Prospects for a HELE USC Coal-fired Power Station

June 2017

Prepared by Solstice Development Services (SDS) Pty Ltd

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The scope of this Report does not include:

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- Any review of the technical soundness of any proposed works; or
- Any review of the technical validity of any engineering related data referenced in this Report.

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1. Executive Summary

1.1. NEM Snapshot

Australia's electricity generation fuel mix is changing and electricity prices to consumers have risen significantly over the past two decades.

For the foreseeable future, the electricity price outlook for consumers remains high due to the retirement of existing base load generation and hence a greater reliance on gas-fired and renewable generation. Under investment in new low cost, reliable and secure base load generation has resulted from increased investment risks associated with regulatory and policy uncertainty.

Coal remains the dominant fuel source for power generation in the NEM, but has declined from serving 87% of demand to 74.8%[1] over the last decade.

Variable Renewable Energy (VRE), such and wind and solar, is displacing but not replacing base load schedulable generation. Over the past decade, NEM demand has declined from 204.6 TWh to 202.3 TWh pa and NEM coal-fired generation has reduced by 26.7 TWh pa, primarily due to plant retirements. VRE, supported by subsidies from renewable energy target schemes and government grants, has grown from a virtual zero base to serving 8.6% of demand, representing production of 17.4 TWh pa. Gas-fired generation, driven in part by support from previous state-based government subsidy schemes, also now meets 8.6% of demand and produces 17.5 TWh pa, an increase of 5.3 TWh pa over the past decade.

Penetration of VRE varies by region across the NEM. For example, Queensland and New South Wales have renewable energy levels of 3.9% and 5.0% respectively, well below the NEM average of 8.6%. By contrast, Victoria, Tasmania, and South Australia, where the majority of wind farms have been commissioned, have renewable energy demand contributions of 10.1%, 12.1%, and 40.5% respectively.

Electricity prices to Australian manufacturers have doubled over the past decade. In addition to significant electricity network-related price increases, retirement of low cost base load coal-fired generation, increased intermittency from renewables, and increasing gas prices for gas-fired generation, have led to increased prices and price volatility in the spot and wholesale hedge markets. On top of wholesale energy price rises, environmental charges (LRET & SRES) and state-based schemes have also increased total electricity charges to consumers.

Demand for gas in eastern Australia increased by 170% between 2014 and 2017, and continues to climb based largely on growth in exports. Looking forward, approximately two thirds of gas production from eastern Australia is forecast to be exported as LNG. Gas supply-demand balance continues to tighten due to the massive LNG-related demand increase and the various moratoria and restrictions on gas exploration and development in New South Wales, Victoria, Tasmania and the Northern Territory.

Increasing gas demand and restrictions on gas development have seen diminished availability of gas contracts and large increases in gas prices, and these increases are feeding through into higher priced gas-fired generation for electricity production.

[1] Calculated as total generated electricity (sent out) and "behind the meter" solar PV generation (estimated) and does not take into account network losses.

1.2. South Australia the bellwether?

In terms of renewable energy penetration, South Australia (SA) leads the NEM with VRE reaching 40.5% of demand[2] over the past year. SA is now the only mainland NEM state with no coal-fired generation.

SA also has the highest priced wholesale electricity in the NEM, having delivered on average a time-weighted spot price premium of 12% compared to Queensland (QLD), 21% compared to New South Wales (NSW), and 31% compared to Victoria (VIC), since the commencement of the NEM (January 1999 to December 2016).

Looking forward, ASX Base Futures prices are also higher in SA than the other NEM states. For example, as at 31 May 2017:

- For FY2018 contracts, the SA price traded at a premium of 16% to VIC, 34% to NSW and 38% to QLD prices;
- For FY2019 contracts, the SA price traded at a premium of 27% to VIC, 37% to NSW and 48% to QLD prices;
- For FY2020 contracts, the SA price traded at a premium of 21% to VIC, 24% to NSW and 39% to QLD prices.

In the absence of coal-fired generation, SA is reliant on gas-fired generation (37%[3]), imports from Victoria (20%[3]), and VRE, primarily wind (40.5%[3]). Heavy reliance on gas-fired generation exposes South Australian electricity consumers to the risk of high gas prices. Heavy reliance on VRE exposes South Australia to increased risks to supply security and reliability, given that this generation capacity cannot be relied upon at times of peak demand.

Due to its intermittency, wind generation cannot be relied upon to contribute significantly at times of peak demand. AEMO de-rates wind generation capacities to account for the output most likely to be available during times of peak demand. AEMO's "firm contribution" from wind generators during peak periods in South Australia is currently set at 9.4% of installed capacity during summer and 7% in winter.

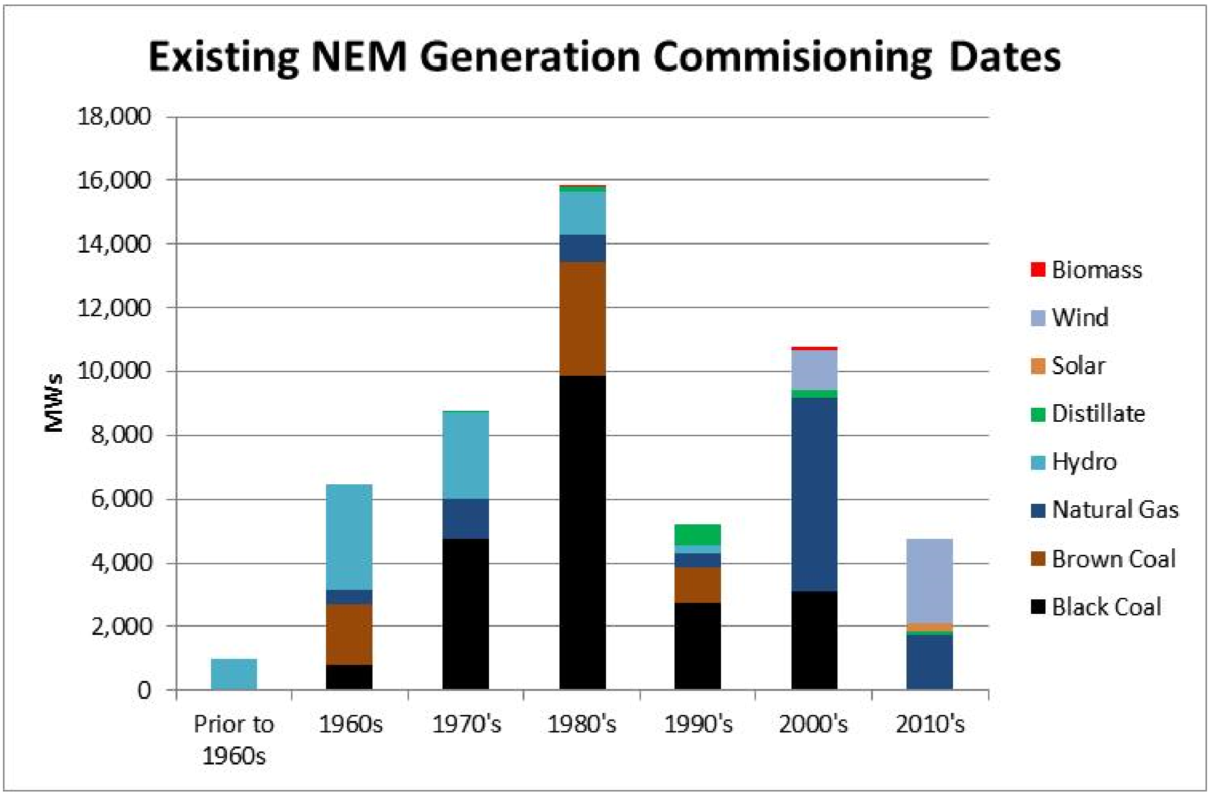
The withdrawal of synchronous generation, or its replacement by non-synchronous generation (particularly wind), has reduced the availability of services that are required to ensure the secure operation of the electricity system in South Australia, including frequency control, system re-start, inertia and rate of change of frequency. Reduced supply of these services has also increased the cost of ancillary services in South Australia compared to other NEM regions.

1.3. Need for New Generation

Much of the existing NEM generation fleet has been in service for more than 30 years (refer Figure 1).

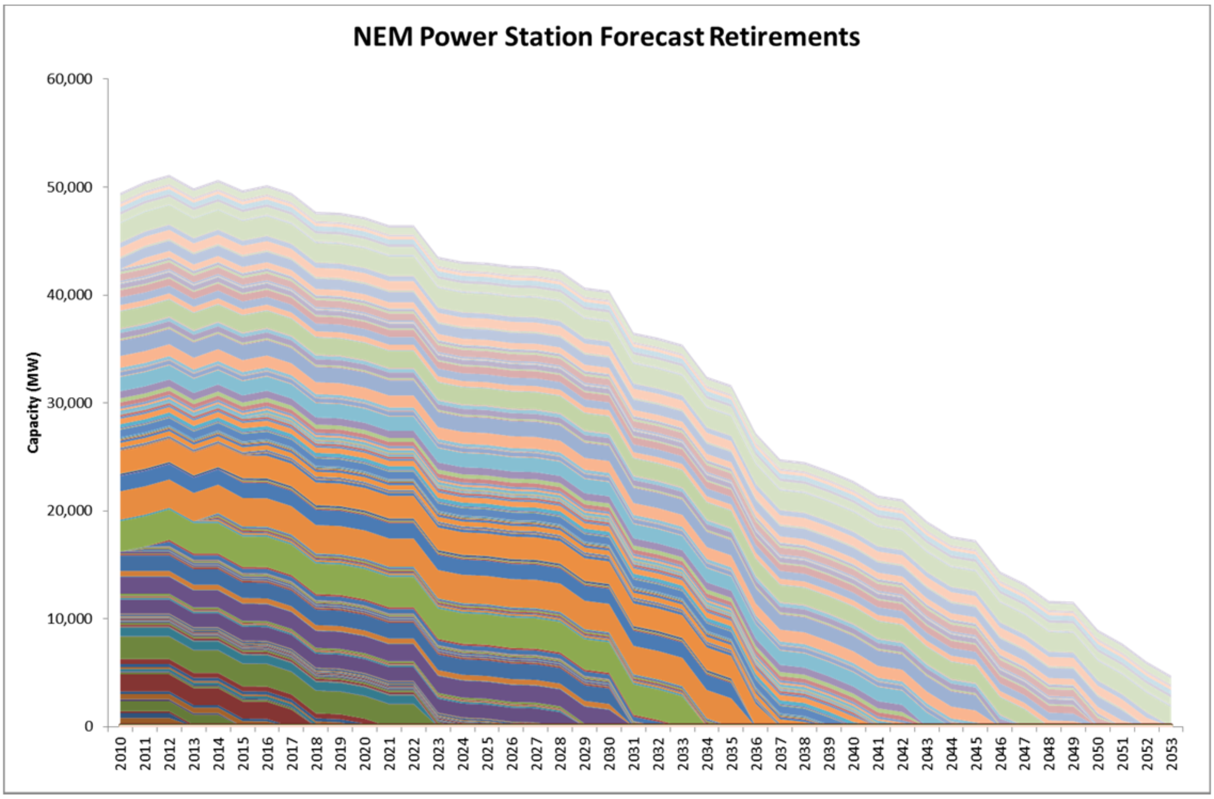
[2] Calculated as total generated electricity (sent out) and "behind the meter" solar PV generation (estimated) plus interconnection imports if the region is a net importer in that period and does not take into account network losses.
[3] Percentage of demand served by generation type in the 12 months to 31 March 2017.

Figure 1 Existing NEM Generation Commissioning Dates



Approximately 75% of this fleet relies on base load thermal generation technology which has a notional useful engineering/economic life of up to 50 years. Approximately 50% of this existing fleet is likely to be retired and will need to be replaced within the next two decades (refer Figure 2).

Figure 2 NEM Power Station Forecast Retirements



AEMO produces the National Electricity Forecast Report (NEFR) which provides electricity consumption forecasts for each NEM region and for a range of consumer and economic outlooks over a 20 year period. The last published NEFR (released in June 2016) found that consumption of grid-supplied electricity was forecast to remain flat for the next 20 years (despite a projected 30% growth in population and average growth in the Australian economy). Over the 20 year period, demand was forecast to increase from an estimated 183,258 GWh in 2015–16 to 184,467 GWh in 2035–36.

AEMO also publishes an annual Electricity Statement of Opportunities (ESOO) report, which provides an assessment of supply adequacy in the NEM over a 10 year outlook and highlights opportunities for investment in power generation. In the latest ESOO, AEMO forecasts a Low Reserve Condition (LRC) in SA and VIC from 2017/18, albeit this condition may be deferred with the commissioning of committed power station developments and reduced operational demand in these regions. In any event, unserved energy levels are projected to remain close to or above the reliability standard.

In NSW, under the neutral economic growth scenario, AEMO forecasts a LRC in 2025/26. Since the release of the 2017 ESOO, AGL has announced the planned closure of Liddell Power Station in 2022, which is likely to bring forward the forecast LRC to this point in time.

In QLD, under the neutral economic growth scenario, AEMO do not forecast a LRC within the forecast period (i.e. it occurs sometime beyond 2025/26). However, under the high economic growth scenario, a LRC is forecast to occur in 2022/23.

Given this outlook, including the pending retirements beyond the AEMO outlook, new base load generation is likely to be required in the NEM over the next 5-10 years. Victoria and New South Wales present as favourable locations for the development of new HELE USC coal-fired power stations to replace existing coal-fired generation as it retires.

1.4. HELE USC coal-fired costs

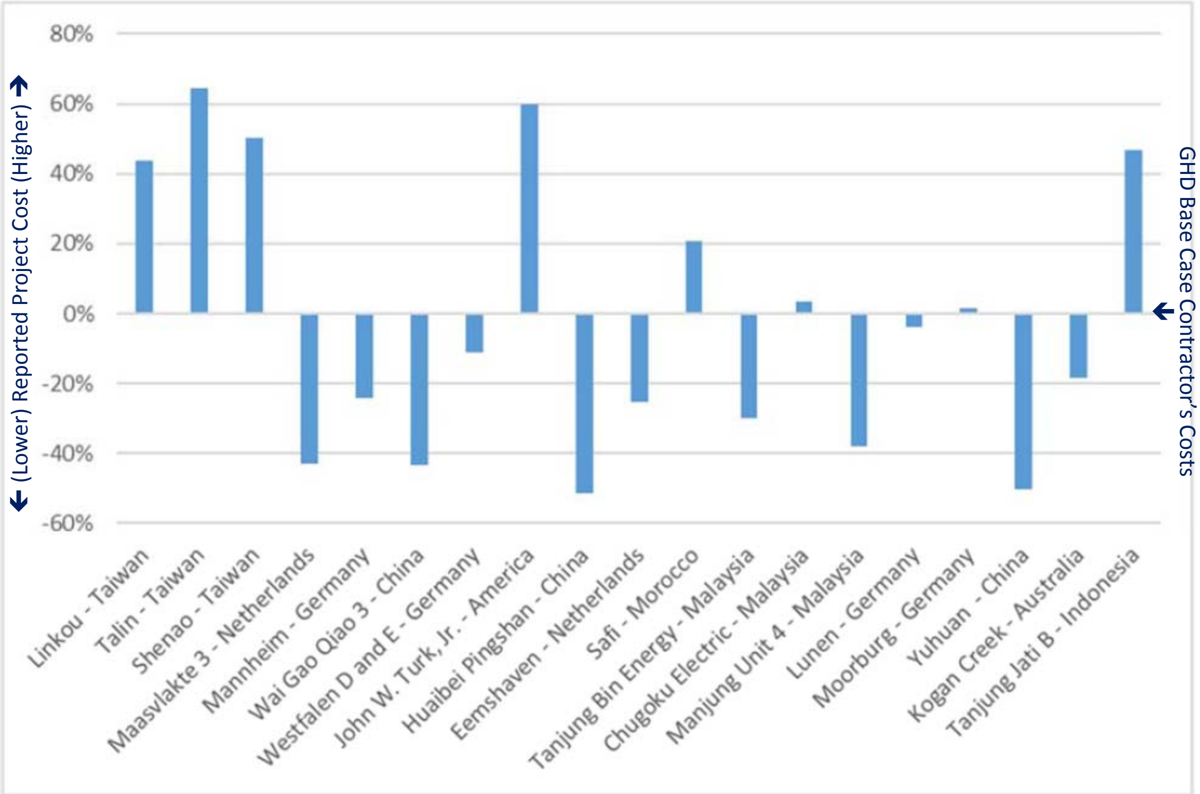
In conjunction with the development of this report, GHD was commissioned by ACALET to provide generic cost estimates for a new HELE USC coal-fired power station operating on black coal without and with Carbon Capture and Storage (CCS). In carrying out these assessments, GHD identified savings that could be achieved by:

- redeveloping ("brownfield") existing retiring coal-fired power station sites, utilising existing dedicated water resources for wet cooling where possible; and
- procuring lower cost specialised equipment from Asia (given the number of USC power stations currently being deployed in China and Japan).

GHD's forecasts indicate that these savings would reduce the estimated Contractor's Costs for a HELE USC coal-fired power station to approximately $2.2M/MW.

In order to validate its cost estimates, GHD also carried out a benchmarking exercise against publicly available cost information for similar existing HELE USC power stations (refer Figure 3).

Figure 3 GHD HELE estimate benchmarking



GHD found that its HELE USC cost estimates were comparable to actual project outcomes, with more than 50% of reported project costs lower than GHD's estimates (including Kogan Creek Power Station, the last coal-fired power station constructed in the NEM).

1.5. Comparative Power Station Cost Analysis

The analysis in this report utilises a Discounted Cash Flow (DCF) analysis to compare generation technology options for a notional 650 MW base load power station that can deliver reliable, secure, affordable and sustainable base load electricity to consumers, and that can be deployed on a commercial scale in the near term. In order to make a like-for-like comparison, it has been assumed that revenue for the 650 MW power station is "underwritten" in the form of a long-term agreement covering the purchase of the output or capacity of the plant.

Using the GHD cost estimates and drawing data from a number of recently published reports which provide cost and performance information for a range of generation technologies, a comparative assessment of relative costs was prepared for each technology for a notional 650 MW base load power station. Technologies considered in this assessment were limited to those that are able to be economically deployed on a large-scale over the next 10 years.

The results of the comparative cost assessment, using Long Run Marginal Cost (LRMC) as the relative benchmark, are shown in Figure 4 and Figure 5.

Note: The left vertical axis provides the LRMC for the relevant technology range (blue bar) and the right vertical axis provides the CO_2e emissions intensity indicated as the red diamond vertically adjacent each technology option.

The LRMC analysis shows that, of the available schedulable generation technology options, a HELE USC coal-fired power station (without and with CCS) is the lowest cost generation option that can meet all of the key criteria for reliable, secure, affordable and sustainable electricity, using both current-day costs (2017) and projected costs as at 2030.

Figure 4 Comparative Assessment of the LRMC of base load technologies

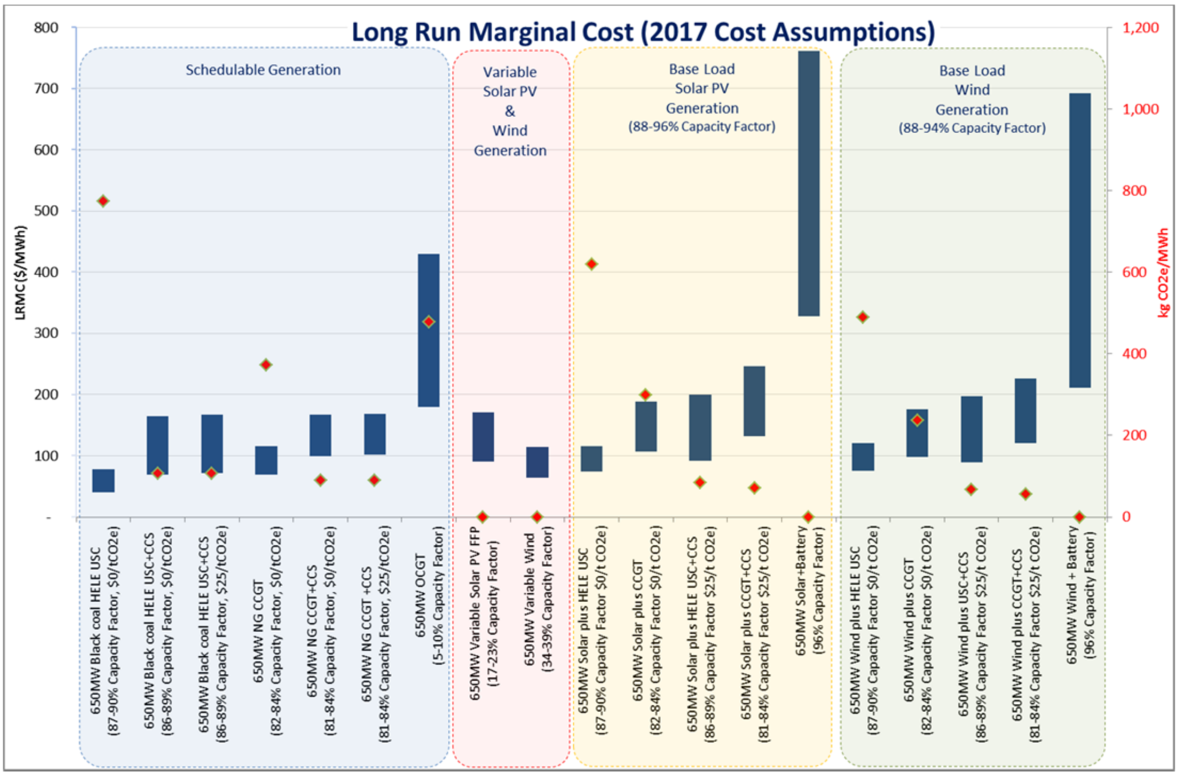
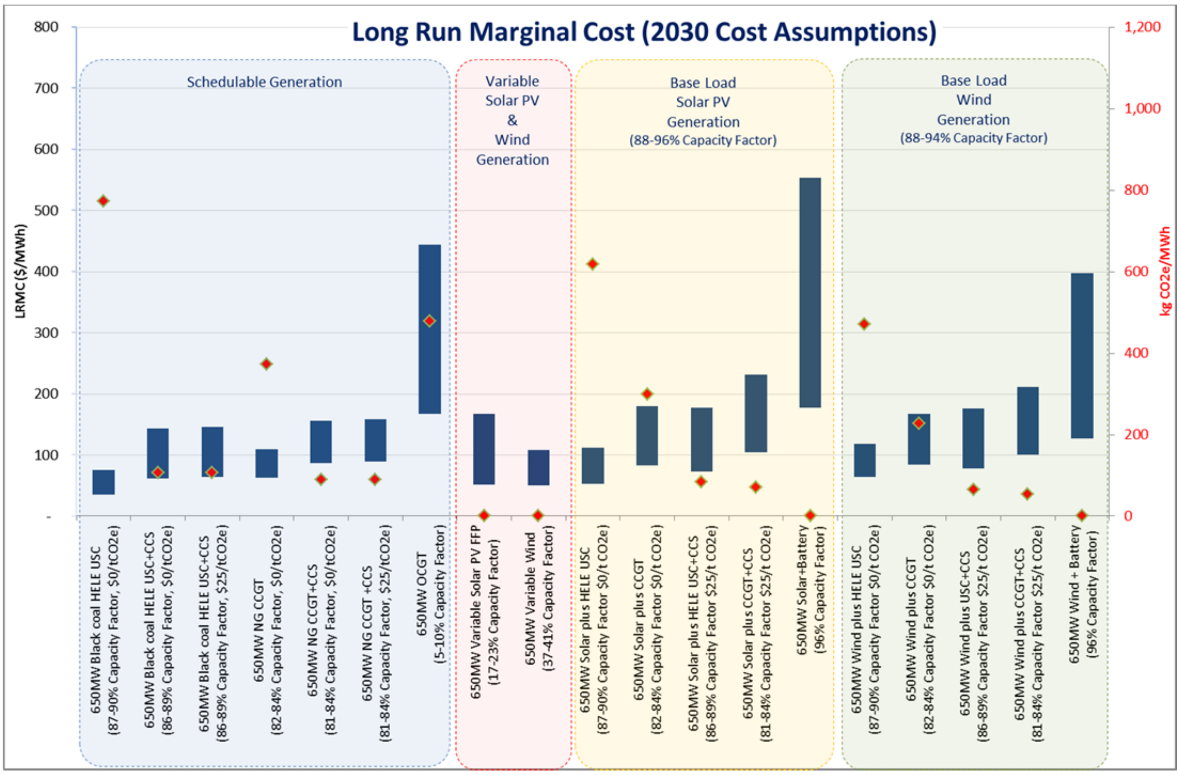


Figure 5 Comparative Assessment of the LRMC of base load technologies



The 2017 and 2030 LRMCs of natural gas CCGT are approximately 45-75% more expensive than the LRMCs of a HELE USC coal-fired power station and are particularly sensitive to higher fuel costs (refer Table 1).

Table 1 USC and CCGT LRMC comparison

LRMC	UoM	650MW Black coal HELE USC (87-90% Capacity Factor, $0/tCO2e)		650MW NG CCGT (82-84% Capacity Factor, $0/tCO2e)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	40	78	69	115
Total (2030 cost assumptions)	$/MWh	36	75	62	109

Whilst the 2017 cost base LRMC of variable Solar PV and Wind generation is forecast to reduce through to 2030 (refer Table 2), this excludes the additional cost of firming (backing up) their intermittency, and therefore, these technologies fail to meet the reliable and secure criteria on a stand-alone basis (or the affordability criterion if taking account of firming).

Table 2 Variable Solar PV and Wind LRMC comparison

LRMC	UoM	650MW Variable Solar PV FFP (17-23% Capacity Factor)		650MW Variable Wind (34-39% Capacity Factor)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	90	171	64	115
Total (2030 cost assumptions)	$/MWh	51	168	50	108

A USC coal-fired power station (without and with CCS) and a natural gas CCGT are both technically capable of firming VRE, however, 2017 and 2030 costs for a USC coal-fired power station with CCS are lower than 2017 and 2030 costs for a natural gas CCGT costs (refer Table 3).

Table 3 USC plus CCS and CCGT plus CCS LRMC comparison

LRMC	UoM	650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $25/tCO2e)		650MW NG CCGT +CCS (81-84% Capacity Factor, $25/tCO2e)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	72	168	102	169
Total (2030 cost assumptions)	$/MWh	65	146	89	158

VRE firmed exclusively with batteries is significantly more expensive than VRE firmed using a USC coal-fired power station with CCS (refer Table 4).

Table 4 VRE firmed with battery versus VRE firmed with USC plus CCS LRMC comparison

LRMC	UoM	650MW Solar + Battery (96% Capacity Factor)		650MW Wind + Battery (96% Capacity Factor)		650MW Solar plus HELE USC+CCS (86-89% Capacity Factor $25/t CO2e)		650MW Wind plus USC+CCS (86-89% Capacity Factor $0/t CO2e)	
		Low	High	Low	High	Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	328	913	211	693	91	199	90	198
Total (2030 cost assumptions)	$/MWh	177	554	127	397	73	177	77	177

Whilst reducing the level of battery storage to four to seven hours (38-44% capacity factor for solar plus batteries and 53-61% for wind plus batteries) reduces the overall cost of VRE coupled with battery backup ($140-500), this system displaces peak and mid-merit generation and does little to alleviate the increased risks to supply security and reliability resulting from the retirement of existing base load capacity.

The level of capital investment required to deliver base load renewables with batteries exclusively is significantly higher than both the coal-fired and natural gas-fired generation options, even with CCS factored into the cost base.

The emissions intensity of the Victorian brown coal fleet is approximately 1.45 t CO_2e/MWh, and the emissions intensity of the NSW black coal-fired fleet is approximately at 0.98 t CO_2e/MWh. Replacing existing older coal-fired power stations with USC black coal-fired generation (which has an emissions intensity of approximately 0.77tCO_2e/MWh) will yield an immediate significant reduction in CO_2e emissions.

A black coal-fired USC plant with a 90% CCS rate can achieve an emissions intensity of approximately 0.106 t CO_2e/MWh[4]. Therefore, if new HELE USC coal-fired generation is developed with provision for the retrofitting of CCS, further significant emissions reductions may be achieved.

Given its lower variable operating costs, a USC coal-fired power station is likely to have a lower short-run marginal cost (SRMC) compared to a natural gas-fired CCGT. Consequently, the deployment of USC coal-fired power stations would likely result in lower wholesale electricity spot prices to the extent that coal displaces gas-fired generation as the dominant marginal price setting technology. In effect, new USC coal-fired power generation would provide a hedge against rising gas prices.

1.6. Key Project Development Risks

This report highlights the looming “cliff edge” of large ageing power station retirements. The future implementation of emissions abatement measures (for example, an emissions trading scheme; or carbon tax “Mark II”) may exacerbate the cliff edge, as existing coal-fired generators align retirement plans around scheme implementation timelines.

To avoid continuing disruption, potential supply shortages, and ongoing price shocks due to power station closures, regulatory intervention is required in order to:

- signal when replacement capacity is required, so that replacements are progressed in a cost effective and timely manner; and
- ensure an orderly, optimal and cost-effective transition and retirement process for existing ageing plant.

The National Bureau of Economic Research (NBER) published a research paper titled “Bridging The Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion”[5] (NBER BTG). The NBER BTG study confirmed that the deployment of VRE historically and for the foreseeable future (in the absence of lower cost storage solutions), is intrinsically bound to the ability of the existing schedulable generation fleet to operate when the renewable generation cannot.

Historically, the level of VRE in the NEM has been modest, and the wholesale market has been able to absorb the cost of backing up intermittent renewables. However, as the penetration of VRE increases, the profitability of other schedulable generation is likely to be impacted to the extent that reliable generation capacity is forced out of the market.

The misalignment of payment mechanisms for generators who derive income from the sale of wholesale electricity is a potential barrier to a new HELE power station development, and puts at risk ongoing reliable, secure, safe, affordable and sustainable electricity for consumers. Market mechanisms should be realigned to recognise and reward generation capacity that will be reliably available when required.

[4] http://www.ieaghg.org/docs/General_Docs/IEAGHG_Presentations/A_Global_Perspective_on_the_Status_of_Carbon_Capture.pdf
[5] Bridging The Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion? (Verdolini, Vona, Popp) Working Paper 22454 http://www.nber.org/papers/w22454

2. Background

2.1. Australian electricity landscape

The National Electricity Market (NEM) covers the five transmission interconnected regional market jurisdictions of Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania. The NEM is managed and operated by Australian Energy Market Operator (AEMO).

The NEM facilitates the production of electricity from wholesale generators which is transported via high voltage transmission lines to large industrial energy users and to local electricity distributors in each region, who in turn deliver it to residential, commercial and industrial consumers.

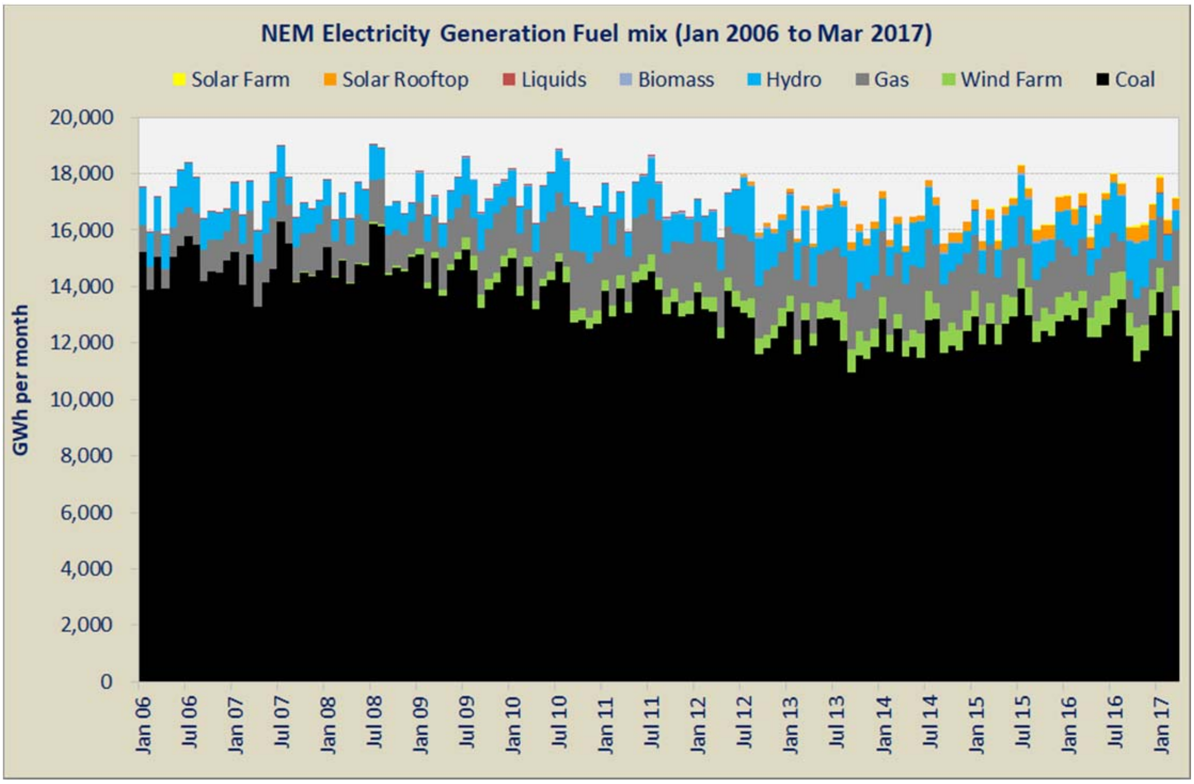
AEMO is the independent market operator responsible for NEM and system operation, and system security. AEMO also has responsibility for the operation of eastern Australian gas markets, WA gas bulletin board and the WA Wholesale Electricity Market (WEM).

2.2. NEM generation fuel mix and level

Over the past decade, the composition of electricity generation in the NEM has changed from an almost exclusively coal-fired generation system, to one with increasing electricity production from gas-fired and renewable energy sources, driven in part by environmental policies of successive federal and state governments.

Figure 6 shows the monthly contribution from all NEM connected generation and “behind the meter” solar PV generation (estimated), arranged by fuel type, for the period from 1 January 2006 to 31 March 2017.

Figure 6 NEM Electricity Generation Fuel mix (January 2006 to March 2017)



In calendar year 2006 (CY2006), NEM generation produced 205 terawatt hours (TWh) of electricity[6].

Just over a decade later, for the 12 months ending 31 March 2017, NEM plus Rooftop Solar PV generation collectively produced 202 TWh of electricity, representing a decline of 1% in total energy generated.

Electricity generation contribution by fuel mix in CY2006 and for the 12 months ended 31 March 2017 is also shown in Table 5.

Table 5 NEM Generation by Fuel Type (CY2006 & Year Ending 31-Mar-2017)

Fuel Source	NEM Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	178.0	87.0%	151.3	74.8%
Gas-fired generation	12.2	6.0%	17.5	8.6%
Liquids/Distillate generation	0.0	0.0%	0.2	0.1%
Hydro generation	14.4	7.1%	15.9	7.9%
Renewable generation	0.0	0.0%	17.4	8.6%
Variable Wind	*0.0*	*0.0%*	*11.6*	*5.8%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.5*	*0.3%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*4.9*	*2.4%*
Biomass	*0.0*	*0.0%*	*0.3*	*0.2%*
Total NEM Demand	**205**	**100%**	**202**	**100%**

The data in Table 5 shows a reduction in coal-fired generation with a corresponding increase in renewable and gas fired generation.

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[6] Excludes semi-schedule generation (wind and solar) which commenced reporting from 2007 onwards.

Renewable generation (wind, solar, biomass) grew from a baseline of practically zero in CY2006 to a market share of 8.6% (excluding hydro) for the year ending 31 March 2017, and gas-fired generation increased from 6% to 8.6% over the same corresponding period.

The change in fuel mix over the past decade has varied from region to region driven by many factors including:

- the availability and cost of generation fuel types (e.g. coal, gas, hydro, biomass, wind etc.) in each region;
- sustainability and emissions reductions policies (i.e. renewable energy policies; carbon tax and emissions policies); and
- the level of electrical interconnection between regions.

Nevertheless, coal-fired generation remains the predominant form of generation in the NEM.

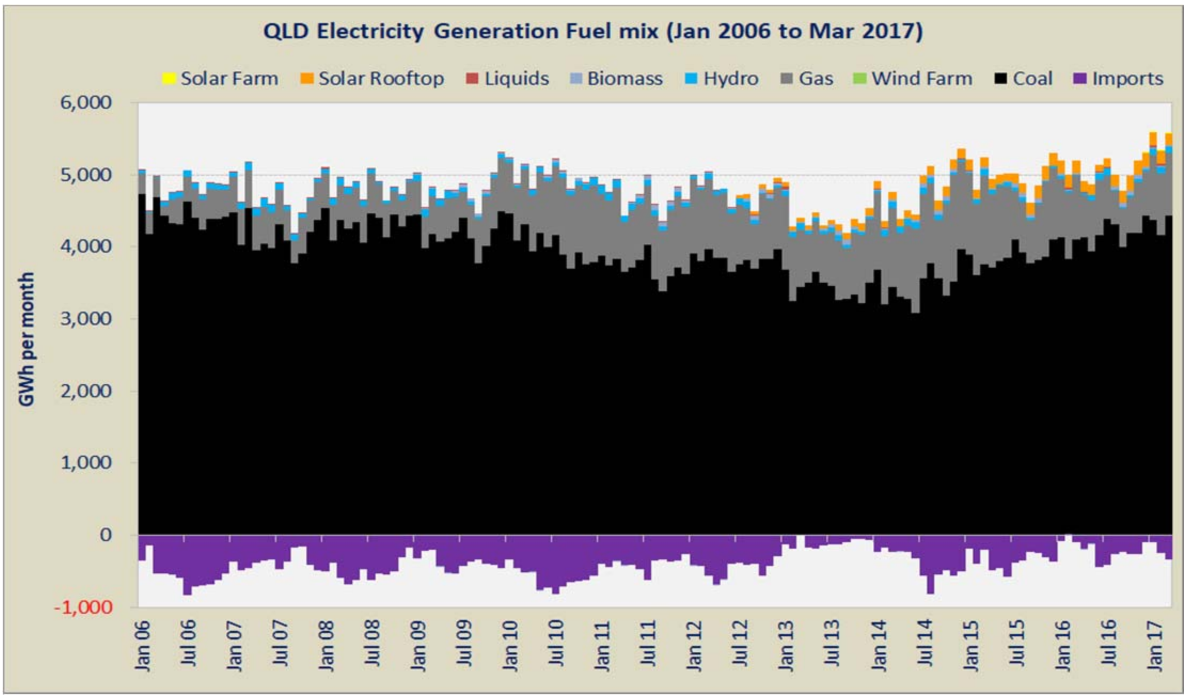
2.2.1. Queensland

Queensland is the only NEM region to experience a substantial increase in electricity demand[7] over the past decade, with total energy demand rising from 51 TWh in CY2016 to 59 TWh for the year ending 31 March 2017. Figure 7 shows that black coal-fired generation continues to dominate Queensland's electricity supply, which is primarily due to the abundance and low cost of black coal coupled with the considerable sunk investment in coal-fired generation in the state.

Queensland experienced a doubling in gas-fired generation over the past decade, driven initially by the State Government Gas Electricity Certificates (GEC) scheme (introduced in 2005).

Renewable generation in Queensland (primarily behind the meter solar PV) now serves 3.9% of the state's electricity demand, which is less than half of the NEM average of 8.6%.

Figure 7 QLD Electricity Generation Fuel mix (January 2006 to March 2017)



[7] Measured as the sum of NEM connected and "behind the meter" solar PV generation (estimated) plus interconnection imports if the region is a net importer in that period.

The Queensland electricity generation fuel mix in CY2006 and for the 12 months ended 31 March 2017 is shown in Table 6.

Table 6 QLD Generation by Fuel Type (CY2006 &Year Ending 31-Mar-2017)

Fuel Source	QLD Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	53.1	103.8%	50.7	86.1%
Gas-fired generation	4.1	8.0%	8.1	13.7%
Liquids/Distillate generation	0.0	0.0%	0.1	0.2%
Hydro generation	0.7	1.4%	0.7	1.2%
Renewable generation	0.0	0.0%	2.3	3.9%
Variable Wind	*0.0*	*0.0%*	*0.0*	*0.0%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.0*	*0.0%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*2.0*	*3.3%*
Biomass	*0.0*	*0.0%*	*0.3*	*0.5%*
Interconnection Import/(Export)	(6.8)	(13.2%)	(2.9)	(5.0%)
Generated Electricity Consumed in State	**51.2**	**100%**	**58.9**	**100%**
Gross State Generation	**58.0**	**113%**	**61.9**	**105%**
Total State Demand[8]	**51.2**	**100%**	**58.9**	**100%**

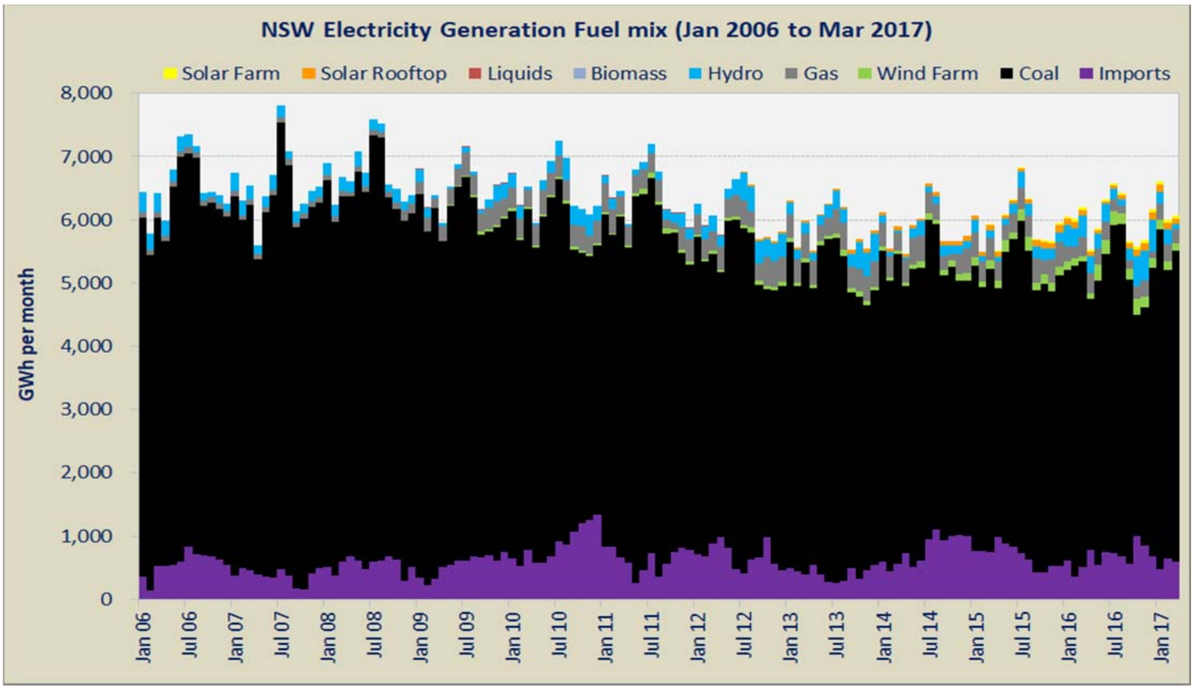
In CY2006, Queensland generated a total of 58 TWh of electricity of which 6.8 TWh was exported to New South Wales. Just over a decade later, for the 12 months ending 31 March 2017, Queensland generated a total of 61.9 TWh of electricity, with 2.9 TWh exported to New South Wales.

