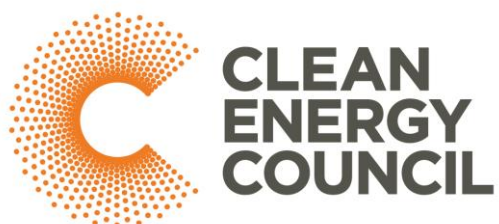


ROAM CONSULTING

ENERGY MODELLING EXPERTISE

ROAM Consulting Pty Ltd
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Report to



RET policy analysis

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VERSION HISTORY

Revision	Date Issued	Prepared By	Approved By	Revision Type
1.0	2014-04-29	Joel Gilmore Clare Giacomantonio	Joel Gilmore	First release
1.1	2014-05-23	Clare Giacomantonio	Joel Gilmore	Corrections of minor errata

EXECUTIVE SUMMARY

ROAM Consulting has conducted industry consultation, modelling, and detailed analysis to investigate the impact of Australia's Renewable Energy Target (RET) on the electricity market and retail bills.

Three scenarios were modelled:

- A Business as Usual (BAU) scenario, where the RET continues as legislated;
- A No RET scenario, where the RET is repealed, with only existing and financially committed projects being covered by the scheme;
- An increased and extended RET scenario, where the RET is increased to a 30% by 2030 target and extended to 2040.

ROAM's modelling, supported by industry consultation, shows that the legislated Large-scale Renewable Energy Target (LRET) can be met under the BAU scenario. Furthermore, both RET scenarios result in lower net electricity costs to consumers in the medium- to long-term.

KEY OUTCOMES

Wholesale price increases are reduced by the RET

Under the existing LRET and Small-scale Renewable Energy Scheme (SRES), wholesale electricity prices are expected to rise only moderately for the period to 2020, with growth in new renewables acting to reduce price rises that would otherwise occur.

The cost of the RET is largely offset by reductions in wholesale prices in the near-term

This is because of the *merit order effect*, whereby additional low Short Run Marginal Cost (SRMC) generation displaces more expensive generation thereby lowering the wholesale price of electricity in the market. Solar and wind energy have very low SRMCs predominately because their fuel is free. These wholesale energy price savings are easily overlooked by consumers, as they do not appear as a "line item" on analyses of retail bills.

Repealing the RET would increase retail electricity bills

In the longer-term, in the absence of new renewable generation being built, wholesale electricity prices will increase from their current levels in response to demand growth and generator bidding strategies. The increase in wholesale electricity costs is greater than the costs of the RET in the medium- to long-term. Average residential electricity bills would be \$56 a year higher in 2020, an average of \$108 a year higher beyond 2020, and could be as much as \$148 higher, if the RET is repealed compared to the BAU scenario. It is worth noting that the size of the wholesale electricity price merit order effect modelled for Australia is comparable with international studies of similar electricity markets.

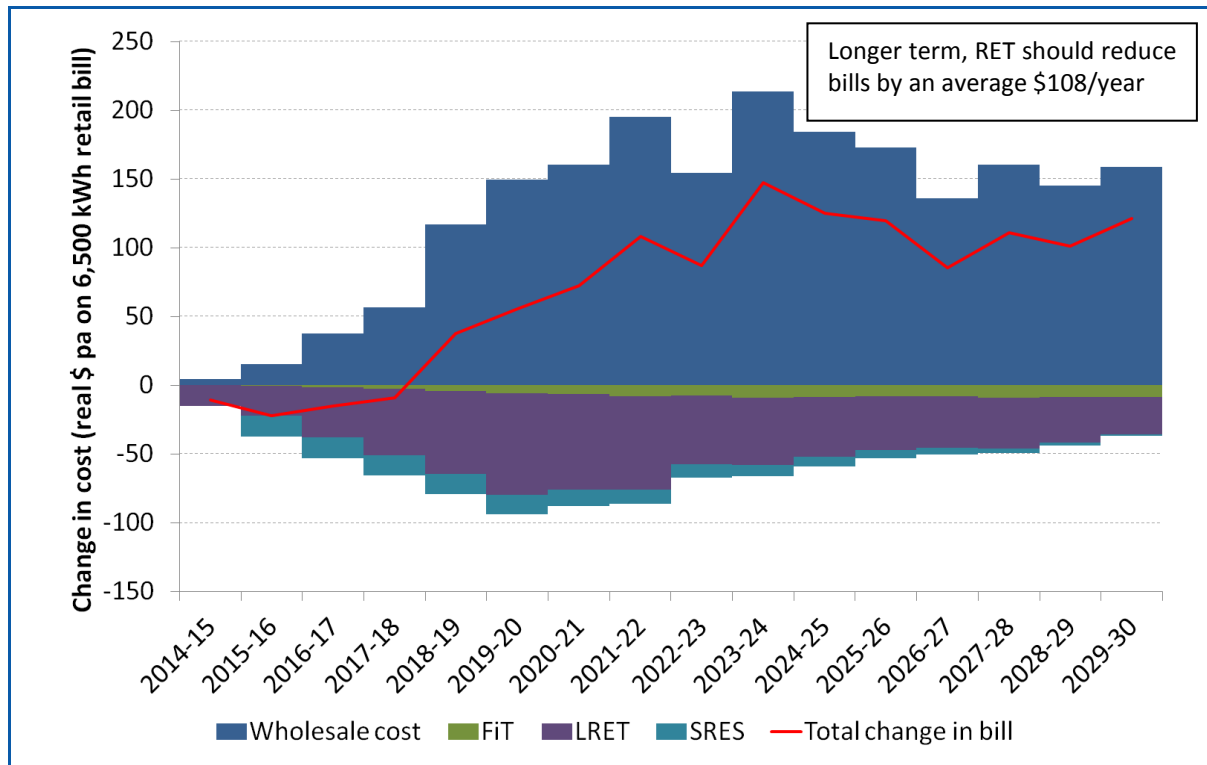


Figure 1 – Change in retail price components in No RET scenario relative to BAU scenario

Increasing and extending the RET will further benefit consumers

If the RET is extended to a 30% target by 2030 (a fixed LRET of 65,000 GWh), residential electricity bills will continue to decrease relative to BAU in the longer term as shown in Figure 2. This reflects the continued merit order effect and the low marginal cost of renewables.

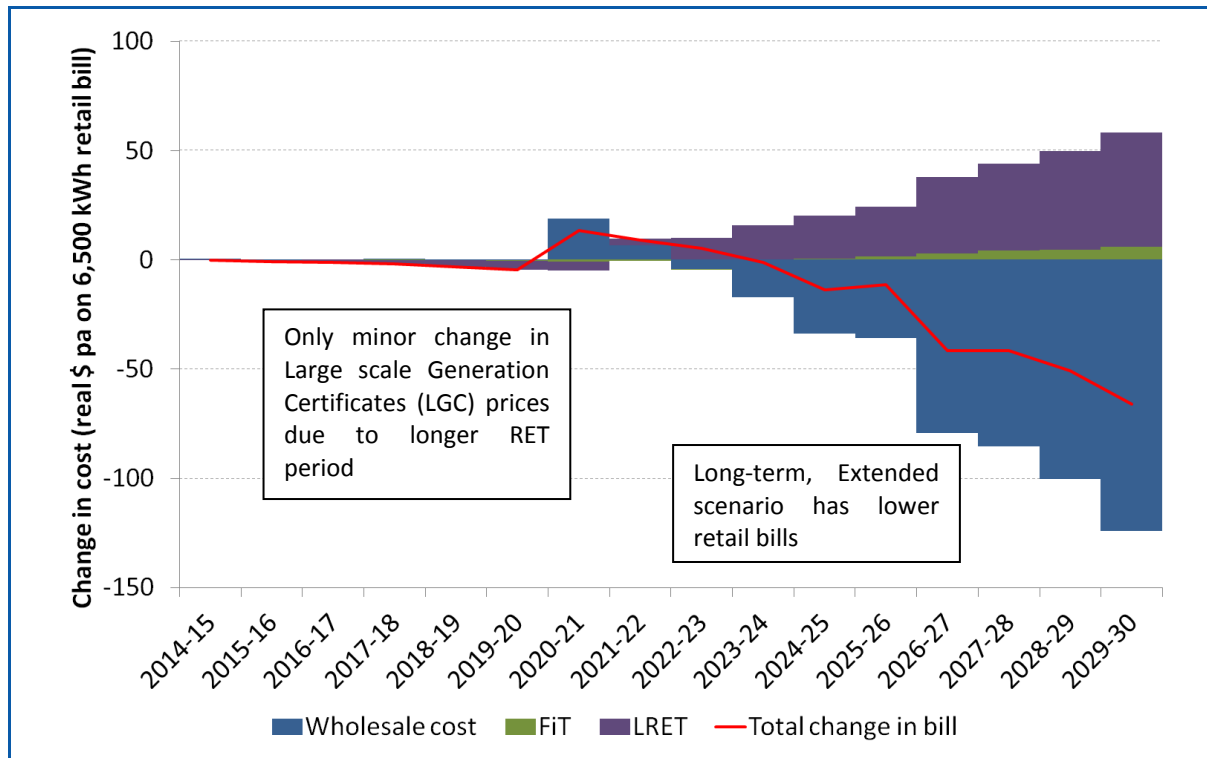


Figure 2 – Change in retail price components in Extended scenario relative to BAU scenario

The RET will drive significant job creation

A significant number of jobs will be required to meet these targets as shown in Table 1. ROAM estimates that 18,400 positions in renewables will be created between 2014 and 2020 as a result of the RET remaining unchanged. This includes 9,700 positions created in large-scale renewables and 8,700 positions in small-scale renewables.

Repealing the RET would lead to the creation of 8,000 fewer jobs in large-scale renewables and 3,800 fewer jobs in small-scale renewables compared to the currently legislated target (BAU). Increasing the target beyond 2020 does not result in additional positions in renewables before 2020, but does result in a longer average duration of positions.

Table 1 – Renewable energy industry positions in Australia by 2019-20 under each RET scenario

Scenario	Large-scale renewables construction	Large-scale renewables operations and maintenance	Small-scale renewables	All renewables
BAU	8,600	1,100	8,700	18,400
No RET	1,200	500	4,900	6,600
Extended RET	8,600	1,100	8,700	18,400
Difference between No RET and BAU	-7,400	-600	-3,800	-11,800
Difference between Extended RET and BAU	0	0	0	0

The RET will drive new investment

Under the existing target, the total cumulative investment in large-scale renewables will be nearly \$15 billion in today's dollars between now and 2020. If the RET is repealed, this investment will be significantly reduced by \$11 billion.

Repealing the RET will increase greenhouse emissions

If the RET is repealed, electricity sector emissions in 2020 are modelled to increase by 14.8 million tonnes relative to BAU. This is a 12.6 million tonne rise in emissions relative to 2000 levels. Cumulative emissions to 2019-20 will be 34.7 million tonnes higher if the RET is repealed. If the RET is repealed and the Federal Government is to achieve its commitment of reducing greenhouse gas emissions by five per cent of 2000 levels by 2020, the increase in electricity sector emission would have to be matched by reductions in emissions in other sectors.

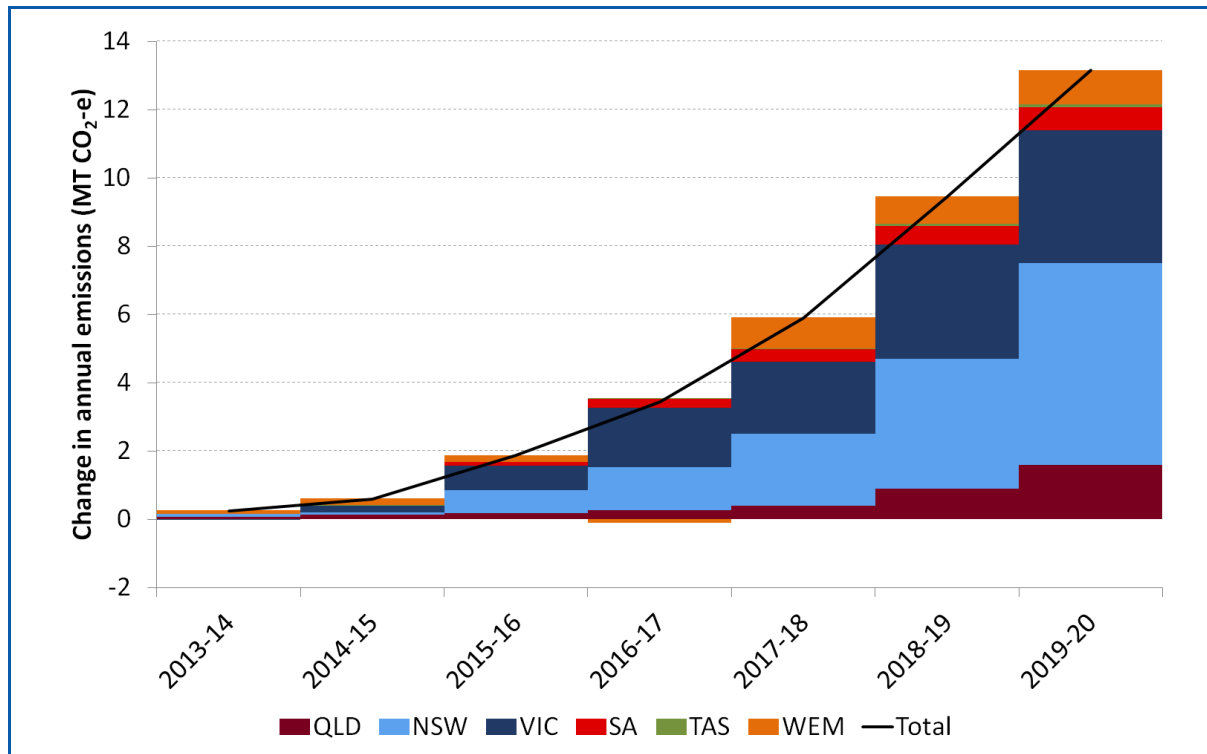


Figure 3 – Electricity sector emissions in No RET scenario relative to BAU (NEM and WEM)

RENEWABLES AS A PERCENTAGE OF AUSTRALIA'S ENERGY USAGE

Much debate around the RET centres on forecasts of the percentage contribution of renewables to Australia's energy usage. When the original GWh targets were set in legislation in 2009, the intention was that "the equivalent of at least 20 per cent of Australia's electricity supply is generated from renewable sources by 2020".¹ Since that time, forecasts of Australia's electricity demand in 2020 have decreased and rooftop PV uptake has been larger than anticipated. The combined effect of these factors is that achieving the current LRET target of 41,000 GWh in 2020 will likely deliver slightly more than 20% of Australia's electricity supply from renewables in that year. ROAM estimates that renewables will deliver 22.6% of electricity consumed in Australia in 2020.

ROAM has reviewed multiple methodologies and papers to develop its view of the most appropriate basis for estimating both demand and renewable generation. The Australia-wide demand forecast from the Australian Government's Bureau of Resources and Energy Economics is used in our calculations² as it provides the most comprehensive account of electricity demand and generation in Australia.

¹ Martyn A & Styles J, Parliamentary Library, June 2009, *Bills Digest no. 182 2008-09: Renewable Energy (Electricity) Amendment Bill 2009*. Available at: http://www.aph.gov.au/Parliamentary_Business/Bills_Legislation/bd/bd0809/09bd182. Accessed 18 February 2014.

² Bureau of Resources and Energy Economics, December 2012, *Australian energy projections*. Available at: <http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%939350>. Accessed 13 February 2014.

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GLOSSARY

Acronym	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BAU	Business As Usual
BREE	Bureau of Resources and Energy Economics
CCGT	Closed Cycle Gas Turbine
DC	Direct Current
FiT	Feed in Tariff
IMO	Independent Market Operator
LGC	Large-scale Generation Certificate
LNG	Liquid Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long-Run Marginal Cost
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
PPA	Power Purchase Agreement
PV	Photovoltaic
QLD	Queensland
RET	Renewable Energy Target
SA	South Australia
STC	Small-scale Technology Certificate
SRES	Small-scale Renewable Energy Scheme
SRMC	Short-Run Marginal Cost
SWIS	South-West Interconnected System
Tas	Tasmania
Vic	Victoria
WA	Western Australia
WEM	Wholesale Electricity Market

1 INTRODUCTION

The Clean Energy Council commissioned ROAM Consulting (ROAM) to undertake market modelling and analysis of Australia's Renewable Energy Target (RET), comprising the Large-Scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES).

In addition, ROAM has calculated the percentage contribution of renewables based on the current LRET and SRES and the GWh totals that correspond to various market share percentages utilising prevailing electricity demand forecasts.

ROAM also conducted interviews with the members of the renewable industry in Australia to better inform its understanding of how achievable the RET is in its current form.

Finally, ROAM conducted detailed market modelling of wholesale electricity prices, retail electricity prices and other system costs associated with the LRET and SRES. In addition to a forecast of the costs associated with the existing schemes, ROAM has forecast two alternative formulations of the schemes to inform discussion during the 2014 RET Review.

All monetary figures provided in this report are listed in June 2013 dollars, unless indicated otherwise.

2 PERCENTAGE CONTRIBUTION OF RENEWABLES

2.1 POLICY INTENTION

In 2009, Expanded Renewable Energy Target legislation was passed, replacing the existing Mandatory Renewable Energy Target scheme. This expanded scheme significantly increased the targets and extended the duration of the scheme. The new targets were designed:

to ensure that the equivalent of at least 20 per cent of Australia's electricity supply is generated from renewable sources by 2020, when combined with an estimated baseline renewable generation of 15 000 GWh.³

In order to provide regulatory certainty, the government fixed the GWh trajectory based on the prevailing independent energy forecasts at the time of the 2007 federal election. ROAM could not find detailed documentation of these calculations beyond those calculations published in the 2012 RET Review Final Report⁴.

³ Martyn A & Styles J, Parliamentary Library, June 2009, *Bills Digest no. 182 2008-09: Renewable Energy (Electricity) Amendment Bill 2009*, Available at: http://www.aph.gov.au/Parliamentary_Business/Bills_Legislation/bd/bd0809/09bd182. Accessed 18 February 2014.

⁴ Climate Change Authority, December 2012, *Renewable Energy Target Review Final Report: Chapter 4*. Available at: <http://climatechangeauthority.gov.au/ret/final-report/chapter-4>. Accessed 9 December 2013.

Since the Expanded RET was legislated in 2009, energy demand in Australia has decreased and the outlook to 2020 and beyond is much lower than forecast in 2009. In addition, the uptake of residential rooftop solar PV has been larger than was anticipated in 2009. Since renewable energy certificates were “deemed” at installation and solar multipliers were applied, this resulted in the rapid creation of renewable energy certificates from rooftop solar and a stall in the development of large-scale renewables. To provide stable investment signals for the continued development of large-scale renewables, the government split the scheme in to the LRET and SRES on 1 January 2011. The original target of 45,000 GWh in 2020 from the combined scheme was reduced to 41,000 GWh for the LRET at this time.⁵ The SRES is an uncapped scheme and current forecasts suggest more than the implicit 4,000 GWh of energy will be generated (specifically, deemed⁶) by rooftop solar in 2020.

The combined effects of falling demand and higher-than-expected rooftop PV generation mean that achieving the current LRET 41,000 GWh target in 2020 will likely deliver more than 20% of Australia’s energy from renewables in that year. As the original policy intention was to generate *at least* 20%, this is arguably consistent with the policy. Regardless, discussions about the future of the RET frequently focus on the percentage contribution from renewables under the current or alternative formulations of the RET.

Key to any discussion about a percentage target is defining the denominator of that calculation – what is “Australia’s electricity supply”? Uncertainty surrounds the issue of whether “supply” is energy “as-generated”, “sent-out” (which excludes auxiliary energy used within power stations) or consumed (which excludes losses in transmission and distribution). Independent of this question, certainly any definition of Australia’s supply should include electricity generated not just in the National Electricity Market (NEM) in the eastern states of Australia and Wholesale Electricity Market (WEM) in Western Australia, but also in smaller grids and off-grid. These components are frequently excluded from calculations because they are not as regularly and rigorously measured or forecast. Similarly, “behind the meter” generation (in particular, rooftop PV) is still electricity “supply” that should be considered in calculations.

On the other hand, it is less clear whether displacement technologies such as solar water heaters should be counted as “supply”. These technologies do not generate electricity, but instead displace electricity consumption. Currently, displaced consumption by these technologies is eligible to produce Small-scale Technology Certificates under the SRES.

⁵ Both the original 45,000 GWh target and the updated 41,000 GWh target represent *additional* energy from renewables. The actual amount of renewable generation in any year includes a significant contribution from hydro stations that existed before the scheme began. These stations can create LGCs for generation above a legislated baseline.

⁶ Actually implicit in the split was that 4 million STCs would be *deemed* in 2020, rather than 4,000 GWh of energy would be generated by rooftop PV in 2020. However, since deeming STCs at installation is for administrative convenience, discussion around what the target should be in 2020 or any future year should focus on energy actually generated in that year.

The question of the continued inclusion of displacement technologies was considered in the 2012 RET Review.⁷ At that time, the review ultimately recommended that the eligibility of solar water heaters and heat pumps should be maintained, but no new displacement technologies should be admitted in the future.

2.2 ALTERNATIVE DEMAND FORECASTS

Forecasting demand is inherently difficult as it depends on multiple assumptions about the future, including:

- Future economic growth;
- Behaviour of specific large customers;
- Removing the effects of “extreme” events in historical years, and forecasting them into the future, in order to produce probabilistic forecasts;
- Development of behind-the-meter technologies; and
- Accurate measurements of historical usage, particularly in off-grid applications.

As such, forecasters regularly provide a range of forecasts, and different forecasters may have different input assumptions.

Electricity demand forecasts are published regularly by several agencies including:

- Australian Energy Market Operator (AEMO)
 - AEMO publishes annual forecasts of electricity as-generated and sent-out for the NEM. This encompasses the grid-connected areas of New South Wales, Queensland, Victoria, South Australia and Tasmania. The most recent forecast period extends to 2022-23.⁸ Included in the report are forecasts of energy production by rooftop PV to 2032-33.
- Independent Market Operator (IMO)
 - IMO publishes annual forecasts of electricity sent-out for the WEM. This encompasses the south-western corner of Western Australia connected to the South-West Interconnected System (SWIS). The most recent forecast period extends to 2023-24.⁹ Included in the report are forecasts of energy generation by rooftop PV to 2023-24.
- Bureau of Resources and Energy Economics (BREE)
 - BREE publishes forecasts of electricity consumed for all of Australia. These forecasts include off-grid electricity and are net of auxiliaries, transmission and distribution losses, and generation by rooftop solar. The forecast published in December 2012 included two forecast years, 2034-35 and

⁷ Climate Change Authority, December 2012, *Renewable Energy Target Review Final Report: Chapter 7*. Available at: <http://climatechangeauthority.gov.au/ret/final-report/chapter-4>. Accessed 9 December 2013.

⁸ AEMO, June 2013, *National Electricity Forecasting Report*, Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Accessed 17 February 2014.

⁹ IMO, June 2013, *2013 Electricity Statement of Opportunities (ESOO)*, Available at: [http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-\(soo\)](http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(soo)). Accessed 17 February 2014.

2049-50.¹⁰ It also included a separate estimate of energy generation by rooftop PV.

In the interests of using a single, consistent data source that covers electricity use across Australia, not just in areas connected to the two largest grids, ROAM has used BREE's demand forecasts in the calculations presented in this section.

2.3 SELECTED DATA SOURCES

Calculations of the percentage of energy sourced from renewables in this section are performed on the following basis:

$$\% \text{ energy generated by renewables} = \frac{\text{Gen by large-scale renewables} + \text{Gen by pre-existing renewable generators up to 1997 baseline} + \text{Gen by rooftop PV}}{\text{Total energy consumed} + \text{Gen by rooftop PV assumed in demand forecast}} \quad (1)$$

Demand forecasts net of PV are based on particular assumed values for energy from rooftop PV. The denominator of equation (1) should be energy consumed inclusive of rooftop PV; therefore, the rooftop PV contribution assumed in the demand forecast must be used in the denominator. If a different PV forecast is more recent or more credible or reflects a different SRES assumption, then it should be used in the numerator, but not the denominator.

Note also, that ROAM has not included displaced consumption by solar water heaters and heat pumps in the calculations.

The source of each term and rationale for use of this source are discussed further in Sections 2.3.1 to 2.3.4.

2.3.1 Large-scale renewables

The calculations use the LRET GWh targets as the values for electricity generated by large-scale renewables term. It should be recognised that the actual electricity generated by large-scale renewables in a given year could be different to the target due to range of reasons including banking provisions and fluctuations in renewable generation¹¹. Additionally, in this section, exactly the legislated amount is installed; in other sections of this report, economic arguments are used to determine whether the RET is met or exceeded.

¹⁰ BREE, December 2012, *Australian energy projections*. Available at: <http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%9350>. Accessed 13 February 2014.

¹¹ In the modelling presented in Sections 4, 5 and 6, banked certificates were taken into account and site-specific half-hourly generation were used.

2.3.2 Pre-existing renewables

We assume generation by pre-existing hydro of 15,000 GWh. This was the market expectation in 2007 when the target was set.¹²

2.3.3 Rooftop PV

In the current legislation, Small-scale Technology Certificates (STCs) are created at the time of installation for the amount of electricity an installation is expected to produce or displace over its lifetime. In the calculations in this section, ROAM has used rooftop PV generation in 2020 instead of rooftop PV *deemed* in 2020 to reflect actual generation.

ROAM has assumed rooftop PV generation in each year is the sum of the most recent central generation forecast in the NEM from AEMO¹³ and WEM from IMO¹⁴. Analysis of installed rooftop PV capacity by postcode between 2001 and January 2013¹⁵ suggests that approximately 99% of capacity is in NEM- and WEM-connected postcodes.

Note that these rooftop PV forecasts differ to the contribution from rooftop PV assumed in the BREE demand forecast for Australia-wide electricity consumption.¹⁶ We have used the AEMO and IMO forecasts in preference to the BREE forecast since they are more recent. The combined AEMO/IMO forecast is incorporated as a term in the sum in the numerator of equation (1). The BREE rooftop PV forecast is used in the denominator since electricity consumption net of PV is based on particular assumed values for the contribution from rooftop PV.

