NESA – electricity shock scenario

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Executive summary

The National Energy Security Assessment (NESA) identifies key strategic energy security issues in the liquid fuels, natural gas and electricity sectors in Australia. The Department of Resources, Energy and Tourism (DRET) released the inaugural NESA in March 2009. DRET has now developed the 2011 NESA.

DRET has included "shock scenarios" in the 2011 NESA. These shock scenarios are hypothetical physical or market-based disruptions to the liquid fuels, electricity and natural gas sectors that are designed to provide insights into the impacts that such disruptions may have on Australia's energy security. The shock scenarios analyse energy security impacts under current market conditions and in the longer term.

Frontier Economics was engaged to advise DRET on the impact of shock scenarios in the electricity and natural gas sectors. This report sets out Frontier Economics' advice to DRET on the impact of a shock scenario in the electricity sector. The assessment of the electricity shock scenario considers outcomes in electricity markets as well as affects on the gas market.

The examination by DRET of shock scenarios in the electricity sector is intended to provide insight into the effects that significant disruptions may have on Australia's energy markets. While specific pieces of infrastructure (in this case Loy Yang A) have been used to provide 'real world' information, this is neither a reflection on the reliability of that infrastructure nor a reflection on the mitigation options that exist to prevent loss of capacity of that infrastructure.

Shock scenario analysed

The electricity shock scenario analysed by Frontier Economics in this report is defined as hypothetical outages at Loy Yang A power station. The shock scenario includes cases in which the power station permanently exits the market and cases in which there is a full power station forced outage of 14 days duration. The temporary outage cases are defined to occur during both peak and shoulder periods in both 2011/12 and 2015/16.

Conclusions on outcomes in the electricity market

Frontier Economics' analysis shows that, under the assumptions and methodology adopted for this analysis, the permanent exit of Loy Yang A power station does not result in a material reduction in reliability in the National Electricity Market (NEM) and would not be expected to result in a breach of the system reliability standard. However, analysis by the Australian Energy Market Operator (AEMO) indicates that an increase in unserved energy is likely to arise in the event that demand levels are higher than assumed by Frontier Economics, multiple forced outages at other power stations coincide with the outage to Loy Yang A, or network constraints occur.

The permanent exit of Loy Yang A power station is expected to result in substantial increases in pool prices, particularly in the period before new generation plant can be commissioned. In Victoria, average annual pool prices increase by around 80 per cent in the first year of the outage and 60 per cent in the second year of the outage. Thereafter, with the commissioning of new baseload capacity as a result of the permanent exit of Loy Yang A, price impacts are mitigated.

Similarly, Frontier Economics' modelling finds that a temporary outage of Loy Yang A power station results in increases in pool prices rather than reductions in reliability. Again, however, an impact on reliability is likely to arise in the event that demand levels are higher than forecast, multiple forced outages coincide with the temporary outage to Loy Yang A or network constraints occur. An outage of Loy Yang A power station does result in higher cost generation being required to meet demand, particularly on the high demand peak days.

It should be noted that Frontier Economics has modelled 'system normal'[1] conditions for the electrical transmission system; in particular, Frontier Economics has not incorporated transmission constraints within its modelling of the electricity shock scenario. In reality, if there was a significant transmission constraint that coincided with the electricity shock scenario examined in this report the impact of the electricity shock scenario, including the impact on system security, could be exacerbated. This could lead to either higher prices, or greater levels of unserved load, than observed under the 'system normal' conditions examined in this report.

Conclusions on outcomes in the gas market

Frontier Economics' analysis shows that generation that would otherwise be provided by Loy Yang A would largely be provided by gas fired plant. Our modelling shows that there is likely to be sufficient capacity in gas infrastructure in the NEM region to manage the permanent exit or temporary outage of Loy Yang A power station.

In the event of the permanent exit of Loy Yang A power station, it may be the case that there are short-term capacity constraints affecting particular gas infrastructure during peak gas demand periods in winter. However, Frontier Economics considers that the flexibility in the electricity market and the gas market would mean that even short-term capacity constraints to particular gas infrastructure would not result in any significant reduction in reliability. However, any short-term capacity constraints to gas infrastructure would likely increase the cost of meeting electricity demand.

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1 System normal is a configuration of the power system in which all major transmission elements are in service.

1 Introduction

The National Energy Security Assessment (NESA) identifies key strategic energy security issues in the liquid fuels, natural gas and electricity sectors in Australia. The Department of Resources, Energy and Tourism (DRET) released the inaugural NESA in March 2009. DRET has now developed the 2011 NESA.

DRET has included "shock scenarios" in the 2011 NESA. These shock scenarios are hypothetical physical or market-based disruptions to the liquid fuels, electricity and natural gas sectors that are designed to provide insights into the impacts that such disruptions may have on Australia's energy security. The shock scenarios analyse energy security impacts under current market conditions and in the longer term.

The examination by DRET of shock scenarios in the electricity sector is intended to provide insight into the effects that significant disruptions may have on Australia's energy markets. While specific pieces of infrastructure (in this case Loy Yang A) have been used to provide 'real world' information, this is neither a reflection on the reliability of that infrastructure nor a reflection on the mitigation options that exist to prevent loss of capacity of that infrastructure.

1.1 Frontier Economics' engagement

Frontier Economics was engaged to advise DRET on the impact of shock scenarios in the electricity and natural gas supply sectors.

Frontier Economics has undertaken modelling of the electricity sector and the natural gas sector in order to provide advice as to the likely impacts on security of supply in these sectors, including advice on energy security vulnerabilities and risks in these sectors.

1.2 This report

This report sets out Frontier Economics' advice to DRET on the impact of a shock scenario at Loy Yang A on the electricity sector. Frontier Economics has separately provided a report that sets out its advice to DRET on the impact of a shock scenario to infrastructure within the natural gas sector.

This report is structured as follows:

- Section 2 defines the electricity shock scenario
- Section 3 describes Frontier Economics' modelling framework
- Section 4 sets out Frontier Economics' electricity market modelling assumptions
- Section 5 sets out Frontier Economics' gas market modelling assumptions

- Section 6 describes outcomes in the Reference Case
- Section 7 describes outcomes in the permanent exit shock scenario case
- Section 8 describes outcomes in the temporary outage shock scenario cases.

2 Defining the electricity shock scenario

The electricity shock scenario is the sudden exit or failure of a Victorian base-load power station from the National Electricity Market (NEM).

2.1 Hypothetically affected infrastructure

The electricity shock scenario is defined such that Loy Yang A power station in Victoria is the affected power station. Loy Yang A is the largest generator in the Victorian region of the NEM, with winter maximum capacity of 2,270 MW.

Importantly, the shock scenario assumes that all other power stations remain operating. For instance, in the case of the permanent closure of Loy Yang A power station it is nevertheless assumed that Loy Yang B power station continues to operate (which implies that it continues to make use of, and fund the operating costs of, the infrastructure that it shares with Loy Yang A, including the coal mine). While the closure of Loy Yang A power station may ultimately have implications for the economic operation of Loy Yang B power station, we expect that higher prices in the period immediately following the unexpected closure of Loy Yang A would likely make the ongoing operation of Loy Yang B profitable in the short term. As a result, any ongoing issues for Loy Yang B power station would likely be resolved after an investment response to the initial closure of Loy Yang A power station.

The shock scenario also does not incorporate the closure of a baseload power station as a result of a contract for closure with the Commonwealth Government. The Commonwealth Government's contract for closure policy forms part of the Clean Energy Future, which was announced after the modelling of the shock scenario in this report.

2.2 Nature of the supply interruption

The electricity shock scenario is defined to include two different kinds of event affecting the power station:

- A full power station forced outage of 14 days duration
- The permanent exit of the power station from the NEM, commencing at the beginning of 2012/13. The permanent exit is assumed to result from an act of god, such that there is no advance notice of the exit of the power station.

2.3 Timing of the temporary supply interruption

The temporary outages affecting the power station are defined to occur at a number of different periods:

- a peak period in 2011/12
- a shoulder period in 2011/12
- a peak period in 2015/16
- a shoulder period in 2015/16

In each case:

- the peak period is defined as a two-week period commencing at 4 am Monday, with the peak daily demand for the year occurring in the first week of the two-week period
- the shoulder period is defined as a two-week period commencing at 4 am Monday, with the lowest average daily demand for the spring and autumn months occurring in the first week of the two-week period.

2.4 Summary of cases

Given that the electricity shock scenario includes different types of interruptions occurring at different times, the electricity shock scenario in fact consists of a number of different cases. These cases are summarised in Table 1.

Table 1: Modelling cases for electricity shock scenario

Case name	Affected power station	Type of interruption	Duration	Timing of interruption
LYA-Permanent	Loy Yang A	Market exit	Permanent	From 2012/13
LYA-Temp-2012-Peak	Loy Yang A	Forced outage	14 days	Peak 2011/12
LYA-Temp-2012-Shoulder	Loy Yang A	Forced outage	14 days	Shoulder 2011/12
LYA-Temp-2016-Peak	Loy Yang A	Forced outage	14 days	Peak 2015/16
LYA-Temp-2016-Shoulder	Loy Yang A	Forced outage	14 days	Shoulder 2015/16

2.5 Defining energy security

DRET defines energy security as the adequate, reliable and competitive supply of energy to support the functioning of the economy and social development, where:

- adequacy is the provision of sufficient energy to support economic and social activity

- reliability is the provision of energy with minimal disruptions to supply
- competitiveness is the provision of energy at an affordable price that does not adversely impact on the competitiveness of the economy and which supports continued investment in the energy sector.[2]

2 DRET, *National Energy Security Assessment*, 2009, page 5.

3 Modelling framework

This section provides a brief overview of the modelling framework used by Frontier Economics to analyse the likely impact on energy security of the electricity shock scenario.

3.1 Frontier Economics' relevant energy market models

In examining outcomes from the electricity shock scenario, Frontier Economics has adopted a three-staged modelling approach, which makes use of three proprietary inter-related electricity and gas market models: *WHIRLYGIG, SPARK* and *WHIRLYGAS*. The key features of these models are as follows:

- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* determines the least cost investment in, and operation of, generation plant to meet demand and to meet any regulatory obligations (such as renewable energy targets).
- *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. *SPARK* determines the optimal pattern of bidding by having regard to the reactions by generators to discrete changes in bidding behaviour by other generators. The model determines profit outcomes from all possible actions (and reactions to these actions) and finds equilibrium bidding outcomes based on game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.
- *WHIRLYGAS* optimises total production and transmission cost in the gas market, calculating (among other things) the least cost operation of gas production and transmission assets to meet gas demand.

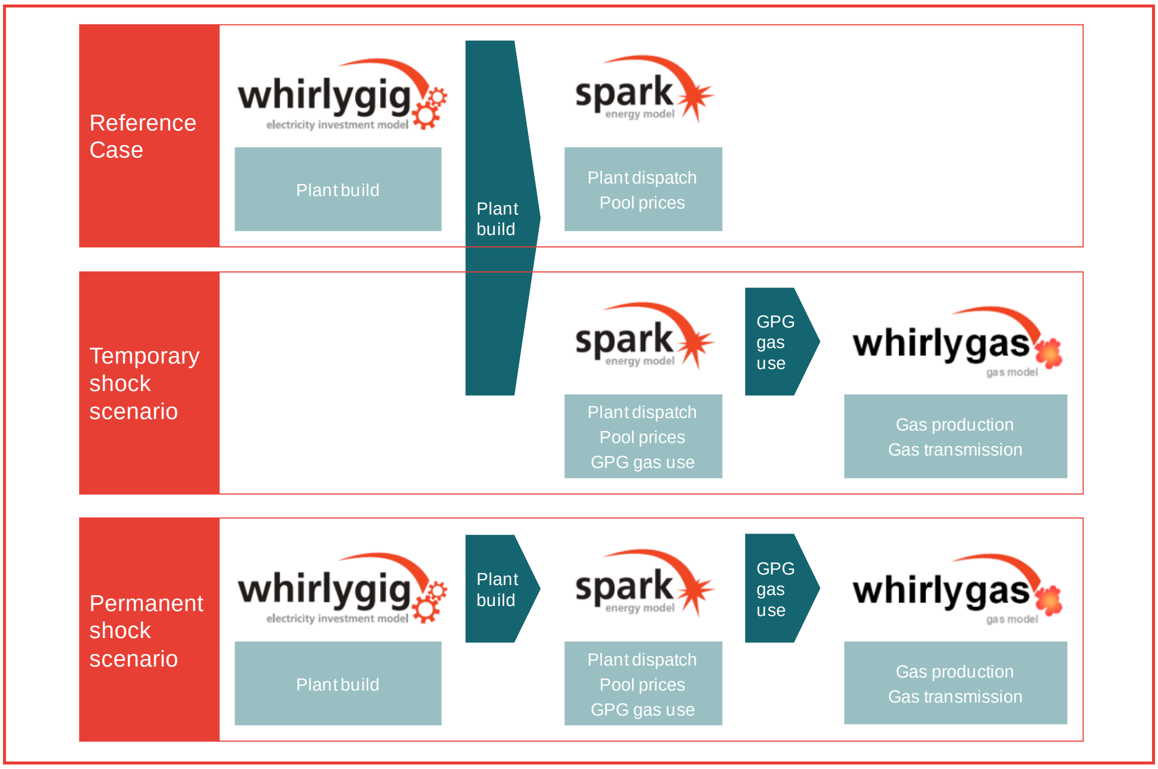
Both *WHIRLYGIG* and *SPARK* incorporate a representation of the physical infrastructure in the NEM that includes all existing generation plant in the NEM (including technical and cost information for those existing plant), all existing inter-regional interconnectors in the NEM, demand forecasts for each region in the NEM and options for new generation plant.

WHIRLYGAS incorporates a representation of the physical gas infrastructure in the eastern States that includes all existing production plant, all existing transmission pipelines, demand forecasts for each region and options for new plant and pipelines.

3.2 Modelling framework for the electricity shock scenario

As discussed, the electricity shock scenario includes a case in which Loy Yang A power station permanently exits the market and a number of cases in which there is a temporary forced outage at the power station. Permanent and temporary interruptions are likely to result in different responses, with new investment a likely response to a permanent exit but not a likely response to a temporary forced outage. Given this, different modelling approaches are adopted. The framework that Frontier Economics has adopted is illustrated in Figure 1 and discussed in detail in the following sections.

Figure 1: Modelling framework



* GPG = Gas Powered Generation

3.2.1 Modelling the Reference Case

The first step in Frontier Economics' modelling framework is to model outcomes in the Reference Case.

The Reference Case is intended as the most likely set of future outcomes, and does not include any interruption to Loy Yang A power station. The Reference

Case provides a set of outcomes against which the outcomes under the various shock scenario cases can be compared.

Modelling the Reference Case involves two integrated stages: *WHIRLYGIG* modelling and *SPARK* modelling.

WHIRLYGIG

WHIRLYGIG modelling for the Reference Case provides a least cost investment path for the electricity sector. This least cost investment is an important input for *SPARK* modelling of both the Reference Case and the shock scenario cases in 2015/16: as electricity demand grows over the period to 2015/16, there will be a need for new investment simply to meet reserve constraints. Undertaking market modelling in 2015/16 without incorporating this new investment would be unrealistic.

SPARK

SPARK modelling for the Reference Case provides a set of optimal bidding patterns for generators in the NEM, and the power station dispatch outcomes and pool prices outcomes that correspond to these optimal bidding patterns.

The least cost investment outcomes from the *WHIRLYGIG* modelling for the Reference Case will be used as an input in the *SPARK* modelling for the Reference Case.

The dispatch outcomes and pool price outcomes from the Reference Case provide the point of comparison against which electricity market outcomes in the various shock scenario cases can be compared.

3.2.2 Modelling the temporary shock scenario cases

The second step in Frontier Economics' modelling framework is to model outcomes in each of the temporary shock scenario cases.

Each of the temporary shock scenario cases is based on the Reference Case and incorporates all of the same input assumptions as the Reference Case except for the assumptions relevant to the forced outage at Loy Yang A power station.

SPARK

As with the *SPARK* modelling for the Reference Case, *SPARK* modelling for the each of the temporary shock scenario cases provides a set of optimal bidding patterns for generators in the NEM, and the power station dispatch outcomes and pool prices outcomes that correspond to these optimal bidding patterns.

The least cost investment outcomes from the *WHIRLYGIG* modelling for the Reference Case will be used as an input in the *SPARK* modelling for the temporary shock scenario cases. The *WHIRLYGIG* modelling for the Reference

Case is appropriate for this purpose because an investment response would not be expected as a result of a 14 day forced outage to a power station.

WHIRLYGAS

WHIRLYGAS modelling for each of the temporary shock scenario cases is used to ensure that dispatch outcomes of gas-powered generators under the temporary shock scenario cases are achievable within the existing capacity constraints of the gas market.

3.2.3 Modelling the permanent shock scenario cases

The final step in Frontier Economics' modelling framework is to model outcomes in the permanent shock scenario cases.

Like the temporary shock scenario cases, the permanent shock scenario cases are based on the Reference Case and incorporate all of the same input assumptions as the Reference Case except for the assumptions relevant to the permanent exit of Loy Yang A power station.

Modelling the Reference Case involves three integrated stages: *WHIRLYGIG* modelling, *SPARK* modelling and *WHIRLYGAS* modelling.

WHIRLYGIG

WHIRLYGIG modelling for the permanent shock scenario cases provides a least cost investment path for the electricity sector that reflects the permanent exit of Loy Yang A power station. This least cost investment path is an important input for *SPARK* modelling of both the permanent shock scenario cases in 2015/16: by 2015/16 new investment will have occurred both in response to the permanent exit of Loy Yang A power station and as a result of demand growth.

SPARK

As with the *SPARK* modelling for the Reference Case, *SPARK* modelling for the permanent shock scenario cases provides a set of optimal bidding patterns for generators in the NEM, and the power station dispatch outcomes and pool prices outcomes that correspond to these optimal bidding patterns.

The least cost investment outcomes from the *WHIRLYGIG* modelling for the permanent shock scenario case is used as an input in the *SPARK* modelling for the permanent shock scenario case.

WHIRLYGAS

WHIRLYGAS modelling for each of the permanent shock scenario cases is used to ensure that dispatch outcomes of gas-powered generators under the permanent shock scenario case are achievable within the existing capacity constraints of the gas market.

4 Electricity market modelling assumptions

This section provides a brief overview of the key electricity market modelling assumptions used by Frontier Economics to analyse the likely impact on energy security of the electricity shock scenario.