2.2.2. New South Wales

Like Queensland, New South Wales power generation continues to be dominated by black coal-fired generation due to the abundant supply of low cost fuel and the considerable sunk investment in coal-fired generation in the state (refer Figure 8).

[8] Generated Electricity (sent out) does not take into account network losses.

Figure 8 NSW Electricity Generation Fuel mix (January 2006 to March 2017)



The New South Wales electricity generation fuel mix in CY2006 and for the 12 months ended 31 March is shown in Table 7.

Table 7 NSW Generation by Fuel Type (CY2006 &Year Ending 31-Mar-2017)

Fuel Source	NSW Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	68.7	87.2%	54.8	75.5%
Gas-fired generation	1.0	1.3%	2.6	3.6%
Liquids/Distillate generation	0.0	0.0%	0.0	0.0%
Hydro generation	2.3	2.9%	3.2	4.4%
Renewable generation	0.0	0.0%	3.6	5.0%
Variable Wind	*0.0*	*0.0%*	*2.1*	*2.9%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.5*	*0.7%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*1.0*	*1.4%*
Biomass	*0.0*	*0.0%*	*0.0*	*0.0%*
Interconnection Import/(Export)	6.8	8.6%	8.3	11.4%
Generated Electricity Consumed in State	**72.0**	**100%**	**64.2**	**100%**
Gross State Generation	**72.0**	**91%**	**64.2**	**89%**
Total State Demand[9]	**78.8**	**100%**	**72.5**	**100%**

In CY2006, New South Wales' demand for electricity was 78.8 TWh which was supplied via state generated electricity of 72 TWh plus a further 6.8 TWh of imported electricity from Queensland and Victoria.

A decade later, for the 12 months ending 31 March 2017, New South Wales demand for electricity was 72.5 TWh which was supplied via state generated electricity of 64.2 TWh plus a further 8.3 TWh of imported electricity from Queensland and Victoria.

[9] Generated Electricity (sent out) does not take into account network losses.

New South Wales experienced an increase in gas-fired generation over the past decade, with gas now meeting 3.6% of state demand.

Renewable generation (including behind the meter solar PV) reached 5% of state demand in the past year, compared to the NEM average of 8.6%.

2.2.3. Victoria

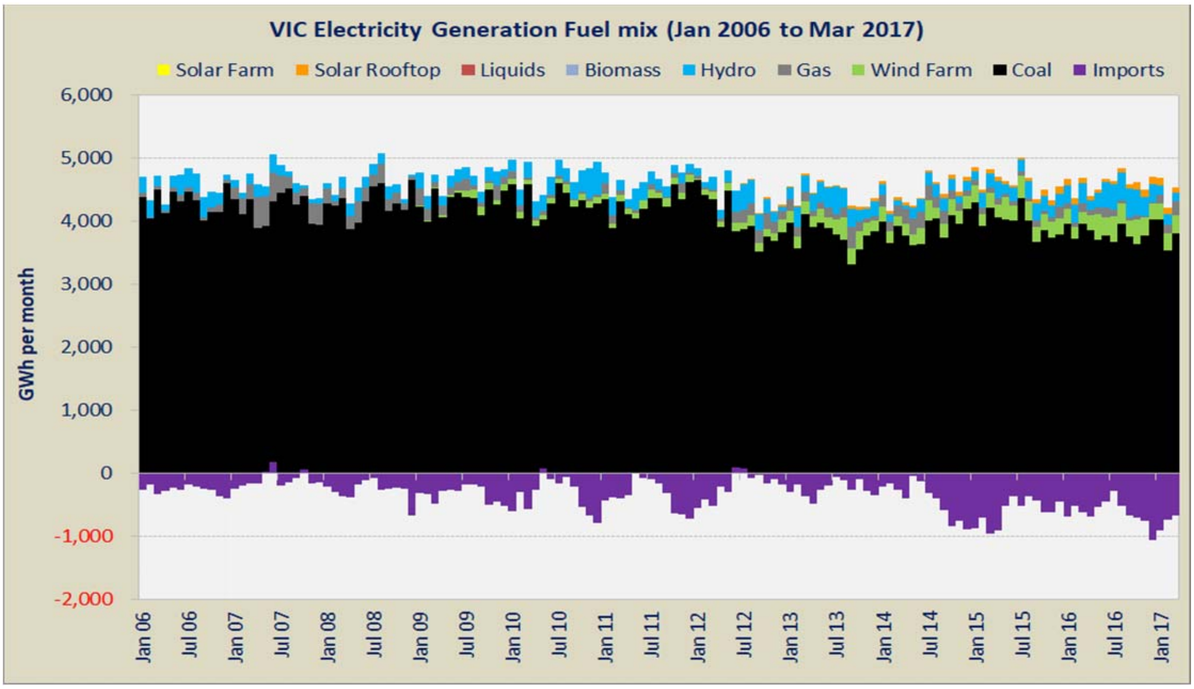
Like NSW, Victoria experienced a decline in electricity demand over the past decade, falling from 51.8 TWh in CY2016 to 46.8 TWh for the 12 months ending 31 March 2017. As shown in Figure 9, Victoria's electricity supply remains dominated by brown coal-fired generation due to the abundant supply of low cost fuel and the considerable sunk investment in coal-fired generation in the state.

Victoria has experienced an increase in gas-fired generation over the past decade (increasing from 0.8 TWh to 1.1 TWh), albeit its contribution to meeting state demand is still a modest 2.3%.

Renewable generation in Victoria reached 10.1% of demand (exceeding the NEM average of 8.6%) for the year ending 31 March 2017. Victoria's renewable generation is comprised primarily of wind generation (7.8% of demand) and behind the meter solar PV (2.2% of demand).

In the year ended 31 March 2017, Victoria had 7.2 GW of installed brown coal generation capacity producing 97% of Victoria's generated electricity. The contribution of brown coal reduced to 5.5 GW following the retirement of the Hazelwood Power Station in March 2017.

Figure 9 VIC Electricity Generation Fuel mix (January 2006 to March 2017)



The Victorian electricity generation fuel mix in CY2006 and for the 12 months ended 31 March is shown in Table 8. In CY2006, Victorian demand for electricity totalled 51.8 TWh. The Victorian power station fleet generated 55 TWh of electricity, of which, 3.3 TWh of electricity was exported to New South Wales, Tasmania and South Australia.

Table 8 VIC Generation by Fuel Type (CY2006 &Year Ending 31-Mar-2017)

Fuel Source	VIC Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	51.4	99.3%	45.4	97.2%
Gas-fired generation	0.8	1.6%	1.1	2.3%
Liquids/Distillate generation	0.0	0.0%	0.0	0.0%
Hydro generation	2.8	5.4%	3.6	7.6%
Renewable generation	0.0	0.0%	4.7	10.1%
Variable Wind	*0.0*	*0.0%*	*3.7*	*7.8%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.0*	*0.0%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*1.0*	*2.2%*
Biomass	*0.0*	*0.0%*	*0.0*	*0.0%*
Interconnection Import/(Export)	(3.3)	(6.3%)	(8.0)	(17.2%)
Generated Electricity Consumed in State	**51.8**	**100%**	**46.8**	**100%**
Gross State Generation	**55.0**	**106%**	**54.8**	**117%**
Total State Demand[10]	**51.8**	**100%**	**46.8**	**100%**

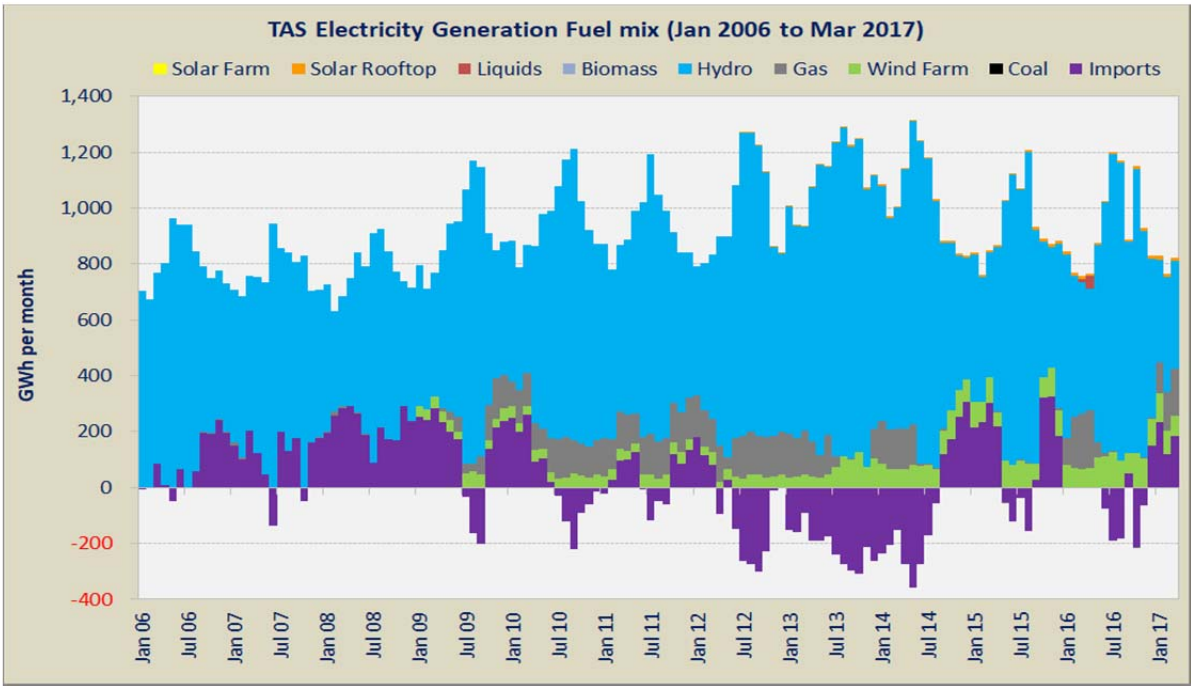
For the 12 months ending 31 March 2017, Victorian demand for electricity totalled 46.8 TWh. The Victorian power station fleet generated 54.8 TWh of electricity and exported 8 TWh.

2.2.4. Tasmania

Tasmanian electricity demand has experienced a slight increase over the past decade, with total electricity demand rising from 9.6 TWh in CY2016 to 10.5 TWh for the year ending 31 March 2017.

As shown in Figure 10, Tasmania's electricity supply remains hydro dominant.

Figure 10 TAS Electricity Generation Fuel mix (January 2006 to March 2017)



[10] Generated Electricity (sent out) does not take into account network losses.

Tasmania experienced a significant increase in gas and liquids-fired generation in the last year and a marked decline in imports from Victoria, largely due to the failure of the Basslink interconnect between Victoria and Tasmania between December 2015 and June 2016.

Renewable generation (excluding hydro) in Tasmania now serves 12.1% of Tasmanian demand (including behind the meter solar PV). Renewables growth has been largely attributable to growth in wind generation, representing 11.1% of demand. Tasmania's renewable generation contribution of 12.1% exceeds the NEM average of 8.6%.

The Tasmanian electricity generation fuel mix in CY2006 and for the 12 months ended 31 March is shown in Table 9.

Table 9 TAS Generation by Fuel Type (CY2006 &Year Ending 31-Mar-2017)

Fuel Source	TAS Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	0.0	0.0%	0.0	0.0%
Gas-fired generation	0.0	0.2%	0.7	6.6%
Liquids/Distillate generation	0.0	0.0%	0.0	0.5%
Hydro generation	8.6	89.5%	8.5	80.6%
Renewable generation	0.0	0.0%	1.3	12.1%
Variable Wind	*0.0*	*0.0%*	*1.2*	*11.1%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.0*	*0.0%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*0.1*	*1.1%*
Biomass	*0.0*	*0.0%*	*0.0*	*0.0%*
Interconnection Import/(Export)	1.0	10.3%	0.0	0.2%
Generated Electricity Consumed in State	**8.6**	**100%**	**10.5**	**100%**
Gross State Generation	**8.6**	**90%**	**10.5**	**100%**
Total State Demand[11]	**9.6**	**100%**	**10.5**	**100%**

In CY2006, Tasmanian demand for electricity totalled 9.6 TWh. The Tasmanian power station fleet generated 8.6 TWh of electricity and imported 1 TWh of electricity from Victoria.

For the 12 months ending 31 March 2017, Tasmanian demand for electricity totalled 10.5 TWh. The Tasmania power station fleet generated 10.5 TWh of electricity with negligible net imports from Victoria due to the failure of the Basslink interconnector and imports in some months offset by exports from Tasmania to Victoria in other months.

2.2.5. South Australia

South Australia experienced a modest increase in electricity demand over the past decade, rising from 13.2 TWh in CY2006 to 13.5 TWh over the year to 31 March 2017.

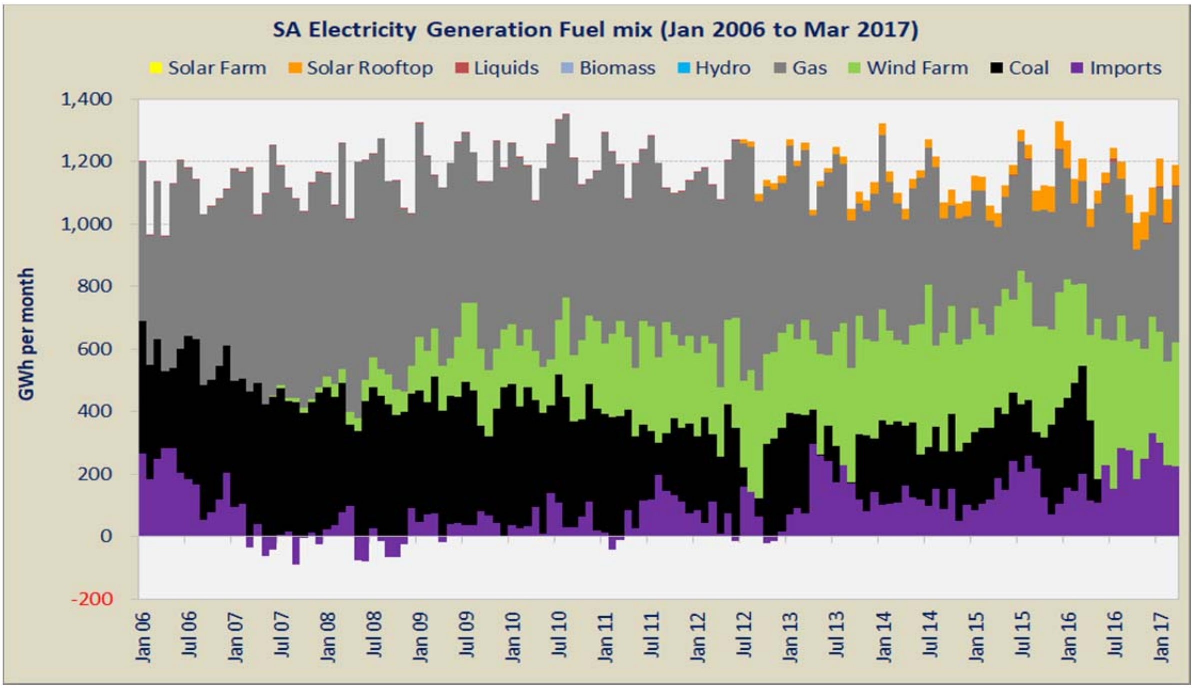
As shown in Figure 11, South Australia's electricity supply has transitioned from a primary reliance on gas and coal, supplemented by Victorian imports, to a primary reliance on gas and wind, with continuing support from Victorian imports.

Renewable generation in South Australia has now reached 40.5% of South Australian demand (including behind the meter solar PV), which is 4.7 times the NEM average of 8.6%. The contribution from renewables is dominated by wind.

South Australia has historically been more heavily reliant on gas than the other NEM regions, due to the lack of low cost coal and hydro resources available in other NEM states.

[11] Generated Electricity (sent out) does not take into account network losses.

Figure 11 SA Electricity Generation Fuel mix (January 2006 to March 2017)



The South Australian electricity generation fuel mix in CY2006 and for the 12 months ended 31 March is shown in Table 10.

Table 10 SA Generation by Fuel Type (CY2006 &Year Ending 31-Mar-2017)

Fuel Source	SA Generated Electricity			
	Y/E 31-Dec-2006		Y/E 31-Mar-2017	
	TWh	%	TWh	%
Coal-fired generation	4.7	35.6%	0.3	2.5%
Gas-fired generation	6.2	47.2%	5.0	37.0%
Liquids/Distillate generation	0.0	0.0%	0.0	0.2%
Hydro generation	0.0	0.0%	0.0	0.0%
Renewable generation	0.0	0.0%	5.5	40.5%
Variable Wind	*0.0*	*0.0%*	*4.7*	*34.8%*
Variable Solar PV (Grid)	*0.0*	*0.0%*	*0.0*	*0.0%*
Variable Solar PV (Roof top)	*0.0*	*0.0%*	*0.8*	*5.7%*
Biomass	*0.0*	*0.0%*	*0.0*	*0.0%*
Interconnection Import/(Export)	2.3	17.2%	2.7	19.9%
Generated Electricity Consumed in State	**10.9**	**100%**	**10.8**	**100%**
Total State Generation	**10.9**	**83%**	**10.8**	**80%**
Total State Demand	**13.2**	**100%**	**13.5**	**100%**

In CY2006, South Australian demand for electricity was 13.2 TWh and the state generators produced approximately 10.9 TWh of electricity with 2.3 TWh of electricity imported from Victoria.

For the 12 months ending 31 March 2017, South Australian demand for electricity was 13.5 TWh; supplied by the state generators who produced 10.8 TWh plus 2.7 TWh of net imports from Victoria.

2.2.6. Fuel mix summary

The preceding charts show the electricity generation energy mix over the past decade measured in energy (GWh).

Figure 12 shows the current grid connected generation capacity[12] by region, excluding distributed generation "behind the meter" (e.g. smaller diesel generation, solar PV, etc.), plus interstate network import capacity; compared to the historic grid based maximum demand for each region (measured in MW). The Victorian installed capacity stack includes the now retired Hazelwood Power Station.

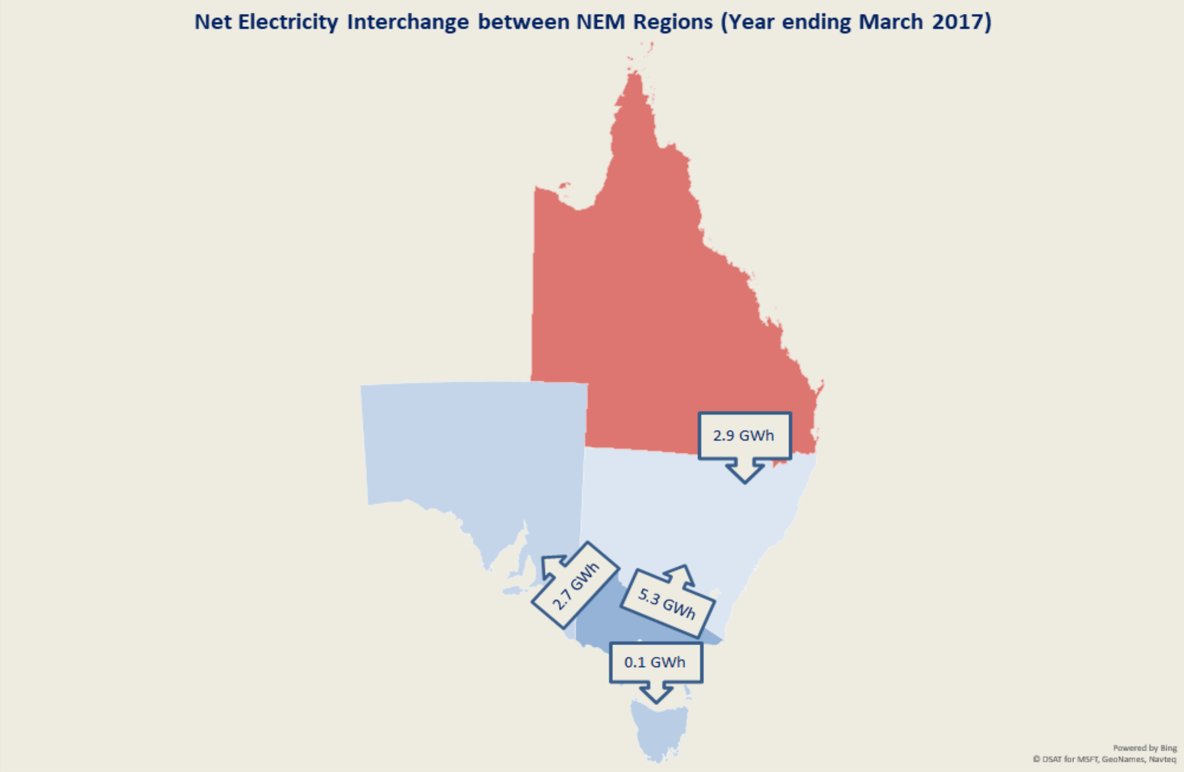
Figure 12 NEM grid connected electricity generation capacity by Fuel type as at April 2017

2.2.7. Interconnection

In the year ended 31 March 2017, Queensland and Victoria were net exporters of electricity to other regions. The net electricity interchange (not adjusted for network losses) between regions for this period is summarised in Figure 13.

[12] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information Generation_Information_SA_27022017.xlsx [Background Information] AEMO Maximum Capacity definition: Some thermal (generation that burns fuel) and non-thermal (renewable generation) generating systems can provide additional, short-term capacity that exceeds the registered capacity. This is known as maximum capacity. Source: NemSight

Figure 13 Net Electricity Interchange between NEM Regions (year ending 31 March 2017)

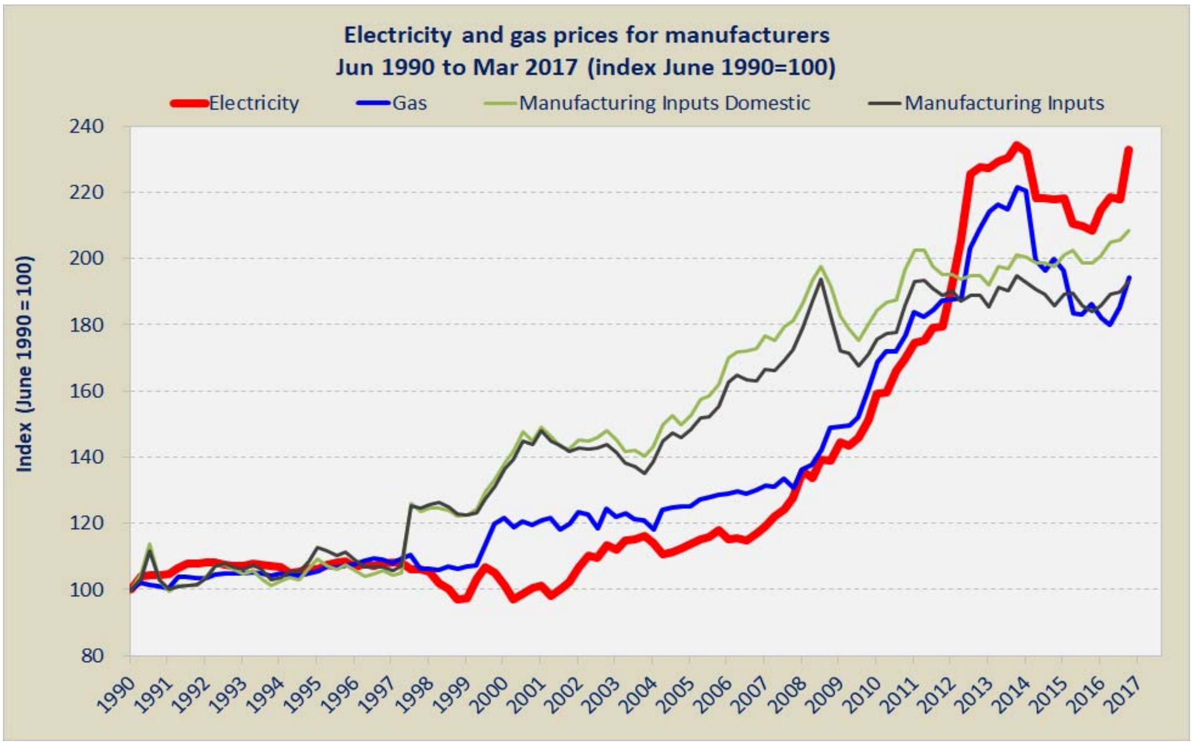


2.3. Electricity market prices

2.3.1. Electricity prices to large customers

The electricity and gas price index shown in Figure 14 has been compiled from Australian Bureau of Statistics (ABS) source data for the period from June 1990 to March 2017.

Figure 14 Electricity and gas prices for manufacturers from June 1990 to March 2017 (ABS).



The ABS data includes total electricity bill costs to Australian manufacturers including wholesale electricity commodity charges, network charges, environmental and other charges.

Figure 14 shows that whilst electricity prices were relatively flat throughout the 1990s, todays electricity prices have increased by almost 140% over the last quarter of a century and have doubled over the past decade. Figure 14 also shows a high correlation between gas and electricity prices over most of this period.

Electricity price rises that occurred from around 2006 were associated with the impact of the east coast drought, the impacts of which included a shortage of water and snow melt for hydro generation in the Snowy; and reduced availability of cooling water for large coal-fired generators, leading to temporary mothballing of some generation units. Rapid escalation of prices in recent quarters has been associated with coal-fired generation retirements, increasing gas costs for power generation, and extreme summer weather conditions.

The Mandatory Renewable Energy Target (MRET) scheme which was first introduced in 2001 (2% target), and was then increased in 2009 to a 20% target by 2020 and then again in 2010, with the scheme life extended until 2030. In 2011 MRET was split into two schemes, the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET target was then reduced from 41 TWh to 33 TWh (LRET) by 2020 in June 2015. Renewable energy charges now comprise around 6% to 12% (range varies by customer and region due in particular to relative network tariffs and wholesale energy prices) of total electricity charges to large customers in the NEM. For CY2017, customers are obliged to pay LRET charges at a rate of 14.22% (Renewable Power Percentage [RPP]) of their energy usage for LRECs (Large-scale Renewable Energy Certificates) and SRES charges at a rate of 7.01% (Small-scale Technology Percentage [STP]) for SRECs (Small-scale Renewable Energy Certificates).

The carbon tax lasted for two years from July 2012 to June 2014 and the impact of its introduction and withdrawal is apparent in Figure 14.

Over the almost 27 years of data shown in Figure 14, in relative terms, increases in electricity prices were equal to or below rises in average manufacturing input prices up until about 2012, but have risen above and stayed above average manufacturing input prices since that time.

Electricity prices to Australian manufacturers have doubled over the past decade. In addition to significant electricity network-related price increases, retirement of low cost base load coal-fired generation, increased intermittency from renewables, and increasing gas prices for gas-fired generation, have led to increased prices and price volatility in the spot market and increased prices in the wholesale hedge markets. On top of wholesale energy price rises, environmental charges (LRET & SRES) and state-based schemes have also increased total electricity charges to consumers.

2.3.2. Electricity spot market prices

The monthly time-weighted average ("flat") spot price (excluding network, environmental or other charges) by NEM region from January 1999 to April 2017 is shown in Figure 15.

Figure 15 NEM monthly time-weighted (flat) average spot prices by NEM region (AEMO).

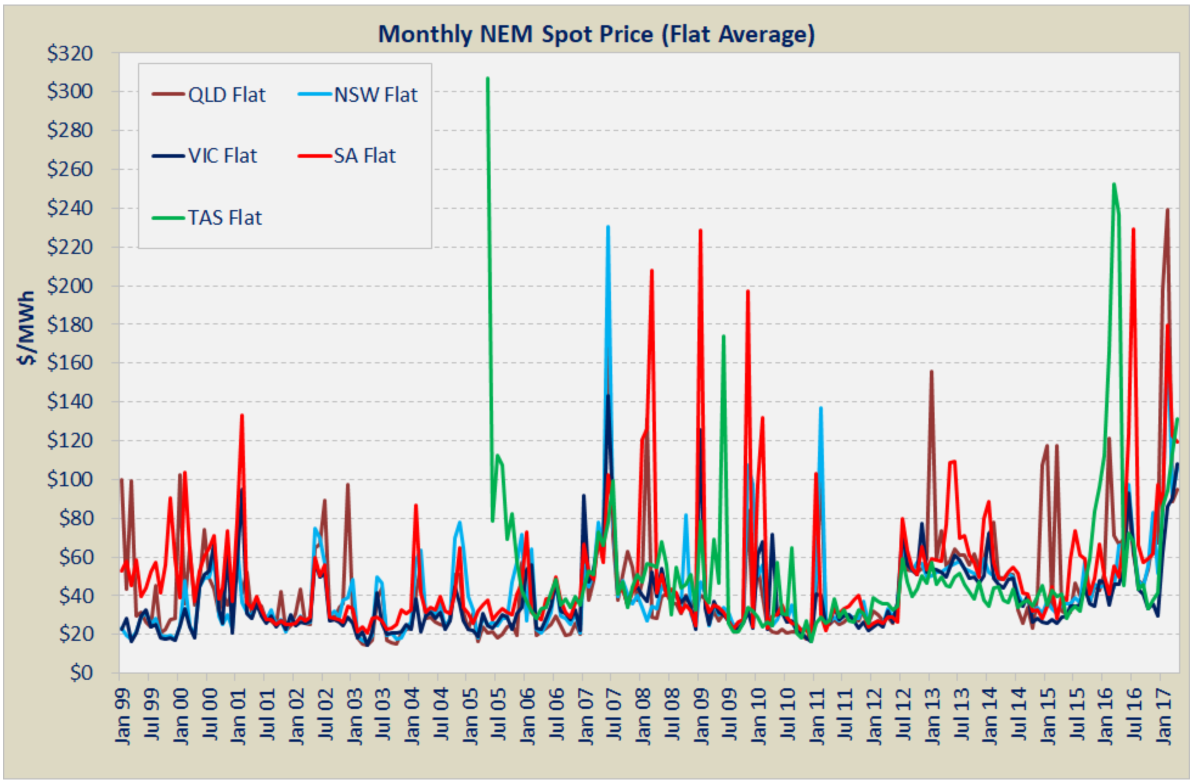


Figure 15 shows periods of volatility, particularly in Queensland and South Australia in the early years of the NEM and then again in the second half of the drought affected noughties. High prices occurred in Tasmania when it first joined the NEM in 2005 and across the NEM with the two-year carbon tax period (July 2012 to June 2014).

Since the winter of 2014, prices and volatility have increased significantly associated with coal-fired generation plant retirements, the Basslink interconnect outage, increasing gas prices, and extreme summer weather conditions.

2.3.3. Wholesale electricity contract prices

The closing daily ASX Base Futures prices across the four NEM regions of Queensland, New South Wales, Victoria and South Australia for contract years FY2017, FY2018, and FY2019 respectively up until the end of April 2017 are shown in Figure 16, Figure 17 and Figure 18. These futures price charts reflect recent higher and more volatile spot prices, together with power generation supply uncertainty, anticipated generation shortages, and increasing fuel prices. It should be noted that these prices do not include network, environmental or other charges.

Figure 16 ASX Base Electricity Futures daily closing prices for FY2017 contracts for QLD, NSW, VIC and SA from July 2014 to April 2017.

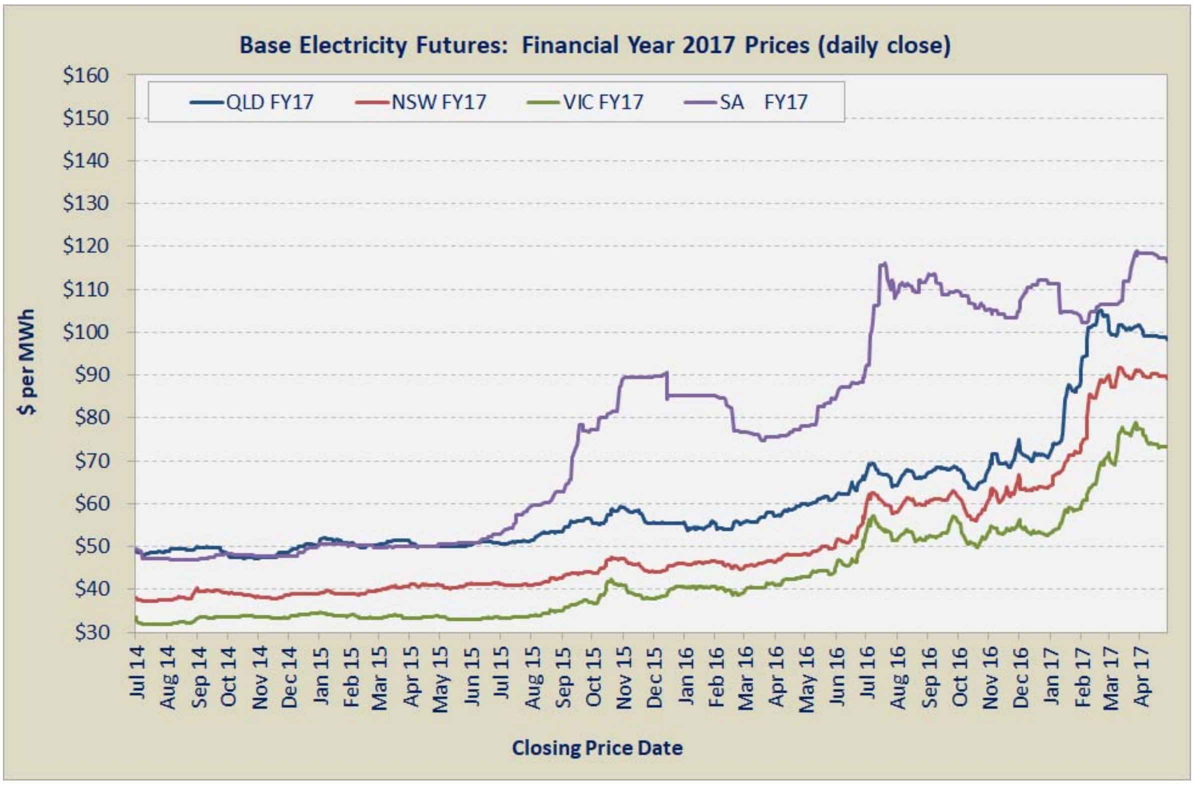


Figure 17 ASX Base Electricity Futures daily closing prices for FY2018 contracts for QLD, NSW, VIC and SA from July 2015 to April 2017.

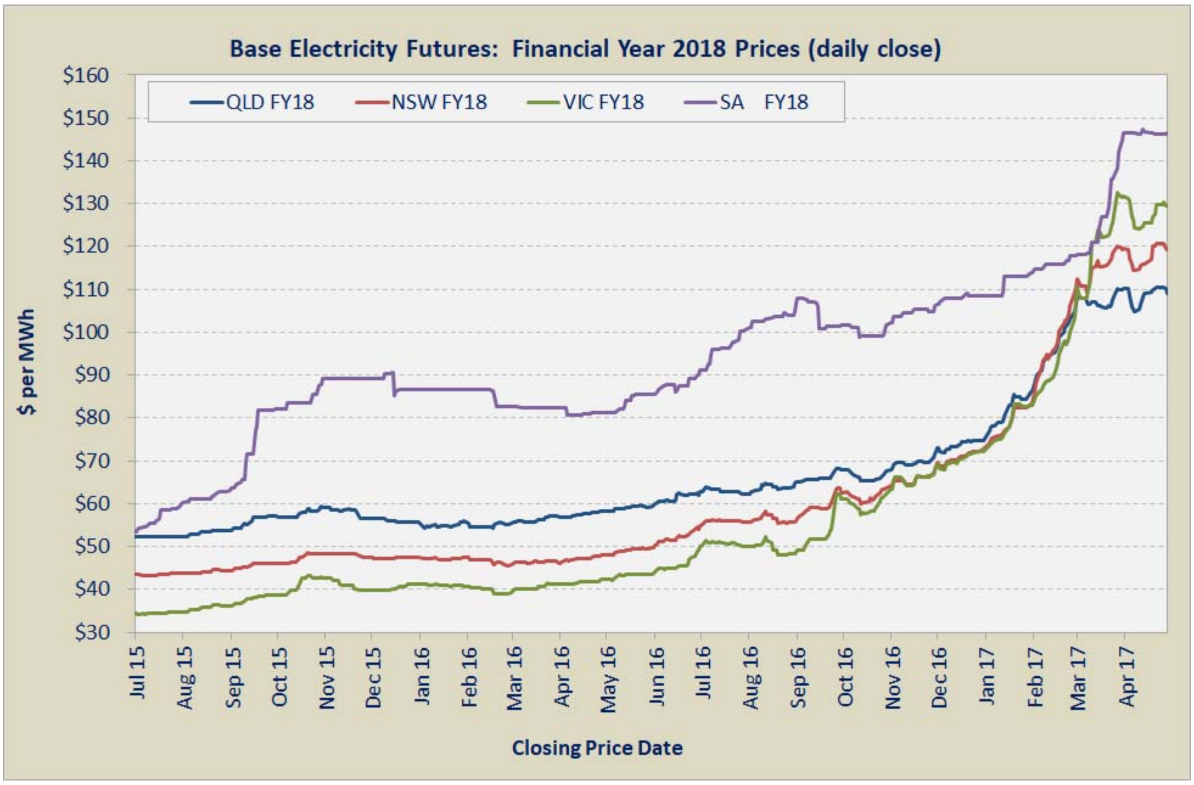
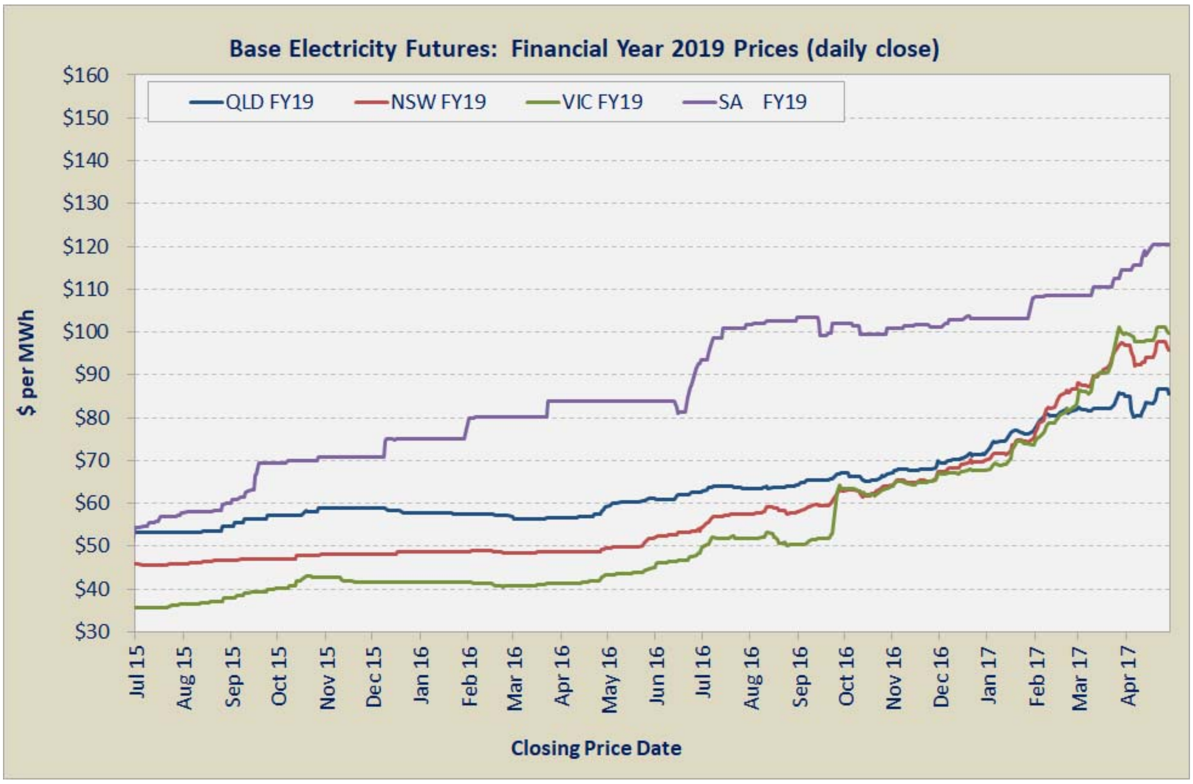


Figure 18 ASX Base Electricity Futures daily closing prices for FY2019 contracts for QLD, NSW, VIC and SA from July 2015 to April 2017.



Recent public announcements regarding the closure of major power stations, summarised in Table 11, have influenced the rise in forward market electricity prices over the past 2 years.

Table 11 Summary of Significant Public Announcements (Power Station Closures)

Date	Event / Announcement
11 June 2015	Alinta Energy announce that its Flinders Operations in Port Augusta (Northern and Playford B Power Stations) and Leigh Creek Mine will not operate beyond March 2018 (and may close earlier but not before March 2016)[13].
30 July 2015	Alinta Energy announce that its Flinders Operations will not operate beyond March 2017. An earlier closure date will not be before March 2016[14].
7 Oct 2015	Alinta Energy announce that its Flinders Operations will close on 31 March 2016, in line with previous guidance. Timing for this closure means that operational mining at Leigh Creek will cease on 17 November 2015 and the Augusta Power Stations plan to cease generation around 31 March 2016[15].
28 Apr 2016	Alinta Energy announce final haulage of coal railed from Leigh Creek coal mine to Port Augusta Power Stations, ahead of the closure of Flinders Operations on or around 9 May 2016[16].
9 May 2016	Augusta Power Station ceased power generation[17]
3 Nov 2016	ENGIE and Mitsui announced that the Hazelwood power generation business in

[13] https://www.alintaenergy.com.au/about-us/news/flinders-operations-announcement
[14] https://www.alintaenergy.com.au/about-us/news/flinders-operations-closure-update
[15] https://www.alintaenergy.com.au/about-us/news/flinders-operations-update
[16] https://www.alintaenergy.com.au/about-us/news/final-coal-hauled-for-flinders-operations
[17] https://www.alintaenergy.com.au/about-us/news/augusta-power-station-ceases-generation

Date	Event / Announcement
	the Latrobe Valley would close at the end of March 2017[18].
29 Mar 2017	Hazelwood power station ceased operation[19].

2.4. Sustainability, emissions reductions and renewables targets

AEMO identifies the significance of international, national and state based emissions reductions targets as a driver of the future generation mix required to meet electricity demand going forward in the AEMO Gas Statement of Opportunities 2017[20].

Grid scale electricity generation assets typically have long economic lives, ranging from 20 to 50 years. Securing funding and avoiding excessive financial risk premiums for these long-term investments requires an environment of investment certainty.

Sections 2.4.1 through to 2.4.5 summarise some of the influencing factors, events and recent environmental imposts which have affected the power generation investment environment and contributed to the increasing cost of electricity.

2.4.1. COP21 Paris climate agreement

Australia committed at the 21st Conference of Parties (COP21) to reduce greenhouse gas emissions (COP21 commitment) by 26% to 28% from 2005 levels by 2030 in support of Article 2 (a) of the Paris Agreement aimed at holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change.

2.4.2. Carbon tax

The carbon pricing scheme was introduced as the Clean Energy Act 2011, which came into effect on 1 July 2012 and operated for 2 years until 30 June 2014 (repealed on 17 July 2014 and backdated to 1 July 2014). The carbon pricing scheme levied a cost of \$23 per tonne of CO_2 in FY2013, rising to \$24.15 per tonne of CO_2 in FY2014.