Projections beyond the forecast end points (2033-34 for the NEM and 2023-24 for the WEM) were calculated by slowing growth over time so that the NEM forecast remains under the NEM saturation level published alongside the NEM forecasts. Calendar year forecasts are calculated as the average of the relevant financial year forecasts.

¹² Climate Change Authority, December 2012, *Renewable Energy Target Review Final Report: Chapter 4*. Available at: <http://climatechangeauthority.gov.au/ret/final-report/chapter-4>. Accessed 9 December 2013.

¹³ AEMO, July 2013, *National Electricity Forecasting Report Supplementary Information 2013: Rooftop PV* [Microsoft Excel file]. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013/NEFR-Supplementary-Information-2013>. Accessed 9 December 2013.

¹⁴ IMO, July 2013, *2013 Electricity Statement of Opportunities (ESOO)*, Available at: [http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-\(soo\)](http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(soo)). Accessed 9 December 2013.

¹⁵ Clean Energy Regulator, 31 January 2014, *Small-scale installations by postcode: RET postcode data for January 2014*, Available at: <http://ret.cleanenergyregulator.gov.au/REC-Registry/Data-reports>. Accessed 18 February 2014.

¹⁶ BREE, December 2012, *Australian energy projections*. Available at: <http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%932050>. Accessed 13 February 2014.

2.3.4 Demand forecast

BREE have published estimates of Australia-wide electricity consumption. These estimates include off-grid electricity, exclude generation by rooftop solar, and are net of auxiliaries, transmission and distribution losses. The most-recent forecast, from 2012, published forecasts for 2034-35 and 2049-50 as summarised in Table 2.1.¹⁷

Table 2.1 – BREE forecasts for Australia-wide electricity consumption

Financial year	BREE forecast, December 2012 (GWh)
2012-13	253,000
2034-35	325,000
2049-50	377,000

To obtain values for intermediate years, in the absence of knowledge about the shape of demand growth between these fixed points, ROAM performed an interpolation for the intervening years using the average annual growth rate of 1.14% between 2012-13 and 2034-35. Using this interpolation method, demand exclusive of rooftop PV generation in 2019-20 is forecast to be 273,985 GWh, while demand in 2020-21 is forecast to be 277,122 GWh. Demand for calendar year 2020 is calculated as the average of these two numbers, which equates to 275,553 GWh.

The denominator of equation (1) needs to include the generation by rooftop PV assumed in the BREE forecast. ROAM calculated this component by interpolating between the rooftop PV generation published in the BREE report using a method similar to that applied to the demand forecast. Using this method, ROAM calculated that 5,423 GWh of rooftop PV generation was assumed in BREE's demand forecast in calendar year 2020.

Overall, this means that the expected total demand in 2020, inclusive of rooftop PV, is 280,977 GWh, according to the BREE forecasts.

2.4 OUTCOMES

2.4.1 Percentage contribution of renewables under current LRET

The percentage of energy generated by renewables under the assumptions outlined in Section 2.3 is shown in Table 2.2.

¹⁷ BREE, December 2012, *Australian energy projections*. Available at: <http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%932050>. Accessed 13 February 2014.

Table 2.2 – Percentage of electricity generated by renewables under current LRET GWh trajectory and BREE's Australia-wide energy forecast

Calendar year	LRET (GWh)	Pre-existing renewable generators (GWh)	Rooftop PV (GWh)	Annual electricity consumed including rooftop PV (GWh)	Electricity generated by renewables ¹⁸
2014	16,100	15,000	4,001	260,741	13.5%
2015	18,000	15,000	4,482	263,964	14.2%
2016	20,581	15,000	4,993	267,244	15.2%
2017	25,181	15,000	5,551	270,583	16.9%
2018	29,781	15,000	6,167	273,983	18.6%
2019	34,381	15,000	6,852	277,447	20.3%
2020	41,000	15,000	7,610	280,977	22.6%
2021	41,000	15,000	8,377	284,576	22.6%
2022	41,000	15,000	9,129	288,249	22.6%
2023	41,000	15,000	9,915	291,997	22.6%
2024	41,000	15,000	10,739	295,825	22.6%
2025	41,000	15,000	11,597	299,736	22.6%
2026	41,000	15,000	12,485	303,736	22.5%
2027	41,000	15,000	13,394	307,827	22.5%
2028	41,000	15,000	14,310	312,016	22.5%
2029	41,000	15,000	15,221	316,308	22.5%
2030	41,000	15,000	16,118	320,707	22.5%

The current LRET of 41,000 GWh in 2020 results in 22.6% market share for renewable energy utilising BREE's demand forecast.

2.5 **ELECTRICITY FROM LARGE-SCALE RENEWABLES TO ACHIEVE A GIVEN PERCENTAGE TARGET**

Table 2.3 shows the electricity to be generated by large-scale renewables under various percentage targets and BREE's Australia-wide energy forecast.

¹⁸ These calculations use the LRET GWh targets as values for the term for energy generated by large-scale renewables in equation (1). Actual generation by large-scale renewables in each year may vary due to the use of banked certificates and the installation of large-scale renewable capacity above the LRET.

Table 2.3 – Estimate of the total energy generated by large-scale renewables under various percentage targets and BREE’s Australia-wide energy forecast

Calendar year	Pre-existing renewable generators (GWh)	Rooftop PV (GWh)	Annual energy consumed (GWh)	Energy generated by renewables	Generation by large-scale renewables (GWh)
2020	15,000	7,610	280,977	20%	33,586
2025	15,000	11,597	299,736	25%	48,337
2030	15,000	16,118	320,707	30%	65,094

3 INDUSTRY CONSULTATION

A key question, and the cause of significant industry debate, is to what extent the existing (or modified) LRET GWh targets are achievable, and whether meeting the LRET is “easy”, “hard” or “impossible”. To answer this question, as well as to better inform the renewable generation development plans in each scenario, ROAM conducted interviews with representatives from the Australian renewable energy industry. ROAM sampled views from thirteen organisations, including wind developers, solar developers and retailers as well as construction companies and suppliers of raw materials (such as steel); interviews were conducted in October and November, 2013. In order to receive frank and honest responses, ROAM used its independent position in the market and conducted the discussions under the Chatham House Rule (the agreement that no information would be attributed to any particular company or individual in this report, or in our discussions with the Clean Energy Council).

3.1 ACHIEVING THE EXISTING LRET GWH TARGET

The achievability of the existing 41,000 GWh by 2020 LRET was discussed in detail with each interviewee. ROAM informed each discussion by stating that, according to its analysis, Australia would need to build 1,500-1,800 MW of new renewable energy for several consecutive years to meet the target. All interviewees unanimously agreed that the industry had the capacity to meet the target. The following points summarise the key aspects of potential physical constraints to meet this target discussed by the interviewees:

- **Current install rates.** Through the current set of committed projects, the wind industry alone will install around 650 MW in 2014 and another 900 MW in 2015.
- **Availability of raw materials.** Some industry members indicated that local steel production and fabrication can ramp-up sufficiently to meet the required installation rate of wind and solar plant. Other interviewees suggested this may not be possible, but they did agree that availability of steel towers is not a constraint because imported steel towers are easily obtained.
- **Availability of components.** There is sufficient capacity to increase supply in Australia through a combination of Australian and imported components. For example, Australian wind turbine tower production could be doubled from its

current rate of 150-200 towers/year. Due to a levelling off of wind farm installation growth in China in the past few years, factories in China currently have an excess of wind turbine components with plenty to meet the comparatively small Australian demand under the existing target.

- **Availability of labour.** More than half of the interviewees noted that there is currently a lot of spare capacity in the Australian workforce and many highly trained people looking for work, especially in the energy industry. Reasons for this include the high Australian dollar, the downturn in the mining industry and the recent levelling off of electricity demand growth in Australia halting non-renewable plant developments. In the unlikely event that domestic skilled labour is in short supply, skilled labour can also be brought in from overseas.
- **Availability of construction equipment.** There is spare capacity due to the above-mentioned downturn in the mining sector. Crane availability can also be quickly ramped up if needed by bringing in cranes from overseas.

Despite broad agreement on a lack of physical constraints, there were some diverse views on whether the existing LRET GWh target can be met due to financial and social constraints. All of the interviewees said that the existing LRET could have been met if RET policy certainty prevailed after the 2012 RET Review, but pointed out that the market is currently stalled with the price of LGCs (including bundled in Power Purchase Agreements, PPAs) too low for new projects to be viable. A majority of the interviewees were still optimistic that the currently legislated LRET can be met, as long as the LGC price (bundled or spot) increases soon (within the next 12 months).

All the interviewees emphasised that a key reason for the stalling market is the perceived uncertainty as to the trajectory of the LRET in the future due to the RET review in 2014. The market responded similarly in advance of the last review. Almost all of the interviewees identified this uncertainty as the main constraint to meeting the LRET. Contributing to the market stalling are the following two factors:

- Entities liable to purchase LGCs consider the uncertainty in the target is great enough such that they are only willing to sign contracts for bundled PPAs at prices below that required for wind farms and other renewable projects to be viable.
- Entities liable to purchase LGCs still have a significant number of banked LGCs left over from the two-year period in which deemed LGCs from small-scale rooftop PV and solar hot water were included in the market.

Many of the interviewees pointed out that a bi-annual review does not allow the market to operate smoothly and achieve its goals, when target reductions are perceived to be within the scope of the reviews. The outcome of the 2012 RET review resulted in no change to the LRET, and the industry was subsequently able to develop some new projects. However, renewed activity only lasted 12 months and slowed again as the 2014 review drew closer. The current hiatus in renewables development is happening at a critical time in terms of the challenge of meeting the LRET. Wind and large-scale solar projects typically need a PPA for 10-15 years to achieve financial close, and since the LGC

liability is legislated to end in 2030, the required window will begin closing very soon in 2015.

The other major barrier to achieving the LRET discussed widely among the interviewees was the current social and political environment in Australia which is making development approvals difficult and time-consuming to obtain. Development approvals are taking three or more years to obtain, which threatens the industry's ability to have enough projects approved to meet the 41,000 GWh target by 2020. However, it should be noted that wind farms sufficient to meet more than half of the 41,000 GWh target already have planning consent or are under construction.

The social-acceptance requirements on a wind farm are also becoming more stringent. For example, planning scheme amendment VC82 which specifies that no wind turbines can be installed within a 2 km radius of a dwelling without their consent, is making new greenfield wind farm developments in Victoria problematic.

Several interviewees also cited the length of time required for grid connection agreements as a potential short-term constraint in getting enough projects through the pipeline to construct at the rates required to meet LRET as currently legislated. ElectraNet in South Australia was considered to have the most streamlined approval process due to their experience in grid connection for wind farms. Consequently, these interviewees were hopeful that Transmission Network Service Providers (TNSPs) in other states would improve their processes as they gained experience in grid connection of wind farms so that this potential constraint is not an issue.

Another concern raised by several interviewees is the combination of factors that is conspiring to create a likely boom-bust cycle in the wind industry in the next decade. The delay in committing projects now due to the oversupply of LGCs generated before the LRET/SRES split, combined with delays due to regulatory uncertainty, means that construction to meet the LRET as currently legislated will have to ramp up quickly, and then will suddenly come to a halt in 2020 when the GWh target becomes a constant 41,000 GWh/year until 2030.

3.2 CHANGES TO CARBON PRICING

The Australian Government plans to remove Australia's carbon price mechanism, and indications are that this may be achievable in the second half of 2014, depending on negotiations in the Senate from 1 July 2014. The consensus from the interviewees is that this has little effect on project viability in the short-term as the carbon price was expected to be low when the Emissions Trading Scheme (ETS) was due to commence on 1 July 2015.

However, some of the interviewees explained how the imminent removal of the carbon price is creating doubt about whether there will be a carbon price in 2030, when the LGC liability is legislated to end. The expanded RET policy was designed to work in conjunction

with the carbon price; the wholesale pool price inclusive of a carbon pass-through was expected to be high enough by 2030 such that renewable energy projects would be cost competitive with other generation sources without the LRET (driving the LGC price towards zero sometime in the 2020's). The doubt over the carbon price in 2030 creates a potential large drop in competitiveness of renewable generators in that year creating additional risk for financiers granting loans extending past 2030 and putting downward pressure on PPAs being negotiated for a period extending beyond 2030.

3.3 SOLAR PV CONTRIBUTION TO THE LRET

A few utility-scale projects are currently under construction and are being built with help from additional Government funding and/or a Feed-In Tariff. However, the total amount of new large scale solar PV capacity is expected to be minor.

Any reduction or delay in the 41,000 GWh target would significantly impact the development of utility scale solar plants in Australia and reduce their potential contribution to the RET by 2020.

4 BACKGROUND TO MODELLING AND ASSUMPTIONS

To inform the 2014 review of the RET, ROAM investigated the impact of the Renewable Energy Target on residential and commercial electricity prices, as well as flow-on effects of the RET, including the impact on other generators, job creation and carbon emissions. Section 4 outlines the input assumptions and methodology for this modelling.

4.1 MODELLING TOOLS

A key component of this modelling is simulation of Australia's main electricity markets: the NEM (encompassing Queensland (QLD), New South Wales (NSW), Victoria (Vic), South Australia (SA) and Tasmania (Tas)), and the WEM in Western Australia, which covers the SWIS-connected area around Perth and the South-West.

The modelling methodology used by ROAM is outlined in Figure 4.1. The key steps in this process are outlined below.

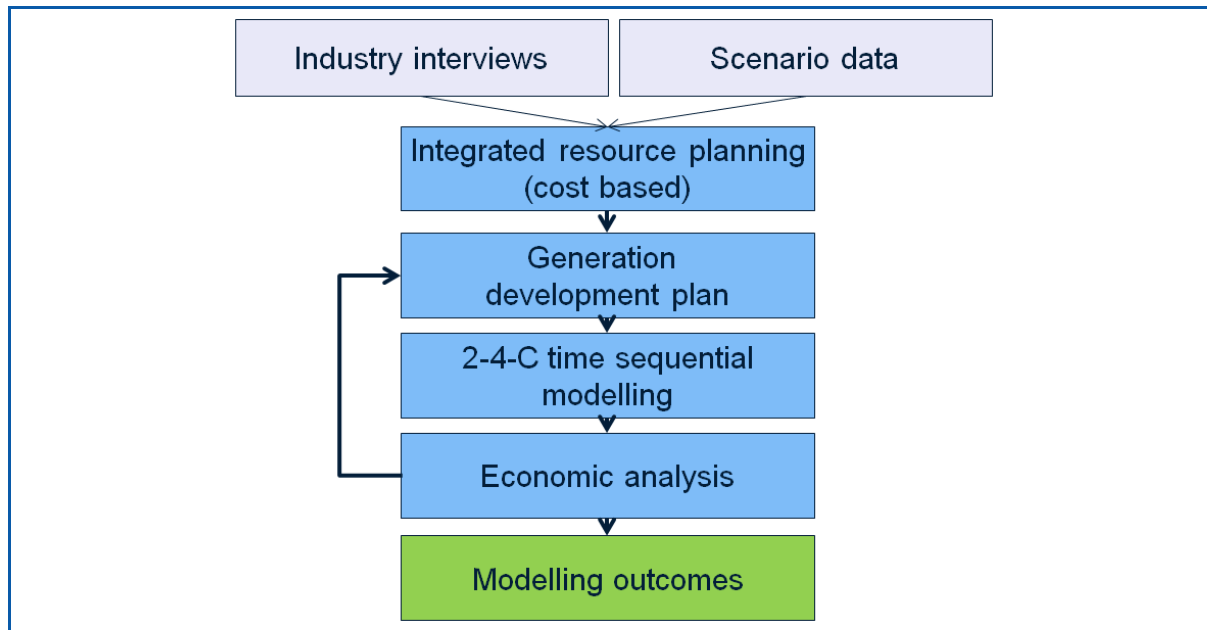


Figure 4.1 – Modelling flowchart

Industry consultation

ROAM engaged with wind developers, solar PV developers and electricity retailers to understand the ability of the industry to meet the RET as well as any costs or benefits to reviewing the RET at this time. Our findings from this analysis are discussed in Section 3.

Input data

As with all modelling, input assumptions are critical to producing accurate outcomes. ROAM Consulting has sourced the most up to date forecasts of future conditions from organisations such as BREE, AEMO and the IMO. Section 4.3 outlines these in more detail.

Integrated Resource Planning

A key step in the modelling of electricity systems is to model new entrants in the market, as well as the possibility of retirements of existing plant. For this modelling, ROAM employs our LTIRP software, which seeks to co-optimize the development of new generation capacity, retirements and transmission upgrades in order to achieve the most efficient system. ROAM modelled the development of the system with and without the RET out to the year 2050.

The LTIRP is a valuable tool for planning, as it represents a (comparatively) straight forward mathematical model for modelling long-term developments. ROAM has successfully used this tool for a diverse range of clients, including the Treasury, network service providers and project proponents. Its strength lies in determining when new technologies are likely to become favourable, and the relative mix of each.

2-4-C dispatch modelling

Although LTIRP and similar “least-cost” models are valuable tools for long-term planning, they do not typically capture the short-term effects of active markets. For example, developers and retailers don’t necessarily require the *most* profitable project, provided that available projects meet their required rate of return, and there is often a first-mover advantage, which can drive project investment. Similarly, uncertainty over future developments or costs tends to drive additional risk avoidance strategies.

Furthermore, such models typically underestimate wholesale electricity prices in the NEM, because they don’t take into account strategic bidding occasionally used by generators to maximise returns in an opportunistic fashion. Reviews of historical operation of the NEM show that it is inappropriate to model all generators bidding at their short-run marginal costs (SRMCs). For example, historical analysis by ROAM has shown that price spikes well above operating costs would have contributed up to 50% of revenue of a hypothetical solar plant.¹⁹

As such, ROAM’s primary modelling for this project was done using our dispatch market model 2-4-C. We conducted modelling of every half-hour of the study period under a range of demand and generator availabilities to produce the most realistic market outcomes. This model includes the highest possible level of detail of the NEM and SWIS markets, including bidding strategies (for the NEM), demand forecasts, transmission constraints and the variable output of wind and solar generators.

Further details of 2-4-C can be found in Appendix A.

Economic analysis

As a starting point, ROAM used the output of the LTIRP to guide generation development, particularly of renewables. After detailed dispatch modelling, however, ROAM conducted an analysis of each existing and new generator to assess its technical and financial performance. Based on this analysis, ROAM’s models added or removed capacity in order to achieve a more efficient and financially optimal operation. This included an analysis of the Renewable Energy Target and ensuring that both generators and retailers would be willing to sign PPAs for any projects installed under the RET.

Modelling results

Once a stable solution was obtained, ROAM then undertook a detailed analysis of the simulations, to produce key outcomes such as total system cost, the price of LGCs, and scenario emissions. A summary of these outcomes is presented in Sections 5, 6 and 7.

¹⁹ ROAM Consulting, Jun 2012, *Solar Generation – Australian Market Modelling* [Report to Australian Solar Institute]. Available at:

http://www.austela.com.au/docs/20120606_Solar%20Generation%20Australian%20Market%20Modelling%20ROAM%20Consulting%20ASI.pdf. Accessed 23 April 2014.

4.2 KEY OUTPUTS

4.2.1 Retail prices

General assumptions

ROAM has provided forecasts for each component of the retail bill. However, due to the difficulties of forecasting future network investment cost, prudential hedging for retailers and other similar “non-market” factors, ROAM has deliberately taken a simple approach to forecasting these components, using analysis by the Australian Energy Regulator (AER) of recent retail prices²⁰ and moderate growth or development assumptions in the short term.

In particular, ROAM has modelled only a moderate short-term increase in network costs, which are then held constant for the remainder of the study. Whether additional network infrastructure (beyond replacement and maintenance) will be required in the future, or whether recent years have seen an increase in network investment that won’t continue into the future, will be subject to many external factors, including social and political preferences as well as reliability standards and regulatory changes such as the proposed Optional Firm Access framework. In any case, these factors are not expected to be affected by the future of the LRET and so will be constant across all scenarios and thus will not affect the qualitative conclusions of this report. It is worth noting that the AEMC has found the required investment in networks is likely to be higher without the expanded RET scheme in place.²¹

For the wholesale components of retail prices, ROAM has calculated the “costs” that would be incurred by retailers based on the pool price outcomes observed by ROAM. In practice, retailers typically develop complex hedge portfolios, sign long-term PPAs and/or acquire generators in order to cover a range of possible futures. As such, retailers typically need to recover additional costs (in this way, they are effectively selling “reduced risk” to consumers by providing flat price contracts).

Similarly, ROAM has assumed that retailers are able to pass through the full cost of their purchased LGCs, and that future annual RPPs and STC targets have been set at the “correct” level for each year, requiring no “overs or unders” in subsequent years.

ROAM has taken a long-term approach for producing forecasts for this modelling, reflecting key drivers and trends. As such ROAM does not distinguish between retailers or distribution networks within a region. This may result in minor inconsistency in comparison to regionally focussed organisations to IPART but are immaterial to the outcomes of this report.

²⁰ AEMC, March 2013, *Electricity Price Trends Final Report*. Available at: <http://www.aemc.gov.au/Markets-Reviews-Advice/Retail-Electricity-Price-Movements-2012>. Accessed 23 April 2014.

²¹ AEMC, December 2011, *Impact of the enhanced Renewable Energy Target on energy markets*. Available at: <http://www.aemc.gov.au/Markets-Reviews-Advice/Impact-of-the-enhanced-Renewable-Energy-Target-on#>. Accessed 23 April 2014.

SWIS retail price assumptions

There are several recent publications that attempt to estimate the breakdown of retail prices in the SWIS market. However, each study employs different categories and where their categories are consistent, their contribution estimates vary by up to five percentage points. Furthermore, while the NEM is an energy-only market, the SWIS wholesale market consists of bilateral trades, a short-term day-ahead energy market (the STEM), a real-time balancing market and a capacity credit market. All of these have significant contributions to retail prices but a lack of transparency in both retail prices and market costs makes analysis difficult.

No recent reports directly break down the wholesale costs into the energy and capacity components. However, ROAM observed that the allowable capacity credits from renewables (as a percentage of nameplate capacity) has been decreasing in recent years²² thus reducing the impact of the LRET on the capacity credit market. ROAM has therefore assumed that the cost of procuring capacity credits passed through on a retail bill remains effectively constant (on a per MWh basis) regardless of the development of new renewable or thermal generation.

Finally, ROAM has assumed that ancillary services costs remain constant, on a per-MWh basis, in the absence of any certainty in this regard. Previous analysis suggests that these costs are likely to increase but are unlikely to be significant for consumers.²³

ROAM drew a consensus view of the retail price breakdown in the SWIS in 2012-13 in line with the AEMC's estimates in its publication on electricity price trends from March 2013²⁴. Future WEM retail prices are then modelled through estimating the impact of changes to the modelled energy price and the LRET, SRES and Feed in Tariff (FiT) contributions in the future years, while keeping all other components the same in each scenario.

4.2.2 LGC price calculation

Spot versus contract prices

It is important to make a distinction between the prices for LGCs traded on the "spot market" and the implied prices for LGCs traded through PPAs.

Historically, the certificate spot market has been relatively volatile, with large rapid shifts in the spot price being driven by policy announcements and other unpredictable factors. This strongly suggests that spot market prices are not representative of the underlying

²² IMO, *Capacity Credit Information*. Available at: <http://www.imowa.com.au/reserve-capacity/capacity-credit-information>. Accessed 23 April 2014.

²³ ROAM Consulting, September 2014, *Impact of the LRET on the costs of FCAS, NCAS and Transmission augmentation* [Report to the AEMC]. Available at: <http://www.aemc.gov.au/Markets-Reviews-Advice/Impact-of-the-enhanced-Renewable-Energy-Target-on>. Accessed 23 April 2014.

²⁴ AEMC, March 2013, *Electricity Price Trends Final Report*. Available at: <http://www.aemc.gov.au/Markets-Reviews-Advice/Retail-Electricity-Price-Movements-2012>. Accessed 23 April 2014.

costs involved with the creation of the certificates, but rather are associated with longer term price signals. This is consistent with discussions between ROAM and market participants. ROAM's experience is that retailers view the spot market for LGCs as an "overs-and-unders" market, used for securing small volumes of LGCs to meet a small portion of their annual liabilities.

By contrast, contract prices for LGCs (the difference between bundled PPA prices and the wholesale electricity price) are expected to be driven strongly by the cost of renewable technologies (Long-Run Marginal Cost, LRMC, of approximately \$90/MWh at present) and will generally be above the spot market prices. Table 4.1 shows the details of public wind PPA prices, as well as FiT rates for solar projects for reference. For example, Snowtown in 2011-12 received approximately \$27/MWh for its electricity; based on a \$75/MWh PPA, this would have translated to a contract LGC price of \$48/MWh – significantly higher than the reported spot market prices for LGCs in that year. Similarly, Hallett 2 received approximately \$27/MWh for its electricity in 2011-12 suggesting an implied contract price of \$77/MWh.

Table 4.1 – Summary of public PPA and feed-in tariff prices

Project	Off-taker(s)	Details	Date of PPA announcement	Starting PPA price
Snowtown	Sun Retail/ Origin Energy	90% of electricity and LGCs to December 2018	Pre-June 2007	\$75 ²⁵
Hallett 2	AGL Energy	All electricity and LGC revenue	August 2008	\$104 ²⁶
Hallett 4	AGL Energy	All electricity and LGC revenue	October 2009	\$120 ²⁷

²⁵ Equivalent AUD amount converted from NZD amount calculated from TrustPower, 2011, *Financial statements 2011*. Available at: <http://annualreport.trustpower.co.nz/en/2011/Financial-Statements-2011/Note-6.aspx>. Accessed 4 September 2013.

and

Office of the Clean Energy Regulator, *REC Registry*. Available at: <https://www.rec-registry.gov.au/>. Accessed 4 September 2013.

²⁶ AGL, *AGL earns \$59 million development profit on sale of Hallett 2 Wind Farm* [Press release]. Available at: [http://www.agl.com.au/about/ASXReleases/Pages/AGLearns\\$59milliondevelopmentprofit.aspx](http://www.agl.com.au/about/ASXReleases/Pages/AGLearns$59milliondevelopmentprofit.aspx). Accessed 4 September 2013.