Frontier Economics has, where possible, used input assumptions developed by AEMO. Frontier Economics has adopted this approach on the basis that the input assumptions developed by AEMO are commonly used for modelling work of this type and, to varying extents, can be considered an industry standard. Adopting this approach, Frontier Economics has, to a large extent, relied on the following sources:

- AEMO, *Electricity Statement of Opportunities for the National Electricity Market*, 2010 (**AEMO 2010 ESOO**). This is the source for system demand forecasts used in Frontier Economics' modelling.
- AEMO, *National Transmission Network Development Plan*, 2010 (**AEMO 2010 NTNDP**). The **NTNDP Modelling Assumptions** (supplied by ACIL Tasman and EPRI) and the **NTNDP Input Tables**, both released with the AEMO 2010 NTNDP, are the source for most of the input assumptions for existing and potential new generation plant.

4.1 NTNDP scenarios

The National Transmission Network Development Plan (NTNDP) examines the future through five market development scenarios. These scenarios outline a range of plausible future outcomes for key issues and policy settings facing the energy industry and investors.

None of the NTNDP scenarios represents a base case forecast, or a forecast that reflects the most likely state of the world. The NTNDP scenarios are designed to reflect "different combinations of the principal energy sector and national transmission network development drivers".[3] AEMO makes clear that none of the five scenarios is a base case but neither does each scenario have an equal probability of occurring.[4]

While none of the five scenarios is a base case, for a number of input assumptions that will be important determinants of the outcomes from this modelling project (including capital costs for new generation plant and fuel costs), the Decentralised World scenario has input assumptions that fall within the range for the other scenarios. For these key input assumptions, therefore, the

3 AEMO, *National Transmission Network Development Plan*, 2010, page 22.

4 AEMO, *National Transmission Network Development Plan*, 2010, page 23.

Decentralised World scenario provides as close to a mid-point as is available from the NTNDP. For this reason, for the purposes of this modelling project, Frontier Economics has largely adopted the input assumptions from the Decentralised World scenario. The key exceptions to this are the assumed carbon price and demand forecasts, which are discussed in more detail below.

4.2 Discount rate

WHIRLYGIG optimises the total system costs of meeting demand over the entire modelling period. Total system costs are calculated as a net present cost in a specified base year using an assumed discount rate. The objective to be minimised by the model is the net present cost.

For the purposes of all modelling, Frontier Economics has used the WACC of 9.79% from the Decentralised World scenario.

4.3 Inflation rate

For the purposes of all modelling, Frontier Economics has used an inflation rate of 2.75%.

4.4 Electricity demand forecasts

Given this modelling project is focused on the impact on system security of the loss of a major baseload power station in Victoria, demand forecasts are a key input assumption. In order to examine the impact of both the permanent exit and a 14 day forced outage of Loy Yang A power station, it is necessary to develop a set of demand forecasts for each region in the NEM that reflect the variation of demand throughout the year. The approach and assumptions that Frontier Economics has used to develop the required demand forecasts are as follows:

- The starting point is a half-hourly load profile for each NEM region that reflects a representative year. Frontier Economics has used the historic half-hourly load profile for each NEM region from calendar year 2010 to provide this representative year. The advantage of using the load profile for calendar year 2010 is that we can get a load profile for both electricity and gas for 2010 (the gas data available from the National Gas Market Bulletin Board for 2010 is the most complete data set for gas) and thereby account for the correlations between electricity and gas demand in our analysis.
- Modelling every half-hourly demand point in a year is computationally very demanding. For this reason, to make the modelling problem more tractable, Frontier Economics models a representation of the load profile for each year, rather than the full half-hourly load profile for each year. The representative

load profile is generated by averaging demand during half hours where demand is relatively constant within each NEM region. This method allows us to best capture the correlation in demand between the different NEM regions in our forecasts.

- For each NEM region, this representative half-hourly load profile is then scaled to reflect forecast growth in both total demand and peak demand. Frontier Economics has used the medium growth, 50% probability of exceedence demand forecasts for summer and winter from the AEMO 2010 ESOO to scale the representative half-hourly load profile for each year of the modelling period. The modelling results for these representative load profiles can then be aggregated to provide annual results.
- Given that the focus on this project is on supply interruptions that occur over a period of 14 consecutive days, Frontier Economics has modelled these periods with a more detailed load profile to the other modelling periods. Each 14 day period has been modelled as a number of 'representative days', which include a Sunday/public holiday, a Saturday and a number of working weekdays that reflect different levels of demand.

  The modelling results for these representative days can then be aggregated (based on the frequency of occurrence of each representative day during the affected quarter) to provide annual results. The representative days can also be ordered in sequence to reflect a period of 14 consecutive days, allowing analysis of the day-to-day impact of a supply interruption during this period.

The same system demand forecasts are used as an input to both *WHIRLYGIG* and *SPARK*. Importantly, however, in addition to using the medium growth, 50% probability of exceedence demand forecasts to develop load profiles for each year, Frontier Economics also uses the medium growth, 10% probability of exceedence demand forecasts for summer and winter for the purpose of modelling reserve constraints. These 10% probability of exceedence demand forecasts are assumed to be 100% co-incident across NEM regions, implying that maximum demand occurs in each NEM region at the same time. This assumption of co-incidence is made to ensure consistency with AEMO's reported regional reserve margins in the reserve constraints.

4.5 Existing NEM generation plant

This section provides an overview of the key input assumptions for existing generation plant that Frontier Economics has adopted.

Capacity and ownership

Frontier Economics has used the latest information available from AEMO's website[5] on existing and committed scheduled and semi scheduled generation plant in each region of the NEM. This provides both the identity of existing and committed generation plant and the summer and winter capacity of these generation plant.

In addition, Frontier Economics' market modelling (using *SPARK*) also requires information on ownership of existing generation plant. Frontier Economics has used up-to-date publicly available information on plant ownership in its modelling.[6]

Outage rates

Frontier Economics has used information on equivalent forced outage rates and planned maintenance rates from the NTNDP Input Tables.[7]

Frontier Economics' typical modelling approach is to derate all generation plant at a flat outage rate throughout the year. The assumption is that while different plant will have outages at different times during the year, on average across the system outages will occur at a constant rate.

Auxiliary power requirements, heat rate and emissions intensity

Frontier Economics has used assumptions on auxiliary power requirements, heat rates and emissions intensities for each existing power station that are set out in the NTNDP Modelling Assumptions.

VOM

Frontier Economics has used assumptions on variable operating and maintenance (VOM) costs for each existing power station that are set out in NTNDP Modelling Assumptions.

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5 AEMO, Tables of Existing and Committed Scheduled and Semi Scheduled Generation – by Region. Available from:

http://www.aemo.com.au/data/gendata.shtml

6 Note that Frontier Economics' modelling incorporates the Queensland Government's proposed restructure of the three Government-owned generators in Queensland (CS Energy, Stanwell and Tarong Energy) into two Government-owned generators.

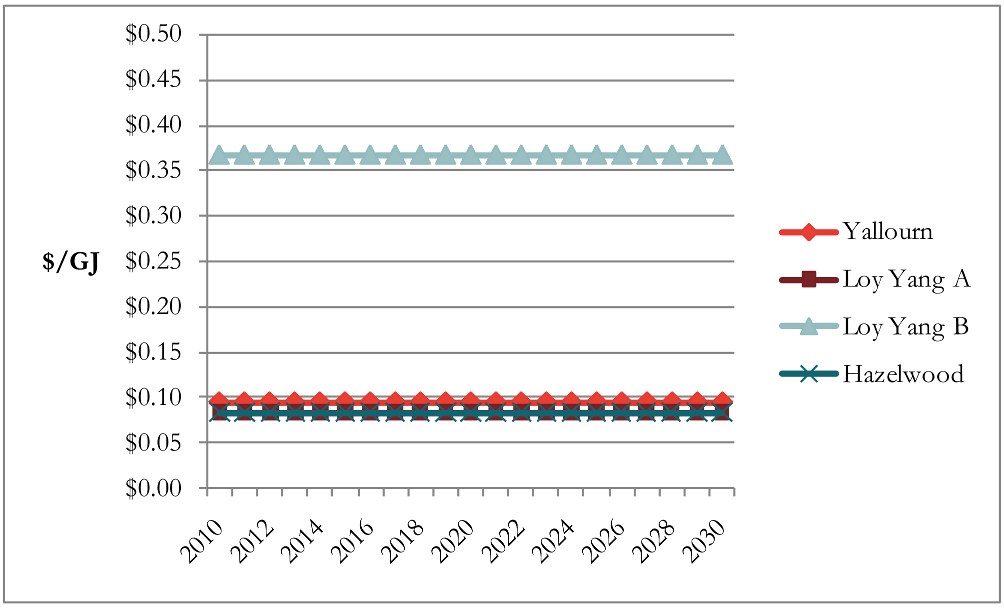
7 The exception is the equivalent forced outage rate for OCGT plant which is in excess of 25% in the 2010 NTNDP Input Tables. This outage rate reflects the fact OCGT plant may be unavailable during shoulder periods. However, the forced outage rate of OCGT plant during peak periods (when their capacity is needed) is much lower. For this reason, Frontier Economics has used an equivalent forced outage rate of 3% for OCGT plant.

Fuel costs

Frontier Economics has used assumptions on fuel costs for each existing power station that are set out in NTNDP Modelling Assumptions.

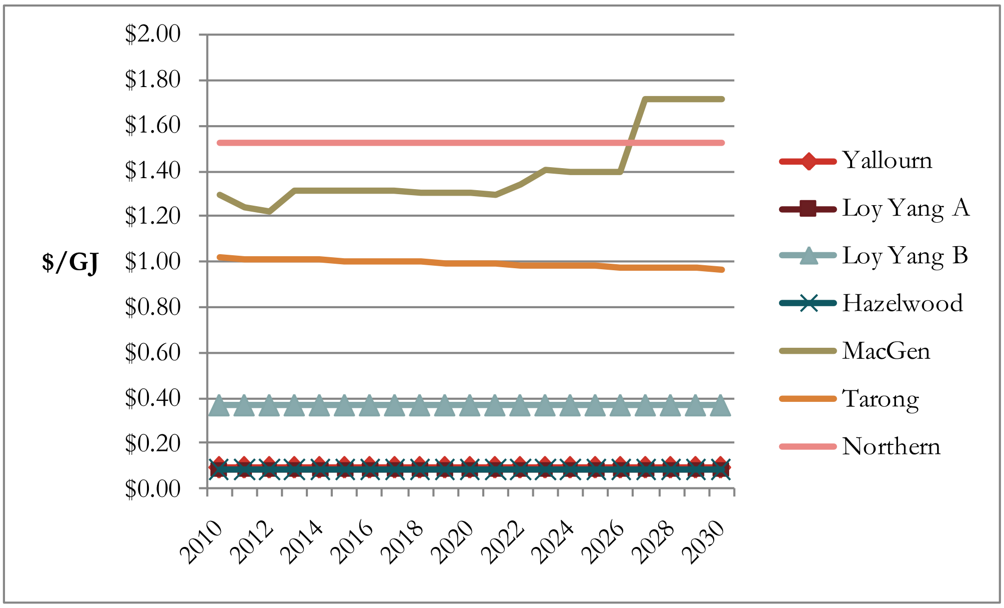
The coal costs for each of the base load power stations in Victoria are shown in Figure 2. This shows that each of Yallourn, Loy Yang A and Hazelwood have very low coal costs, while Loy Yang B has somewhat higher coal costs. Compared to coal-fired generators in other NEM regions, each of the base load power stations in Victoria has very low coal costs. Figure 3 compares the coal costs for the Victorian base load power stations with the coal costs for the lowest cost coal-fired generators in each of the other NEM regions.

Figure 2: Coal costs – Victorian brown coal



Source: NTNDP Modelling Assumptions

Figure 3: Coal costs – Victorian brown coal compared with other NEM regions



Source: NTNDP Modelling Assumptions

4.6 New generation plant

This section provides an overview of the key input assumptions for new generation plant that Frontier Economics has adopted.

Generation options

Frontier Economics has used assumptions on new generation options that are set out in the NTNDP Modelling Assumptions (however, given the timeframe for this modelling project, Frontier Economics has excluded those generation options that involve carbon capture and storage). Frontier Economics has also adopted constraints on construction times for new generation options and annual build limits that are set out in the NTNDP Modelling Assumptions.

The available thermal generation options, and key renewable generation options, are set out in Table 2.

While the lead times for development of these plant is relatively short, Frontier Economics considers that these lead times are realistic in the context of the permanent exit of a major power station. In particular, proponents have various generation projects throughout the NEM at reasonably advanced stages of development. Frontier Economics expects that, in the event of the permanent exit of a major power station, some of these projects would proceed and could be commissioned within the assumed lead times.

Table 2: New generation options – thermal plant

Technology	Fuel Type	First Year Available for Construction	Lead time for development (years)
OCGT	Gas	2011	1
CCGT	Gas	2012	2
Supercritical PC - Black coal	Black Coal	2014	4
Supercritical PC - Brown coal	Brown Coal	2014	4
IGCC - Black coal	Black Coal	2015	4
IGCC - Brown coal	Brown Coal	2015	4
Wind - Small scale (50 MW)	Renewable	2012	2
Wind - Medium scale (200 MW)	Renewable	2012	2
Wind - Large scale (500 MW)	Renewable	2012	2
Geothermal - HSA	Renewable	2015	4
Biomass	Renewable	2012	2

Source: NTNDP Modelling Assumptions

Outage rates

As is the case for existing generation plant, Frontier Economics has used information on equivalent forced outage rates and planned maintenance rates from the NTNDP Input Tables.[8]

Auxiliary power requirements, heat rate and emissions intensity

As is the case for existing generation plant, Frontier Economics has used assumptions on auxiliary power requirements, heat rates and emissions intensities for new generation plant that are set out in NTNDP Modelling Assumptions.

8 As with existing generation plant, the exception is the equivalent forced outage rate for OCGT plant, for which Frontier Economics has used an equivalent forced outage rate of 3%.

Capital costs, FOM and VOM

For existing generation plant, the only cost information that is required for Frontier Economics' modelling is the variable costs of production: VOM and fuel costs (and carbon costs, once thermal generators are exposed to a carbon price).

For new entrant generation plant, Frontier Economics' modelling also requires information on the capital costs and the fixed operating and maintenance costs (FOM) of generation plant. This cost information is an important factor in least cost investment decisions.

Frontier Economics has drawn all required cost information for new entrant generation plant from the NTNDP Modelling Assumptions. Capital costs, FOM and VOM for important new generation options are set out in Table 2.

Table 3: New generation costs

Technology	Capital costs (Real 2009-10 $/kW)	FOM ($/MW/year) for 2009-10	VOM ($/MWh sent-out) for 2009-10
OCGT	985	9,000	2.50
CCGT	1,368	14,000	2.00
Supercritical PC - Black coal	2,676	33,000	4.60
Supercritical PC - Brown coal	3,571	41,000	5.10
IGCC - Black coal	4,201	73,000	12.80
IGCC - Brown coal	5,025	50,000	5.20
Wind - Small scale (50 MW)	3,178	42,000	0.00
Wind - Medium scale (200 MW)	2,886	39,000	0.00
Wind - Large scale (500 MW)	2,744	37,000	0.00
Geothermal - HSA	7,260	125,000	0.00
Biomass	5,000	40,000	2.25

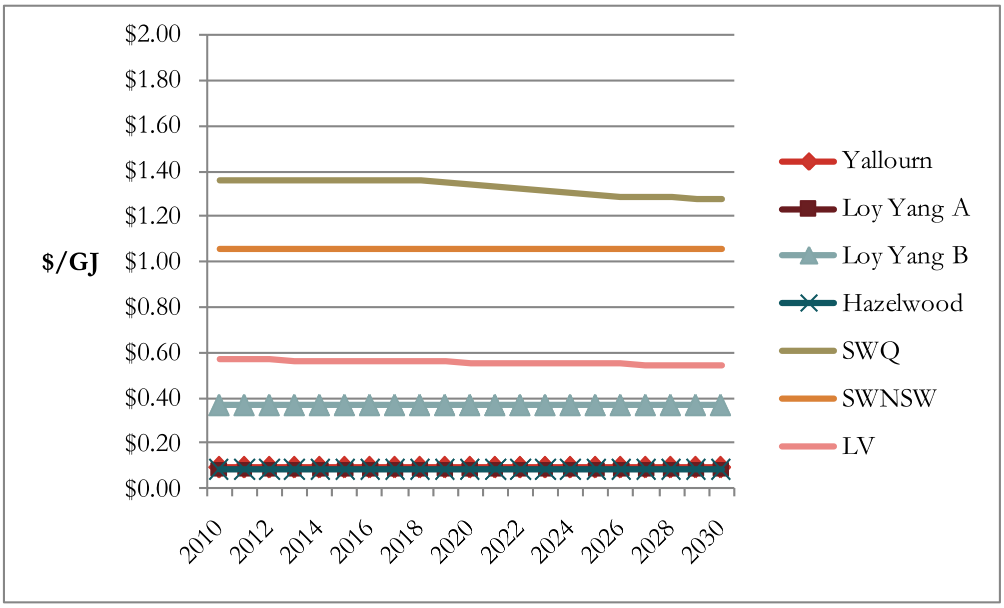
Source: NTNDP Modelling Assumptions

Fuel costs

As is the case for existing generation plant, Frontier Economics has used assumptions on fuel costs for new generation plant that are set out in NTNDP Modelling Assumptions.

Compared to new coal-fired generators, each of the base load power stations in Victoria have very low coal costs. Figure 4 compares the coal costs for the Victorian base load power stations with the lowest available new entrant coal costs in each of the other NEM regions (South West Queensland, South West NSW and the Latrobe Valley). Even for new entrants, coal costs in Victoria are far lower than gas costs.

Figure 4: Coal costs – Victorian brown coal compared with new entrant coal



Source: NTNDP Modelling Assumptions

4.7 Carbon price

Consistent with current policy, Frontier Economics' modelling is undertaken on the basis of an assumption that there will be a carbon price introduced from the beginning of 2012/13. The starting carbon price is assumed to be $20/tonne CO_2-e (in $2010/11), escalating thereafter at CPI + 4%.