2.4.3. Australia's national renewable energy target

The Mandatory Renewable Energy Target (MRET)[21] scheme was first introduced nationally in 2001 and targeted 2% of energy generation from renewable sources by 2020.

MRET was increased in 2009 to 41,000 GWh pa, representing an estimate of 20% of annual electricity demand in 2020.

The MRET target was increased again in 2010 to 45,000 GWh pa by 2020, and the life of the scheme was extended to 2030.

[18] http://www.gdfsuezau.com/media/newsitem/Hazelwood-to-close-in-March-2017
[19] http://www.gdfsuezau.com/media/newsitem/End-of-generation-at-Hazelwood
[20] http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf [page 27]
[21] http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/History-of-the-scheme

In January 2011, the Renewable Energy Target (RET) was split into two schemes:

- the Large-scale Renewable Energy Target (LRET), providing a financial incentive to large grid connected renewable projects, including wind farms and solar farms (41,000 GWh pa by 2020); and
- the Small-scale Renewable Energy Scheme (SRES), providing a financial incentive to install smaller-scale renewables, including roof top solar PV (nominally 4,000 GWh pa by 2020).

In June 2015, the LRET was reduced from 41,000 GWh pa to 33,000 GWh pa (by 2020).

The LRET scheme is currently scheduled to run until 2030 and the Renewable Power Percentage (RPP) to be applied to Liable Entities for CY2017 is 14.22%[22]. The SRES scheme is currently also scheduled to run until 2030 and the Small-scale Technology Percentage (STP) to be applied to Liable Entities for CY2017 is 7.01%[23].

2.4.4. State-based renewable energy targets

Apart from the national renewable energy policy, most State governments have either implemented or are investigating the implementation of a renewable energy or emissions target.

The Queensland Government is investigating the implementation of a 50% renewable energy target by 2030 policy[24].

The New South Wales Government has an aspirational target of zero-net emissions by 2050[25].

The Victoria Government committed in 2016 to the Victorian renewable energy generation targets (VRET) of 25% by 2020 and 40% by 2025. The targets will be supported by a competitive reverse auction scheme[26].

The ACT Government legislated the Australian Capital Territory Renewable Energy Target (ACT RET) in 2016, setting a target for renewable generation to produce 90% of total electricity generation in ACT by 2020, and 100% by 2025[27].

The South Australia Government in 2015 committed to a target of zero net carbon emissions by 2050 in its Climate Change Strategy 2015-2050: Towards a low carbon economy, and South Australia has set a target of 50% of electricity production from renewable energy by 2025[28].

The Tasmanian Government has not promoted a state-based target beyond the National RET.

2.4.5. Expanding penetration of variable renewables

The growing penetration of VRE has been most evident to date in South Australia where intermittent renewable generation, primarily wind, has displaced but not replaced base load generation.

This displacement has been accompanied by reduced synchronous generation capacity threatening system security and reliability[29]. In the absence of coal-fired generation, South Australia has become increasingly reliant on gas-fired generation and interconnection with neighbouring Victoria to "firm" the intermittency of wind generation.

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[22] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage
[23] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage
[24] https://www.dews.qld.gov.au/electricity/solar/solar-future
[25] http://www.resourcesandenergy.nsw.gov.au/energy-consumers/sustainable-energy/renewable-energy-action-plan
[26] http://www.delwp.vic.gov.au/energy/renewable-energy/victorias-renewable-energy-targets
[27] http://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target,-legislation-and-reporting; http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf [page 27]
[28] http://statedevelopment.sa.gov.au/upload/energy/facts/Renewable%20and%20future%20electricity%20generation_DSD_11216.pdf?t=1481241303925
[29] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2016/2016_SAER.pdf page 5.

With reduced fuel diversity supply options, and in situations where South Australia cannot rely upon imports via interconnection from Victoria, it becomes solely reliant on gas-fired generation capacity. This situation is exacerbated by the current market environment in which gas supply is tight and gas demand has tripled, with two thirds of east-coast gas production now being exported to international markets.

3. South Australia the bellwether?

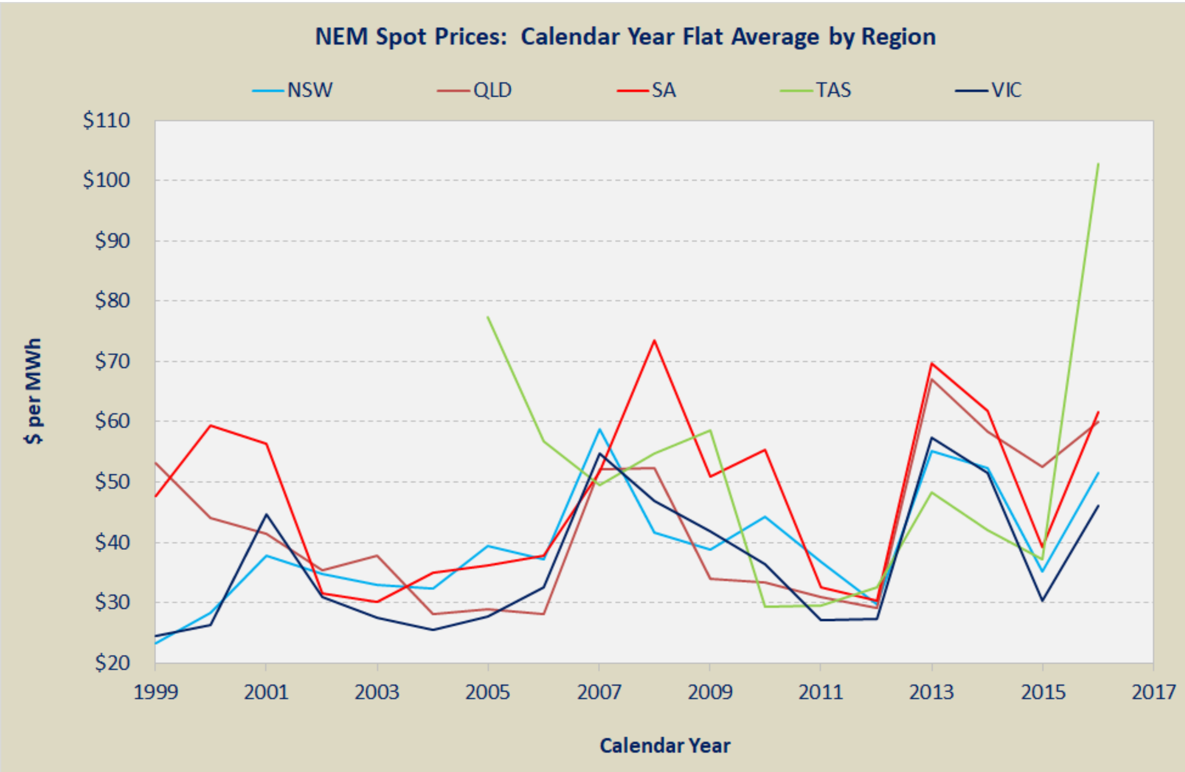
The fuel mix charts by region in section 2.2 clearly show that South Australia has experienced a significantly higher proportional change in penetration of large-scale renewable generation than the other NEM states.

South Australia has also typically experienced higher wholesale electricity prices in both the spot and forward markets, both before and after the growth of large-scale renewable generation.

On average, over the past 11 calendar years (2006-2017), South Australia's time-weighted annual average (flat) spot prices have been higher than all other NEM states. The South Australian price "premium" over this period has been 4% to Tasmanian prices, 13% to Queensland prices, 17% to New South Wales prices, and 25% to Victorian prices.

Since the commencement of the NEM (1999), South Australia's time-weighted average annual spot prices have represented a premium of 12% to Queensland prices, 21% to New South Wales prices, and 31% to Victorian prices, on average over the past 18 calendar years (refer Figure 19).

Figure 19 Calendar year time-weighted average (flat) spot prices by NEM Region[30].



[30] TAS joined the NEM during 2005.

Likewise, South Australia's forward and futures prices have historically traded, and continue to trade at a premium to the other NEM regions.

Figure 20 shows daily closing prices from January 2012 to April 2017 for Australian Securities Exchange (ASX) electricity base futures contracts from CY2014 to CY2019 across Queensland, New South Wales, Victoria and South Australia. Victoria's wholesale energy prices (dark blue series) have traditionally been the lowest in the NEM. New South Wales wholesale energy prices (light blue series) have historically tracked Victorian wholesale energy prices, but at a slight premium. Queensland wholesale energy prices (red series) have historically tracked New South Wales wholesale energy prices but again at a slight premium to New South Wales. South Australian wholesale energy prices (green series) have historically sat above all other regions. From mid-2015, South Australian wholesale energy prices spiked significantly following the Alinta Energy announcement of the closure of the Leigh Creek Coal Mine and Augusta Power Stations.

Figure 20 ASX Base Futures Contract closing daily price from Jan 2012 to Apr 2017 for CY14, CY15, CY16, CY17, CY18 and CY19 contracts by NEM region.

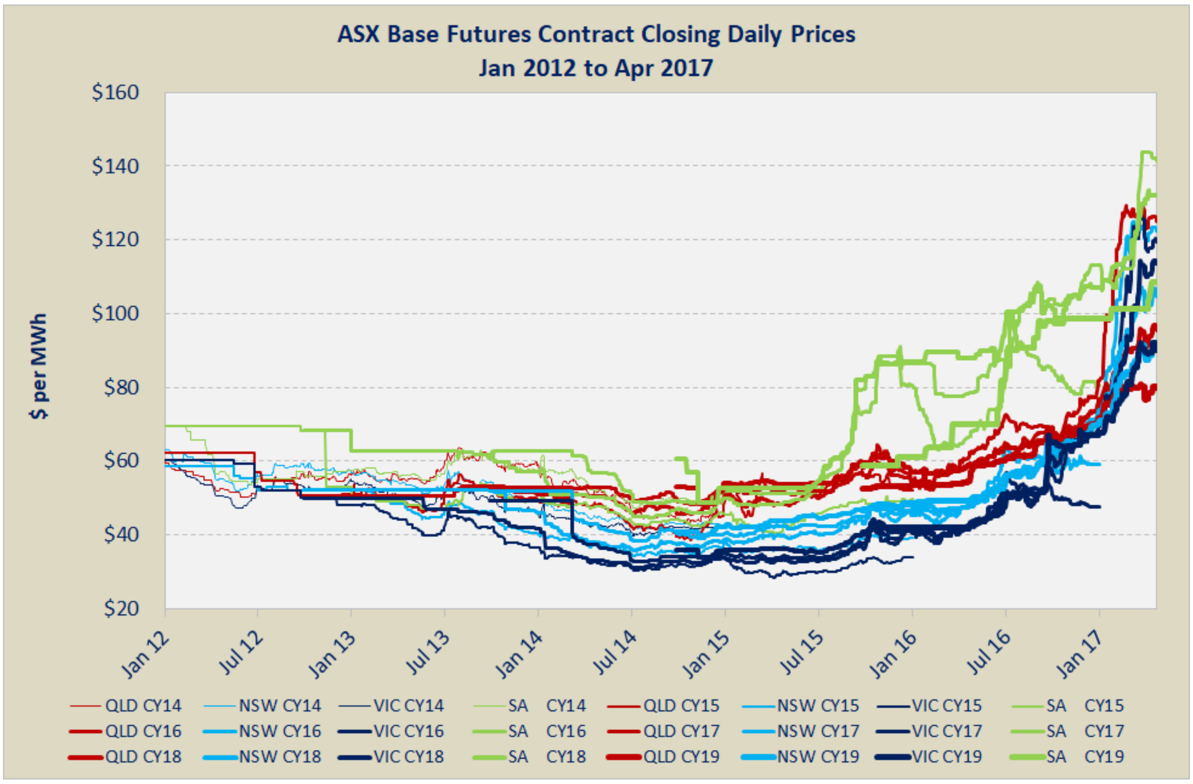


Figure 20 also shows the spike in futures prices that occurred across all regions, but led by Victoria, following the November 2016 announcement by Engie and Mitsui that their Hazelwood coal-fired power station would close in March 2017.

Historically, South Australia has had less hedge contract trading liquidity than other NEM regions. Whilst forward and futures markets are used to hedge future spot market prices, the deep penetration of VRE affects the liquidity of the hedge market in South Australia where hedging instruments are not as prevalent relative to their availability in other regions.

VRE projects typically contract the sale of output differently to large schedulable generation. For example, a large renewable energy project will benefit from revenue derived from the long-term sale of Large-scale Generation Certificates (LGCs), making it less reliant on spot market pool payments. This is particularly apparent when LGC prices are high (recently LGC spot prices were trading in the $80 to $90 range) thus providing less incentive to hedge spot pool sales.

Conversely fossil fuel generators derive their income from spot pool sales and hedged pool sales which are typically of a shorter duration contract term, e.g. months or 1 or 2 years. Renewable projects often sell a long-term offtake contract (e.g. 10 to 20 years[31]) covering the entire project's output of spot energy and LGCs to a single counterparty as a condition of the project achieving financial close.

Therefore, any spot energy produced by the renewable project is sold through the spot market, but the wind farm owner is indifferent to the spot market price, because the price received under the offtake agreement has been fixed for whenever the wind farm generates.

The sale of firm hedge contracts by a wind farm generator would expose the owner to significant spot market price risk. That is, a wind generator selling conventional firm hedges (swaps), faces the risk of potentially extreme difference payments when spot prices are higher than the contract hedge price and the generator is not being dispatched due to a lack of wind resource.

This is simply a function of intermittency, rather than the fact that the generation source is renewable. A wind generator operator may be confident that its power station will run at a 35% to 40% capacity factor over the coming year. However, they will have a much lower level of confidence about the level of generation in any specific operating half hour of the year. Likewise, the off-taker of a non-firm hedge from the wind farm may be confident that it has an energy price hedge that will cover 35% to 40% of the capacity of the wind farm over a year, but the off-taker will not be confident about how much hedge cover they will receive from the wind farm on a hot summer day when the wind is not blowing and spot pool prices are very high.

In South Australia, AEMO de-rates wind generation capacities due to their intermittent nature to account for the output most likely to be available during times of maximum demand. AEMO refers to this as the "firm contribution" from wind during peak periods and the current AEMO rates applied in South Australia are 9.4% of the installed capacity in summer, and 7% during winter.

As intermittent generation penetration increases, firm wholesale hedge contract liquidity diminishes, market concentration increases and lack of retail competition intensifies, increasing prices to consumers.

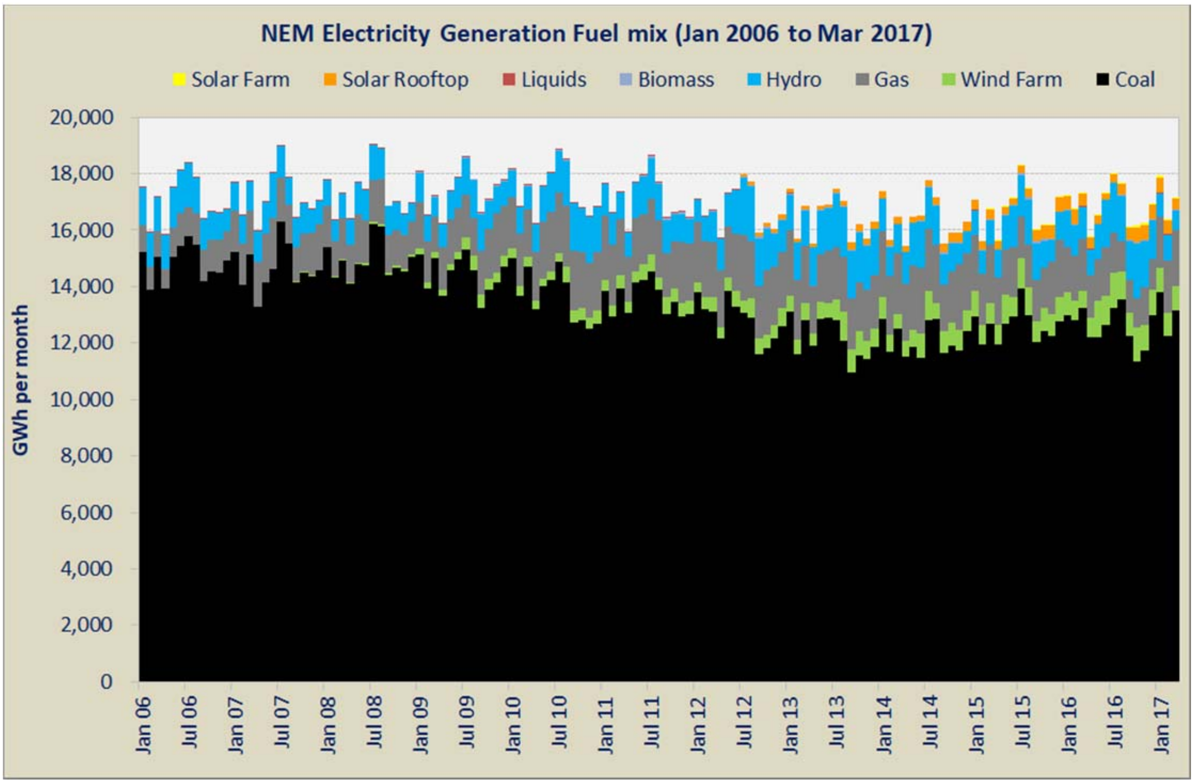
3.1. Why are South Australian prices typically higher than other states?

The power generation fuel mix is a major driver of wholesale market electricity prices.

Contrast the NEM fuel mix in Figure 21 with that of South Australia in Figure 22.

[31] 31 Mar 2016, Origin signs 15 year PPA 56 MW Moree Solar Farm (all energy & LGCs)
https://www.originenergy.com.au/about/investors-media/media-centre/origin-announces-landmark-moree-solar-farm-ppa-with-frv.html
8 May 2017, Origin signs 12 year PPA 530 MW Stockyard Hill Wind Farm (all energy & LGCs)
https://www.originenergy.com.au/content/origin-ui/en/about/investors-media/media-centre/origin-adds-530mw-of-renewable-energy-to-its-portfolio.html
3 August 2016, Hornsdale Wind Farm Stage 3 wins 20 year 109 MW Feed-in-Tariff in ACT Next Generation Renewables Auction
http://hornsdalewindfarm.com.au/hwf-stage-3-wins-a-109mw-offtake-agreement/

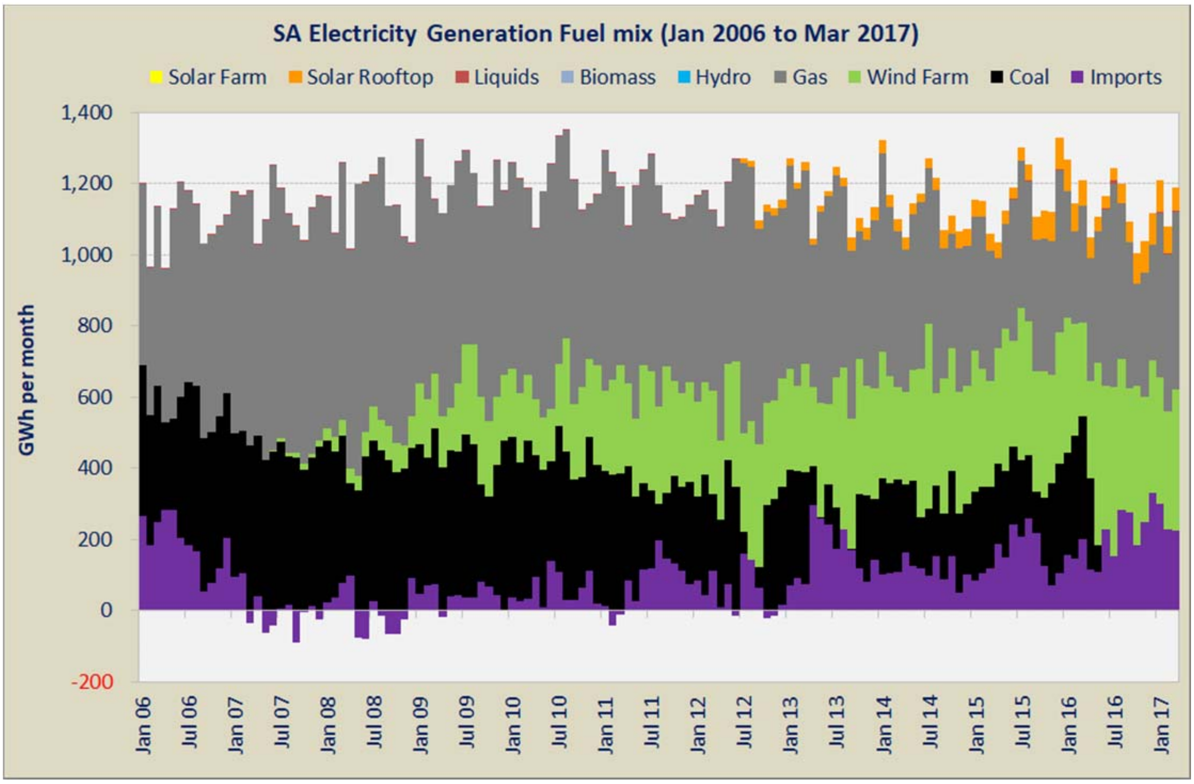
Figure 21 National Electricity Market Generation Fuel mix (January 2006 to March 2017)



The National Electricity Market (NEM), which commenced in December 1998, and currently comprises Queensland, New South Wales, ACT, Victoria, Tasmania and South Australia (all but Western Australia and the Northern Territory) remains dominated by coal-fired generation.

However, the implementation of state and federal government subsidies and environmental policies has seen an increase in gas-fired generation, supported in Queensland and New South Wales by the State Government Gas Electricity Certificates (GEC) scheme and New South Wales Greenhouse Abatement Certificates (NGAC) schemes respectively; and an increase in VRE supported by various environmental policies, taxes, subsidies and targets.

Figure 22 South Australian Generation Fuel mix (January 2006 to March 2017)



Historically, South Australia was reliant upon:

- relatively high cost, low quality Leigh Creek coal (for use at the Augusta Power Stations), with a high strip ratio, low calorific value and higher transport costs (250 km rail) compared to Victorian brown coal and New South Wales and Queensland black coal;
- gas-fired generation, a large proportion of which came from relatively inefficient thermal gas generators at the Torrens Island Power Stations (heat rate of ~12 GJ /MWh, compared to Combined Cycle Gas Turbines (CCGT) at Pelican Point with a heat rate of ~7.5 GJ /MWh)[32]; and
- imports from Victoria, initially under the Interchange Operating Agreement on favourable price terms prior to the commencement of the NEM, and subsequently based on the market bidding mechanism.

South Australia is now reliant on:

- Gas-fired generation (37% in the 12 months to 31 March 2017);
- Victorian imports (20%); and
- Intermittent renewables (40.5%).

3.2. South Australian reliance on gas-fired generation

3.2.1. Gas demand

South Australia relied on gas-fired generation to satisfy 37% of the state's electricity demand over the year to March 2017.

[32] http://www.euaa.com.au/files/documents/Schneider-Electric.pdf

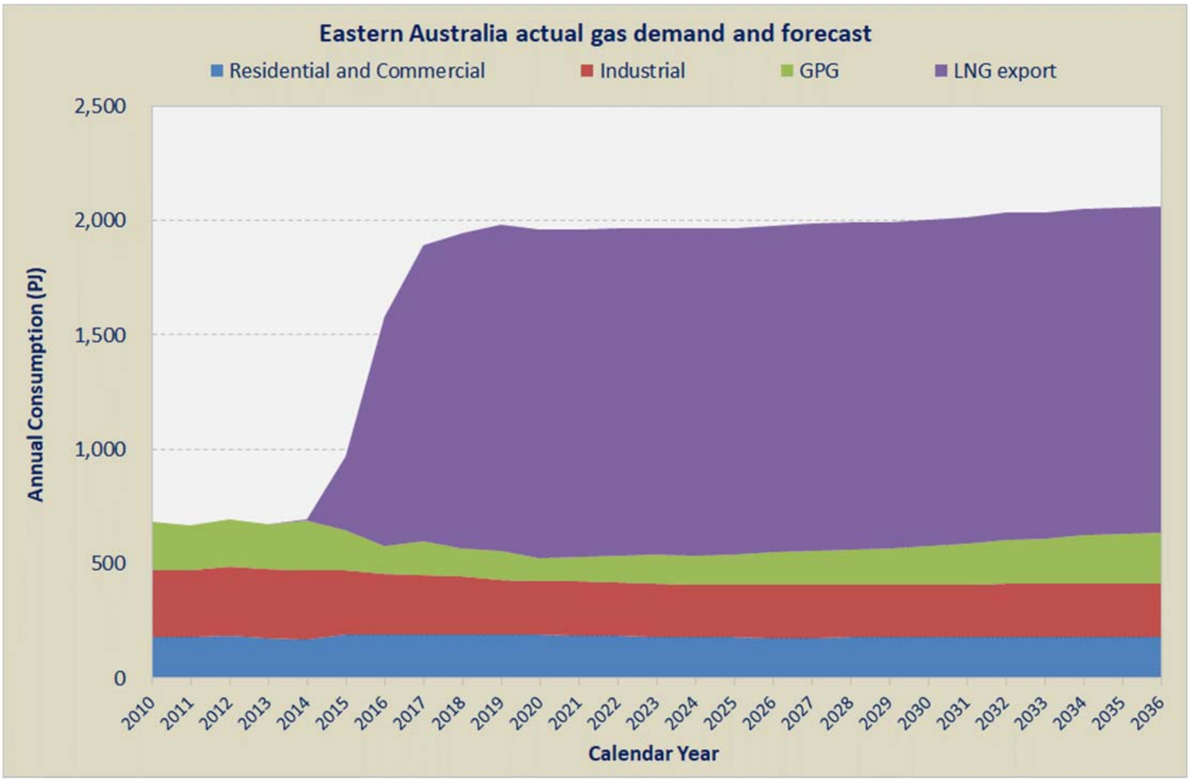
Demand for gas on the east coast of Australia has increased by 170% over 3 years from 2014 and continues to climb.

Prior to December 2014, gas produced in eastern Australia was consumed domestically, with about half consumed by industrial customers; about a quarter by domestic and commercial customers; and the remaining quarter by power generators.

Going forward, approximately two thirds of gas production from eastern Australia is forecast to be exported as LNG.

Figure 23 is based on data sourced from AEMO[33].

Figure 23 Eastern Australia actual gas demand and forecast



South Australia's reliance on gas-fired generation is increasing due to the withdrawal of coal-fired generation capacity from the South Australian and Victorian regions of the NEM, and an increased need to provide firming for intermittent renewables. The growth in intermittent grid connected wind power in South Australia (wind contributed 34.8% to South Australian demand in the year to March 2017) drives a need for schedulable generation that can provide flexible and responsive back up.

3.2.2. Gas prices

Gas contracts are negotiated bilaterally and confidentially, and consequently, gas contract pricing is opaque. However, it is generally understood amongst market participants that contract gas prices for gas-fired generation in South Australia (and elsewhere) have increased significantly in recent years.

Gas prices have increased due to both increased demand, and supply constraints. As discussed in this report, the establishment of the Liquid Natural Gas (LNG) export facilities in Gladstone (Queensland) has led to a massive tripling in demand for gas, the price of which is now linked to this export

[33] http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total

market. Coincidentally, supply constraints, in particular moratoria and other restrictions on gas exploration and development in New South Wales, Victoria, Tasmania and the Northern Territory (anti hydraulic fracturing or "fracking" and "shut the gate" campaigns), have further squeezed gas availability and driven up gas prices.

Increasingly, gas generators also require greater flexibility in gas commodity and gas haulage contracting in order to support the growth in VRE. Gas generators need to have their capacity ready and able to be dispatched (including fuel and fuel transport) when VRE is unavailable or VRE output is reduced. However, reduced domestic supply and increased export demand have resulted in gas contracts becoming more difficult to source, and contract conditions becoming more onerous and less flexible (e.g. higher rates of "take-or-pay"). This lack of flexibility is inconsistent with the market role that gas-fired generators are required to perform.

Figure 24 from the Core Energy Group NGRF (National Gas Forecasting Report) Gas Price Assessment to AEMO in October 2016 shows increasing projected average gas prices for power generation. These prices represent the Neutral Case in real 2016 AUD/GJ at the transmission pipeline delivery point in each region. For clarity, the New South Wales price in this forecast tracks Victorian price until 2016, and then shadows South Australian price from 2018.

Figure 24 Core Energy Neutral Case, real 2016 AUD/GJ forecast

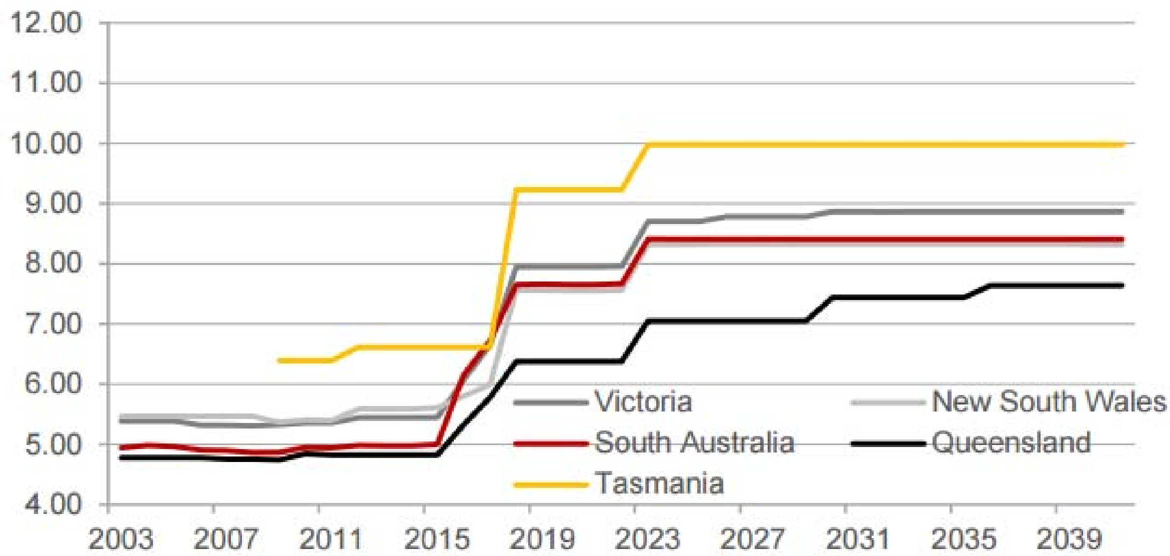
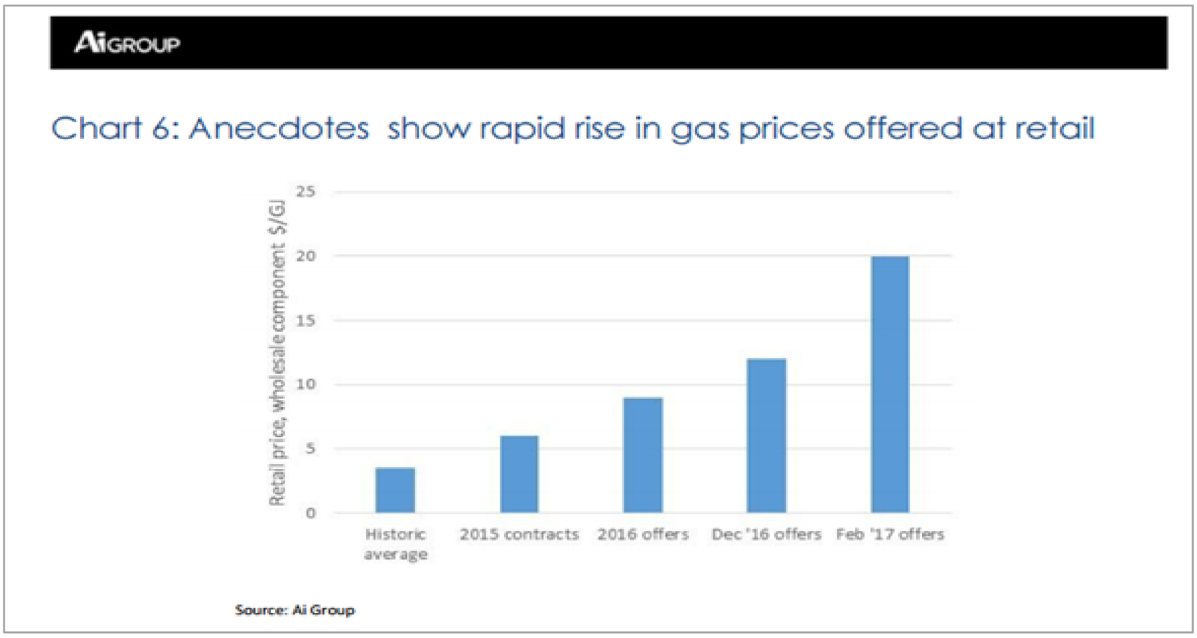


Figure 25, published by the Australian Industry Group (AIG) in February 2017, provides anecdotal evidence of gas pricing in contracts and offers reported by AIG members.

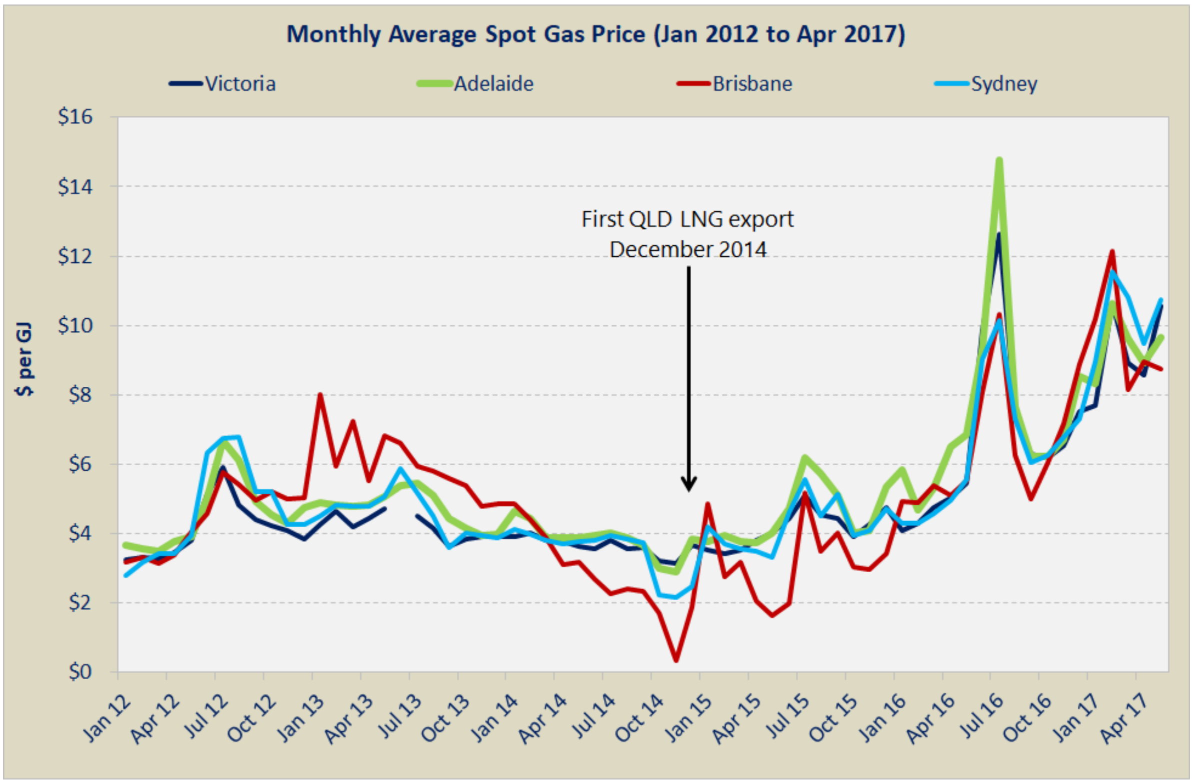
Figure 25 Australian Industry Group anecdotal gas price information from members[34]



With this lack of gas contract availability and flexibility, gas generators are more reliant on the spot gas market for gas purchases.

Figure 26 shows the upward trend in spot gas prices following the first exports of LNG from Queensland in December 2014.

Figure 26 East Coast gas actual spot prices (AEMO, NemSight)



[34] http://cdn.aigroup.com.au/Reports/2017/Energy_shock_report_Feb2017.pdf

The theme of increasing gas prices is consistent across these various market sources.

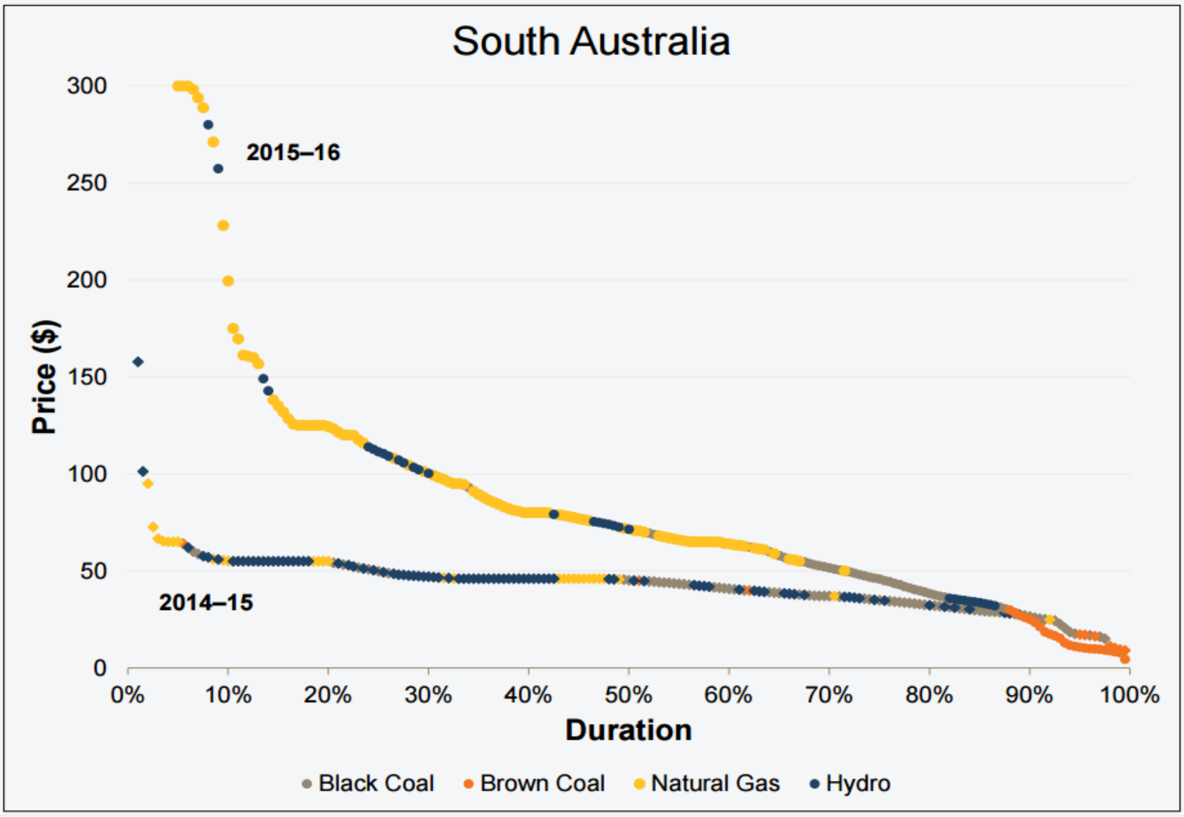
In the 2017 Gas Statement of Opportunities (GSOO)[35], AEMO has identified that gas-fired generators without a fully contracted fuel supply have been, and are continuing to face exposure to higher and more volatile spot gas prices. Further, as coal-fired generation retires, the market's reliance on gas-fired generation is increasing and thus electricity spot prices are becoming increasingly linked to spot gas prices.

AEMO goes on to provide evidence of more frequent spot price setting by gas-fired generation as the marginal generator across the NEM. The following AEMO chart (refer Figure 27) shows the comparison between spot price setting by generation fuel type in FY2015 and FY2016 in South Australia.

Two conclusions are evident:

- spot prices are higher in FY2016 than FY2015; and
- gas-fired generation is setting spot price most frequently.

Figure 27 SA price duration curve by price-setting fuel, 2014–15 compared to 2015–16 (AEMO GSOO, March 2017)



Whilst South Australia had a lack of black coal-fired generation and hydro assets during FY2015 and FY2016, the marginal (price setting) generator in South Australia at any time can be located interstate due to the existence of transmission interconnection across the NEM.

[35] http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf [page 22]

From FY2015 to FY2016 gas-fired generation replaced coal-fired generation and hydro as the primary spot price setting fuels in South Australia. This change was accompanied by a rise in spot prices in South Australia.

AEMO's analysis also demonstrates that this phenomenon has not been restricted to South Australia, as all mainland NEM regions have experienced a similar significant increase in gas-fired generation setting higher prices (comparing FY2015 to FY2016). AEMO's analysis found that across the NEM, gas-fired generation set the electricity spot price more frequently in FY2016 than in FY2015. The increasing influence of gas-fired generation as the price setting technology can be seen in the following AEMO price duration charts for Victoria, New South Wales and Queensland (Figure 28, Figure 29 and Figure 30 respectively).

All three regions show a similar outcome to South Australia, where spot prices are higher in FY2016 than FY2015; and gas-fired generation is setting spot price most frequently.

