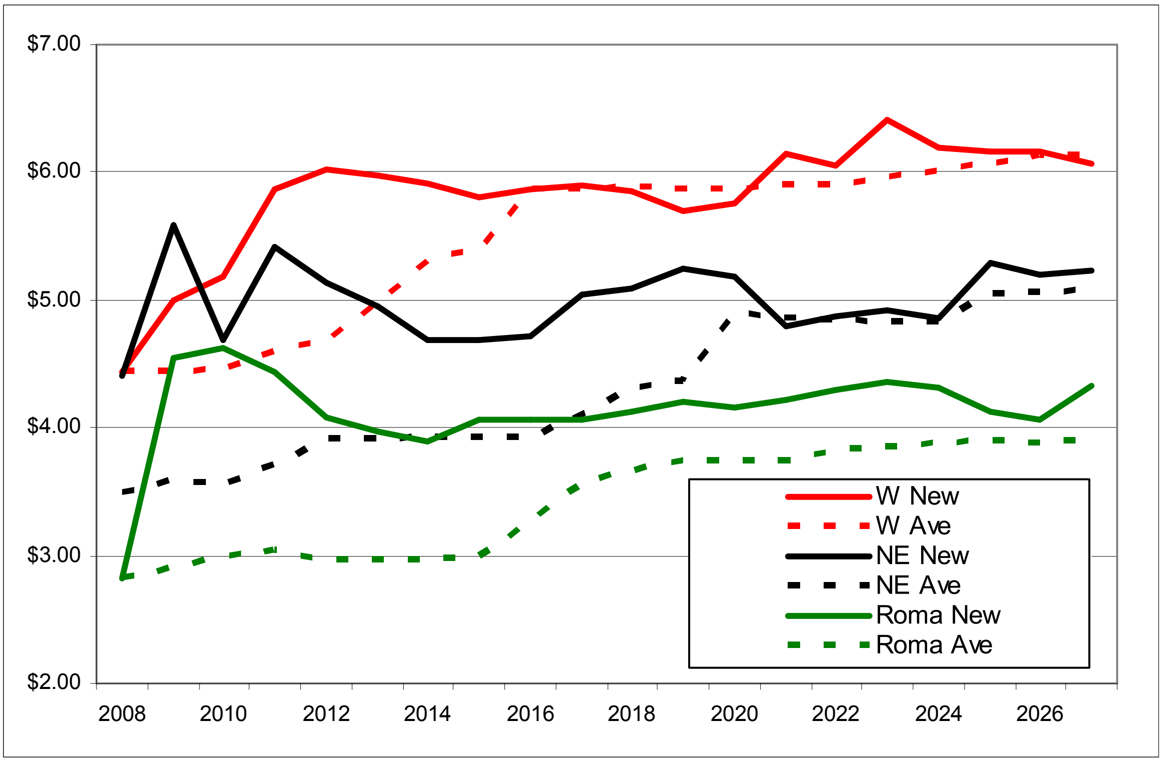


Average prices are expected to rise slowly towards the new contract price as older lower priced contracts are replaced by new higher price contracts.

Some of the rises and falls in the price path for new contracts in Queensland are due to changes in the mix of zones in which contracts are required – the individual zone price paths (Figure B-16 and Figure B-17) present a clearer picture. Table B-7 provides a summary of Queensland zonal average price increases between 2007 and 2024.

The delivered price in the Roma zone corresponds exactly to the wellhead price of CSG in that area, which moves from its current value of about $3.00/GJ to $4.50/GJ initially and then settles in the $4.00/GJ to $4.30/GJ range.

- **Figure B-16 Delivered gas price projections, average and new contracts, Queensland NE, W and Roma Zones ($/GJ, real $2008)**



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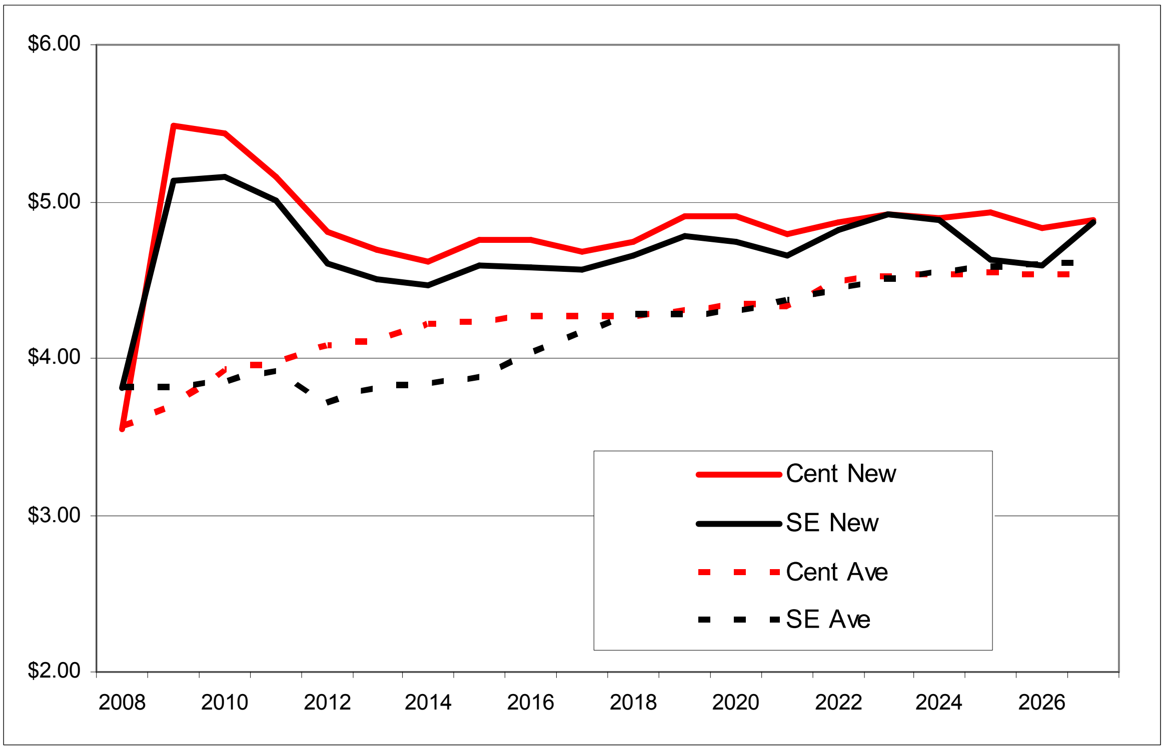
- **Figure B-17 Delivered gas price projections, average and new contracts, Queensland SE and Central Zones ($/GJ, real $2008)**



- **Table B-7 Queensland zonal average gas prices ($/GJ, Real $2007)**

	SE	Cent	NE	W	Roma
2008	$3.81	$3.56	$3.49	$4.44	$2.83
2027	$4.61	$4.53	$5.08	$6.13	$3.91
Increase	$0.80	$0.97	$1.59	$1.69	$1.08

B.5 Gas price forecasts input into PLEXOS

The gas prices for the Standard LNG scenario derived from the MMAGas model input into PLEXOS by NEM region are presented in the charts below. Figure B-18 shows gas costs for new entry plant throughout the forecast period. Similarly, Figure B-19 shows the average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period.

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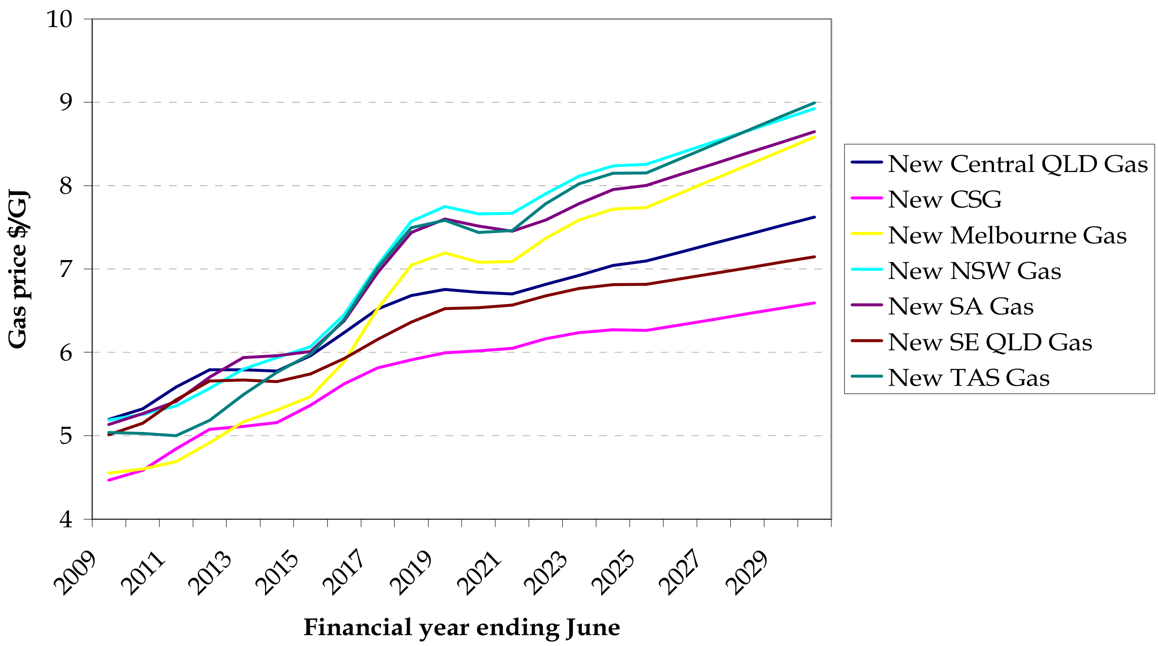
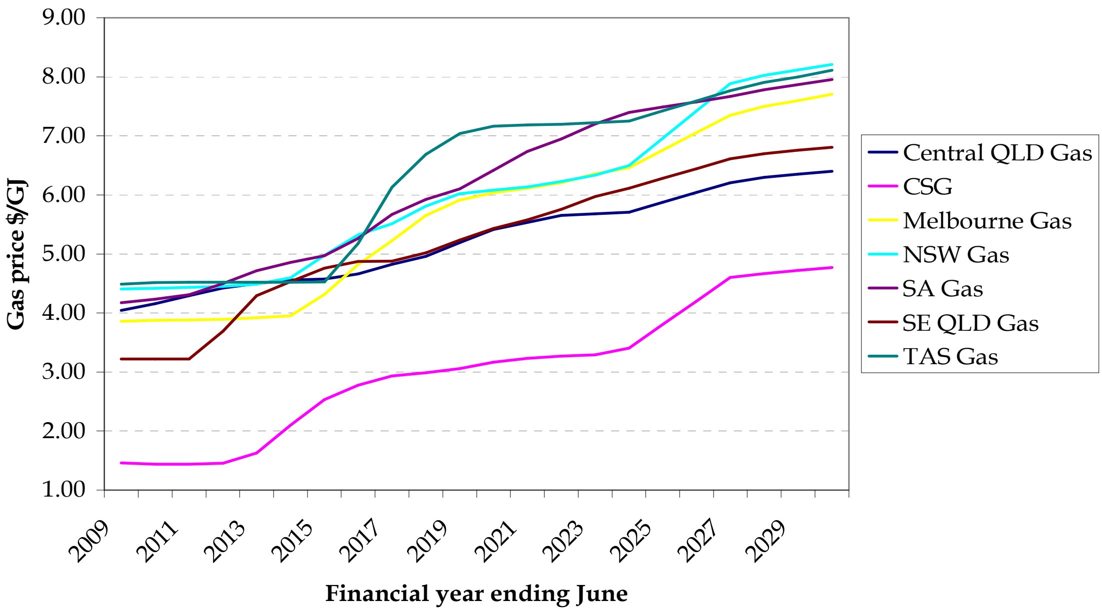
- **Figure B-18 Projected New Contract Gas Prices for the Eastern States, $2008 (CPRS-5% carbon price scenario)**



- **Figure B-19 Projected Average Contract Gas Prices for the Eastern States, $2008 (CPRS-5% carbon price scenario)**



Appendix C Methodology and Assumptions in Detail

The emissions abatement impact that wind farms and large scale solar plant will have in Victoria is driven in part by the future generation mix, which is in turn driven by electricity demand, the carbon price and the expected level of renewable energy projects. The carbon price is a critical component in this equation as it drives the abatement of emissions, primarily through the retirement and/or winding down of coal plant production. However, with respect to renewable energy projects the carbon price has a lesser impact while the carbon price is insufficient to meet the renewable energy targets without additional certificate revenue. This is because any increase in carbon price raises pool prices which then reduce certificate prices. 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
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if REC prices are lower due to high energy prices elsewhere, such as in Western Australia.

C.1 Factors Considered

The market forecasts developed for Sustainability Victoria take into account the following parameters:

- regional and temporal demand forecasts
- generating plant performance
- timing of new generation including embedded generation
- existing interconnection limits
- potential for interconnection development

The following sections summarise the major market assumptions and methods utilised in the forecasts.

C.2 PLEXOS Software platform

The wholesale market price forecasts will be developed utilising SKM MMA's Monte Carlo NEM database. This database uses PLEXOS, a sophisticated stochastic mathematical model developed by Energy Exemplar (formerly Drayton Analytics) which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the

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same techniques that are used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

The long-term capacity expansion model in PLEXOS 5 is called "LT Plan". The purpose of the LT Plan model is to find the optimal combination of generation new builds and retirements and transmission upgrades that minimises the net present value of the total costs of the system over a long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective. Planning horizons for the LT Plan model are user-defined and are typically expected to be in the range of 20 to 30 years.

Once the capacity expansion plan has been determined, PLEXOS can then perform more detailed simulations, typically one year at a time, to more accurately model system dispatch and pricing. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on an hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, inter-connector constraints and any other operating restrictions that may be specified.