The carbon price assumption used in Frontier Economics' modelling was adopted prior to the release of the Commonwealth Government's Clean Energy

Plan. The Clean Energy Plan includes an initial carbon price of \$23/tonne CO_2-e commencing in 2012/13.[9]

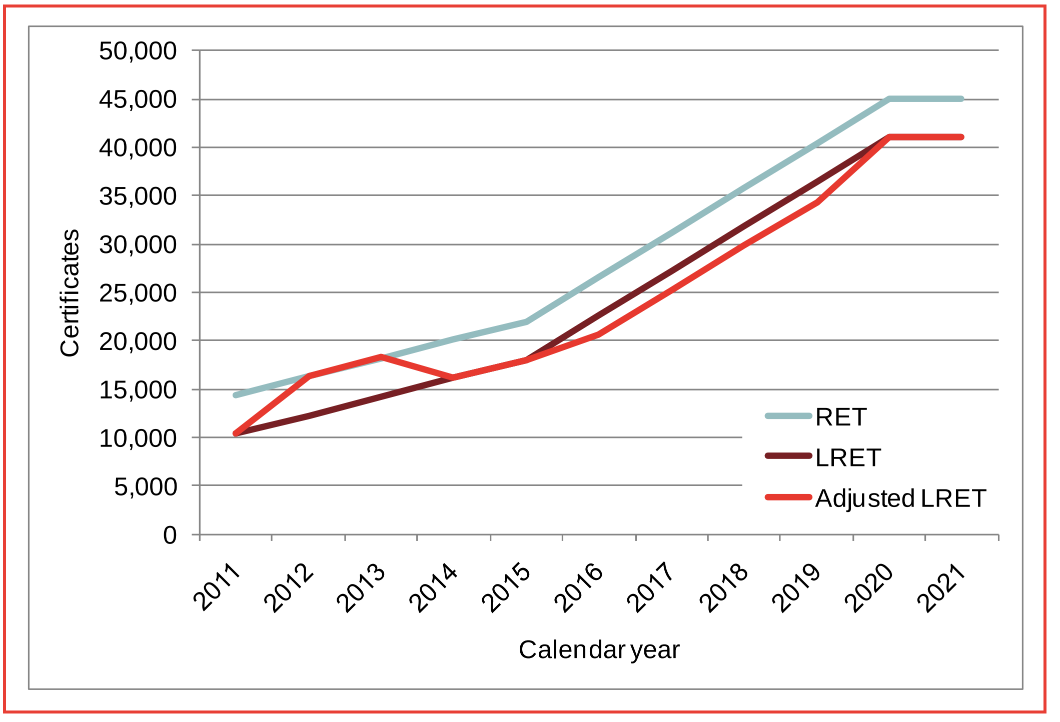
The carbon price assumption used in Frontier Economics' modelling is also different from that assumed for Scenario 3 of the NTNDP. It is worth noting that the input cost assumptions developed for Scenario 3 of the NTNDP are based on the introduction of a carbon price. However, compared to the carbon price assumed by Frontier Economics, the carbon price assumed for the purposes of the NTNDP is introduced a year later and is higher.

4.8 LRET target

From 1 January 2011, the RET scheme has been split into the Large-scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). As part of this process the RET target has been amended to come up with the LRET target and the adjusted LRET target (which accounts for the surplus of RECs available at the end of 2010). Figure 5 shows the RET target, the LRET target and the adjusted LRET target. Frontier Economics has used the adjusted LRET target in its modelling.

9 Commonwealth Government, *Securing a clean energy future, The Australian Government's Climate Change Plan*, 2011.

Figure 5: LRET target



Source: ORER, Frontier Economics.

5 Gas market modelling assumptions

This section provides a brief overview of the key modelling assumptions used by Frontier Economics to analyse the likely impact on energy security in the gas sector of the electricity shock scenario.

Consistent with the approach for electricity market input assumptions, Frontier Economics has, where possible, adopted input assumptions developed by AEMO. Adopting this approach, Frontier Economics has, to a large extent, relied on the AEMO 2010 GSOO[10] for key modelling assumptions relating to gas demand and transport capacity.

5.1 Gas demand forecasts

Given this modelling project is focused on the impact on system security of the loss of a major baseload power station in Victoria, demand forecasts are a key input assumption. In order to examine the impact of both the permanent exit and a 14 day forced outage of Loy Yang A power station, it is necessary to develop a set of demand forecasts for each region in the NEM that reflect the variation of demand throughout the year. The approach and assumptions that Frontier Economics has used to develop the required demand forecasts are as follows:

- The starting point is a daily demand profile for each demand region that reflects a representative year. Frontier Economics has used historic daily flow information available from the National Gas Market Bulletin Board (GasBB) from calendar year 2010 to provide this representative year. In Frontier Economics' view, calendar year 2010 provides by far the most complete set of flow data available from the GasBB.
- For each demand region this representative daily demand trace is then scaled to reflect forecast growth in both total demand and peak demand. Frontier Economics has used the Decentralised World, 1-in-2[11] demand forecasts for summer and winter from the AEMO 2010 GSOO to scale the representative half-hourly load profile for each year of the modelling period.

  To ensure consistency between the electricity market modelling in the Reference Case and the shock scenario cases, Frontier Economics has forecast demand growth using the demand forecasts from the AEMO 2010 GSOO that exclude demand from gas-fired generation, and added to this

10 AEMO, *Gas Statement of Opportunities for Eastern and South Eastern Australia*, 2010.

11 1-in-2 peak demand forecasts are expected to be exceeded 50 per cent of the time, or once in every two years.

demand Frontier Economics' own forecasts of demand from gas-fired generation in each region.

- As gas market modelling is computationally much less demanding than electricity market modelling, we have been able to complete daily modelling, and have not need to use 'representative days' as we have for the electricity market modelling.

5.2 Existing gas reserves

Given that the AEMO 2010 GSOO does not contain information on remaining gas reserves by gas field, Frontier Economics has used information on remaining gas reserves by gas field from a range of sources, including company reports and other public information. Information on remaining reserves for the gas fields in southern Australia is set out in Table 4.

Table 4: Reserves in existing gas fields in southern Australia

Gas field	Basin	Type	Remaining 2P reserves (as of 30 June 2010) (PJ)
SWQ	Cooper/Eromanga	Conventional	295
SACBUP	Cooper/Eromanga	Conventional	860
Minerva	Otway	Conventional	138
Casino-Henry	Otway	Conventional	171
Thylacine-Geographe	Otway	Conventional	768
Yolla	Bass	Conventional	268
Esso-BHP	Gippsland	Conventional	3,929
Kipper	Gippsland	Conventional	600
Longtom	Gippsland	Conventional	348
Camden	Sydney	CSM	154
Hunter	Hunter	CSM	142
Gloucester	Gloucester	CSM	669
Narrabri	Gunnedah	CSM	1,520
Casino	Clarence-Moreton	CSM	397

Source: Frontier Economics estimates.

5.3 Existing gas production facilities

Frontier Economics has used the AEMO 2010 GSOO as a source for information on existing gas production facilities. The AEMO 2010 GSOO provides information on the identity and capacity of each gas production facility in eastern Australia. Information on the gas production facilities in southern Australia is set out in Table 5.

Table 5: Capacity of existing gas production facilities in southern Australia

Production facility	State	Type	Capacity (TJ/d)
Ballera Plant	QLD	Conventional	150
Moomba Plant	SA	Conventional	430
Minerva Plant	VIC	Conventional	94
Iona Plant	VIC	Conventional	180
Otway Plant	VIC	Conventional	205
Lang Lang Plant	VIC	Conventional	67
Longford Plant	VIC	Conventional	1,145
Orbost Plant	VIC	Conventional	100
Camden	NSW	CSM	27

Source: AEMO 2010 GSOO

5.4 Existing gas transmission pipelines

Frontier Economics has used the AEMO 2010 GSOO as a source for information on existing gas transmission pipelines. The AEMO 2010 GSOO provides information on the identity and capacity of each major gas transmission pipeline in eastern Australia, a summary of which is provided in Table 6.

Table 6: Existing gas transmission pipelines in south-east Australia

Pipeline	Capacity (TJ/d)
Roma to Brisbane Pipeline	219
Queensland Gas Pipeline	134
South West Queensland Pipeline	181
South West Queensland Pipeline - Stage 3 *	380
Carpentaria Gas Pipeline	119
Moomba to Adelaide Pipeline System	253
Moomba to Sydney Pipeline	435
SEAGas Pipeline	314
South West Pipeline (SWP)	353
Longford to Melbourne Pipeline	1,030
Culcairn-North	72
Culcairn-South	92
Eastern Gas Pipeline	268
Tasmanian Gas Pipeline	129
Roma to Brisbane Pipeline	219
Queensland Gas Pipeline	134
South West Queensland Pipeline	181

Source: AEMO 2010 GSOO

** Not listed in AEMO 2010 GSOO. Capacity sourced from company reports.*

6 Reference Case outputs

This section provides the results from Frontier Economics' modelling of the Reference Case.

The focus of the Reference Case modelling is to develop a set of outcomes against which the various shock scenario cases can be compared. As discussed in Section 3, modelling of the Reference Case requires the following steps:

- **Power station investment modelling**. The outputs of this modelling include efficient generation investment, including any new investment in generation in Victoria. These investment results are an important input into market modelling (particularly in 2015/16, by which point new investment in electricity generation is required).
- **Electricity market modelling**. The outputs of this modelling include the following:
  - Power station dispatch, including dispatch of baseload generation in Victoria.
  - Electricity pool prices.

  These Reference Case dispatch and price outcomes provide a basis for comparison of dispatch and price outcomes under the various shock scenario cases.

6.1 Power station investment modelling

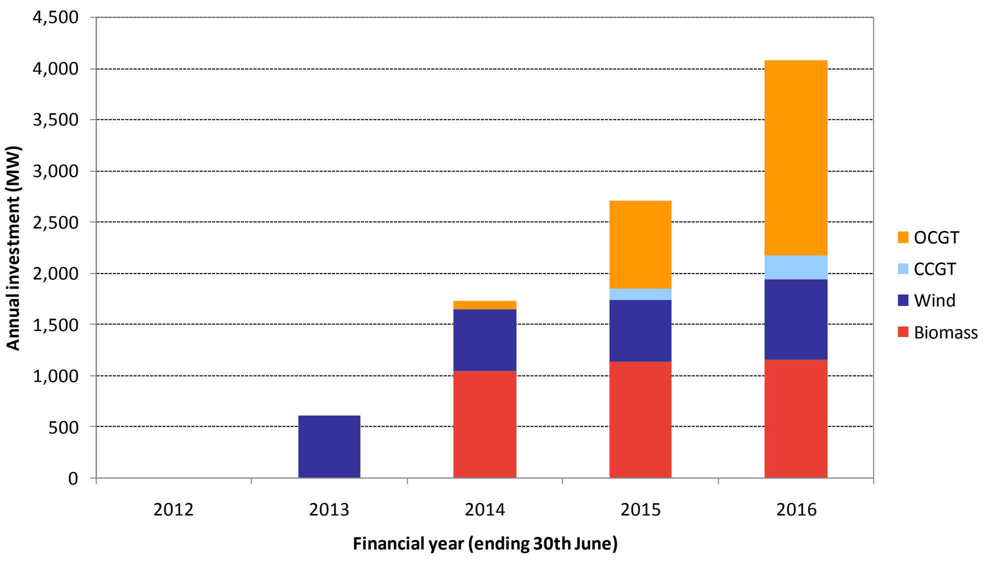
Frontier Economics has modelled new investment going forward using our least-cost investment model, *WHIRLYGIG*. *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load.

The quantity and time of new investment in the NEM in the Reference Case is shown in Figure 6:

- Wind is being built from 2012/13 to meet the RET target
- Biomass is being built from 2013/14 to meet the RET target
- OCGT is being built from 2013/14 to meet peak demand growth
- CCGT is being built from 2014/15 in response to a carbon price and to meet energy demand growth

Biomass appears in the investment mix as it is cheap on an LRMC basis under the assumptions used in the modelling. If biomass were assumed to be more expensive (or less available) then the modelling would include more investment in wind to meet the RET target. The Reference Case illustrates that demand growth will be met with gas fired generation instead of coal fired generation due to the carbon price introduction in 2013/14.

Figure 6: Cumulative NEM investment path – Reference Case



Source: Frontier Economics

6.2 Electricity market modelling

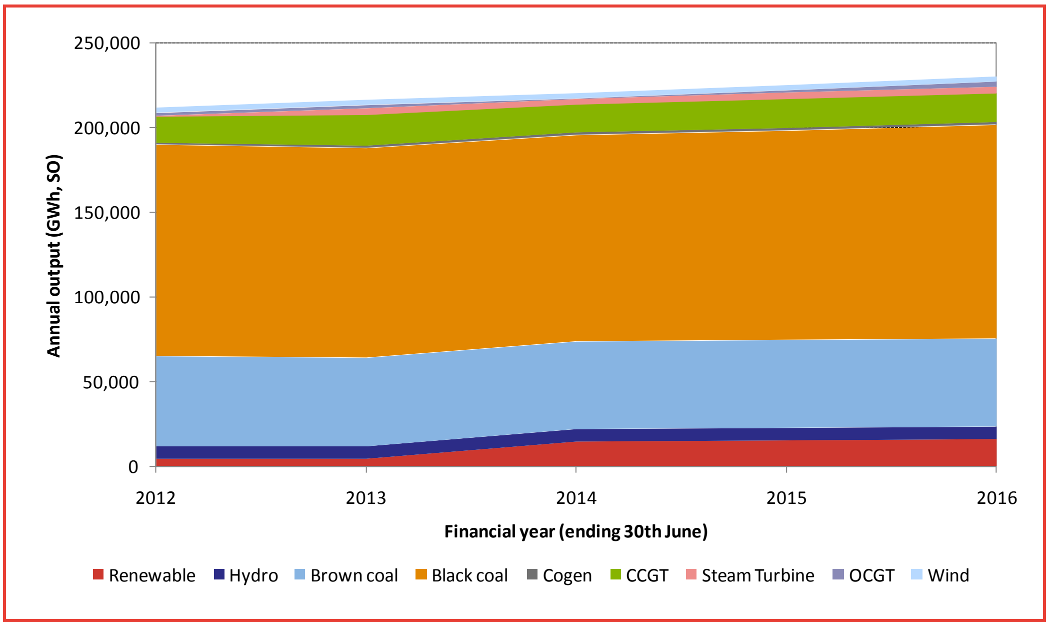
Frontier Economics has modelled plant dispatch and market prices going forward using our game-theoretic pool dispatch model, *SPARK*. *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

6.2.1 Market Dispatch

Figure 7 shows the annual market output across the NEM for the Reference Case. As expected, the generation mix is dominated by baseload coal generation. From 2012/13, there is a slight displacement of coal with CCGT generation as a result of carbon prices. The extent of displacement is driven by the relativities between the assumed coal price, gas price and carbon price. For the carbon prices assumed over this period, which are well under $30/tCO2e, only minor displacement of black coal plant and no significant displacement of brown coal is observed. At this level the carbon price is not sufficient to cause switching between existing brown coal and gas fired generation in the southern states but is sufficient to result in some displacement of black coal in the northern states where coal prices are higher and gas prices are lower in the initial years. The main impact of the introduction of a price on carbon in the modelling forecasts is to influence the type of new plant being built, which is lower-emitting CCGT as shown in Figure 6.

There is also an increasing proportion of generation from renewables, which run in order to meet the RET target.

Figure 7: NEM annual market output – Reference Case

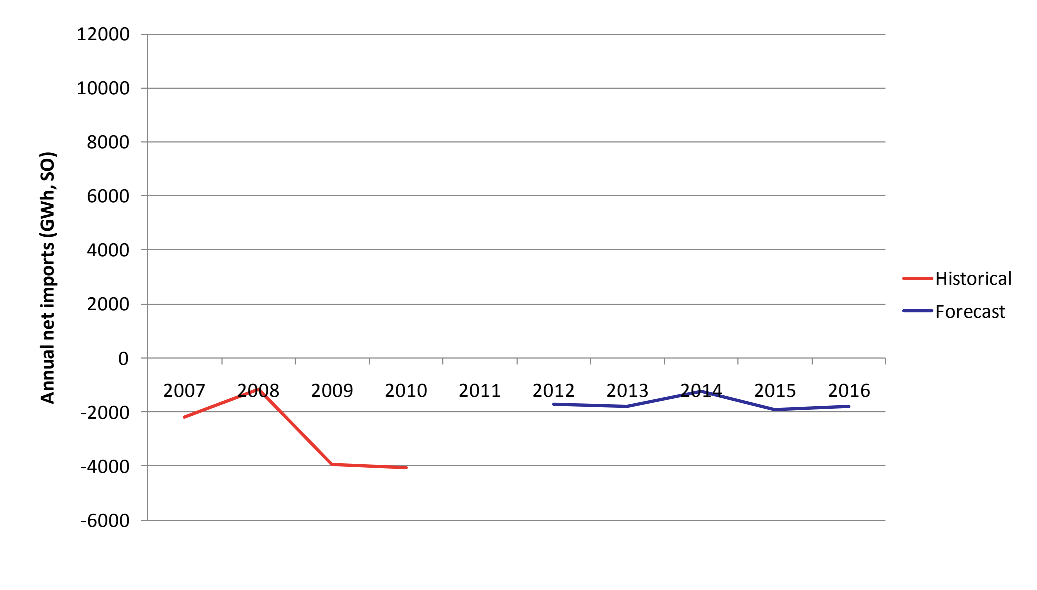


Source: Frontier Economics

6.2.2 Net imports – Victoria

Figure 8 shows the annual net imports to Victoria for the last four complete financial years and over the forecast period for the Reference Case. It illustrates that Victoria continues to be a net exporter of energy, even after the introduction of a carbon price. This is an expected result since Victoria holds a large fleet of brown coal generators, which produce some of the cheapest baseload generation in the NEM. Victorian brown coal generation continues to be relatively low cost in the early stages of carbon pricing because the relatively high carbon cost faced by these generators is not sufficient to outweigh the relatively low fuel cost faced by these generators.