²⁷ AGL, *AGL to earn \$88 million in development fees from the sale of Hallett 4 Wind Farm* [Press release]. Available at: [http://www.agl.com.au/about/media/Pages/AGLtoearn\\$88millionindevelopmentfeesfromthesaleofHallett4WindFarm.aspx](http://www.agl.com.au/about/media/Pages/AGLtoearn$88millionindevelopmentfeesfromthesaleofHallett4WindFarm.aspx). Accessed 4 September 2013.

Project	Off-taker(s)	Details	Date of PPA announcement	Starting PPA price
Oaklands Hill	AGL Energy	All electricity and LGC revenue	June 2011	\$99 ²⁸
Royalla	FRV	Feed-in tariff (including LGCs)	Sep 2012	\$186 ²⁹
Canberra 2	Zhenfa	Feed-in tariff (including LGCs)	August 2013	\$178 ²⁹
Canberra 3	Elementus Energy	Feed-in tariff (including LGCs)	August 2013	\$186 ²⁹

Although the recent surplus of certificates (driven by the so-called “phantom RECs”, produced before the split of the RET into the LRET and SRES) resulted in retailers sourcing an increasing proportion of their liability from the spot market, ROAM expects that the majority of future projects will be financed through long-term PPAs.

LGC price calculation

Given that most retailers will be seeking to secure future LGC liabilities through PPAs, and that historically the spot market price has not reflected the contract LGC price in publicly announced PPAs (which reflects the total cost to retailers), ROAM has utilised forecasts of contract LGC prices, rather than the more volatile spot market price, in the retail price forecasts of this report. As contract LGC prices have historically been more than spot market prices, this methodology may tend to overestimate the retail cost increase of the LRET scheme.

Any forecast of LGC contract prices requires a view of the technologies which will contribute to meeting the LRET, the LRMCs of those technologies and the revenue that such plants will earn through the electricity market (in wholesale electricity revenue or capacity payments).

ROAM’s modelling finds that, under BAU, the LRET will be largely met by wind generation. If another technology replaces wind generation as the cheapest source of LGCs (or wind capital costs are lower than expected), the forecasts in this report provide an upper bound for LGC prices. Although small amounts of other technologies are likely to be

²⁸ AGL, *AGL to earn \$38 million in development fees from the sale of Oaklands Hill Wind Farm* [Press release]. Available at: <http://www.agl.com.au/Downloads/ASX%20-%20Oaklands%20Hill%20Sale%20final%20270611.pdf>. Accessed 4 September 2013.

²⁹ These are nominal FITs that require the voluntary surrender of LGCs. Comparable PPAs would require LGC prices above the penalty price. ACT Government, September 2013, *Work to start on Royalla Solar Farm* [Press release]. Available at: http://www.cmd.act.gov.au/open_government/inform/act_government_media_releases/corbell/2013/work-to-start-on-royalla-solar-farm. Accessed 4 September 2013.

introduced, they are unlikely to be price setters, and instead will negotiate prices for LGCs comparable to wind farms.

One possible exception is the development of a significant number of behind the meter mid-size (100 kW) solar PV installations. Some market participants indicated that these systems could be cost-effective based on current retail tariffs and future cost projections by 2018. If so, they could act as a source of low-cost LGCs that could assist in meeting the target at lower cost than modelled.

To calculate the cost of LGCs on a retail bill, ROAM has assumed that:

- New renewable projects receive flat (in real terms) PPAs for up to 15 years, or the end of the LRET, whichever is sooner; and
- Beyond that period, renewables receive the spot price electricity and LGCs (if the LRET is ongoing at the end of the PPA).

Spot prices have historically been very volatile and not necessarily cost reflective; as such, a conservative estimate of spot prices has been used. A price of \$35/MWh (real June 2013) is assumed up to 2030, which represents a discount to the LGCs required by new projects.

Approaching 2030, the technology cost estimates used in this study suggest that new renewables (in particular, solar PV in Queensland) could begin to be installed in their own right. ROAM has therefore assumed that the price of certificates will eventually fall, and has set the spot price of certificates to \$10/MWh post-2030 under the LRET scenario extended beyond 2030. Prices may actually be higher (if only limited new projects are independently viable) or lower (if new capacity is widely available).

In all cases, ROAM assumes that contracted projects can achieve higher than spot prices for LGCs in any given year, as this is a necessary condition of projects being financially viable and based on industry interviews is the current situation for many projects in the market.

Project PPA prices are then set at the level required to achieve a Net Present Value (NPV) of zero (given the capital costs, financing and operating cost assumptions) over the life of the project. The implied LGC price for a specific project in any given year is then the difference between the PPA and the average wholesale electricity revenue for wind generators, or the spot price for LGCs once the PPA has expired.

Retailers are assumed to purchase an “average” portfolio of wind, with their cost of LGCs in any year determined as a weighted average of the LGCs required by the installed wind farms (which vary by installation year, driven by capital costs). The prices published in this report therefore represent the average LGC cost to retailers in that year; this will be different to the LGC price that a new entrant project would receive or require.

Shortfall charge

The LRET legislation specifies a shortfall charge of \$65/MWh (nominal dollars). Purchases of LGCs are eligible for tax exemption, whereas payment of the shortfall charge is not. This means that the \$65/MWh shortfall charge is equivalent to a 93 nominal \$/MWh effective "cap" on the price of LGCs. At LGC prices higher than this, retailers are expected to prefer to pay the shortfall charge. Importantly, the shortfall charge is defined in nominal terms. This means that in real terms it reduces over time due to inflation. The effective cap on the price of LGCs will therefore reduce (in real terms) from \$93/MWh in 2013 to \$79/MWh in 2020 and \$62/MWh in 2030.

In the Extended RET scenario, ROAM has increased the nominal price cap to \$110/MWh in 2020 to reflect the additional requirements for new build not anticipated under the existing scheme. The existing shortfall charge was utilised, and found sufficient, for the BAU (and No RET) scenarios.

4.2.3 STC prices

The historical prices for STCs are shown in Figure 4.2. In 2012, and previous years, the bulk of STCs were sold at a discount from the Clearing House price of \$40 (nominal). This is because uptake of small-scale systems consistently exceeded the small-scale technology percentage in those years, creating a surplus of certificates. More recently, however, certificates have been trading closer to the Clearing House price (around \$36-\$39), which ROAM expects represents the "holding cost" to installers from waiting for certificates to sell through the Clearing House.

ROAM expects that, in the future, supply and demand of certificates in each year will continue to be relatively closely matched. As such, we have used an STC price of \$38 (nominal) in all subsequent years, representing a small discount from the Clearing House price. This is a conservative scenario; if certificates trade at lower values, this will translate to a reduction on retail bills.

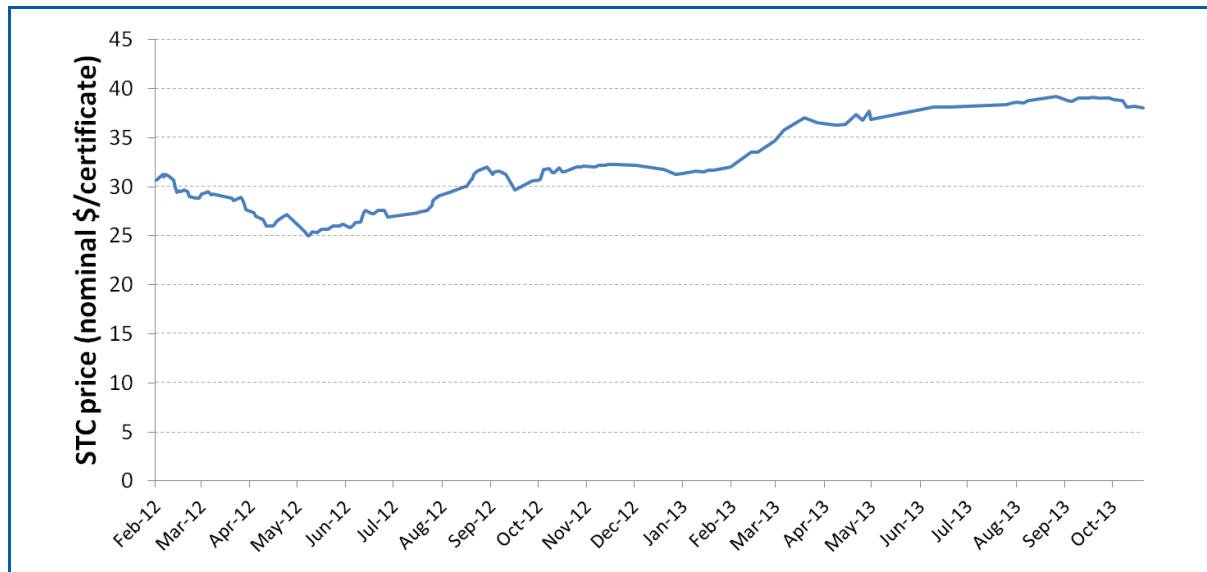


Figure 4.2 – Historical STC prices³⁰

4.2.4 Jobs estimate

ROAM has estimated the number of jobs required in each year in the period 2014-15 to 2029-30 under different LRET and SRES scenarios.

Jobs in large-scale renewables

To assess jobs required under different LRET scenarios, ROAM determined an indicative number of jobs required per MW of wind and large-scale solar during construction and operation phases. This calculation was based on a survey we performed of published estimates of the number of jobs associated with existing and planned wind farms in Australia. These estimates are typically published on project websites, in planning applications and press releases. We found information on 22 wind farms and four large-scale solar projects. The number of jobs was multiplied by the number of years the job would exist for to arrive at job-years/MW.

ROAM has assumed that job numbers reported are for full-time equivalent roles for the duration of a project. For example, if a wind farm requires a particular contractor to work for six months of a two year construction period, we have assumed this would be incorporated into the reported total number of jobs as 0.25 jobs (or 0.5 job-years).

Using this methodology, we estimate rates for direct jobs in large-scale renewables as summarised in Table 4.2.

³⁰ Sourced from Clean Energy Council website.

Table 4.2 – Estimate of job requirement rates in large- and small-scale renewables

Technology	Construction	Operations and maintenance
Wind	4.4 job-years/MW under construction Typical duration = 2 years 2.2 jobs/MW for two years	2.5 job-years/MW operational Typical duration = 25 years 0.10 jobs/MW for 25 years
Large-scale solar	2.4 job-years/MW under construction Typical duration = 1 year 2.4 jobs/MW for one year	3.3 job-years/MW operational Typical duration = 25 years 0.13 jobs/MW for 25 years
Rooftop solar	15 job-years/MW under construction	

For large-scale renewables, these values are intended to cover direct site-related jobs only, although it is frequently difficult to determine which jobs are included in published estimates and which are excluded. Additional indirect employment created in Australia could include jobs related to:

- the manufacture of towers, turbines or other components,
- the manufacture and supply of materials used in wind farm manufacture and installation e.g. steel, paint.
- the development and approvals process.

An estimate of employment opportunities created by some of these more indirect streams has been published elsewhere.³¹

ROAM's job-year estimates include all projects built between 2014-15 and 2029-30. A small number of projects are not directly attributable to the RET since they can cover costs with wholesale pool revenue alone (particularly in the No RET scenario), or are subsidised by other means (such as the ACT solar reverse auction projects). Since the total capacity in this category varies between scenarios, we have included these jobs to facilitate a fair comparison between scenarios.

ROAM also estimated the number of jobs that will exist in each year by assuming that wind construction jobs will exist for two years prior to commissioning, solar construction jobs will exist for one year prior to commissioning and operations and maintenance jobs will exist for 25 years from the year of commissioning. These assumptions create some end effects. For example, capacity commissioned in 2014-15 will have no construction jobs attributed to it since these jobs will be required prior to 2014-15. Similarly, a project commissioned in 2029-30 will have operations and maintenance jobs associated with it extending from 2029-30 to 2043-44. However, only 2029-30 year falls in the period of interest and so only one job-year will be counted toward the totals reported.

³¹ SKM, July 2012, *Wind farm investment, employment and carbon abatement in Australia* [Report to the Clean Energy Council]. Available at: <https://www.cleanenergycouncil.org.au/dam/cec/policy-and-advocacy/reports/2012/Wind-Farm-Investment-Employment-and-Carbon-Abatement-in-Australia/Wind%20Farm%20Investment%2C%20Employment%20and%20Carbon%20Abatement%20in%20Australia-1.pdf>. Accessed: 20 February 2014.

Jobs in small-scale renewables

To assess jobs required under different SRES scenarios, ROAM assumed that in any one year, there were 15 jobs/MW of capacity installed in that year. This multiplier was provided by the Clean Energy Council and is included in Table 4.2. There was no distinction made between jobs in installation and those in maintenance. This estimate also includes other small-scale renewables sector jobs such as sales.

When attributing small-scale jobs to a particular year, ROAM assumed they exist in the year of commissioning.

Number of positions created by 2019-20 and 2029-30

ROAM also estimated the number of 'positions' created by 2019-20 and by 2029-30 under each scenario by assuming that this is equal to the peak number of jobs, treating large-scale construction, large-scale operations and maintenance and small-scale jobs separately. This assumption has a number of important implications.

- All positions last for at least one year.
- If the number of jobs fluctuates instead of growing steadily, we are effectively assuming that some positions last for longer than others. Furthermore, some positions disappear and then reappear, but are not counted as a new position.
- The peak number of jobs in each region is not always coincident (with each other, or the Australian total). By calculating the number of positions as the total Australian peak, we are assuming that some positions require employees to move between regions, but are not counted as a new position.
- The peak number of jobs in construction and operations and maintenance of large-scale renewables is not coincident. In theory some positions may be able to be filled by a single employee transitioning from a construction role to an operations and maintenance role. Our methodology counts this as two separate positions.

Further discussion of the implications of our methodology in each scenario is presented with the outcomes (Sections 5.5, 6.7 and 7.6 respectively for the BAU, No RET and Extended RET scenarios respectively).

4.3 DATA SOURCES

4.3.1 LRET

Figure 4.3 shows the three trajectories considered in this modelling:

- BAU: the currently legislated trajectory;
- No RET: a repeal scenario, where no new projects are eligible after 2015, but existing and committed projects continue to produce and sell LGCs.
- Extended RET: a 30% by 2030 scenario, where the target is increased and extended beyond 2020; and

All scenarios rely on a contribution from banked certificates to meet annual liability in the short-term.

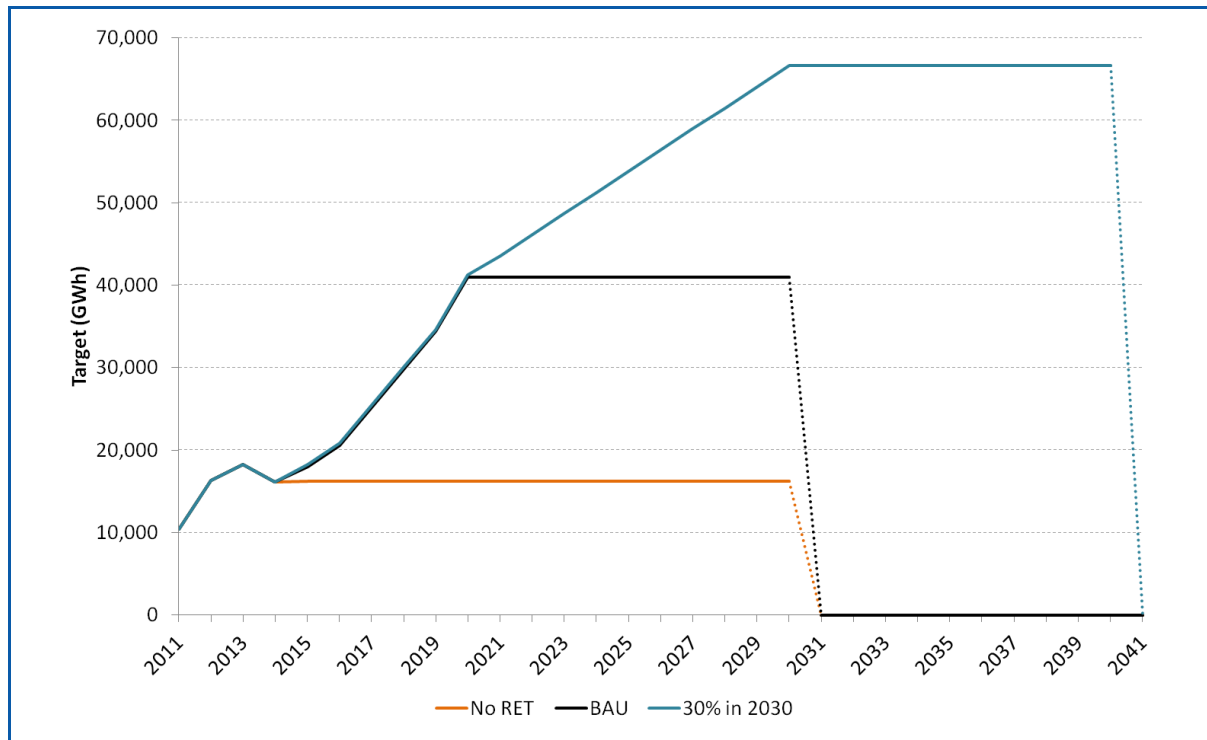


Figure 4.3 – Modelled LRET GWh targets

4.3.2 Carbon pricing

Based on announcements from the Government, ROAM modelled a repeal of the existing carbon price from 1 July 2014 and no explicit or implicit carbon price was reintroduced for the electricity sector during the study period. This is therefore a conservative scenario for renewables, where no long-term price signal is present (which would support PPAs beyond the end of the LRET period) and where there is less financial incentive to retire or reduce the use of fossil fuels. Additionally, if a price on carbon emissions were to be applied to the electricity sector in the future, this would reduce any costs attributable to the RET.

4.3.3 Rooftop PV

In consultation with the Clean Energy Council, ROAM has used the AEMO Moderate Uptake³² and IMO scenario as the basis for the BAU and Extended scenarios, representing the most recent public forecast of medium-term solar PV uptake.

In the No RET scenario, SunWiz provided ROAM with a forecast of the percentage reduction in the annual growth rate of rooftop PV out to 2017-18, relative to BAU, due to a repeal of the SRES. This included a small increase in uptake when the scheme repeal was announced, followed by a reduction in annual installs of 40-45%. ROAM extrapolated

³² AEMO, June 2013, *National Electricity Forecasting Report*, Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Accessed 17 February 2014.

this forecast over the study period, trending back to the AEMO annual growth rate post-2030. Figure 4.4 shows the rooftop PV capacity modelled by ROAM in the NEM and SWIS systems, combined. By 2030, installed PV falls by 30% if the RET is repealed.

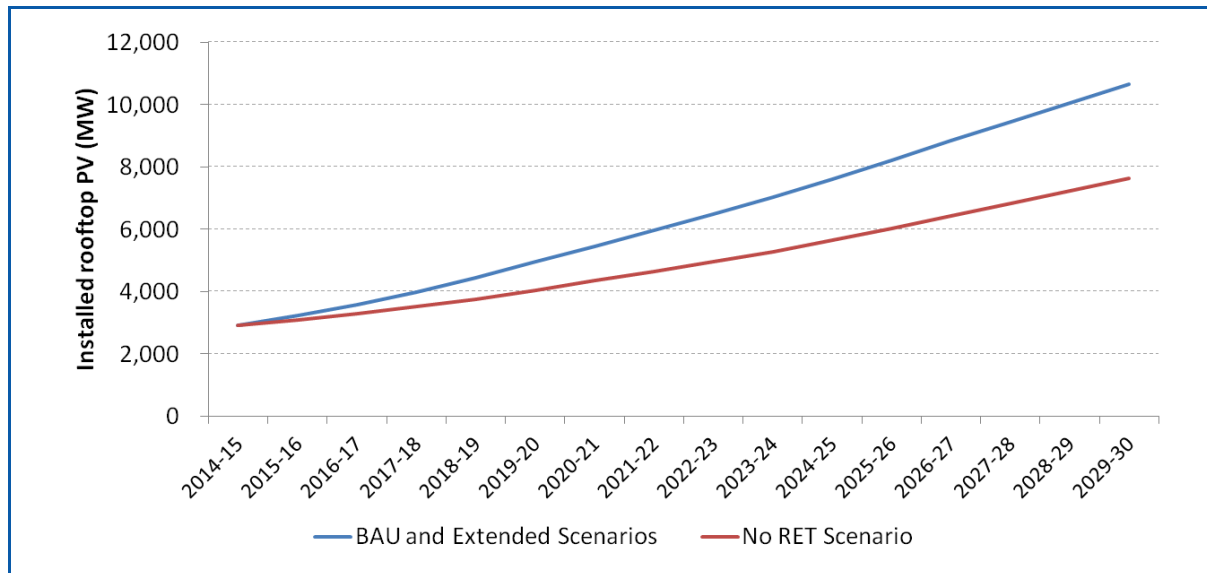


Figure 4.4 – Modelled rooftop solar PV in the NEM and SWIS

4.3.4 Plant closures

ROAM undertakes economic analysis of all plant to determine whether it would be economically rational to retire or mothball (temporarily retire) existing units. In addition to saving annual fixed costs (e.g., maintenance) this decision can also be driven by portfolio effects (where withdrawal of capacity increases profits for other units in the portfolio sufficient to cover that unit's lost revenue; this also provides a windfall to other market generators).

ROAM's analysis suggests that relatively little plant will choose to retire in the absence of a carbon price, even under the BAU and Extended RET scenarios. Currently mothballed plant was returned to service on announced schedules. In this study, ROAM has retired both units of Wallerawang based on reports from AEMO and union sources; after the modelling commenced, it has been confirmed by EnergyAustralia that Wallerawang will be removed from service, but placed on three month recall³³. Under the Extended RET scenario, ROAM has retired Pelican Point CCGT in South Australia. However, this was a marginal decision. Other outcomes such as alternative mothballing, capacity withholding or bidding strategies are plausible.

³³ Lithgow Mercury, 21 January 2014, *Uncertain future for Wallerawang Power Station*. Available at: <http://www.lithgowmercury.com.au/story/2034049/uncertain-future-for-wallerawang-power-station/>. Accessed: 13 February 2014.

4.3.5 Demand forecast

For this study, demand forecasts were required for the whole of Australia in order to assess the percentage of total demand that would be sourced from renewables to determine the Renewable Power Percentage in each year. Additionally, to model the NEM and WEM electrical system, ROAM required forecasts of demand to be met by grid-connected generators.

ROAM therefore used two key sources. Firstly, for Australia-wide demands, ROAM used the *Australian Energy Projections* published by BREE³⁴ (see Section 2.3.4 for more detail). For the NEM, ROAM used the Medium scenario of the AEMO 2013 National Electricity Forecast³⁵ demand and energy forecasts. The AEMO forecasts are for NEM-connected demand only, and offer additional detail to the BREE forecasts that is necessary for market modelling. These forecasts expect relatively low growth in all regions except Queensland, which experiences moderate growth due to the development of the LNG industry. For the WEM, ROAM used the IMO Expected demand forecast³⁶. Again, this offers additional detail to the BREE forecasts for grid-connected generators.

Although future demand can be affected by a range of factors, including international competitiveness, fuel prices, and uptake of energy efficiency, in each case, these forecasts represent the best and most recently available demand forecasts of “midpoint” demand. ROAM notes, however, that inconsistencies between assumptions may exist between the separate forecasts.

4.3.6 Capital and O&M costs

ROAM Consulting used plant cost data from the BREE AETA 2012 report³⁴. Based on feedback from the industry, as well as ROAM’s analysis of announced projects, the capital cost curve for solar PV technologies was brought forward by two years, to better capture actual prices currently seen in the market.

4.3.7 Gas prices

ROAM used gas and coal prices forecast from Scenario 3 of the AEMO 2013 Planning Assumptions³⁷.

³⁴ BREE, December 2012, *Australian energy projections*. Available at: <http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%932050>. Accessed 13 February 2014.

³⁵ AEMO, June 2013, *2013 National Electricity Forecasting Report (NEFR)*. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Accessed 13 February 2014.

³⁶ IMO, July 2013, *2013 Electricity Statement of Opportunities (ESOO)*. Available at: [http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-\(soo\)](http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(soo)). Accessed 9 December 2013.

³⁷ AEMO, June 2013, *2013 Planning Assumptions*. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>. Accessed 9 December 2013.

Figure 4.5 shows the gas prices that were modelled for each region of the NEM; additional transport costs were applied for neighbouring NTS zones. When bidding gas generators, ROAM used these gas prices to uplift all generator bid offer bands for all new gas generators as well as for existing gas generators after the expiration of any existing gas contracts. OCGTs have a 25% premium added to fuel costs in line with AEMO's methodology for low load factor generators³⁸.

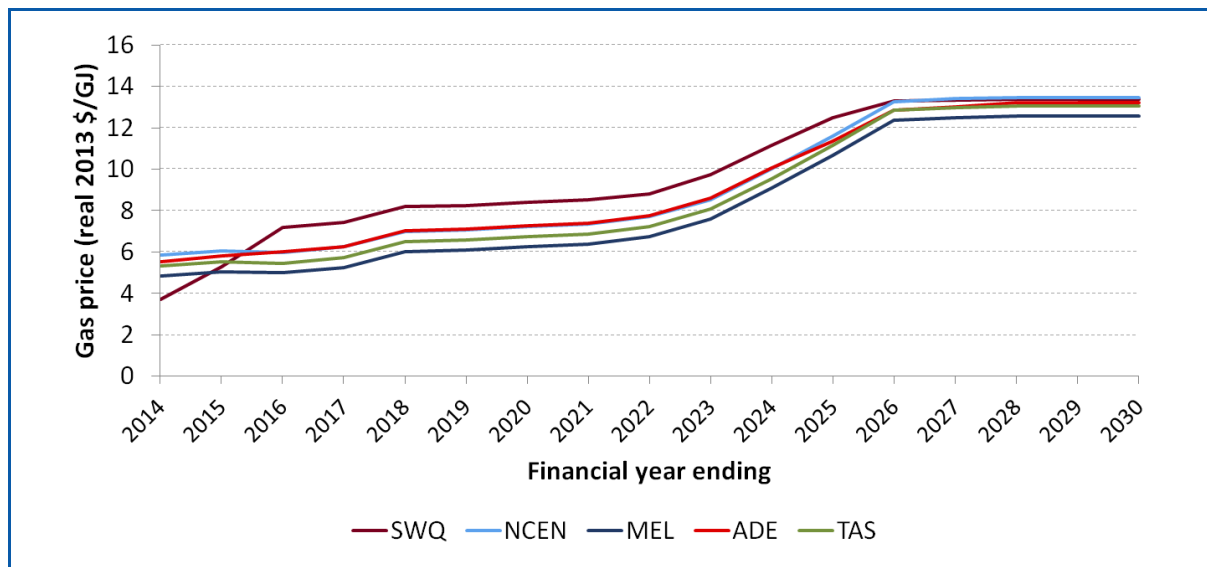


Figure 4.5 – Gas price trajectories

5 MODELLING RESULTS: BUSINESS AS USUAL SCENARIO

5.1 WHOLESALE ELECTRICITY PRICE OUTCOMES

No new thermal generation capacity is required in the NEM until after 2020 in Queensland and not until after 2030 in the other regions. In the WEM, moderate amounts of new CCGT capacity is installed in conjunction with new wind. Figure 5.1 shows the growth in capacity across the NEM and WEM out to 2020.