Expected hourly electricity prices for the NEM are produced as output, calculated either on a marginal cost bidding basis, or if desired, by modelling strategic behaviour, based on gaming models such as the Cournot equilibrium, long-run marginal cost recovery (or revenue targeting) or shadow pricing. SKM MMA uses a combination of user-defined bids and long-run marginal cost recovery to produce the price forecasts, and has benchmarked its NEM database to 2008/09 market outcomes using this algorithm to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes. There is no guarantee that such bidding behaviour and contracting levels will continue in the future but there is evidence of stable bidding behaviour for similar market conditions that supports this approach. Bidding behaviour post CPRS is more uncertain.

The impact of financial contracts on the bidding strategy of market participants can be incorporated either explicitly through specification of volumes and prices of individual contracts, or implicitly by specifying a proportion of a portfolio’s output that is typically contracted, and hence restricting strategic bidding to the uncontracted proportion.

There are four key tasks performed by PLEXOS:

- Forecast demand over the planning horizon, given a historical load profile, expected energy generation and peak loads.

- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models
- Calculate hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and price impacts of abatement schemes.

The model can estimate:

- Hourly, daily, weekly and annual generation levels, SRMC, fuel usage and capacity factors for individual units.
- Regional generation and prices for each trading period.
- Flows on transmission lines for each trading period.
- Total costs of generation and supply in the NEM including capital costs of generation, fixed and variable fuel costs, and fixed and variable non-fuel operating costs. This can be done for the system as a whole, for generation companies operating in the system and for each generating plant.
- Reliability, which can be measured in terms of expected energy not served and expected hours of load shedding.
- Company and generator costs and operating profits.
- Emissions of greenhouse gases. Emissions for each fuel type are modelled to get total system emissions.

One of the key advantages of this model is the detail in which the transmission constraints of electricity grids can be modelled. The PLEXOS model includes 5 regions: Tasmania, South Australia, Victoria, New South Wales, and Queensland. Inter-regional transmission constraints and the dispatch impacts of intra-regional transmission constraints are modelled using the constraint set provided by AEMO as used in the Annual National Transmission Statement (ANTS) 2008[34]. These constraints are dynamic with the limits typically being a function of regional demand, flows on other lines, inertia, number of units generating, and generation levels of relevant units. AEMO currently provides parameters for these constraints to 2020, and has also included a list of possible augmentations and the impact of these on the constraint set, for inclusion in forecasting models.

[34] The 2009 NTS has just been released but there is insufficient time to incorporate these new constraints in the modelling.

C.3 Scenario assumptions

The present study consists of seven scenarios, each with different levels of wind and large scale PV penetration in Victoria. The first scenario is the baseline scenario, in which no new wind or large scale PV capacity enters Victoria. The second through to the fifth scenarios model additional Victorian wind penetrations of 1000 MW, 2000 MW, 3000 MW and 4000 MW respectively, with no additional large scale PV capacity. These levels of wind penetration represent plausible market outcomes over the life of the expanded RET scheme. The sixth and seventh scenarios model 2000 MW of additional Victorian wind capacity, together with 250 MW and 500 MW respectively of additional large scale PV capacity. The scenario definitions are summarised in Table 4-1.

All scenarios assume that the 5% emission reduction target for 2020 is adopted by the Government, although its implementation is delayed until July 2014. The carbon price path is shown in Figure 4-1, and is adapted from the CPRS-5% price path employed in the Federal Treasury modelling.

C.3.1 Scenario methodology

Here we describe the methodology underlying the formulation of the scenarios. The first step is to run a base expansion plan with optimal least-cost new entry for thermal plant, which simultaneously satisfies the LRET constraint, also in a least cost way. All wind and PV capacity is then removed from Victoria, with the scenario specific wind and PV capacity added in its place, and any necessary thermal capacity in also installed at least cost in order to satisfy system adequacy and reliability constraints.

In running the initial base expansion plan, we found that about 2,500 MW of wind was the optimal renewable generation mix for Victoria. However, this meant that for Scenarios 4 and 5, we would have to remove renewable generation capacity from other regions to avoid over subscribing the LRET target, at least for the latter years. The wind capacity was removed from the other states on a proportional basis, but there was some lumpiness in the capacity removed (especially around 2015 and 2016, which is when wind capacity began ramping up in sufficient volume).

C.3.2 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 seven scenarios and reflect the most probable market outcomes given the current state of knowledge of the market. They include medium energy growth as well as median peak demands, as provided in AEMO's 2009 ESOO. The demand forecasts have been amended slightly to take account of differences in assumptions related to carbon prices in formulating the forecast, although the adjustment is quite minor at less than 0.3% after 2022.

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 medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market.
- Moomba to Sydney gas pipeline tariffs are consistent with the July 2002 submission to the ACCC by the Australian Pipeline Trust (APT).
- The Gunns pulp mill load and generation is not included in these scenarios as it is not apparent in the 2009 Tasmanian demand forecast.

Emissions abatement

- The MRET commenced on 1 April 2001, and was designed to integrate a renewable energy industry within the electricity market. The Australian Government's policy to achieve 2% additional renewable energy by 2010 has been implemented as a 9,500 GWh target. In August 2009, legislation was passed to expand the original MRET scheme to a 45,000 GWh target. Under more recent legislation, the LRET and SRES schemes have superseded the expanded MRET scheme. The LRET target as legislated is for 41,000 GWh of renewable generation by 2020 from large-scale renewable generation projects, and both schemes are expected to deliver more than 45,000 GWh of additional renewable energy by 2020. The LRET scheme remains similar to the existing scheme 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 \$10/tCO2e carbon price, there is enough gas fired generation to meet the Queensland gas fired generation target and so the GEC price would go to zero.
- The assessed DSM for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.

New entry technology

- Carbon capture and storage is not available until 2025/26.
- Generation from any nuclear process is not available in the study period.
- Geothermal generation becomes commercially viable in 2017.

Commissioned new entrants and assumed retirements

- The development of an additional four 230 MW gas turbines at the Braemar site in Queensland, two in October 2011 and two in October 2012[35]. These units are treated as variable in timing according to the market scenario.
- The commissioning of a 150 MW cogeneration plant by QAL in September 2012 located in central Queensland.
- ERM Power's plan for four 175 MW gas turbines at Wellington are treated as an expansion option according to market requirement[36].
- The commissioning of a third 25 MW unit at Port Lincoln in South Australia by International Power in January 2010.
- The commissioning of a 621 MW CCGT at Darling Downs by Origin Energy in May 2010, consisting of three 117 MW gas turbines and one 270 MW steam turbine.
- The commissioning of 2 x 275 MW gas turbines at Mortlake in Victoria by Origin Energy in October 2010.
- The commissioning of a 169 MW cogeneration plant by Rio Tinto in May 2010 at its Yarwun alumina refinery located in central Queensland.
- The development of the 400 MW Integrated Gasification Combined Cycle (IGCC) plant by HRL in the Latrobe Valley from November 2018. This project still seeks financial support and has a four year construction lead time, so this is considered the earliest feasible timing plus one year's further delay.
- The retirement of the 2 x 300 MW Munmorah units at the end of March 2014.
- The four units at Swanbank B progressively shut down from June 2010 to April 2012.
- Callide A is in indefinite dry storage but is to be used to test oxy-firing. We have included a single unit in our model from 2010/11 to 2015/16.

Network Augmentations

A series of network augmentations in Queensland and North New South Wales are included, consistent with the constraint workbook used for AEMO's ANTS studies. All routine augmentations listed in Table 9.2 of the 2008 SOO are included. Key augmentations assumed include:

35 Note that this power station has not yet reached financial closure
36 Note that this power station has not yet reached financial closure

- A series of augmentations to increase the Central to North Queensland intraregional limit by up to 870 MW by the summer of 2012/13
- A series of augmentations to gradually increase the Tarong limit over time.
- Removal of most intraregional transmission constraints post 2020, assuming that congestion would be alleviated as and when needed[37].

Any other interconnector upgrades will be co-optimised with generation capacity expansion in the LT Plan.

Drought effects and Hydro Optimisation

The drought has had a major impact in different regions, on hydro, pump and thermal units. The following modifications to 'normal' assumptions have been made to replicate these effects.

- Snowy Hydro annual generation has been reduced only for the Tumut scheme in the 2009 financial year to 95% of the long-term average. Full recovery is assumed thereafter.
- Dartmouth has been shutdown until winter 2011 due to drought effects. It comes on-line with a capacity of 130 MW and does not resume normal operation until winter 2012.
- Eildon has restricted energy limits up until winter 2011, at which time it resumes normal operation at 120 MW.
- The long-term annual generation of Hydro Tasmania's hydro generators has been reduced to 9500 GWh from 2012/13 and thereafter. The annual generation level is assumed to be 8249 GWh in 2009/10, and increases linearly to 9309 GWh in 2011/12 to reflect gradual recovery from the drought. The future generation level of 9500 GWh is less than the historical average of some 10,300 GWh.

C.4 Demand

C.4.1 Demand forecast and embedded generation

The demand forecast adopted by SKM MMA is based on AEMO's 2009 ESOO. The forecast was applied to the 2005/06 actual half-hourly demand profiles and is shown below for each region from Figure C-2 to Figure C-6 after being adjusted for carbon price. We have used the 2005/06 load shape as it reflects demand response to normal weather conditions and captures the observed demand coincidence between States. The demand and energy forecasts were originally developed by KPMG Econtech.

The flow chart in Figure C-1 presents SKM MMA's methodology for formulating the PLEXOS load forecasts.

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[37] Interconnector limits, and the central to north Queensland limit are still observed though.

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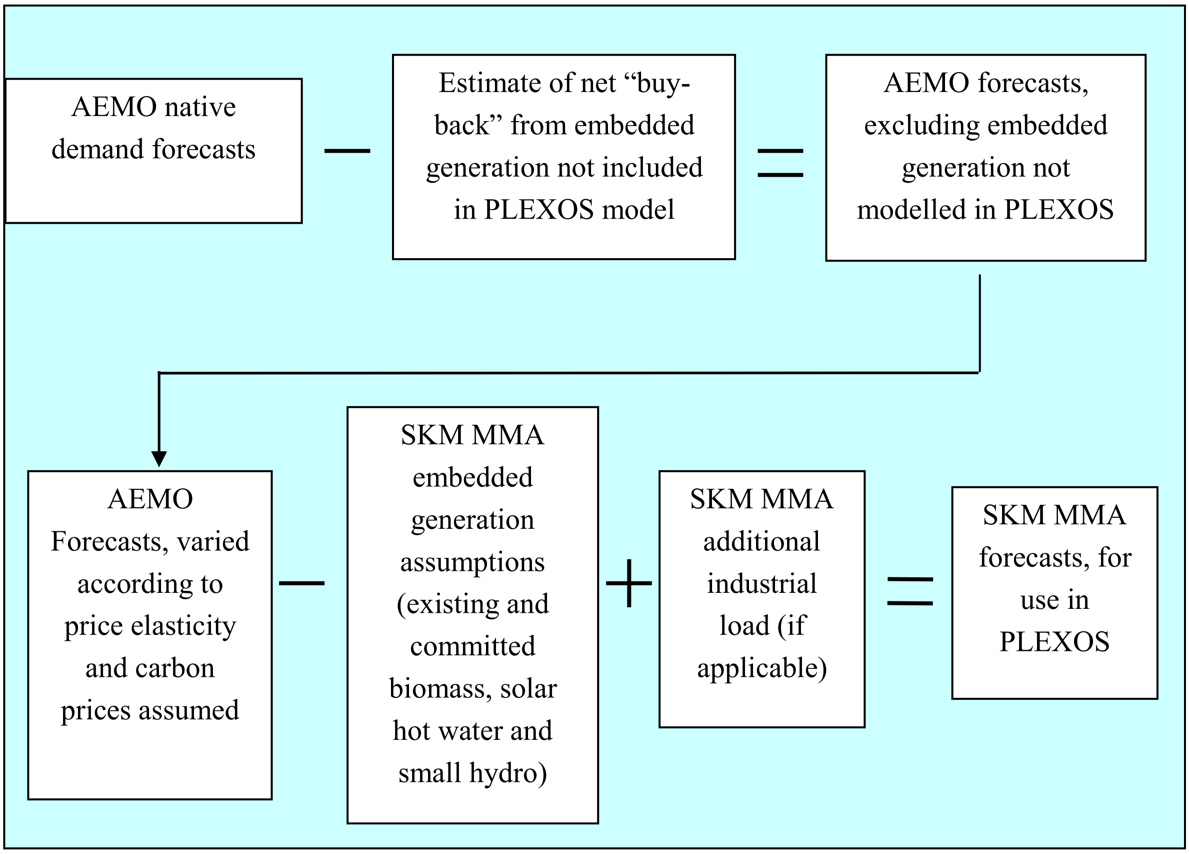
- **Figure C-1 SKM MMA's load forecast methodology**



The input demand is assumed to be sent-out demand rather than generator-terminal demand. AEMO's energy projections are expressed on a sent-out basis, but peak demand is expressed on a generator-terminal basis. Therefore the peak demand projections have been scaled down based on estimates of region average auxiliary losses.

In previous years, the input demand used by PLEXOS was assumed to be generator-terminal demand, and indeed the historical demand trace used to grow the loads is reported on a generator-terminal basis. Because regional auxiliary losses vary from period to period depending on the mix of generation being dispatched, there will be some error arising from using a generator-terminal base load profile for forecasting sent-out load on a half-hourly basis. Moreover, minimum reserve levels specified by AEMO are formulated on a generator-terminal basis rather than a sent-out basis.

However, this forecasting inconsistency was accepted to be minor compared to the error that could arise if assuming generator-terminal load for capacity planning purposes. Some of the potential new technologies such as Integrated Gasification Combined Cycle (IGCC) with or without Carbon Capture and Storage (CCS) have considerably larger auxiliary losses than current generation technologies. If demand were measured on a generator-terminal basis, any capacity expansion plan with these technologies included would essentially be implying lower demand from end-users relative to a plan without these technologies. This implication is clearly erroneous and was the motivating factor for switching to forecasting demand on a sent-out basis.