Figure 8: NEM annual net imports to Victoria – Reference Case



Source: Frontier Economics

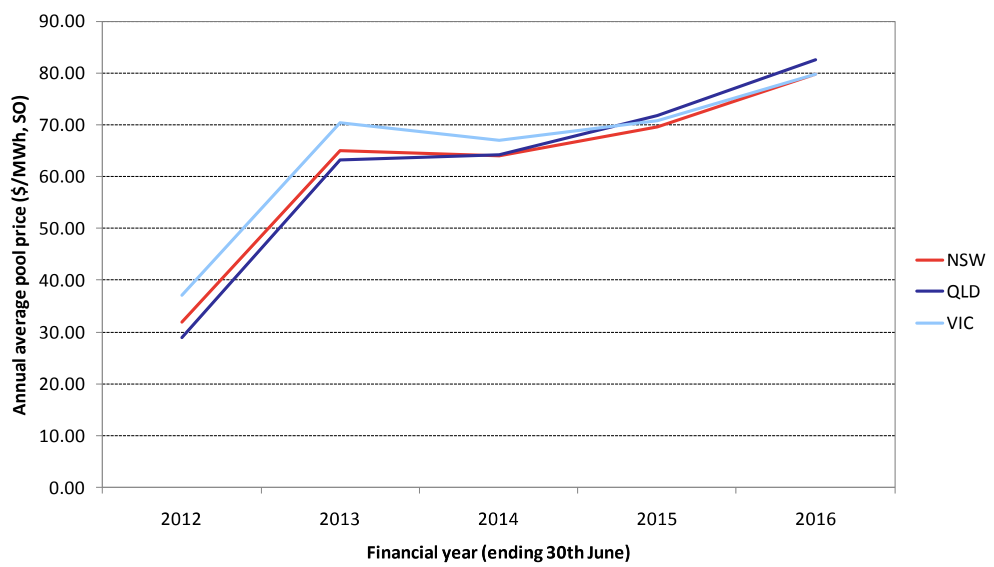
6.2.3 Pool prices

Figure 9 shows the annual time-weighted average forecast pool prices for NSW, Queensland and Victoria over the modelling period. These price forecasts are broadly consistent with forward prices published by d-Cypha, suggesting that these key drivers are anticipated in the market.

It is clear from Figure 9 that prices increase markedly over the modelling period in all regions. This increase in pool prices over the modelling period is driven by:

- rising costs, since generators face increasing fuel prices and carbon prices over the forecast period
- growth in demand, which results in a tightening in the supply-demand balance and therefore an increase in output from higher cost plant.

Figure 9: Annual pool prices by NEM region – Reference Case



Source: Frontier Economics

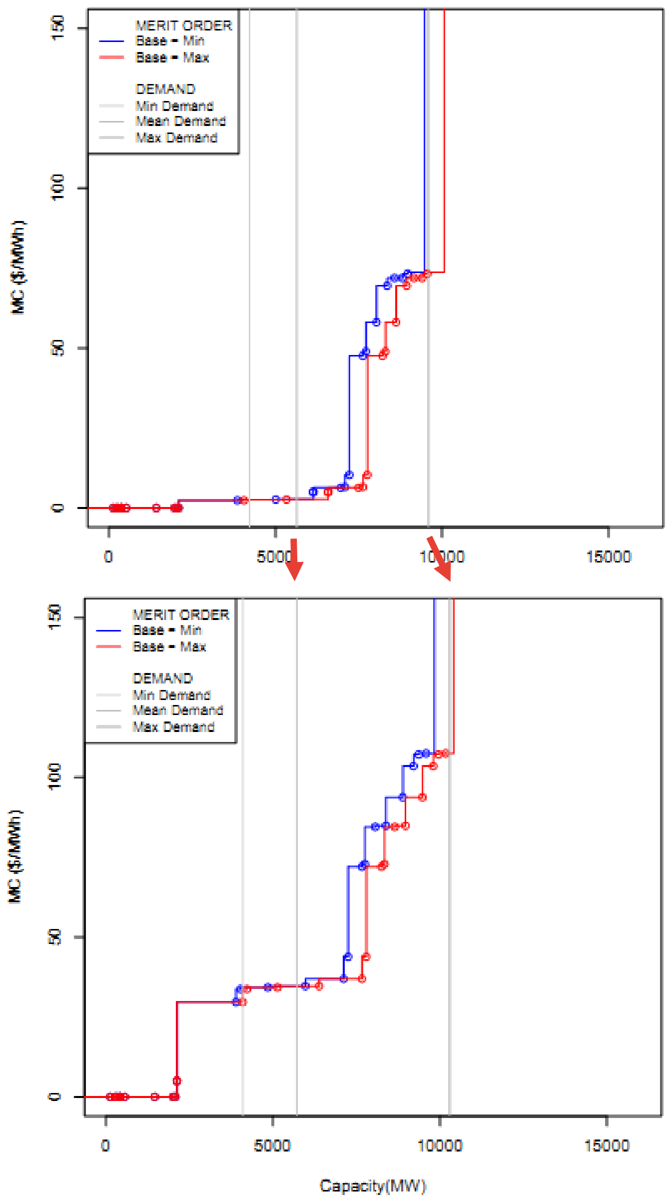
These two factors affect different regions to different extents. This is illustrated by considering outcomes in Victoria and outcomes in Queensland. Further detail of supply and demand dynamics in the Reference Case are illustrated for Victoria in Figure 10 and for Queensland in Figure 11.

These figures show the supply and demand curves in both 2011/12 and 2015/16 for Victoria and Queensland respectively.[12] Cumulative capacity is shown on the horizontal axis and cost in $/MWh is shown on the vertical axis. In *SPARK*, the ability of generators to bid strategically is captured by allowing strategic generators to choose how much of their capacity to bid into the market (where the generators are constrained to offer at least a defined minimum amount of capacity to the market, in order to make the modelling problem tractable). The extent to which generators can behave strategically in *SPARK* is illustrated by the two supply curves on each chart (the red and blue curves). The red curve is the supply curve corresponding to all generators in the region offering the maximum amount of capacity into the market. The blue curve is the supply curve corresponding to all generators in the region offering the minimum amount of capacity into the market. Between the blue curve and the red curve are many thousands of possible supply curves, each corresponding to a different combination of possible generator bids. *SPARK* models each of these different

12 Note that these figures are for illustrative purposes only. These curves show demand and supply in Queensland only, ignoring inter-regional interconnectors. Frontier Economics' modelling, however, models each region in the NEM and incorporates the inter-regional interconnectors.

combinations of bids (and corresponding supply curves) for each demand level in the modelling, and determines equilibrium combinations of bidding strategies using Game Theory. For the purposes of comparison, the vertical lines in the figures represent key levels of demand used in the modelling – the peak, average and minimum demand level in the region. Each of these levels of demand, as well as a range of other demand levels that make up the representative demand curve, are modelled in *SPARK*.

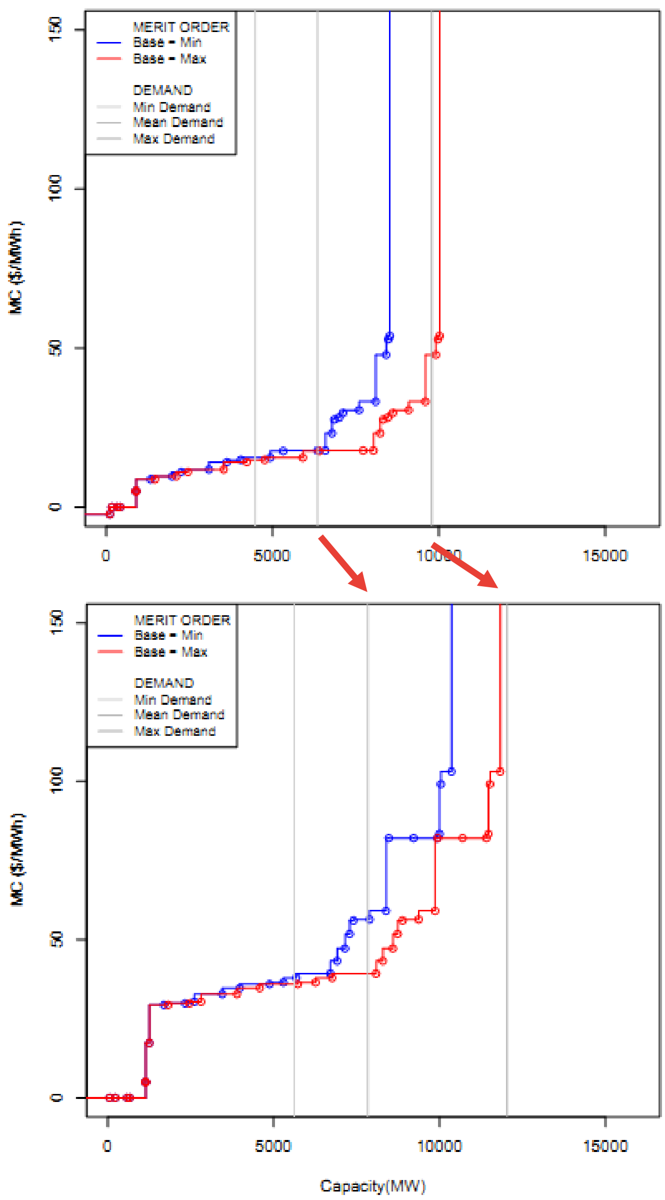
Figure 10: Victoria's supply and demand for FY2012 and FY2016 – Reference Case



Source: Frontier Economics

Reference Case outputs

Figure 11: Queensland's supply and demand for FY2012 and FY2016 – Reference Case



Source: Frontier Economics

It is clear from Figure 10 and Figure 11 that there is a different generation structure in Victoria and Queensland. While Victoria has a significant supply of very cheap brown coal generation (represented by the very low and flat portion of the supply curve) the capacity of this cheap brown coal generation is not sufficient to meet Victorian demand throughout the year. Rather, the substantially more expensive gas-fired generation (represented by the steep vertical portion of the demand curve) is often required to meet demand in Victoria. In contrast, Queensland has a significant supply of black coal generation at various coal prices and a number of gas-fired generators with relatively low gas prices. The overall effect is that there is not such a steep step increase in the supply curve in Queensland as there is in Victoria, suggesting that prices during higher demand periods in Queensland may not increase to the same extent as they do in Victoria (although this will also depend, ultimately, on flows in inter-regional interconnectors).

In both Queensland and Victoria, there is significant structural change in the supply curve from 2011/12 to 2015/16. Both supply curves shift upwards to various degrees as carbon prices and increasing fuel costs affect the cost of generation (the only exception being renewable generators, which do not face any increase in variable costs). This results in increased pool prices. An additional effect of carbon prices is to change the merit order of supply, because of the different extent to which the carbon price affects generators' costs. This is illustrated as a change in the shape of the supply curve over time. This effect does not necessarily result in increased pool prices.

The figures also illustrate the degree to which demand growth (as shown by the arrows in each figure) affects prices. There is mild demand growth in Victoria, implying that demand growth has a relatively small effect on Victorian pool prices. However, Queensland sees considerable growth in average and peak demand, which can only be met with dispatch from higher cost generators and results in greater upward pressure on prices in Queensland. Although the figures show that in 2015/16 the peak demand level is equal to or higher than the red supply curve (representing maximum supply from generators in the region), this does not necessarily imply loss of load: these illustrative figures do not show the capacity in other regions that is available to Victoria and Queensland through inter-regional interconnectors.

7 Shock scenario – permanent exit

This section provides the results from Frontier Economics' modelling of the shock scenario case that involves the permanent exit of Loy Yang A. As discussed in Section 3, modelling of the shock scenario case that involves permanent exit requires the following steps:

- **Power station investment modelling**. The outputs of this modelling include efficient generation investment (including any new investment in generation in Victoria) taking account of the fact of the permanent exit of Loy Yang A power station. These investment results indicate the least-cost investment response to the permanent exit and are also an important input into market modelling over the period to 2015/16.
- **Electricity market modelling**. The outputs of this modelling include the following:
  - Power station dispatch, including dispatch of baseload generation in Victoria.
  - Electricity pool prices.

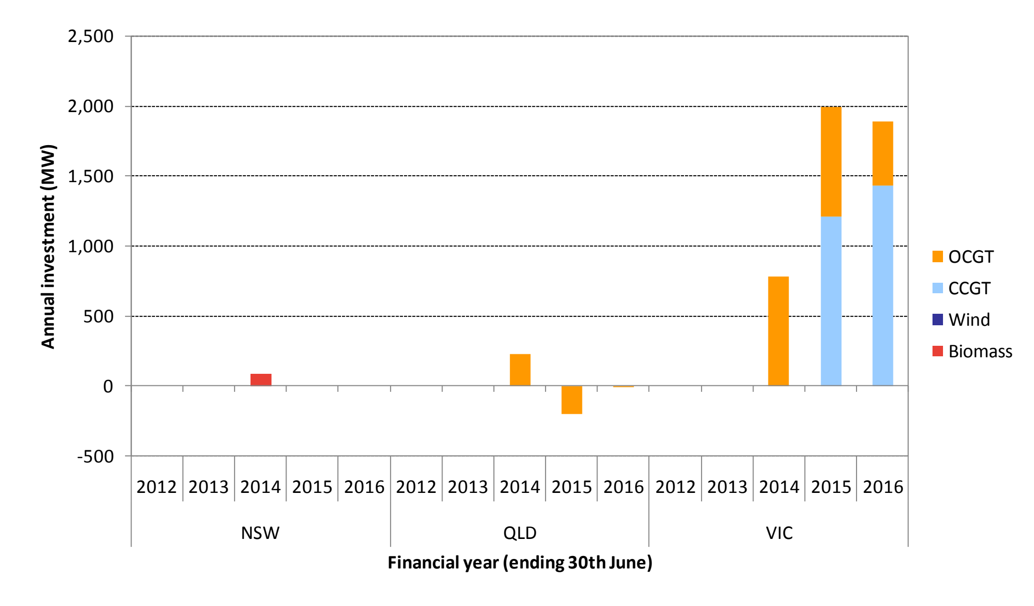
  These shock scenario dispatch and price outcomes can be compared with outcomes under the Reference Case to gauge the impact of the shock scenario cases.
- **Gas market modelling**. The permanent exit of a coal-fired power station in Victoria will result in greater demand for gas from gas-fired generators. The purpose of the gas market modelling is to determine whether the increased demand for gas from gas-fired generators can be accommodated with existing gas supply infrastructure.

7.1 Power station investment modelling

Figure 12 shows the incremental change in installed generation capacity caused by the permanent exit of Loy Yang A. Positive values on the chart indicate more installed generation capacity in a given year in the shock scenario case than in the Reference Case.

Figure 12 shows that there is an investment response to the supply shortfall in 2013/14, with additional OCGT plant being constructed in Victoria and Queensland and biomass investment in NSW. Both these plant types can be constructed within a year, making them the quickest possible investment response to the permanent outage. Additional CCGT is constructed in Victoria in 2014/15 – as soon as possible given the two year lead time for CCGT plant. Ultimately, the new CCGT and OCGT capacity effectively replaces the capacity of Loy Yang A power station.

Figure 12: Change in installed capacity by NEM region – LYA-Permanent



7.2 Electricity market modelling

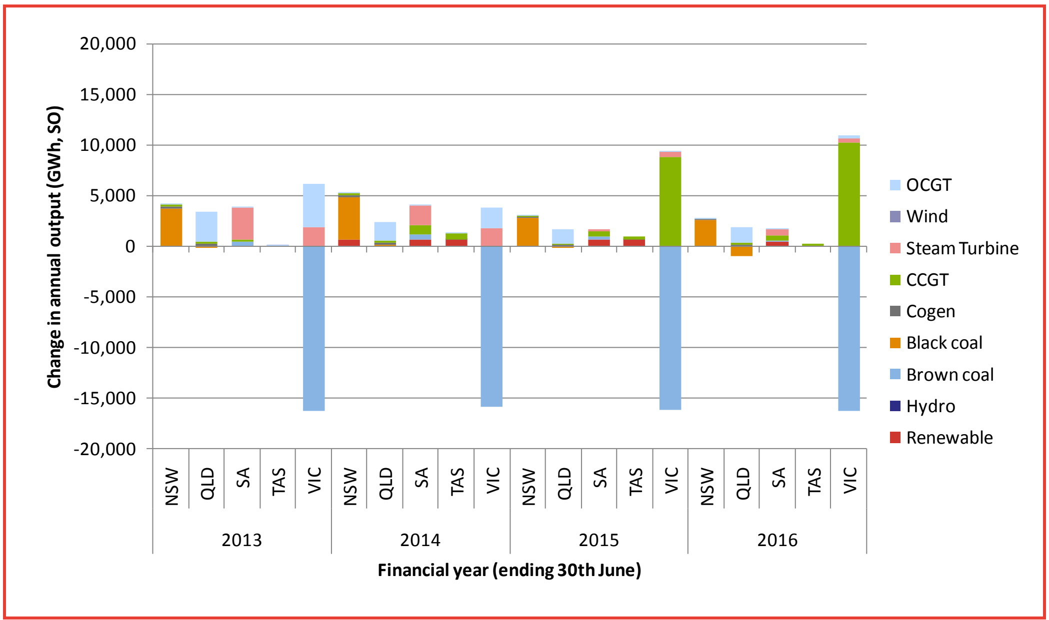
For the permanent exit cases, Frontier Economics has modelled plant dispatch and market prices going forward using our game-theoretic pool dispatch model, *SPARK*. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

7.2.1 Market dispatch

Figure 13 shows the incremental change in market output caused by the permanent exit of Loy Yang A. Negative values on the chart represent the generation lost since Loy Yang A no longer operates, and positive values on the chart represent the mix of generation in each region that replaces Loy Yang A.

In 2012/13 and 2013/14 the majority of lost output from Loy Yang A is replaced with output from black coal generation in NSW and more expensive gas plant in South Australia, Victoria and Queensland. In 2013/14 there is increased generation from renewables, which is possible in part because investment in biomass in NSW has occurred in 2013/14. However, the principal investment response to the permanent exit of Loy Yang A is not seen until 2014/15 and 2015/16, at which point the majority of replacement generation comes from new CCGT plant in Victoria.