Figure 28 VIC price duration curve by price-setting fuel, 2014–15 compared to 2015–16 (AEMO GSOO, March 2017)

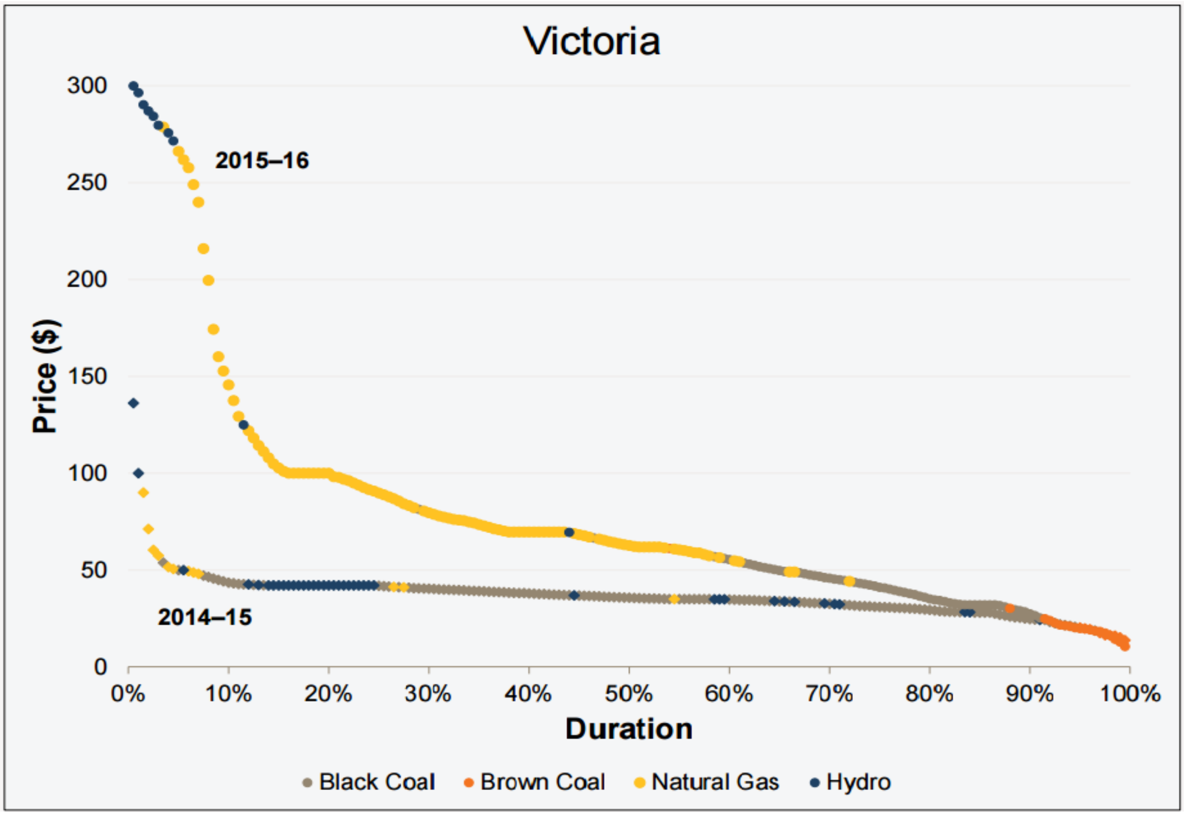


Figure 29 NSW price duration curve by price-setting fuel, 2014–15 compared to 2015–16 (AEMO GSOO, March 2017)

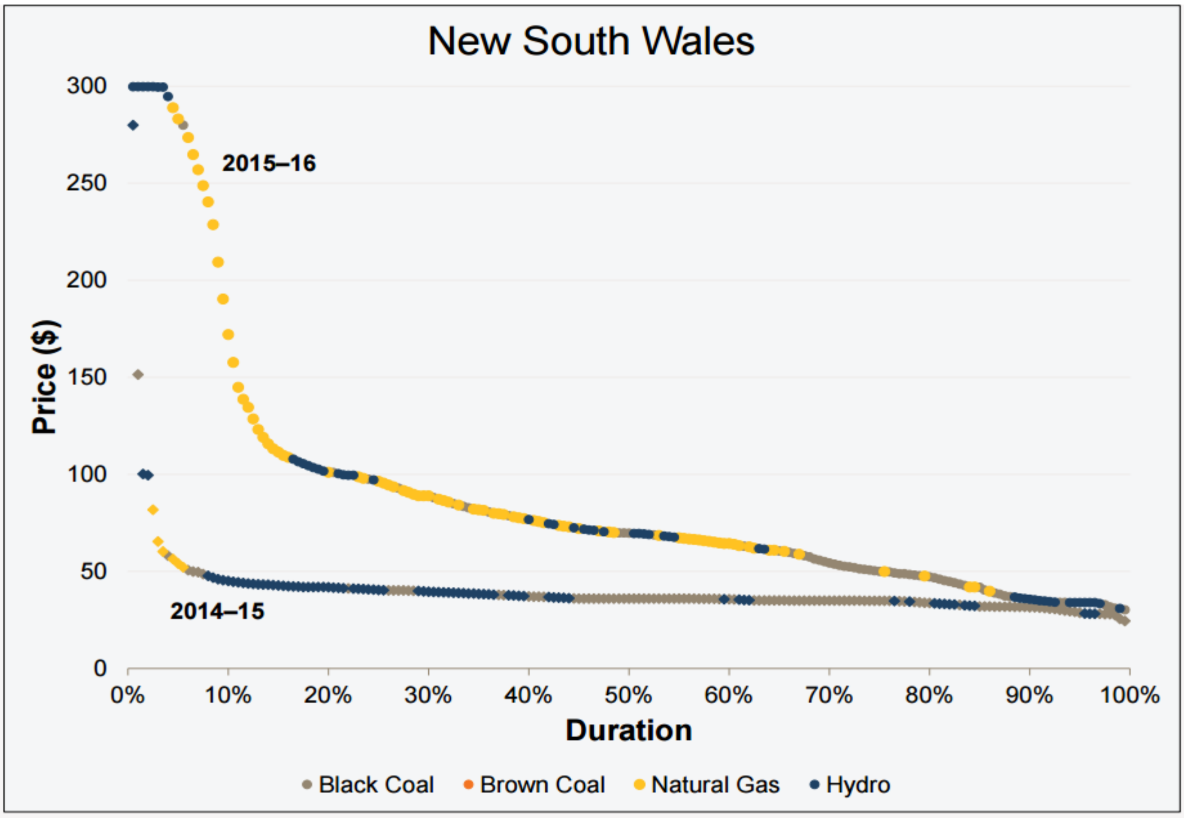
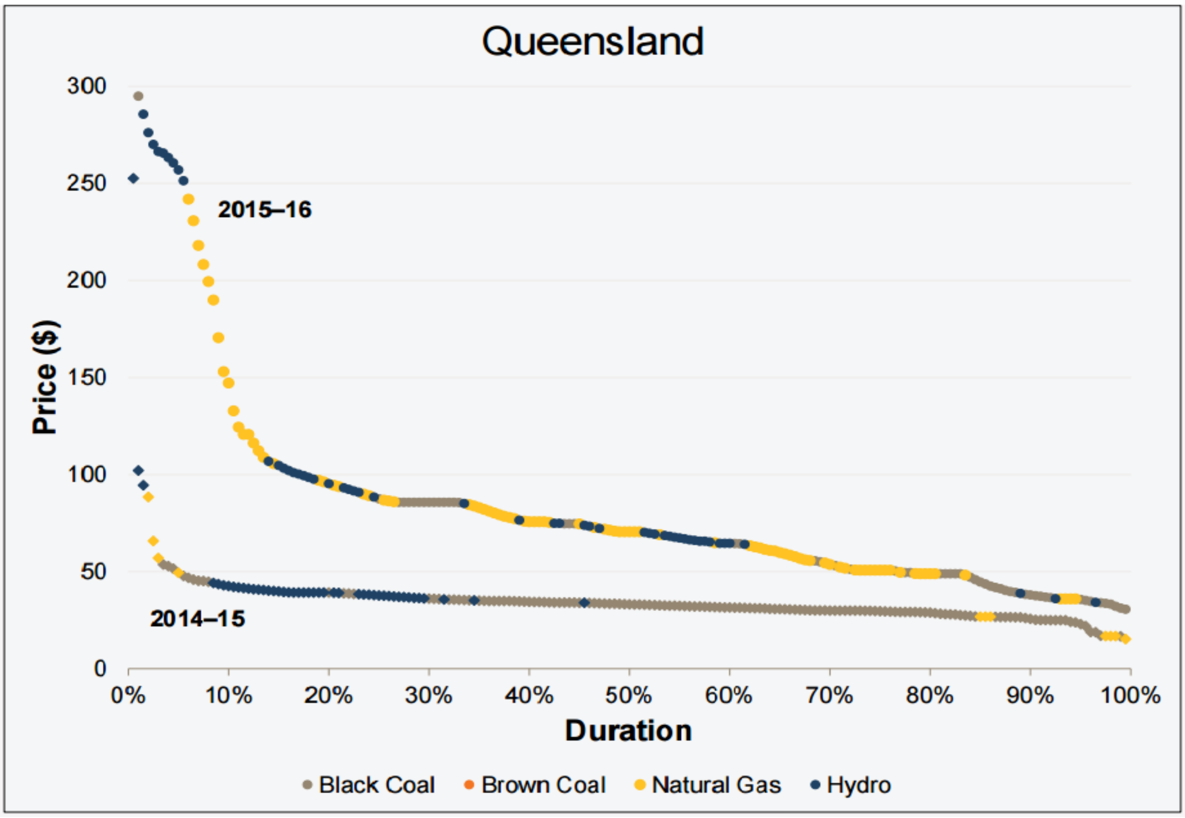


Figure 30 QLD price duration curve by price-setting fuel, 2014–15 compared to 2015–16 (AEMO GSOO, March 2017)



3.3. South Australian reliance on VIC interconnection (and the retirement of Hazelwood)

South Australia has two interconnectors with Victoria, the 200 MW capacity Murraylink in the Riverland, and the 600 MW Heywood interconnector in the south-east of South Australia.

South Australia relied on Victorian imports to satisfy 20% of South Australian demand in the year ended 31 March 2017.

In simple terms, and with some exceptions:

- when market generators' offer prices are lower in Victoria than South Australia, then power flows from east to west across these interconnectors to South Australia; and
- when market generators' offer prices are lower in South Australia than Victoria, then the flow reverses from west to east.

Consequently, electricity supply/demand conditions in Victoria and interconnector availability have an important impact on electricity supply and electricity prices in South Australia.

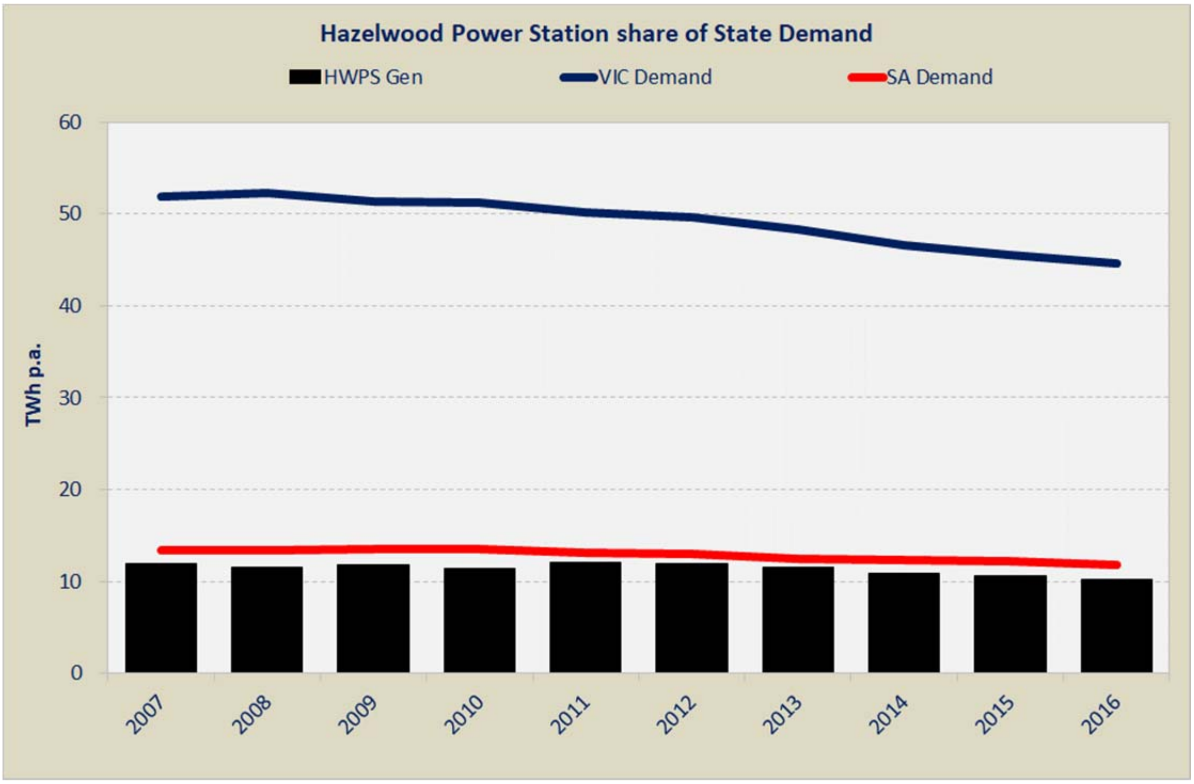
Victoria has always had the advantage of abundant low-cost brown coal for power generation, and has therefore typically been a net exporter of electricity to New South Wales, Tasmania and South Australia. The Victorian fuel mix today compared to a decade ago is largely unchanged in terms of coal and gas share, and the growth in renewables (to a 10% share) has coincided with Victorian exports increasing from 6% to 17% (refer Table 24).

Table 12 Victorian Fuel Mix Changes as a percentage of Victorian State Demand

Fuel Mix	VIC CY2006 (TWh %)	VIC 12 months ended 31/03/17 (TWh %)	Change
Coal	99.3%	97.2%	minor fall
Gas	1.6%	2.3%	minor rise
Hydro	5.4%	7.6%	up a bit, but fluctuates
Wind		7.8%	new
Solar		2.2%	new
Imports/(Exports)	(6.3%)	(17.2%)	almost tripled

The fuel mix represented in Table 12 does not take account of the retirement of the Engie/Mitsui owned eight unit 1,600 MW Hazelwood Power Station in Victoria, which occurred at the end of March 2017. This significant event in Victoria has also impacted South Australian electricity supply and prices.

Figure 31 Hazelwood Power Station production (energy) share of Victorian Demand and compared to South Australian Demand from CY2007 to CY2016



Hazelwood has served approximately 23% of Victoria's electricity demand over the past decade (refer Figure 31). Relative to South Australia, Hazelwood has produced the equivalent of almost 90% of South Australian demand over the same period.

As noted by AEMO in the 2017 GSOO[36]:

"The 1,600 MW Hazelwood Power Station accounts for about:

- *14% of total firm capacity in Victoria*
  Firm capacity is the capacity AEMO conservatively assumes will be available during peak demand conditions (with 85% confidence of exceedance). In Victoria, wind generation capacity is currently discounted 93% in this calculation (i.e. 7% is considered "firm" by AEMO).
- *12% of combined firm capacity across Victoria and South Australia.*
- *4% of total firm capacity installed in the NEM.*

In 2015–16, Hazelwood Power Station produced 10,326 GWh (22% of Victoria's operational demand) of electricity.

As Hazelwood Power Station retires from the NEM, the remaining generators will need to increase their generation to meet electricity demand, or new generation will be required to make up the difference.

The demand scenarios studied in the 2017 GSOO all take the retirement of Hazelwood Power Station into account, and assume that other generation types – including GPG (gas powered generation) *– will be operating instead."*

[36] http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf [page 25]

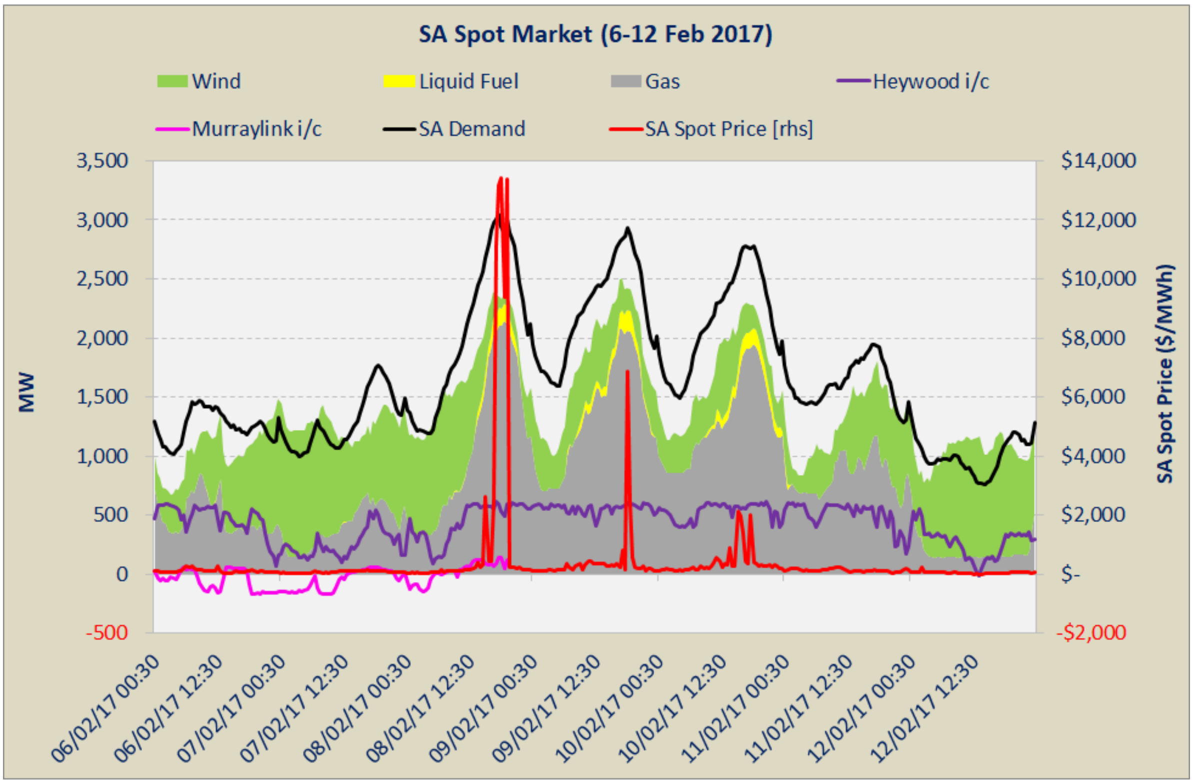
3.4. South Australian reliance on variable wind generation

Renewables, and in particular large-scale grid connected wind generation, satisfied 35% of South Australia's electricity demand last year.

3.4.1. How does large scale wind interact with the market?

Figure 32 shows some of the typical patterns now observed in South Australia in the spot electricity market (including some examples of extreme price spikes).

Figure 32 SA Demand, spot price, generation fuel mix and interconnect flows by ½ hour from the 6th to 12th of February 2017



The key series in Figure 32 are as follows:

- The black line represents South Australian demand (half-hourly resolution over the week commencing midnight Sunday night/Monday morning on 6th February 2017 to midnight Sunday night on 12th February 2017).
- The purple and fuchsia lines show imports from Victoria into South Australia across the Heywood and Murraylink interconnectors. Negative values indicate that South Australia was exporting to Victoria.
- The grey area represents gas-fired generation in South Australia.
- The green area represents wind generation in South Australia.
- The yellow area represents liquids or diesel-fired generation in South Australia, which only run at very high demand/high price times.
- The red line is the half-hourly spot market price (right hand scale).

With respect to weather temperature and demand, the week commenced with mild weather (maximum temperature was in the high teens to low 20's) and electricity demand was low. By Wednesday 8th February, maximum temperature increased to 42 degrees. The daily maximum temperature stayed around 40 degrees on Thursday and Friday and dropped back to the low 30s on Saturday 11th February.

If we examine Tuesday the 7th February with maximum temperature reaching 31 degrees, South Australian demand peaked in the evening at just under 1,800 MW. Wind was contributing approximately 700 MW at peak demand time, after generating as high as 1,100 MW earlier that morning. Imports from Victoria fluctuated between approximately 0 MW and 600 MW throughout the day, but had not been constrained. South Australian gas generation peaked at approximately 700 MW including Torrens Island, Pelican Point, Osborne and Ladbroke Grove power stations. The time-weighted average spot price for the day was $71/MWh.

Contrast the next day, Wednesday the 8th February with maximum temperature rising to over 42 degrees. Demand peaked in the evening at over 3,000 MW which was 70% higher than the previous day. Wind generation contributed less than 100 MW at peak demand time after being as high as 1,000 MW earlier in the day. South Australia was importing over 730 MW from Victoria up to the constraint limits of the interconnectors at that time. South Australian gas generation peaked at over 2,100 MW, with all gas-fired power stations running (except the second unit at Pelican Point), plus an additional 150 MW of diesel-fired generation in service. Engie's second unit at Pelican Point was not directed to start by AEMO, and AEMO ordered rotational load shedding in South Australia. The time-weighted spot price averaged nearly $1,500/MWh for the day, which was over 20 times the previous day's average, with a half-hourly maximum price on the day of $13,440/MWh (over $13 per kWh).

In South Australia, there is a strong negative correlation between high wind generation output and pool prices. From CY2008 to CY2016 the wind-weighted spot price has represented (on average) a 20% discount to the time-weighted average spot price in South Australia.

Over the same period and prior to the retirement of the Augusta coal-fired power stations, the coal-fired generation weighted spot price reflected (on average) a 2% discount to the time-weighted average spot price; and the gas generation weighted spot price reflected (on average) a 40% premium to the time-weighted spot price, reinforcing the contemporary market dynamic observed in South Australia.

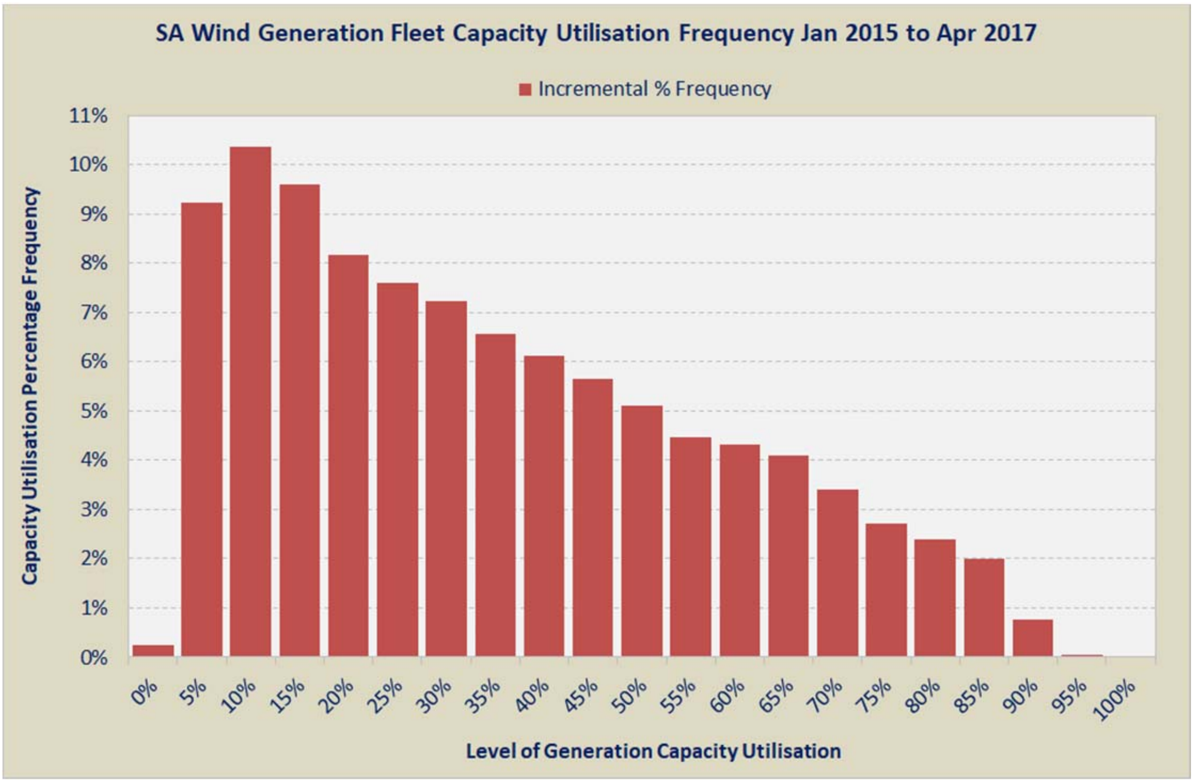
In general, when the wind is blowing, spot prices are low, imports ease from Victoria, sometimes South Australia exports to Victoria, and prices are sometimes negative. When the wind isn't blowing, imports from Victoria increase, gas-fired generation increases, and prices rise (significantly in some cases).

3.4.2. South Australian wind generation fleet capacity utilisation performance

Over the period from January 2015 to April 2017, the South Australia wind generation fleet (refer Figure 33):

- never generated at 100% capacity;
- generated less than 4% of the time at between 80% and 100% of capacity;
- generated 5% of the time at greater than 75% of capacity;
- generated 24% of the time at 50% capacity utilisation or above; and
- generated 76% of the time at below 50% capacity utilisation.

Figure 33 SA Wind Generation Fleet Capacity Utilisation Frequency January 2015 to April 2017



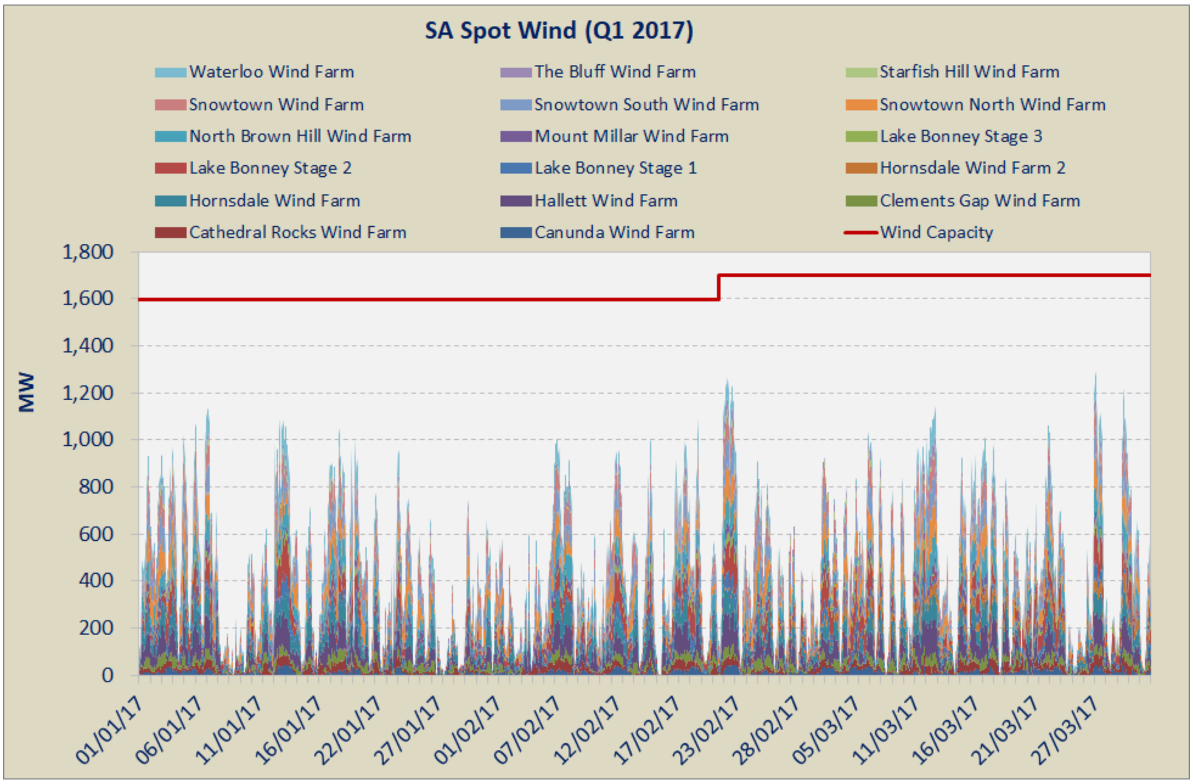
According to the AEMO regional generation information pages, with respect to South Australia:

"Due to the intermittent nature of wind, wind generation capacities are de-rated to account for the output most likely to be available during times of maximum demand. AEMO refers to this as the "firm contribution" from wind generators during peak periods. These figures are 9.4% of the installed capacity during summer, and 7.0% during winter, based on AEMO's analysis of historical wind output over summer 2011-12 to 2015-16, and winter 2011 - 2015."[37]

The following charts (refer Figure 34 and Figure 35) show the intermittent nature of South Australian wind farm generation by trading interval in the first quarter of CY2017. The first chart shows the stacked aggregate wind farm output by half hour compared to the maximum capacity of the wind farm fleet in South Australia. The second chart shows aggregate wind farm output compared to South Australian demand by half hour over the same period.

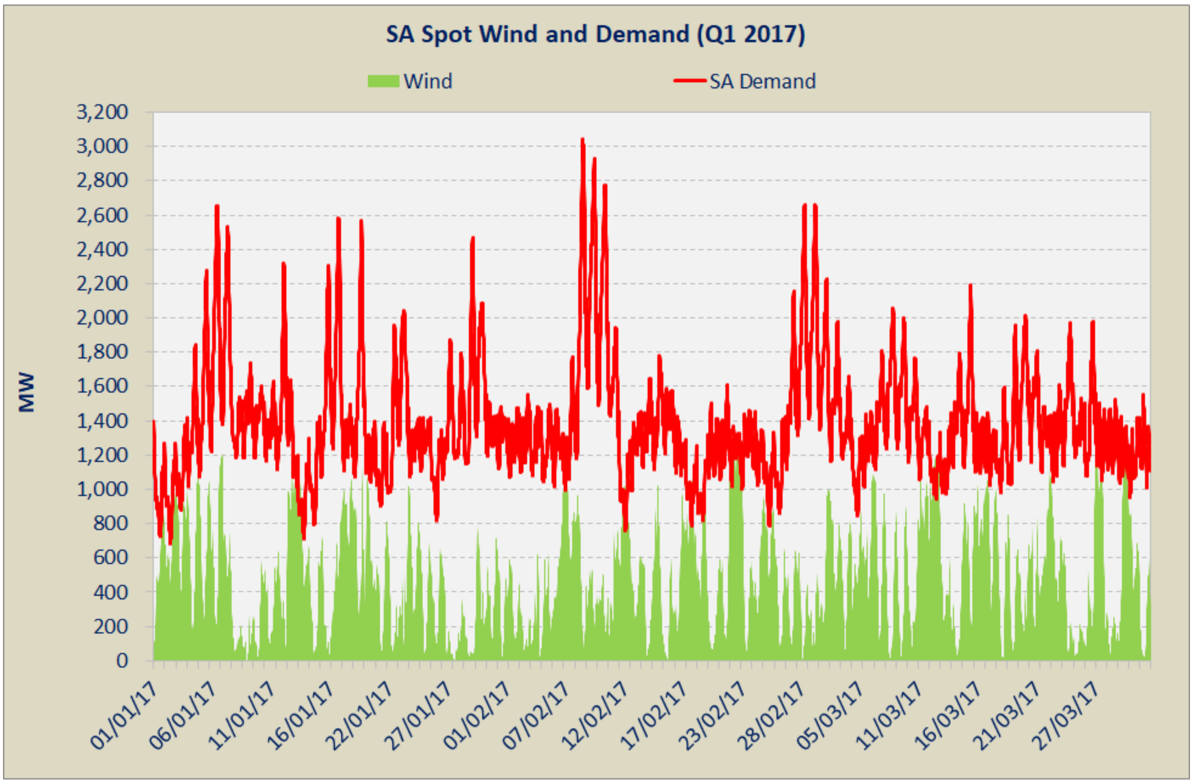
[37] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information Generation_Information_SA_27022017.xlsx [Summer Scheduled Capacities]

Figure 34 SA Wind Generation by half hour compared to wind maximum capacity January 2017 to March 2017 (Q1 2017)



The correlation between SA demand and aggregate generation from the SA wind portfolio is low and negative. The correlation coefficient between SA demand and wind was -0.2 over the period 1 January 2015 to 30 April 2017.

Figure 35 SA Wind Generation by half hour compared to wind maximum capacity January 2017 to March 2017 (Q1 2017)



3.5. South Australian system operation

The withdrawal of synchronous generation, or its replacement by non-synchronous variable generation, has reduced the availability of services that are required to ensure the secure operation of the electricity system in South Australia, including frequency control, system re-start, inertia and rate of change of frequency.

Reduced supply of these services has also increased the cost of ancillary services in South Australia compared to other NEM regions.

One month prior to the South Australia System Black event on 28 September 2016, AEMO released the South Australian Electricity Report[38] (South Australian Advisory Functions) to provide information about South Australia's electricity supply and demand, including a review of Frequency Control Ancillary Services, System Restart Ancillary Services, inertia, and rate of change of frequency.

3.5.1. Frequency Control Ancillary Services (FCAS)

AEMO reviewed the South Australian supply and demand of Frequency Control Ancillary Services (FCAS) and determined that under NEM system normal operation conditions where FCAS can be sourced from anywhere in the NEM (interconnectors available and operating), that existing registered FCAS facilities are adequate to meet demand. AEMO also determined that where a credible risk of islanding of South Australia exists (South Australia disconnected from the NEM) then FCAS supply was adequate locally in South Australia if all FCAS facilities are operating at that time.

The AEMO report also states:

"AEMO is observing a reduction in the available capacity of FCAS across the NEM. Changes to the operating patterns of registered FCAS facilities, or closure of these facilities, would reduce future FCAS supply. Reduction in the available FCAS capacity in South Australia would result in additional constraints on interconnector transfers, when a credible risk of separation exists.

For the operation of South Australia as an island, all registered FCAS providers need to be online and operating to be able to supply some types of FCAS. Withdrawal of any FCAS facilities, or any FCAS facilities being offline during an islanding event, would increase the risk of widespread load shedding.

Further connection of non-synchronous generation may increase the demand for FCAS in South Australia, and unless this generation has FCAS capability this could create additional supply gaps.

In South Australia, FCAS provision is presently from thermal generators. Other generation technologies may be capable of providing FCAS if configured appropriately."

3.5.2. System Restart Ancillary Services (SRAS)

With respect to System Restart Ancillary Services (SRAS), the AEMO report found that South Australia currently has enough local sources of SRAS to meet the system restart standard, but AEMO identified that the market is tight. Historically, SRAS has been sourced from hydro, gas and coal-fired generation. AEMO's report states that other generation technologies may be able to configure plant to be able to contribute to the provision of SRAS.

3.5.3. Inertia and rate of change of frequency

Synchronous generators produce power through machines that rotate at a speed that is synchronised to the frequency of the power system providing inherent inertia that contributes to the stability of the system by dampening the impact of frequency changes.

[38] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2016/2016_SAER.pdf

Reduced inertia from the withdrawal of synchronous generation leads to higher rates of change of frequency resulting from generator trips or major load changes, increasing the risk of further system instability and further generation plant or load trips.

AEMO's report states that the South Australian system is more susceptible to high rate of change of frequency following the upgrade to increase the capacity of the Heywood Interconnector with Victoria, because this increased the contingency that South Australia needs to then cover the interconnect failure, and because of a decrease in system inertia due to the closure of South Australia's coal-fired Northern Power Station.

AEMO's report identifies that:

"In the rare event of the unexpected concurrent loss of both Heywood Interconnector lines, there is a high risk of a region-wide blackout in South Australia. South Australia has separated from the rest of the NEM due to such non-credible contingency events four times since 1999. The likelihood that a region-wide blackout would follow a non-credible islanding event has increased as the region has become more reliant on energy imports, and wind and rooftop photovoltaic (PV) generation, to meet demand."

3.6. South Australian situation in summary:

3.6.1. Security and Reliability

South Australia has suffered a number of significant system events over the past 18 months, including:

- November 2015: Heywood interconnector tripped causing separation between South Australia and Victoria. No power was lost, but FCAS prices rose significantly to approximately $27 million for the month to 10 Nov 2015, or almost 60 times the typical FCAS cost in South Australia for a similar period.
- September 2016: System black event where 850,000 customers lost supply.
- December 2016: Heywood interconnector outage due to transmission failure in Victoria. In South Australia, 200,000 customers faced power restrictions (browned out) and BHP's Olympic Dam mine suffered a 5 hour outage.
- December 2016: Storm damage to the distribution network in South Australia where 155,000 customers lost supply, half for more than 12 hours and 1,000 lost power for 4 days.
- February 2017: High demand from South Australian heat wave conditions led to rotational load shedding and 90,000 customers lost supply.
- March 2017: Torrens Island Power Station fire led to a sudden loss of supply, but imports from Victoria increased to compensate. The power system was not in a secure operating state for 5 hours, but customers did not lose supply.

The changing generation fuel mix has presented greater technical challenges to the operation of the electricity system in South Australia. South Australia now relies on non-synchronous intermittent renewables for over 40% of its generation and the contribution of renewables continues to increase. Over one third (35%) of this generation came from wind farms over the past year.

South Australia has approximately 1,700 MW of wind capacity, but it is rare (5% of the time) for aggregate wind production to exceed 75% of that capacity. When the wind isn't blowing, back up is required to cover physical supply. Since the retirement of Augusta Power Stations, this comes down to reliance upon gas-fired generation capacity within South Australia, and imports from Victoria.

3.6.2. Affordability

Spot and contract electricity prices have risen significantly across the NEM and particularly in South Australia.

South Australia is more reliant upon gas-fired generation than the other NEM regions. Gas prices have increasingly driven spot electricity market prices and spot price volatility higher in South Australia (and increasingly, in the wider NEM).

Lack of firm generation capacity that can be scheduled contributes to a shortage of firm hedging capacity in the financial market. This shortage of hedging supply increases hedging risk premiums in South Australia, and leads to greater market concentration as fewer electricity retailers (particularly those without physical generation assets in South Australia) are active in the market, further increasing prices to South Australian electricity consumers.

3.6.3. Sustainability

South Australia is leading the country in the rate of emissions reduction from power generation, and remains second only to Tasmania in absolute emissions intensity terms (due to Tasmania's legacy hydro power capacity).

3.6.4. Investment Certainty

Higher spot and contract electricity market prices (compared to the other NEM states), arguably makes South Australia the most attractive NEM region for investment in power generation. However, South Australia has not attracted commercial investment in a mix of generation assets that will ensure a secure, reliable and affordable electricity supply.

There has been a dearth of investment in synchronous generation throughout the NEM. Recent investment in generation supply has been focussed on variable renewable generation projects that are able to access supplementary LGC income. There has been a recent rush to develop these large-scale, primarily wind and solar farm projects, with a view to maximising LGC income from the renewable energy scheme that is currently scheduled to expire in 2030.

The South Australia Government has determined that the national energy market has "failed", and in response has announced the South Australia Energy Plan.

3.7. South Australian Energy Plan

The South Australian Energy Plan[39] is the South Australian Government's response to what it defines as national energy market failure.

The South Australian Energy Plan vision is *"To source, generate and control more of South Australia's power supply in South Australia so we can increase self-reliance and provide reliable, competitive and clean power for all into the future."*

The key elements and goals of the plan are:

- **Battery storage and renewable technology fund**, to provide South Australia with large-scale storage for renewable energy so that power is available when it is needed, beginning the transformation to next generation renewable technology.
- **New gas power plant**, to provide South Australia with a government-owned source of emergency electricity generation (up to 250 MW gas generator, plus temporary energy

[39] http://ourenergyplan.sa.gov.au/assets/our-energy-plan-sa-web.pdf

security measure of up to 200 MW of diesel fired generation via Electranet and SA Power Networks).

- **Local power over national market**, to give South Australia greater local power over national market operators and privately-owned generators. The Minister for Energy will have powers of direction.
- **Energy Security Target**, to create new investment in cleaner energy to increase competition, put downward pressure on prices and provide more energy system stability. The target will require energy retailers to source more electricity from generators using South Australian resources.
- **South Australian gas incentive**, to encourage South Australia to source and use more South Australian gas to generate its own electricity, increasing the state's self-reliance. The measures include grant supported gas exploration and a royalties-for-landowners scheme where landowners receive royalties where their property overlies a petroleum field which is brought into production.
- **New generation for more competition**, to create more electricity generation to increase competition and put downward pressure on prices. The South Australian Government will use its own purchasing power when contracting electricity supply for hospitals, schools and government services to seek new generation capacity for South Australia.

4. Electricity Supply / Demand Balance

4.1. AEMO Supply/Demand Balance

AEMO is the body responsible for planning and operation of the NEM. AEMO publishes an annual Electricity Statement of Opportunities (ESOO) report, which provides an assessment of supply adequacy in the NEM over the next 10 years and highlights opportunities for investment in power generation. AEMO assesses supply adequacy in relation to meeting the NEM reliability standard which sets an expectation that demand will be met 99.998% of the time (the NEM Reliability Standard specifies that the level of expected unserved energy should not exceed 0.002% of operational consumption per region, in any financial year[40]).

4.1.1. 2016 ESOO

AEMO's 2016 ESOO[41] supply adequacy and projected timing assessment of any potential breach of the reliability standard for each NEM region is summarised in Figure 36.

Figure 36 Summary of projected supply adequacy - ESOO 2016

Region	Includes announced generation capacity withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced generation capacity withdrawals only	
	Weak economic growth, with COP21		Neutral economic growth, with COP21		Strong economic growth, with COP21		Neutral economic growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
NSW	Beyond 2025–26	N/A	2025–26	0.0031%	2022–23	0.0095%	2025–26	0.0025%
QLD	Beyond 2025–26	N/A	Beyond 2025–26	N/A	2022–23	0.0029%	Beyond 2025–26	N/A
SA	2020–21	0.0021%	2019–20	0.0028%	2018–19	0.0029%	Beyond 2025–26	N/A
TAS	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A
VIC	Beyond 2025–26	N/A	2024–25	0.0021%	2023–24	0.0026%	Beyond 2025–26	N/A

4.1.2. 2016 ESOO Update (November 2016)

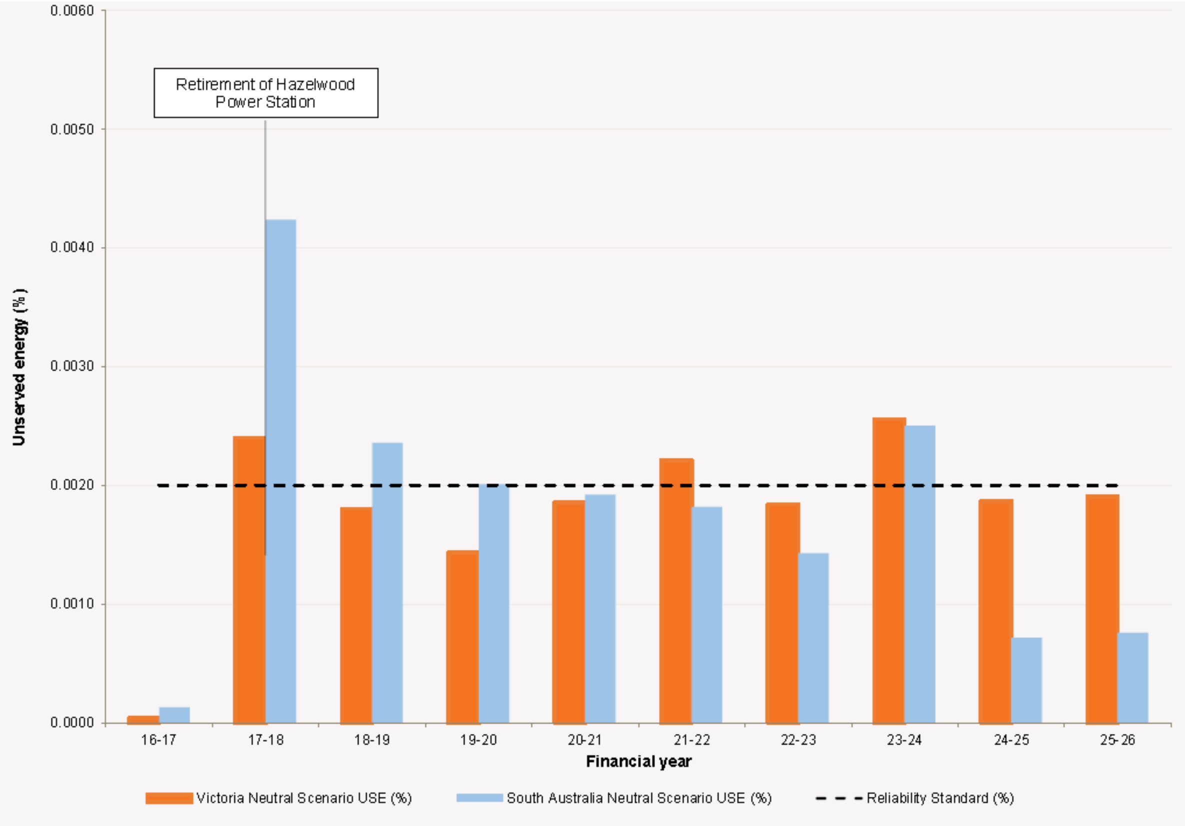
AEMO published an update[42] to the ESOO in November 2016 following Engie's announcement that Hazelwood Power Station in Victoria would be withdrawn from service by 31 March 2017.