The introduction of the CPRS adds yet another complexity to the demand forecasting as it is anticipated that there will be some demand response to the predicted increase in electricity prices. We understand that the forecasts published in the 2009 ESOO already include assumptions on how demand may change in response to these higher electricity prices. The 2009 ESOO reports the long-run own price elasticity of electricity (PED) by region used to derive this anticipated demand response; these values are summarised in Table C-1 below. This PED represents the percentage change in demand expected for a 1% increase in electricity price.

The magnitude of the expected electricity price increase depends on a number of assumptions, but the key driver is the carbon price that is assumed. AEMO's carbon price assumptions are slightly lower than the assumptions we have used for the CPRS – 5% scenario. Consequently, it was necessary to reduce AEMO's forecasts slightly based on an assessment of how our higher carbon prices would influence electricity prices and hence demand response.

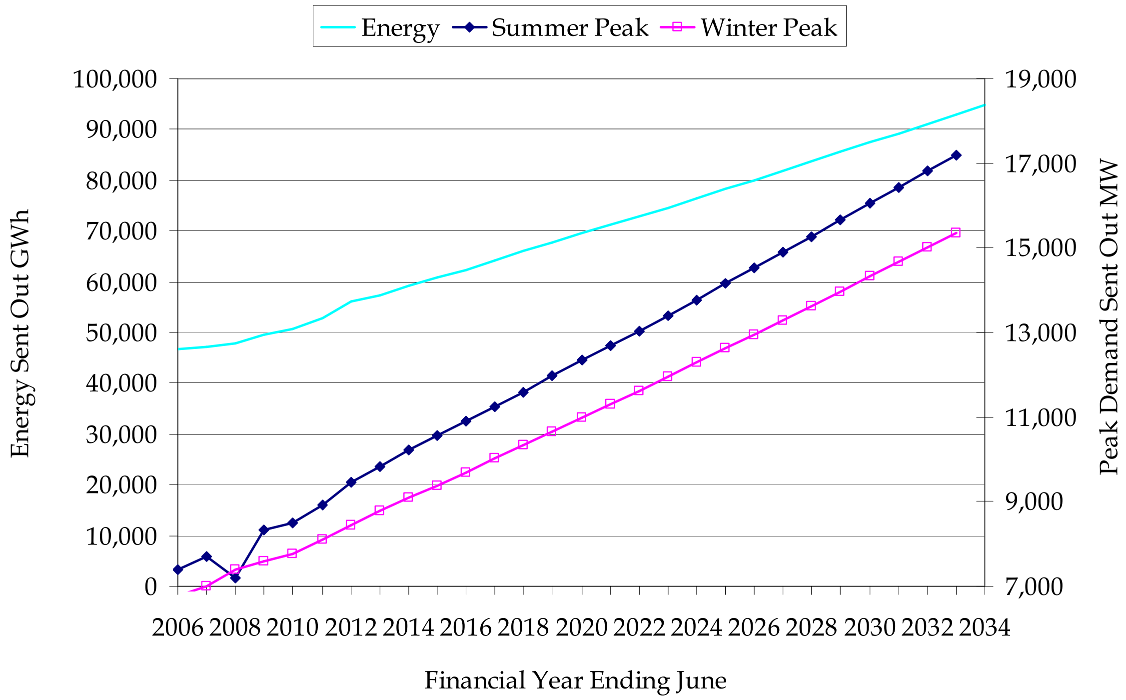
With respect to peak demand, we assumed the demand response would be significantly lower and therefore the corresponding change in peak demand was assumed to be only 25% that of the energy reduction.

- **Table C-1 Assumed price elasticity of demand**

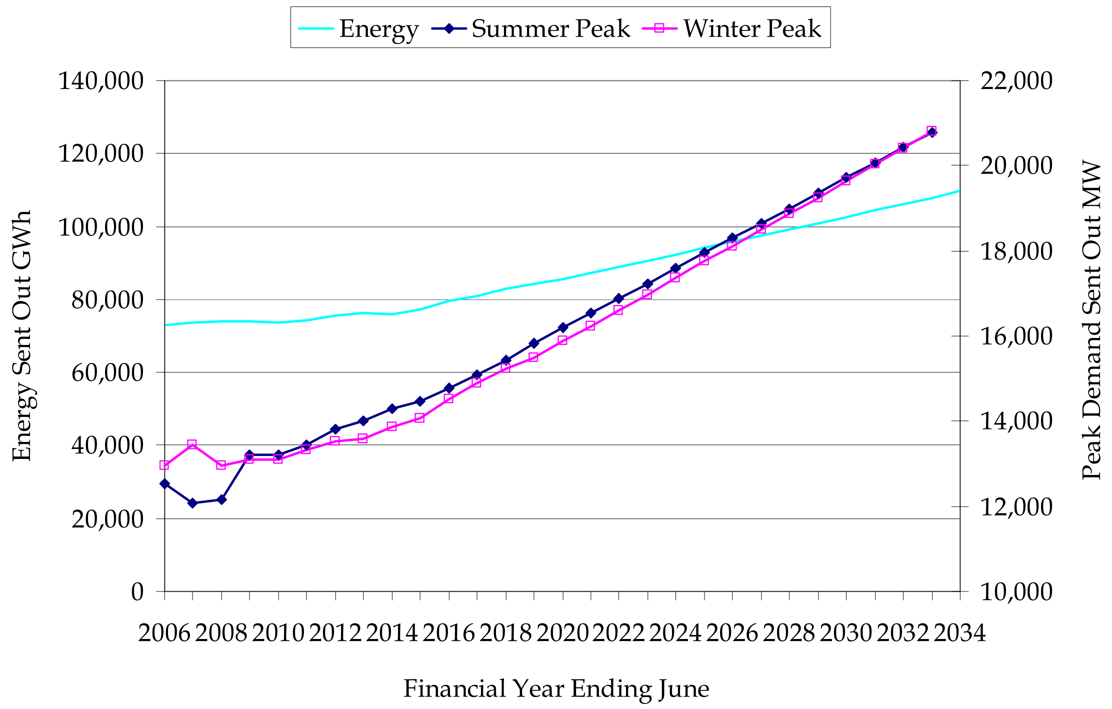
State	Price elasticity (%)
NSW	-0.37
VIC	-0.38
QLD	-0.29
SA	-0.25
TAS	-0.23

Source: Table 3.51 NEMMCO SOO 2008, ESIPC Annual Planning Report June 2009 page ix

- **Figure C-2 Demand growth forecast sent out for Queensland, Med 50POE**



- **Figure C-3 Demand growth forecast sent out for New South Wales, Med 50POE**



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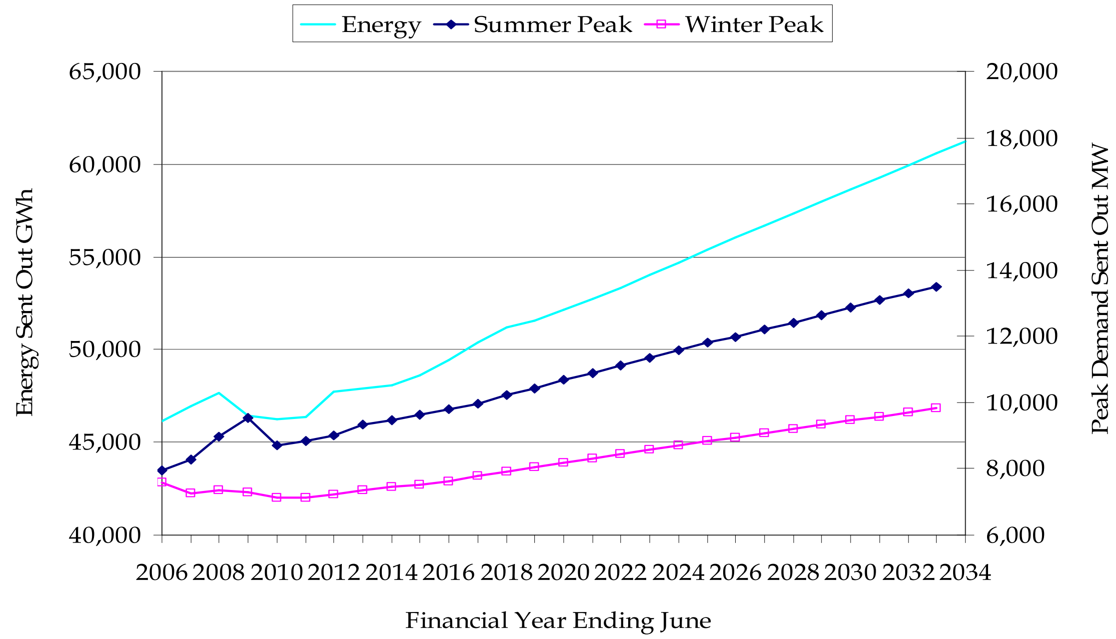
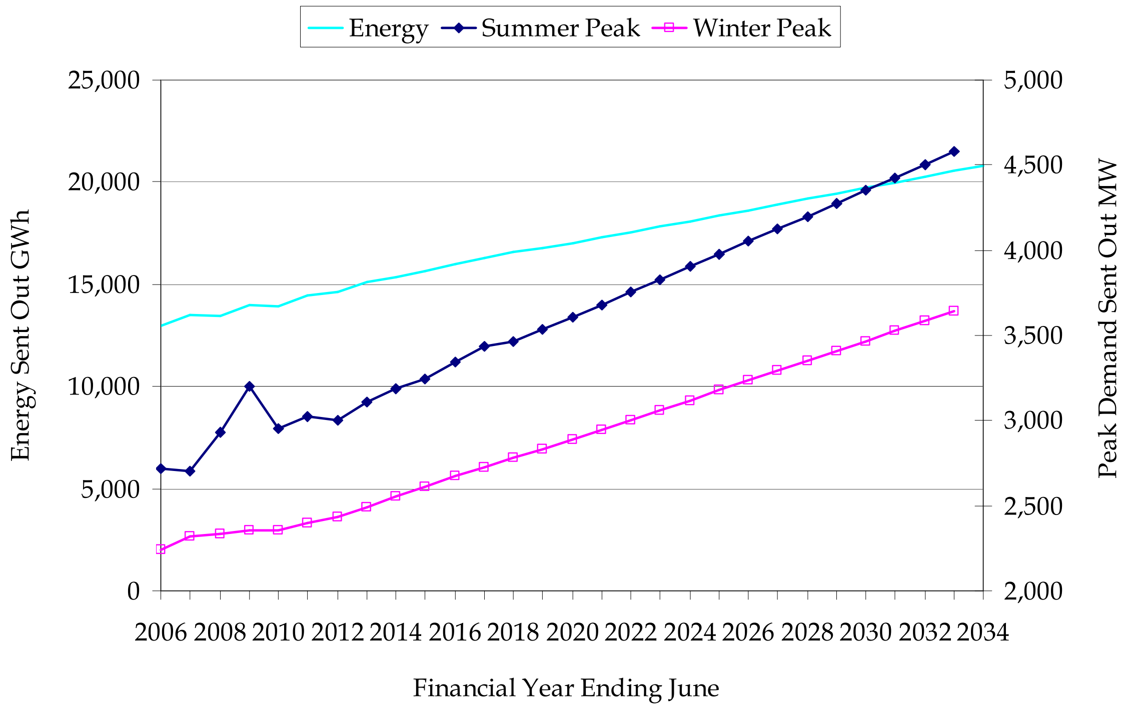
- **Figure C-4 Demand growth forecast sent out for Victoria, Med 50POE**



- **Figure C-5 Demand growth forecast sent out for South Australia, Med 50POE**



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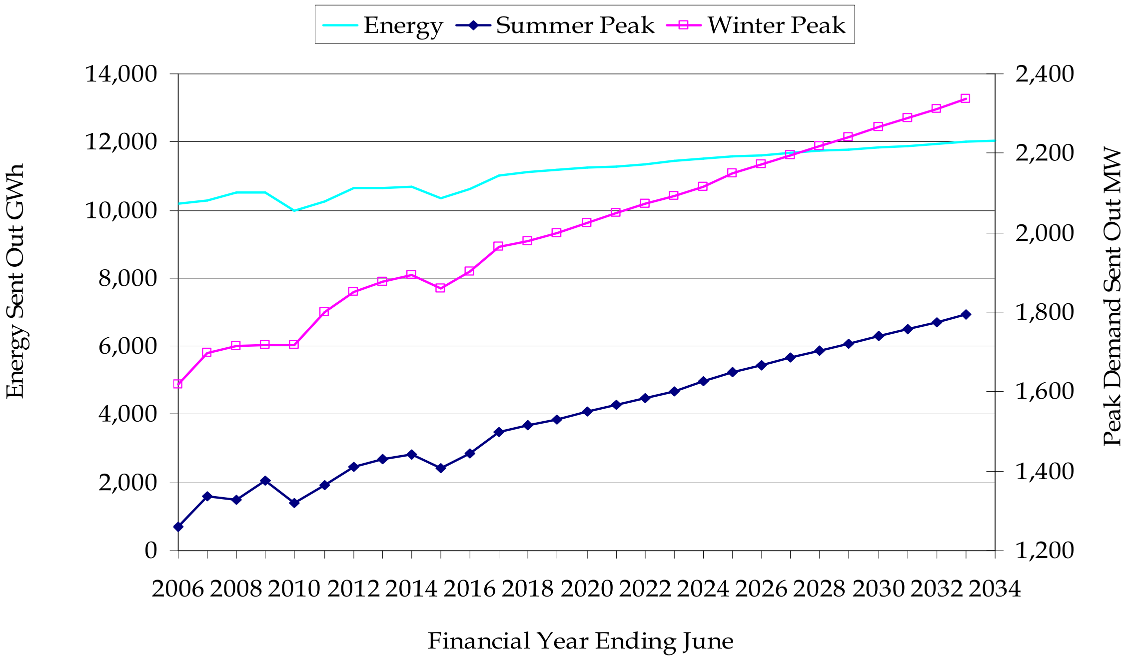
- **Figure C-6 Demand growth forecast sent out for Tasmania, Med 50POE**



C.4.2 Demand side participation

The total amount of demand side participation (DSP) explicitly modelled in SKM MMA's NEM database, as shown in Table C-2 is approximately 113 MW. These figures are based on committed DSP levels reported in AEMO's 2009 ESOO, apportioned to the various price bands using the ratios specified in the 2008 ANTS consultation final report.