Figure 13: Change in NEM annual output – LYA-Permanent



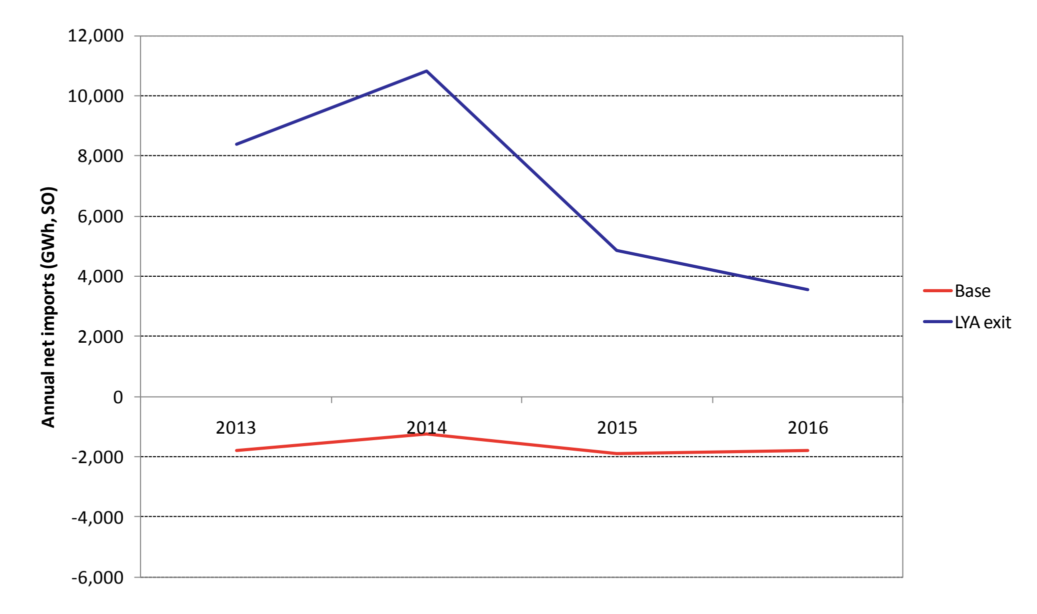
Source: Frontier Economics

7.2.2 Net imports – Victoria

Figure 14 shows Victoria's net annual imports in the Reference Case and with the permanent exit of Loy Yang A power station. It illustrates that, in contrast to the Reference Case, Victoria becomes a net importer of electricity in the event of a permanent exit of Loy Yang A. This result is in-line with the market output results that show an increase in output from NSW black coal generators, some of which is used to supply Victorian demand.

Over time, there is a drop in net imports, reflecting the ability of Victoria to manage the lost supply with new CCGT investment within Victoria. Victoria does not return to a net exporting region within the modelling period as the replacement capacity (CCGT and OCGT) sits in a different position on the merit order to the brown coal plant it has replaced, causing a structural change to the supply curve of the Victorian market.

Figure 14: VIC net annual imports – Reference Case and LYA-Permanent



Source: Frontier Economics

Frontier Economics has analysed the extent to which the increase in Victorian imports approaches the ability of the interconnectors to physically transfer power into Victoria. Given the bi-directional nature of interconnectors, the best measure of this is the amount of time that a given interconnector is binding (i.e. power transfers are at maximum capacity).

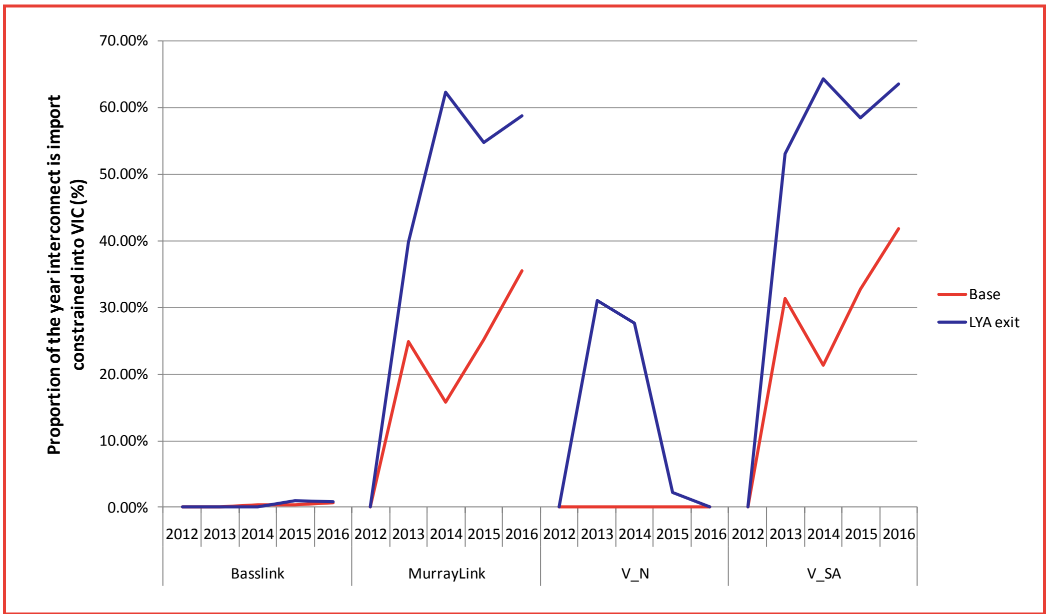
Figure 15 shows the percentage of the year that Victorian imports bind each of the four interconnectors with end points in Victoria. Clearly, the permanent exit of Loy Yang A power station results in a significant increase in the proportion of the year for which imports bind these interconnectors: the interconnectors with South Australia bind around 60 per cent of the time with the permanent exit of Loy Yang A and the interconnector with NSW binds around 30 per cent of the time with the permanent exit of Loy Yang A. While this reflects a significant change in patterns of operation in the NEM, these import levels are achieved within the constraints of the physical design of the interconnectors.[13] Furthermore, the outages do not result in transfers of power at or near 100 per cent of potential interconnector capacity.

While the new pattern of inter-regional flows into Victoria is feasible given changes in dispatch as a result of the permanent exit of Loy Yang A and existing interconnector capacity, the higher average utilisation of these transmission assets

13 Note, however, that Frontier Economics' modelling does not incorporate intra-regional transmission constraints that may limit flows on inter-regional interconnectors.

would result in a larger impact on the market in the event of a major transmission failure. Since Victoria has become more reliant on imports from other regions, it is also now more reliant on the transmission infrastructure that allows inter-regional trade of energy.

Figure 15: VIC imports – percentage of year interconnectors bind – LYA-Permanent



Source: Frontier Economics

7.2.3 Pool Prices

Figure 16 compares the annual average pool prices in the Reference Case and the LYA-Permanent case. As expected, the price impact of the permanent exit of Loy Yang A is largest in Victoria. New South Wales and Queensland also face price increases as they change their generation pattern in order to offset the supply shortage in Victoria.

The price impacts of the permanent exit are largest in 2012/13 and 2013/14, because investment in new CCGT plant does not occur until 2014/15:

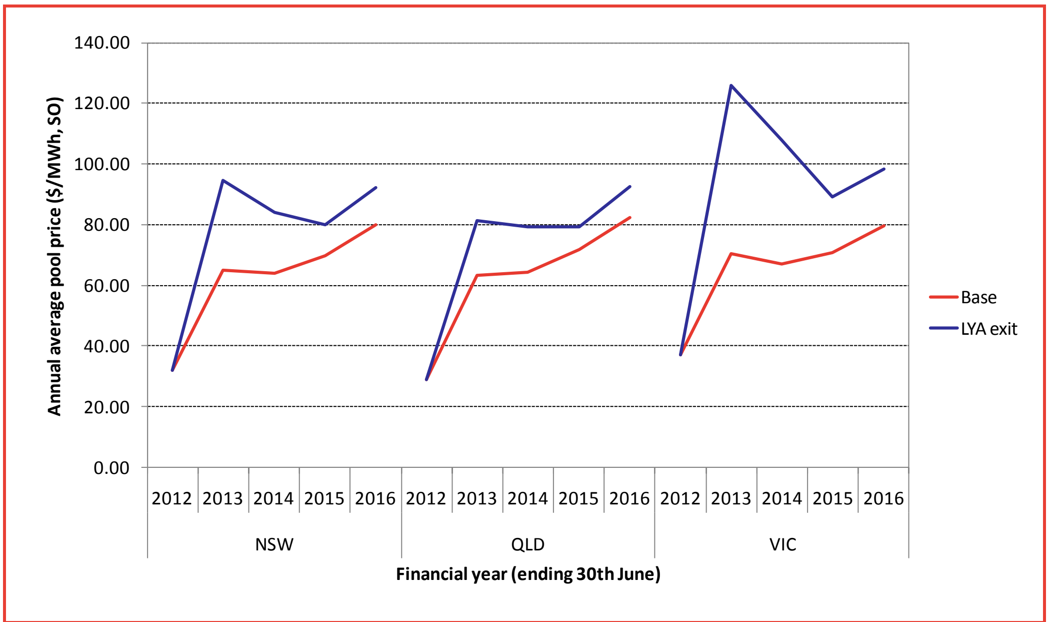
- Prices in 2012/13 increase dramatically as a result of the exit of Loy Yang A. In Victoria, annual average prices increase from \$70.34/MWh to \$125.80/MWh. Prices also increase significantly in New South Wales and Queensland.
- Prices in 2013/14 stay at an elevated level, although investment in OCGT mitigates the price effects to some extent. In Victoria, annual average prices increase from \$66.96/MWh to \$107.81/MWh. The reduction in prices in

both the Reference Case and the LYA-Permanent case in 2013/14 is a result of the forecast reduction in energy demand in Victoria in 2013/14, among other things.

With significant new investment in CCGT plant in Victoria, prices fall from 2014/15. However, prices do not return to the levels seen in the Reference Case because the replacement CCGT plant has a higher marginal cost than Loy Yang A power station.

While these price increases are certainly substantial, Frontier Economics' modelling indicates that the permanent exit of Loy Yang A power station would not result in a breach of the Cumulative Price Threshold (CPT). However, under AEMO's modelling framework (discussed in more detail in Section 7.2.4) it would be expected that one or more high priced events could occur that would breach the CPT (as a result of a high demand event and/or multiple outages occurring in the period before new investment).

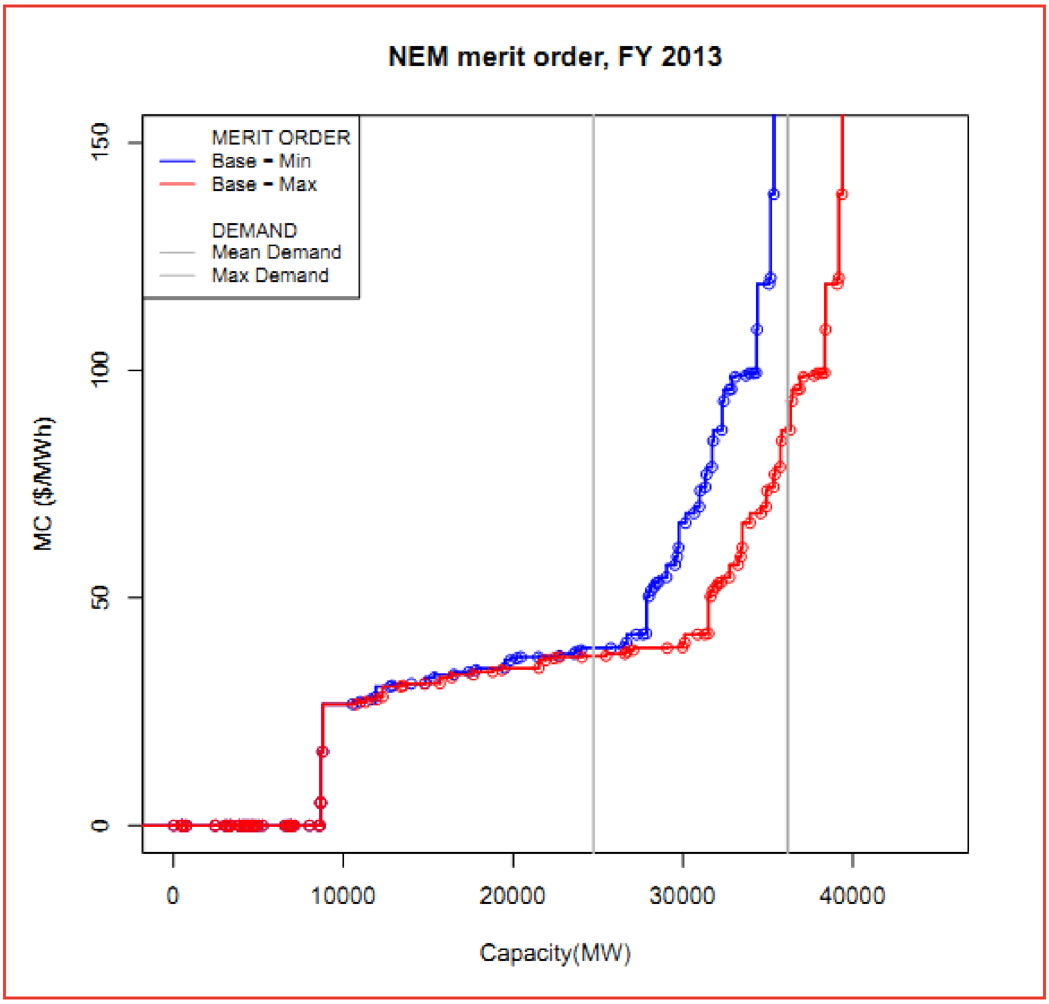
Figure 16: Annual pool prices by NEM region – Reference Case and LYA-Permanent



Source: Frontier Economics

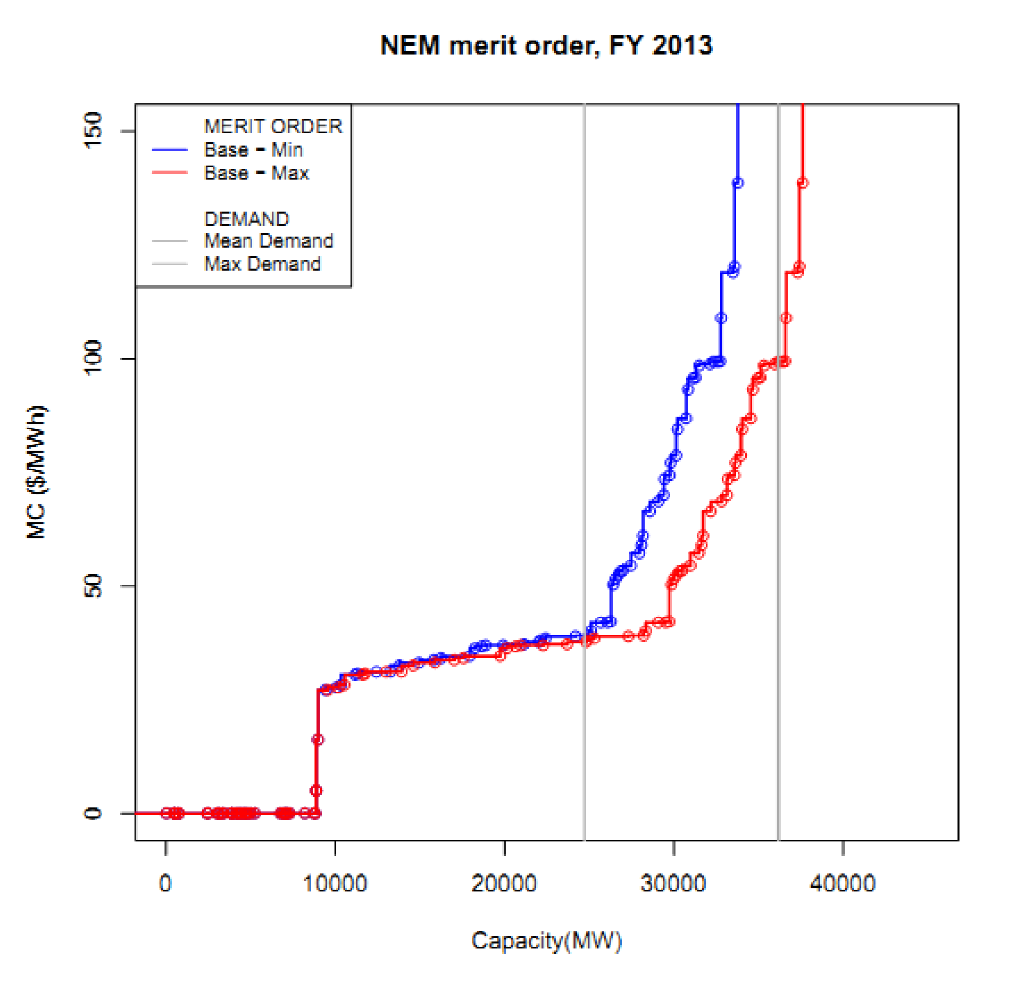
In order to help understand the reasons that prices in 2012/13 increase as a result of the permanent exit of Loy Yang A power stations, Figure 17 and Figure 18 show the supply and demand curves for the NEM for the Reference Case and the LYA-Permanent case. It is clear that the permanent exit of Loy Yang A power station requires the dispatch of more expensive generation plant, particularly during peak demand periods. This is most apparent by comparing the point at which peak demand intersects with the red supply curve (which is the supply curve corresponding to all generators in the region offering the maximum amount of capacity into the market). The peak demand curve intersects with the red supply curve at a lower cost in the Reference Case than in the LYA-Permanent case. However, even with the permanent exit of a Victorian baseload power station there remains significant reserve plant in the system: that is, the peak demand curve does not lie to the right of the red supply curve.

Figure 17: NEM merit order – Reference Case (2012/13)



Source: Frontier Economics

Figure 18: NEM merit order – LYA-Permanent (2012/13)



Source: Frontier Economics

Note that the price increases forecast by Frontier Economics are based on the assumption that existing generators are able to access additional fuel supplies (as required to increase their output) without facing higher fuel costs. If it is the case that generators would face higher marginal fuel prices as a result of an increase in output, the price impact would be somewhat higher than forecast.

7.2.4 Unserved energy

Frontier Economics' energy market modelling indicates that, under the assumptions and methodology adopted for this analysis, the permanent exit of Loy Yang A power station does not result in a substantial increase in unserved energy in Victoria or other NEM regions. In particular, Frontier Economics' modelling indicates that the reliability standard of 0.002 per cent unserved energy for each NEM region would not be breached.

Importantly, however, the extent to which unserved energy is observed in Frontier Economics' modelling results is dependent on a number of key methodological approaches and input assumptions, including:

- Frontier Economics' modelling does not incorporate intra-regional network constraints
- Frontier Economics have modelled the medium growth, 50% probability of exceedence demand forecast for each NEM region
- Frontier Economics have derated all generation plant at a flat outage rate throughout the year.

In large part, this approach has been adopted in order to simplify the modelling problem and allow Frontier Economics to model both long-term investment decisions and strategic bidding in the market. Clearly, a different modelling approach would likely lead to a different conclusion on the extent of unserved energy in the LYA-Permanent case:

- Intra-regional network constraints are likely to increase unserved energy, especially where intra-regional network constraints effectively constrain the capacity of inter-regional interconnectors
- With higher levels of demand, greater unserved energy would be expected. In particular, under the 10% probability of exceedence demand forecast the capability of the generation and transmission system to meet demand will be further tested
- In the event that multiple forced outages occur during periods of high demand (rather than evenly across the year) the capability of the generation system to meet demand will be further tested.