³⁸ ACIL Tasman, June 2012, *Fuel cost projections: Updated natural gas and coal outlook for AEMO modelling*. [Report to AEMO]. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>. Accessed 23 April 2014.

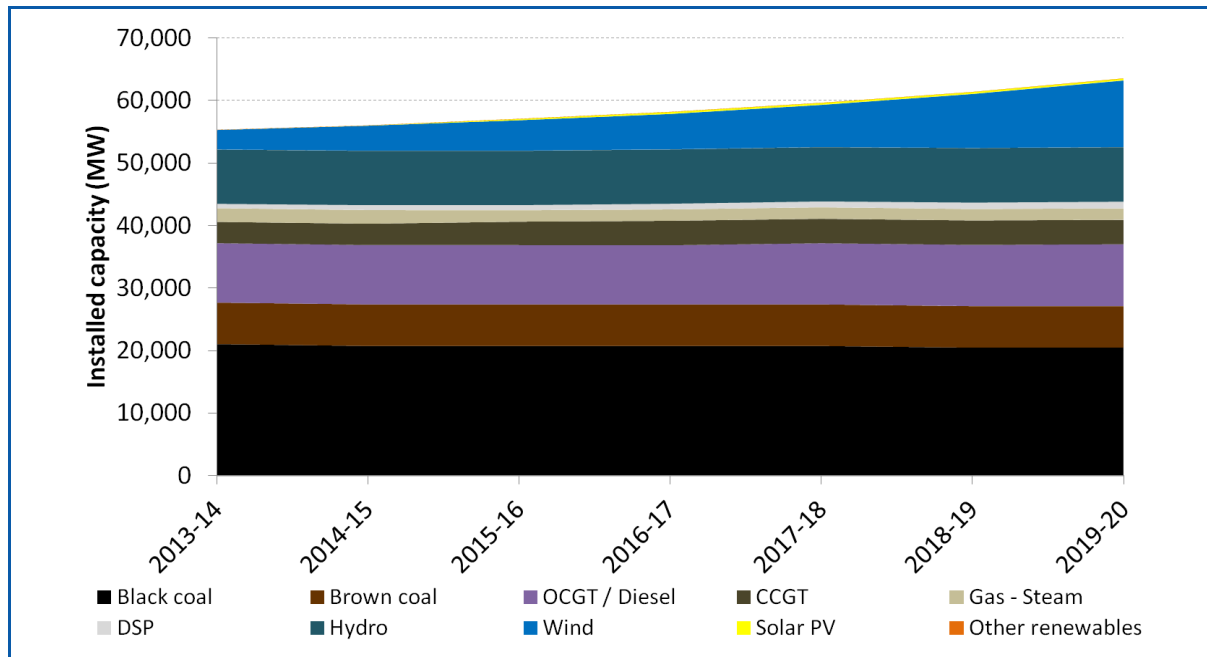


Figure 5.1 – Installed capacity (NEM and WEM, BAU)

Figure 5.2 shows the price outcomes for each region under the BAU scenario, based on ROAM's 2-4-C modelling.

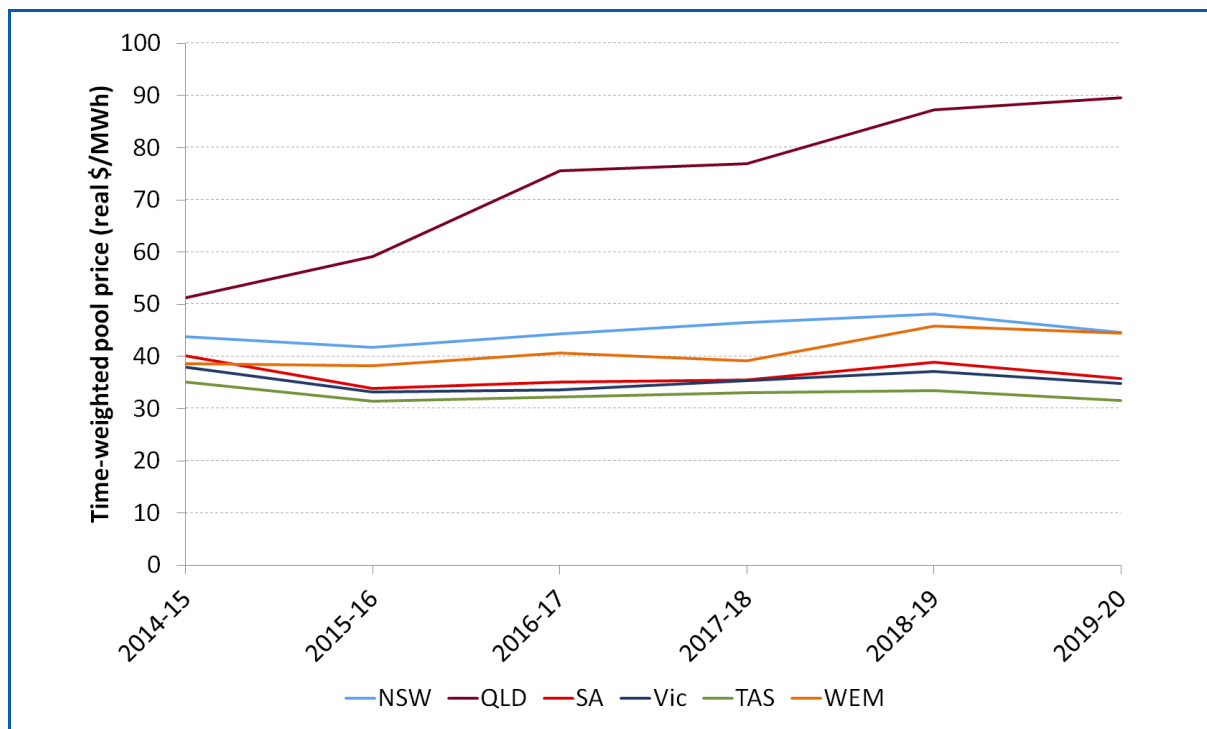


Figure 5.2 – Time-weighted pool price (BAU)

Renewables delay price rises in most regions

In New South Wales, Victoria, South Australia and Tasmania, prices remain low out to 2020, and below the LRMC of any prospective new entrant technology, because of new

renewable generation installed under the LRET. This reflects the merit order effect, where additional low SRMC capacity in the market reduces wholesale prices.

After the RET GWh target is reached, and new renewables are not installed, continued growth in annual peak demand means moderate additional peaking capacity is eventually required. Additional energy providing plant (as opposed to peaking capacity) is not required in most NEM regions until after 2030.

Queensland at risk of higher prices

ROAM's modelling shows that Queensland wholesale prices will begin trending upwards from 2015 – in contrast to the relatively flat prices in the other regions. There are several drivers for this effect.

In Queensland, the current excess of supply is rapidly eroded for two reasons: stronger demand growth due to development of the LNG production industry, and a smaller share of renewables based on ROAM's market analysis. If additional renewables can be built in Queensland, they would act to slow electricity price rises and reduce the LRET implementation costs. One way this could be accomplished would be for Queensland retailers to be encouraged to offer PPAs for Queensland-based renewable energy projects.

A further issue for Queensland is that existing gas-fired generators in the region, such as Darling Downs, have previously provided significant energy to the system through the use of relatively low-cost gas. In the future, as gas prices rise and availability of gas becomes more restricted, electricity output from gas plant will reduce, further tightening the supply/demand balance in Queensland. Similarly, pressure on gas supply and prices has meant that ROAM has not installed new CCGT plant in Queensland until after 2025. As with renewables, if additional CCGT generation could secure reasonably priced gas contracts and come online sooner, it would help to reduce upward pressure on Queensland electricity prices.

In addition, export capacity from New South Wales to Queensland is low relative to Queensland demand which means that other regions can rarely "import" the high prices in Queensland. This drives price separation between Queensland and the other regions. An upgrade of interconnection between Queensland and New South Wales would result in greater price convergence between Queensland and the other regions, but has not been considered in this modelling.

As such, Queensland prices increase and stabilise after approximately 2020, consistent with AEMO's requirement for new capacity in their 2013 Statement of Opportunities³⁹.

³⁹ AEMO, August 2013, *Statement of Opportunities*. Available at: <http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities>. Accessed 13 February 2014.

After this point, new entrant capacity (a mix of gas and renewables) is installed in response to growing demand.

Longer term, prices will begin to rise

After the LRET 2020 target is reached, and additional renewables are not being incentivised to enter the market, the supply-demand balance will tighten. In a competitive energy market, pool prices in the short-run (i.e., for a given mix of plant and a given demand profile) are driven by the level of competition in the market and the short-run costs. As a broad generalisation, the supply-demand balance can be used as a proxy for this: if there is an excess of capacity compared to demand, prices are likely to be low (with generators competing on volume), while if there are limited reserves, prices can be driven up either through market power (in the NEM) or simply the need to run more expensive plant (such as extreme peakers or diesel generation).

Longer term, as supply and demand become more closely matched, prices would be expected to rise until they reach the level of a new entrant generator. At this point, additional capacity would be economically viable and would enter the market, improving the supply demand balance and pushing prices back below a new entrant level. As market demand slowly increases over time, prices in the NEM should therefore be expected to rise slowly until a point beyond 2030, except for Queensland which sees prices rise to new entrant levels by around 2020.

In this modelling, new entrant generators include wind, solar and CCGT. This represents a significant transformation from the historical operation of the system, where the bulk of energy came from comparatively low-cost, long-term coal contracts. At the same time, gas prices are forecast to rise significantly; at least doubling in the short term compared to existing contracts, and rising to \$10-\$12/GJ by 2030 (or sooner). This will tend to put upward pressure on wholesale pool prices. Longer-term prices will necessarily rise above historical levels, and this additional revenue is key for supporting the longer-term viability of renewable projects, and the signing of PPAs by retailers.

5.1.1 Sensitivity of pool prices

Pool prices are sensitive to many factors, including:

- The size and shape of electricity demand in any year;
- Mothballing or retirement of generation;
- New entrant generation;
- Changing bidding strategies of portfolios of generation;
- Extreme weather, such as droughts (limiting hydro availability and cooling water), floods (restricting transmission or coal supply) and heat waves;
- Actual renewable generation; and
- Fuel costs.

These forecasts therefore represent a single, but well-considered view of the future, drawing on “planning scenario” assumptions from sources such as AEMO and internal ROAM analysis.

Impact of mothballing and retirements

ROAM has modelled Wallerawang as retiring from 1 July 2014. All other currently mothballed plants are brought back online by this time in this modelling. This modelling does not include the mothballing of Swanbank E power station⁴⁰ as it had not been announced when modelling commenced.

Additional mothballing or retirement of capacity has not been included in this modelling. Such retirements might be more likely in the presence of the LRET, but ROAM’s long-term integrated resource planning model has indicated that, particularly in the absence of a carbon price, no significant retirements would be expected before 2030.

If additional capacity is withdrawn, however, wholesale prices would tend to increase, LGCs prices decrease and the cost of the RET as a proportion of total retail bills would decrease.

Another factor is that large industrial loads (particularly, but not exclusively, smelters) have faced increasing international pressures, leading to the closure of plants such as the Kurri Kurri smelter in New South Wales. If additional loads are removed from the system, this would tend to exacerbate the supply-demand imbalance, and push wholesale electricity prices lower. In particular, this modelling does not include the recently announced closure of the Point Henry aluminium smelter.⁴¹

Sensitivity to gas prices

The gas prices used by ROAM in this modelling, sourced from AEMO, feature two major price increases. The first is due to domestic prices rising to international netback prices (driven by the growth of the LNG export industry) and a second increase beyond 2020 due to a forecast rise in international LNG prices.

However, AEMO provides a range of trajectories (supplied by ACIL Tasman⁴²) that reflect the significant uncertainty in future gas prices. As such, the SRMC of any particular gas generator could be higher or lower by up to \$30/MWh than the SRMC modelled by ROAM.

⁴⁰ Howells M, 5 February 2014, ‘33 jobs lost as Ipswich power station mothballed’, *ABC News*. Available at: <http://www.abc.net.au/news/2014-02-05/33-jobs-lost-as-ipswich-power-station-mothballed/5240324>. Accessed 24 April 2014.

⁴¹ ABC, 18 February 2014, *Aluminium producer Alcoa confirms decision to close Point Henry smelter, rolling mills*. Available at: <http://www.abc.net.au/news/2014-02-18/aluminium-producer-alcoa-confirms-decision-to-close-point-henry/5266330>. Accessed 18 February 2014.

⁴² Now called ACIL Allen.

However, the impact of this cost uncertainty on pool prices will be less in systems with high penetration of renewables⁴³. This could have further flow on benefits in terms of reducing risk and uncertainty for retailers which could potentially reduce their hedging costs. ROAM has not included any potential cost savings in this regard for this analysis.

5.2 LGC PRICES

The average LGC prices incurred by a retailer with a broad portfolio are shown in Figure 5.3. Prices rise initially, driven by new entrant wind generation. Bundled prices are above the LRMC of a new entrant wind farm because of the need for projects to recover sufficient revenue costs during their PPA period to cover possible shortfalls in later years. ROAM notes that, as discussed in Section 4.2.2, LGCs under long-term PPAs are effectively already being traded at prices of 50-70 \$/MWh, well above the LGC spot market prices of 30-40 \$/MWh.

Longer term, prices decline in response to pool price increases and also because of reducing costs for new wind farms. The existing shortfall charge was maintained in all years.

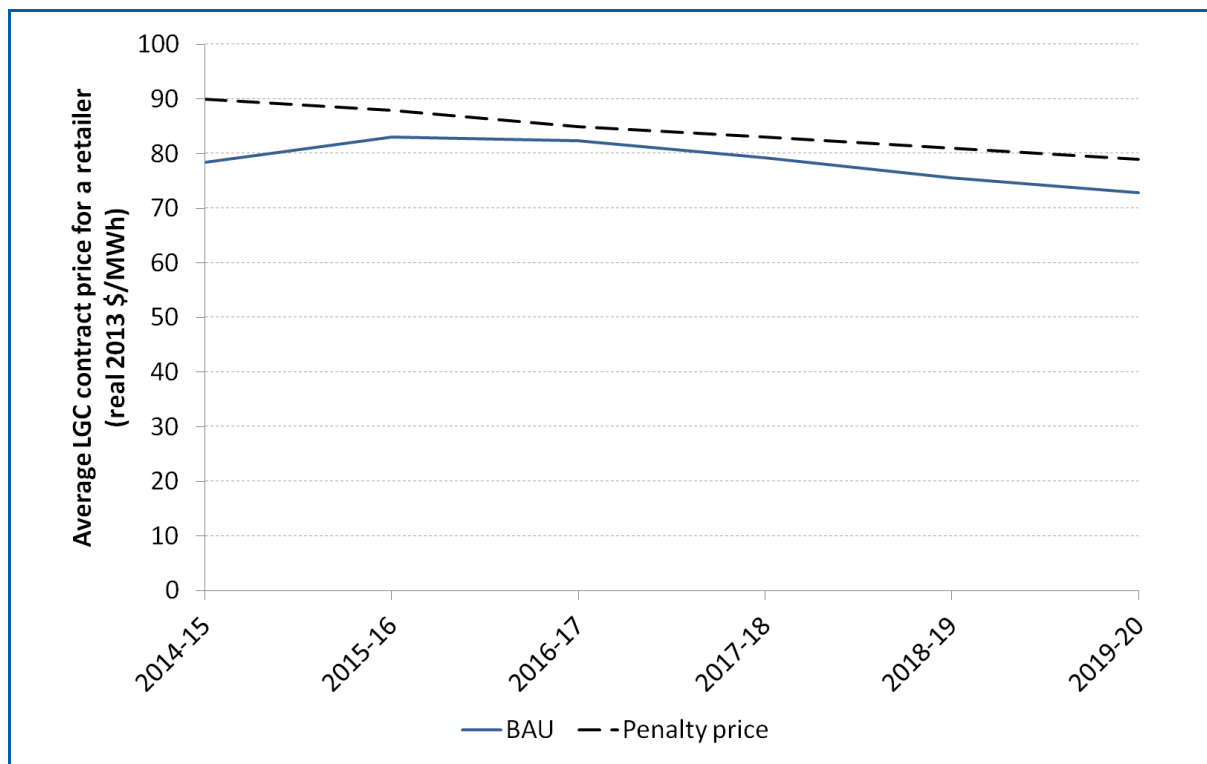


Figure 5.3 – Modelled contract LGC prices (BAU)

⁴³ For example, Riesz and Tourneboeuf for AECOM, 2013, *Delivering energy price security in an age of uncertainty*, Available at: http://www.aecom.com/deployedfiles/Internet/Geographies/Australia-New%20Zealand/DeliveringEnergyPriceSecurity_DrJennyRiesz.pdf. Accessed: 9 December 2013.

PPA viability

ROAM has conducted analysis of new wind installed in each year to verify that the costs incurred by the retailer in signing a PPA with a wind farm is preferable to paying the shortfall charge and purchasing energy from the pool instead.

This analysis suggests that, in the absence of a carbon price, signing a PPA for new wind generators in each year would be economic for retailers as LGC prices remain below the tax effective shortfall penalty. Risk adverse retailers, however, might decide to take long positions, and instead be prepared to accept the risk of a few years of penalty payments. However, the failure of a retailer to meet its legal obligations under the LRET scheme would also result in adverse publicity that retailers might want to avoid.

ROAM notes that some purely cost-based studies (without strategic or portfolio bidding effects) have found the LRET target unlikely to be met; this highlights the importance of more comprehensive time-sequential market modelling.

More pessimistic views of wind farm capital costs, capacity factors, or of lower pool prices are possible and could make securing PPAs more difficult. Extending the duration of the LRET scheme improves the position of all projects, by extending the period within which retailers would be willing to sign PPAs.

On balance, ROAM therefore believes that meeting the RET in the BAU scenario without a carbon price is economically feasible. An increase in the shortfall charge or scheme duration would further increase the likelihood of the goals of the legislation being met.

Impact of the shortfall charge

ROAM finds that sufficient renewable projects can be economically constructed under the existing shortfall charge to meet the LRET in all scenarios. The effective cost of LGCs to a retailer rises to close to the cap in the short-term, but declines longer term with wholesale price growth and cheaper sources of LGCs. Historically, the LGC/REC price has not approached the tax effective shortfall penalty of the RET legislation.

However, if the LRET is not met in any particular year, the spot price for certificates would rise to the shortfall charge in that year. In the preceding years, in anticipation of a shortfall, the LGC spot price would be discounted from the shortfall price by the “cost of carry” of certificates.

5.3 RETAIL PRICE OUTCOMES

Figure 5.4 and Table 5.1 show a national average retail bill for a household with an annual consumption of 6,500 kWh; higher or lower electricity usage (particularly for households with rooftop PV) would have different percentage contributions from each item. Trends in the contribution of the RET to retail bills are the same for all regions.

23 May 2014

Retail bills are forecast to rise moderately over time, primarily in response to rising wholesale market costs. In the short term, wholesale costs are forecast to account for an average of 20-25% of retail bills, although wholesale electricity costs in any year could be somewhat higher or lower.

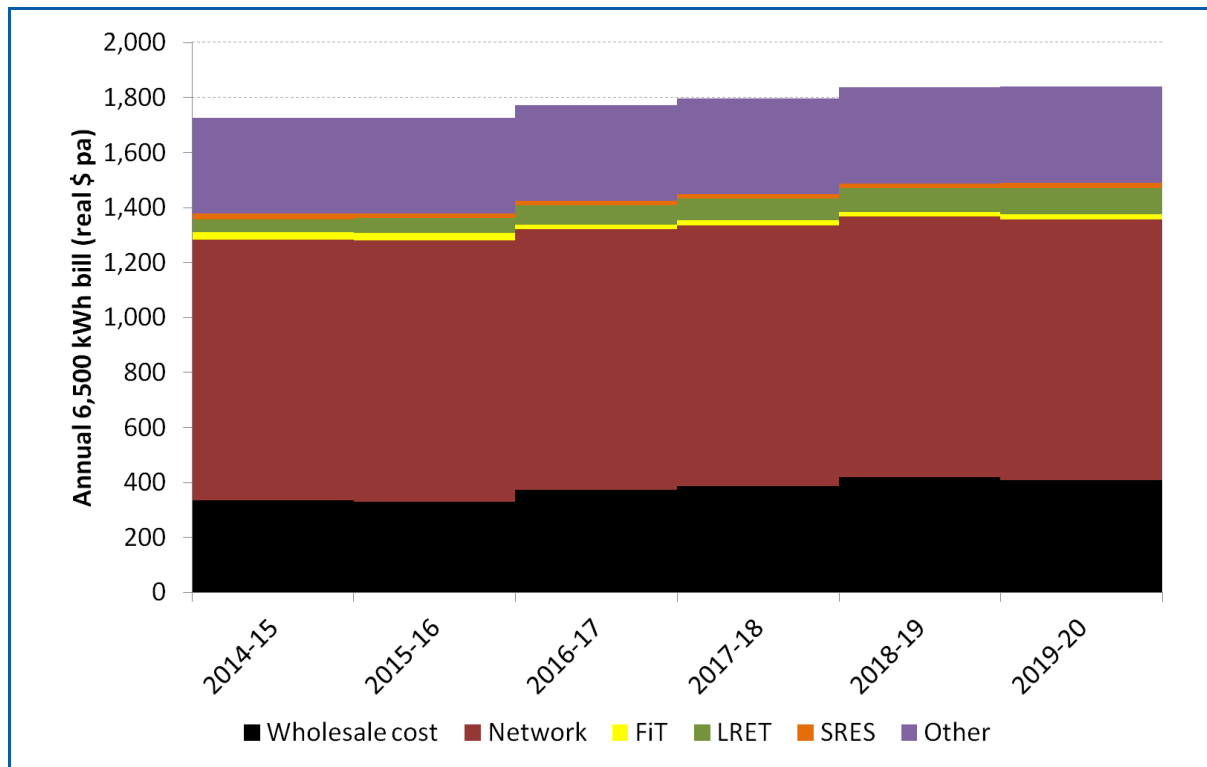


Figure 5.4 – Retail bill breakdown (Australian average, BAU)

Between now and 2020, the RET (LRET plus SRES) is expected to contribute between 4-6% to the total Australian average retail bill. This percentage is predicated on the assumption that 'Other' and, in particular, network charges do not rise; any increase in these components would increase the total bill and therefore reduce the percentage contribution of the RET.

ROAM notes that the theoretical maximum cost of the LRET is limited to \$79/MWh in real terms by 2020 (the year with the highest RPP). Therefore, on a 6,500 kWh retail bill (with a total cost of \$1,500-2,000), the maximum cost of the LRET relative to today would be an increase of \$9 (in real, 2013 dollars) in 2020, from the \$91 in this modelling. The "downside" risk of this percentage calculation is therefore low.

Furthermore, although the prima facie cost of the RET can be broken out as a distinct "line item" in an electricity bill, it is the total costs that must be compared to the counterfactual scenario without the RET in order to assess the net "cost" to electricity consumers. ROAM has addressed this in Section 6.3.

Table 5.1 – Breakdown of 6,500 kWh retail bill (real 2013 \$, Australian average, BAU scenario)

Region	Component	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Aust. average	Wholesale cost	333	330	371	386	418	408
	Network	949	949	949	949	949	949
	FiT	28	27	18	18	17	18
	LRET	47	56	70	78	85	96
	SRES	20	15	15	15	14	14
	Other	349	349	349	349	349	349
	Total bill	1,726	1,727	1,773	1,796	1,833	1,835
	Total RET	67	71	85	93	99	110

5.3.1 Cost to businesses

The majority of business customers will face comparable (pro rata) costs for the LRET and SRES, as these schemes are defined on percentage of purchased electricity basis. However, depending on their specific tariffs, this may be a higher or lower percentage of bills. For example, if a large business had comparatively lower fixed costs on retail bills, the LRET and SRES would make up a larger component of the bill. The percentage costs and savings in subsequent sections would then be amplified, but the absolute changes in costs (on a c/kWh) basis should be similar for both residential and business customers.

5.4 INVESTMENT

Based on the construction costs assumed in this modelling, under the BAU scenario, annual investment in renewable generation will be two to four billion dollars, predominantly in wind generation. The annual (real dollars; not discounted) investment is shown in Figure 5.5. Total investment in renewables is forecast to be, in NPV terms, \$14.8 billion.