- **Table C-2 DSP bid prices and quantities (MW) in the PLEXOS NEM database**

DSP Bid Price ($/MWh)	NSW	QLD	SA	VIC	TAS
500	0	1.6	0	10.77	0
1000	0	2	6.85	14.68	0
3000	0	2.8	5.87	21.53	0
5000	11	3.6	6.85	25.45	0

C.5 Supply

C.5.1 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 C-3. The parameters underlying these costs are presented in detail on a plant by plant basis in Appendix A. We 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 costs in Victoria and South Australia.

- **Table C-3 Indicative average variable costs for existing thermal plant ($June 2009)**

Technology	Variable Cost $/MWh	Estimated emissions intensity (t CO_2e/ MWh)	Technology	Variable Cost $/MWh	Estimated emissions intensity (t CO_2e/ MWh)
Brown Coal – Vic	$7 - $11	1.2 – 1.7	Brown Coal – SA	$20 - $26	1.1 – 1.7
Gas – Vic	$43 - $61	0.6 – 0.8	Black Coal – NSW	$19 - $22	0.9 – 1.1
Gas – SA	$36 - $170	0.4 – 0.7	Black Coal - Qld	$8 - $21	0.9 – 1.2
Oil – SA	$253 - $314	0.8 – 1.1	Gas - Queensland	$25 - $96	0.4 – 0.8
Gas Peak – SA	$96 - $172	0.6 – 1.0	Oil – Queensland	$240	0.9 – 1.1

C.5.2 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%. Capacity, fuel cost, heat rate and emissions production data at generator are shown in Appendix A. The heat rate and emissions production data quoted in Appendix Aare at full load. The average heat rate, and hence the emissions production coefficient, tend to degrade at lower load levels.

C.5.3 Planned Maintenance

By specifying the relevant maintenance rates and mean times to repair, PLEXOS will automatically schedule planned maintenance in the PASA and preschedule stage of simulation. Separate to this, the NEM database also has explicit planned maintenance schedules as published by AEMO or the plant operators. Accordingly, CS Energy major planned outages are included in the database[38].

Hydro power stations do not contain planned or forced outage data as they are assumed to be fitted out during times when they are not in operation.

C.6 Future NEM developments

C.6.1 Optimal new entry – LT Plan

The long-term capacity expansion model in PLEXOS 5 is called "LT Plan". The purpose of the LT Plan model is to find the optimal combination of generation new builds and retirements and transmission upgrades that minimises the net present value of the total costs of the system over a

[38] Updates taken from their respective sites and are current as of 5th January 2010

long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective. Planning horizons for the LT Plan model are user-defined and are typically expected to be in the range of 20 to 30 years.

LT Plan can be run either separately or integrated with PASA/MT Schedule/ST Schedule in a single simulation. In the latter role, the long-term build/retirement decisions made by LT Plan will be automatically passed to the more detailed simulation phases, providing a seamless solution.

This year, the LT Plan has been used to develop a NEM capacity expansion plan to 2030, accounting for expected carbon prices and the expanded RET. This section summarises the key assumptions and results.

Current computational restrictions limit the planning horizon for a NEM LT Plan to approximately 20 years; using monthly LDC's represented using fourteen load blocks per month.

New generation technologies

There are a number of proposed scheduled generation projects identified in the 2009 ESOO that are included as possible new entrants in the LT Plan. Additionally, generic new entrant technologies are considered including:

- Combined cycle gas turbines (CCGT) with and without carbon capture and storage (CCS)
- Generic open cycle gas turbines
- Integrated gasification combined cycle generators (IGCC), with and without CCS.

Supercritical and ultra-supercritical coal units are considered highly unlikely in the current market environment and are therefore not included in the current LT Plan, although they are present in the database to allow for modelling of alternate market scenarios.

The key input parameters assumed for each of the thermal new entrants considered in the current LT Plan are summarised in Table C-5. The capital costs have been annualised assuming an economic life of 30years. The pre-tax real equity return was 12% and the CPI applied to the nominal interest rate was 4%. With respect to modelling capital costs, we note that the rapid rate of increase in new entry capital costs experienced from 2005 to 2008 has now collapsed with the global financial crisis, which has seen metal prices fall sharply. We model this price collapse by allowing capital costs 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%.

Existing and new renewable generation

SKM MMA has developed an extensive renewable energy database that contains key costs and operating characteristics for existing, committed, and proposed renewable energy projects in

Australia. SKM MMA's renewable energy model (REMMA) uses this database to determine the least cost combination of renewable energy projects to meet the expanded RET in each year. Renewable generators across all states in Australia are eligible to contribute towards the expanded RET scheme.

In the LT Plan it is not plausible to include every potential renewable energy project identified in our database. However, it is important to co-optimise renewable and thermal generation within the expansion plan to ensure that the impact of expanded RET is being adequately represented. We have therefore used the information in our renewable energy database to develop time-dependent supply cost curves by state for four key renewable sources: wind, geothermal, hydro, and biomass.

By fitting a step-function to these cost-curves, up to five generic renewable projects where identified for each technology by state, with various cost structures. These projects were included as options within the LT Plan and were co-optimised with thermal generation taking account of the:

- assumed firm contribution to peak load,
- renewable generation volumes required to meet the expanded RET (ignoring banking)
- impact of large volumes of renewable generation on the operating regime of thermal generators.

Additionally, penetration into the market of intermittent technologies such as wind is dependent on the ability of the system to absorb such generation. Therefore, the amount of installed wind capacity in each region was capped at 25% of that region's peak demand, consistent with assumptions made for the Federal Treasury modelling of the impact of CPRS.[39] If the transmission network to Victoria was upgraded we would expect that this cap could be exceeded in South Australia.

Retirements

The retirements are co-optimised with new entry, taking account of the avoidable costs assumed and the minimum reserve levels required in each state. Only units considered most significantly impacted by CPRS are included as retirement options in the LT Plan. These units include:

- Hazelwood, Yallourn, Loy Yang A and Loy Yang B brown coal units in Victoria
- Playford in South Australia, and
- Collinsville and Tarong in Queensland.

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[39] MMA (2008) Impact of the Carbon Pollution Reduction Scheme on Australia's Electricity Market.

The avoidable costs assumed for these units are consistent with the Federal Treasury assumptions used to model the impact of CPRS. Table C-4 summarises the avoidable cost assumptions for the key incumbents at risk from the CPRS.

In addition, the Munmorah black coal units are retired in May and July 2014 as per the 2009 ESOO, and Swanbank B is gradually retired between 2010 and 2012, as per CS Energy's recent announcement.

Table C-4 Avoidable cost assumptions for incumbents

Power station	Avoidable costs ($/kW/yr)
Collinsville	36
Tarong	38
Playford	55
Hazelwood	88
Yallourn	82
Loy Yang A	74
Loy Yang B	59

Network augmentations

Major network augmentations are co-optimised with commitment and retirement of generators in the LT Plan.

Constraints

The LT Plan seeks to minimise the cost of investment and production from a centrally co-ordinated perspective subject to a number of constraints including:

- Constraints on construction resources limiting the rate of IGCC development to one unit per state per year
- Earliest start years for some technologies (for example CCS is assumed not to be available prior to 2024 in Victoria and 2026 in other states, and geothermal is assumed not to be commercially viable until 2017 at the earliest)
- Requirements to meet the expanded RET
- wind limited to 25% of peak demand in each region
- Limits on the maximum number of units built in year, and maximum number of units built total
- Firm capacity requirements to meet minimum reserve levels for each zone

For upgrades of GTs to CCGTs, constraints are imposed to ensure that the GTs are retired and replaced by the CCGT alternatives.

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Table C-5 Key input assumptions for prospective new entrants (generator terminal assumptions)

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)	Emissions intensity at max (t CO_2e /MWh)
Victorian new entry options													
Generic-VIC-GT	161	757	1.04	-1.0%	-1.0%	1%	10	2011	2.27	1.009	10.3	10.9	0.671
Maryvale Cogen	150	2393	1.04	-1.0%	-1.0%	2%	1	2011	3.22	0.957	27.6	6.9	0.425
Latrobe CCGT	373	1078	1.06	-1.0%	-1.0%	2%	0	2011	3.26	0.970	19.8	7.1	0.437
Generic-VIC-IGCC	500	2404	1.10	-1.0%	-1.0%	25%	0	2014	4.08	0.970	39.8	7.3	0.690
Generic-VIC-IGCC-CS	500	2970	1.10	-1.6%	-0.5%	24%	10	2025	4.94	0.961	57.6	8.7	0.823
Generic-VIC-Sup	723	2017	1.10	-0.5%	-0.5%	12%	10	2012	5.22	0.970	40.5	9.0	0.851
Generic-VIC-USup	723	2420	1.10	-1.0%	-0.5%	12%	10	2012	5.22	0.970	40.5	8.6	0.813
Generic-VIC-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	10	2011	3.26	0.970	23.9	7.1	0.437
Generic-VIC-CCGT-CS	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.18	0.970	39.0	7.2	0.443
Mortlake CCGT upgrade	500	1016	1.06	-1.0%	-1.0%	2%	1	2011	3.39	1.008	95.1	7.1	0.439
ShawRiver CCGT	500	1118	1.06	-1.0%	-1.0%	2%	3	2011	3.39	1.008	95.1	7.1	0.439
New South Wales new entry options													
Buronga GT	140	869	1.03	-1.0%	-1.0%	1%	1	2011	2.28	1.018	10.3	10.9	0.803
Parkes GT	136	872	1.04	-1.0%	-1.0%	1%	1	2011	2.32	1.016	10.3	10.9	0.680
Pt Kembla	190	1300	1.04	-1.0%	-1.0%	2%	0	2014	3.58	0.995	29.8	6.9	0.430

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)	Emissions intensity at max (t CO_2e /MWh)
Generic-NSW-GT	200	874	1.04	-1.0%	-1.0%	1%	10	2011	2.22	0.997	10.3	10.7	0.667
Generic-NSW-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	10	2011	3.31	0.987	23.9	7.1	0.443
Generic-NSW-CCGT-CS	500	1795	1.05	-1.0%	-0.5%	10%	10	2025	4.16	0.961	39.0	7.1	0.443
NSW-CCGT-MM	350	1199	1.06	-1.0%	-1.0%	2%	4	2011	3.31	0.984	18.8	7.1	0.443
Tomago GT	250	694	1.04	-1.0%	-1.0%	1%	2	2011	2.16	0.980	10.3	10.5	0.655
Tomago CCGT upgrade	750	996	1.06	-1.0%	-1.0%	2%	1	2011	3.24	0.980	18.8	7.1	0.443
Bamarang GT	330	676	1.04	-1.0%	-1.0%	1%	1	2011	2.16	0.980	10.3	10.5	0.655
Bamarang CCGT upgrade	450	1055	1.06	-1.0%	-1.0%	2%	1	2011	3.24	0.980	18.8	7.1	0.443
Marulan_D GT	330	676	1.04	-1.0%	-1.0%	1%	1	2011	2.21	0.981	10.3	10.5	0.655
Marulan_D CCGT upgrade	420	1063	1.06	-1.0%	-1.0%	2%	1	2011	3.32	0.981	18.8	7.1	0.443
Mt Piper Ext 1	1000	889	1.03	-1.0%	-1.0%	6%	0	2010	2.39	0.961	27.6	9.1	0.821
Mt Piper Ext 2	1000	889	1.03	-1.0%	-1.0%	6%	0	2011	2.39	0.961	27.6	9.1	0.821
Wellington GT	175	853	1.04	-1.0%	-1.0%	1%	5	2007	2.17	0.953	10.3	10.9	0.680
Generic-NSW-IGCC	710	2397	1.07	-1.6%	-1.0%	22%	0	2014	1.98	0.961	37.1	7.1	0.641
Generic-NSW-IGCC-CS	630	3181	1.10	-1.6%	-1.0%	25%	10	2025	2.91	0.987	40.6	8.6	0.776
Generic-NSW-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.12	0.980	29.9	8.8	0.800
Generic-NSW-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.18	0.987	37.3	8.0	0.727

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)	Emissions intensity at max (t CO_2e /MWh)
South Australian new entry options													
Arckaringa	280	2404	1.10	-1.0%	-1.0%	25%	3	2014	4.05	0.964	39.8	7.3	0.709
Generic-SA-GT	130	909	1.04	-1.0%	-1.0%	1%	10	2011	5.60	1.001	32.0	10.9	0.673
Generic-SA-CCGT	242	1393	1.06	-1.0%	-1.0%	2%	0	2011	3.36	1.001	22.1	7.1	0.438
Hallett 11_12	130	472	1.03	-1.0%	-1.0%	1%	3	2010	3.72	1.001	32.0	10.9	0.673
Mintaro2	40	577	1.03	-1.0%	-1.0%	1%	0	2010	3.60	0.965	33.9	15.9	0.982
PPCCGT2	300	1105	1.06	-1.0%	-1.0%	2%	1	2010	3.36	1.001	22.1	7.1	0.438
Large-SA-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	0	2011	3.24	0.980	23.9	7.1	0.438
Generic-SA-CCGT-CS	500	1795	1.05	-1.0%	-0.5%	10%	10	2025	4.31	1.001	39.0	7.2	0.445
Queensland new entry options													
Generic-QLDNth-GT	130	909	1.04	-1.0%	-1.0%	1%	10	2011	5.60	1.000	32.4	10.9	0.673
Generic-QLDNth-CCGT	170	1447	1.06	-1.0%	-1.0%	2%	10	2011	3.36	1.000	19.5	7.8	0.482
Generic-QLDNth-CCGT-CS	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.31	1.000	39.0	7.2	0.445
Large-QLDNth-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	0	2011	3.29	1.000	23.9	7.1	0.438
Generic-QLDSth-GT	146	765	1.04	-1.0%	-1.0%	1%	10	2008	3.81	1.068	31.9	10.9	0.673
Generic-QLDSth-CCGT	393	1324	1.06	-1.0%	-1.0%	2%	10	2011	3.64	1.068	19.3	7.1	0.438
Generic-QLDSth-CCGT-CS	500	993	1.06	-1.0%	-0.5%	10%	10	2025	4.54	1.068	39.0	7.2	0.445