At the request of DRET, AEMO's operational planning team have undertaken monte carlo modelling of the LYA-Permanent case. The base modelling used by AEMO is the same as that used for the Energy Adequacy Assessment Projection (EAAP) and the Power System Adequacy (PSA) report. This modelling incorporates all inter-regional and intra-regional network constraints, incorporates two demand forecasts (the medium growth, 10% and 50% probability of exceedence forecasts) and incorporates a stochastic treatment of outages. Given this, AEMO's modelling will reflect a range of potential outcomes, including some outcomes in which outages at other power stations coincide with high levels of demand (including demand from the medium growth, 10% probability of exceedence forecast).

AEMO have run a base case and a case in which Loy Yang A power station is permanently unavailable but there is no investment response. This suggests that AEMO's modelling can provide a good indication of likely levels of unserved energy in 2012/13, when no investment response occurs, but becomes less informative in later years when new plant is commissioned to replace Loy Yang A.

AEMO's modelling indicates that the permanent exit of Loy Yang A power station would be expected to cause a significant increase in unserved energy in 2012/13, particularly in Victoria. AEMO's modelling indicates that the reliability standard of 0.002 per cent unserved energy likely would be breached in Victoria, New South Wales and South Australia.

7.3 Gas market modelling

The results of Frontier Economics' electricity market modelling show that the permanent exit of Loy Yang A power station results in a significant increase in output by gas-fired generation.

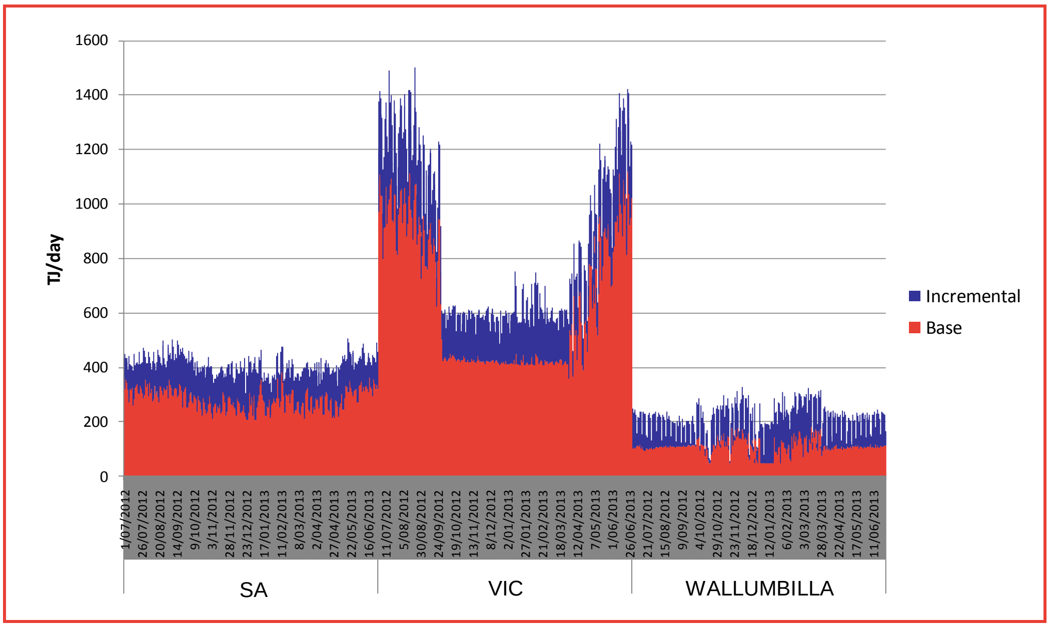
In the first instance, existing gas-fired plant, including CCGT, OCGT and older steam turbines, increase their output in order to replace some of the energy that would otherwise have been provided by the Loy Yang A power station. In the longer term, the capacity and output of Loy Yang A is replaced largely by new CCGT plant in Victoria.

Given this, there is a permanent and substantial increase in demand for gas by gas-fired generators, particularly in Victoria (with shorter-term increases in demand for gas by gas-fired generators in South Australia and around Wallumbilla). The purpose of this section is to assess whether the demand for gas implied by Frontier Economics' electricity market modelling of the permanent exit of Loy Yang A can be supported by gas supply infrastructure in the eastern States.

Since the longer-term gas demand by new CCGT is likely to be accompanied by expansions in the capacity of gas infrastructure, Frontier Economics' analysis of outcomes in gas markets focuses on the initial year immediately following the exit of Loy Yang A. The logic behind this approach is that if existing gas infrastructure is sufficient to meet the increased gas supply caused by the exit of Loy Yang A power station, then there are unlikely to be issues in the longer term when new gas infrastructure can be commissioned as required. This is particularly the case given that a number of major gas pipelines supplying south-eastern Australia can be quickly expanded at relatively low cost through the commissioning of further gas compression.

As discussed in Section 7, following the assumed permanent exit of Loy Yang A at the beginning of 2012/13, Frontier Economics' electricity market modelling finds that existing generation plant, including existing gas-fired generation plant, increase their output during 2012/13. Figure 19 shows the incremental increase in gas demand in Victoria, South Australia and Wallumbilla as a result of the permanent exit of Loy Yang A. The largest increase in gas-fired generation is in Victoria, where gas demand increases by an average of roughly 200 TJ/d across the year. In comparison, the increase in gas-fired generation in South Australia results in an increase in gas demand that averages around 115 TJ/d and the increase in gas-fired generation in Wallumbilla results in an increase in gas demand that averages around 95 TJ/d. There are much smaller changes in other regions.

Figure 19: Regional gas demand – Reference Case and LYA-Permanent (2012/13)

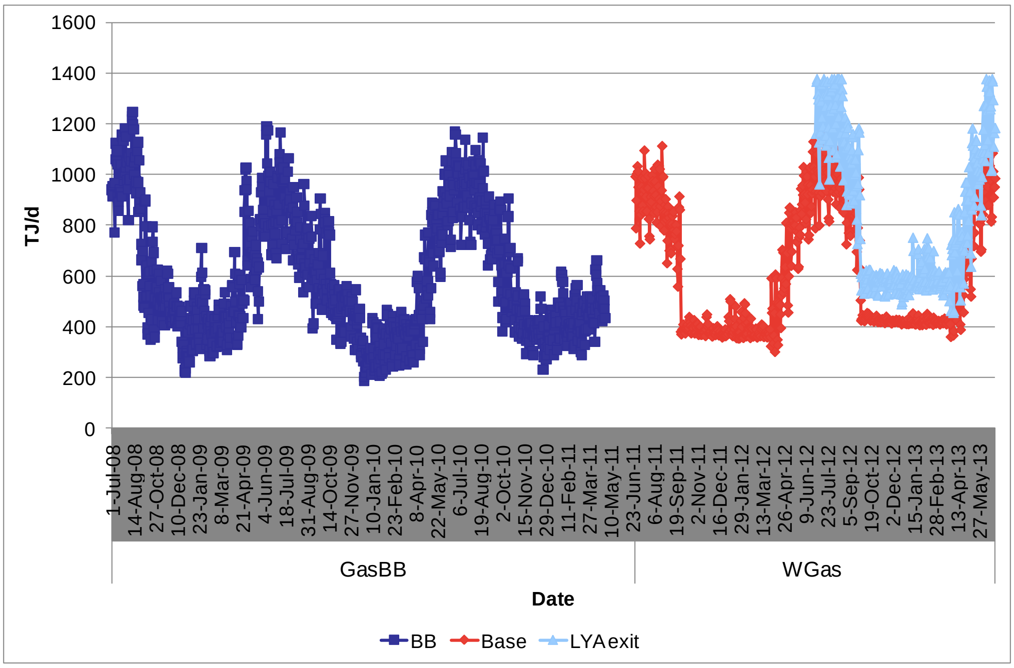


Source: Frontier Economics

While these increases in gas demand are substantial, Frontier Economics' analysis indicates that they are likely to be achievable. Frontier Economics' *WHIRLYGAS* modelling indicates that, based on the processing plant capacities and pipeline capacities reported in the AEMO 2010 GSOO, the increases in gas demand in the event of the permanent exit of Loy Yang A power station can be met without exceeding the existing capacity of gas infrastructure.

Undoubtedly, the increase in gas demand in Victoria will result in gas market infrastructure operating at or near capacity for a much larger proportion of the year. Figure 20 shows combined pipeline flows into Victoria (on the Longford to Melbourne Pipeline and the South West Pipeline), both as recorded on the GasBB and as modelled using *WHIRLYGAS* for the Reference Case and the LYA-Permanent case.

Figure 20: Pipeline flows supplying Victoria – Historical, Reference Case and LYA-Permanent (2012/13)



Source: Frontier Economics

Clearly, the LYA-Permanent case shows a step increase in gas pipeline flows into Victoria as compared to both historic flows and forecast flows in the Reference Case. However, these flows are achievable given the pipeline capacities reported in the AEMO 2010 GSOO. When combined with withdrawals from storage in Victoria and some increase in southward flows on the gas interconnect at Culcairn, the results from *WHIRLYGAS* modelling indicate that demand in Victoria can be met with existing infrastructure. The same is observed for processing plant capacity: while the LYA-Permanent requires a step increase in gas production in Victoria as compared to both historic production and forecast production in the Reference Case, these rates of production are achievable given the plant capacities reported in the AEMO 2010 GSOO.

In practice, there may be constraints that prevent the gas infrastructure in Victoria from operating to the capacities reported in the AEMO 2010 GSOO. For instance, it may be the case that operational constraints at offshore gas fields in Victoria mean that the associated gas plant cannot operate at the reported capacity. Or there may be operational issues with the gas pipeline infrastructure in Victoria. For instance, Frontier Economics understands that, depending on pipeline linepack levels, injections at Longford and Iona may need to be balanced where both are attempting to achieve high rates of injection.

Shock scenario – permanent exit

Even if such issues do arise from time to time, however, Frontier Economics' analysis indicates that there is considerable scope for increased gas-fired generation in neighbouring South Australia or NSW:

- While demand for gas by gas-fired generators increases in South Australia as a result of the permanent exit of Loy Yang A, there remains scope for further increases in gas-fired generation in South Australia. For instance, under the LYA-Permanent case Torrens Island A operates at a capacity factor of around 30 per cent and Torrens Island B operates at a capacity factor of around 65 per cent, while both Quarantine and Ladbroke Grove continue to operate at very low capacity factors consistent with high-cost peaking plant. These power stations could likely increase output during the forecast modelling period if required. Furthermore, an increase in output from these power stations would likely be achievable with the existing gas infrastructure in South Australia, with periods of spare pipeline capacity into South Australia and spare production capacity available through the Moomba hub.
- Demand for gas by gas-fired generators in NSW changes little as a result of the permanent exit of Loy Yang A. The reason is that the gas-fired generators in NSW are predominantly peaking power stations that tend to operate for limited periods of the year. Even under the LYA-Permanent case, both Uranquinty and Colongra operate at very low capacity factors consistent with high-cost peaking plant. However, if required, these NSW peakers could operate during periods when gas supplies to Victorian or South Australia gas-fired generators are constrained. An increase in output from these power stations is likely to be achievable with the existing gas infrastructure in NSW, with ample spare pipeline capacity into NSW and spare production capacity available through the Moomba hub.

Longer-term, as new CCGT plant is commissioned to replace Loy Yang A, Frontier Economics would expect that additional gas infrastructure would be commissioned as required. In particular, pipeline capacity could be expanded through the addition of further compression or through the re-commissioning of moth-balled compressor stations. In the event that new processing plant capacity is required, there are a number of opportunities to develop further gas reserves in Australia, particularly through CSM in Queensland and NSW. Any investments in gas infrastructure required could be commissioned within the timeframes required for investment in gas-fired generation plant.

7.4 Financial consequences of a permanent exit

The price increases caused by the sudden and permanent exit of a Victoria baseload power station will have substantial financial consequences for electricity market participants and customers. This section assesses the likely consequences for generators, retailers and residential electricity customers.

7.4.1 Generators

The financial consequences of the sudden and permanent exit of a Victoria baseload power station will be very different for the generator whose power station exits the market and for other generators.

For the generator whose power station exits the market, the financial consequences will be negative and substantial. Most likely, in the event that the generator has not planned the exit of its power station from the market, the generator will have a substantial contract position backed by the power station. The exit of the power station will therefore expose the generator to substantial unfunded difference payments: the generator will have to continue making payments on its contract position, but will not receive any pool revenues to fund these contract payments. The increase in spot prices caused by the exit of the power station will mean that these unfunded difference payments will be very substantial.

However, there are a number of factors that may mitigate the financial consequences for the generator whose power station exits the market:

- The generator will almost certainly have insurance for its power station. If the event that causes the sudden exit of the power station is an insurable event, the generator will receive payments through its property insurance (reflecting the loss of the capital invested in the power station) and through its business interruption insurance (reflecting the loss of operating profit). Even in this case, however, there will be deductions; for instance, the business interruption insurance will likely have a time deductible period of a number of weeks and a dollar deductible amount.
- The generator may have long-term offtake contracts with large energy users that contain force majeure provisions. In this case, if the event that causes the sudden exit of the power station falls within the definition of force majeure, and if an event of force majeure relieves the generator of its financial obligations under the contract, the financial consequences for the generator will be reduced (but only because these financial consequences will effectively be passed to the generators' contract counterparty).

For the other generators in the market, the financial consequences of the sudden and permanent exit of a Victoria baseload power station will be positive. Generally speaking, other generators in the market will benefit because the pool price that they receive will increase while their costs will not. In addition, a number of generators will increase their dispatch to make up for the generation lost when the baseload power station exits. Increased prices and/or increased dispatch will increase the pool revenues that these generators receive.

Of course, at the time of the sudden exit of the power station from the market, other generators in the market will likely have a substantial contract position in place. Because these existing hedge contracts would have been struck at prices that do not account for the sudden exit of the baseload power station, these existing hedge contracts will reduce other generators' exposure to higher pool prices. As these existing contracts expire, however, generators will re-contract at higher prices.

7.4.2 Retailers

For retailers, the immediate financial consequences of the sudden and permanent exit of a Victoria baseload power station will only be negative. As a result of the increase in pool prices, retailers will face higher costs of acquiring electricity in the wholesale market.

The extent of the negative financial consequences for retailers will depend on their contract position and the nature of their retail supply arrangements:

- Retailers that have completely hedged their retail load will not be exposed to the increase in the pool price for as long as their contract position is in place. It will only be when the hedge contracts of these retailers begin to expire, and they need to re-contract, that they will be exposed to higher pool prices and higher contract prices.
- Retailers that have retail supply arrangements that allow them to pass-through any increases in wholesale prices will also not be exposed to the increase in the pool price. In effect, the pass-through arrangement means that it is retail customers who face the risk of higher pool prices.

In reality, all retailers will have customers to whom they cannot immediately pass-through an increase in pool prices. For instance, in jurisdictions where retail tariff regulation remains in place (all jurisdictions other than Victoria) retailers will only be able to increase tariffs at the time of the next regulatory review (which most jurisdictions undertake annually) or by applying for a cost pass-through.

Recognising that this fixed retail price exposes them to price risk, retailers will typically attempt to completely hedge their retail load by backing their retail supply arrangements with equivalent hedge contracts. However, this is not always possible, either because generators are not willing to offer sufficient hedge contracts at a price that the retailers consider to be reasonable or because the retailers are not able to perfectly predict their customers' load.

For this reason, retailers will almost certainly face some exposure to higher pool prices and will face financial consequences as a result of this. For retailers that have material exposure to the wholesale market the increase in prices caused by the sudden and permanent exit of a Victoria baseload power station may well be sufficient to place these retailers in financial distress. This is not without precedent in the NEM, with retailer One Energy collapsing in 2007 as a result of high wholesale prices and retailer Jack Green collapsing in 2010.

7.4.3 Residential customers

Wholesale electricity prices are ultimately passed through to residential retail customers. In Victoria, where there is no longer retail tariff regulation, electricity retailers are able to increase residential retail prices to reflect wholesale prices, constrained only by competition from other retailers. In other jurisdictions, where retail tariff regulation remains in place, jurisdictional regulators determine residential retail prices to reflect, among other things, wholesale prices. In both cases, therefore, the sudden and permanent exit of a Victoria baseload power station will ultimately lead to an increase in retail prices; there may be some delay between the increase in wholesale prices and the subsequent increase in residential retail prices, but any such delay will be temporary.

The size of the increase in retail tariffs caused by the sudden and permanent exit of a Victoria baseload power station can be estimated based on the estimated increase in wholesale prices. As discussed in Section 7.2.3, Frontier Economics estimates that the permanent exit of Loy Yang A power station will increase wholesale prices in 2012/13 as follows:

- in Victoria, wholesale prices are estimated to increase 78.84% from $70.34/MWh to $125.80/MWh
- in New South Wales, wholesale prices are estimated to increase 45.11% from $65.08/MWh to $94.44/MWh
- in QLD, wholesale prices are estimated to increase 28.45% from $63.19/MWh to $81.16/MWh.

Analysis of the various components of retail tariffs indicates that in each of these jurisdictions, wholesale prices account for around 30% of total residential retail prices.[14] Given this, the increases in wholesale prices in 2012/13 would (if fully passed through to retail customers) result in increases in residential retail prices in the same year as follows:[15]

- in Victoria, residential retail prices are estimated to increase 23.65%
- in New South Wales, residential retail prices are estimated to increase 13.35%
- in Queensland, residential retail prices are estimated to increase 8.54%.

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14 AEMC, *Future Possible Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*, 30 November 2010

15 The increase in wholesale prices would be expected to lead to some reduction in the price of Renewable Energy Certificates (RECs) because the price of a REC is effectively the cost of the 'subsidy' in excess of wholesale prices that is required to fund investments in renewable energy. Higher wholesale prices lower the 'subsidy'. The effect on residential retail tariffs of any such change in the price of RECs, however, will be minor compared to the effect of the increase in wholesale electricity prices.

As the impact on wholesale prices moderates in subsequent years so too will the impact on residential retail prices.

7.5 Conclusion

Ultimately, our analysis shows that the permanent exit of a Victorian baseload power station is not likely to result in a significant and ongoing reduction in reliability in the electricity market.

Analysis by AEMO indicates that, with no investment response, there would likely be unserved energy in excess of the reliability standard in Victoria, NSW and Queensland. However, Frontier Economics' modelling indicates that there will be significant investment in OCGT plant one year after the permanent exit of a Victorian baseload power station and significant investment in CCGT plant two years after the permanent exit. This investment will mitigate any increase in unserved energy.