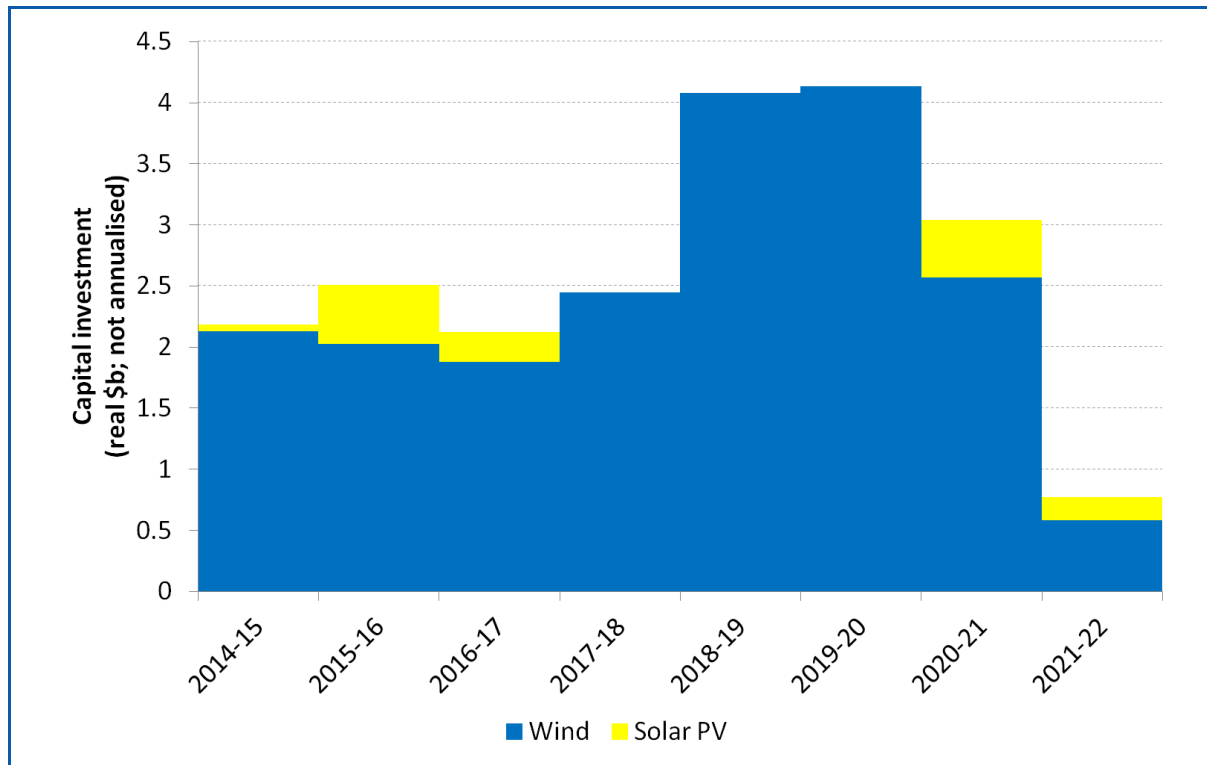


Figure 5.5 – Annual investment in renewables under the BAU scenario

5.5 JOBS

An indicative number of jobs in each region in each year is shown in Figure 5.6 under the BAU scenario. This estimate was performed using the capacity multipliers and assumptions outlined in Section 4.2.4.

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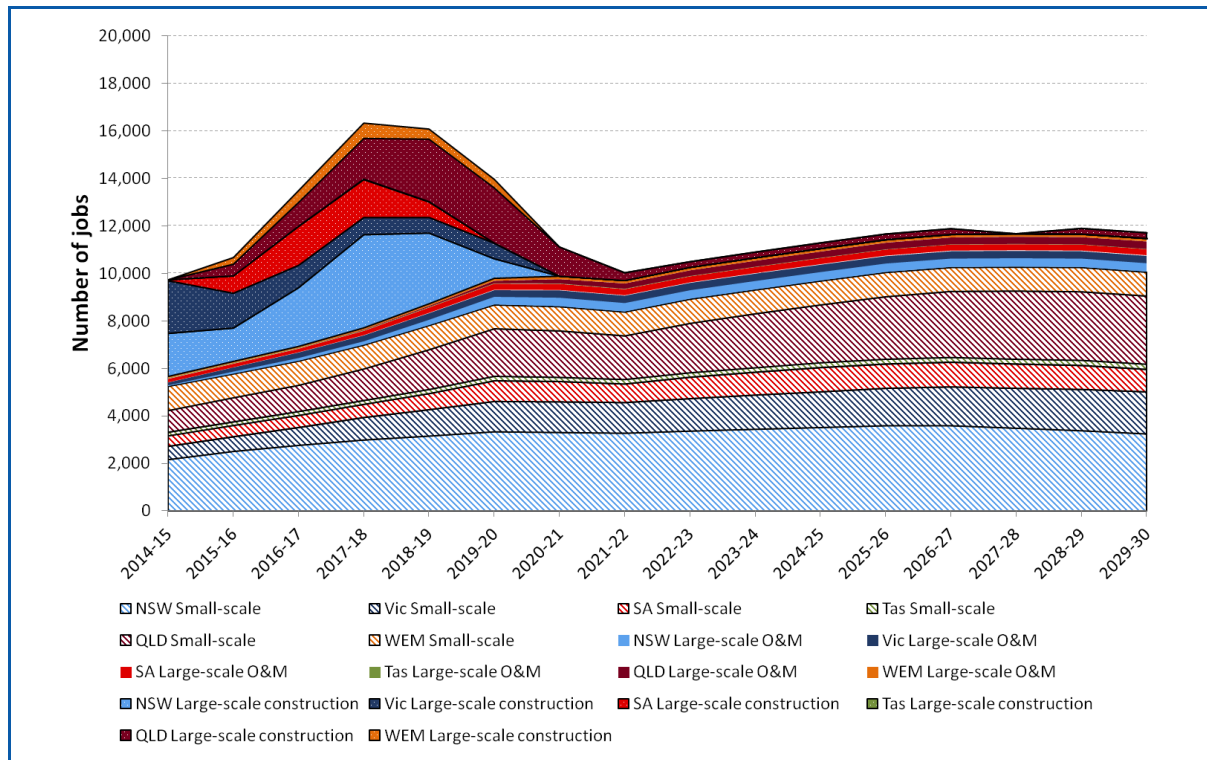


Figure 5.6 – Jobs in each region in large- and small-scale renewables under BAU scenario

The build schedule to meet the LRET under BAU requires a large amount of capacity to be built in a short period of time. As a result, construction jobs will be concentrated in this period of high annual build rates. Since operations and maintenance roles for large-scale renewables are required for the lifetime of the plant (typically 25 years), the number of jobs in operations and maintenance increases steadily as the amount of installed capacity increases. Jobs in small-scale renewables also increase steadily over the period 2014-15 to 2029-30, with a small decrease in 2020-21 and 2021-22. These jobs are predominately related to sales and installation and in ROAM's methodology are required only in the year of installation. This means the steady increase in jobs in small-scale renewables is due to the annual installation rate increasing each year.

ROAM also estimated the number of positions created (of varying length) in the period 2014-15 to 2019-20 and 2014-15 to 2029-30 by assuming that this is equal to the peak number of jobs, treating large-scale construction, large-scale operations and maintenance and small-scale jobs separately. The number of positions created by 2019-20 and by 2029-30 in the BAU scenario, calculated using this methodology and under the caveats described in Section 4.2.4, is summarised in Table 5.2.

Table 5.2 – Positions in renewables in Australia by 2019-20 and 2029-30 under BAU scenario

Year	Large-scale renewables construction	Large-scale renewables operations and maintenance	Small-scale renewables	All renewables
By 2019-20	8,600	1,100	8,700	18,400
By 2029-30	8,600	1,400	10,300	20,300

6 MODELLING RESULTS: REPEALING THE RET

ROAM has considered a scenario where the LRET is repealed, with only existing and committed projects (defined by signed financial agreements) considered eligible for the scheme. Under this scenario, the LRET is reduced to the level necessary to ensure that existing investments are protected and can continue to produce and sell LGCs; no new projects, however, will be eligible to produce LGCs.

6.1 IMPACT ON WHOLESALE ELECTRICITY PRICES

With less new renewable generation entering the market, the supply-demand balance will become tighter sooner and wholesale electricity markets prices will rise relative to the BAU scenario in most regions, as shown in Figure 6.1.

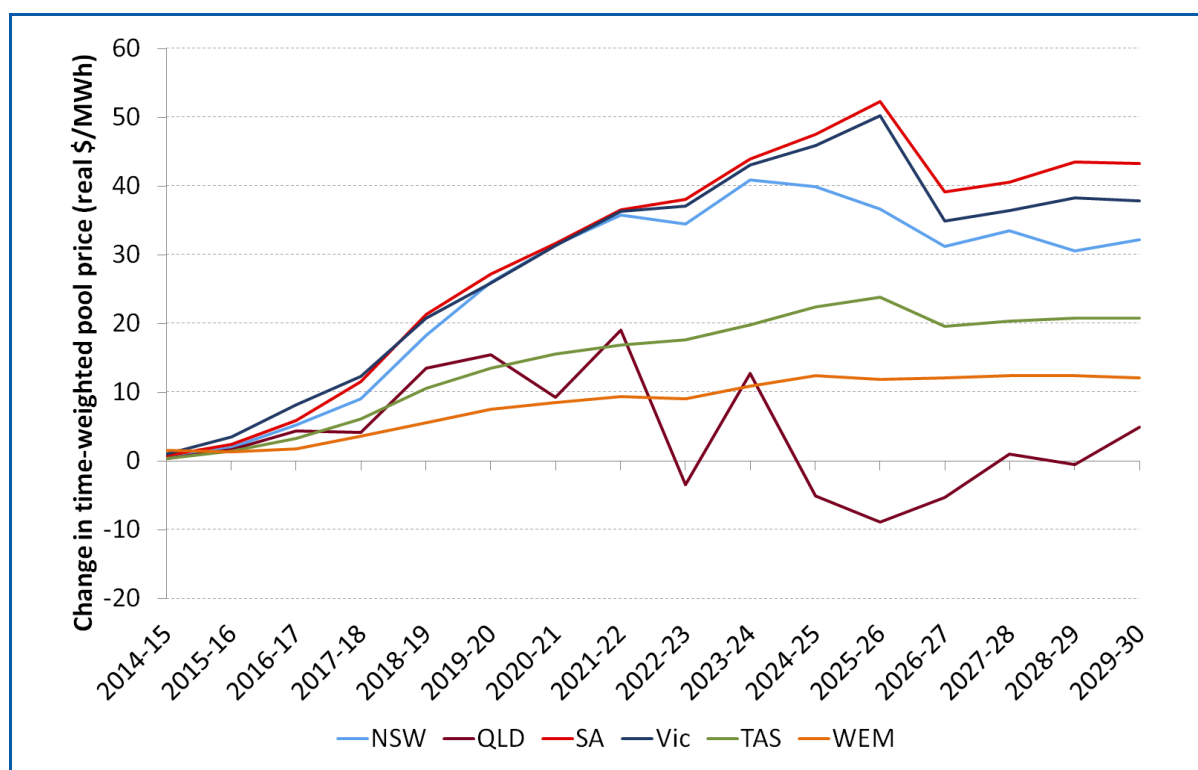


Figure 6.1 – Change in annual average wholesale spot price for BAU and No RET scenarios

A repeal of the RET increases wholesale prices

By 2020, New South Wales, Victoria and South Australia wholesale prices are approximately 25-30 \$/MWh higher in the No RET scenario than the BAU scenario. This equates to 2.5-3 cents/kWh and would need to be reflected in retail electricity prices.

This price difference represents the reduction, post-2015, of the wind energy merit order effect more prevalent in the BAU scenario, whereby new, low-SRMC generation decreases market prices. Two separate reasons are responsible for this. Firstly, new generation can decrease market power and hence the ability of incumbent generation portfolios to seek “rents” in periods of tight supply-demand balance (which is a normal part of NEM operation, designed to ensure adequate capacity at peak times, but is not present in the WEM).

Secondly, low SRMC plant decrease the wholesale price of electricity by causing fewer periods of more expensive plant being dispatched and setting the market price. With gas prices set to rise significantly, less renewable generation capacity means a greater reliance on high-priced gas to generate electricity relative to the BAU case.

Outcome is consistent with previous studies

The wholesale price difference is consistent with previous analysis by ROAM⁴⁴, which showed a price sensitivity of approximately \$10/MWh per 1,000 MW of installed wind in a region. Given the approximately 8,000 MW of new wind capacity installed in the system, and the cumulative effects across the regions, a combined effect of \$30/MWh is consistent.

Furthermore, a recent study from the University of Melbourne⁴⁵ noted that rooftop PV could be responsible for a reduction of \$2-4/MWh in average prices per 1,000 MW installed across the NEM; given that wind farms typically have twice the capacity factor, a reduction of \$4-8/MWh would be a lower bound. For 8,000 MW of new wind, this translates to at least \$30/MWh, comparable to the observed effect in this modelling.

Historically, wind generation can be seen to have had an even larger impact on volume weighted average pool prices. For example, in South Australia, historical prices have been

⁴⁴ ROAM Consulting, 2010, *Transmission congestion and renewable generation: Figure 9.4* [Report to the Clean Energy Council].

⁴⁵ McConnell D et al., 2013, ‘Retrospective modeling of the merit-order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market, *Energy Policy*.

Available at:

http://jaeger.earthsci.unimelb.edu.au/msandifo/Publications/Manuscripts/Manuscripts/2013_EP.pdf.

Accessed 24 April 2014.

significantly lower when wind generation is high as documented by AEMO in several reports on the SA Electricity market.⁴⁶

Potential for regional differences

In Queensland, a lower share of renewables and significant demand growth means that prices are more similar in the BAU and No RET scenarios, as expected. Higher Queensland demand, as well as “lumpy” new entrant capacity produces more volatile price differences between scenarios. The two scenarios converge as supply and demand become matched towards 2030.

In Western Australia, ROAM has only explicitly modelled the energy (as opposed to capacity) market. Due to mandatory cost-reflective bidding, which prohibits strategic bids, the merit order effect is lower.

Outcome reflects underlying trends

It is possible that this price differential could be affected by a number of factors, such as increased retirements in the BAU scenario, additional withholding of capacity in the BAU scenario, or additional offering of capacity at lower prices. Similarly, lower or higher than modelled gas prices could decrease or increase the difference, respectively. Nevertheless, a reduction in pool price due to the introduction of new low SRMC capacity (not just renewables) is an inevitable outcome in electricity markets like the NEM.

6.2 LGCs

In the No RET scenario, LGCs do not have any value beyond the modelled repeal date of 1 January 2015. However, ROAM expects that renewable generators would have to be allowed to recover costs of existing and committed projects which operate despite the repeal of the RET. Hence, ROAM has calculated the implied LGC price in the No RET scenario based on the cost of existing and committed renewables and we have included these costs in the retail price calculation.

LGC price forecasts for the No RET scenario relative to BAU are shown in Figure 6.2. In general, the low renewable penetration in the No RET scenario means that electricity prices are higher, and therefore a lower LGC price is required to cover the cost of installing renewables.

⁴⁶ For example, see Table 1 in AEMO, September 2013, *2013 South Australian electricity market economic trends*. Available at: http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/~/_media/Files/Other/planning/SAAF/2013%20SAEMET_Final.ashx. Accessed 24 April 2014.

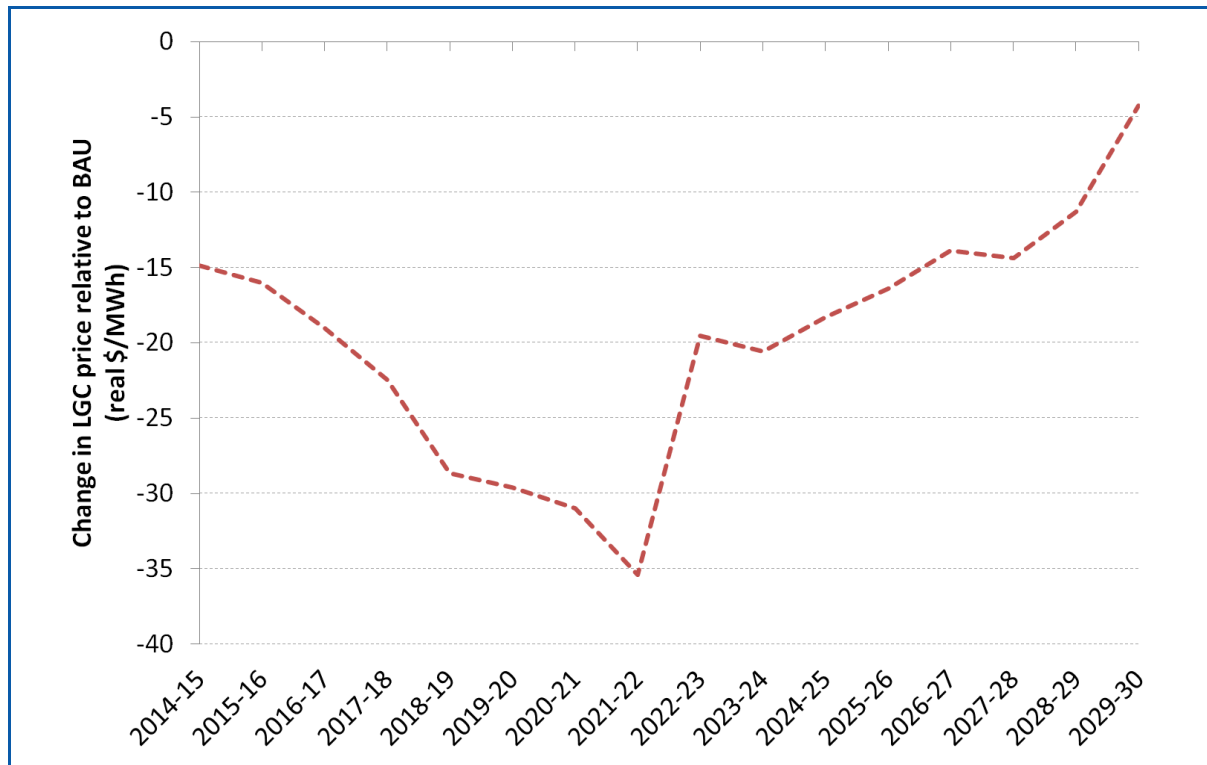


Figure 6.2 – Change in LGC price in No RET scenario relative to BAU scenario

It is important to note that the difference in LGC price on a \$/MWh basis is relatively small. In general, changes to the LRET will primarily affect LGC prices through the impact of the scheme on wholesale electricity prices: a higher penetration of renewables reduces electricity prices (and hence revenues for renewables), which means a higher LGC price is required to meet the LRMC of renewables. The cost of installing new renewables, and the quality of the resource, does not change between the scenarios. The reduction in the total cost of LGCs therefore comes from a reduction in volume, rather than price.

6.3 RETAIL PRICE OUTCOMES

In the shorter-term, to 2017-18, repealing the RET would save consumers \$9 to \$22 each year on an annual bill of over \$1,700. This represents a decrease of between 0.5% and 1.3% relative to the BAU scenario. This demonstrates that from a consumer's perspective, to 2017-18, the cost of LGCs on a retail bill is roughly balanced by savings on the wholesale electricity component. Figure 6.3 and Table 6.1 show the Australian average change in cost of a 6,500 kWh retail bill in the No RET scenario relative to the BAU scenario.

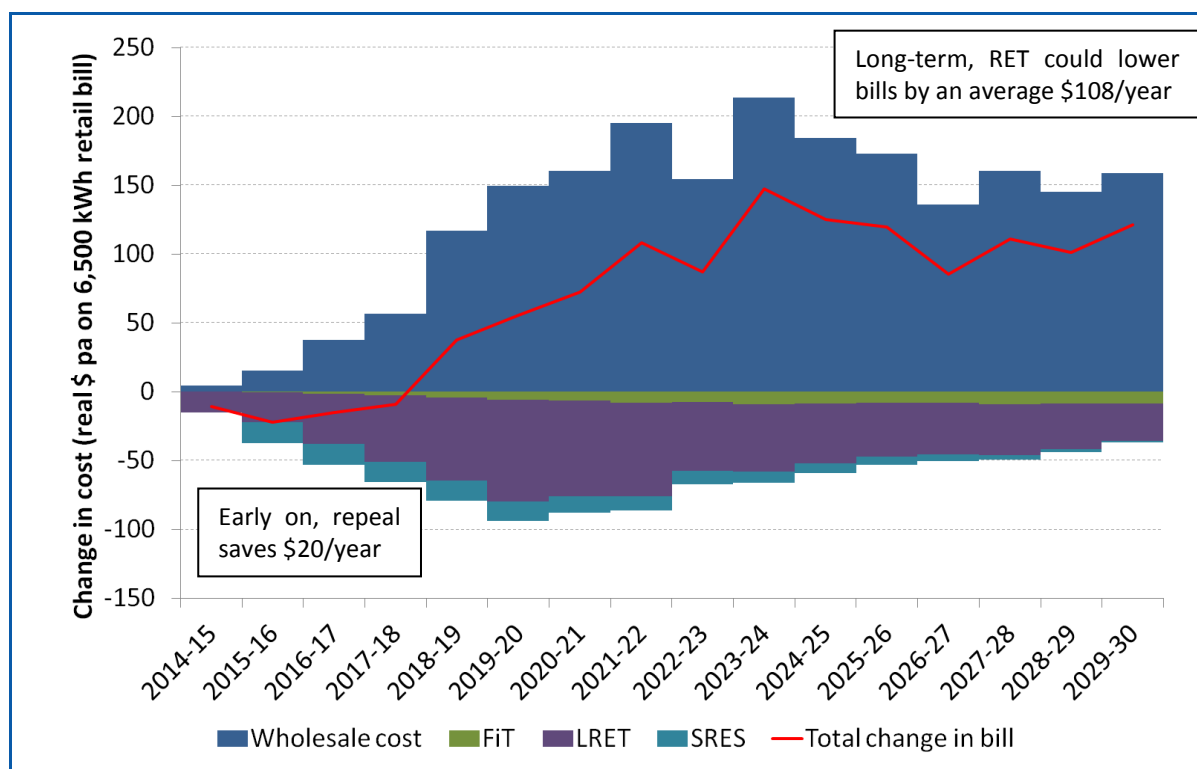


Figure 6.3 – Change in retail price components in No RET scenario relative to BAU scenario

Table 6.1 – Breakdown of 6,500 kWh retail bill (real 2013 \$, Australian average, No RET scenario and comparison to BAU)

Region	Component	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2024-25	2029-30
Aust. average	Wholesale cost	337	345	409	443	535	558	759	833
	Network	949	949	949	949	949	949	949	949
	FiT	27	27	16	15	13	12	8	6
	LRET	32	34	33	30	24	22	14	15
	SRES	20	0	0	0	0	0	0	0
	Other	349	349	349	349	349	349	349	349
	Total bill	1716	1705	1757	1786	1871	1891	2079	2152
	Total RET	52	34	33	30	24	22	14	15
	Change in bill from BAU (\$)	-11	-22	-15	-9	+37	+56	+125	+121
	Change in bill from BAU (%)	-0.6%	-1.3%	-0.9%	-0.5%	+2.0%	+3.0%	+6.4%	+6.0%

From 2018-19 onwards, the annual bill with No RET is higher than BAU due to a higher wholesale cost of electricity in the No RET case. In these years, from a consumer's perspective, the savings gained by not having to pay for an LGC and STC component, and

reduced FiT payments, are outweighed by the increased cost of more expensive electricity on the wholesale market when renewables are not present to suppress prices. In 2019-20, the annual retail bill in this modelling is \$56 higher without the LRET.

Beyond 2020, ROAM's modelling shows that annual bills could be an average of \$108 higher if the RET is repealed, and up to \$148 in some years. The exact magnitude of costs and benefits depends on the same factors outlined in Section 5.1.1, but ROAM expects that across a broad range of scenarios, bills in the BAU and No RET scenarios will generally be comparable (from the perspective of an average consumer) in the short term, with savings in the BAU scenario relative to No RET in the medium to longer term. The NPV of the difference in retail bills between the BAU and No RET scenarios for the ten year period from 2014-15 is \$291⁴⁷.

Although a repeal of the RET would result in increased costs for consumers in aggregate over the long-term, there may be subsets of consumers for whom a repeal would provide a moderate saving, while for other customers the cost of a repeal could be even higher. This can depend on price region and energy usage. The spread of benefits will depend on the details of the development of the RET; the more even the distribution of renewables across regions, the more even the distribution of benefits.

Business customers would expect to see comparable increases in their retail bills in 2020, on a pro-rata basis. Differences in load shapes and negotiated tariffs might slightly increase or decrease relative costs, but ROAM expects that the absolute changes in "per unit" costs will be the very similar for residential and commercial customers.

6.4 OTHER BENEFITS AND COSTS OF THE RET

There are a number of other factors which could influence the relative costs of maintaining or repealing the RET. These could include:

- **Network costs.** As discussed in Section 4.2.1, it is not anticipated major network upgrades will be required as a result of the LRET. Local network augmentations and network costs associated with new generator connections are paid by the connecting generator, so there are no additional network charges in this regard. ROAM took into account existing network constraints when producing the renewable generation development plans.
- **Network losses.** Depending on the location of renewables, network losses could be higher or lower than in the current system. This would not have a direct impact on retail costs.
- **Reduction in marginal loss factors.** New generation projects will depress marginal loss factors at their connection points. While this impacts on revenue for the generator, this can act to reduce the cost of energy purchases for large users in that area. This could incentivise new local industry and produce local and nationwide economic benefits not captured by this study.

⁴⁷ As calculated using a discount rate of 5%.

- **Community service obligation payments.** Similarly, a reduction in marginal loss factors in areas such as North Queensland could act to reduce state government costs for schemes that maintain equal retail tariffs across regions.

6.5 EMISSIONS

In the No RET scenario, electricity sector emissions rise year-on-year throughout the study period. This translates to a 7% increase in emissions in 2019-20 relative to BAU and a cumulative additional 31.9 Mt CO₂-e in the period 2013-14 to 2019-20 relative to BAU. The increase in emissions relative to BAU is shown in Figure 6.4.