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)	Emissions intensity at max (t CO_2e /MWh)
SWAN_F	400	1069	1.06	-1.0%	-1.0%	2%	1	2011	3.31	0.978	23.9	7.1	0.393
Generic-QLDTar-BLCL	450	2057	1.10	-1.0%	-1.0%	6%	0	2017	3.35	0.995	32.8	9.4	0.823
Spring Gully	500	1136	1.06	-1.0%	-1.0%	3%	10	2011	3.37	0.968	19.3	7.0	0.387
Generic-QLDTar-CCGT	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.21	0.968	39.0	7.2	0.398
MPP_BLCL	420	1739	1.12	-1.0%	-1.0%	6%	0	2013	2.23	0.995	27.5	9.4	0.823
TNPS2	441	1841	1.12	-1.0%	-1.0%	6%	0	2013	1.03	1.000	31.5	9.4	0.849
Braemar exp	173	348	1.04	-1.0%	-1.0%	1%	10	2008	3.55	0.968	31.9	10.9	0.603
Generic-QLDTar-IGCC	710	2397	1.07	-1.6%	-1.0%	22%	0	2014	2.05	1.000	37.1	7.1	0.622
Generic-QLDTar-IGCC-CS	630	3181	1.07	-1.6%	-1.0%	25%	10	2025	2.89	0.968	40.6	8.6	0.753
Generic-QLDTar-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.000	29.9	8.8	0.771
Generic-QLDTar-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.16	0.968	37.3	8.0	0.701
Generic-QLDCen-CCGT	388	1374	1.06	-1.0%	-1.0%	2%	1	2011	3.25	0.971	19.5	7.4	0.457
Generic-QLDCen-BLCL	450	2057	1.10	-1.0%	-1.0%	6%	0	2012	3.89	0.971	32.8	9.4	0.917
Generic-QLDCen-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.002	29.9	8.8	0.858
Generic-QLDCen-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.002	37.3	8.0	0.780
Generic-QLDCen-IGCC	710	2397	1.10	-1.6%	-1.0%	22%	10	2014	2.05	1.002	37.1	7.1	0.692
Generic-QLDCen-IGCC-CS	630	3181	1.10	-1.6%	-1.0%	25%	10	2025	2.96	1.002	40.6	8.6	0.839

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)	Emissions intensity at max (t CO_2e /MWh)
Tasmanian new entry options													
Generic-Tas-GT	161	354	1.04	-1.0%	-1.0%	1%	10	2011	5.67	1.009	31.7	10.9	0.684
Generic-Tas-CCGT	200	1422	1.06	-1.0%	-1.0%	2%	3	2012	3.36	0.999	16.8	7.8	0.489
Large-Tas-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	0	2011	3.36	0.999	23.9	7.1	0.445
Generic-Tas-CCGT-CS	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.30	0.999	39.0	7.2	0.452

*IDC = Interest during construction

SKM MMA

C.6.2 New entry

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 C-6 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.

- **Table C-6 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

C.7 Transmission losses

C.7.1 Inter-regional losses

Inter-regional losses are modelled in PLEXOS directly through the use of the Loss Factor equations which are periodically published by AEMO. The latest set produce by AEMO[40] is incorporated in the current database as follows:

Loss factor equation of NSW1-QLD1 (South Pine 275 referred to Sydney West 330)

$= 0.9751 + 1.8839E\text{-}04*NQ_t – 7.9144E\text{-}07*N_d + 1.1623E\text{-}05*Q_d$

Loss factor equation of VIC1-NSW1 (Sydney West 330 referred to Thomastown 66)

$= 0.9649 + 1.7257E\text{-}04*VN_t – 1.4631E\text{-}05*V_d + 5.7202E\text{-}06*N_d + 1.4938E\text{-}05*S_d$

Loss factor equation of V-SA (Torrens Island 66 referred to Thomastown 66)

$= 1.0235 + 3.5816E\text{-}04*VSA_t – 4.6640E\text{-}06*V_d + 5.9808E\text{-}06*S_d$

Loss factor equation of Terranora (South Pine 275 referred to Sydney West 330)

$= 0.0726*Flow_t + 7.9652\text{-}04*(Flow_t)^2$

40 List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year.

Loss factor equation of Murraylink (Torrens Island 66 referred to Thomastown 66)

$= 0.0596*Flow_t + 1.4770E\text{-}03*(Flow_t)^2$

where,

Q_d = Queensland demand

V_d = Victorian demand

N_d = New South Wales demand

S_d = South Australian demand

NQ_t = transfer from New South Wales to Queensland

VN_t = transfer from Victoria to New South Wales

VSA_t = transfer from Victoria to South Australia

$Flow_t$ = flow through the relevant line

The Basslink loss factor equations were optimised to match flows against losses (in both transfer directions) in a separate SKM MMA analysis. The parameters of the quadratic fit are used in PLEXOS and are presented in Table C-7. SKM MMA treats Basslink's losses in this way in order to model all losses between the Georgetown reference node and the Thomastown reference node. AEMO's published equations for Basslink losses are not sufficient to input into PLEXOS as they are only applicable between Georgetown and the Loy Yang node, which is Basslink's connection point to the mainland.

- **Table C-7 PLEXOS loss parameters for Basslink flows**

PLEXOS Property	Value
Loss Base (Constant)	0.92985000
Loss Incr (Linear term)	0.03663000
Loss Incr2 (Quadratic term)	0.00007400
Loss Base Back (Constant)	0.02589937
Loss Incr Back (Linear term)	-0.03552415
Loss Incr2 Back (Quadratic term)	0.00010341

C.7.2 Apportioning Inter-Regional Losses to Regions

PLEXOS emulates AEMO's dispatch engine (NEMDE) in that it allocates the inter-regional losses arising from the preceding loss factor equations to the two regions associated with the relevant interconnector. The apportioning factors used are those published by AEMO in its periodic publication on Marginal Loss Factors[41]. The latest apportioning factors are presented in Table C-8.

- **Table C-8 Interconnector loss apportioning factors**

Interconnector	Apportioning factor	Region applied to
NSW1-QLD1	0.57	NSW
Terranora	0.65	NSW
VIC1-NSW1	0.61	NSW
V-SA	0.70	Vic
Murraylink	0.72	Vic

C.7.3 Intra-regional losses

Intra-regional loss factors refer each generating unit to the regional reference node and are entered into PLEXOS directly. These factors are also sourced from AEMO's periodic publication on Marginal Loss Factors[42].

C.8 Hydro modelling

Small hydro systems such as those owned by Southern Hydro are modelled using bids supplied with the ANTS 2008 or annual energy limits. Dartmouth and Eildon have energy constraints restraining production due to the effects of drought.

For larger hydro systems such as the Snowy hydro generation system (excluding Blowering), a more complex cascading network has been set up in the database to emulate physical water flows and levels in the storages. This follows a similar modelling structure to that used by AEMO. Details of AEMO's methodology can be found in the 2008 ANTS Consultation: Final Report.

The inflow data in the 2008 ANTS was provided for the Eucumbene storage rather than for Tumut and Murray separately. Accordingly, we have now included this storage in the Snowy representation. Furthermore, in order to allow PLEXOS to appropriately allocate hydro from this large storage to Tumut and Murray, volumes in storage are now measured in cumec days (CMD) rather than GWh, and efficiencies (MW/cumec) are input for each of the generators on the river chain. This required changing the storage model used in the database from "potential energy" to "metric volume".

The ANTS storage volumes are expressed in ML and can be simply converted to CMD given that 1 CMD is equivalent to 86.4 ML. Similarly, we have converted storage inflows from GL to cumecs.

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41 *Ibid.*

42 *Ibid.*

The *efficiency incr* (MW/cumec) property values for generators drawing water from storage are summarised in Table C-9 and have been calculated using the following formula:

MW/cumec = head [in meters] * efficiency * 9.80665 /1000

where an efficiency of 83% is assumed for all generators.

All hydro systems within the same database need to use the same units. Therefore, all storages are measured in CMD and inflows are measured in cumecs. One CMD is equivalent to 24 cumecs. For most of the storages outside the Snowy hydro scheme, rather than convert inflows from MW to cumecs, we have converted the storage initial and end volumes assuming that 1 CMD = 24 MWh. This ensures internal consistency when calculating hydro energy potential[43].

- **Table C-9 Calculation of MW/cumec efficiency factors for hydro generators attached to storages**

Station	head [m]	efficiency	MW/cumec
Kareeya	420	0.83	3.42
Murray Inflow	855	0.83	6.96
Murray1	517	0.83	4.21
Murray2	285	0.83	2.32
Tumut Inflow	811	0.83	1.83
Tumut1	330	0.83	2.69
Tumut2	275	0.83	2.24
Tumut3	160	0.83	1.30

The storages in PLEXOS cycle back to their initial volumes at the end of every year which means all inflows must either be released from the system via generation or waterways. Inflow inputs are based on historical monthly inflows. Since storages are assumed to recycle within a year, the inflows (less spill) determine the generation levels on an annual basis[44].

C.8.1 Queensland hydro

The Barron Gorge, Kareeya and Wivenhoe hydro systems in Queensland are modelled in PLEXOS using storage objects. Storage inflows assumed are consistent with the 2009 NTS assumptions.

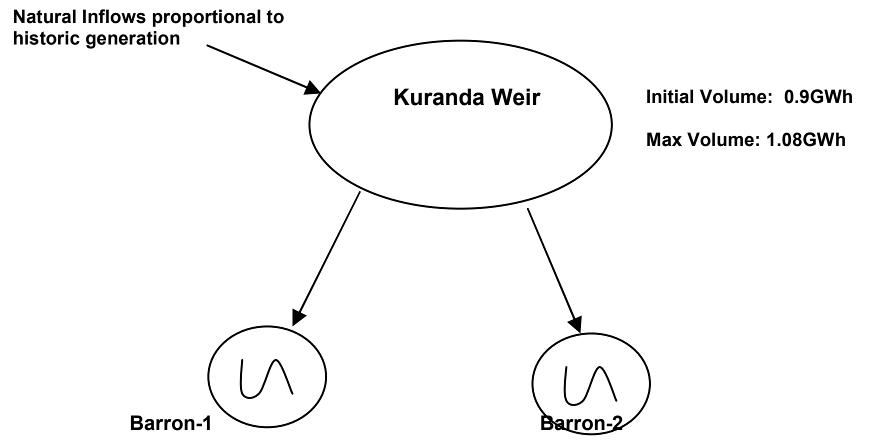
43 This is an interim measure. In future versions of the database, we anticipate converting all inflows from MW to cumecs.

44 Distribution of generation within the year is based on the water value (an endogenous variable) which accounts for the opportunity cost of thermal resources displaced by the hydro generation in future periods.

SKM MMA

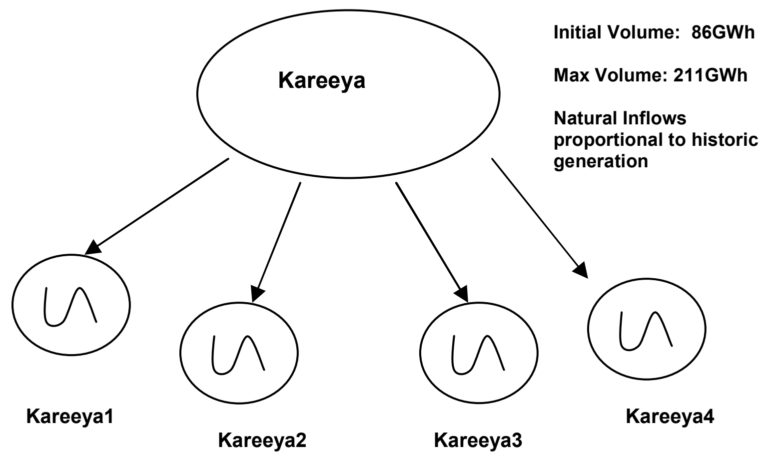
Visual representations and properties of the hydro systems modelled in PLEXOS are presented below from Figure C-7 to Figure C-9.