A key metric in the ESOO is the Low-Reserve Condition (LRC) point. LRC points indicate when additional generation capacity (or a demand-side response) may be required in each NEM region in order to maintain reliable supply consistent with the NEM Reliability Standard.

The withdrawal of Hazelwood is now projected to result in potential breaches of the reliability standard and an LRC point in Victoria and South Australia from 2017–18 under a Neutral Growth scenario as shown in Figure 37.

[40] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2016/2016-NEM-ESOO-Methodology.pdf
[41] 2016 NEM Electricity Statement of Opportunities v2.0 - 21 September 2016 accessed
[42] Update: Electricity Statement of Opportunities Published: November 2016

Figure 37 Victoria and South Australia supply adequacy (Neutral Growth scenario)



Both South Australia and Victoria are forecast to breach the reliability standard in 2017-18. This is due in part to:

- the retirement of Hazelwood power station;
- South Australia's dependence on support from Victoria;
- high coincidence of maximum demand between the two regions; and
- limited support from New South Wales to Victoria due to constraints invoked when Murray Hydroelectric Power Station approaches maximum capacity.

After the initial projected breach in 2017–18, forecast unserved energy is reduced in both Victoria and South Australia due to a forecast decrease in operational demand in both regions and the addition of committed power stations. Regardless, unserved energy levels are projected to remain close to or above the reliability standard through the 10-year forecast period.

4.1.3. Other AEMO updates

AEMO also produces the National Electricity Forecast Report (NEFR) which provides electricity consumption forecasts for each NEM region and for a range of consumer and economic outlooks over a 20 year period.

The last published NEFR (released in June 2016) found that consumption of grid-supplied electricity was forecast to remain flat for the next 20 years (despite a projected 30% growth in population and average growth in the Australian economy). Over the 20 year period, demand was forecast to increase from an estimated 183,258 GWh in 2015–16 to 184,467 GWh in 2035–36. This flat growth forecast was attributed in part to households acquiring energy efficient appliances, which offset increasing use of electric appliances, and also strong growth in the installation of rooftop photovoltaic (PV) generation which is projected to increase from current levels by 350% by 2035–36 (equivalent to 11% of current operational consumption). The 2016 NEFR forecast maximum and minimum demand values are shown in Figure 38.

Figure 38 Extract from AEMO NEFR 2016 - Forecast Maximum and Minimum Demand[43]

Table 1 Maximum demand for summer and winter[7] (10% POE[8]) (GW)

	2016–17		2021–22		2026–27		2035–36	
State	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
New South Wales	14.2	12.3	14.1	12.5	14.0	12.8	14.1	13.2
Queensland	9.6	8.5	10.0	9.2	10.3	9.7	10.6	10.5
Queensland (excl. LNG)	8.8	7.9	9.0	8.2	9.2	8.7	9.5	9.6
South Australia	3.1	2.5	2.8	2.5	2.6	2.5	2.6	2.5
Tasmania	1.5	1.8	1.5	1.8	1.5	1.8	1.5	1.9
Victoria	9.9	7.9	9.7	8.2	9.5	8.4	9.4	8.7

Table 2 Minimum demand[9] (90% POE) (GW)

State	2016–17	2021–22	2026–27	2035–36
New South Wales	4.9	5.0	4.3	2.9
Queensland	4.3	4.1	3.4	1.8
Queensland (excl. LNG)	3.7	3.2	2.4	0.8
South Australia	0.6	0.3	0.0	-0.4
Tasmania	0.8	0.8	0.7	0.6
Victoria	3.1	2.5	1.8	0.5

Subsequent the publication of the 2016 NEFR, AEMO released an update in March 2017[44] which included revised Queensland forecasts of annual operational consumption as well as maximum and minimum demand. AEMO based these new forecasts on more recent information on electricity usage from Queensland's Boyne Island Smelter and the Liquefied National Gas (LNG) sector. The revised Queensland operational, maximum and minimum demand forecasts from 2015-16 through to 2030 are shown in Figure 39. The March revision reduces the expected amount of electricity forecast to be used in the production of aluminium and LNG. Consequently, maximum and minimum demand, and annual energy consumption forecasts have been reduced for Queensland, effective from March 2017 until the mid-2020s. Thereafter the forecasts recover to normal levels.

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[43] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf
[44] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2017/Update-to-2016-National-Electricity-Forecasting-Report-NEFR.pdf

Figure 39 Extract from AEMO Update to the 2016 NEFR

Table 1 Annual operational consumption for the Neutral sensitivity (GWh)

State	2016–17	2021–22	2026–27	2035–36
Queensland updated	50,488	51,753	53,014	51,888

As for annual consumption, Queensland maximum and minimum demand forecasts are lower in each year until the mid-2020s after which they recover to normal levels, as shown in Table 2 and Table 3.

Table 2 Maximum demand for summer and winter[2] (10% POE[3]) for the Neutral sensitivity (GW)

	2016–17		2021–22		2026–27		2035–36	
State	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Queensland updated	9.6	8.4	9.9	9.0	10.3	9.7	10.6	10.5

Table 3 Minimum demand[4] (90% POE) for the Neutral sensitivity (GW)

State	2016–17	2021–22	2026–27	2035–36
Queensland updated	4.2	4.0	3.4	1.8

5. Evolution of Electricity Generation in the NEM

In the late 1940s and early 1950s, Australia faced serious electricity supply shortages, initially due to the inability to install generation during wartime, and subsequently due to the post-war economic boom (with its corresponding demand for electricity). These shortages were made worse by prolonged and severe droughts on the hydro-electric catchments of Tasmania, and coal shortages in all the mainland states[45].

As a result of these supply shortages, Australia experienced a rapid expansion of its generation fleet over the following four decades.

As much as 90% of Australia's existing power generation fleet was constructed between the 1960s and the turn of the century. The investment during this period was led by publicly-owned state government-controlled electricity commissions and corporations, e.g.

- in Victoria, the State Electricity Commission of Victoria developed brown coal-fired power stations located in the Latrobe Valley (e.g. Hazelwood, Loy Yang and Yallourn Power stations);
- in New South Wales, several black coal-fired power stations (e.g. Liddell, Eraring, Bayswater) were commissioned by the New South Wales State Government around mines located in the Hunter Valley; and
- in Queensland, the Queensland Electricity Commission (QEC) led the development of numerous black coal-fired power stations.

The 1,680 MW Gladstone Power Station is a notable exception in that whilst it was initially built by the QEC, it was subsequently sold to a joint venture between a number of private sector entities, including Rio Tinto Ltd (42.125%) and NRG Energy Inc. (37.5%). However, all of the station's output is currently contracted to CS Energy (a QLD government-owned corporation) under a long-term Power Purchase Agreement (PPA) which operates until 2029. As part of the contractual arrangements, CS Energy is required to supply electricity to the Boyne Smelter, leaving approximately 800 MW to trade into the wholesale electricity market. Whilst the terms of the PPA are confidential, typically PPAs shield the owners of the power station from wholesale market risk, which is borne by the off-taker[46].

In Victoria, similar arrangements were entered into, under which the State Electricity Commission of Victoria (SECV) purchases electricity from the wholesale market and on sells this electricity to the Portland aluminium smelter. As noted on the SECV's website, "[the] SECV manages a complex array of derivatives to manage its extensive financial exposure to the electricity pool price and to the price of aluminium on global markets. The SECV also purchases futures contracts on the Sydney Futures Exchange."[47]

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[45] A Dictionary on Electricity a joint project of CIGRE and AHEF contribution on Australia / prepared for the Australian National Committee of CIGRE, by a Panel under general editorship of Frank Brady.
[46] http://www.csenergy.com.au/userfiles/file/Gladstone%20Power%20Station.pdf
[47] http://www.secv.vic.gov.au/about/

Since the turn of the century, the private sector has led the majority of new power generation developments. To summarise:

- coal-fired generation represents approximately 20% of all new capacity developed since 2000, of which 68% of all new coal-fired generation was developed by government controlled entities (e.g. Kogan Creek, Tarong North[48] and Callide C[49] power stations); with the balance (32%) developed by private sector (e.g. Millmerran and Redbank power stations);
- gas-fired OCGT and CCGT represents approximately 51% of all new capacity developed since 2000;
- distillate generation represents approximately 2% of all new capacity developed since 2000; and
- renewable generation represents approximately 27% of all new capacity developed since 2000.

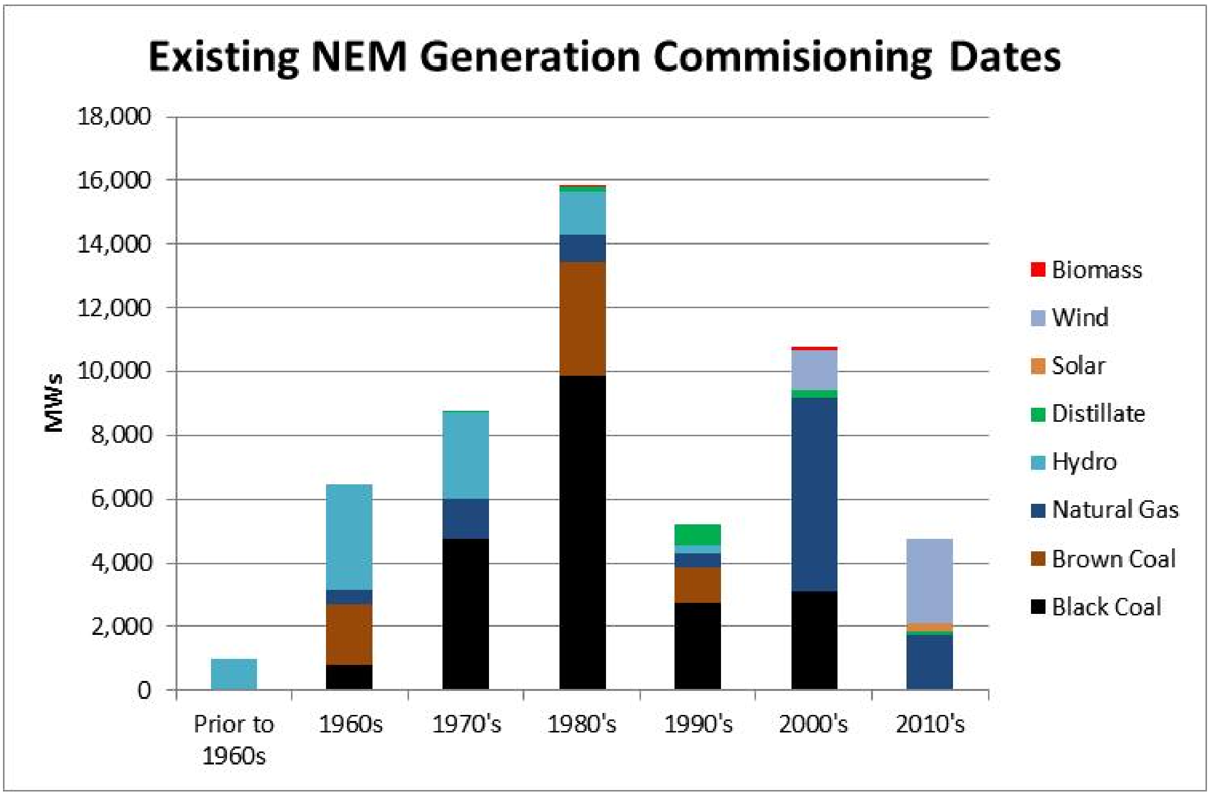
However, most of this private sector investment occurred as a result of state and federal government stimulus. For example, schemes like the Queensland Gas Electricity Certificates (GEC) scheme, which commenced in January 2005, required electricity retailers and other liable parties to source 13 percent of the electricity they sell or use in Queensland from gas-fired generation. The GEC scheme facilitated much of the investment in the existing gas-fired generation fleet in Queensland. Similarly, in New South Wales, the state government's Greenhouse Gas Abatement Scheme (GGAS), which commenced in 2003, aimed to lower greenhouse gas emissions in New South Wales by imposing obligations on New South Wales electricity retailers and other parties (such as large electricity users) to reduce their attributable greenhouse gas emissions by purchasing New South Wales Greenhouse Abatement Certificates (also known as NGACs). The NGACs stimulated a wide range of accredited abatement projects, including investment in a number of gas-fired generation projects in New South Wales.

5.1. Ageing existing fossil fuel fleet (coal, gas and liquid fuel)

Much of the existing NEM generation fleet has been in service for more than 30 years. Approximately 75% of this fleet relies on thermal power station technology which has a notional useful engineering/economic life of up to 50 years (refer Figure 40). Accordingly, most of this existing fleet is likely to be retired and will need to be replaced within the next two decades.

[48] 50% of Tarong North was sold to the private sector after completion and then reacquired in 2009 by Tarong Energy (now Stanwell Corporation)
[49] 50% of Callide C was sold to the private sector after completion

Figure 40 Existing NEM Generation Commissioning Dates



Decisions to retire generation capacity are based on a range of factors, including the condition of the asset, the cost competitiveness of the asset, the cost of future overhauls and sustaining capital investment, the role of the asset in the owner's portfolio of generation assets, the financial position of the owner, the cost of rehabilitation, and other company policies.

In some cases, the owners of existing NEM generators have already closed or announced closure of their respective power stations (refer Table 11).

In the absence of specific announcements, a relevant guide is the theoretical useful (engineering/economic) life of the generation technology. Useful life is an estimate of when the repairs of a technology become so frequent, extensive and expensive that replacement is a more attractive investment decision.

Typical useful engineering/economic lives for a range of technologies are shown in Table 13.

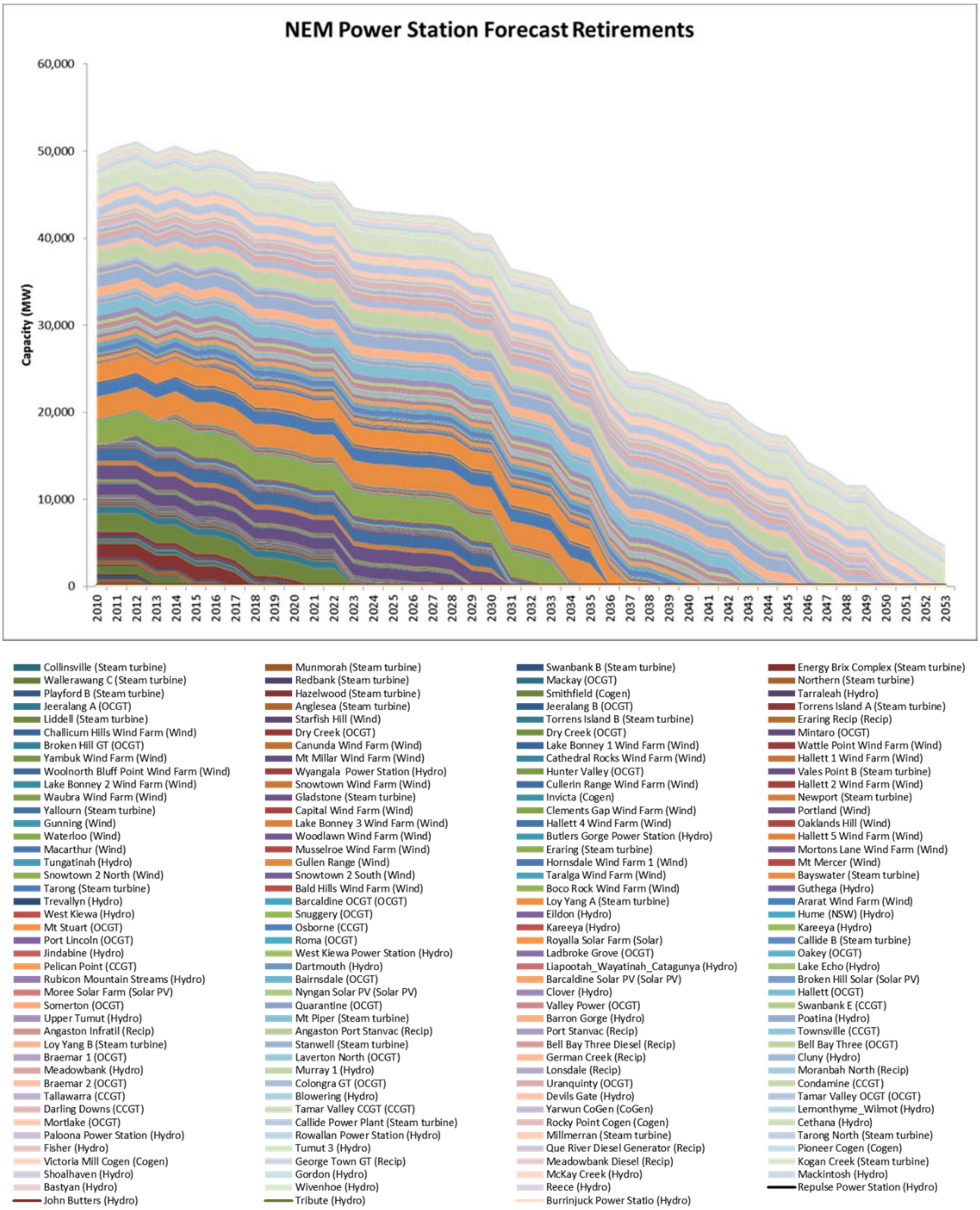
Table 13 Assumed useful economic life

Generation Type	Economic Life (Years)
Battery Storage	10
Wind	20
Solar PV[50]	25
Biomass	50
CCGT	40
OCGT/Engine (Low Capacity Factor)	40
Black/Brown coal thermal plant	50

[50] Solar PV inverters will require replacement more frequently.

The retirement outlook for existing NEM generation is shown in Figure 41 and is based on either public announcements or, in the absence of any announcement, an estimate of the remaining useful engineering/economic life using the values in Table 13.

Figure 41 NEM power station forecast retirements



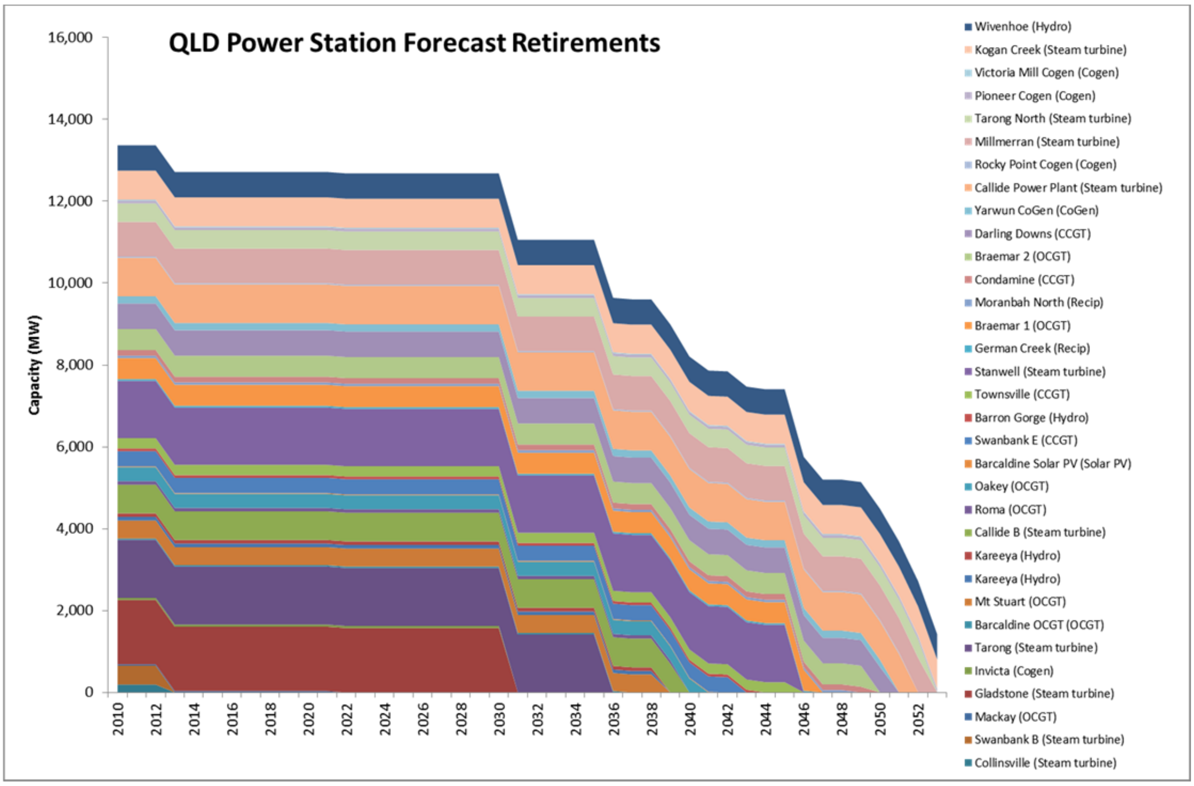
Approximately 50% of the current available power generation fleet is forecast to retire within the next 20 years (by around 2037-38). These retirements are predominantly coal-fired power stations and represent approximately 69% of retirements with an aggregate capacity of approximately 25GW (refer Table 14).

Table 14 NEM forecast power station retirements by 2036-37

Generation Type	Retired MW	% of 2016/17 fleet
Black Coal	11,824	24%
Brown Coal	5,264	11%
Natural Gas	2,927	6%
Hydro	541	1%
Distillate	147	0%
Solar	0	0%
Wind	3,924	8%
Biomass	51	0%

In Queensland, approximately 24% of the current available power generation fleet is forecast to retire by around 2036-37, and 55% by 2045 (refer Figure 43).

Figure 42 QLD power station forecast retirements



The retirement timeline for the Queensland fleet reflects the more recent commissioning dates for many of Queensland coal-fired power stations relative to other generators across the NEM.

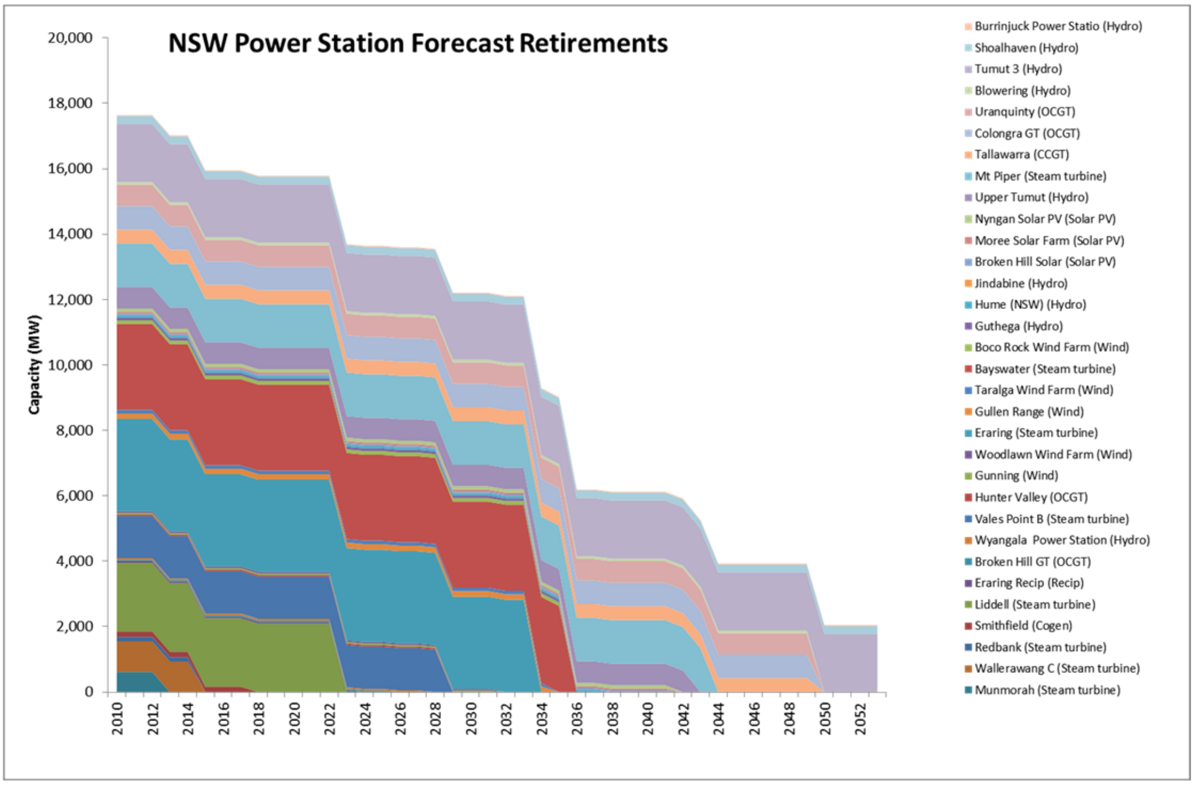
Forecast retirements by 2036-37 are almost entirely made up of coal-fired generation capacity, representing 96% of total forecast Queensland retirements (refer Table 15).

Table 15 QLD forecast power station retirements by 2036-37

Generation Type	MW	% of 2016/17 fleet
Black Coal	2,990	23.5%
Brown Coal	0	0.0%
Natural Gas	37	0.3%
Hydro	0	0.0%
Distillate	34	0.3%
Solar	0	0.0%
Wind	0	0.0%
Biomass	51	0.4%

In New South Wales, approximately 60% of the current available power generation fleet is forecast to retire by 2036-37 (refer Figure 43).

Figure 43 NSW power station forecast retirements



Forecast retirements by 2036-37 consist almost entirely of coal-fired power stations (refer Table 16), and represent approximately 9 GW of capacity.

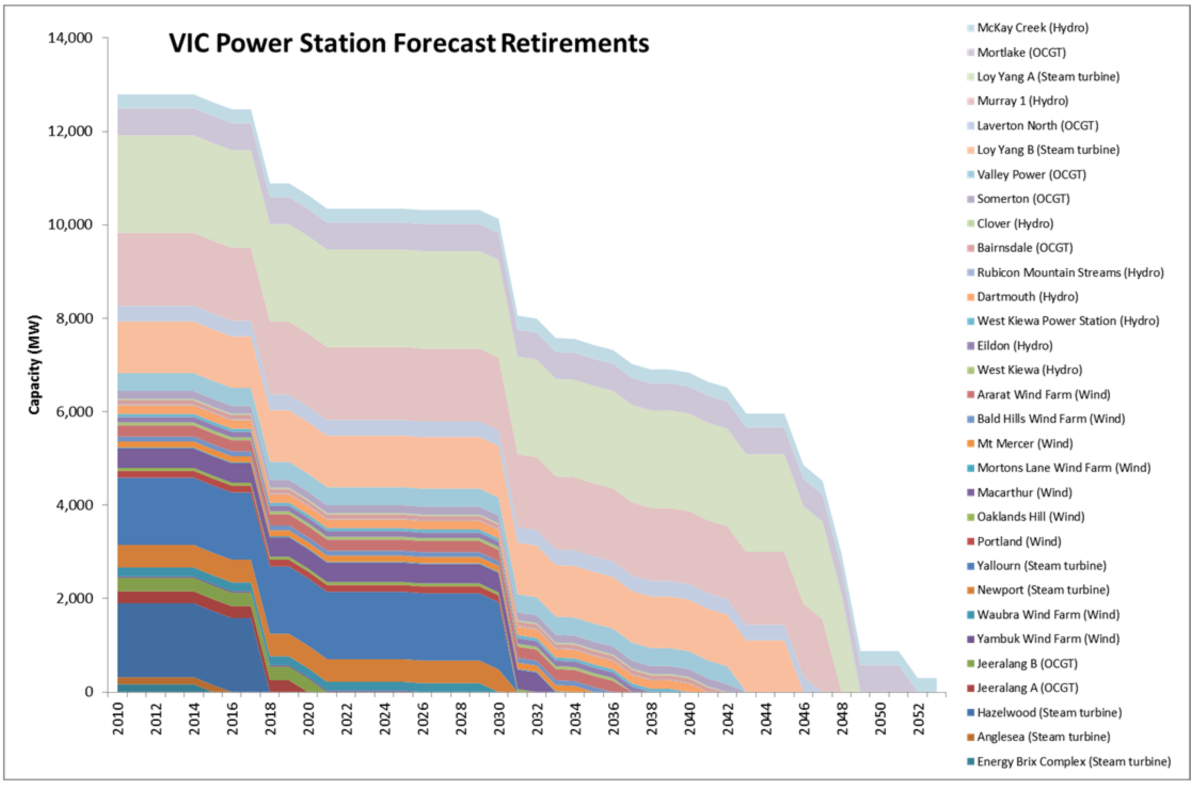
Replacement of this amount of capacity in these timeframes is not a trivial task. For context, the total capacity required is broadly equivalent to the entire existing Queensland generation fleet, and the estimated replacement cost is in the order of $30B.

Table 16 NSW forecast power station retirements by 2036-37

Generation Type	MW	% of 2016/17 fleet
Black Coal	8,834	55.4%
Brown Coal	0	0.0%
Natural Gas	166	1.0%
Hydro	129	0.8%
Distillate	147	0.9%
Solar	0	0.0%
Wind	481	3.0%
Biomass	0	0.0%

In Victoria, approximately 44% of the current available power generation fleet is forecast to retire by 2036-37 (refer Figure 44).

Figure 44 VIC power station forecast retirements



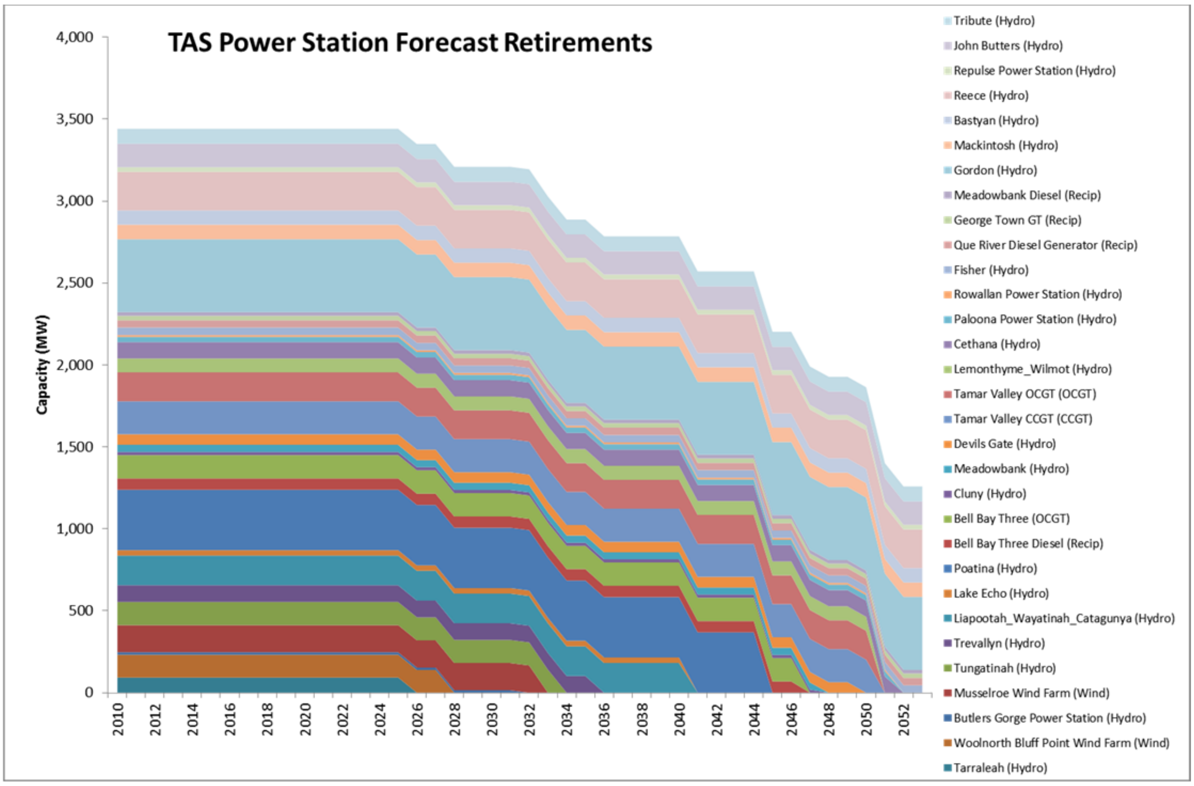
Forecast retirements in Victoria by 2036-37 consist of approximately 3 GW of coal-fired generation capacity and approximately 1 GW of gas-fired generation capacity. In addition to these fossil fuel power stations retirements, a number of wind farms are also forecast to be at end of life (refer Table 17).

Table 17 VIC forecast power station retirements by 2036-37

Generation Type	MW	% of 2016/17 fleet
Black Coal	0	0.0%
Brown Coal	3,024	24.2%
Natural Gas	1,028	8.2%
Hydro	61	0.5%
Distillate	0	0.0%
Solar	0	0.0%
Wind	1,337	10.7%
Biomass	0	0.0%

In Tasmania, approximately 19% of the current available power generation fleet is forecast to retire by 2036-37 (refer Figure 45).

Figure 45 TAS power station forecast retirements

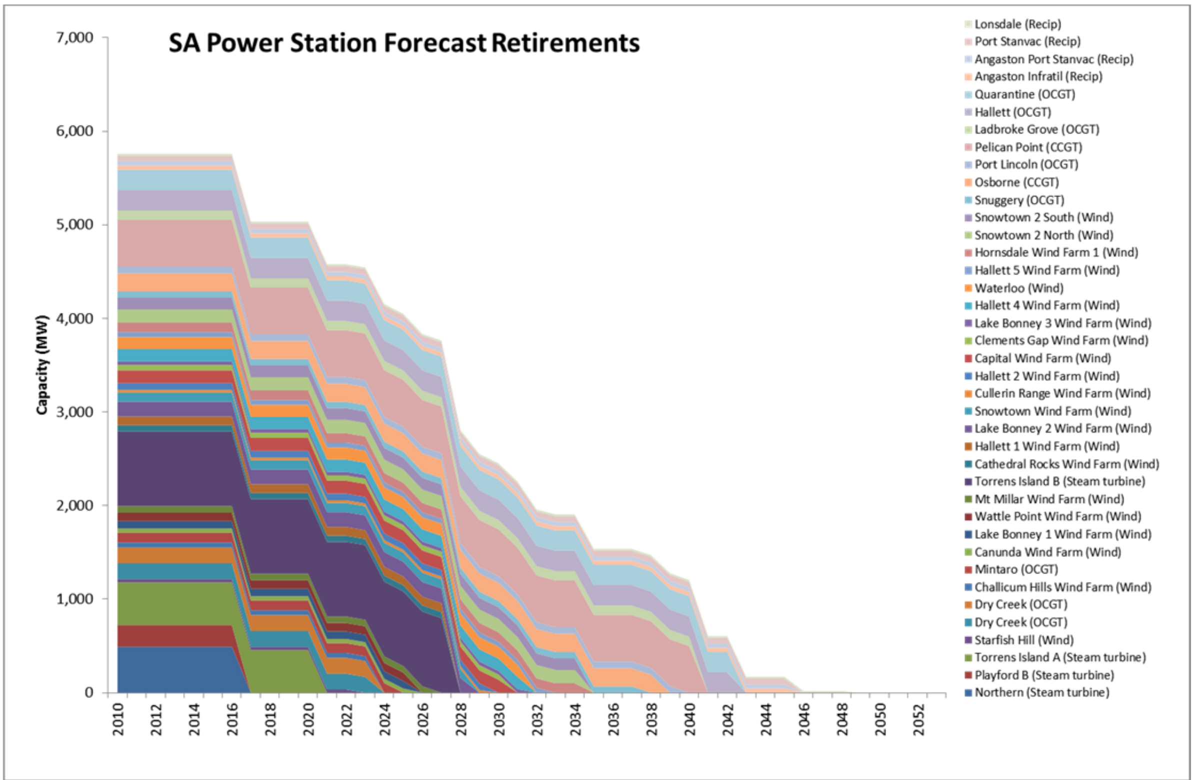


Forecast retirements by 2036-37 in Tasmania consist of 350 MW of the hydro generation fleet, and 305 MW of existing wind generation (refer Table 18).

Table 18 TAS forecast power station retirements by 2036-37

Generation Type	MW	% of 2016/17 fleet
Black Coal	0	0.0%
Brown Coal	0	0.0%
Natural Gas	0	0.0%
Hydro	350	10.2%
Distillate	0	0.0%
Solar	0	0.0%
Wind	305	8.9%
Biomass	0	0.0%

Figure 46 SA power station forecast retirements



Forecast retirements by 2036-37 in South Australia consist of 1,697 MW of the gas-fired generation fleet, and 1,801 MW of the existing wind farm capacity.

Note, this does not include the 723 MW of coal-fired generation which retired in 2016.

Table 19 SA forecast power station retirements by 2036-37

Generation Type	MW	% of 2016/17 fleet
Black Coal	0	0.0%
Brown Coal	0	0.0%
Natural Gas	1,697	33.7%
Hydro	0	0.0%
Distillate	0	0.0%
Solar	0	0.0%
Wind	1,801	35.8%
Biomass	0	0.0%

5.2. Need for New Generation

AEMO forecasts a Low Reserve Condition (LRC) in SA and Victoria from 2017/18 but this condition may be deferred with the development of committed power stations and reduced operational demand in these regions. However, unserved energy levels are projected to remain close to or above the reliability standard.

Development of a new HELE USC coal-fired power station in Victoria would relieve this condition (in the absence of any other retirements).

In NSW, under the neutral economic growth scenario, AEMO forecast a LRC in 2025/26. Since this announcement, AGL has announced the planned closure of the Liddell Power Station in 2022, which is likely to bring forward the LRC condition to this point in time.

Development of a new HELE USC coal-fired power station in NSW would relieve this condition (in the absence of any other retirements).

In QLD, under the neutral economic growth scenario, AEMO do not forecast a LRC within the forecast period (i.e. the next LRC occurs sometime beyond 2025/26). However, under the high economic growth scenario, a LRC is forecast to occur in 2022/23.

6. Future of NEM Generation Plant Characteristics

The NEM deploys a mix of generation technologies, each with different attributes, to respond to fluctuating electricity demand.

Generators are required to exhibit many capabilities and characteristics in order to respond to system load changes and other ancillary service requirements, across all time intervals, from seconds, to days, to seasons.

Base load generation, which is required to operate continuously over extended periods (24 hours per day, seven days per week, over many consecutive months), has historically been provided by coal-fired power stations and to a lesser extent, natural gas-fired combined cycle gas turbine (CCGT) generation. Base load generators typically have low variable operating costs and are designed to operate in continuous operation roles. Base load generators also provide ancillary services to maintain key technical characteristics of the system (e.g. frequency control, voltage control, network loading and system restart).

Generators with the ability to start quickly, such as natural gas or distillate-fired open cycle gas turbine generators, or hydro power, typically operate at peak demand times when wholesale prices are higher.

Intermittent generation, such as wind and solar, operate only when weather conditions are favourable. In a stable and secure system, deployment of intermittent generation is limited by the amount of available base load and peak generation which can cycle and adjust its output to support the changing output of the intermittent generation.

6.1. Relationship between intermittent and fossil fuel generation

In July 2016, The National Bureau of Economic Research (NBER) published a research paper titled "Bridging The Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion"[51] (BTG) which considered the relationship between the role of fossil fuel based power generation in supporting renewable energy investments.

The NBER BTG study considered the deployment of these two technologies in 26 OECD countries between 1990 and 2013, and established the relationship between VRE deployment and the deployment of fast reacting fossil fuel generation (or hydro to the extent further hydro can be developed) to support the variable output of renewable energy. It also confirmed the substantial indirect costs of renewable energy integration, and highlighted the complementarity of investments in different generation technologies required for a successful "decarbonisation" process.

The NBER BTG study found that over the long-term, the relationship between new investment in fast reacting fossil fuel and VRE capacity has been almost a one-to-one (0.88%) increase, that is a 1% increase in the generation capacity share of fast reacting fossil fuel plant was associated with 0.88% increase in VRE capacity in the long run. It found that, in the absence of viable economic storage options, intermittent renewable energy integration into electrical networks was only possible in the presence of fast-reacting mid-merit fossil-fuel based technologies, which provide reliable and schedulable back-up capacity to hedge against the variability of intermittent generation.

The NBER BTG study recommended that the policy debate must recognise the high correlation between deployment of fast reacting fossil fuel generation and renewable energy in order to avoid serious challenges to the security of electricity supply in the coming years. The technical and financial

[51] Bridging The Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion? (Verdolini, Vona, Popp) Working Paper 22454 http://www.nber.org/papers/w22454

system costs (i.e. pricing both back-up and ancillary services) associated with the deployment of VRE also need to be considered, and must be factored into the cost of delivered energy. Addressing current policy deficiencies in this regard (e.g. unfunded back-up, ancillary services) appears as a key priority of a sound energy policy.

Unlike some existing coal-fired power stations, modern day HELE coal-fired plants are fast reacting and can provide back up support to variable renewables. HELE coal-fired plant has flexibility performance characteristics equivalent to the most modern gas-fuelled CCGT plants, including the ability to change output at comparable rates (as shown in Figure 47 [52]).

Figure 47 Typical flexible parameters HELE PC and gas fuelled CCGT

Figure 20 • Typical flexibility parameters for coal- and gas-fuelled power plants

Parameter	Units	NGCC new build*	Hard coal new build	Existing hard coal (optimised)
Capacity	MW	800	800	300
Minimum load/nominal load	%	~60%	~25-40%	~20%
Mean load change rate**	% min	~3.5	~3***	~3

* Standard operation of two gas turbines and one steam turbine
** With respect to nominal load
*** In the lower load range (25 to 40%) the load change rate differs from this value
Source: RWE

Figure 21 • Natural gas plant operational flexibility

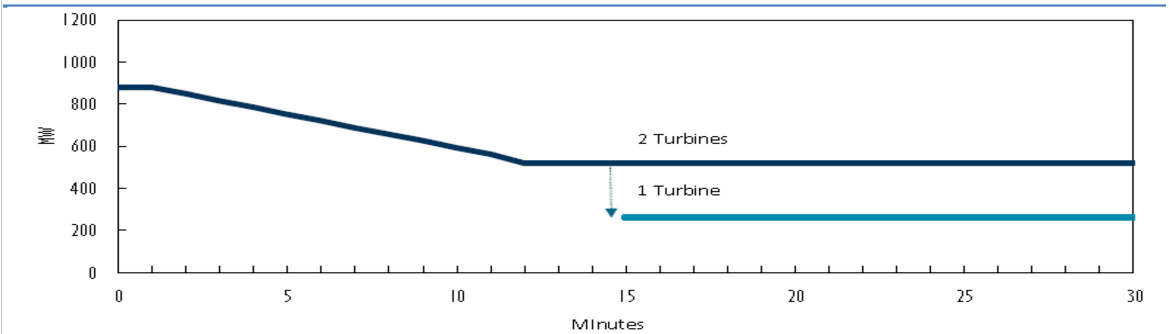
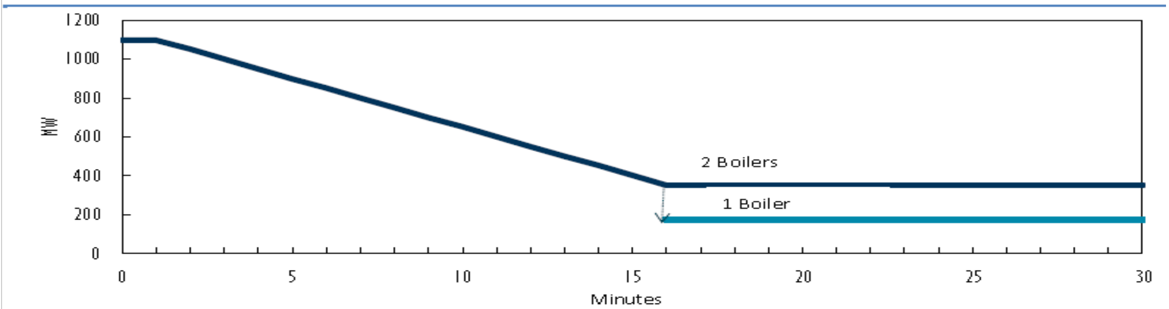


Figure 22 • Advanced coal flexibility curve



[52] The Socio-economic Impacts of Advanced Technology Coal-Fuelled Power Stations (Report by the Coal Industry Advisory Board) [Page 74-75].