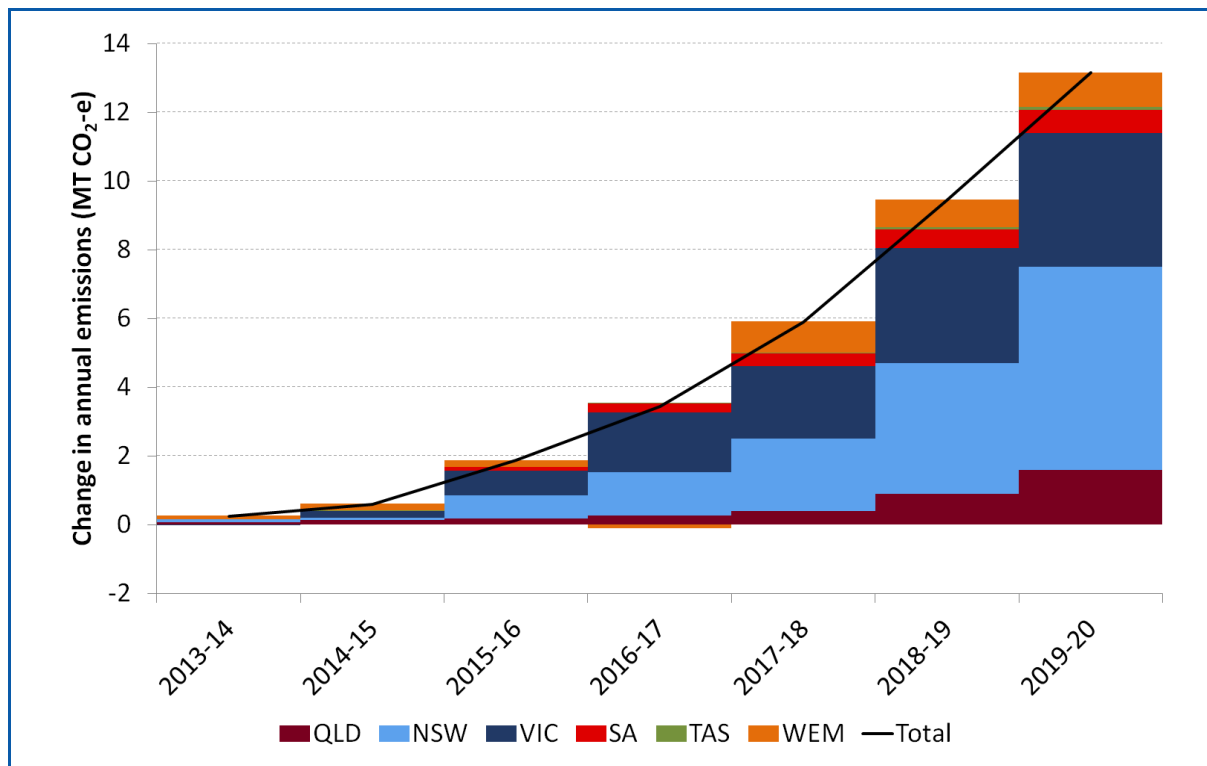


Figure 6.4 – Electricity sector emissions in No RET scenario relative to BAU (NEM and WEM)

ROAM has also calculated the contribution of emissions to Australia's target of reducing total emissions in 2020 by 5% relative to levels in 2000. In 2000, Australia emitted 585.9 Mt CO₂-e; a 5% decrease means emissions in 2020 will need to be reduced by 29.3 Mt. In the No RET scenario, electricity sector emissions in 2020⁴⁸ increase by 12.6 Mt CO₂-e relative to 2000 levels reversing the trend since 2009 where electricity emissions in the NEM have significantly declined (and declined faster than the reduction in electricity usage)⁴⁹. In contrast, in the BAU scenario, electricity sector emissions decrease by 2.2 Mt in 2020 relative to 2000 levels. Consequently, in the No RET scenario, to cover the increase in electricity sector emissions and meet the target of 5% reduction relative to

⁴⁸ Calculated as average of emissions in financial years 2019-20 and 2020-21.

⁴⁹ Pitt and Sherry, March 2014, *Cedex: carbon emissions index*. Available at: <http://www.pittsh.com.au/assets/files/Cedex/CEDEX%20April%202014.pdf>. Accessed 24 April 2014.

2000, an additional 14.8 Mt of emissions reductions will have to be found in other sectors in 2020. Cumulative emissions to 2019-20 will be 34.7 million tonnes higher if the RET is repealed.

6.6 INVESTMENT

Without the RET, investment in renewables is significantly reduced. A small number of renewable projects are still built, including currently committed projects and a small amount of new entry wind generation beyond 2020, modelled to be constructed in Queensland as a result of high electricity prices.

Without the LRET, additional new generation capacity will be required in the system in the longer term and, in the absence of the RET, is expected to be provided mostly by new gas-fired generation.

Figure 6.5 shows the annual reductions in new renewable investment by technology across Australia if the RET is repealed. This translates to a reduction in investment in large-scale renewables of approximately \$11 billion, in today's (net present value) dollars.

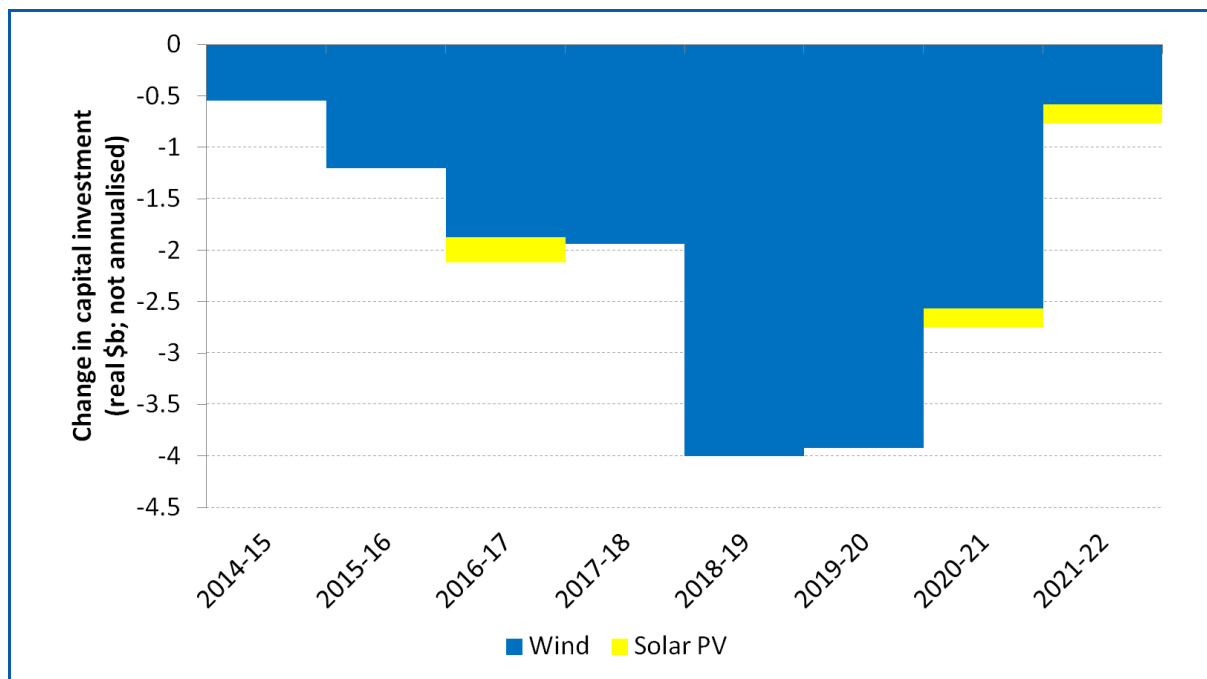


Figure 6.5 – Reduction in investment in renewables due to repeal of RET (cumulative total has not been discounted)

6.7 JOBS

An indicative number of jobs in each region in each year is shown in Figure 6.6 under the No RET scenario. This estimate was performed using the capacity multipliers and assumptions outlined in Section 4.2.4. In the short term, there is a reduction of 6,600 jobs

in 2015-16 in the No RET scenario relative to the BAU scenario. Particularly hard hit are NSW and Victorian jobs in the large-scale renewables sector.

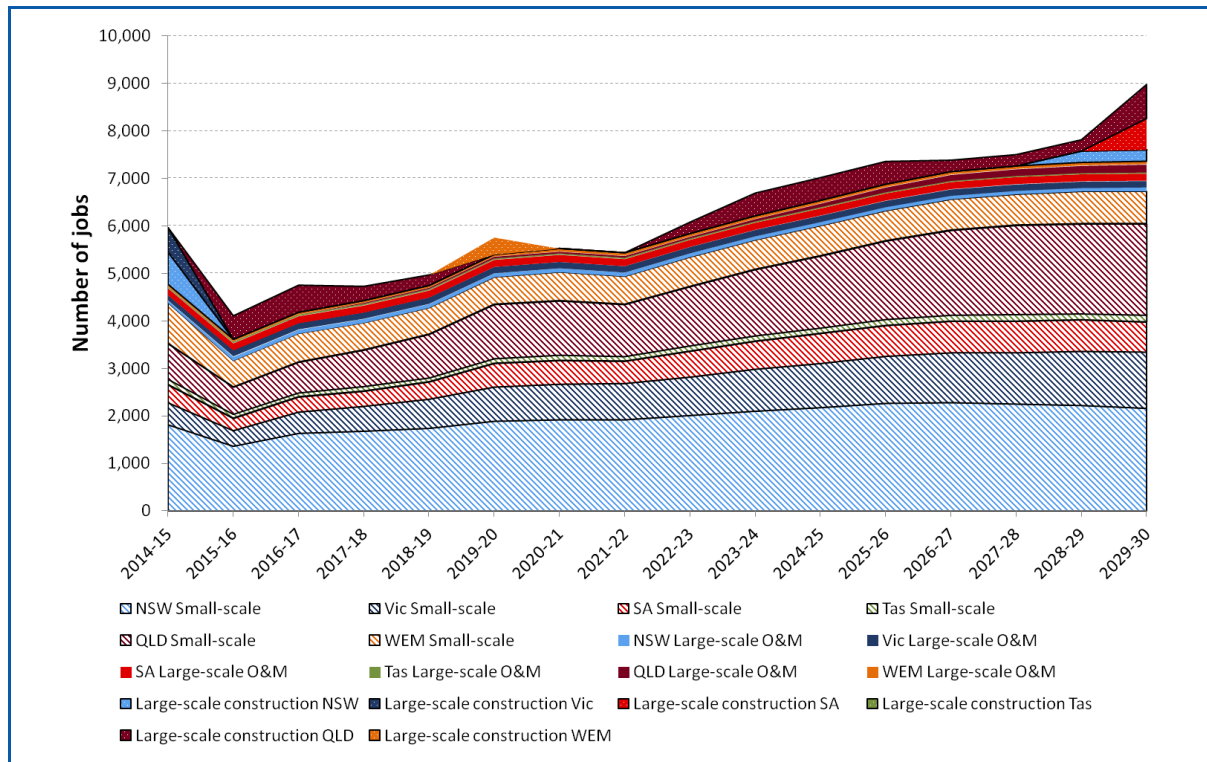


Figure 6.6 – Jobs in each region in large- and small-scale renewables under No RET scenario⁵⁰

In the longer term, the reduction in employment in renewables caused by the repeal of the RET represents a cumulative reduction of 100,000 job-years in renewables between 2014-15 and 2029-30 where a job-year is a full-time position for one year. In comparison, the BAU scenario has a cumulative 193,000 job-years between 2014-15 and 2029-30. Hence, the No RET scenario has a 48% decrease in cumulative job-years in large- and small-scale renewables relative to BAU. However, it is worth noting that additional thermal capacity may be built in the No RET scenario in the 2020-2030 timeframe and there would be associated jobs that have not been taken into account in this analysis.

As in the BAU scenario, ROAM also estimated the number of positions created (of varying length) in the period 2014-15 to 2019-20 and 2014-15 to 2029-30 by assuming that this is equal to the peak number of jobs, treating large-scale construction, large-scale operations and maintenance and small-scale jobs separately. The number of positions created by 2019-20 and 2029-30 in the No RET scenario, calculated using this methodology and under the caveats described in Section 4.2.4, is summarised in Table 6.2. There are fewer jobs in the No RET scenario than BAU scenario in all categories.

⁵⁰ When comparing to Figure 5.6, note the change in scale of the y-axis.

Table 6.2 – Positions in renewables in Australia by 2019-20 and 2029-30 under No RET scenario

Scenario	Year	Large-scale renewables construction	Large-scale renewables operations and maintenance	Small-scale renewables	All renewables
No RET	By 2019-20	1,200	500	4,900	6,600
No RET	By 2029-30	1,600	600	6,700	9,000
BAU	By 2019-20	8,600	1,100	8,700	18,400
BAU	By 2029-30	8,600	1,400	10,300	20,300
No RET - BAU	By 2019-20	-7,400	-600	-3,800	-11,800
No RET - BAU	By 2029-30	-7,000	-800	-3,600	-11,300

7 MODELLING RESULTS: EXTENDING THE TARGET

ROAM has considered a scenario where the LRET is extended, maintaining the existing 2020 trajectory and targeting 30% of renewables by 2030. The 2030 target is held flat to 2040 and the shortfall charge is increased to \$110/MWh in nominal dollars from 2020 onwards (this is necessary because, by 2030, the shortfall charge has decreased in real dollars to a level that is unable to support renewables without, for example, an additional carbon price).

7.1 IMPACT ON WHOLESALE ELECTRICITY PRICES

The additional renewables continue to apply downward pressure on electricity prices beyond 2020, with both WEM and NEM prices reduced by 10-20 \$/MWh on average by 2030 compared to the BAU scenario (Figure 7.1).

Increased renewables, beyond the current LRET target, could temporarily increase prices in some cases or regions. For example in South Australia in this modelling, Pelican Point is forecast to retire from 2020 in response to increased pressure from competing renewables, which places upward pressure on prices. However, this retirement and price increase facilitates additional renewables in South Australia, and prices then continue their downward trend.

The increase in renewable generation under this scenario is comparable to the decrease under the No RET scenario. Similarly, price decreases due to this additional generation are comparable to the price increases if the RET is repealed, showing that there is a consistent trend for low-bidding renewables to reduce wholesale prices, subject to the step changes that would likely occur if incumbents leave the market.

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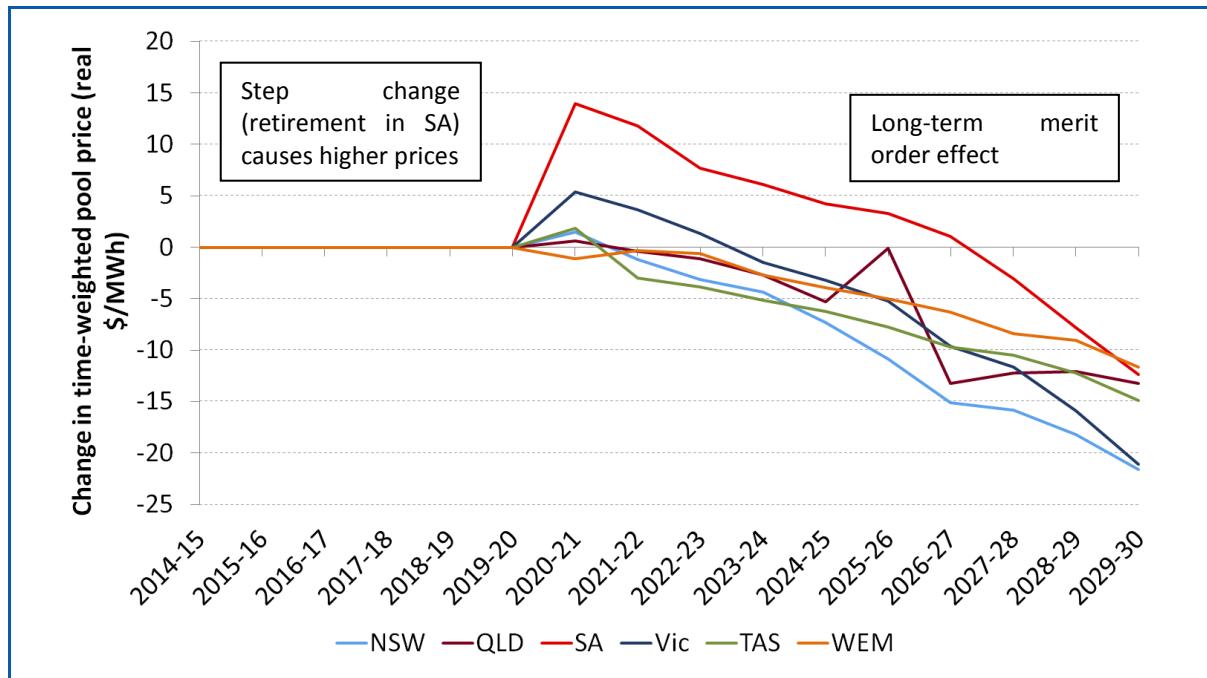


Figure 7.1 – Change in annual average wholesale spot price in Extended RET scenario relative to BAU

7.2 LGCs

With a higher LRET, LGC prices are relatively flat for the first ten years of the study, before slowly rising, as shown in Figure 7.2.

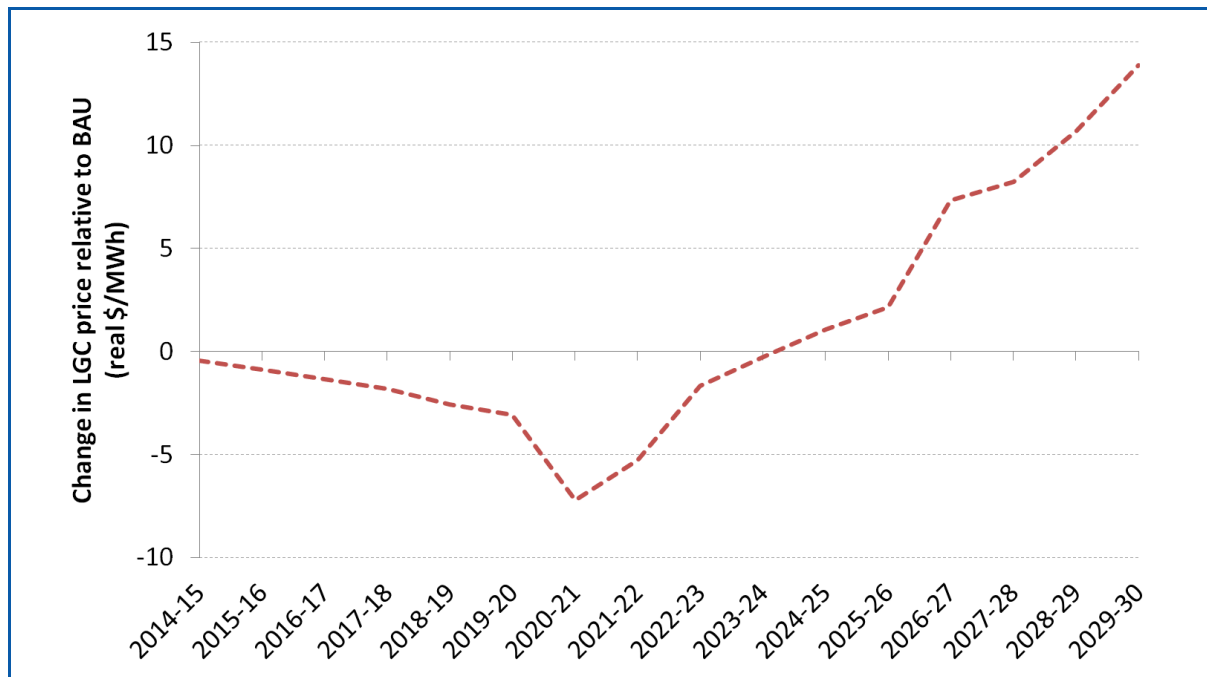


Figure 7.2 – Change in LGC price in Extended RET scenario relative to BAU scenario

This trend is a result of several factors. The longer period of the LRET (to 2040) gives renewable generator additional revenue and higher revenue certainty for longer, supporting PPAs and reducing the “front loading” necessary on the PPA to recover long-run costs. However, additional renewables also reduce pool prices (as discussed in Section 7.1), which reduces pool revenue for renewables and increases the LGC revenue required. This is most significant from 2025 onwards, where renewables will not be able to secure 15 year PPAs with LGCs due to the end of the scheme in 2040, while at the same time are experiencing the greatest merit order effect. In these years, the shortfall charge of \$93/MWh, which is fixed in nominal dollars and so declines to \$70/MWh in real 2013 dollars, becomes too low to support renewables. However, a moderate increase to \$110/MWh nominal is sufficient to incentivise liable entities to build renewable capacity to meet the Extended target rather than pay the shortfall charge⁵¹. In today’s dollars, this revised shortfall charge in 2020 is less than the current penalty price.

Solar generators, in particular, are affected by the merit order effect in ROAM’s modelling. The extended LRET gives solar additional support and allows earlier and greater uptake in solar generation, and ROAM expects a moderate amount of solar to be particularly useful given the diversity it provides with respect to the wind generation installed pre-2020.

As with the No RET case (Section 6.2), the change in LGC costs is relatively small, compared to the changes in purchase volumes between scenarios and consequently changes in volume have a larger impact on retail bills than the price of a single LGC.

7.3 *RETAIL PRICE OUTCOMES*

Retail price outcomes are identical to the BAU before 2020, except for a slight reduction in LGC costs (due to the longer period available for PPAs). Figure 7.3 and Table 7.1 show the change due to extending the RET in the average Australian retail bill assuming 6,500 kWh of annual consumption. In this chart, positive values show a cost on retail bills from an Extended RET scenario, while negative values indicate a saving.

⁵¹ As calculated after allowing for company tax of 30%.

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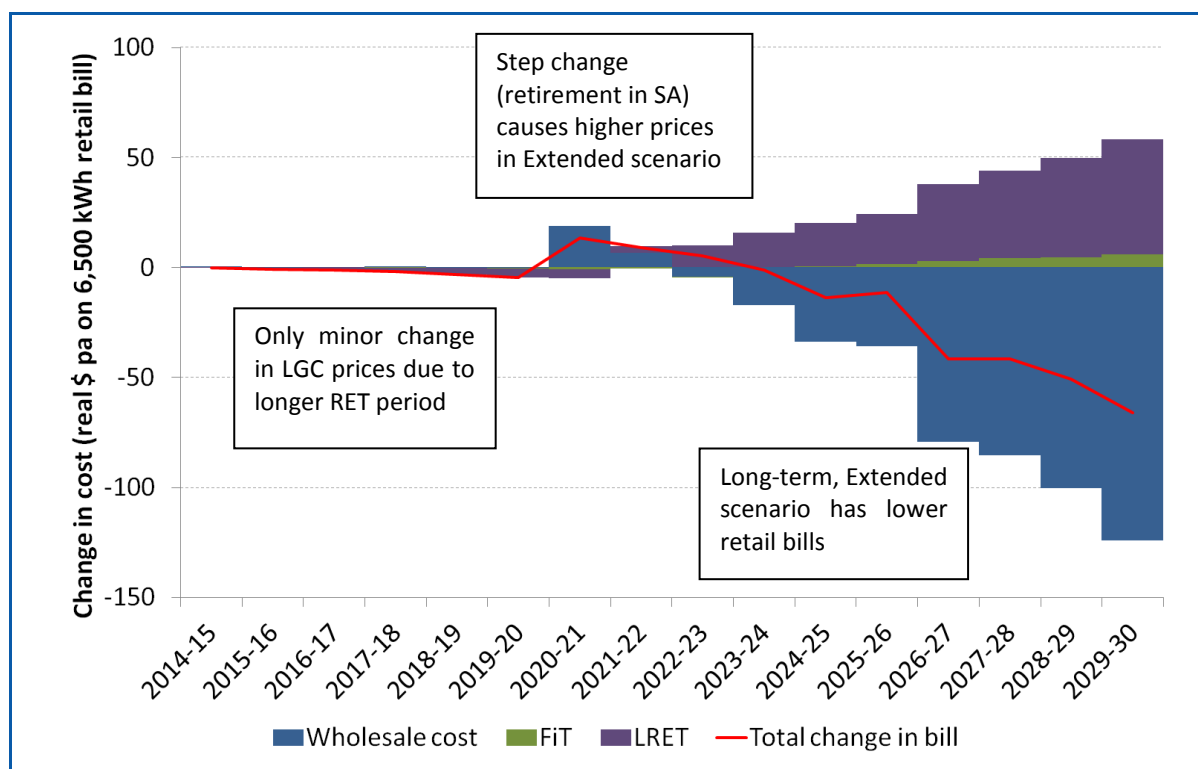


Figure 7.3 – Change in retail price components in Extended RET scenario relative to BAU scenario

Table 7.1 – Regional breakdown of 6,500 kWh retail bill (real 2013 \$, Australian average, Extended RET scenario and comparison to BAU)

Region	Component	2014-15	2019-20	2024-25	2029-30
Australia	Wholesale cost	333	408	540	550
Average	Network	949	949	949	949
	FIT	28	18	17	20
	LRET	47	92	77	94
	SRES	20	14	7	1
	Other	349	349	349	349
	Total bill	1,726	1,831	1,940	1,965
	Total RET	67	106	84	95
	Change in bill relative to BAU (\$)	0	-4	-14	-66
	Change in bill relative to BAU (%)	0.0%	-0.2%	-0.7%	-3.3%

By the mid-2020's, the Extended RET scenario produces savings in retail bills relative to the BAU scenario. From the perspective of retail bills, an Extended RET could therefore provide long-term benefits Australia-wide.

In 2020, the modelled retirement of Pelican Point is responsible for a small increase in South Australian (and, hence, Australian average) retail bills, but by 2030 the average Australian retail bill would be 2-3% lower under an extended LRET compared to BAU.

The increase in the LRET between 2020 and 2030 represents an approximately 50% increase in the portion of renewable energy that must be purchased on retail bills. Over the same period, however, Australian average wholesale prices rise by 20-30% and LGC prices fall by 30%. As such, the cost of LGCs on the retail bill from 2020 to 2030 remains relatively constant (4-5%), although is a moderate increase (up to three percentage points) over the BAU scenario for the same period. This demonstrates that longer term, higher renewable targets can be met with comparable premiums to existing retail bills.

ROAM notes that there is significant uncertainty around long-term price forecasting of this nature. As such, savings could be higher or lower than forecast. For example, additional retirements could produce higher prices in any region. These retirements, however, would tend to focus additional renewable generation into that region, and so act to even out prices across the NEM.

7.4 EMISSIONS

In the Extended RET scenario, electricity sector emissions are the same as the BAU scenario to 2019-20. From 2020-21 to 2034-35, there are a cumulative 121 Mt CO₂-e additional emissions savings relative to BAU, as shown in Figure 7.4.