- **Figure C-7 Representation of Barron Gorge hydro system**



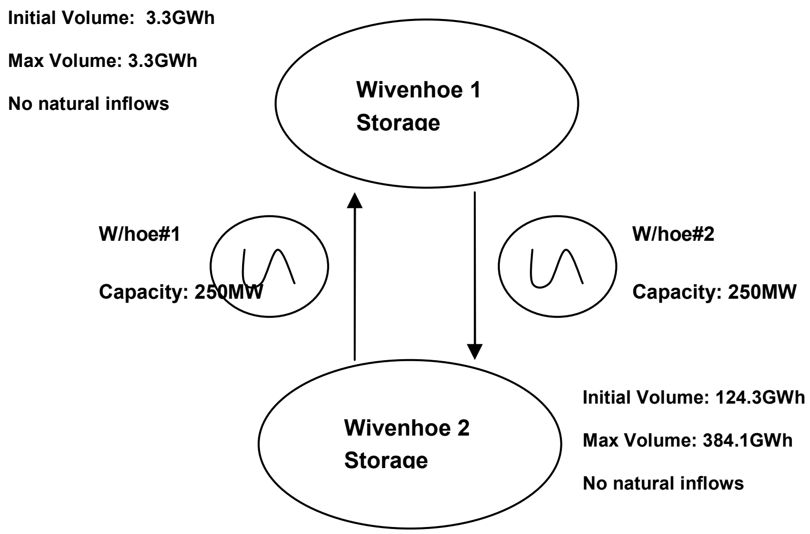
NOTE: In PLEXOS, the storage volumes for this storage are increased by a factor of 41.6667 (1/0.0024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

- **Figure C-8 Representation of Kareeya hydro system**



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

- **Figure C-9 Representation of Wivenhoe pump storage system**



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

C.8.2 Snowy Mountains Scheme

There are seven power stations in the Snowy Mountains Scheme: Guthega, Blowering, Tumut 1, Tumut 2, Tumut 3, Murray 1 and Murray 2. The combined average annual production from the scheme is 4,500 GWh[45], excluding additional generation obtained from pumping. Lake Eucumbene is the main storage for the scheme, with inflows from the storage feeding both the Tumut and Murray hydro systems. There are also three pump storage units at Tumut 3, allowing water to be pumped back up to the Talbingo dam if economic to do so. In PLEXOS we have assumed a pump efficiency of 70% for these three units, meaning that for every MW of pump load, 0.7 MW of potential energy is returned to the Talbingo dam.

The Guthega power station is modelled as a separate hydro system with natural inflows equivalent to the inflows assumed in the 2009 NTS.

In PLEXOS the Blowering power station is not connected to any storage, but instead we use monthly energy constraints to limit its generation potential. These constraints are summarised in Table C-10 below.

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45 http://www.snowyhydro.com.au/levelThree.asp?pageID=244&parentID=66&grandParentID=4. last cited 08/01/2010

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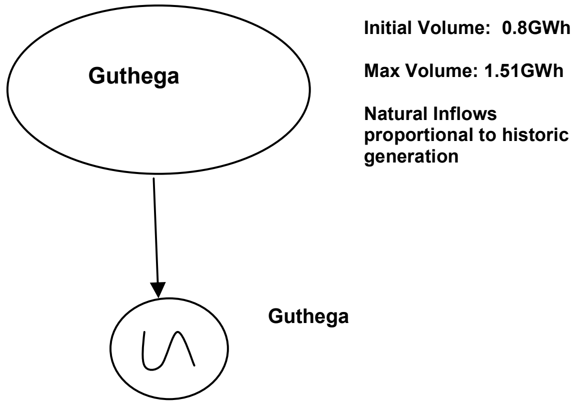
Table C-10 Monthly energy constraints for Blowering (GWh)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	0	0	0	0	0	6	25	31	34

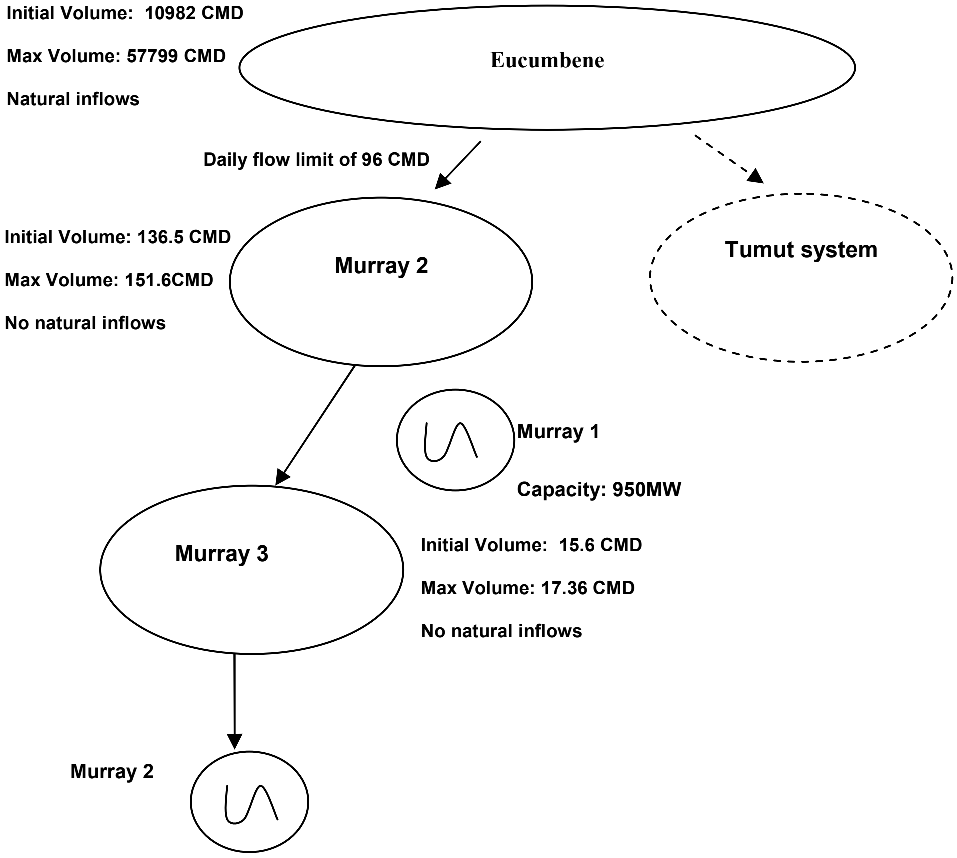
Source: NEMMCO (2009) NTS Consultation Final Report, Table 18, pg62

Visual representations and properties of the Snowy Mountains hydro storage systems modelled in PLEXOS are presented below from Figure C-10 to Figure C-12.

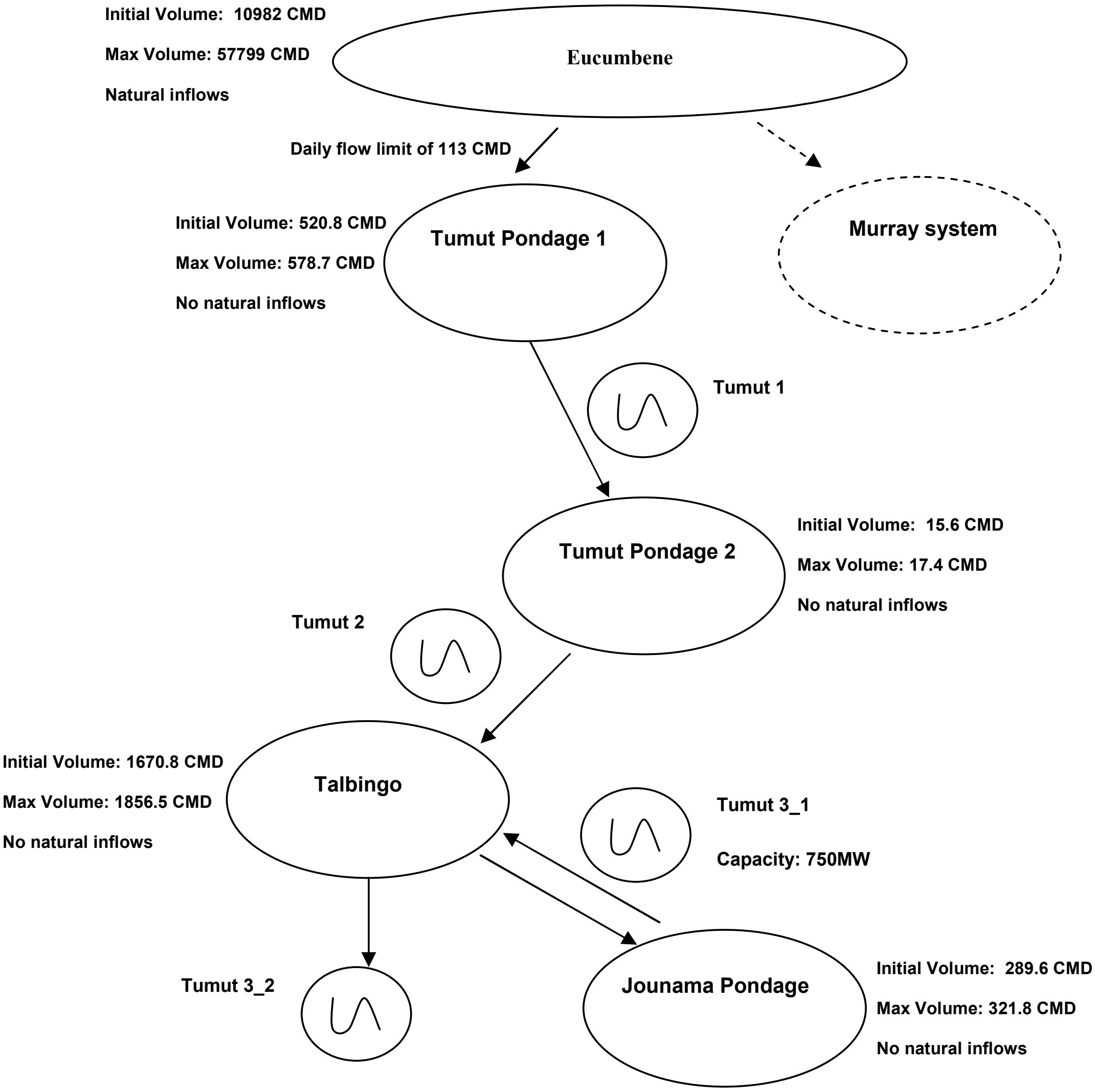
Figure C-10 Representation of Guthega hydro system



- **Figure C-11 Representation of Murray hydro system**



- **Figure C-12 Representation of Tumut hydro and pump storage systems**



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

C.8.3 Southern Hydro

Southern Hydro operates Dartmouth, Eildon, West Kiewa, and McKay Creek hydro power stations, with Bogong currently under construction. In PLEXOS, these power stations are modelled using monthly energy constraints, based on average output from 1999 to 2007. The last two years have not been used in calculating these long-term averages due to the drought impact. Bogong is assumed to have an annual average output of 94 GWh.

■ **Table C-11 Monthly energy constraints for Blowering (GWh)**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Dartmouth	24.9	21.0	10.8	4.3	3.3	6.0	11.3	28.7	27.9	35.3	35.2	29.5
Eildon	20.0	16.0	16.3	10.3	1.8	0.4	0.6	2.1	3.7	5.9	7.0	13.6
McKay	4.9	6.1	2.0	3.6	4.5	7.7	9.9	6.2	12.0	12.6	8.6	6.0
W. Kiewa	5.7	5.5	4.0	4.6	6.7	13.2	15.0	16.9	24.9	21.6	14.0	9.3

In the short term, the winter ratings and annual output for both Dartmouth and Eildon and have been reduced to reflect the drought impact. These reductions are progressively lifted and by summer 2012/13 Southern Hydro is expected to be back to full capacity. Dartmouth does not expect to commence operation again until winter 2011.

C.8.4 Hydro Tasmania

The Tasmanian hydro system is represented using three water storages which can be identified in the database as TAS Long-Term, TAS Medium-Term and TAS Run of River. The individual power stations associated with each of the three storages are presented below in Table C-12.

Tasmanian storage inflows are historical monthly inflows obtained from the 2009 NTS that have been adjusted in the short to medium term to reflect the current drought conditions. For the 2009 financial year, Tasmanian storage inflows are at 73% of the long-term average. This percentage is increased linearly until 2013, by which time we assume that the Tasmanian storages have fully recovered from the current drought conditions. Long-term average inflows are assumed to be equivalent to 9,500 GWh per annum, consistent with the ANTS, although it is noted that Hydro Tasmania has indicated that the future long-term average may be lower than this.

As with the other hydro systems, having specified monthly inflows obtained from the 2009 NTS, PLEXOS will optimise the use of the water within the year taking account of storage upper and lower bounds.

- **Table C-12 Tasmanian hydro power station maximum capacities and allocation to the three storages**

Storage	Generator	Max Capacity (MW)
Long Term	Gordon	432
	Poatina110	100
	Poatina220	200
Medium Term	Bastyan	80
	Catagunya	48
	Fisher	43
	JohnButters	144
	LakeEcho	32
	Liapootah	84
	Mackintosh	80
	Tarraleah	90
	Tungatinah	125
	Wayatinah	38
Run of River	Cethana	85
	DevilsGate	60
	Meadowbank	40
	Reece1	116
	Reece2	116
	Lemonthyme	51
	Trevallyn	95
	Tribute	83
	Wilmot	31

C.8.5 Other hydro systems

Other hydro systems included in the market simulations include the Shoalhaven pump storage system and the Hume hydro system.

The Shoalhaven pump storage system is effectively a closed-system with little/no storage inflows. The representation of this system in PLEXOS is shown in Figure C-13. For the pumping units, a pump efficiency of 70% is assumed.