6.2. Security and system reliability

Power stations are required to generate electricity in a manner that is consistent with system reliability and stability standards and, when required, be able to supply ancillary services to the system (e.g. reactive power/voltage control, system strength (short circuit contribution), frequency support including inertial response support).

Ongoing stability includes maintaining the frequency of the network within tightly controlled parameters, and having sufficient inertia (the measure of the rotating mass of a generation unit) so that the frequency doesn't change too rapidly. A rapid change in frequency can lead to cascading failures and system collapse. While intermittent generators could, in theory, be configured to provide some of these services when they are available, their intermittency limits their ability to do so.

With regards to system inertia, the rate of speed of rotation of generators on a network determines the frequency of the system. Inertial response is the adjustment in electrical power output of a generator in response to a generation and load imbalance. When the amount of mechanical power being developed by the turbine (connected to a synchronous generator) is balanced with the electrical power being drawn by the system load, then the rotor remains at a constant speed and thus system frequency is constant. As such, the greater the inertia in the system, the less the network is susceptible to frequency variations outside the normal operating parameters due to sudden disturbances. Coal-fired power generation is "synchronous" generation and has the ability to provide large levels of inertia. Wind and solar generation are "asynchronous" and are instead based on power electronics, as are batteries, and current technologies cannot provide inertia, albeit industry is investigating ways for renewables to potentially provide "synthetic inertia".

In the future and in the absence of fossil fuel synchronous generation, any reliance on batteries to manage intermittency will likely require these installations to also provide synchronous generation solutions to overcome limitations in batteries to supply sufficient inertia and system strength. This will further add to the cost of batteries coupled with VRE.

7. Power Station Cost Assumption Reference Data

In 2015 the CO2CRC (et al) prepared “The Australian Power Generation Technology Study” (APGT) which provided a comparative assessment of alternative power generation technology costs and performance data for the period 2015 to 2030.

The intent of this study was to provide up to date reference data which could then be used for further modelling of Australian electricity generation options. The study presented an assessment of current and projected capital costs, operation and maintenance costs, and detailed performance data.

Periodically, AEMO commissions a similar comparative study titled “Fuel and Technology Cost Review” (FATC or ACIL) as part of its planning functions, which provides an underlying set of input assumptions for existing generation assets, and the economics/location of future investment and retirement decisions. The last update was prepared by ACIL ALLEN Consulting and was released in June 2014. This study includes projections of fuel and technology costs for both existing and emerging generation technologies and the technical operating parameters of these technologies.

In June 2017, Jacobs published a report “Emissions mitigation policies and security of electricity supply” (EMPSES or Jacobs) for the independent review into the future security of the NEM. Jacobs included in the EMPSES its base assumption capital costs, operation and maintenance costs, and detailed performance data for a variety of technologies.

The APGT, FATC and the EMPSES reports provide a comprehensive set of project assumptions for a range of technologies on a like-for-like basis and in an Australian context.

A number of other similar international comparative assessments have been identified, however, these studies were not considered as a primary source of data for this analysis given that they are less current, and given the complexity of conversion of performance data and reported US dollar costs to an Australian context (costs, construction conditions, regulatory and tax environment).

Also, since the publication of the APGT, FATC and EMPSES reports, there have been a number of public announcements for new power generation projects in Australia (primarily wind and solar PV). Typically, these announcements do not include sufficient detail or a basis for reported project costs and performance characteristics, as this type of information is generally considered by the project sponsors to be “commercial and in confidence”.

Accordingly, given that the APGT, FATC and EMPSES reviews are the most recent and comprehensive assessments of a broad spectrum of power generation options in an Australian context, the data sets from these reports have been utilised as the basis for the comparative power station cost analysis in this report.

Whilst the APGT, FATC and EMPSES reports provide data on a broad range of potential technologies that could be deployed in the future as they are commercialised, the focus of this report has been limited to those technologies which have or are likely to be able to be cost effectively deployed on a large-scale within the next decade.

A summary of the key assumptions identified in the APGT, FATC and EMPSES reports are shown in Table 20.

Kogan Creek Power Station was the last coal-fired power station constructed in Australia (construction commenced in 2004). Given the length of time since Kogan Creek was constructed, and the fact that it utilised super critical technology, GHD was commissioned to produce current cost and performance estimates for a generic Australian USC coal-fired power station (refer section 7.2).

Table 20 Key APGT/FATC/EMPSES Study Generation Cost Assumptions (in current Australian Dollars)

Item	Report	UoM	Black Coal HELE USC (or SC)	Black coal HELE USC plus CCS	NG CCGT - Large	NG CCGT plus CCS	NG OCGT F-Class	Wind	Solar PV FFP	Large Scale Battery Storage
Lead Time for Development (incl. construction)	ACIL	Years	6	8	4	4	2	4	4	3
	APGT		Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified
	JACOBS		Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified
	Range		*6*	*8*	*4*	*4*	*2*	*4*	*4*	*3*
Construction Lead Time	ACIL	Years	4	4	2	2	1	2	2	2
	APGT		4	4	2	3	1	2	1	Unspecified
	JACOBS		Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified
	Range		*4*	*4*	*2*	*3*	*1*	*2*	*2*	*2*
Plant Life	ACIL	Years	50	50	40	40	30	20	25	10
	APGT		30	30	30	30	30	20	30	?
	JACOBS		35	30	30	30	30	25	20	10
	Range	*Years (Low)*	*30*	*30*	*30*	*30*	*30*	*20*	*20*	*10*
		Years (High)	*50*	*50*	*40*	*40*	*30*	*25*	*30*	*10*
Nominal capacity	ACIL	MW	750	750	390	363	530	500	100	20
	APGT		695	595	451	417	281	200	50	Unspecified
	JACOBS		743	480	559	524	284	100	50	Unspecified
	Range	*MW (Low)*	*695*	*480*	*390*	*363*	*281*	*100*	*50*	*20*
		MW (High)	*750*	*750*	*559*	*524*	*530*	*500*	*100*	*20*

Item	Report	UoM	Black Coal HELE USC (or SC)	Black coal HELE USC plus CCS	NG CCGT - Large	NG CCGT plus CCS	NG OCGT F-Class	Wind	Solar PV FFP	Large Scale Battery Storage
Available Capacity Factor (2017)	ACIL	% (Low)	89%	88%	93%	91%	Unspecified	35%	10%	96%
		% (High)	89%	88%	93%	91%	Unspecified	35%	20%	96%
	APGT	% (Low)	85%	85%	65%	65%	5%	35%	19%	Unspecified
		% (High)	85%	85%	65%	65%	10%	42%	22%	Unspecified
	JACOBS	% (Low)	86%	86%	87%	87%	Unspecified	33%	22%	Unspecified
		% (High)	95%	95%	95%	95%	Unspecified	40%	27%	Unspecified
	Range	*% (Low)*	*87%*	*86%*	*82%*	*81%*	*5%*	*34%*	*17%*	*96%*
		% (High)	*90%*	*89%*	*84%*	*84%*	*10%*	*39%*	*23%*	*96%*
Available Capacity Factor (2030)	ACIL	% (Low)	89%	88%	93%	91%	Unspecified	35%	10%	96%
		% (High)	89%	88%	93%	91%	Unspecified	35%	20%	96%
	APGT	% (Low)	85%	85%	65%	65%	5%	42%	19%	Unspecified
		% (High)	85%	85%	65%	65%	10%	49%	22%	Unspecified
	JACOBS	% (Low)	86%	86%	87%	87%	Unspecified	33%	22%	Unspecified
		% (High)	95%	95%	95%	95%	Unspecified	40%	27%	Unspecified
	Range	*% (Low)*	*87%*	*86%*	*82%*	*81%*	*5%*	*37%*	*17%*	*96%*
		% (High)	*90%*	*89%*	*84%*	*84%*	*10%*	*41%*	*23%*	*96%*
Auxiliary load	ACIL	%	7.1%	18.5%	3.0%	10.0%	1.0%	1.0%	1.0%	0.5%
	APGT		7%	22%	2%	12%	1%	0%	0%	0%
	JACOBS		4.5%	17.5%	2.2%	7.9%	1.0%	2.0%	2.0%	Unspecified
	Range	*% (Low)*	*5%*	*18%*	*2%*	*8%*	*1%*	*0%*	*0%*	*0%*
		% (High)	*7%*	*22%*	*3%*	*12%*	*1%*	*2%*	*2%*	*1%*

Item	Report	UoM	Black Coal HELE USC (or SC)	Black coal HELE USC plus CCS	NG CCGT - Large	NG CCGT plus CCS	NG OCGT F-Class	Wind	Solar PV FFP	Large Scale Battery Storage
Capital cost, 2017	ACIL	$M/MW (Low)	$2.854	$5.310	$1.102	$2.980	$0.738	$2.576	$2.345	$0.56/MWh
		$M/MW (High)	$2.889	$5.366	$1.128	$3.074	$0.768	$2.669	$2.428	$0.57/MWh
	APGT	$M/MW (Low)	$2.900	$6.200	$1.300	$2.800	$0.900	$2.200	$2.100	$0.40/MWh
		$M/MW (High)	$3.300	$7.800	$1.600	$3.300	$1.100	$2.700	$2.500	$0.60/MWh
	JACOBS	$M/MW (Low)	$3.08	$6.84	$1.41	$3.04	$0.97	$2.40	$2.19	$0.53/MWh
		$M/MW (High)	$3.08	$6.84	$1.41	$3.04	$0.97	$2.40	$2.19	$0.53/MWh
	Range	*$M/MW (Low)*	*$2.854*	*$5.310*	*$1.102*	*$2.800*	*$0.738*	*$2.200*	*$2.100*	*$0.40/MWh*
		$M/MW (High)	*$3.300*	*$7.800*	*$1.600*	*$3.300*	*$1.100*	*$2.700*	*$2.500*	*$0.60/MWh*
Capital cost, 2030	ACIL	$M/MW (Low)	$2.746	$5.068	$1.126	$3.081	$0.775	$2.662	$2.406	$0.30/MWh
		$M/MW (High)	$2.817	$5.214	$1.146	$3.124	$0.784	$2.696	$2.439	$0.30/MWh
	APGT	$M/MW (Low)	$2.465	$5.022	$1.170	$2.296	$0.990	$1.760	$1.050	$0.20/MWh
		$M/MW (High)	$2.805	$6.318	$1.440	$2.706	$1.210	$2.160	$1.250	$0.28/MWh
	JACOBS	$M/MW (Low)	$3.04	$4.60	$1.38	$2.04	$0.94	$1.97	$1.27	$0.25/MWh
	JACOBS	$M/MW (High)	$3.04	$4.60	$1.38	$2.04	$0.94	$1.97	$1.27	$0.25/MWh
	Range	*$M/MW (Low)*	*$2.465*	*$4.605*	*$1.126*	*$2.044*	*$0.775*	*$1.760*	*$1.050*	*$0.20/MWh*
		$M/MW (High)	*$3.036*	*$6.318*	*$1.440*	*$3.124*	*$1.210*	*$2.696*	*$2.439*	*$0.30/MWh*

Item	Report	UoM	Black Coal HELE USC (or SC)	Black coal HELE USC plus CCS	NG CCGT - Large	NG CCGT plus CCS	NG OCGT F-Class	Wind	Solar PV FFP	Large Scale Battery Storage
HHV Heat rate (2017)	ACIL	GJ/MWh	8.52	11.31	6.99	8.01	10.23	n/a	n/a	n/a
	APGT		8.80	12.00	7.20	8.60	10.60	n/a	n/a	n/a
	JACOBS		8.85	9.87	6.86	7.87	10.38	n/a	n/a	n/a
	Range	*GJ/MWh (Low)*	*8.52*	*9.87*	*6.86*	*7.87*	*10.23*	*0.00*	*0.00*	*0.00*
		GJ/MWh (High)	*8.85*	*12.00*	*7.20*	*8.60*	*10.60*	*0.00*	*0.00*	*0.00*
HHV Heat rate (2030)	ACIL	GJ/MWh	7.93	10.24	6.54	7.42	9.53	n/a	n/a	n/a
	APGT		8.67	9.11	6.00	7.20	8.78	n/a	n/a	n/a
	JACOBS		8.85	9.87	6.86	7.87	10.38	n/a	n/a	n/a
	Range	*GJ/MWh (Low)*	*7.93*	*9.11*	*6.00*	*7.20*	*8.78*	*0.00*	*0.00*	*0.00*
		GJ/MWh (High)	*8.85*	*10.24*	*6.86*	*7.87*	*10.38*	*0.00*	*0.00*	*0.00*
Fixed operating cost	ACIL	$/kW	50.5	73.2	10.0	17.0	4.0	45.0	25.0	30.0
	APGT		45.0	55.0	20.0	35.0	8.0	55.0	25.0	Unspecified
	JACOBS		87.0	157.0	35.0	62.0	13.0	40.0	25.0	Unspecified
	Range	*$/kW (Low)*	*45.0*	*55.0*	*10.0*	*17.0*	*4.0*	*40.0*	*25.0*	*30.0*
		$/kW (High)	*87.0*	*157.0*	*35.0*	*62.0*	*13.0*	*55.0*	*25.0*	*30.0*
Variable non-fuel operating cost	ACIL	$/MWh	4.0	9.0	7.0	12.0	10.0	15.0	0.0	6.0
	APGT		2.50	9.00	1.50	12.00	12.00	0.0	0.0	Unspecified
	JACOBS		1.6	4.8	3.6	4.5	7.2	5	2	Unspecified
	Range	*$/MWh (Low)*	*1.6*	*4.8*	*1.5*	*4.5*	*7.2*	*0.0*	*0.0*	*6.0*
		$/MWh (High)	*4.0*	*9.0*	*7.0*	*12.0*	*12.0*	*15.0*	*2.0*	*6.0*

Item	Report	UoM	Black Coal HELE USC (or SC)	Black coal HELE USC plus CCS	NG CCGT - Large	NG CCGT plus CCS	NG OCGT F-Class	Wind	Solar PV FFP	Large Scale Battery Storage
Fuel Cost	ACIL (2017)	$/GJ (Low)	1.32	1.32	4.90	4.90	6.90	0.00	0.00	0.00
		$/GJ (High)	2.56	2.56	10.96	10.96	12.96	0.00	0.00	0.00
	ACIL (2030)	$/GJ (Low)	1.32	1.32	6.92	6.92	8.92	8.92	0.00	0.00
		$/GJ (High)	2.74	2.74	12.96	12.96	14.96	14.96	0.00	0.00
	APGT (2017)	$/GJ (Low)	2.00	2.00	5.00	5.00	5.00	0.00	0.00	0.00
		$/GJ (High)	4.00	4.00	8.00	8.00	8.00	0.00	0.00	0.00
	APGT (2030)	$/GJ (Low)	2.00	2.00	6.00	6.00	6.00	0.00	0.00	0.00
		$/GJ (High)	4.00	4.00	10.00	10.00	10.00	0.00	0.00	0.00
	JACOBS (2017)	$/GJ (Low)	1.60	1.60	5.50	5.50	5.50	0.00	0.00	0.00
		$/GJ (High)	2.40	2.40	7.30	7.30	7.30	0.00	0.00	0.00
	JACOBS (2030)	$/GJ (Low)	2.00	2.00	8.40	8.40	8.40	0.00	0.00	0.00
		$/GJ (High)	2.75	2.75	9.25	9.25	9.25	0.00	0.00	0.00
	Range (2017)	*$/GJ (Low)*	*1.32*	*1.32*	*4.90*	*4.90*	*5.00*	*0.00*	*0.00*	*0.00*
		$/GJ (High)	*4.00*	*4.00*	*10.96*	*10.96*	*12.96*	*0.00*	*0.00*	*0.00*
	Range (2030)	*$/GJ (Low)*	*1.32*	*1.32*	*6.00*	*6.00*	*6.00*	*0.00*	*0.00*	*0.00*
		$/GJ (High)	*4.00*	*4.00*	*12.96*	*12.96*	*14.96*	*14.96*	*0.00*	*0.00*
CO_2 Transport and Storage	ACIL	% (Low)	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	n/a	n/a	n/a
		% (High)	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	n/a	n/a	n/a
	APGT	% (Low)	10.00	10.00	10.00	10.00	10.00	n/a	n/a	n/a
		% (High)	20.00	20.00	20.00	20.00	20.00	n/a	n/a	n/a
	JACOBS	% (Low)	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	n/a	n/a	n/a
		% (High)	Unspecified	Unspecified	Unspecified	Unspecified	Unspecified	n/a	n/a	n/a
	Range	*% (Low)*	*10.0*	*10.0*	*10.0*	*10.0*	*10.0*	*n/a*	*n/a*	*n/a*
		% (High)	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*	*n/a*	*n/a*	*n/a*

7.1. Updates to the APGT and FATC cost assumptions

Developments since the publication of the APGT and FATC reports warrant further examination of the following cost elements.

7.1.1. Gas Supply Agreements (GSA)

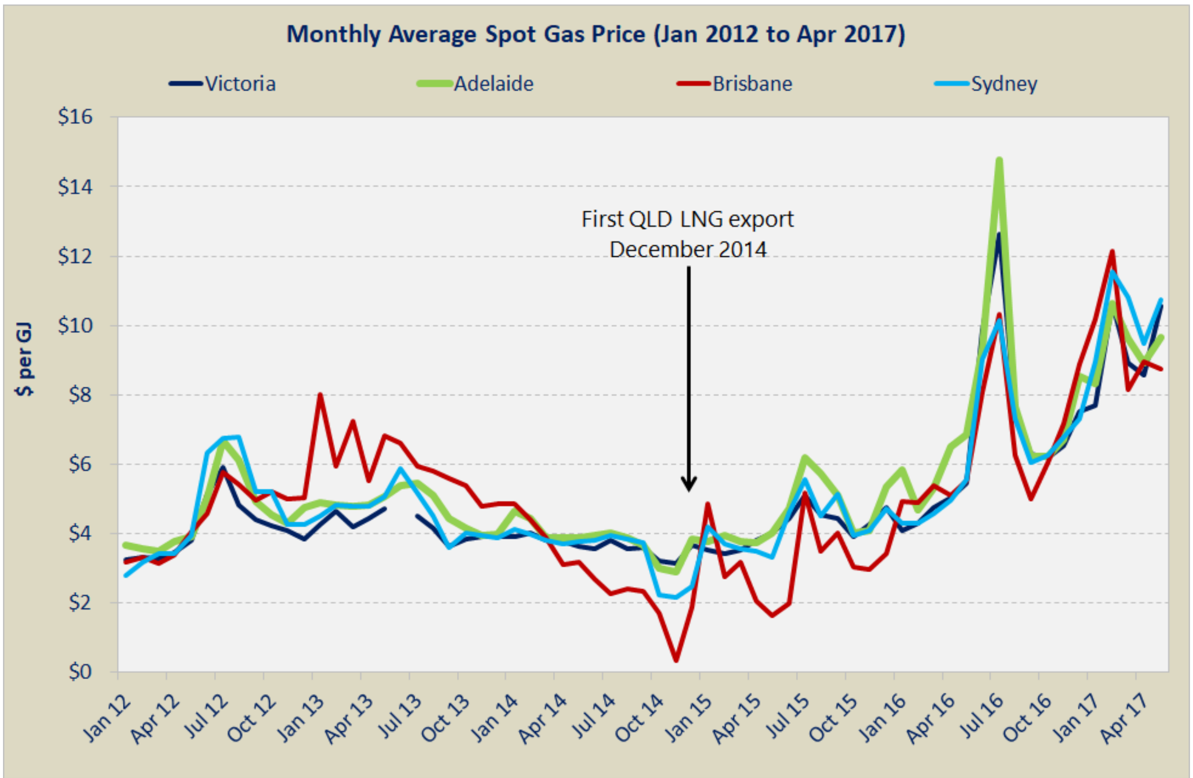
Historically generators have entered into long-term GSAs with gas producers for the supply of gas for a significant portion of the life of a generation project (10-15 years), locking in fuel price and volume at financial close, as a precondition of the financing agreements.

In some cases, the generator manages gas price and volume risks by entering into “farm-in” agreements with owners of gas tenements in order to obtain access to lower cost gas, albeit potentially exposing the project to gas exploration and development risks.

Since the development of the coal seam methane (CSM) Liquefied Natural Gas (LNG) projects near Gladstone in Queensland, coupled with the moratorium on CSM exploration and development in other states (e.g. New South Wales, Victoria and Northern Territory), the opportunity to contract long-term gas or enter into “farm-in” arrangements has become increasingly limited.

As shown in Figure 48 and as discussed in section 3.2.2 wholesale gas prices have increase significantly in recent years.

Figure 48 Wholesale gas prices



In a recent McKinsey Australia report[53], East Australian gas demand is forecast to remain flat until 2030 at up to 2,155 PJ, with 68% allocated to LNG exports and the remaining 32% for domestic consumption.

McKinsey Australia also forecast that as current supply sources follow normal rates of decline, new supply sources will be needed and that there are sufficient undeveloped resources to meet east Australia's full demand. Should the undeveloped resources be developed in line with the natural decline of current supply sources, then the expected gas price could range from a low case of A$7–8 per GJ. However, if development of the undeveloped resources be delayed, prices could rise to a high case of parity with global markets of up to A$12 per GJ.[53].

In addition to higher gas prices, it has become increasingly difficult to contract sufficient volumes of gas over the long-term. Anecdotal reports from major users indicate that GSA contract terms beyond 2-3 years are extremely difficult to source, and that any such contracts include more onerous 100% take-or-pay (ToP) provisions[54] .

This report assumes a GSA for a base load CCGT will include gas prices in the range defined in Table 21.

Table 21 Assumed base load CCGT GSA Gas Prices

Range	Low	High
GSA gas price at the injection point	$8/GJ	$12/GJ

7.1.2. Gas Transportation Agreement (GTA)

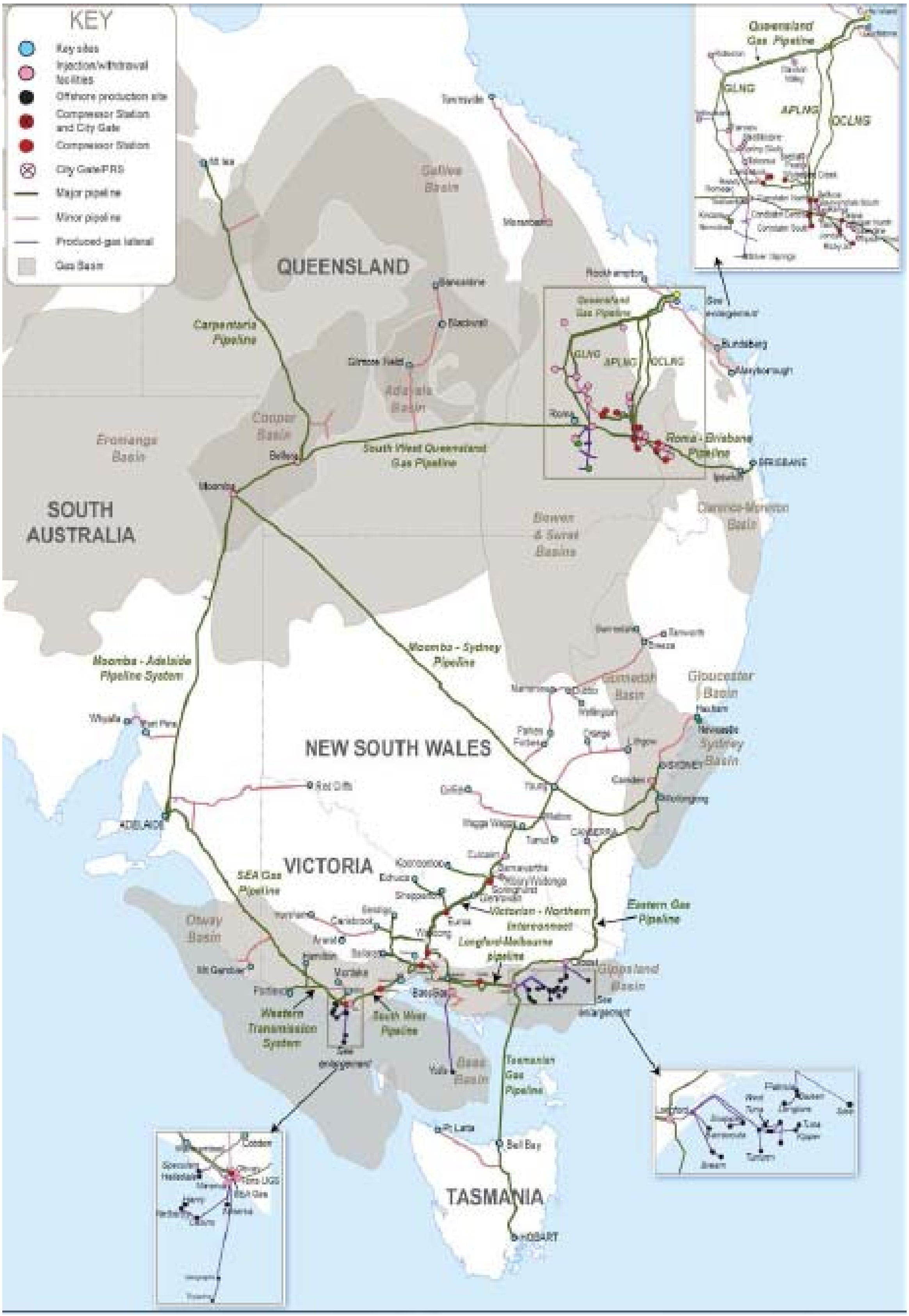
Separate to the GSA, large customers such as generators typically enter into a Gas Transportation Agreement (GTA) with a transmission pipeline provider for the transportation of gas from the GSA injection point to the relevant delivery point on a firm basis.

Transmission charges are typically based on a capacity reservation charge, normally for the Maximum Daily Quantity (MDQ) on a firm basis, and a throughput charge. More recently, some pipeline owners no longer include a throughput charge[55] simply charging for capacity on a firm basis (i.e. equivalent to 100% ToP provisions). In addition to these charges, major users also face other pipeline costs such as storage charges and penalties for overrunning MDQ or being out of balance with daily injections or deliveries.

The gas transmission pipeline network within the NEM is shown in Figure 49.

[53] Meeting east Australia's gas supply challenge (McKinsey Australia March 2017)
[54] Energy Shock: No Gas, No Power, No Future? (The Australian Industry Group February 2017)
[55] https://www.apa.com.au/our-services/gas-transmission/indicative-transmission-tariffs/

Figure 49 Gas Transmission Pipelines in the NEM[56]



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[56] AEMO - Gas Statement of Opportunities (GSOO) March 2017

AEMO publish gas pipeline transmission tariffs for each transmission pipeline in the Gas Statement of Opportunities (GSOO). The 2017 GSOO gas pipeline transmission tariffs are set out in Table 22.

Table 22 2017 GSOO Gas Pipeline Transmission Tariffs

Pipeline	2017	2030
CGP	\$1.32/GJ	\$1.32/GJ
EGP	\$1.25/GJ	\$1.25/GJ
LMP	\$0.32/GJ	\$0.32/GJ
MAP	\$0.75/GJ	\$0.75/GJ
MSP	\$1.03/GJ	\$1.03/GJ
NQGP	\$1.17/GJ	\$1.17/GJ
QGP	\$0.97/GJ	\$0.97/GJ
RBP	\$0.69/GJ	\$0.69/GJ
SEA Gas	\$0.70/GJ	\$0.70/GJ
SWP	\$0.30/GJ	\$0.30/GJ
SWQP	\$1.15/GJ	\$1.15/GJ
TGP	\$2.12/GJ	\$2.93/GJ
VNI	\$0.80/GJ	\$0.80/GJ

The ultimate total applicable tariff is dependent on the location of the gas generation project and from where it has sourced its gas, and may include shipping through a number of gas pipelines.

Additionally, the published reference transportation tariffs do not always reflect the charges generators face, as power station gas transport services are often bilaterally negotiated arrangements, the details of which are commercial-in-confidence. Negotiated services can be higher or lower than the published tariff and are dependent on the service being sought and the level of pipeline augmentation required to deliver that service. However, in the absence of location and project-specific gas transport cost estimates, the published tariffs are a useful proxy for gas-generation fuel transport costs.

Accordingly, this report assumes a GTA for a base load CCGT (based in Queensland, New South Wales, Victoria or South Australia) will include gas transmission tariffs as set out in Table 23.

Table 23 Assumed base load CCGT GSA transmission tariffs

Location	Low	High
GTA gas transmission tariff	\$1.00/GJ	\$2.20

7.1.3. Impact of 100% Take-or-Pay Provisions

The cost implications for 100% ToP GSA and GTA obligations are minimal for a base load generator, given that the power station will require gas to be delivered almost every hour of every day of the year to run at base load.

However, a gas generator coupled with VRE in order to provide an equivalent level of base load production (i.e. gas generator “firming up” an equivalent amount of intermittent generation), would be required to ramp production up and down in a diametrically opposite pattern (load follow) to the variable renewable energy generator, the output from which can fluctuate significantly hour-to-hour, day-to-day and seasonally. In this case, the cost implications of 100% ToP services (GSAs and GTAs) become far more onerous.

As set out in section 7.6, AEMO has assessed the level of reliable firm wind capacity in the NEM. AEMO assessed the level of firm wind coincident with maximum demand in Victoria and South Australia to be approximately 7% of the total installed capacity of wind generation. In New South Wales, AEMO have assessed the level of firm wind capacity to be 3.0% of the installed capacity during summer, and 4.2% of installed capacity during winter.

Assuming then that a base load PPA is backed by a notional 100MW base load power station consisting of 100MW of wind farm which is firmed by a CCGT with a notional efficiency of 50% (HHV), that must collectively operate and deliver the 100MW, 24 hours per day, every day of the year:

- The average capacity factor of the notional wind farm would be ~30-40%, but the level of firm wind capacity would be as low as 7%, thus the notional CCGT would need to be at least 93MW in size in order to ensure 100MW of capacity is available to be delivered at all times[57]; and
- The CCGT would need to have gas available so that it could run at its full rated output at any time and would therefore need to contract gas and gas transportation services accordingly.

Table 24 Delivered Gas Price Uplift

Cost or Production Element	UoM	NSW Wind (Low)	NSW Wind (High)	VIC/SA Wind (Low)	VIC/SA Wind (High)
Wind Average Capacity Factor	%	30%	40%	30%	42%
Firm Wind Capacity (AEMO)	%	3.0%	4.2%	7.0%	9.5%
CCGT Capacity to firm Wind	%	97.0%	95.8%	93.0%	90.5%
Actual Wind Capacity	MW	100	100	100	100
Firm Wind Capacity (AEMO)	MW	3	4.2	7	9.5
CCGT Capacity to firm Wind	MW	97	95.8	93	90.5
CCGT Heat Rate (HHV)	GJ/MWh	6	6	6	6
CCGT MHQ	GJ/hr	582	575	558	543
CCGT MDQ (24 hours)	GJ/d	13,968	13,795	13,392	13,032
CCGT ACQ (365 days)	PJ pa	5.10	5.04	4.89	4.76
Assumed delivered Gas Cost	$/GJ	$10	$10	$10	$10
Annual Gas Cost	$M p.a	$51.0	$50.4	$48.9	$47.6
Actual CCGT Capacity Factor	%	72.16%	62.63%	75.27%	64.09%
Actual CCGT Annual Production	MWh	613,200	525,600	613,200	508,080
Actual CCGT gas consumption	PJ pa	3.68	3.15	3.68	3.05
CCGT implied actual gas price	$/GJ	$13.86	$15.97	$13.29	$15.60
Effective gas price uplift	%	39%	60%	33%	56%

The analysis shown in Table 24 suggests that delivered gas prices need to be uplifted by between 33% and 60% to reflect the uncertainty as to how much and when the CCGT is required to operate to support the VRE.

[57] Ignoring the impact of planned and forced plant outages.

For the comparative power station cost analysis in this report it has been assumed a base load CCGT used to firm variable renewable energy will pay a premium for delivered gas of 30-60% over and above the base load GSA and GTA prices.

Note, in reality, generators that have available unused firm gas will seek to dispatch generation at other times to earn additional income. This "blue sky" opportunity applies to whatever "firming" technology is deployed. In the power station cost analysis in this report, for all options involving "firming" of renewable generation, for consistency we have excluded any opportunistic value attributable to the residual firm fuel position.

7.1.4. Summary Gas Assumptions

The current combination of significantly higher gas prices, limited contract duration (and therefore firm gas volumes) and onerous contract service terms (e.g. high take-or-pay) in recent GSAs and GTAs, is unlikely to meet the minimum requirements of financiers considering the funding of new gas generation projects, and therefore likely renders new gas power generation unviable.

In the unlikely event that developers are able to secure project financing for a new build gas-fired CCGT without long-term gas contracts, then this report assumes the project will face delivered gas costs comparable to those set out in sections 7.1.1, 7.1.2 and 7.1.3.

7.2. Review of coal-fired power station costs and performance

High Efficiency Low Emissions (HELE) power stations operate at higher temperatures, pressures and efficiencies. The temperature and pressure of the steam determine the relative efficiency of the plant.

With the advancement of metallurgical design, new Ultra Super-Critical (USC) pulverised coal-fired plants operate at increasingly higher temperatures and pressures, and therefore achieve higher efficiencies than conventional sub-critical plants.

Australia's ageing coal-fired power station fleet is dominated by sub-critical pulverised coal-fired power station technology. As shown in section 5.1, this coal-fired fleet is approaching the end of its engineering and commercial life and will need to be replaced with other forms of schedulable generation.

From the underlying data in the FATC review, the average efficiency of Australia's existing coal-fired fleet was approximately 32% (% HHV sent out). The most efficient Australian coal-fired power stations were Tarong North (wet-cooled and 39% efficient) and Kogan Creek (dry-cooled and 37.5% efficient) both of which utilize Super-Critical technology.

New HELE coal-fired power station technology use USC technology which can operate at steam conditions where the temperature is approximately 600C and pressure is greater than 25 MPa, resulting in efficiencies 40-45%.

The first USC coal-fired plant was built in Japan in 1993. Since then, approximately 188 GW of new HELE USC coal-fired generation has been installed and is operating in China, Japan, the USA and Europe with a further 92-110 GW planned or being constructed[58].

[58] IEA CCC; "An overview of HELE technology deployment in the coal power plant fleets of China, EU, Japan and USA", Report 273, December 2016.

In the future, Advanced Ultra Super-Critical technology is forecast to operate at steam conditions where the temperature is approximately 700C and pressure is greater than 34 MPa, resulting in efficiencies of 45-50%.

To date, no USC PC (or Advanced Ultra Supercritical) power stations have been built in Australia, however, given they have been deployed internationally, this report focuses on USC coal-fired power stations as the likely coal-fired technology to be deployed in the short to medium term.

GHD was a sub-contractor to ACIL ALLEN Consulting for the FATC review and provided the expert advice and estimates on new entrant technology costs, engineering and technical matters.

Given the lack of actual USC coal-fired power station cost information from an Australian project (against the vast amount of actual Australian cost data for fossil fuel and renewable technologies), GHD was engaged to provide an Australian estimate of the capital cost and performance data for a HELE USC coal-fired (without and with CCS) plant built in Australia.

In order to calibrate the Australian estimate against international experiences, GHD benchmarked the estimated cost against the reported cost of HELE plants constructed overseas.

The full GHD report has been included in Appendix 1.

7.2.1. GHD Greenfield USC PC Power Station

The GHD base case HELE plant was assumed to be a 650MW (sent out) USC coal-fired, wet-cooled single unit generator with the boiler fuelled by black coal of a typical Hunter Valley specification. The base case steam conditions were 27.5 MPa (gauge) and 604 C for the high pressure steam and 5.9 MPa and 604 C for the intermediate pressure steam, with a resulting sent out heat rate and efficiency of 8.7 GJ/MWh and 41.4% (HHV) respectively (or 8.4 GJ/MWh and 42.9% LHV).

GHD has prepared preliminary cost estimates for the base case using Thermoflow's PEACE™ (Preliminary Engineering and Cost Estimation) software. The cost estimate for a wet-cooled and a dry-cooled base case are presented in Table 25.

Table 25 GHD Base Case USC PC Power Station (wet-cooled or dry-cooled)

Cost categories	UoM	Base Case Wet-Cooled	Base Case Dry-cooled
Contractor's Internal Cost	US$M	1,122	1,162
Contractor's Soft & Miscellaneous Costs	US$M	212	225
Contractor's Price	US$M	1,333	1,387
	AU$M[59]	1,778	1,849
Net Plant Output	MW	650	650
Contractor's Cost	US$/kW	2,052	2,134
	AU$/kW[59]	2,735	2,845

7.2.2. Asian Sourced Equipment

PEACE uses a number of cost multipliers to reflect the local cost of constructing a power station relative to the cost at the USA reference location. The PEACE database contains default cost multipliers for different regions in the USA as well as for various countries around the world.

[59] Assumes an exchange rate of 1AUD=0.75USD.

The default multipliers can be manually overridden by the user if better project specific figures are available. GHD has considered three alternative scenarios in order to assess the potential range of outcomes under different combinations of cost multiples. These alternative scenarios are:

- cost multipliers developed by WorleyParsons for the CO2CRC Report;
- incorporation of a lower cost multiplier to reflect the lower cost of “Specialised Equipment” from China; and
- a combination of scenario 1 and 2.

The costs for the alternative scenarios are shown below and illustrate the potential cost savings from the use of Asian Specialised Equipment.

Table 26 Asian sourced specialised equipment cost estimate

Cost categories	UoM	Thermoflow default Australia	Worley Parsons Hunter Valley	Thermoflow default, Chinese Specialised Equipment	Worley Parsons Chinese Specialised Equipment
Total Contractor's Cost	US$M	1,333	1,294	1,144	1,187
	AU$M[59]	1,778	1,725	1,525	1,583
Net Plant Output	MW	650	650	650	650
Contractor's Price	US$/kW	2,052	1,990	1,760	1,827
	AU$/kW[59]	2,735	2,653	2,347	2,436
% of default cost	%	100%	97.0%	85.8%	89.1%

Sourcing equipment from Asia (particularly China) has led to a significant lowering of plant cost for a range of industries including wind and solar PV equipment. China has made significant investment in the research and development of HELE coal-fired generation and has developed and deployed a range of HELE (including USC) technologies. Some of the Chinese manufactured specialised equipment used in its USC coal-fired power stations is made under licence from the original equipment manufacturers (OEMs) such as Siemens and Alstom[60].

Given the number of HELE power stations being constructed throughout Asia, leveraging this experience by sourcing specialised equipment from Asia (rather than more expensive markets) could yield savings of up to 14% over the base case estimate.

7.2.3. Brownfield Cost Savings Redeveloping Existing Power Station Sites

Given that much of the existing Australian coal-fired fleet is approaching the end of its engineering/commercial life, an opportunity exists to secure further cost savings by redeveloping these brownfield sites with new HELE power stations.

GHD also assessed the possible cost savings that may be achievable in areas such as:

- use of existing common infrastructure (buildings, roads, services, etc.);
- reduction of cost from repurposing existing equipment (e.g. coal handling, stockpile); and
- use of existing ancillary equipment (e.g. black start generators).

[60] IEA CCC “China – policies, HELE technologies and CO2 reductions” [page 46]

The preliminary assessment indicates there are likely to be brownfield redevelopment savings of approximately US$92.456M for the 650 MW wet-cooled base case project capital cost, through reuse of existing assets and facilities.

Any potential savings or avoided costs in infrastructure outside of the power station (e.g. existing fuel supply, water supply, transmission system, roads, etc.) were not considered.

7.2.4. Wet Cooling versus Dry Cooling

The APGT report assumed that any coal-fired power station will require dry-cooling given potential future water restrictions. Most existing coal-fired power stations currently have access to existing dedicated water storage for wet-cooling.

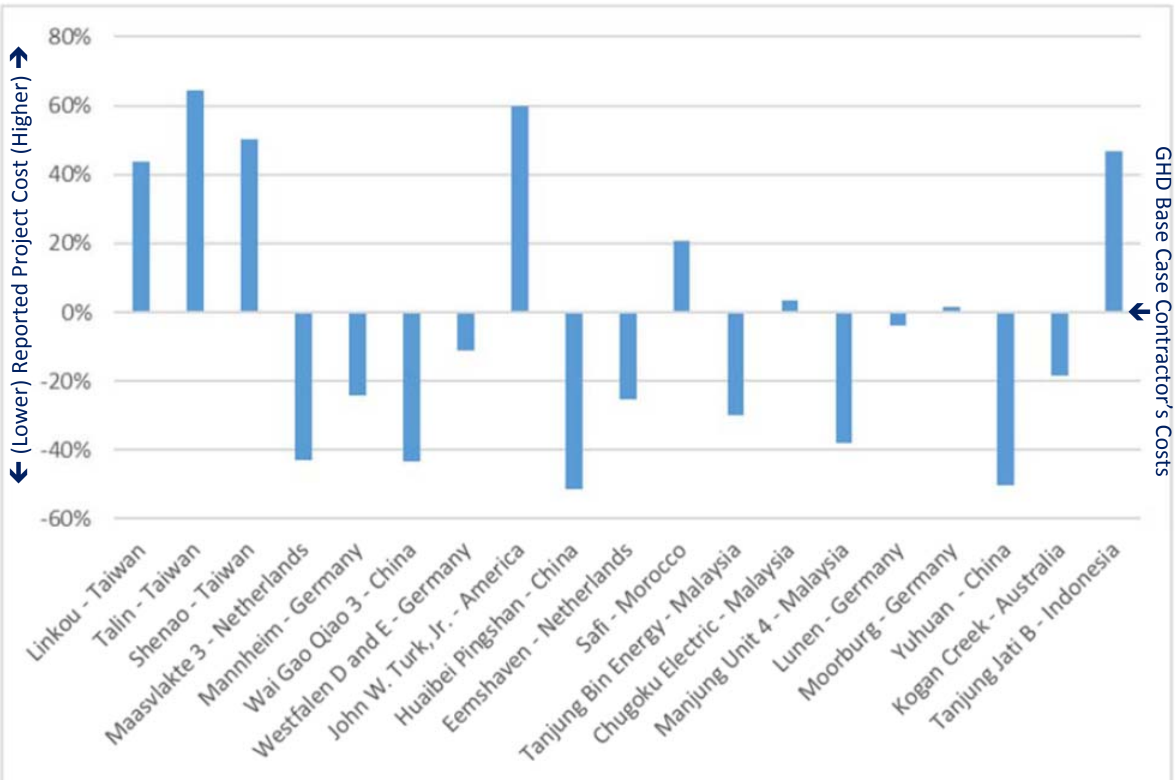
Redevelopment of these existing brownfield sites with HELE Power Station technology will likely provide access to these same water storages.