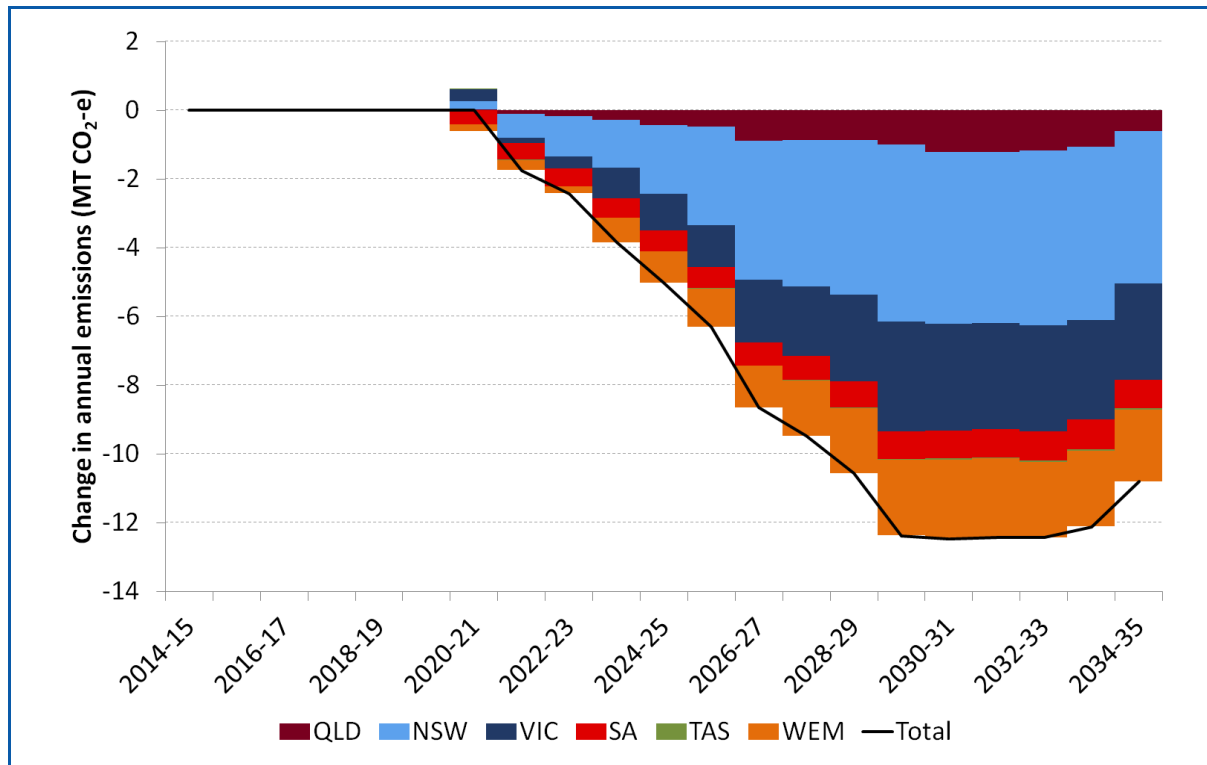


Figure 7.4 – Electricity sector emissions in Extended RET scenario relative to BAU (NEM and WEM)

7.5 INVESTMENT

Extending the RET target would drive additional investment in the electricity sector of approximately one billion dollars a year from 2020 to 2030.

7.6 JOBS

An indicative number of jobs in each region in each year is shown in Figure 7.5 under the Extended RET scenario. This estimate was performed using the capacity multipliers and assumptions outlined in Section 4.2.4.

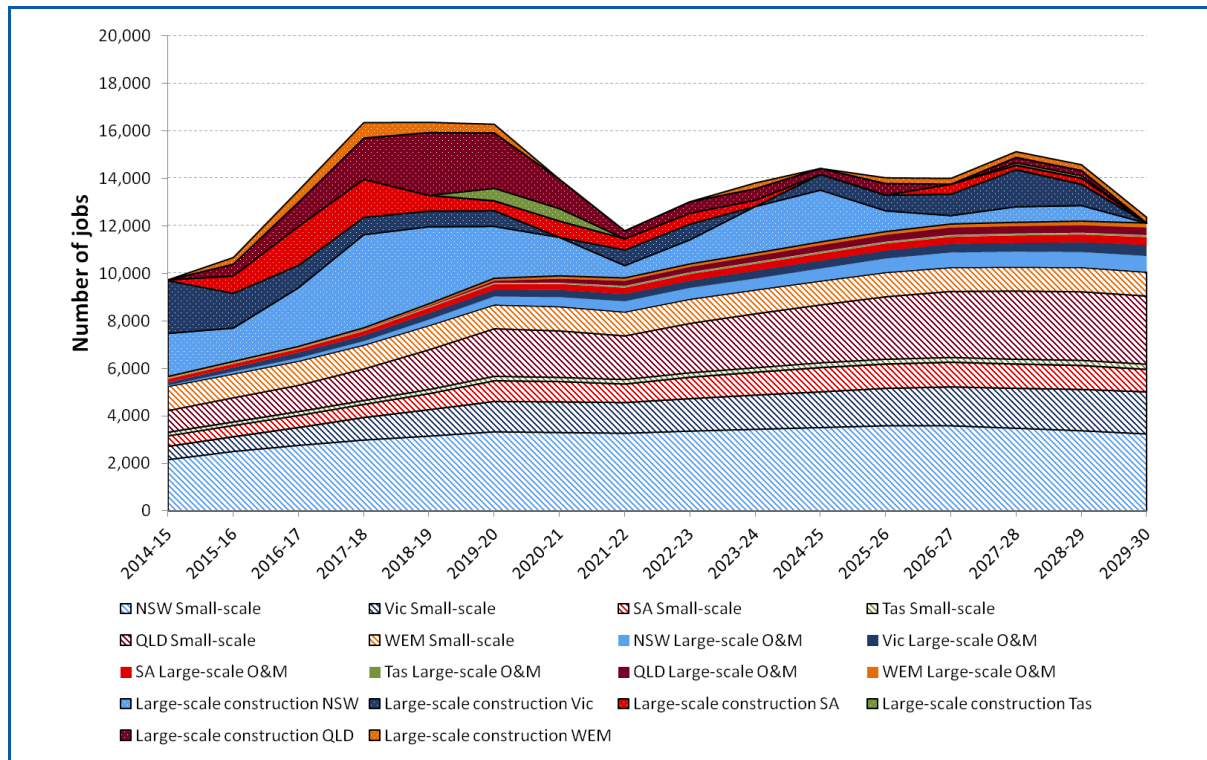


Figure 7.5 – Jobs in each region in large- and small-scale renewables under Extended RET scenario

This represents a cumulative 220,000 job-years in renewables between 2014-15 and 2029-30 where a job-year is a full-time position for one year. In comparison, the BAU scenario has a cumulative 193,000 job-years between 2014-15 and 2029-30. Hence, the Extended RET scenario has a 14% increase in cumulative job-years in large- and small-scale renewables relative to BAU. It is worth noting that there is slightly less thermal capacity relative to the BAU scenario case. ; in the Extended RET, new OCGTs are delayed and Pelican Point is retired. The flow-on effect on jobs outside the renewables sector resulting from these differences has not been taken into account.

As in the BAU scenario, ROAM also estimated the number of positions created (of varying length) in the period 2014-15 to 2019-20 and 2014-15 to 2029-30 by assuming that this is equal to the peak number of jobs, treating large-scale construction, large-scale operations and maintenance and small-scale jobs separately. The number of positions created by 2019-20 and by 2029-30 in the Extended RET scenario, calculated using this methodology and under the caveats described in Section 4.2.4, is summarised in Table 7.2. Although there is no difference in the number of construction positions between the Extended RET and BAU scenarios, the additional renewable capacity in the Extended RET scenario means that many construction jobs will continue for longer, smoothing out the peak. There is a slight increase in operations and maintenance positions associated with the larger installed capacity of large-scale renewables. The capacity of small-scale renewables is the same in the Extended RET and BAU scenarios and so the estimated number of positions in this sector is also the same.

Table 7.3 – Positions in renewables in Australia by 2019-20 and 2029-30 under Extended RET scenario

Scenario	Year	Large-scale renewables construction	Large-scale renewables operations and maintenance	Small-scale renewables	All renewables
Extended RET	By 2019-20	8,600	1,100	8,700	18,400
Extended RET	By 2029-30	8,600	2,100	10,300	21,000
BAU	By 2019-20	8,600	1,100	8,700	18,400
BAU	By 2029-30	8,600	1,400	10,300	20,300
Extended RET relative to BAU	By 2019-20	0	0	0	0
Extended RET relative to BAU	By 2029-30	0	700	0	700

Appendix A MODELLING WITH 2-4-C

A.1 FORECASTING WITH 2-4-C

2-4-C is ROAM's flagship product, a complete proprietary electricity market forecasting package. It was built to match as closely as possible the operation of the AEMO Market Dispatch Engine (NEMDE) used for real day-to-day dispatch in the NEM. However, it is capable of modelling any electricity network, and is in use to model small systems such as the North-West Interconnected System (NWIS) of Western Australia, and the large 4000 bus CALISO system of California.

2-4-C implements the highest level of detail, and bases dispatch decisions on generator bidding patterns and availabilities in the same way that the real NEM operates. The model includes modelling of forced full and partial and planned outages for each generator, including renewable energy generators and inter-regional transmission capabilities and constraints.

ROAM continually monitors real generator bid profiles and operational behaviours, and with this information constructs realistic 'market' bids for all generators of the NEM. Then any known factors that may influence existing or new generation are taken into account. These might include for example water availability, changes in regulatory measures, or fuel availability. The process of doing this is central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on behalf of AEMO (previously NEMMCO) since 2004 to estimate the level of reliability in the NEM and consequently set the official Minimum Reserve Levels for all regions of the NEM.

A.2 THE 2-4-C MODEL

The multi-node model used by 2-4-C when modelling the NEM is shown in Figure A.1. This nodal arrangement features a single node per region of the NEM, the same as the regional configuration used by NEMDE.

This network representation means that there is no direct visibility of intra-regional network capabilities. In order to model these important aspects of the physical system, AEMO employs the use of constraint equations that transpose intra-regional network issues to the visible parts of the network; that is, the inter-connectors joining the regions of the NEM. These constraint equations consist of several hundred mathematical expressions which define the interconnector limits in terms of generation, demand and flow relationships. 2-4-C implements these constraint equations within its Linear Programming engine in fully co-optimised form.

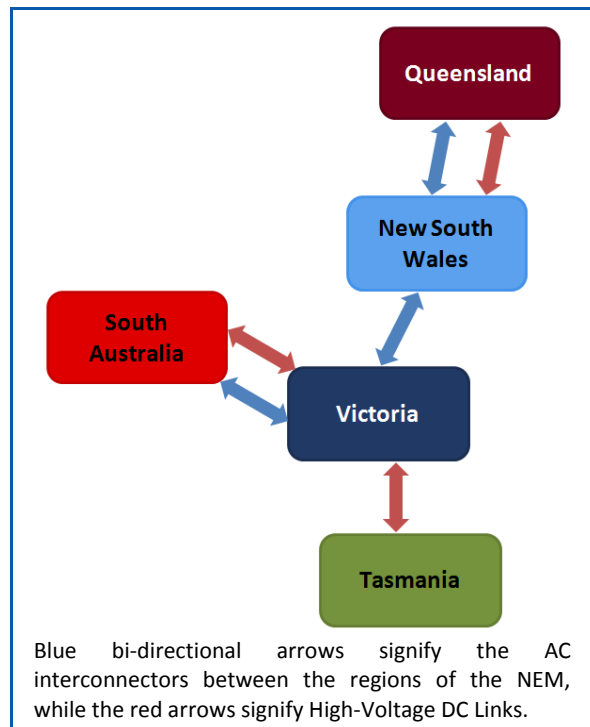


Figure A.1 – 2-4-C NEM Representation

Modelling major transmission lines and constraint equations delivers an outcome consistent with the real operation of the NEM under normal system conditions. Additionally, the occurrence of congestion in the network is the primary factor that drives out-of-merit dispatch outcomes and hence price volatility. These important aspects of the NEM would not be seen in a more simplistic model.

A.3 MODELLING THE TRANSMISSION SYSTEM

ROAM's 2-4-C dispatch model implements the full set of AEMO NTNDP constraints as supplied by AEMO with the annual Statement of Opportunities. These constraint equations define interconnector flow limits in terms of generation, demands and flows. A constraint equation for an interconnector is defined in a particular direction and is of the following form:

$$X * Flow_{Interconnector\ A\ Direction\ B} + Y * Output_{GenA} \leq C + Z * Demand_{RegionA} + P * Output_{GenA} + Q * Output_{GenB} + R * Flow_{Interconnect\ B\ Direction\ A} \quad (2)$$

where: C, X, Y, Z, P, Q are constants

A.4 KEY PARAMETERS USED BY THE MODEL

Data contained within the 2-4-C model is a combination of the best information sources available in the public domain including:

- All released AEMO Statements of Opportunity reports through to the present, together with half-hourly historical load profiles by region;
- Annual Planning Statements by Network Service Providers;
- All published Powerlink statements, together with half hourly historical load profiles by zone;
- All published TransGrid statements;
- All published AEMO VAPR statements;
- All published AEMO SASDO statements, and;
- All published Transend statements.
- Corporate Annual Reports for many market participants (generators, retailers and network service providers), and;
- General reports from market participants.

Appendix B MODELLING ASSUMPTIONS

B.1 DEMAND SIDE ASSUMPTIONS

B.1.1 Demand and energy forecasts

To account for sensitivities to the load, ROAM considers a variety of load forecasts, as supplied annually by AEMO. These include:

- M10 case - Medium load growth, 10% P.O.E.
- M50 case - Medium load growth, 50% P.O.E.

where P.O.E. is the probability of exceedance.

The 10% P.O.E. case represents an extreme weather year resulting in demand levels exceeded only 1 year in 10. The 50% P.O.E. case represents a reasonably mild weather year (exceeded 1 year in 2).

These 10% and 50% P.O.E. cases represent upper and lower bounds. To show the 'likely' case, ROAM calculates a 'weighted' value for all properties. This weighted value is calculated as 30% of the 10% P.O.E. value and 70% of the 50% P.O.E. value.

The regional load trace forecasts (that is, the half-hourly load data) has been developed using our Trace Extrapolation Tool (TEX), that takes historical load data for one or more reference years and produces forecast half-hourly load traces based on the summer and winter energy and demand targets provided by AEMO, as well as baseload demand trajectories and the impact of historical and future rooftop PV penetration.

B.1.2 Inclusion of customers

At each region, a bulk load consumption facility has been included to represent the cumulative, time-sequential, load consumption profile anticipated at each of the five regions used in the study.

B.1.3 Regional load profiles

Load data for each bulk consumption facility has been derived directly from historical load profiles for each region, and grown to meet the energy and demand forecasts published in the most recent energy and demand projections from AEMO.

B.1.4 Demand-side participation

The vast majority of demand in the wholesale market currently operates as a series of aggregated loads for the purposes of schedule and dispatch. Though some individual customers may be responsive to price, the majority of end-consumers are shielded from short-term price fluctuations through retail contracts. Thus, incentives to reduce demand during high-price periods are dissipated.

B.1.5 New base loads

No new base loads are included in this study, aside from those included in the AEMO demand projections.

B.1.6 Hydroelectric pump storage loads

The 2-4-C version used for this study includes a hydroelectric model, including pump storage loads. The pumping loads for the following hydroelectric facilities have been included in the load profile:

- Wivenhoe power station;
- Shoalhaven power station
- Snowy Mountains Scheme: Tumut 3 power station.

B.2 SUPPLY SIDE ASSUMPTIONS (GENERATION ASSETS)

B.2.1 Existing projects

These market forecasts take into account all existing market scheduled generation facilities. In addition, the likely commissioning schedule (beginning typically three months prior to commercial operation) for new generators has been taken into account.

B.2.2 Individual unit capacities and heat rates

Details of unit capacities and heat rates (for thermal plants) have been collated and included on the basis of information available in the public domain.

B.2.3 Unit emissions intensity factors

Emissions intensity factors have been collated from public sources and along with heat rates are the basis for calculating the emissions for each generator based on their modelled generation profile.

B.2.4 Unit operational constraints

Information on unit minimum load and ramp rate constraints is included in the 2-4-C database. This database has been developed based on pre-market information, moderated with information being currently supplied to the market. Such information is taken into consideration in the simulation of market operation (to ensure that an infeasible solution is not simulated).

B.2.5 Maintenance and forced outages

For each unit, 2-4-C utilises independent schedules of:

- Planned maintenance, and
- Randomised forced outage (both full and partial outage).

These schedules have been constructed based on information in the public domain and historical generator availabilities. In particular, six key parameters are used in the development of outage schedules, as detailed in Table B.1.

Table B.1 – Generator outage modelling assumptions

Outage parameter	Definition
Full forced outage rate	Proportion of time per year the unit will experience full forced outages.
Partial forced outage rate	Proportion of time per year the unit will experience partial forced outages.
Number of full outages	The frequency of full outages per year.
Number of partial outages	The frequency of partial outages per year.
Derated value	Proportion of the unit's maximum capacity by which the unit will be derated in the event of a partial outage.
Full maintenance schedule	Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).

B.3 GENERATOR BIDDING BEHAVIOUR

ROAM has developed an algorithm to analyse generation for each unit of each existing station in the NEM for peak (7 am to 10 pm) and off-peak (10 pm to 7 am) times on weekdays and weekends (four distinct periods). Bids are generated by ROAM's algorithm to produce the best fit of the simulated generation to the actual generation over the review period, while also respecting other constraints such as historical bidding profiles and minimum generation levels.

Some generators have been observed to exhibit special bidding behaviour and these are assigned special bids to emulate this. For example, much of Bairnsdale's generation occurs in the overnight off-peak periods. At times, some gas turbines such as Quarantine and Roma have a baseload component to their generation, which is not modelled, although their bids are modified in such a way as to ensure their generation closely matches their historical capacity factors.

The bids of new entrant stations is based on the forecast bids of existing stations of the same type, or on estimated marginal costs if appropriate.

B.3.1 Generation commercial data

In the development of the chosen trading strategy for each generator across the NEM, key commercial data is used, including:

- The intra-regional Marginal Loss Factor (MLF);
- Operations and maintenance cost;
- Fuel cost, which has been computed with reference to:
 - Unit heat rate;
 - Fuel heating value, and;
 - Fuel unit price;
- Emission factors for greenhouse gas production.

B.3.2 Energy constraints

Time-varying bid profiles for all hydro power stations including Hydro Tasmania, Snowy Hydro, Southern Hydro, Kareeya and Barron Gorge have been engineered to deliver production patterns corresponding to historical patterns whilst maintaining appropriate price signals. Competitive bidding strategies for pumped storage hydro plant have been developed to maintain high revenues whilst ensuring energy limitations are not violated.

B.3.3 Applying a carbon price

No carbon price has been applied in this modelling. Historical bids from 2012-13 have been analysed to remove the influence of the carbon price.

B.4 MODELLING OF RENEWABLE GENERATION

B.4.1 Wind modelling

The selected individual wind farm projects around the NEM will be included in dispatch and transmission congestion calculations on a half hourly basis.

To model the half hourly dispatch of the NEM into the future, it is important to accurately model half hourly traces of available wind power production for each wind farm. These available wind generation traces may then be curtailed at certain times when congestion occurs in the dispatch model.

Chronological profiles of wind resource are highly location specific. To account for this fact, ROAM has developed its Wind Energy Simulation Tool (WEST) to simulate the half hourly wind speeds and wind farm power generation traces on a locational resolution of 0.11 degrees in latitude and longitude (~11 km). WEST also predicts the capacity factor of a wind farm at each 11 km grid cell.

Table B.2 summarises five desirable characteristics for modelled half-hourly wind speed and generation profiles. To highlight WEST's ability to produce each desirable characteristic, the table also summarises the methodology used by WEST.

Table B.2 – Desirable characteristics for time sequential wind farm power traces

Characteristic	Reasons	WEST approach
Capture variability of wind	Wind output can vary significantly from one trading interval to another and from one location to another.	WEST uses a combination of ground-based weather station data and Numerical Weather Prediction (NWP) model forecasts to produce locational variable generation traces.
Exhibits realistic correlation with hourly demand levels on average over the year	Each wind farm exhibits a typical time of day generation profile (although day to day output can vary significantly). It is important to capture this trend and, in particular, its correlation with demand. For example, if wind power from a certain region is typically high overnight when demand is low, this may result in congestion in the power system.	WEST uses a NWP model to predict the average wind power generation for each hour of the day over the year for existing and prospective wind farms.
Exhibits realistic behaviour during extreme demand events	The contribution of wind generation during extreme demand events is important to capture from a system reliability and power system security point of view. Since extreme demand is driven by weather patterns, it is important to capture the effect these weather patterns have on wind power.	WEST uses historical hourly wind speed observations and recent NWP forecast data. This ensures the wind power traces are a direct outcome of the weather patterns during extreme demand periods.
Capture spatial correlations across multiple wind farm sites	Capturing the correlation of hourly wind power generation from multiple wind farm sites over a large spatial area is important to accurately model the power flow on transmission lines and potential congestion issues.	WEST uses a consistent data set of NWP system forecasts or ground-based weather station data to accurately capture these effects.
Model wind farm capacity factors accurately	Total wind generation contributes to meeting energy demand, and thus displaces other sources of power. This influences greenhouse gas emissions and average interconnector flows. It is therefore important for wind farm capacity factors to be modelled as accurately as possible.	An NWP system is used to predict the capacity factors for individual wind farm sites, with a de-rating for assumed turbine availability.

B.4.2 The WEST methodology

The ACCESS-A Numerical Weather Prediction system

WEST uses the Australian Bureau of Meteorology's (BOM) Numerical Weather Prediction (NWP) systems, ACCESS-A and ACCESS-R⁵². ACCESS-A/R represent the atmosphere above the Australian topography at a 0.11 degree (approximately 11 km) horizontal resolution and this defines the horizontal resolution limit for WEST. The vertical resolution varies with height (with increasing distance between grid points with increasing height) with a total of fifty vertical levels.

ACCESS-A/R are initialised every six hours based on an extensive data set of observations, including satellite-derived scatterometer wind measurements over the ocean, and ground-based observations on land.

ACCESS-A was in continuous operation from early 2010 until May 2013. ACCESS-R has been in continuous operation since early 2013. Every six hours, ACCESS-R produces forecasts at every grid point across Australia, at an hourly resolution, up to 72 hours ahead. To model wind generation based on the 2010-11 and 2011-12 reference years, WEST uses ACCESS-A forecast data and 2012-13 uses a combination of ACCESS-A and ACCESS-R. To model the reference years prior to 2010-11, WEST uses BOM weather station data (the methodology for this is described at the end of this section).

Constructing a continuous wind speed traces for a wind farm site

WEST uses the hourly wind speed forecasts from ACCESS-A/R at approximately the hub-height of wind turbines above the earth's surface. A continuous hourly wind speed trace for a year is extracted for a representative grid point for each wind farm site by combining the forecasts using the method illustrated in Figure B.1. The preferred range of projection times is four to nine hours. This range achieves a trade-off between forecasts losing accuracy with increased projection time, and allowing for some model 'spin-up time'⁵³. It is not always possible to use data from within the preferred projection time range because of occasional missing forecasts as demonstrated in Figure B.1.

⁵² Australian Bureau of Meteorology, 2010, *ACCESS NWP data website and Operations Bulletin 83, October 2010* plus updated website. Available at: <http://www.bom.gov.au/nwp/doc/access/NWPData.shtml>

⁵³ As NWP system forecasts are initialised from real-world observations, the observations may not correspond well with each other on the NWP model grid. NWP systems usually require about four hours of simulated time ('spin-up time') for perturbations from these real-world observations to stabilise, reducing the forecast accuracy over the first four hours.

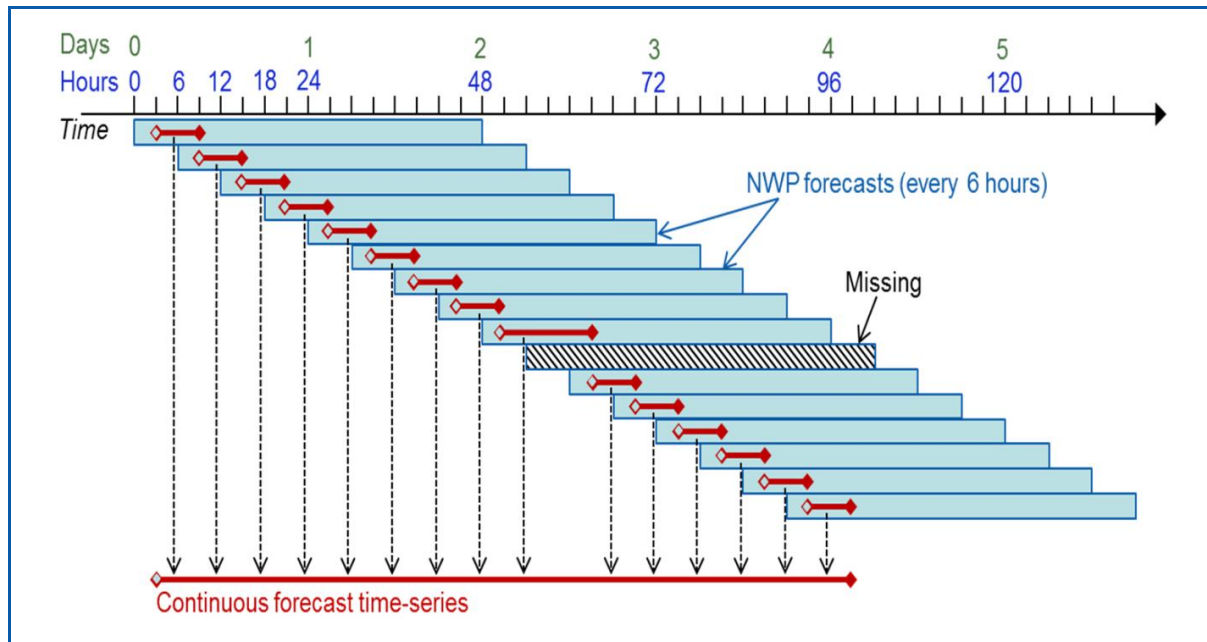


Figure B.1 – Constructing a continuous generation trace from ACCESS-A NWP forecasts

Converting an hourly wind speed trace to wind power

ACCESS-A/R continuous wind speed traces are scaled by a wind speed scaling factor, f , before transforming them with a wind farm power curve to get an hourly wind farm power trace.