The permanent exit of a Victorian baseload power station will result in substantial increases in the cost of meeting demand, particularly in the 2 years before an investment response from CCGT plant. Even following the investment response, prices will remain higher as a result of the permanent exit of a lower cost baseload power station.

These price increases caused by the permanent exit of a Victorian baseload power station will ultimately result in higher retail electricity prices, with residential electricity tariffs likely to increase by around 23.65% in 2012/13 and 18.31% in 2013/14. To the extent that electricity retailers have not fully hedged their retail load (through contracting or vertical integration) and are unable to pass on these additional costs to end-users immediately, the electricity price increases will also result in substantial financial losses to these retailers.

In the gas market, our analysis also shows that there is likely to be sufficient capacity in gas infrastructure in the NEM region to manage the permanent exit of a Victorian baseload power station. It may be the case that there are short-term capacity constraints affecting particular gas infrastructure. However, Frontier Economics considers that the flexibility in the electricity market and the gas market would mean that even short-term capacity constraints would not result in a significant reduction in reliability. Any short-term capacity constraints to gas infrastructure would likely increase the cost of meeting electricity demand.

It should be noted that Frontier Economics has modelled 'system normal' conditions for the electrical transmission system. A significant transmission outage occurring during the first two years after the permanent exit of a Victorian baseload power station (before investment can respond) may increase the likelihood of a reduction in reliability. In Victoria, the majority of transmission constraints occur on the section of the grid between the Melbourne node (where most load is located) and the La Trobe Valley (where most supply is located, including Loy Yang A power station). As such, the permanent outage of Loy Yang A would in all likelihood lead to less transmission constraints within Victoria by freeing up capacity.

8 Shock scenario – temporary outage

This section provides the results from Frontier Economics' modelling of each of the shock scenario cases that involve temporary outages. As discussed in Section 3, modelling of the shock scenario cases that involve temporary outages requires the following steps:

- **Electricity market modelling**. The outputs of this modelling include the following:
  - Power station dispatch, including dispatch of baseload generation in Victoria.
  - Electricity pool prices.

  These shock scenario dispatch and price outcomes can be compared with outcomes under the Reference Case to gauge the impact of the shock scenario cases.
- **Gas market modelling**. The temporary outage of a baseload power station in Victoria will result in greater demand for gas from gas-fired generators. The purpose of the gas market modelling is to determine whether the increased demand for gas from gas-fired generators can be accommodated with existing gas supply infrastructure.

8.1 Temporary Outage – peak periods

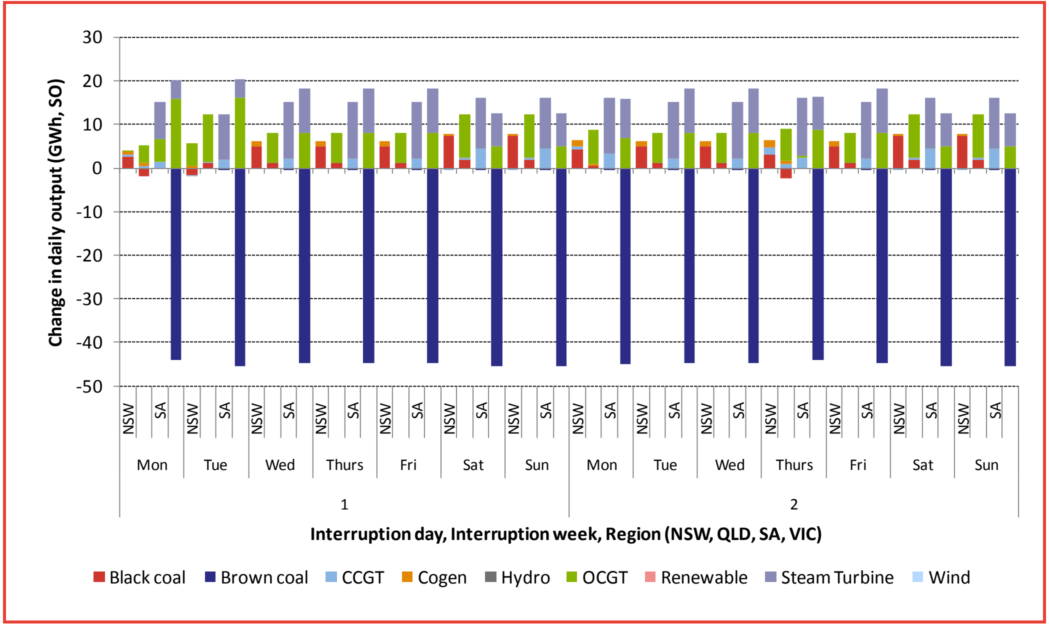
For the shock scenario cases that involve temporary outages during peak periods, Frontier Economics has modelled plant dispatch and market prices going forward using our game-theoretic pool dispatch model, *SPARK*. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

8.1.1 Market dispatch

Figure 21 and Figure 22 show the incremental change in daily dispatch in the NEM from the Reference Case to the cases in which there is a temporary 14 day outage during peak periods. Outcomes during the temporary outages in both 2011/12 and 2015/16 are shown. Negative values on the chart represent the generation lost since Loy Yang A no longer operates,[16] and positive values on the chart represent the mix of generation in each region that replaces Loy Yang A.

16 Clearly the majority of negative values reflect the lost output of Loy Yang A power station. However, there are also occasional instances of minor reductions in output of other plant. This reflects a change to the strategic incentives of these plant caused by the outage at Loy Yang A.

Figure 21: Change in NEM daily dispatch – LYA-Temp-2012-Peak



Source: Frontier Economics

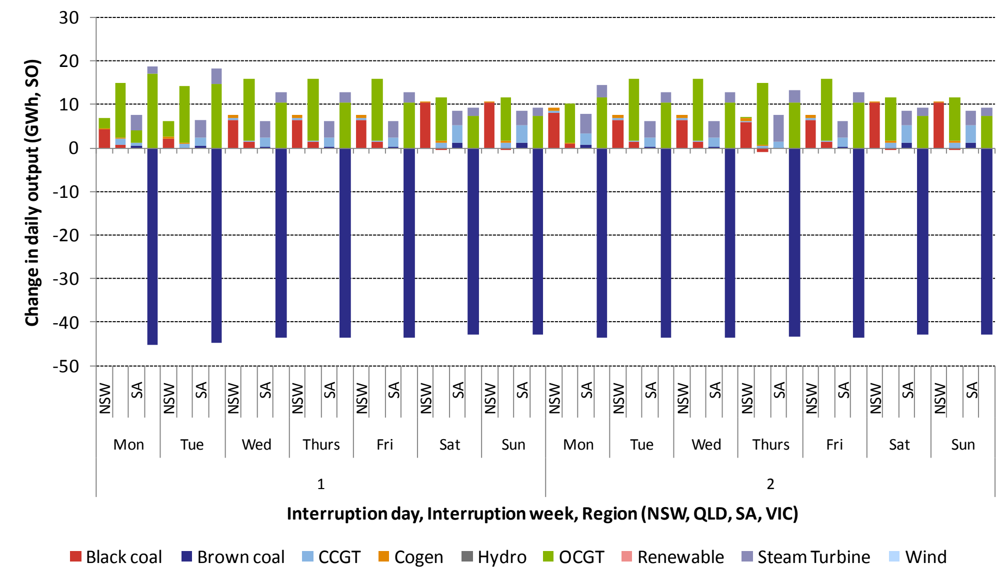
Note: for clarity of presentation, the x-axis label does not show each region. In each case, the regions are ordered as follows: NSW, QLD, SA, VIC.

In the LYA-Temp-2012-Peak case, a significant amount of replacement generation comes from SA and VIC thermal gas plant, QLD OCGT plant and NSW black coal plant. This indicates that there is surplus capacity in the system so that replacement generation can be provided by other, albeit generally non-baseload, generators. The ability for NSW coal generators to replace lost Loy Yang A output stems from the anti-correlation of Victorian demand with demand in other regions: when Victorian demand is high, demand in the other regions is sufficiently low that their baseload plant are not at full capacity. This system "slack" tends to be largest at weekends where there is relatively more replacement generation from black coal generators. Clearly, there is a limit to the increase in output that can be achieved by black coal generators and CCGT plant, which means that an increase in output from more expensive steam turbines and OCGT plant is also required.

An exception to this general pattern is on the two peak days during this peak period. The first Monday and Tuesday of the 14 day period are the two highest demand days for NSW and Queensland. Demand during these days is sufficiently high that the baseload generators in these regions are running at near full capacity when Loy Yang A would be operating. Therefore, in the event of an outage, replacement generation is sourced instead from more expensive OCGT plant. While there is still sufficient spare capacity during these days that there is no significant increase in lost load, it is clear that the loss of a baseload plant has the most significant consequences when a number of regions simultaneously have high demand.

A different pattern of replacement generation is seen in the LYA-Temp-2016-Peak case. Compared to the LYA-Temp-2012-Peak case, there is relatively more black coal and OCGT output and relatively less thermal gas output replacing lost generation for Loy Yang A. The reason is that carbon has increased the utilisation of existing thermal gas plant, meaning they are on average less available to meet lost Loy Yang A output. Black coal and OCGT gas are now the 'swing' generators who, on the margin, can increase output during the two week period to make up for Loy Yang A's lost output.

Figure 22: Change in NEM daily dispatch – LYA-Temp-2016-Peak



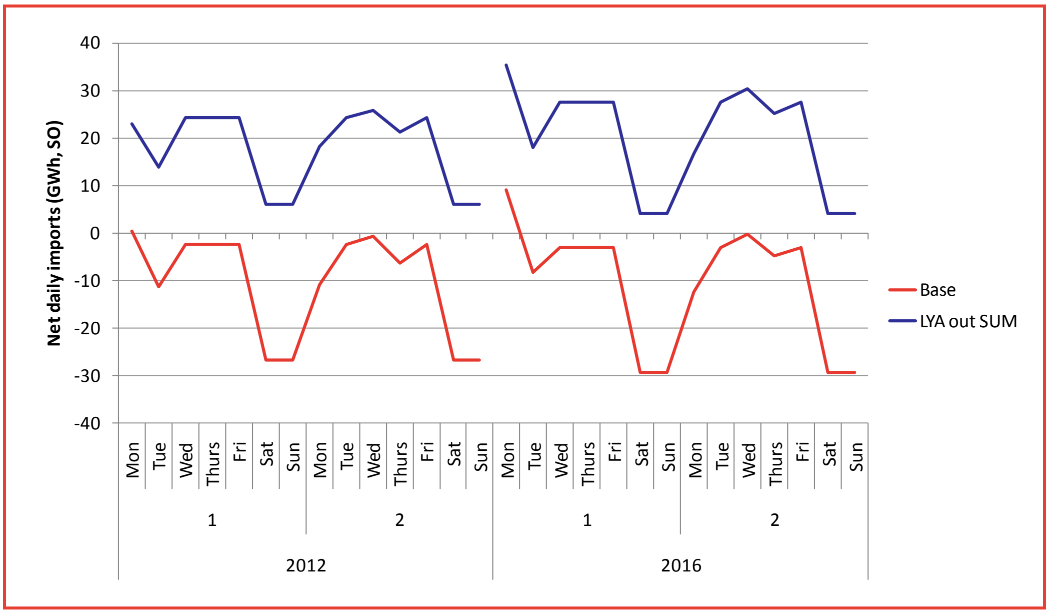
Source: Frontier Economics

Note: for clarity of presentation, the x-axis label does not show each region. In each case, the regions are ordered as follows: NSW, QLD, SA, VIC.

8.1.2 Net Imports – Victoria

Figure 23 compares Victoria's net imports in the Reference Case to the cases in which there is a temporary 14 day outage during peak periods. Outcomes during the temporary outages in both 2011/12 and 2015/16 are shown. As expected, there is an increase in net imports during every day of temporary outage. Also, there are relatively higher imports on weekends when inter-state generators have relatively more spare capacity, and relatively lower imports during the peak demand days where inter-state generators have relatively less spare capacity.

Figure 23: VIC net annual imports – LYA-Temp-2012-Peak and LYA-Temp-2016-Peak



Source: Frontier Economics

8.1.3 Pool prices

Figure 24 shows the daily pool prices in New South Wales, Queensland and Victoria for both the Reference Case and the LYA-Temp-2012-Peak case.

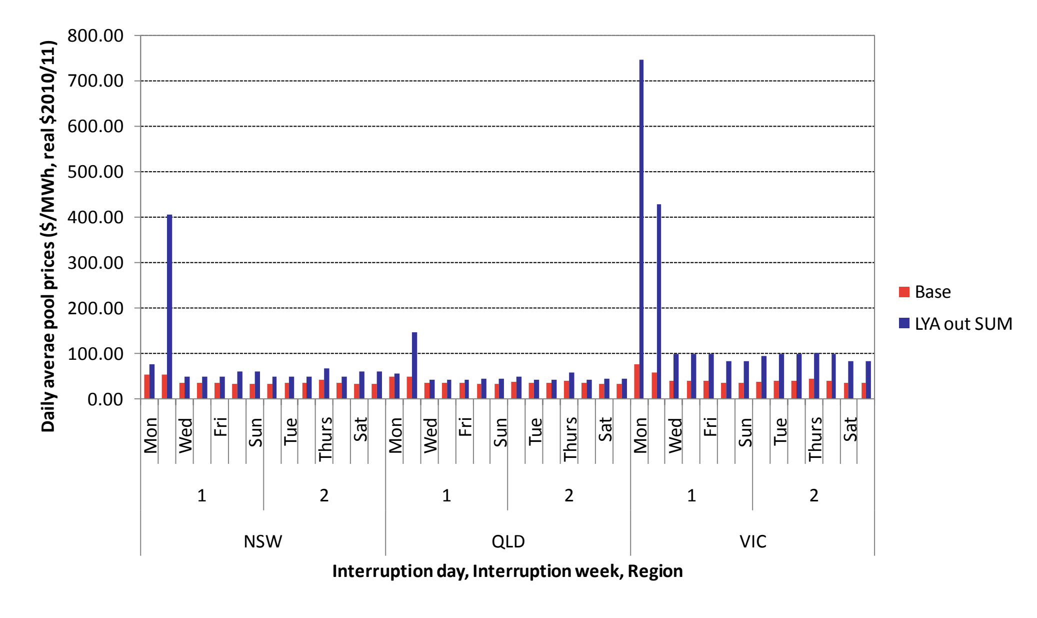
Figure 24 clearly illustrates that the price impact of the outage is largest in Victoria, with smaller price increases seen in New South Wales and Queensland. In Victoria, average pool prices over the two week period are $42.55/MWh in the Reference Case and $163.82/MWh in the LYA-Temp-2012-Peak case.

Figure 24 also shows that, within the two week period, the price impact is substantially higher on the two highest demand days. On these two days demand in New South Wales and Queensland is also high, so that opportunity to import from these regions is reduced. In Victoria, average pool prices over these two days are $66.08/MWh in the Reference Case and $587.33/MWh in the LYA-Temp-2012-Peak case.

While there are material increases in pool prices during the period of the outage, the overall impact on annual average pool prices is relative minor. In Victoria, annual average pool prices in 2011/12 are $37.13 in the Reference Case and $41.78 in the LYA-Temp-2012-Peak case.

While these price increases are certainly substantial, Frontier Economics' modelling indicates that a 14 day outage of Loy Yang A power station during peak periods would not result in a breach of the Cumulative Price Threshold.

Figure 24: Daily pool prices by NEM region – LYA-Temp-2012-Peak



Source: Frontier Economics

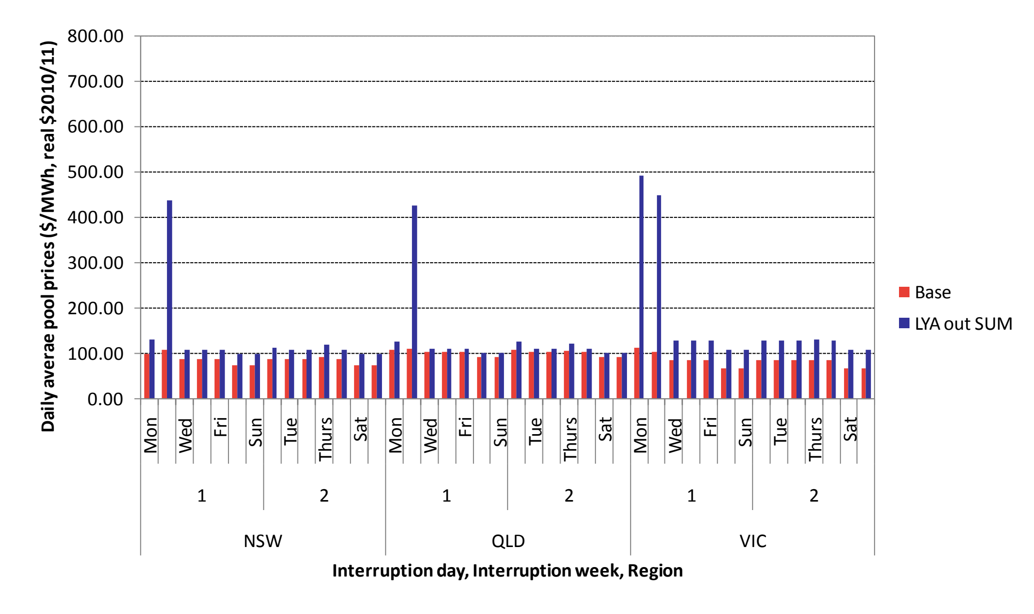
Figure 25 shows the daily pool prices of the three regions for both the Reference Case and the LYA-Temp-2016-Peak case.

Comparing Figure 24 and Figure 25, it is clear that the level of prices in 2015/16 is higher than in 2011/12, in both the Reference Case and the outage case. This is due to demand growth, increasing fuel costs and carbon prices.

The overall pattern of price impacts due to the temporary outage is similar in the LYA-Temp-2012-Peak case and the LYA-Temp-2016-Peak case. The price impact is largest in Victoria, with average pool prices over the two week period are $82.91/MWh in the Reference Case and $171.48/MWh in the LYA-Temp-2016-Peak case.

Again however, while there are material increases in pool prices during the period of the outage, the overall impact on annual average pool prices is relative minor. In Victoria, annual average pool prices in 2015/16 are $79.68/MWh in the Reference Case and $83.08/MWh in the LYA-Temp-2016-Peak case.