7.3. Indicative Capex Cost Range (Benchmarking)

GHD carried out a benchmarking exercise to compare publicly available cost information for similar existing HELE power stations against the estimates produced by PEACE. The intention of this benchmarking exercise is to provide a level of confidence in the PEACE estimates presented in this report, based on the error margins calculated against known projects. GHD included Kogan Creek Power Station in the benchmarking given it is the most recent and only coal-fired plant of similar size and technology built in Australia in the past decade (albeit operating at super critical steam conditions).

The key results from the benchmarking exercise are shown in Figure 50 where a positive percentage indicates that the benchmark project reported a cost that was higher than the PEACE estimate by that percentage. Conversely, a negative percentage indicates that the reported cost was lower than the cost predicated by PEACE.

Figure 50 GHD Benchmark project deviation from PEACE estimate



The following key results are identified:

- Three of the largest negative outliers are for projects that have been undertaken in China.
- Three of the four positive outliers are for three similar projects undertaken in Taiwan, and all present similar error percentages (approx. 40-60% higher than the cost predicted by PEACE).
- One of the two remaining positive outliers is for the first and only USC project carried out in the United States.
- 13 out of the 19 benchmark projects are within (or close to) ±40% accuracy.
- The most recent supercritical project delivered in Australia (Kogan Creek), based on a reported cost of AU$1.2 billion in 2007, is within 20% accuracy with the PEACE estimate approximately 18% higher than the escalated reported project cost.

The level of accuracy for scoping study estimates for infrastructure of this type is typically ±40% range (refer Figure 51 Class 4). As shown in Figure 45 the benchmarking exercise is consistent with this level of accuracy.

The GHD estimates were also benchmarked against the APGT study costs for a dry-cooled USC black coal-fired power station costs with the results shown in Table 27.

Table 27 Comparison GHD HELE USC coal-fired power station cost against APGT report

Item	UoM	Value
CO2CRC total plant cost	US$/kW$_{S.O.}$	2,325
GHD base case cost	US$/kW$_{S.O.}$	2,134

Figure 51 Project Lifecycles Cost Estimate Class and Accuracy[61]

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Table 1 – Cost Estimate Classification Matrix for Process Industries

[61] AACE International Recommended Practice No. 18R-97 COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES TCM Framework: 7.3 – Cost Estimating and Budgeting Rev. March 1, 2016

7.4. Indicative Capex Cost Range USC coal-fired + CCS

GHD also consider the cost estimates for a wet-cooled USC coal-fired power station complete with carbon capture and storage capability for a reference case and also with Asian sourced specialised equipment.

GHD also provided estimated cost savings for a wet-cooled USC plus CCS coal-fired power station with specialised equipment sourced from China (refer Table 28).

Table 28 GHD USC coal-fired + CCS Cost (default and Asian Equipment) estimate

Item	UoM	Thermoflow default Australian cost factors	Thermoflow default, Chinese Specialised Equipment	Percent saving
Contractor's Cost	US$/kW	3,859	3,185	17%
	AU$/kW[59]	5,145	4,247	

Note, the subsequent analysis in section 8 for the USC plus CCS cases adopts the APGT, FATC and EMPSES low-high range of CAPEX costs (i.e. dry cooled, greenfield development, default supplied specialised equipment), and adjusts these costs to account for the GHD assessment of savings from: wet-cooling; Chinese sourced specialised equipment; and brownfield developments.

7.5. AEMO Carbon Price Assumptions

In the 2016 NEFR, AEMO has assumed increasing retail electricity tariffs from 2020 are in part driven by a proxy emissions abatement cost that is assumed to commence at $25/t CO2-e and reach $50/t CO2-e by 2030. AEMO assumed these carbon prices as a way of introducing an approximate valuation of the cost of achieving the 2030 emissions target. This report adopts the same assumptions.

7.6. AEMO Assessment of Firm Wind and Solar PV

AEMO periodically reports on the level of generation capacity (existing, withdrawn, committed, and proposed) within each NEM region[62]. Included in these reports is AEMO's assessment of the reliable level of wind capacity that will be coincident with periods of maximum demand. AEMO refers to this as the "firm contribution" from wind generators during peak periods. The latest assessments are dated 27 February 2017 and cover data assessed over the period FY12-FY16. The assessed level of "firm wind" by region is summarised in Figure 52.

[62] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Figure 52 AEMO Assessment of "Firm Wind"

Region	Firm Wind Summer	Firm Wind Winter
QLD[63]	Not assessed	Not assessed
NSW[64]	3.0%	4.2%
VIC[65]	7.5%	6.8%
TAS[66]	8.5%	4.9%
SA[67]	9.4%	7.0%

In the New South Wales generation data spreadsheet, AEMO state that due to the intermittency of Solar PV the available capacity will need to be de-rated to account for the output most likely to be available during times of maximum demand. However, AEMO has not been able to quantify the amount of "firm Solar PV" given there is insufficient data from solar generation in the NEM to date.

The AEMO estimates of firm wind capacity are not a guarantee this level of wind is assured (refer section 3.4). For example, using the underlying data in Figure 35, for the period 1 January 2017 to 31 March 2017, the aggregate wind generation in South Australia was less than 7% of maximum wind capacity for 12.8% of all trading intervals. Over this same period, max demand occurred at 6:00 pm (EST) on the 8 February and wind capacity was just 5.8% of maximum wind capacity.

[63] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Feb-2017/Generation_Information_QLD_27022017.xlsx
[64] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Feb-2017/Generation_Information_NSW_27022017.xlsx
[65] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Feb-2017/Generation_Information_VIC_27022017.xlsx
[66] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Feb-2017/Generation_Information_TAS_27022017.xlsx
[67] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Feb-2017/Generation_Information_SA_27022017.xlsx

8. Comparative Power Station Cost Analysis

8.1. Discounted Cash Flow Modelling

NEM demand is met using a variety of generators, each with different capabilities, attributes and costs. The relationship between wholesale market prices and the cost of generation consists of:

- the Long-Run Marginal Cost (LRMC), which takes into consideration the capital, financing, operating, fuel and tax costs of new generation and represents the average cost per unit of output over the long run (e.g. life of the asset), and equates to the real electricity price required to be received for each unit of electricity produced so that the capital, operating, fuel, tax and interest (debt and equity return) expenditure are fully paid for over the life of the asset; and
- the Short-Run Marginal Cost (SRMC) of generation, which only includes the out-of-pocket cost to vary output by one unit (e.g. variable operating and fuel costs), and does not include any fixed costs.

Theoretically, as the supply demand balance tightens (reducing availability of excess generation capacity) average wholesale market prices will rise until the average price is equal to or greater than the cost of new generation. When average wholesale prices are sustained over the long-run at the LRMC of new generation, capacity expansions will occur. Conversely when excess capacity exists, additional energy can be supplied at close to short-run marginal cost.

Economic dispatch modelling that reflects the dynamic nature of the electricity system, and can determine the optimal and most cost-effective mix of generation to balance load within the NEM on an interval basis, is a highly complex exercise. Models must be constructed to accommodate the broad range of variables and constraints that impact the electricity system, for example:

- the changing demand profile over time (second to second, minute to minute, 24 hours per day, 365 days per year, throughout the regions of the NEM);
- the availability and cost of dispatching individual generators;
- the availability and efficiency of shifting generated electricity across regions via interconnectors and transmission and distribution networks, to loads throughout the NEM;
- environmental constraints placed on generators; and
- weather impacts.

Absent full economic dispatch modelling, for comparative purposes, a Discounted Cash Flow (DCF) analysis is a useful tool to analyse and demonstrate the relative costs and attributes of a range of different generation technologies.

The analysis in this report utilises a DCF analysis to compare each generation technology option for a notional 650 MW base load power station.

For each technology, a DCF is produced that reflects that technology's capital and operating costs over the assumed technical life of the notional project. The DCF does not try to predict when the capacity is required but rather assumes a project initiation year of 2017 and takes into consideration the timing of capital and operating expenditure (i.e. it accounts for the time required to develop and construct a project prior to commencement of the operations phase).

The DCF discounts after tax cash flows to a present value using a calculated WACC (refer section 8.2), and determines the unit price of electricity ($/MWh) at which the Net Present Value (NPV) of those projected cash flows is equal to zero.

Where technologies cannot deliver base load capacity then these technologies are coupled with an alternative complimentary technology that can collectively deliver base load capacity.

8.2. Weighted Average Cost of Capital (WACC)

WACC is the blended required rate of return for investors of all types (senior debt, junior debt, equity etc.) in a company or project.

In developing the comparative LRMC analysis in this report, a consistent WACC has been applied across all technology options and scenarios. This approach has been adopted in order to provide a like-for-like comparison of underlying power generation costs, unfettered by arbitrary risk premiums intended to reflect current-day regulatory uncertainty or other assumed investment risk differentials.

This approach implies that any generation project, regardless of technology type, will typically require "underwriting" in the form of a long-term agreement covering the purchase of the output or capacity of the plant. Such arrangements could include:

- internalised offtakes, that is, vertically integrated participants investing in generation plant to meet their future energy purchase and wholesale market risk management requirements;
- long-term hedge or dispatch control contracts entered into with creditworthy market participants; or
- long-term capacity agreements entered into with market operators or governments (e.g. in order to underwrite system reliability), which in addition to general market risks, may also address other key investment risks, including potential future emissions imposts.

The WACC assumptions used in this report is shown in Table 29.

Table 29 WACC Assumptions

Assumptions	Value
Corporate Tax Rate	30%
Inflation Rate	2.50%
Capital Structure:	
Debt / Value	60.00%
Equity / Value	40.00%
Cost of Debt	
Nominal Pre-Tax Cost of Debt	7.0%
Nominal Post-Tax Cost of Debt	4.9%
Cost of Equity	
Nominal Pre-Tax Cost of Equity	13.0%
Nominal Post-Tax Cost of Equity	9.1%
WACC	
Nominal Pre-Tax WACC	9.4%
Nominal Post-Tax WACC	**6.6%**

8.3. Battery Storage Cost Assumptions

The APGT, FATC and EMPSES reports included cost assumptions for battery storage.

The cost of battery storage to backup VRE will vary with the level of storage capacity required, and the level of storage capacity is a function of the charging technology (e.g. wind or solar PV) and the desired capacity factor of the combined system (Hybrid System).

In order to make a like-for-like comparison, this study assumes the Hybrid System must be capable of delivering the equivalent capacity (650 MW) on a schedulable basis (i.e. 24 hours per day continuously). Given the charging technology is intermittent (i.e. wind or Solar PV) then this will require the battery system to be recharged between discharges when the intermittent generator is not generating at the required output of 650 MW. This therefore requires the intermittent generator to be scaled up so that it can deliver 650 MW during generating periods, plus producing sufficient excess energy to charge the battery system at the same time.

A Hybrid system that incorporates four to seven hours of storage in addition to intermittent generation capacity can time-shift when the stored energy is used (e.g. typically during peak periods), but will still require other generation to cover periods where the intermittent generation is unavailable and the batteries are exhausted. A Hybrid system of this type replaces peak or mid merit generation, not base load generation, and does not alleviate the need for additional base load capacity.

Battery storage systems do not return all of the energy that is used to charge the system, and different battery storage technologies operate at varying efficiencies. Lithium ion batteries typically have reasonably long lifetimes and are able to store large amounts of energy and are compact. Lithium ion batteries typical efficiencies are 90–95% (not including AC–DC conversion) and can accept high depth of discharge levels (typically 80%)[68].

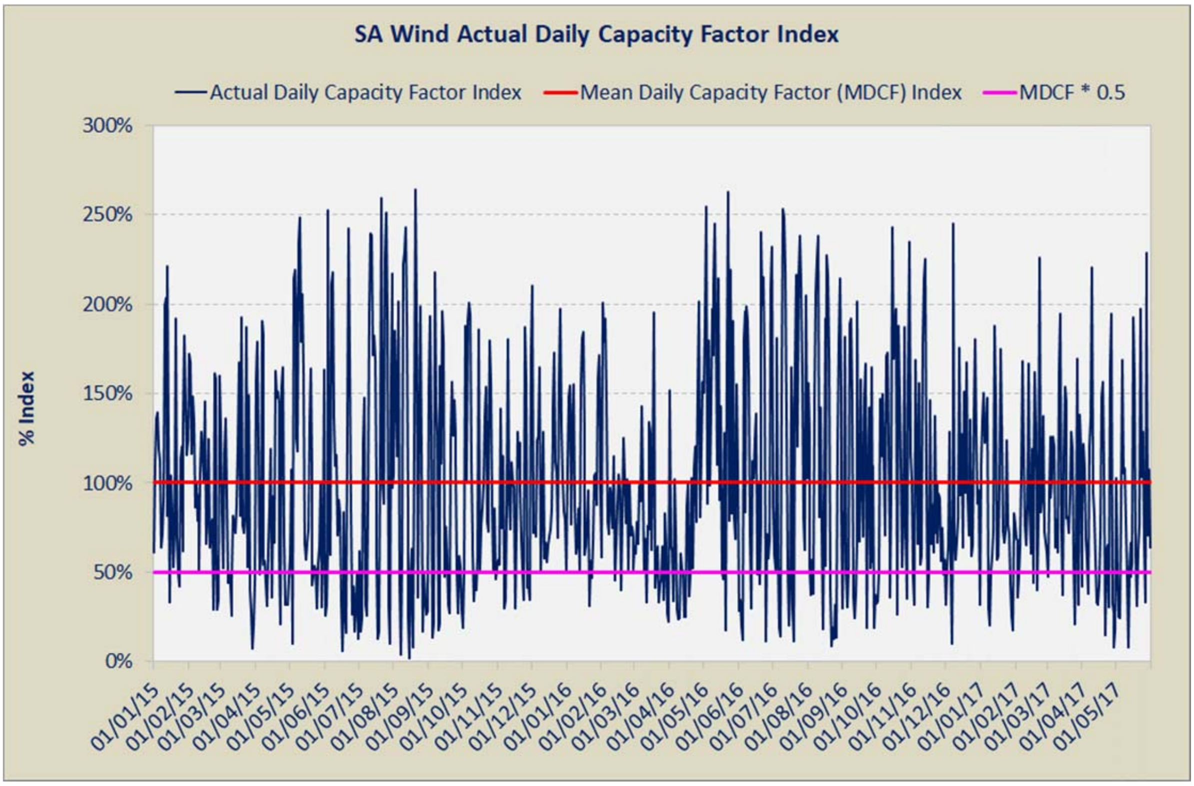
8.3.1. Required Battery Capacity to back-up intermittent renewable energy

The LRMC analysis in this report assumes that the level of battery backup ("firming") capacity required to support wind or solar farm VRE, is equivalent to 2 to 3 times the inverse of the average capacity factor of the primary generation source in energy terms. These assumptions are conservative to the low side when compared to actual capacity factor performance of a portfolio of wind farms and solar PV farms in the NEM.

Figure 53 compares the actual daily capacity factor index of the portfolio of 18 wind farms in South Australia over the period January 2015 to May 2017 (with a total capacity at 31 May 2017 of 1,698 MW).

[68] http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf

Figure 53 South Australian Wind Farm Actual Daily Capacity Factor Index compared to the Mean (average) Daily Capacity Factor (MDCF) Index and 50% of the MDCF



The data shows that on 43.2% of days, the wind farm portfolio generated at or above the Mean (average) Daily Capacity Factor (MDCF) and on 78.9% of days, the wind farm portfolio generated at or above 50% of the MDCF. The wind farm portfolio generated below 50% of the MDCF on a single day and then returned to or above the MDCF on the following day on 11.9% of days. On 9.2% of days, the wind farm portfolio generated below 50% of the MDCF on multiple consecutive days.

Table 30 South Australian Wind Farm frequency of Consecutive Days generating below 50% of the MDCF Index

Consecutive Days	Incremental Frequency of Consecutive Days below MDCF Index * 0.5	Incremental % Frequency of Consecutive Days below MDCF Index * 0.5
0	696	78.91%
1	105	11.90%
2	45	5.10%
3	22	2.49%
4	9	1.02%
5	3	0.34%
6	2	0.23%
7	0	0.00%
Total	**882**	**100%**

Table 30 shows, the longest number of consecutive days that the wind farm portfolio generated below 50% of the MDCF was 6 days. This occurred on 2 occasions, from 25 June 2015 to 30 Jun 2015 and 21 August 2016 to 26 Aug 2016 (refer Figure 54).

Figure 54 South Australian Wind Farm Actual Daily Capacity Factor Index compared to the Mean (average) Daily Capacity Factor (MDCF) Index and 50% of the MDCF for August 2016

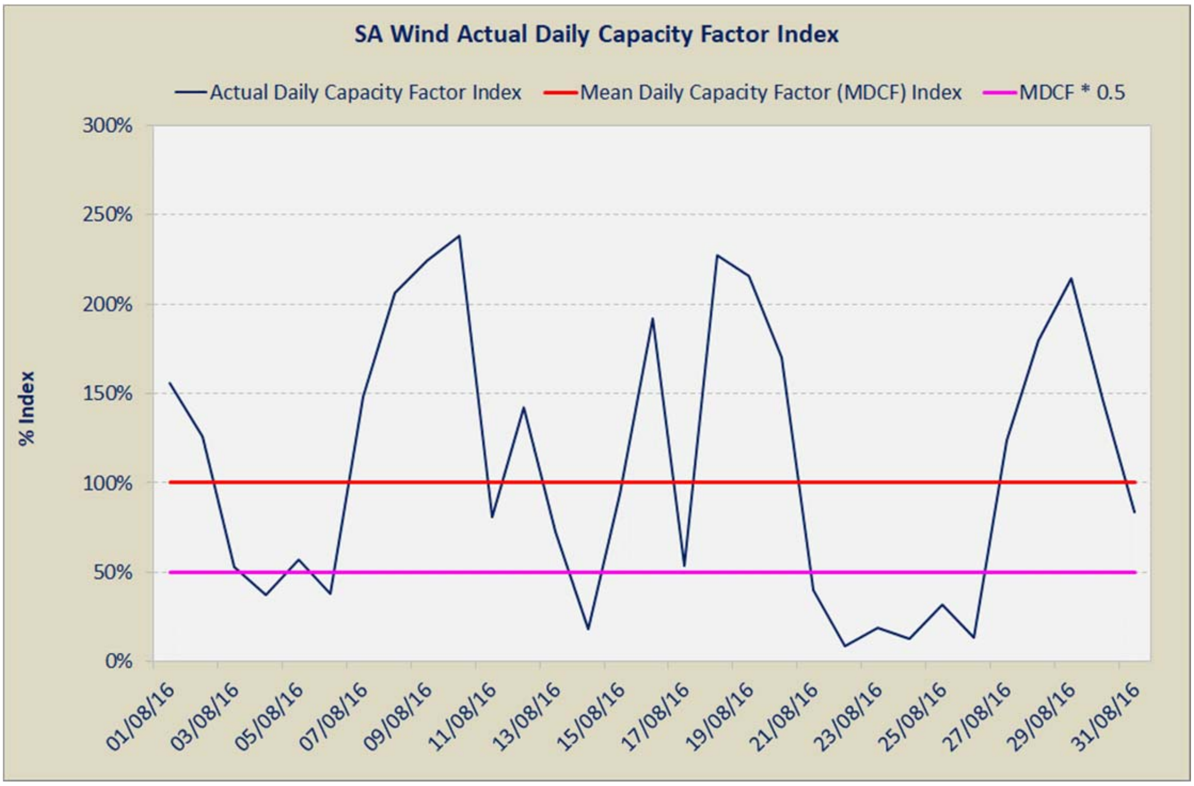
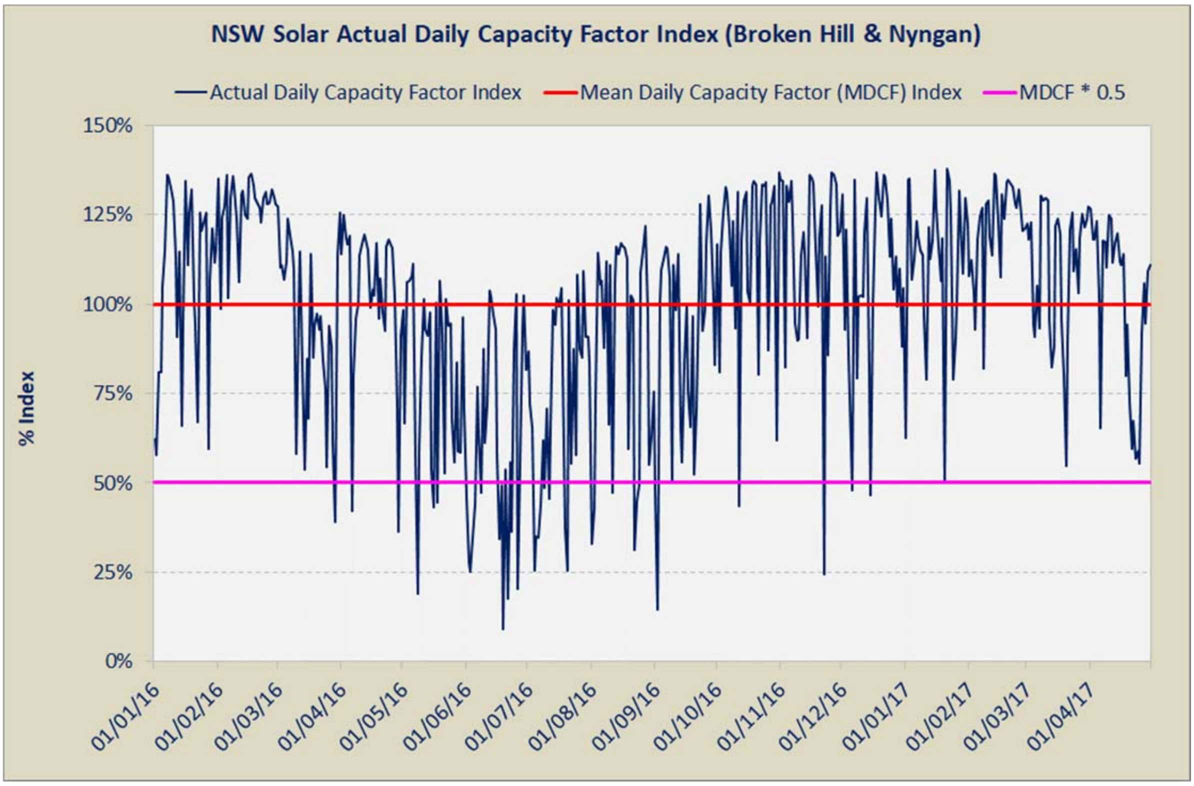


Figure 55 compares the actual daily capacity factor index of a portfolio of 2 solar PV farms in New South Wales over the period from January 2016 to May 2017 with a total capacity at 31 May 2017 of 102 MW[69].

[69] Due to limited data only Broken Hill and Nyngan solar PV farms have been included.

Figure 55 New South Wales Solar Farm PV Actual Daily Capacity Factor Index compared to the Mean (average) Daily Capacity Factor (MDCF) Index and 50% of the MDCF



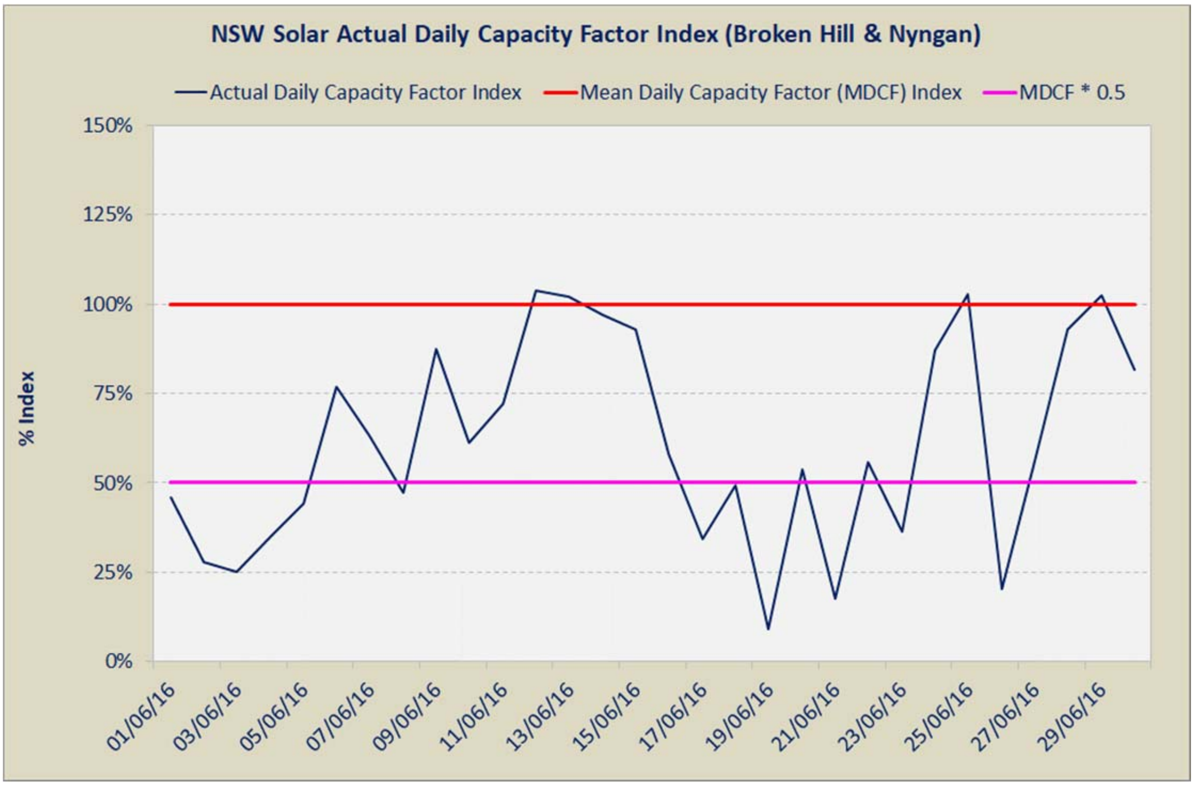
The data shows that on 59.7% of days, the solar PV farm portfolio generated at or above the Mean (average) Daily Capacity Factor (MDCF) and on 91.8% of days, the solar PV farm portfolio generated at or above 50% of the MDCF. The solar PV farm portfolio generated below 50% of the MDCF on a single day and then returned to or above the MDCF on the following day on 5.3% of days. On 2.9% of days, the wind farm portfolio generated below 50% of the MDCF on multiple consecutive days.

Table 31 New South Wales Solar PV Farm frequency of Consecutive Days generating below 50% of the MDCF Index

Consecutive Days	Incremental Frequency of Consecutive Days below MDCF Index * 0.5	Incremental % Frequency of Consecutive Days below MDCF Index * 0.5
0	446	91.77%
1	26	5.35%
2	7	1.44%
3	4	0.82%
4	2	0.41%
5	1	0.21%
6	0	0.00%
Total	**486**	**100%**

As Table 31 shows, the longest number of consecutive days that the solar PV farm portfolio generated below 50% of the MDCF was 5 days. This occurred on 1 occasion, from 1 June 2016 to 5 June 2015 (refer Figure 56).

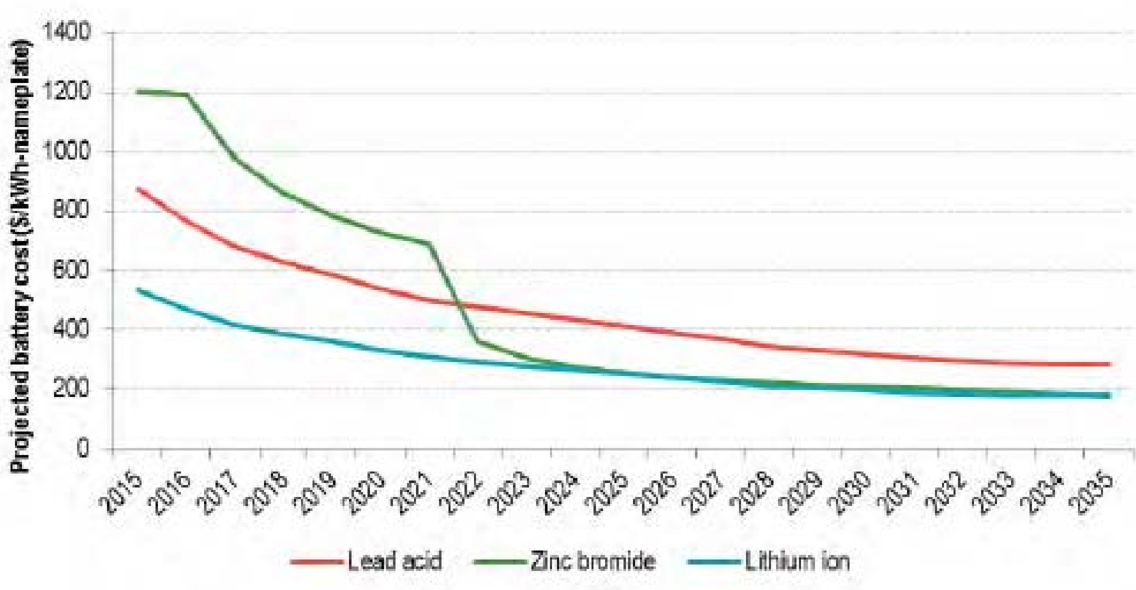
Figure 56 New South Wales Solar PV Farm Actual Daily Capacity Factor Index compared to the Mean (average) Daily Capacity Factor (MDCF) Index and 50% of the MDCF for June 2016



8.3.2. Hybrid Variable Renewable Energy Plus Battery Storage Costs

Battery cost rates used in the comparative analysis are summarised in Table 32, and are based on the cost information in the APGT report, which shows current day costs and projected costs based on learning curves (refer Figure 57).

Figure 57 APGT Battery and Inverter Cost Estimates 2015-2035



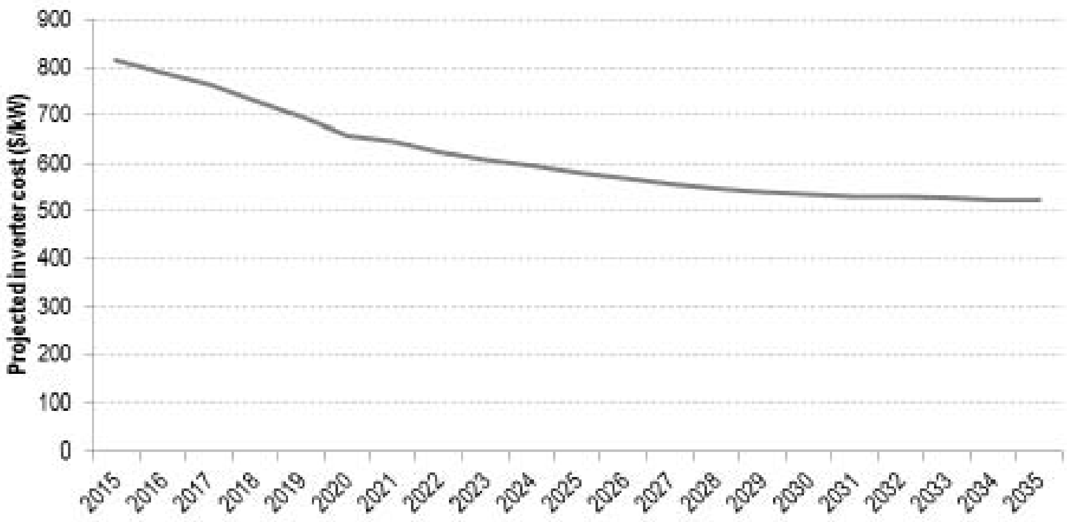


Table 32 Battery and Inverter Cost Assumptions

Element	UoM	2017	2030
Battery CAPEX	$/kWh	400-600	200-275
Battery OPEX[70]	$/MW pa	26,667	26,667
Inverter CAPEX	$/kW	750	550
Assumed Life	Years	10	10

It should also be noted that the proposed VRE plus battery hybrid system would not provide a secure response in line with that provided by a synchronous generator. A secure response would require provision of system strength (fault current) and inertia (initial inherent inertial response) services, which would require equipment such as a combination of synchronous condenser (for system strength) and a flywheel (for the initial inherent inertial response). These are not inexpensive items of equipment and would contribute significantly to the $/kW capital cost for the hybrid system.

Using the assumptions and rationale set out in section 0, a summary of the key parameters used to determine the specific plant requirements for a 650 MW base load Solar PV or Wind plus battery hybrid system are shown in Figure 58 and Figure 59.

[70] http://www.nrel.gov/docs/fy16osti/64987.pdf

Figure 58 Example Base Load Hybrid Solar PV plus Battery Storage

Hybrid Capacity	MWSO	650	650
Solar PV + Battery Daily Availability	%	96%	96%
Solar PV+ Battery Availability	h / d	23.1	23.1
Solar PV Installed Capacity	MWSO	2,846	4,017
Solar PV Capacity Factor	%	23%	17%
Solar PV Daily Production	h / d	5.488	4.08
Solar PV Daily Production	MWh / d	15,619	16,390

Battery Losses	%	5%	10%

Energy Required to Charge Battery	MWh / d	12,052	13,738

Battery Capacity when Available	MW	650	650
Battery Back-up Capacity Factor	%	73%	79%
Battery Back-up Required Production	h / d	17.61447	19.02247
Battery Cycle Efficency	%	95%	90%

Solar PV energy sent directly to grid	MWh / d	3,567	2,652
Solar PV capacity sent directly to grid	MWSO	650	650

Battery exportable energy	MWh / d	11,449	12,365
Battery net capacity	MW	650	650

Allowable DoD	%	80%	80%
Required Battery Storage	MWh / d	14,312	15,456
Consecutive unproductive days	days	2.00	3.00
Battery Storage	MWh / d	28,624	46,367

Figure 59 Example Base Load Hybrid Wind plus Battery Storage

Hybrid Capacity	MW_{SO}	650	650
Wind + Battery Daily Availability	%	96%	96%
Wind+ Battery Availability	h / d	23.1	23.1
Wind Installed Capacity	MW_{SO}	1,660	1,945
Wind Capacity Factor	%	39%	34%
Wind Daily Production	h / d	9.328	8.272
Wind Daily Production	MWh / d	15,488	16,088

Battery Losses	%	5%	10%

Battery Capacity when Available	MW	650	650
Battery Back-up Capacity Factor	%	57%	62%
Battery Back-up Required Production	h / d	13.77447	14.83047
Battery Cycle Efficency	%	95%	90%

Solar PV energy sent directly to grid	MWh / d	6,063	5,377
Solar PV capacity sent directly to grid	MW_{SO}	650	650

Energy Required to Charge Battery	MWh / d	9,425	10,711

Battery exportable energy	MWh / d	8,953	9,640
Battery net capacity	MW	650	650

Allowable DoD	%	80%	80%
Required Battery Storage	MWh / d	11,192	12,050
Consecutive unproductive days	days	2.00	3.00
Battery Storage	MWh / d	22,384	36,149

8.4. Generation Cost Assumptions

The key assumptions used for the LRMC comparative analysis (derived from the low and high assumptions in Table 20 and the updates outlined in the preceding sections) are shown in Table 33 and Table 34.

Table 33 Assumed 2017 Generation Cost Assumptions (in current Australian Dollars)

LRMC 2017 Cost Assumptions		650MW Black coal HELE USC (87-90% Capacity Factor, $0/tCO2e)		650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $0/tCO2e)		650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $25/tCO2e)		650MW NG CCGT (82-84% Capacity Factor, $0/tCO2e)		650MW NG CCGT+CCS (81-84% Capacity Factor, $0/tCO2e)		650MW NG CCGT +CCS (81-84% Capacity Factor, $25/tCO2e)	
Item Description	**UoM**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Power Station Capacity	$MW_{(SO)}$	650	650	650	650	650	650	650	650	650	650	650	650
Capacity Factor (Plant & Fuel/Storage)	%	90%	87%	89%	86%	89%	86%	84%	82%	84%	81%	84%	81%
Feasibility Period	Years	2	2	4	4	4	4	2	2	2	2	2	2
Construction Period	Years	4	4	4	4	4	4	2	2	3	3	3	3
EPC Contractor CAPEX Rate	$M/MW	2.85	3.30	5.31	7.80	5.31	7.80	1.10	1.60	2.80	3.30	2.80	3.30
Brownfield Cost Savings	$M/MW	-0.19	-0.19	-0.19	-0.19	-0.19	-0.19	-	-	-	-	-	-
Wet-Cooled Cost Savings	$M/MW	-0.11	-0.11	-0.11	-0.11	-0.11	-0.11	-	-	-	-	-	-
Asian Sourced Specialised Equipment	$M/MW	-0.39	-0.39	-0.90	-0.90	-0.90	-0.90	-	-	-	-	-	-
EPC Contractor CAPEX Rate Net Savings	$M/MW	2.16	2.61	4.11	6.60	4.11	6.60	1.10	1.60	2.80	3.30	2.80	3.30
CAPEX - Construction & Commissioning	$B	$1.41	$1.70	$2.67	$4.29	$2.67	$4.29	$0.72	$1.04	$1.82	$2.15	$1.82	$2.15
CAPEX - Owner's Soft/Misc Costs	$M	$20	$30	$25	$35	$25	$35	$10	$20	$15	$25	$15	$25
CAPEX - Interest during construction	$B	$0.21	$0.25	$0.40	$0.64	$0.40	$0.64	$0.05	$0.07	$0.20	$0.23	$0.20	$0.23
Total CAPEX	$B	$1.64	$1.98	$3.10	$4.97	$3.10	$4.97	$0.78	$1.13	$2.03	$2.40	$2.03	$2.40
Total CAPEX (exc. IDC)	$B	$1.43	$1.73	$2.70	$4.33	$2.70	$4.33	$0.73	$1.06	$1.84	$2.17	$1.84	$2.17
Replacement CAPEX	$M	-	-	-	-	-	-	-	-	-	-	-	-
Replacement CAPEX Year	Year	-	-	-	-	-	-	-	-	-	-	-	-
Plant Life	Years	30	30	50	30	50	30	30	30	40	30	40	30
Heat Rate (HHV_{SO})	GJ/MWh	8.52	8.85	9.87	12.00	9.87	12.00	6.86	7.20	7.87	8.60	7.87	8.60
Efficiency (HHV_{SO})	%	42.3%	40.7%	36.5%	30.0%	36.5%	30.0%	52.5%	50.0%	45.7%	41.9%	45.7%	41.9%
Fixed O&M per annum	$'000/MW	$45	$87	$55	$157	$55	$157	$10	$35	$17	$62	$17	$62
Variable O&M	$/MWh	$1.60	$4.00	$4.80	$9.00	$4.80	$9.00	$1.50	$7.00	$4.50	$12.00	$4.50	$12.00
Fuel Cost	$/GJ	$1.32	$4.00	$1.32	$4.00	$1.32	$4.00	$8.00	$12.00	$8.00	$12.00	$8.00	$12.00
Gross CO_{2e} emissions	kg CO2e/MWh	773	773	1056	1056	1056	1056	373	373	444	444	444	444
CO_{2e} Captured	kg CO2e/MWh	-	-	950	950	950	950	-	-	355	355	355	355
Residual CO_{2e} emissions	kg CO2e/MWh	773	773	106	106	106	106	373	373	89	89	89	89
CO_{2e} Transport and Storage	$/T CO2e	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00
Carbon Price	$/T CO2-e	-	-	-	-	$25	$25	-	-	-	-	$25	$25

LRMC 2017 Cost Assumptions		650MW OCGT (5-10% Capacity Factor)		650MW Variable Solar PV FFP (17-23% Capacity Factor)		650MW Variable Wind (34-39% Capacity Factor)		650MW Solar+Battery (96% Capacity Factor)		650MW Wind + Battery (96% Capacity Factor)	
Item Description	**UoM**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Power Station Capacity	$MW_{(SO)}$	650	650	650	650	650	650	650	650	650	650
Capacity Factor (Plant & Fuel/Storage)	%	10%	5%	23%	17%	39%	34%	96%	96%	96%	96%
Feasibility Period	Years	1	1	2	2	2	2	2	2	2	2
Construction Period	Years	1	1	2	2	2	2	2	2	2	2
EPC Contractor Capex Rate	$M/MW	0.74	1.10	2.10	2.50	2.20	2.70	27.56	59.00	20.14	42.20
Brownfield Cost Savings	$M/MW	-	-	-	-	-	-	-	-	-	-
Wet-Cooled Cost Savings	$M/MW	-	-	-	-	-	-	-	-	-	-
Asian Sourced Specialised Equipment	$M/MW	-	-	-	-	-	-	-	-	-	-
EPC Contractor CAPEX Rate Net Savings	$M/MW	0.74	1.10	2.10	2.50	2.20	2.70	27.56	59.00	20.14	42.20
CAPEX - Construction & Commissioning	$B	$0.48	$0.72	$1.37	$1.63	$1.43	$1.76	$17.91	$38.35	$13.09	$27.43
CAPEX - Owner's Soft/Misc Costs	$M	$5	$15	$5	$10	$5	$15	$5	$15	$5	$15
CAPEX - Interest during construction	$B	$0.02	$0.02	$0.10	$0.11	$0.10	$0.12	$1.25	$2.68	$0.92	$1.92
Total CAPEX	$B	$0.50	$0.75	$1.47	$1.75	$1.54	$1.89	$19.17	$41.05	$14.01	$29.36
Total CAPEX (exc. IDC)	$B	$0.48	$0.73	$1.37	$1.64	$1.44	$1.77	$17.92	$38.37	$13.10	$27.44
Replacement CAPEX	$M	-	-	-	-	-	-	$11,937	$28,308	$9,441	$22,177
Replacement CAPEX Year	Year	-	-	-	-	-	-	15	10	12.5	10
Plant Life	Years	30	30	30	20	25	20	30	20	25	20
Heat Rate (HHV_{SO})	GJ/MWh	10.23	10.60	-	-	-	-	-	-	-	-
Efficiency (HHV_{SO})	%	35.2%	34.0%	-	-	-	-	-	-	-	-
Fixed O&M per annum	$'000/MW	$4	$13	$25	$25	$40	$55	$139	$185	$132	$195
Variable O&M	$/MWh	$7.20	$12.00	-	$2.00	-	$15.00	$4.57	$7.12	$3.58	$19.92
Fuel Cost	$/GJ	$10.40	$19.20	-	-	-	-	-	-	-	-
Gross CO_{2e} emissions	kg CO2-e/MWh	478	478	-	-	-	-	-	-	-	-
CO_{2e} Captured	kg CO2e/MWh	-	-	-	-	-	-	-	-	-	-
Residual CO_{2e} emissions	kg CO2e/MWh	478	478	-	-	-	-	-	-	-	-
CO_{2e} Transport and Storage	$/T CO2e	$10.00	$20.00	-	-	-	-	$10.00	$20.00	$10.00	$20.00
Carbon Price	$/T CO2-e	-	-	-	-	-	-	-	-	-	-

Table 34 Assumed 2030 Generation Cost Assumptions (in current Australian Dollars)