The wind farm power curve used is based on the power generation from an existing wind farm which has broadly similar characteristics to the power curves for other existing wind farms in Australia. This power curve, C , is scaled so that its maximum is 0.95 in order to represent a 1 MW wind farm, taking turbine unavailability and wake effects into account. Converting wind speeds to wind power with this power curve produces a '1 MW wind trace' of wind power, which can then be scaled to the rated capacity of the wind farm it represents.

The scaling factor, f , is estimated with an equation derived by training on the observed capacity factors from existing Australian wind farms over 2010-11, 2011-12 and 2012-13.

The wind power generation, P , is obtained by multiplying the wind speed, W , by the scaling factor, f , and then converting it to power through the power curve, $C\{\}$, as described in equation (3).

$$P = C\{W \times f\} \quad (3)$$

Calculating annual capacity factor

The annual capacity factor is the average power generation of a power plant over a year as a percentage of its rated capacity. This is calculated directly from the power trace produced using equation (3).

B.4.3 Benchmarking the WEST model

A wind farm's capacity factor is highly dependent on the wind resource at its location and is one of the most important factors determining its financial viability as a generation asset. WEST was trained on the actual capacity factors for 27 wind farms across Australia from Woolnorth in Tasmania to Walkaway in Western Australia (the years used depend on data availability). The five-minute generation from each wind farm was scanned in detail to remove abnormal outages and curtailments to estimate a capacity factor representative of the meteorological conditions of the site, along with the typical operational performance of the turbines, including an average turbine availability. These 'observed' capacity factors and the WEST predictions for each wind farm and financial year are shown in Figure B.2.

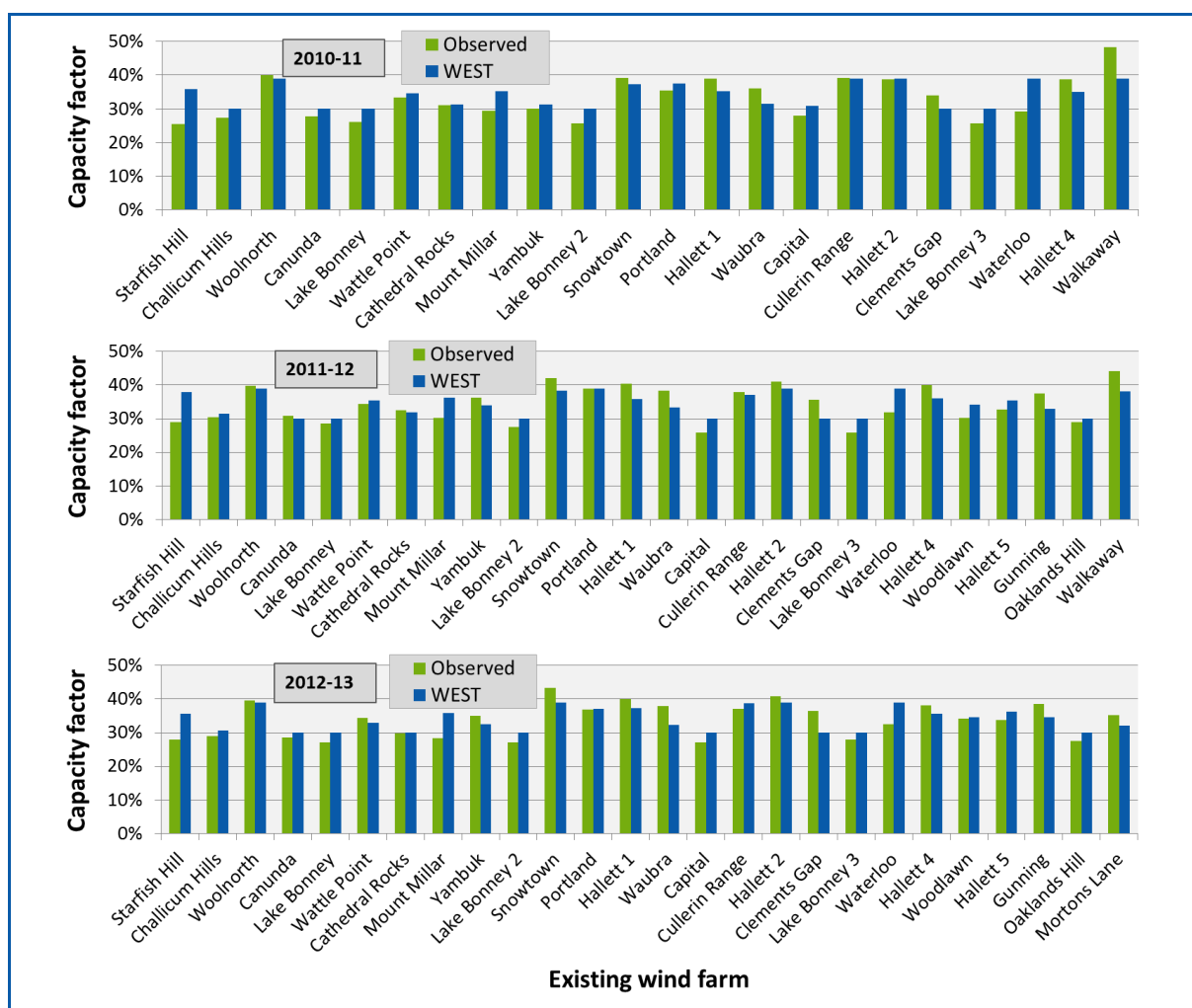


Figure B.2 – Observed capacity factors and WEST predictions on 2010-11, 2011-12 and 2012-13

In summary, 57% of the capacity factors predicted by WEST are within $\pm 3\%$ of rated capacity. The error is within $\pm 5\%$ for 80% of the wind farms and the largest error is 10% for one of the wind farms. The capacity factor prediction is within 0.5% on average across all the existing wind farms. This result has been analysed over smaller regions and demonstrates similar success in predicting the average capacity factor.

Time-of-day averages

The time-of-day generation profile for wind farms is especially important for modelling the interaction of wind generation and electricity prices, and consequently, wind farm spot market revenues. Figure B.3 compares the WEST time-of-day targets with observations for six existing wind farms. The charts show that WEST can predict the quantitative differences in the time-of-day average generation for wind farm sites with high accuracy.

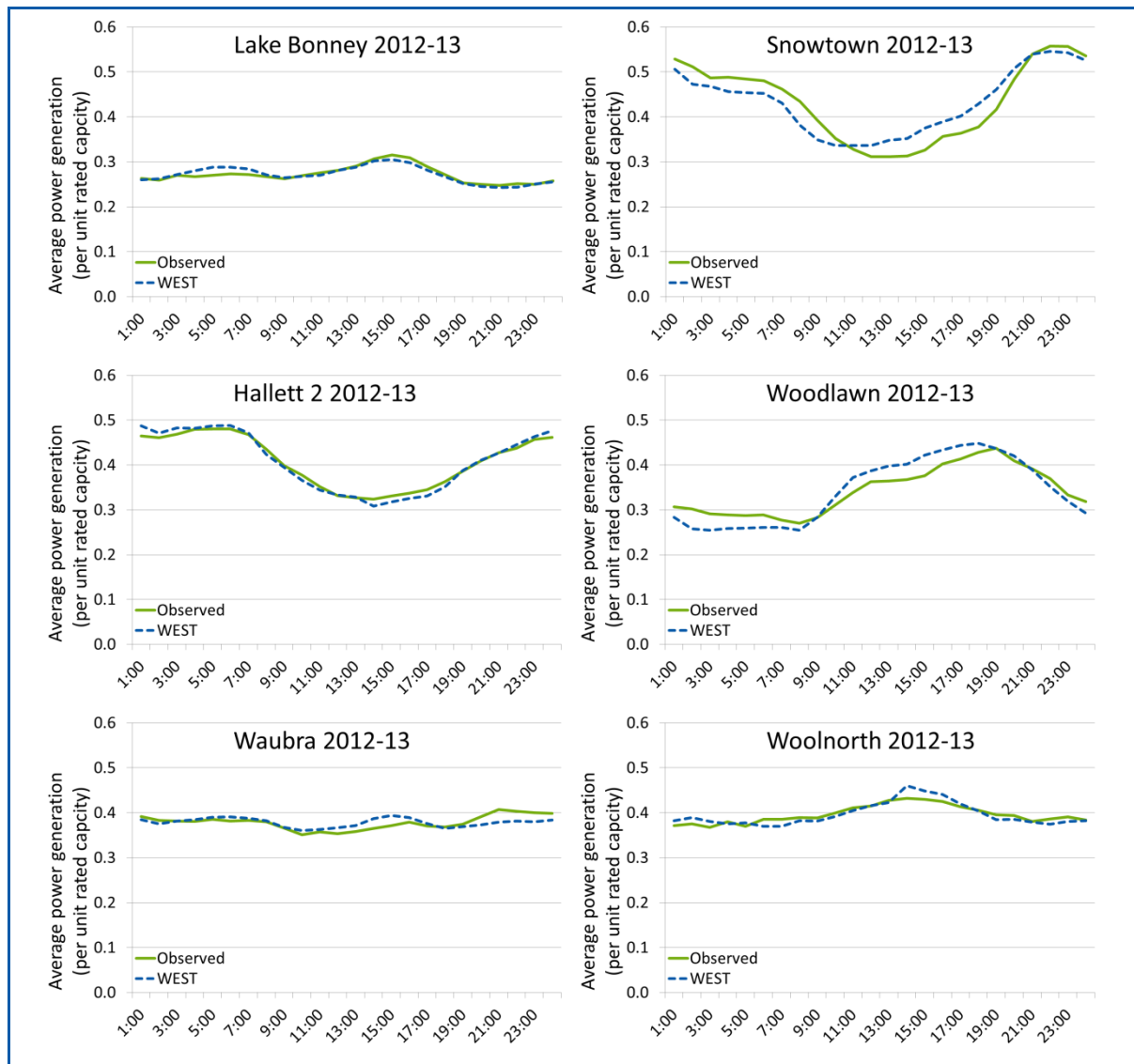


Figure B.3 – Comparison of WEST time-of-day targets and observations for six existing wind farms

An example comparison of wind farm generation traces and the WEST prediction

As another benchmarking exercise, ROAM compared the historical generation profile of Snowtown wind farm with a generation profile developed using WEST. Figure B.4 shows an example five day period where the variability in Snowtown's generation is captured very well by WEST.

23 May 2014

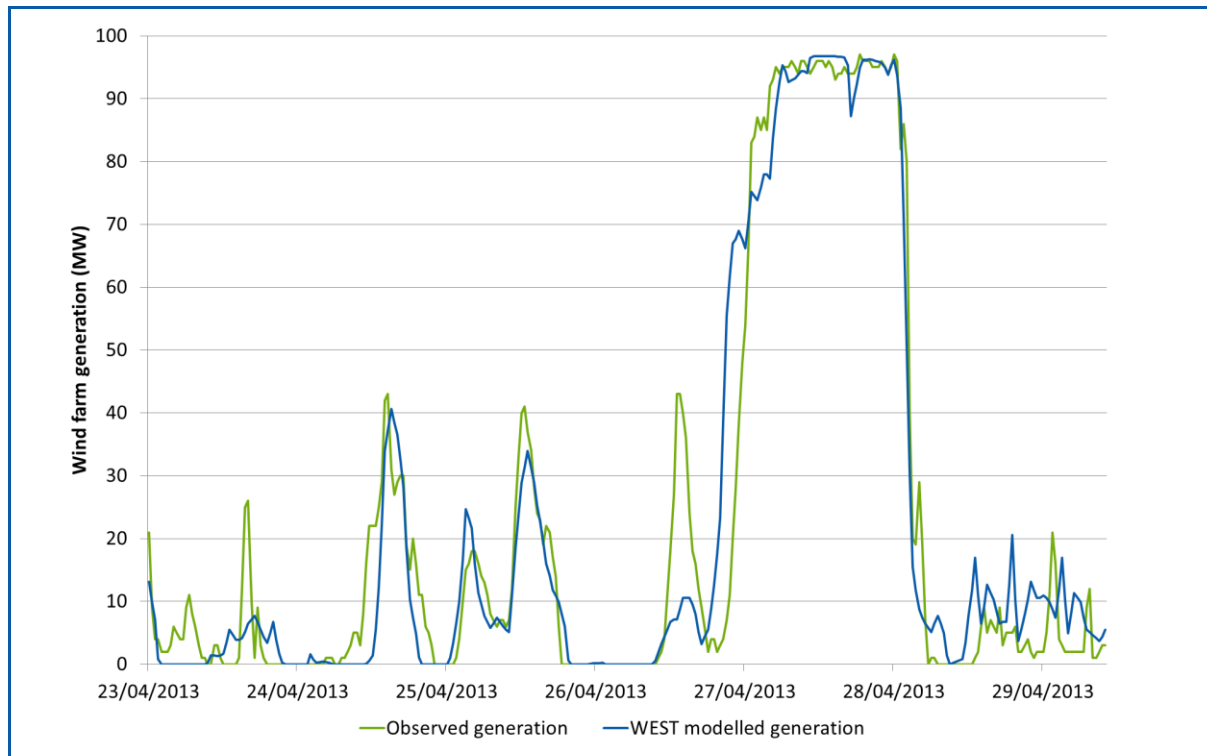


Figure B.4 – An example of a six-day period of WEST half-hourly wind farm generation compared with the observed generation for Snowtown wind farm

B.4.4 Producing hourly traces for years prior to the ACCESS-A model data

As mentioned above, WEST used the BOM weather station wind speed measurements to model the reference years prior to 2010-11. The locations of the stations in eastern Australia are shown in Figure B.5.

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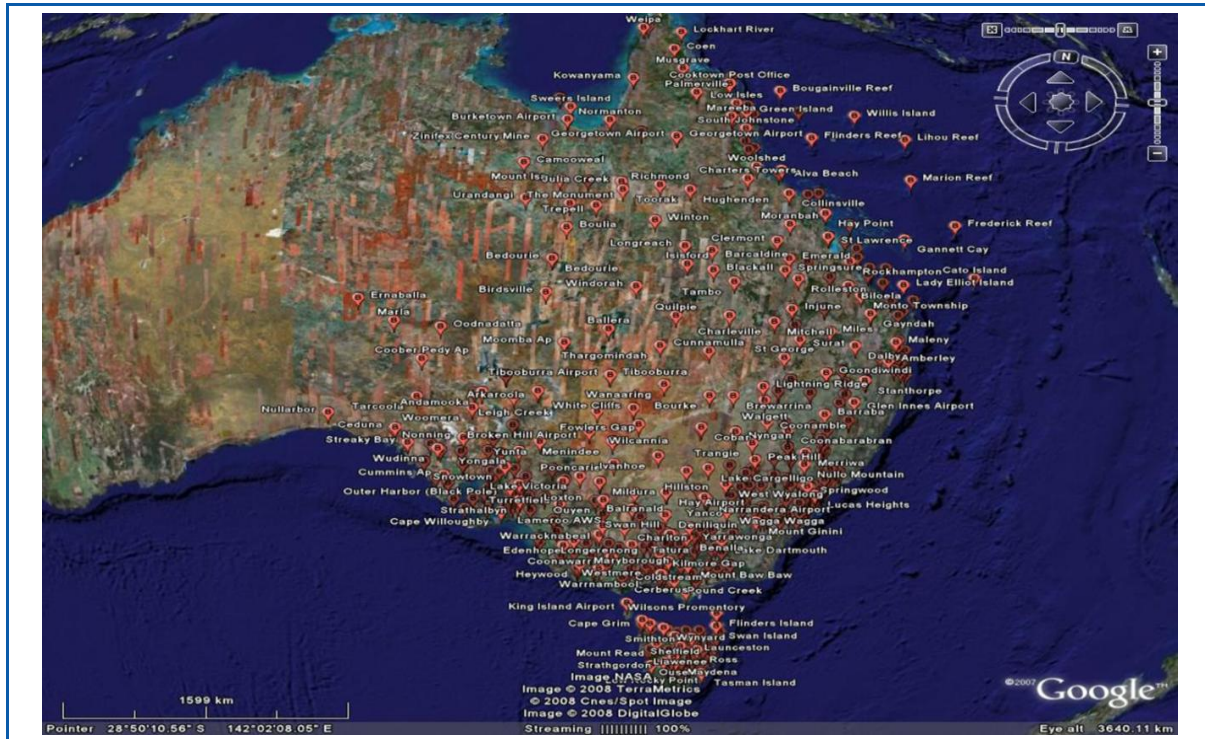


Figure B.5 – Locations of BOM weather stations

The WEST methodology to produce an hourly wind power generation trace using BOM weather station data is as follows.

Step 1: Select a nearby automatic weather station to obtain an hourly trace of wind speed observations to represent the wind farm site.

The wind speed data from the weather stations is taken at a variety of elevations (from 1 m off the ground to 70 m above the ground), and elevation strongly affects wind speeds. The wind at the height of a turbine hub (from 50 m to 80 m) will be much stronger than the wind at ground level, and the amount of increase in speed is strongly dependent upon many factors, including the type of ground cover (rock, grass, shrubs, trees) and the nature of the weather pattern causing the wind. In addition, the local topography affects wind speeds very strongly (for example, winds tend to be focused by flowing up hillsides). The wind speed at a weather station perhaps 30 km away from a wind farm is likely to be correlated strongly in time with the wind at the site of the turbines, but the absolute scaling of the speeds is highly uncertain.

Step 2: Scale the wind speed observations to target the wind farm capacity factor and time-of-day profiles predicted by WEST for 2010-11 and 2011-12.

As with the ACCESS-A wind speeds, the BOM weather station wind speeds are scaled by a factor, f , and then converted to wind power using a representative wind farm power curve. However, to achieve an hourly trace with the target time-of-day profile for the years prior to 2010-11, WEST uses a different scaling factor for each hour of the day. The particular time-of-day profile on any given day is driven by the observed variations in the

BOM weather station wind speeds as well as subtle variations in the wind speed scaling factor from hour to hour.

B.5 SOLAR PHOTOVOLTAIC AND SOLAR THERMAL MODELLING

As for wind, it is also important to accurately model half hourly traces of available solar power production as each solar project location.

B.5.1 Solar data

Solar data is derived from satellite imagery processed by the BOM from the Geostationary Meteorological Satellite and MTSAT series operated by Japan Meteorological Agency and from GOES-9 operated by the National Oceanographic & Atmospheric Administration for the Japan Meteorological Agency, based on updated analysis by BOM as of August 2012.

This data is in the form of hourly global horizontal irradiance (GHI) and direct normal irradiance (DNI) values for the whole of Australia at approximately 5 km resolution. For each grid cell, brightness data was obtained by the BOM from visible images taken by geostationary meteorological satellites and a detailed model involving surface albedo and atmospheric conditions was used to convert this to GHI. An atmospheric model was then used by the BOM to separate out the DNI and diffuse components. Finally, a bias correction method was applied based on comparison with ground-based radiation observations from the BOM's radiation monitoring network. Where necessary, ROAM has applied appropriate filtering and error correction to the data to correct any bad data periods; in particular, missing data are filled in with the output from the corresponding hour of the previous day.

Estimates from the BOM suggest an annual mean bias difference in the GHI data of -4 to +2 W/m², with root mean square differences of around 100 W/m², or around 23% of the mean irradiance. In DNI, this RMS difference may be as high as -20 to 18 W/m², depending on the year and the fact that point-in-time snapshots may not be representative of the full hour. Therefore, while this data does not replace the need for ground-based observations, the observations by BOM and ROAM's own comparison with ground-based data (where available) suggest that the satellite data provides a reasonable estimate of solar resource for planning and scoping purposes.

B.5.2 System Advisor Model (SAM)

Historical hourly solar insolation data is converted into generation traces for each proposed solar plant by ROAM using SAM, a widely used tool published by the National Renewable Energy Laboratory. It allows for detailed modelling of various types of power plants, with a particular focus on solar technologies. The models employed by SAM are sophisticated and, with the right input parameters, produce accurate models of physical plant operation. For solar PV plants, SAM includes modelling of the temperature sensitivity of panels and the inverter efficiency over a range of currents, while for solar thermal plants it includes explicit heat flow modelling around the plant.

SAM generally uses typical meteorological year (TMY) weather files, obtainable for Australian locations from the U.S. Department of Energy⁵⁴. However, these “typical” years (composited from many different reference years) would not preserve the historical correlations between solar generation, demand and wind in ROAM’s modelling. ROAM will therefore create appropriate “EPW” (Energy Plus Weather) format input files based on the BOM solar data extracted for the specific location of each plant and the reference year of interest. These weather files will also incorporate additional data (necessary for solar modelling) from the BOM such as temperature, pressure and wind speed data from the nearest Automatic Weather Station to the site. This will ensure that solar generation in every period is based on the same weather conditions used when constructing wind generation and demand.

In general, in the absence of specific plant information, ROAM will use “typical” design values for each technology (flat plate PV, compact linear Fresnel reflector, etc.) based on either the default SAM values or ROAM’s view of likely parameters if different in the Australian context. Estimates of forced and planned outages, as well as soiling effects averaged over the plant life, are also included.

B.6 BIDDING OF RENEWABLE GENERATORS

Variable renewable generators (wind and solar PV) were bid at \$0/MWh.

B.7 TRANSMISSION AND DISTRIBUTION SYSTEM ASSUMPTIONS

B.7.1 Transmission network constraints

2-4-C performs a dispatch under transmission constraint equations published by AEMO, as well as additional constraint equations developed by ROAM to reflect the changing network over time. In particular, constraints will be relaxed to account for transmission upgrades necessary under the generation expansion plan.

These transmission constraint equations reflect the system normal state of the transmission network, and therefore they represent the most suitable transmission representation for the majority of trading intervals. It should be noted that at any time these limits may not reflect the limits during non-system normal conditions, such as extreme heat waves, bushfires or electrical storms. As such, we believe these results represent the most accurate representation of the transmission network that is feasible to model, particularly over the long term, but that reduced transmission limits due to unplanned outages will occur from time to time which will have an impact on the market.

⁵⁴ U.S. Department of Energy, 2013, *Weather* data. Available at:
http://apps1.eere.energy.gov/buildings/energyplus/cfm/weather_data.cfm.

B.7.2 Transmission losses

Losses are modelled commercially in either of two ways, in accordance with existing market rules. Treatment is as follows.

Inter-regional losses

Inter-regional losses over AC interconnectors are modelled using dynamic loss equations supplied by AEMO.

Intra-regional losses

Intra-regional losses are modelled by static, but periodically adjusted, Marginal Loss Factors in relation to a Regional Reference Node (RRN). These MLF's are published annually by AEMO (and assumed for new stations).

Market forecasting has been completed on a gross basis. Therefore, the energy profiles assumed for each node have incorporated allowance for (transmission and distribution) losses and generator auxiliary energy.

B.7.3 Transmission limits

For each of the links between the nodes defined in the 2-4-C model, bi-directional limits are dynamically calculated based on the most recent publicly available set of transmission limit equations incorporated in the NTNDP data set. This data has been added on the basis of information provided within the relevant planning documentation listed as references in the previous section.

B.7.4 Transmission asset development

The ANTS constraint equations supplied by AEMO assume some limited transmission asset development over time, accounting for minor upgrades. However, they do not include significant transmission development that will be necessary over longer modelling timeframes. To account for this, in longer studies ROAM may 'switch off' a given constraint equation at the point in the study where a significant transmission upgrade is clearly required. From that point onwards, notional transmission limits are applied to the various inter-regional transmission network flow paths, as listed in Table B.3.

Table B.3 – Notional Transmission Line Limits⁵⁵

From region	To region	Interconnector limit (MW)			
		Summer peak	Summer off-peak	Winter peak	Winter off-peak
QLD	NSW	1078	1078	1078	1078

⁵⁵ AEMO, List of Regional Boundaries and Marginal Loss Factors for the 2011-12 Financial Year.

From region	To region	Interconnector limit (MW)			
		Summer peak	Summer off-peak	Winter peak	Winter off-peak
NSW	QLD	400	550	400	550
NSW	VIC	1900 minus Murray Generation	1900 minus Murray Generation	1900 minus Murray Generation	1900 minus Murray Generation
VIC	NSW	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation
VIC	SA	460	460	460	460
SA	VIC	460	460	460	460
Murraylink VIC	SA	220	220	220	220
Murraylink SA	VIC	188 minus North West Bend & Berri loads	198 minus North West Bend & Berri loads	215 minus North West Bend & Berri loads	215 minus North West Bend & Berri loads
Terranora Interconnector QLD	NSW	220	220	220	220
Terranora Interconnector NSW	QLD	122	122	122	122
Basslink VIC	TAS	478	478	478	478
Basslink TAS	VIC	594	594	594	594

B.7.5 Terranora (Gold Coast to Armidale interconnector)

Terranora is modelled as a regulated market scheduled interconnector. As the High-Voltage DC link is controllable it will be dispatched to maximise inter-regional competition if this is the optimal dispatch outcome.

B.7.6 Murraylink (Melbourne to South Australia interconnector)

Murraylink is modelled as a regulated market scheduled interconnector. Murraylink is dispatched in a similar way to Terranora as described above.

B.7.7 Basslink (Latrobe Valley to Tasmania interconnector)

Basslink is modelled as a bi-directional interconnector. The bidding profile allows for transfers of energy from Tasmania to Victoria during peak times and from Victoria to Tasmania during off-peak times.

B.8 *MARKET DEVELOPMENT ASSUMPTIONS*

Several assumptions are made about the development of the market.

B.8.1 Market Price Cap

The Market Price Cap (MPC) was set at \$13,100/MWh in real terms.

B.9 *ASSUMPTIONS WITH REGARD TO MARKET EXTERNALITIES*

There are numerous externalities that will impact on the operation of the competitive energy market. Several of these are outlined below.

B.9.1 Inflation

All monetary figures provided in this report are listed in equivalent June 2013 dollars (net of the impact of inflation), unless indicated otherwise.

B.9.2 The impact of the Goods and Services Tax

Wholesale market prices are quoted exclusive of the Goods and Services Tax (GST). Hence, projections of the wholesale spot price are provided net of GST.