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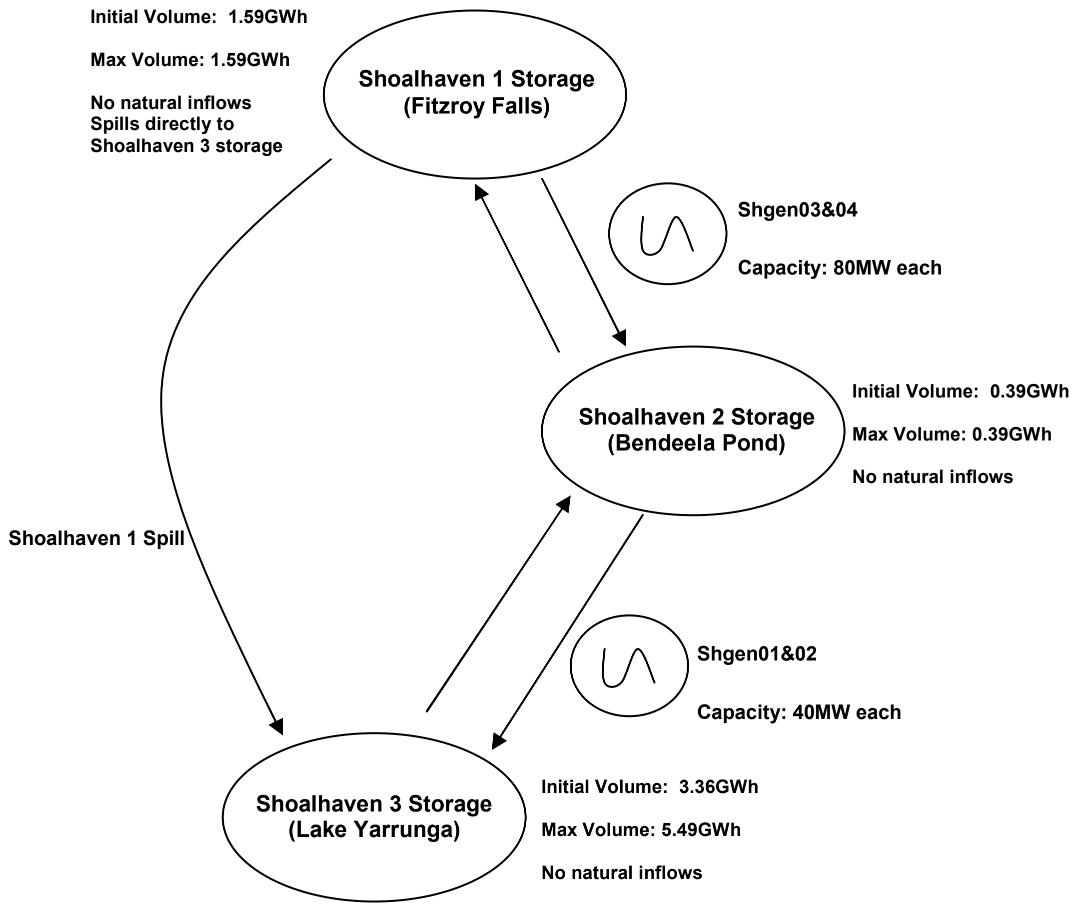
- **Figure C-13 Representation of Shoalhaven pump storage system**



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

The Hume Dam on the Murray River provides storage for the Hume Power Station which can generate into either NSW or VIC. The NEM database is set up to allow PLEXOS to choose whether to dispatch into NSW or VIC by limiting the total generation from the Hume VIC and Hume NSW generators to 58 MW in all periods (*Hume generation constraint*). In addition, monthly generation limits are imposed on the combined output of the two generators. These limits, shown in Figure C-14, are based on historical generation levels. Between May and July the units are effectively unavailable, consistent with the 2009 ESOO assumptions. Moreover, for capacity planning purposes, it is assumed that all generation is dispatched into Victoria over the summer peak demand period. Hence, the firm capacity for Hume NSW is set to zero.

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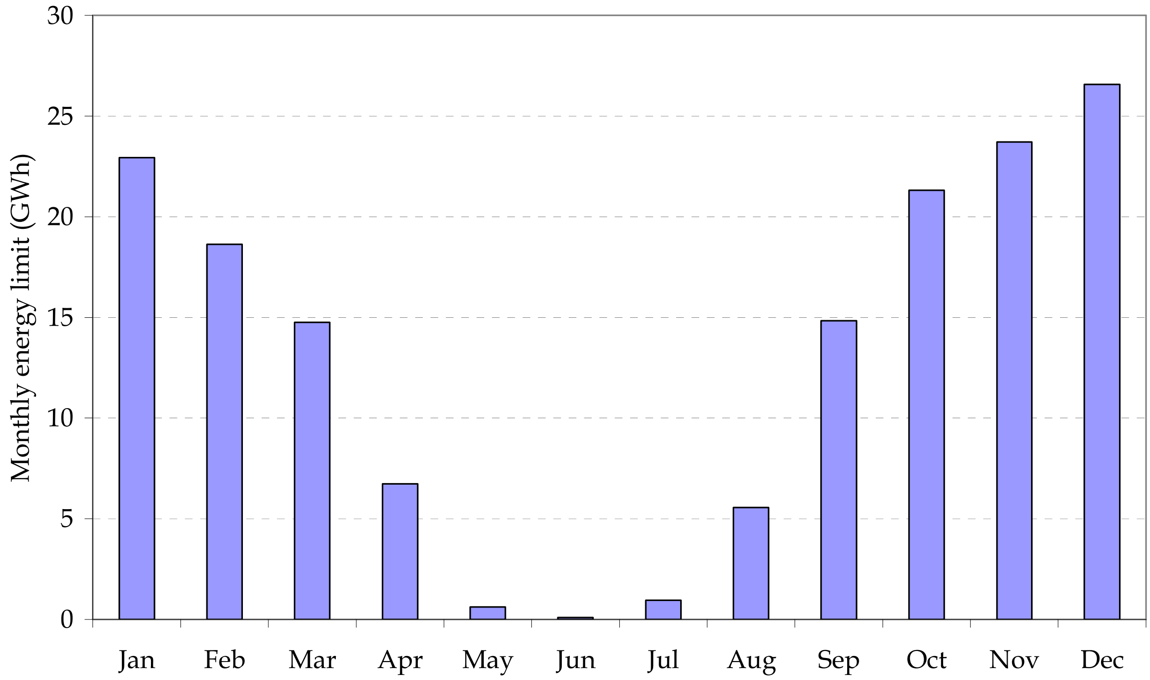
- **Figure C-14 Hume Power Station monthly energy limit (GWh)**



C.9 Modelling other renewable energy technologies

Non-hydro renewable generation modelled in the PLEXOS NEM database includes wind, geothermal, biomass/bagasse, new hydro and solar thermal. The availability of this renewable generation is represented through a combination of profiles, stochastic variables, forced outage rates and maximum capacity factors. This section summarises the key assumptions for each renewable generation type. Table C-14 provides a summary of the range of new entry cost and financial assumptions contained within SKM MMA's database of renewable projects.

C.9.1 Wind

Wind farms are modelled as multiple units, each with a maximum capacity of 1 MW. Up to five generic locations are assumed in each state to represent some diversity in availability. With high wind penetration expected in the future, modelling only five generic locations models the fact that there is high correlation between wind farms situated in similar locations, as observed already in South Australia. Typically, each wind farm operates at an average capacity factor of between 25% and 45%, with intermittency represented through the use of stochastic wind profiles. Wind profiles are randomly developed within PLEXOS assuming a log-normal distribution and high autocorrelation from one period to the next, using parameters determined from historical wind profiles.

In modelling the Victorian wind farms, historical profiles from three existing wind farms, namely, Waubra, Yambuk and Portland, were used. The aggregate period to period swings in the modelled wind farm output therefore capture the correlation and the diversity in output that exist when considering the effect of multiple wind farms on a power system. Yambuk and Portland had an annual average correlation coefficient of 74%, which is remarkably high, and reinforces the statement in the preceding paragraph that the output of wind farms in similar locations is highly correlated (the wind farms are approximately 50km apart). However, we also found that the average correlation decreases as the distance between wind farms increases. Thus, the annual average correlation coefficient between Yambuk and Waubra was 50%, and between Portland and Waubra it was 40%, where the distances between the wind farms were 150 km and 200 km respectively.

For capacity planning purposes, the firm capacity of the wind farms at times of 10% POE peak demand is assumed to be 8% or lower, as shown in Table C-13.

- **Table C-13 Firm capacity assumed for wind farms, by state**

	QLD	NSW	VIC	SA	TAS
Firm capacity	0%	5%	8%	3%	0%

Source: AEMO (2009) Statement of Opportunities, Table B.44, pg B-27

C.9.2 Geothermal

Geothermal generation is modelled in increments of 50 MW with an average availability of 85%. The key assumptions influencing this availability are:

- maintenance rate of 4.2%
- forced outage rate of 8%
- summer derating of 3.5 MW
- commercial viability from 2017 onwards.

For capacity planning purposes, geothermal generation is assumed to be 100% firm.

C.9.3 Biomass, bagasse, wood waste

In PLEXOS, “biomass” encompasses wet waste, wheat/ethanol, agricultural waste, bagasse, black liquor, landfill gas, municipal solid waste, sewage, and wood/wood waste. SKM MMA maintains a renewable database of prospective renewable projects in Australia, detailing costs and generation potential for a large number of these types of projects. However it is unrealistic to model all of these projects explicitly in PLEXOS. Hence, in each state, technologies with similar cost structures have been grouped together to form up to 5 “biomass” generation projects.

Not surprisingly, the expected capacity factor varies greatly between each generation project depending on the type of projects including within the group. Project specific monthly capacity factors are therefore input for each generation project modelled. To represent the possibility of non-firm fuel supply, biomass projects are assumed to be 80% firm for capacity planning purposes.

C.9.4 New hydro

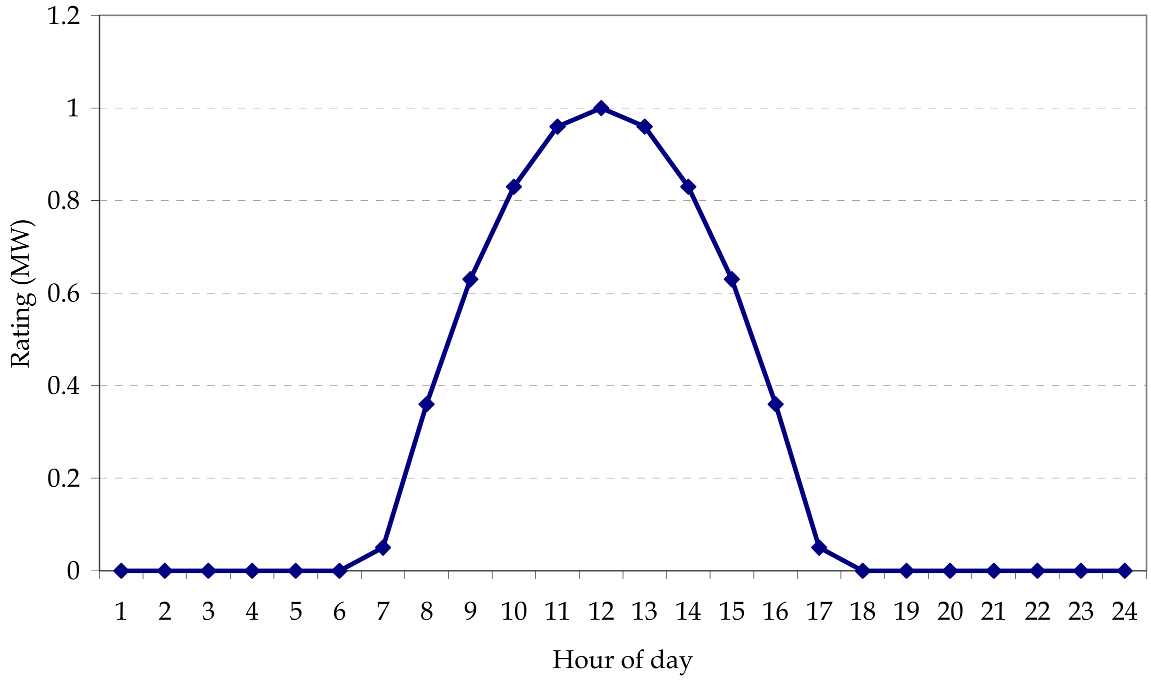
In Queensland, New South Wales and Tasmania, the main new hydro development eligible for renewable energy certificates are likely to be upgrades to the existing hydro schemes. Therefore, in these states, the new hydro projects are modelled as energy constrained units, with annual maximum capacity factors. In Victoria, the new hydro opportunities identified in our renewable database are smaller run-of-river schemes with little or no ability to store the water. Consequently, the renewable hydro projects in Victoria have been modelled with high forced outage rates to reflect a degree of randomness in availability. For capacity planning purposes, this run-of-river hydro is assumed to be 40% firm.

C.9.5 PV and solar thermal generation profiles

Photovoltaic and solar thermal generation are modelled as multiple units of 1 MW, using generic profiles to represent the solar radiation potential throughout a day and across a year. The PV/solar generation profile for a given NEM regional does not assume any locational diversity within the region, although this would be easy enough to model for projects with specific locations. Figure C-15 shows the generic profile applied for December, assuming no storage potential. In winter, the estimated profile is 80% lower than in this figure. Note that the profiles used have been derived by averaging hourly data for a given month, and are not based on a historical trace of solar exposure data. Therefore, they include the average effect cloud cover for a given hour of a given month, and are therefore smoother than what a historical trace may yield.

For capacity planning purposes, PV/solar thermal is assumed to be 100% firm. This means that the total PV capacity is assumed to be generating when the system peak demand occurs, and therefore the total PV capacity contributes to the reserve margin calculation.