Figure 25: Daily pool prices by NEM region –LYA-Temp-2016-Peak



Source: Frontier Economics

8.2 Temporary Outage – shoulder periods

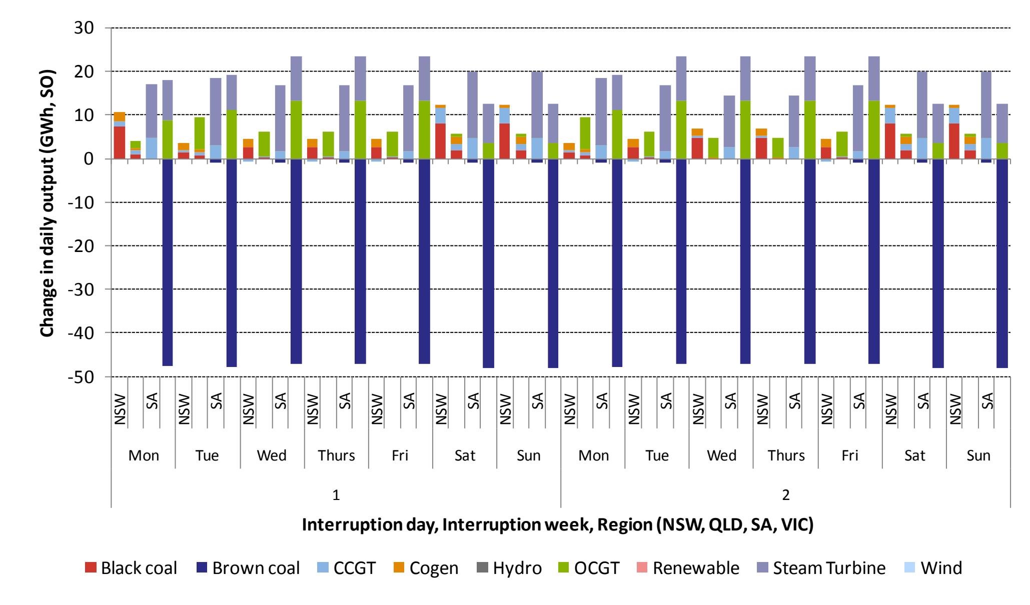
For the shock scenario cases that involve temporary outages during shoulder periods, Frontier Economics has modelled plant dispatch and market prices going forward using our game-theoretic pool dispatch model, *SPARK*. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

8.2.1 Market dispatch

Figure 26 and Figure 27 show the incremental change in daily dispatch in the NEM from the Reference Case to the cases where there is a temporary 14 day outage during shoulder periods. Outcomes during the temporary outages in both 2011/12 and 2015/16 are shown. Negative values on the chart represent the generation lost since Loy Yang A no longer operates,[17] and positive values on the chart represent the mix of generation in each region that replaces Loy Yang A.

[17] Clearly the majority of negative values reflect the lost output of Loy Yang A power station. However, there are also occasional instances of minor reductions in output of other plant. This reflects a change to the strategic incentives of these plant caused by the outage at Loy Yang A.

Figure 26: Change in NEM daily dispatch – LYA-Temp-2012-Shoulder



Source: Frontier Economics

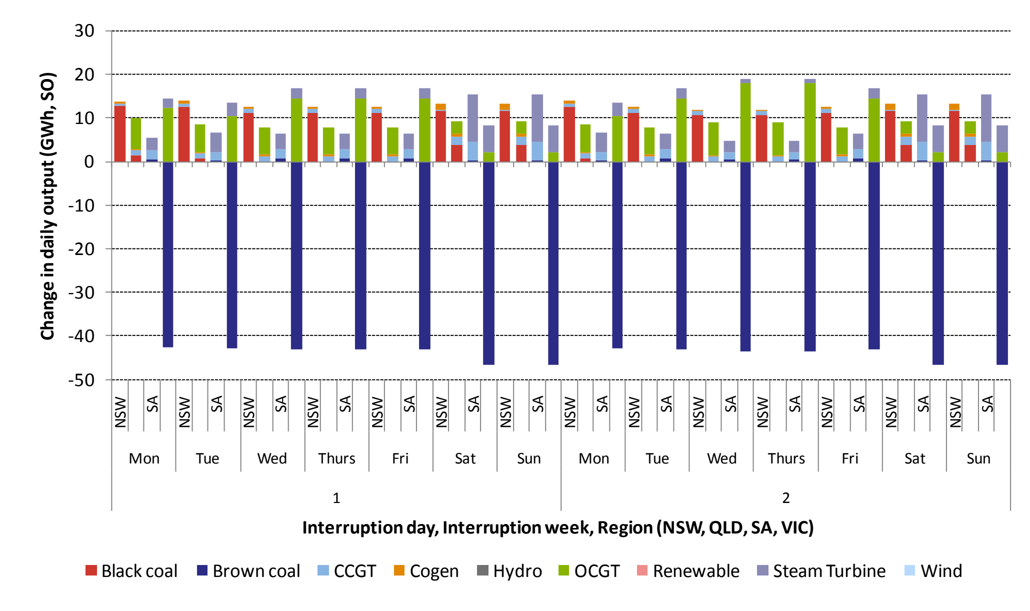
Note: for clarity of presentation, the x-axis label does not show each region. In each case, the regions are ordered as follows: NSW, QLD, SA, VIC.

In the LYA-Temp-2012-Shoulder case, the majority of replacement generation comes from OCGT and steam turbine output, with a smaller quantity of replacement generation from CCGT and black coal generators. This indicates that, during the shoulder period, there is some spare capacity in the system's other baseload plant, but the majority of replacement generation must nevertheless be sourced from more expensive peaking plant.

This result is primarily a consequence of the positive correlation between Victoria demand and demand in other regions during the shoulder period (as compared with the peak period, where there is an anti-correlation). Any "slack" in other regions is largest at weekends, where there is relatively more replacement generation from black coal generators.

In the LYA-Temp-2016-Shoulder case, as in the LYA-Temp-2016-Peak case, carbon has increased the utilisation of existing thermal gas plant to the point where black coal and OCGT gas become the predominate 'swing' generators who are able to increase output on the margin to make up for lost Loy Yang A output.

Figure 27: Change in NEM daily dispatch –LYA-Temp-2016-Shoulder



Source: Frontier Economics

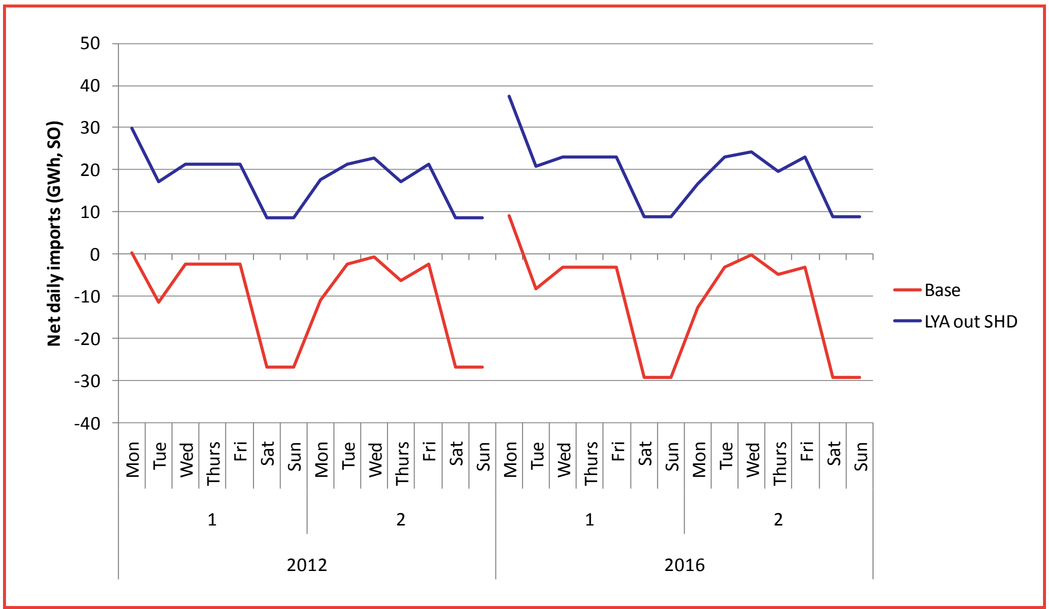
Note: for clarity of presentation, the x-axis label does not show each region. In each case, the regions are ordered as follows: NSW, QLD, SA, VIC.

8.2.2 Net Imports – Victoria

Figure 28 shows the incremental change in Victoria's net imports from the Reference Case to the cases where there is a temporary 14 day outage during shoulder periods. Outcomes during the temporary outages in both 2011/12 and 2015/16 are shown. As expected, there is an increase in net imports during every day of the temporary outage.

Fluctuations in net imports are a result of the day-to-day spare capacity in the system. There are higher imports on weekends when inter-state generators have relatively more spare capacity since demand is lower. Conversely, drops in net imports during the second week of the shoulder period are a result of relatively high demand in Queensland such that inter-state generators have relatively less spare capacity.

Figure 28: VIC net annual imports – LYA-Temp-2012-Shoulder and LYA-Temp-2016-Shoulder



Source: Frontier Economics

8.2.3 Pool prices

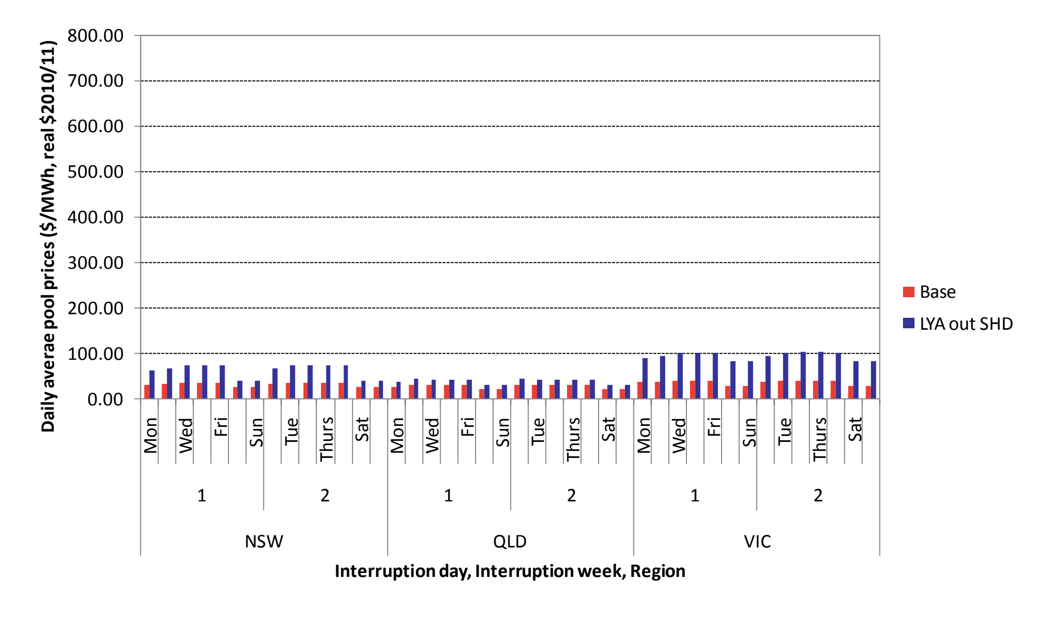
Figure 29 shows the daily pool prices in New South Wales, Queensland and Victoria for both the Reference Case and the LYA-Temp-2012-Shoulder case.

Figure 29 clearly illustrates that the price impact of the outage is largest in Victoria, with smaller price increases seen in New South Wales and Queensland. In Victoria, average pool prices over the two week period are $36.28/MWh in the Reference Case and $94.45/MWh in the LYA-Temp-2012-Shoulder case. As expected, this price increase during the shoulder period is much lower than the equivalent price increase during the peak period (which saw prices increasing from $42.55/MWh in the Reference Case to $168.82/MWh in the LYA-Temp-2012-Peak case).

While there are material increases in pool prices during the period of the outage, the overall impact on annual average pool prices is relative minor. In Victoria, annual average pool prices in 2011/12 are $37.13/MWh in the Reference Case and $39.36/MWh in the LYA-Temp-2012-Shoulder case. Again, this impact on annual average prices as a result of an outage during the shoulder period are lower than the equivalent impact on annual average prices as a result of an outage during peak periods (the annual average pool price in 2011/12 increased to $41.78/MWh in the LYA-Temp-2012-Peak case).

As with the peak period outages, Frontier Economics' modelling indicates that a 14 day outage of Loy Yang A power station during shoulder periods would not result in a breach of the Cumulative Price Threshold.

Figure 29: Daily pool prices by NEM region – LYA-Temp-2012-Shoulder



Source: Frontier Economics

Figure 30 shows the daily pool prices of the three regions for both the Reference Case and the LYA-Temp-2016-Shoulder case.

Comparing Figure 29 and Figure 30, it is clear that the level of prices in 2015/16 is higher than in 2011/12, in both the Reference Case and the outage case. This is due to demand growth, increasing fuel costs and carbon prices.

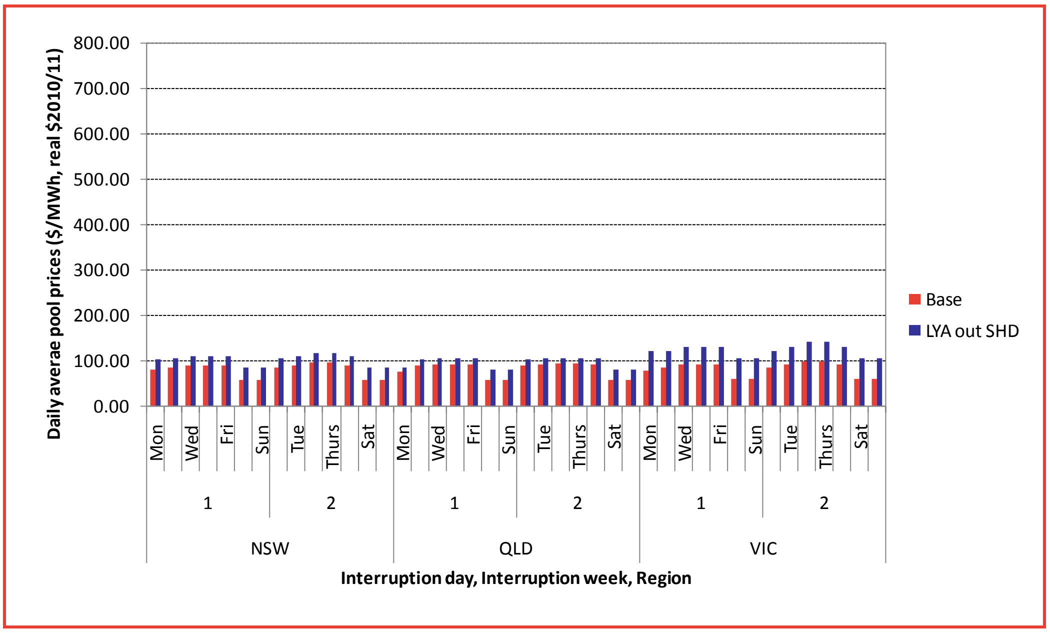
The overall pattern of price impacts due to the temporary outage is similar in the LYA-Temp-2012-Shoulder case and the LYA-Temp-2016-Shoulder case. The price impact is largest in Victoria, with average pool prices over the two week period of $81.21/MWh in the Reference Case and $122.68/MWh in the LYA-Temp-2016-Shoulder case. As expected, this price increase during the shoulder period is much lower than the equivalent price increase during the peak period (which saw prices increasing from $82.91/MWh in the Reference Case to $171.48/MWh in the LYA-Temp-2016-Peak case).

Again, however, while there are material increases in pool prices during the period of the outage, the overall impact on annual average pool prices is relatively minor. In Victoria, annual average pool prices in 2015/16 are $79.68/MWh in the Reference Case and $81.27/MWh in the LYA-Temp-2016-Shoulder case.

This is lower than the impact on annual average prices as a result of an equivalent outage during peak periods (the annual average pool price in 2015/16 increased to $83.08/MWh in the LYA-Temp-2012-Peak case).

The relative price impacts in 2015/16 are slightly lower across the board due to new investment improving the ability for the system to absorb the supply shock.

Figure 30: Daily pool prices by NEM region –LYA-Temp-2016-Shoulder



Source: Frontier Economics

8.3 Gas market modelling

As discussed in Section 7.3, Frontier Economics has undertaken gas market modelling of the permanent exit of Loy Yang A power station. This modelling indicated that exiting gas supply infrastructure has sufficient capacity to manage the increase in gas demand by gas-fired generators that is caused by the permanent exit of Loy Yang A power station. Given these results, and the fact that the temporary outages cases discussed in this Section 8 occur during periods of comparatively low gas demand in Victoria (ie during summer and autumn), Frontier Economics expects that the increase in gas-fired generation caused by the temporary outage of Loy Yang A power station would not cause any capacity issues for existing gas infrastructure.

8.4 Financial consequences of a temporary outage

Temporary outages occur on a regular basis in the NEM. Indeed, the occurrence of unexpected temporary outages is one of the reasons that retailers hedge their retail load.

Nevertheless, a temporary outage will likely have financial consequences for both generators and retailers.

The generator that is subject to the temporary outage will likely face substantial unfunded difference payments. This is particularly the case given that the temporary outage is assumed to affect the entire capacity of the power station. One of the ways that generators manage the risk of unfunded difference payments in the event of a temporary outage is by not contracting the entire capacity of the power station. For instance, generators may contract capacity equivalent to 3 units of a 4 unit power station. Clearly, this strategy will not help a generator manage a full power station outage, so the generator is likely to face significant consequences. Insurance is unlikely to benefit the generator for a two-week temporary outage and neither are force majeure provisions of financial contracts.

In contrast, the financial consequences for other generators will be positive as a result of higher pool prices and greater dispatch, but only to the extent that other generators are not fully contracted.

The financial consequences for retailers are likely to be negative as a result of higher pool prices, but only to the extent that retailers are not fully contracted.

Residential customers would not face any consequences, with residential retail tariffs very unlikely to respond to higher prices over a two week period caused by a temporary outage to a power station.

8.5 Summary

Consistent with results for the permanent outage cases, the impact of the temporary outages presented in this section can best be characterised as impacts on costs rather than on reliability. The modelling of the temporary outages presented in this section extends on the annual results presented in Section 7 and demonstrates that the NEM has enough redundancy to manage the outage of a major baseload power station without a loss of reliability (although an increase in unserved energy is likely to arise in the event that demand levels are higher than forecast, multiple forced outages coincide with the temporary outage to Loy Yang A or network constraints occur). However, the outage of a major baseload power station does result in higher cost generation being required to meet demand, particularly on the high demand peak days. On these days average daily prices exceed $300/MWh in some cases.

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