LRMC 2030 Cost Assumptions		650MW Black coal HELE USC (87-90% Capacity Factor, $0/tCO2e)		650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $0/tCO2e)		650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $25/tCO2e)		650MW NG CCGT (82-84% Capacity Factor, $0/tCO2e)		650MW NG CCGT+CCS (81-84% Capacity Factor, $0/tCO2e)		650MW NG CCGT +CCS (81-84% Capacity Factor, $25/tCO2e)	
Item Description	**UoM**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Power Station Capacity	$MW_{(SO)}$	650	650	650	650	650	650	650	650	650	650	650	650
Capacity Factor (Plant and Fuel/Storage)	%	90%	87%	89%	86%	89%	86%	84%	82%	84%	81%	84%	81%
Feasibility Period	Years	2	2	4	4	4	4	2	2	2	2	2	2
Construction Period	Years	4	4	4	4	4	4	2	2	3	3	3	3
EPC Contractor CAPEX Rate	$M/MW	2.47	3.04	4.60	6.32	4.60	6.32	1.13	1.44	2.04	3.12	2.04	3.12
Brownfield Cost Savings	$M/MW	-0.19	-0.19	-0.19	-0.19	-0.19	-0.19	-	-	-	-	-	-
Wet-Cooled Cost Savings	$M/MW	-0.11	-0.11	-0.11	-0.11	-0.11	-0.11	-	-	-	-	-	-
Asian Sourced Specialised Equipment	$M/MW	-0.39	-0.39	-0.90	-0.90	-0.90	-0.90	-	-	-	-	-	-
EPC Contractor CAPEX Rate Net Savings	$M/MW	1.78	2.35	3.41	5.12	3.41	5.12	1.13	1.44	2.04	3.12	2.04	3.12
CAPEX - Construction & Commissioning	$B	$1.15	$1.53	$2.21	$3.33	$2.21	$3.33	$0.73	$0.94	$1.33	$2.03	$1.33	$2.03
CAPEX - Owner's Soft/Misc Costs	$M	$20	$30	$25	$35	$25	$35	$10	$20	$15	$25	$15	$25
CAPEX - Interest during construction	$B	$0.17	$0.23	$0.33	$0.50	$0.33	$0.50	$0.05	$0.07	$0.14	$0.22	$0.14	$0.22
Total CAPEX	$B	$1.35	$1.78	$2.57	$3.86	$2.57	$3.86	$0.79	$1.02	$1.49	$2.28	$1.49	$2.28
Total CAPEX (exc. IDC)	$B	$1.17	$1.56	$2.24	$3.36	$2.24	$3.36	$0.74	$0.96	$1.34	$2.06	$1.34	$2.06
Replacement CAPEX	$M	-	-	-	-	-	-	-	-	-	-	-	-
Replacement CAPEX Year	Year	-	-	-	-	-	-	-	-	-	-	-	-
Plant Life	Years	30	30	50	30	50	30	30	30	40	30	40	30
Heat Rate (HHV_{SO})	GJ/MWh	7.93	8.85	9.11	10.24	9.11	10.24	6.00	6.86	7.20	7.87	7.20	7.87
Efficiency (HHV_{SO})	%	45.4%	40.7%	39.5%	35.2%	39.5%	35.2%	60.0%	52.5%	50.0%	45.7%	50.0%	45.7%
Fixed O&M per annum	$'000/MW	$45	$87	$55	$157	$55	$157	$10	$35	$17	$62	$17	$62
Variable O&M	$/MWh	$1.60	$4.00	$4.80	$9.00	$4.80	$9.00	$1.50	$7.00	$4.50	$12.00	$4.50	$12.00
Fuel Cost	$/GJ	$1.32	$4.00	$1.32	$4.00	$1.32	$4.00	$8.00	$12.00	$8.00	$12.00	$8.00	$12.00
Gross CO_{2e} emissions	kg CO2-e/MWh	773	773	1056	1056	1056	1056	373	373	444	444	444	444
CO_{2e} Captured	kg CO2e/MWh	-	-	950	950	950	950	-	-	355	355	355	355
Residual CO_{2e} emissions	kg CO2e/MWh	773	773	106	106	106	106	373	373	89	89	89	89
CO_{2e} Transport and Storage	$/T CO2e	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00	$10.00	$20.00
Carbon Price	$/T CO2-e	-	-	-	-	$25	$25	-	-	-	-	$25	$25

LRMC 2030 Cost Assumptions		650MW OCGT (5-10% Capacity Factor)		650MW Variable Solar PV FFP (17-23% Capacity Factor)		650MW Variable Wind (37-41% Capacity Factor)		650MW Solar+Battery (96% Capacity Factor)		650MW Wind + Battery (96% Capacity Factor)	
Item Description	**UoM**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Power Station Capacity	$MW_{(SO)}$	650	650	650	650	650	650	650	650	650	650
Capacity Factor (Plant and Fuel/Storage)	%	10%	5%	23%	17%	41%	37%	96%	96%	96%	96%
Feasibility Period	Years	1	1	2	2	2	2	2	2	2	2
Construction Period	Years	1	1	2	2	2	2	2	2	2	2
EPC Contractor CAPEX Rate	$M/MW	0.78	1.21	1.05	2.44	1.76	2.70	13.95	37.10	11.39	24.20
Brownfield Cost Savings	$M/MW	-	-	-	-	-	-	-	-	-	-
Wet-Cooled Cost Savings	$M/MW	-	-	-	-	-	-	-	-	-	-
Asian Sourced Specialised Equipment	$M/MW	-	-	-	-	-	-	-	-	-	-
EPC Contractor CAPEX Rate Net Savings	$M/MW	0.78	1.21	1.05	2.44	1.76	2.70	13.95	37.10	11.39	24.20
CAPEX - Construction & Commissioning	$B	$0.50	$0.79	$0.68	$1.59	$1.14	$1.75	$9.07	$24.11	$7.41	$15.73
CAPEX - Owner's Soft/Misc Costs	$M	$5	$15	$5	$10	$5	$15	$5	$15	$5	$15
CAPEX - Interest during construction	$B	$0.02	$0.03	$0.05	$0.11	$0.08	$0.12	$0.63	$1.69	$0.52	$1.10
Total CAPEX	$B	$0.53	$0.83	$0.74	$1.71	$1.23	$1.89	$9.71	$25.81	$7.93	$16.84
Total CAPEX (exc. IDC)	$B	$0.51	$0.80	$0.69	$1.60	$1.15	$1.77	$9.08	$24.13	$7.41	$15.74
Replacement CAPEX	$M	-	-	-	-	-	-	$6,082	$14,316	$4,652	$10,829
Replacement CAPEX Year	Year	-	-	-	-	-	-	15	10	12.5	10
Plant Life	Years	30	30	30	20	25	20	30	20	25	20
Heat Rate (HHV_{SO})	GJ/MWh	8.78	10.38	-	-	-	-	-	-	-	-
Efficiency (HHV_{SO})	%	41.0%	34.7%	-	-	-	-	-	-	-	-
Fixed O&M per annum	$'000/MW	$4	$13	$25	$25	$40	$55	$139	$185	$126	$184
Variable O&M	$/MWh	$7.20	$12.00	-	$2.00	-	$15.00	$4.57	$7.12	$3.43	$19.74
Fuel Cost	$/GJ	$10.40	$19.20	-	-	-	-	-	-	-	-
Gross CO_{2e} emissions	kg CO2-e/MWh	478	478	-	-	-	-	-	-	-	-
CO_{2e} Captured	kg CO2e/MWh	-	-	-	-	-	-	-	-	-	-
Residual CO_{2e} emissions	kg CO2e/MWh	478	478	-	-	-	-	-	-	-	-
CO_{2e} Transport and Storage	$/T CO2e	$10.00	$20.00	-	-	-	-	-	-	-	-
Carbon Price	$/T CO2-e	-	-	-	-	-	-	-	-	-	-

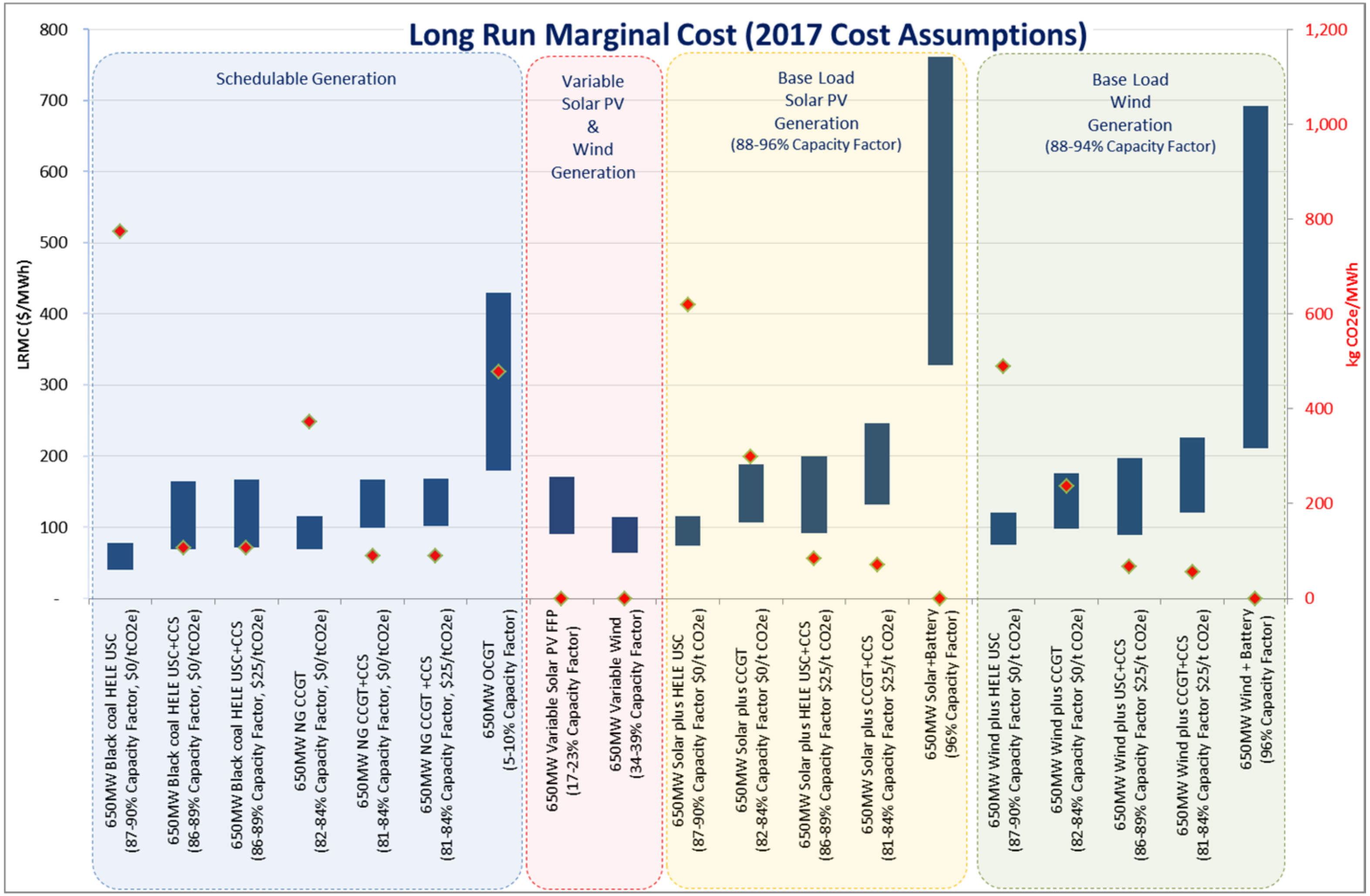
8.5. Comparative Long Run Marginal Cost Results

The comparative LRMC results based on 2017 assumptions are shown in Table 35 and Figure 60; and the comparative LRMC results based on 2030 assumptions are shown in Table 36 and Figure 61.

Table 35 LRMC all cases based on 2017 price assumptions (2017 AUD)

LRMC Dissection (2017 pricing)	UoM	CAPEX	Fuel	Fixed O&M	Variable O&M	CO_{2e} T&S	CO_{2e} Permits	Tax	Total
		$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
650MW Black coal HELE USC	Low	17	11	6	2	-	-	4	40
(87-90% Capacity Factor, $0/tCO2e)	High	22	35	11	4	-	-	6	78
650MW Black coal HELE USC+CCS	Low	26	13	7	5	10	-	8	69
(86-89% Capacity Factor, $0/tCO2e)	High	54	48	21	9	19	-	14	165
650MW Black coal HELE USC+CCS	Low	26	13	7	5	10	3	8	72
(86-89% Capacity Factor, $25/tCO2e)	High	54	48	21	9	19	3	14	168
650MW NG CCGT	Low	9	55	1	2	-	-	2	69
(82-84% Capacity Factor, $0/tCO2e)	High	14	86	5	7	-	-	3	115
650MW NG CCGT+CCS	Low	20	63	2	5	4	-	6	100
(81-84% Capacity Factor, $0/tCO2e)	High	28	103	9	12	7	-	7	167
650MW NG CCGT +CCS	Low	20	63	2	5	4	2	6	102
(81-84% Capacity Factor, $25/tCO2e)	High	28	103	9	12	7	2	7	169
650MW Variable Solar PV FFP	Low	62	-	12	-	-	-	16	90
(17-23% Capacity Factor)	High	127	-	17	2	-	-	26	171
650MW Variable Wind	Low	42	-	12	-	-	-	10	64
(34-39% Capacity Factor)	High	68	-	18	15	-	-	14	115
650MW OCGT	Low	49	106	5	7	-	-	12	179
(5-10% Capacity Factor)	High	148	204	30	12	-	-	36	430
650MW Solar+Battery	Low	263	-	17	5	-	-	44	328
(96% Capacity Factor)	High	782	-	22	7	-	-	102	913
650MW Wind + Battery	Low	156	-	16	4	-	-	36	211
(96% Capacity Factor)	High	577	-	23	20	-	-	73	693
650MW Solar plus HELE USC	Low	47	9	9	1	-	-	8	74
(87-90% Capacity Factor $0/t CO2e)	High	58	29	15	4	-	-	10	116
650MW Solar plus HELE USC+CCS	Low	47	10	10	4	7	-	11	89
(86-89% Capacity Factor $0/t CO2e)	High	91	40	24	8	16	-	19	197
650MW Solar plus HELE USC+CCS	Low	47	10	10	4	7	2	11	91
(86-89% Capacity Factor $25/t CO2e)	High	91	40	24	8	16	2	19	199
650MW Wind plus HELE USC	Low	48	7	11	1	-	-	8	75
(87-90% Capacity Factor $0/t CO2e)	High	61	23	19	8	-	-	10	121
650MW Wind plus USC+CCS	Low	48	8	12	3	6	-	11	88
(86-89% Capacity Factor $0/t CO2e)	High	94	31	28	11	12	-	19	196
650MW Wind plus USC+CCS	Low	48	8	12	3	6	2	11	90
(86-89% Capacity Factor $25/t CO2e)	High	94	31	28	11	12	2	19	198
650MW Solar plus CCGT	Low	40	55	5	1	-	-	6	107
(82-84% Capacity Factor $0/t CO2e)	High	52	115	8	6	-	-	8	189
650MW Solar plus CCGT+CCS	Low	46	63	6	3	3	-	9	130
(81-84% Capacity Factor $0/t CO2e)	High	67	137	12	10	6	-	12	245
650MW Solar plus CCGT+CCS	Low	46	63	6	3	3	2	9	132
(81-84% Capacity Factor $25/t CO2e)	High	67	137	12	10	6	2	12	246
650MW Wind plus CCGT	Low	41	44	7	1	-	-	6	99
(82-84% Capacity Factor $0/t CO2e)	High	55	91	13	10	-	-	8	176
650MW Wind plus CCGT+CCS	Low	47	50	8	3	2	-	9	119
(81-84% Capacity Factor $0/t CO2e)	High	70	108	17	13	5	-	12	225
650MW Wind plus CCGT+CCS	Low	47	50	8	3	2	1	9	120
(81-84% Capacity Factor $25/t CO2e)	High	70	108	17	13	5	1	12	226

Figure 60 LRMC all cases based on 2017 price assumptions (2017 AUD)

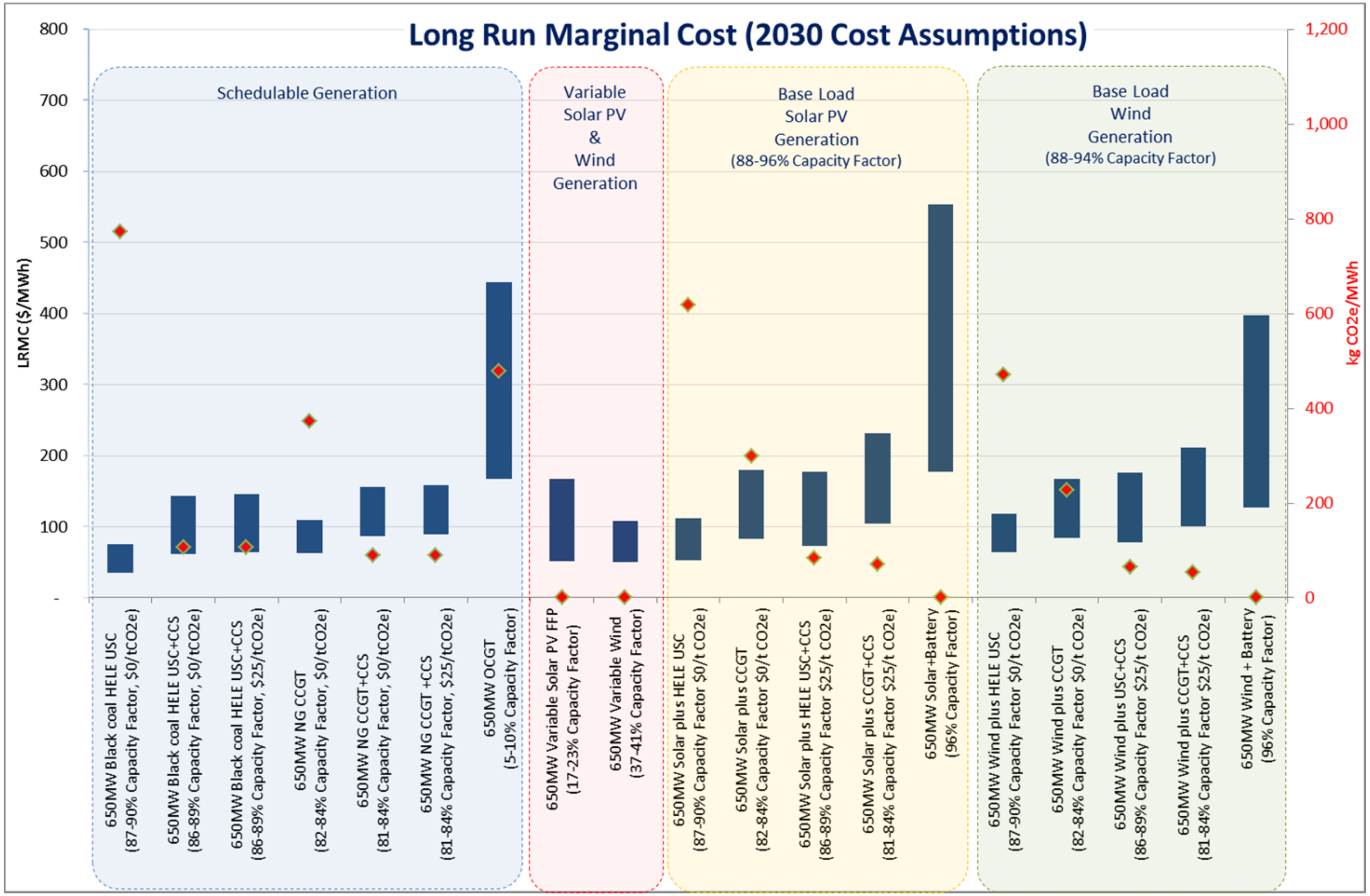


Note: The left vertical axis provides the LRMC for the relevant technology range (blue bar) and the right vertical axis provides the CO_{2e} emission intensity indicated as the red diamond vertically adjacent each technology.

Table 36 LRMC all cases based on 2030 price assumptions (2017 AUD)

LRMC Dissection (2030 pricing)	UoM	CAPEX	Fuel	Fixed O&M	Variable O&M	CO2e T&S	CO2e Permits	Tax	Total
		$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
650MW Black coal HELE USC	Low	14	10	6	2	-	-	4	36
(87-90% Capacity Factor, $0/tCO2e)	High	19	35	11	4	-	-	5	75
650MW Black coal HELE USC+CCS	Low	22	12	7	5	10	-	7	62
(86-89% Capacity Factor, $0/tCO2e)	High	42	41	21	9	19	-	11	143
650MW Black coal HELE USC+CCS	Low	22	12	7	5	10	3	7	65
(86-89% Capacity Factor, $25/tCO2e)	High	42	41	21	9	19	3	11	146
650MW NG CCGT	Low	9	48	1	2	-	-	2	62
(82-84% Capacity Factor, $0/tCO2e)	High	12	82	5	7	-	-	3	109
650MW NG CCGT+CCS	Low	15	58	2	5	4	-	4	87
(81-84% Capacity Factor, $0/tCO2e)	High	27	94	9	12	7	-	7	156
650MW NG CCGT +CCS	Low	15	58	2	5	4	2	4	89
(81-84% Capacity Factor, $25/tCO2e)	High	27	94	9	12	7	2	7	158
650MW Variable Solar PV FFP	Low	31	-	12	-	-	-	8	51
(17-23% Capacity Factor)	High	124	-	17	2	-	-	25	168
650MW Variable Wind	Low	32	-	11	-	-	-	7	50
(37-41% Capacity Factor)	High	63	-	17	15	-	-	13	108
650MW OCGT	Low	52	91	5	7	-	-	13	167
(5-10% Capacity Factor)	High	163	199	30	12	-	-	40	444
650MW Solar+Battery	Low	133	-	17	5	-	-	23	177
(96% Capacity Factor)	High	460	-	22	7	-	-	65	554
650MW Wind + Battery	Low	88	-	15	3	-	-	20	127
(96% Capacity Factor)	High	314	-	22	20	-	-	42	397
650MW Solar plus HELE USC	Low	29	8	9	1	-	-	6	53
(87-90% Capacity Factor $0/t CO2e)	High	55	29	15	4	-	-	9	112
650MW Solar plus HELE USC+CCS	Low	32	9	10	4	7	-	8	71
(86-89% Capacity Factor $0/t CO2e)	High	78	34	24	8	16	-	15	175
650MW Solar plus HELE USC+CCS	Low	32	9	10	4	7	2	8	73
(86-89% Capacity Factor $25/t CO2e)	High	78	34	24	8	16	2	15	177
650MW Wind plus HELE USC	Low	39	6	11	1	-	-	7	64
(87-90% Capacity Factor $0/t CO2e)	High	59	22	19	8	-	-	10	118
650MW Wind plus USC+CCS	Low	39	7	12	3	6	-	9	76
(86-89% Capacity Factor $0/t CO2e)	High	82	26	28	11	12	-	16	175
650MW Wind plus USC+CCS	Low	39	7	12	3	6	2	9	77
(86-89% Capacity Factor $25/t CO2e)	High	82	26	28	11	12	2	16	177
650MW Solar plus CCGT	Low	25	48	5	1	-	-	4	83
(82-84% Capacity Factor $0/t CO2e)	High	49	109	8	6	-	-	7	180
650MW Solar plus CCGT+CCS	Low	28	58	6	3	3	-	6	103
(81-84% Capacity Factor $0/t CO2e)	High	65	125	12	10	6	-	11	230
650MW Solar plus CCGT+CCS	Low	28	58	6	3	3	2	6	105
(81-84% Capacity Factor $25/t CO2e)	High	65	125	12	10	6	2	11	232
650MW Wind plus CCGT	Low	35	37	7	1	-	-	5	85
(82-84% Capacity Factor $0/t CO2e)	High	53	83	13	10	-	-	8	167
650MW Wind plus CCGT+CCS	Low	36	44	8	3	2	-	7	100
(81-84% Capacity Factor $0/t CO2e)	High	69	95	17	13	4	-	12	210
650MW Wind plus CCGT+CCS	Low	36	44	8	3	2	1	7	101
(81-84% Capacity Factor $25/t CO2e)	High	69	95	17	13	4	1	12	212

Figure 61 LRMC all cases based on 2030 price assumptions (2017 AUD)



Note: The left vertical axis provides the LRMC for the relevant technology range (blue bar) and the right vertical axis provides the CO_{2e} emission intensity indicated as the red diamond vertically adjacent each technology.

9. Results Discussion

Historically NEM generators have been able to provide reliable, secure and affordable electricity to consumers through a mix of generation technologies built on a foundation of coal-fired base load capacity.

The existing base load generation fleet is ageing, with 50% of capacity forecast to retire over the next two decades. For the year ending 31 March 2017, the minimum half-hourly demand in the NEM was approximately 16.4 GW. Sufficient base load capacity will need to be maintained to meet minimum demand by an appropriate mix of power generation technologies.

The analysis in this report sets out a like-for-like comparison of the costs of a range of base load technologies for a notional 650 MW stand-alone power station that can deliver reliable, secure, affordable and sustainable electricity to consumers and that can be deployed on a commercial scale in the near term.

The LRMC analysis in Section 8.5 shows that, of the available schedulable generation technology options, a HELE USC coal-fired power station (without or with CCS) is the lowest cost generation option that can meet all of the key criteria of reliable, secure, affordable and sustainable electricity using estimated 2017 and 2030 cost data (refer Table 37 and Table 38).

Table 37 USC and CCGT LRMC comparison

LRMC	UoM	650MW Black coal HELE USC (87-90% Capacity Factor, $0/tCO2e)		650MW NG CCGT (82-84% Capacity Factor, $0/tCO2e)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	40	78	69	115
Total (2030 cost assumptions)	$/MWh	36	75	62	109

Natural gas CCGT is more expensive than HELE USC coal-fired generation (48-71% and 45-74% higher using 2017 and 2030 cost data respectively) and is particularly sensitive to higher fuel costs resulting from limited gas supplies and links to international oil prices.

Natural gas-fired CCGT generation with CCS can also meet the key criteria of reliable, secure, affordable and sustainable electricity, albeit at a cost premium to a USC coal-fired power station with CCS (refer Table 38). However, given the SRMC cost premium for a natural gas CCGT, its optimal role is likely to be at mid-merit capacity factors, rather than base load.

Table 38 USC plus CCS and CCGT plus CCS LRMC comparison

LRMC	UoM	650MW Black coal HELE USC+CCS (86-89% Capacity Factor, $25/tCO2e)		650MW NG CCGT +CCS (81-84% Capacity Factor, $25/tCO2e)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	72	168	102	169
Total (2030 cost assumptions)	$/MWh	65	146	89	158

The low case LRMCs of intermittent Wind and Solar PV generation are converging towards natural gas-fired CCGT and to a much lesser extent, towards USC coal-fired power station costs (refer Table 39). However, these Wind and Solar PV generation options exclude the additional cost of backing up the intermittency, and therefore fail to meet the reliable and secure criteria on a stand-alone basis, or the affordability criterion if taking account of firming.

Table 39 Variable Solar and Wind LRMC comparison

LRMC	UoM	650MW Variable Solar PV FFP (17-23% Capacity Factor)		650MW Variable Wind (34-39% Capacity Factor)	
		Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	90	171	64	115
Total (2030 cost assumptions)	$/MWh	51	168	50	108

Natural gas-fired OCGT generation operating at low capacity factors is expensive, primarily due to high fuel costs and poor cycle efficiency. Given the ability of natural gas-fired OCGTs to respond rapidly to changes in load, it is most likely suited to peaking duty with some contribution towards firming VRE, albeit at low capacity factors (essentially providing some smoothing of volatile VRE output).

A USC coal-fired power station (without and with USC) and a natural gas CCGT (without and with CCS) are both technically capable of firming VRE. However, a USC coal-fired power station with CCS is lower cost than a natural gas-fired CCGT with CCS.

Wind (and to a lesser extent Solar PV) firmed with a natural gas-fired CCGT is particularly vulnerable to the rigid 100% ToP contract terms in current GSAs and GTAs.

VRE firmed exclusively with batteries is prohibitively more expensive than VRE firmed using a USC coal-fired power station with CCS (refer Table 40).

Table 40 VRE firmed with batteries versus VRE firmed with USC plus CCS (LRMC comparison

LRMC	UoM	650MW Solar + Battery (96% Capacity Factor)		650MW Wind + Battery (96% Capacity Factor)		650MW Solar plus HELE USC+CCS (86-89% Capacity Factor $25/t CO2e)		650MW Wind plus USC+CCS (86-89% Capacity Factor $0/t CO2e)	
		Low	High	Low	High	Low	High	Low	High
Total (2017 cost assumptions)	$/MWh	328	913	211	693	91	199	90	198
Total (2030 cost assumptions)	$/MWh	177	554	127	397	73	177	77	177

Whilst reducing the level of battery storage to four to seven hours significantly reduces the overall cost of a hybrid VRE battery system (as low as $100-150/MWh using 2030 low case costs), this system displaces peak and mid-merit generation and does little to alleviate the increased risks to supply security and reliability resulting from the retirement of existing base load capacity.

The comparative investment required for 650 MW of firm base load capacity from coal-fired, natural gas or renewables with batteries is shown in Table 41.

Whilst the initial investment for a natural gas-fired CCGT is approximately half that of USC coal-fired generation, this is more than offset by the much higher annual CCGT operating costs (including fuel costs) which are approximately 170-245% higher than equivalent coal-fired generation annual operating costs.

The level of investment required to deliver base load renewables with batteries is significantly higher than both the coal-fired and natural gas-fired generation options, even with CCS factored into the cost.

Table 41 CAPEX investment for 650MW base load power station (2017 AUD)

Base Load Capacity Capital Cost (excluding IDC)		Black coal HELE USC		Black coal HELE USC + CCS		NG CCGT		NG CCGT + CCS		Solar + Battery		Wind + Battery	
Item Description	**UoM**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Power Station Capacity	MW	650	650	650	650	650	650	650	650	650	650	650	650
Total 2017 CAPEX	$M	1,427	1,727	2,698	4,326	726	1,060	1,835	2,170	17,919	38,366	13,099	27,443
Total 2030 CAPEX	$M	1,347	1,784	2,571	3,861	793	1,021	1,488	2,276	9,710	25,814	7,928	16,843
Fuel $M p.a.	$M p.a.	57	175	66	236	263	401	299	475	0	0	0	0
OPEX Fixed $M p.a.	$M p.a.	29	57	36	102	7	23	11	40	91	120	86	126
OPEX Variable $M p.a.	$M p.a.	8	20	24	44	7	32	21	55	25	39	20	109
CO2 T&S $M p.a.	$M p.a.	0	0	48	93	0	0	17	33	0	0	0	0
CO2e Permits $M p.a.	$M p.a.	0	0	13	13	0	0	11	10	0	0	0	0
Tax $M p.a.	$M p.a.	23	28	42	70	11	16	28	33	244	560	195	399

The emissions intensity of the Victorian brown coal fleet is approximately 1.45 t CO_2e/MWh, and the emissions intensity of the NSW black coal-fired fleet is approximately at 0.98 t CO_2e/MWh. Replacing existing older coal-fired power stations with USC black coal-fired generation (which has an emissions intensity of approximately 0.77tCO_2e/MWh) will yield an immediate and significant reduction in CO_2e emissions.

Black coal-fired USC with 90% CCS can achieve an emissions intensity of approximately 0.106 t CO_2e/MWh[71]. Therefore, if new HELE USC coal-fired generation is developed with provision for the retrofitting of CCS, further significant emissions reductions may be achieved.

Given its lower variable operating costs, a USC coal-fired power station is likely to have a lower short-run marginal cost (SRMC) compared to a natural gas-fired CCGT. Consequently, the deployment of USC coal-fired power stations would likely result in lower wholesale electricity spot prices to the extent that coal displaces gas-fired generation as the dominant marginal price setting technology. In effect, new USC coal-fired power generation would provide a hedge against rising gas prices.

[71] http://www.ieaghg.org/docs/General_Docs/IEAGHG_Presentations/A_Global_Perspective_on_the_Status_of_Carbon_Capture.pdf

10. Key Project Development Risks

10.1. Orderly Replacement of Ageing Fleet

As discussed in section 5.1, over the next two decades, approximately half of the existing electricity generation fleet (25 GW) is forecast to be at the end of its economic / engineering life and will need to be replaced.

As discussed in section 3, recent NEM generation retirements have led to sharp market price increases. Market and regulatory uncertainties have prevented a conducive environment for replacement capacity to be planned, developed and financed in an orderly and timely manner.

To avoid continuing disruption, potential supply shortages, and ongoing price shocks due to power station closures, regulatory intervention is required in order:

- to signal when replacement capacity is needed, to ensure that new generation developments are progressed in a cost-effective and timely manner; and
- to ensure that an orderly, optimal and cost-effective transition and retirement process is achieved for existing ageing plant.

This report highlights the looming “cliff edge” of large ageing power station retirements. The future implementation of emissions abatement measures (e.g. an emissions trading scheme; or carbon tax “Mark II”) is likely to exacerbate the cliff edge, as existing coal-fired generators align retirement plans around scheme implementation timelines.

10.2. Wholesale market and renewable market realignment

Prime Minister, Malcolm Turnbull spoke to the issue of Australia’s energy security, affordability and sustainability in an address to the National Press Club on 1 February 2017.

“So here's the current picture. Old, high emissions coal-fired power stations are closing down as they age, reducing baseload capacity. They cannot simply be replaced by gas, because it's too expensive, or by wind or solar because they are intermittent.

Storage has a very big role to play, that's true. But we will need more synchronous baseload power and as the world’s largest coal exporter, we have a vested interest in showing that we can provide both lower emissions and reliable base load power with state-of-the-art clean coal-fired technology.

The next incarnation of our national energy policy should be technology agnostic. It’s security and cost that matters most, not how you deliver it.

Policy should be all of the above technologies, working together to deliver the trifecta of secure and affordable power while meeting our emission reduction commitments.” [72]

The wholesale electricity market is structured to deliver the lowest generated cost of electricity through a continuous auction (reflecting upcoming load) and bidding process. Successful generator bids are awarded in merit order, starting with the lowest cost offer, followed by the next highest offer and so on, until the desired level of generation is dispatched in order to meet demand, with the price paid to all accepted offers set with reference to the most expensive generation source used during the trading interval.

Wholesale market generators are therefore paid for energy when it is required. More broadly, this means that at peak times (high demand periods) generators can earn a premium price for energy

[72] https://www.pm.gov.au/media/2017-02-01/address-national-press-club

produced, reflecting the need for more expensive forms of generation to serve the load. Conversely, at off-peak times, generators receive prices closer to the marginal cost of generation (fuel and variable operating costs), reflecting low demand and an abundance of available generation capacity.

In contrast, renewable generators such as wind and solar are intermittent and cannot be scheduled, and accordingly will seek to generate whenever the fuel resource (wind and sunlight) is available, thus their dispatch profiles have little or no relationship to underlying electricity demand. Whilst a portion of renewable generation revenue is earnt through the sale of wholesale electricity, a significant and vital source of revenue for intermittent generators stems from the creation and sale of renewable energy certificates (LGCs), a subsidy created to help commercialise these technologies. LGCs are created without reference to underlying demand or corresponding prices in the wholesale electricity market.

Given that wind and solar PV generation marginal costs are low (i.e. they do not need to buy any fuel), when available, these generators displace other forms of generation from the grid. However, a stable and reliable system requires schedulable plant to generate at times when these intermittent renewable generators cannot. If schedulable plant is regularly displaced from the wholesale electricity market by low-cost intermittent renewables, then the financial viability of this generation capacity may be undermined to the extent that it is no longer available when required.

The NBER BTG study confirmed that the deployment of VRE historically and for the foreseeable future (in the absence of lower cost storage solutions), is intrinsically bound to the ability of the existing schedulable generation fleet to operate when the renewable generation cannot[73].

Historically, the level of VRE in the NEM has been modest, and the wholesale market has been able to absorb the cost of backing up intermittent renewables. However, as the penetration of VRE increases, the profitability of other schedulable generation is likely to be impacted to the extent that reliable generation capacity is forced out of the market.

The misalignment of payment mechanisms for generators who derive income from the sale wholesale electricity is a potential barrier to a new HELE power station development, and puts at risk ongoing reliable, secure, safe, affordable and sustainable electricity for consumers. Market mechanisms should be re-aligned to recognise and reward generation capacity that will be reliably available when required.

10.3. Financial Impediments

Investment in generation to serve base load demand, which accounts for over two-thirds of the energy in the NEM, requires investors and lenders to manage long-term market, regulatory and performance risks. Large coal-fired generation plants are typically designed for an operating life of 50 years. Debt financing is typically assessed with close scrutiny of the first 15 years of operation, with equity financiers usually focused on risk and return over the first 25 years.

As discussed in section 5, since the 1950s, both state and federal governments have invested directly or indirectly in power generation. Government’s role in facilitating power generation capacity has ranged from direct development, construction and operation, to public-private partnerships and joint ventures, to acting as a long-term off-taker. All of the existing large coal-fired generators in Australia were developed and financed by state governments, with some recent exceptions in Queensland that were developed by the private sector, or with some private sector equity participation. Generation privatisation in other states involved existing assets.

[73] Bridging The Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion? (Verdolini, Vona, Popp) Working Paper 22454 http://www.nber.org/papers/w2245

Even under a market-based system with many privately-owned companies generating electricity, the public tends to hold governments ultimately responsible for reliability, security and affordability of electricity. The South Australian government's response to the September 2016 black system is a case in point. The Federal Government's proposal to buy out the state-owned shares in Snowy Hydro along with the 'Snowy 2.0' pumped hydro proposal, signals growing concern at the Commonwealth level with power system security and affordability.

Looking ahead, and as the need to replace base load generation capacity becomes clearer, the role of the private sector is expected to continue to remain important, both as a provider of capital and as an asset owner.

The technical and operational risk associated with building a USC coal-fired plant is low as it is a proven technology, with the first plant built in Japan in 1993. To date, there have been 1,015 SC and USC coal-fired generating units brought into operation internationally, and a further 1,231 are planned or under construction[74]. Australia already has four SC coal-fired power stations and USC is an evolution of that technology at a higher efficiency level.

Financing for USC coal-fired power stations overseas has come from a variety of sources, including government, development banks, export credit agencies and investment banks[75]. In the Australian context, the participation of domestic and or international banks is also possible in new generation capacity, provided that credit and other risk exposures are adequately addressed.

Some large coal-fired plants in Queensland were financed on a merchant basis, but in the current market in Australia it is very difficult to obtain debt for new large generation plant, irrespective of the fuel and technology, without the revenue stream being secured in some form. This applies to coal, gas and renewable generation. Revenue is usually secured either by a long-term power purchase agreement (PPA), long-term hedge or dispatch control contract, or vertical integration between generation and retail businesses within one company. It is also assumed that legislative or policy risk relating to environmental or other changes in law would also need to be mitigated to secure financing.

In relation to the latter issue, such arrangements could be negotiated with the relevant government as part of contractual terms of operation, and therefore remain effective beyond the terms of particular governments. Such an approach would facilitate stronger investor interest while securing the wider public benefit of greater energy affordability and reliability.

Notwithstanding the role of the private sector, it is apparent that governments today are still actively engaged in the power generation market - recent examples include the South Australian Energy Plan (including development of South Australian government owned gas-fired generation), the Queensland Government's Powering Queensland Plan, and the Federal Government's Snowy Hydro 2.0 expansion plans.

Given that this active role can be expected to continue, governments may also choose to invest directly or indirectly to facilitate and support any new coal-fired HELE power station, especially in circumstances where this may be linked to providing impetus for regional growth, or where market failure is evident and under investment is likely to lead to higher prices and electricity shortages.

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[74] http://www.minerals.org.au/file_upload/files/publications/Why_HELE_is_part_of_Australias_energy_solution_FINAL.pdf

[75] IEA Clean Coal Centre, Paul Baruya, "International finance for coal-fired power plants" CCC/277 April 2017.

10.4. Other Project Barriers

The development of new HELE power stations will also face a number of other normal project development risks such as:

- Obtaining the necessary permits and approvals to allow the plant to be constructed and operated;
- Obtaining a secure and viable fuel supply;
- Securing viable equipment supply and construction contracts; and
- Construction risks.

10.5. Policy enablers

Policy uncertainty can have a massive impact on investor confidence and result in inaction and underinvestment.

The NEM is in a state of change with the pending retirement of a large portion of the existing generation fleet and a broader transition to a decarbonised environment.

The absence of a clear strategy and strong investment and divestment signals (uniform stable policy), can negatively impact investment decisions required to ensure a safe, reliable, and secure electricity system.

As history shows, government has actively participated in the power generation sector either directly, through investment, subsidies or offtake; or indirectly through policy; in order to facilitate new power generation developments. Looking forward, governments are likely to be called upon to continue to play this role, particularly as the NEM faces a looming cliff-edge of schedulable base load generation retirements over the coming decade and beyond, and where the private sector has been investing almost exclusively in VRE.

11. Glossary

Term	Definition
ABS	means Australian Bureau of Statistics
ACT RET	means ACT Renewable Energy Target
AEMO	means Australian Energy Market Operator
AIG	means Australian Industry Group
APGT	means Australian Power Generation Technology study published by CO2CRC
ASX	Australian Stock Exchange
AUSC	means Advanced Ultra-Super-Critical
CAPEX	means Capital Expenditure
CCGT	means Combined Cycle Gas Turbine
CCS	means Carbon Capture and Storage
CO2e	means Carbon Dioxide Equivalent
Contractor's Cost or Price	means the total cost for a EPC contractor to build the plant, but excludes additional costs incurred by the owner (e.g. project development, finance and legal fees, interest during construction).
CSM	means coal seam methane
CY	means Calendar Year
DCF	means Discounted Cash Flow
DoD	means Depth of Discharge
EPC	means Engineering Procurement and Construction
EMPSES	means Emissions mitigation policies and security of electricity supply
ESOO	means Electricity Statement of Opportunities
EST	means Eastern Standard Time
FCAS	means Frequency Control Ancillary Services
FATC	means Fuel and Technology Cost review published by ACIL Allen
FY	means Financial Year
GEC	means Gas Electricity Certificate
GSA	means Gas Supply Agreement
GSOO	means Gas Statement of Opportunities
GTA	means Gas Transport Agreement
GWh	means Gigawatt hours
HELE	means High Efficiency Low Emissions
HHV	means Higher Heating Value
IDC	means Interest During Construction
LHV	means Lower Heating Value
LNG	means Liquefied Natural Gas
LRC	means Low Reserve Condition
LRET	means Large-scale Renewable Energy Target
LRMC	means Long-Run Marginal Cost
MDFC	means Maximum Daily Capacity Factor
MDQ	means Maximum Daily Quantity
MRET	means Mandatory Renewable Energy Target
MWh	means Megawatt hours

Term	Definition
NBER	means National Bureau of Economic Research
NEFR	means National Electricity Forecast Report
NG	means Natural Gas
NGFR	means National Gas Forecast Report
NEM	means National Electricity Market, which electrically connects QLD, NSW, VIC, TAS and SA
NGAC	means New South Wales Greenhouse gas Abatement Certificates
NSW	means the state of New South Wales
OCGT	means Open Cycle Gas Turbine
OEMs	Original Equipment Manufacturers
OPEX	means Operating Expenditure
pa	means per annum
PV	means Photovoltaic
QEC	means Queensland Electricity Commission
QLD	means the state of Queensland
RET	means Renewable Energy Target
SA	means the state of South Australia
SECV	means State Electricity Commission of Victoria
SRAS	means System Restart Ancillary Services
SRMC	means Short Run Marginal Cost
SRES	means Small-scale Renewable Energy Scheme
VIC	means the state of Victoria
VRET	means Victorian Renewable Energy Target
TAS	means the state of Tasmania
ToP	means Take-or-Pay
USC	mean Ultra Super-Critical
WACC	means Weighted Average Cost of Capital

APPENDIX 1 - GHD HELE Coal-fired Power Station Cost Report