- **Figure C-15 Daily PV/solar profile for December**



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- **Table C-14 New entry cost and financial assumptions for renewable generators for 2009/10 ($ June 2009)**

State	Type of Plant	Capital Cost (sent-out)	Available Capacity Factor	VO&M & Fuel cost	Weighted Cost of Capital	Interest Rate	Debt Level	LRMC	Capital cost reduction
		$/kW sent out		$/MWh	% real	% nominal	%	$/MWh	% per annum
SA	Wind	$2689 - $4217	26% - 36%	$7.3 - $7.3	11.00%	9%	60%	$118 - $238	0.4%
	Biomass	$3159 - $6664	57% - 80%	$20.9 - $50.2	12.00%	9%	60%	$118 - $178	0.3%
	Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Geothermal	$4643 - $6598	85% - 85%	$23 - $23	11.00%	9%	60%	$105 - $138	0.7%
	Solar	$3578 - $16050	15% - 47%	$5.2 - $5.2	11.00%	9%	60%	$128 - $1533	2.0%
Vic	Wind	$2183 - $13421	18% - 41%	$7 - $7.3	11.00%	9%	60%	$105 - $544	0.4%
	Biomass	$2765 - $9693	57% - 80%	$20.9 - $62.7	12.00%	9%	60%	$92 - $298	0.3%
	Hydro	$3123 - $5619	35% - 58%	$3.1 - $3.1	11.00%	9%	60%	$126 - $136	0.2%
	Geothermal	$4677 - $5362	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $117	0.7%
	Solar	$5770 - $11183	15% - 50%	$5.2 - $5.2	11.00%	9%	60%	$204 - $1212	2.0%
NSW	Wind	$1976 - $4743	20% - 35%	$7.3 - $7.3	11.00%	9%	60%	$88 - $217	0.4%
	Biomass	$2363 - $4547	57% - 80%	$20.9 - $60.6	12.00%	9%	60%	$92 - $156	0.3%
	Hydro	$2382 - $2706	36% - 73%	$3.1 - $3.1	11.00%	9%	60%	$48 - $101	0.2%
	Geothermal	$4698 - $5810	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $125	0.7%
	Solar	$3578 - $11980	17% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $1146	2.0%
Qld	Wind	$2680 - $15285	28% - 35%	$7.3 - $7.3	11.00%	9%	60%	$116 - $618	0.4%
	Biomass	$3617 - $5144	35% - 80%	$20.9 - $62.7	12.00%	9%	60%	$105 - $275	0.3%
	Hydro	$2139 - $2348	27% - 38%	$3.1 - $3.4	11.00%	9%	60%	$80 - $122	0.2%
	Geothermal	$4894 - $5265	85% - 85%	$23 - $23	11.00%	9%	60%	$109 - $116	0.7%
	Solar	$3578 - $11183	20% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $910	2.0%
Tas	Wind	$2510 - $3508	33% - 42%	$7.3 - $7.3	11.00%	9%	60%	$112 - $149	0.4%
	Biomass	$1124 - $5708	57% - 80%	$7.7 - $41.8	12.00%	9%	60%	$31 - $195	0.3%
	Hydro	$2822 - $5403	10% - 46%	$3 - $3.1	11.00%	9%	60%	$141 - $400	0.2%
	Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

C.10 Constraints

PLEXOS provides modelling flexibility through user-defined constraints. Constraints take the form of equations, consisting of a constant on the right hand side of the equation (RHS property), variables and coefficients on the left hand side and an operator such as less than or greater than sign (defined via the sense property).

The SKM MMA database contains the major constraints reflected in the physical NEM, although FCAS related constraints are not currently represented.

The majority of constraints in the database reflect network limits that AEMO enforces to manage the security of the power system. These constraints are categorised by their respective zone. They are sourced from AEMO's annual SOO publication, where they are provided separately as ANTS verification study constraints.

C.10.1 Conditions

Conditions are specified in the database to define certain events which are used in activating/deactivating objects or records in the simulation. All of the conditions in SKM MMA's NEM database are used to activate constraints, or properties within constraints, and are grouped according to the object they apply to. For example, the limits on some of the ANTS transmission constraints are conditional on the number of units generating at certain power stations, and the conditions are used to determine the appropriate limit to be applied in any particular trading period.

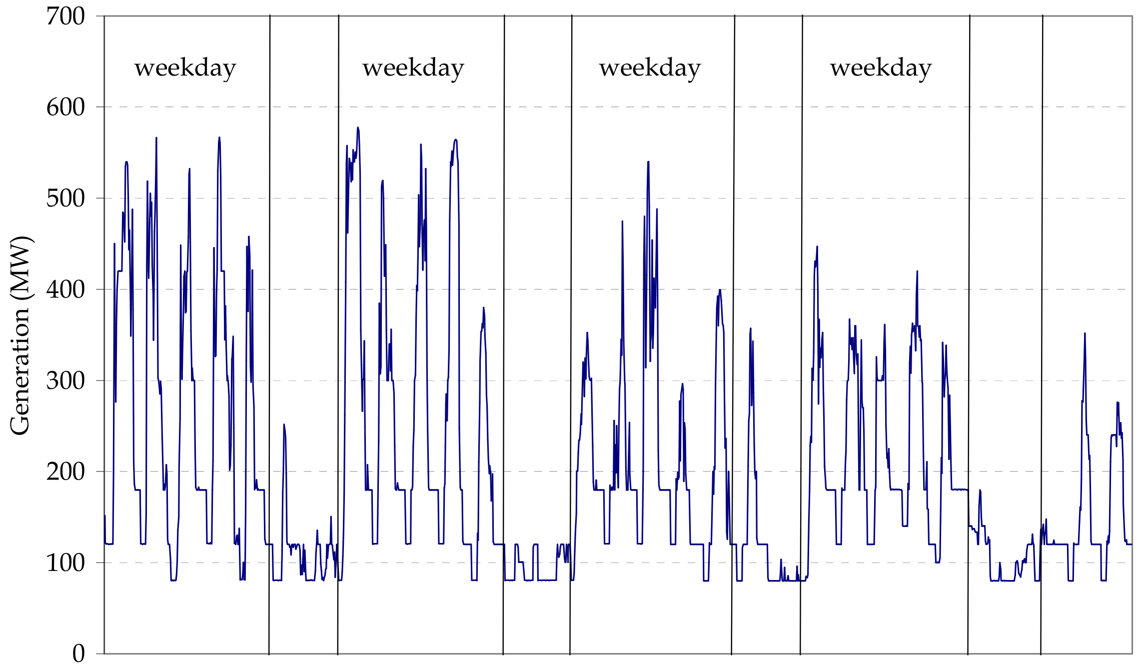
C.10.2 User Defined Constraints and Adjustments

Constraints are also used to model certain aspects of the market which would otherwise not be reflected from pure economic dispatch. FCAS requirement, commercial or strategic objectives and/or industrial load obligations may also influence dispatch but are not explicitly modelled in the SKM MMA database. To approximate these market influences, SKM MMA has specified its own NEM-specific constraints and adjustments which are summarised below.

- Torrens B: PLEXOS dispatch of the Torrens Island B does not produce outcomes observed in the NEM due to frequency control considerations that effectively keep at least two units generating in the weekend and three units generating during the weekday. This is evident in Figure C-16, which shows a typical monthly profile of Torrens Island B's historical dispatch. We model this through a constraint that forces generation from the Torrens Island B to be at least 80MW during weekends and 120MW during weekdays on a trading period basis.
- Pelican Point minimum stable level is defined substantially higher than the physical limit. This is because Pelican Points generally offers over 200 MW of capacity at $-990 and over 300 MW during spring and summer.

- Macquarie mothballing: Macquarie Generation has in the past operated only seven[46] of its eight base load units (Bayswater and Liddell) at any one time. Macquarie therefore typically holds back one Liddell unit, which only operate at high prices or during outages of other Macquarie units. This behaviour is modelled by a constraint with an appropriate penalty price, and the constraint is eventually relaxed around 2014.

Figure C-16 Typical dispatch from Torrens Island B, November-December 2008



- Gladstone mothballing: Stanwell appears to only operate five of its six Gladstone units at any one time. There is a penalty price on this constraint so that it can be relaxed in extreme circumstances.
- Bairnsdale minimum generation: To meet network constraints between 1am and 3am, the two Bairnsdale units are required to generate. Minimum generation constraints in these periods ensure that the units are dispatched at that time to support the network.
- Anglesea typically generates at maximum capacity (160 MW) in all periods. Therefore, to ensure this pattern of dispatch is observed Anglesea has a user-defined offer of 160 MW at -$1000/MWh.

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46 It is noted that, at times, Macquarie has been operating all eight units for extended periods last year, suggesting that we may need to review this approach in the near future.

- Barcaldine has hardly generated this last financial year and has been bidding most of its capacity at $8076/MWh. Energy offers are used to replicate this behaviour.
- Bayswater tends to operate at a capacity factor of about 75% – 80%, however PLEXOS tends to dispatch Bayswater at a higher capacity factor than this. Therefore, a maximum capacity factor of 78% is imposed on these units. Since the maximum capacity factor is effectively an annual energy constraint it does not limit capacity in any one period. Hence, full capacity will still be available at times of high price.
- For summer 2009/10 Playford maximum capacity is limited to 200 MW due to plant issues which are expected to be resolved by 2010/11.
- Smithfield has user-specified energy offers to encourage the unit to be dispatched at maximum capacity during weekdays, and only at about half capacity during weekends, as observed historically, providing steam for its host Visy Industries.
- A maximum capacity factor for the year of 25% has been set for Laverton North, as its operating hours are restricted under the conditions of its licence from the Environment Protection Authority.
- HRL Fuel constraint: HRL's proposed IGCC plant in the Latrobe Valley is set up as a multi-fuelled unit, burning either gasified coal or natural gas. The gasified coal is a lower cost fuel, but we have assumed that its availability will be limited in the first few years of operation given that the drying and gasification of the coal is a pilot project. Moreover, it is assumed that the gasifier is out on maintenance during April each year, further constraining the availability of gasified coal in that month.

C.10.3 CCGT modelling

PLEXOS has the ability to model combined cycle gas turbines in a sophisticated way, with the heat output from the gas turbines driving the operation of the steam unit. This allows for more accurate modelling of unit commitment and outages. The steam units' output will be reduced if one or more gas turbines are out of service. Figure C-17 demonstrates how the CCGT may be set up in PLEXOS.

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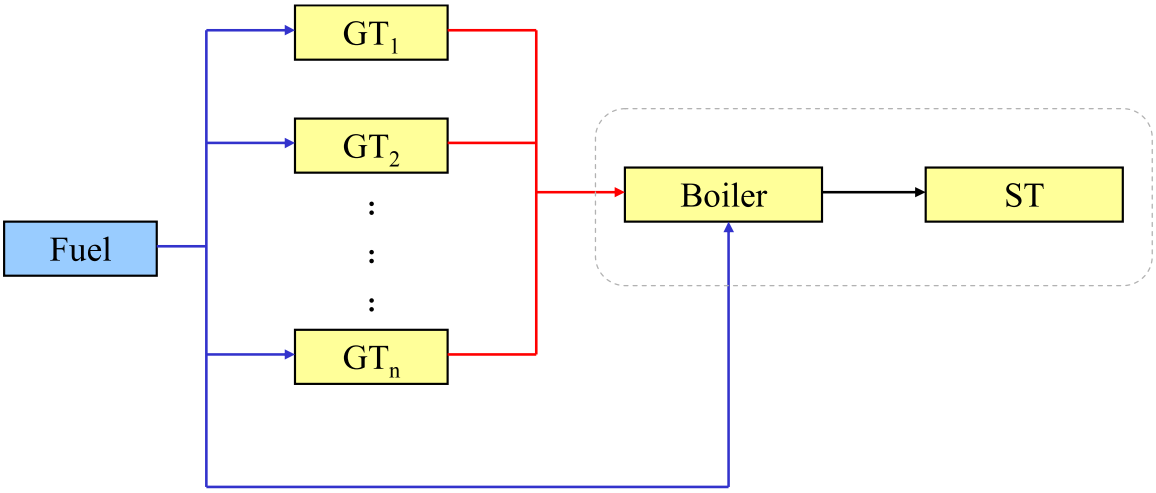
■ **Figure C-17 Example of explicit CCGT representation**



Source: Energy Exemplar, PLEXOS wiki

We have modelled existing and committed CCGTs with known gas turbine/steam configurations utilising this PLEXOS functionality (i.e. Pelican Point, Tallawarra, Condamine and Darling Downs). Typically, a boiler efficiency of between 80% and 90% is assumed.

C.10.4 Ramp rate constraints

Table C-15 shows the ramp rates assumed for each power station in the NEM, as well as the number of units used to model each power station in the PLEXOS model.

■ **Table C-15 Ramp rate assumptions**

Power station	Number of units in model	Ramp rate per unit (MW/minute)
Anglesea	1	2
Hazelwood	8	2
Loy Yang A	4	10
Loy Yang B	2	10
Morwell	5	5
Yallourn W	4	3
Bairnsdale	2	4
Jeeralang A	4	9
Jeeralang B	3	6
Laverton North	2	15
Mortlake	2	10
Newport	1	10
Somerton	1	10
Valley Power	6	2
Bogong	1	10

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Power station	Number of units in model	Ramp rate per unit (MW/minute)
Dartmouth	1	60
Eildon	2	10
McKay	2	20
Murray	2	100
West Kiewa	2	10
Bayswater	4	10
Eraring	4	10
Liddell	4	4
Mt Piper	2	5
Munmorah	2	3
Redbank	1	1
Vales Pt	2	5
Wallerawang	2	3
Colongra	4	12
Hunter Valley GT	1	65
Smithfield	4	1
Tallawarra	1	12
Uranqunity	4	11
Blowering	1	8
Guthega	1	10
Hume	1	12
Lower Tumut	2	100
Shoalhaven	4	2
Tumut	2	65
Callide A	1	3
Callide B	2	3
Callide C	2	3
Collinsville	5	1
Gladstone	6	5
Kogan Creek	1	8
Millmerran	2	5
Stanwell	4	6
Swanbank B	4	3
Tarong	4	5
Tarong North	1	6
Barcaldine	1	2
Braemar	3	10
Braemar 2	3	11
Condamine	3	1
Darling Downs	4	2.5
Mackay GT	1	10

Power station	Number of units in model	Ramp rate per unit (MW/minute)
Mt Stuart	3	9
Oakey	2	11
Roma	2	8
Swanbank E	1	11
Yabulu	1	6
Yarwun	1	6
Barron Gorge	2	3
Kareeya	4	5
Wivenhoe	2	30
Northern	2	2
Playford	1	1
Angaston	2	20
Dry Creek GT	3	5
Hallett	1	10
Ladbroke	2	8
Mintaro	1	6
Osborne	1	2
Pelican Point	1	13
Pt Lincoln	3	3
Quarantine	5	3
Snuggery	3	1
Torrens Is A	4	5
Torrens Is B	4	8
Bellbay 3	3	10
Tamar Valley CCGT	1	9